BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of	**DOCKET NO. 990001-EI**
Fuel and purchased power cost recovery clause and generating performance incentive factor.	

VOLUME 3

Pages 279 through 523

PROCEEDINGS: **HEARING**

BEFORE: COMMISSIONER J. TERRY DEASON
COMMISSIONER SUSAN F. CLARK
COMMISSIONER E. LEON JACOBS, Jr.

DATE: **Tuesday, November 23, 1999**

TIME: Commenced at 9:00 a.m.

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

REPORTED BY: KIMBERLY K. BERENS, CSR, RPR
FPSC Commission Reporter

APPEARANCES:

(As heretofore noted.)

Also Present:

David Wheeler, FPSC Staff

Elisabeth Draper, FPSC Staff

Tom Ballinger, FPSC Staff

Todd Bohrmann, FPSC Staff

Pat Lee, FPSC Staff

I N D E X

WITNESSES

EXHIBITS

NUMBER		ID.	ADMTD.
23	TAD-1	303	303
24	TAD-2	303	303
25	MWH-1	334	368
26	Gulf's response to Staff's first set of interrogatories	341	368
27	KOZ-1	380	401
28	Correction Sheet	380	401
29	Composite Exhibit	395	401
30	TLH-1	424	501
31	TECO's Response to Staff's First Set of Interrogatories No. 10	471	501
32	Composite exhibit	513	522
33	Staff's Second Set of Interrogatories Nos. 21-27	522	523

P R O C E E D I N G S

(Hearing convened at 9:35 a.m.)

COMMISSIONER DEASON: Call the hearing to order. Can I have the Notice read, please.

MR. KEATING: Pursuant to Notice issued September 22, 1999 this time and place have been set for a hearing in Docket No. 990001-EI, Fuel and Purchased Power Cost Recovery Clause and Generating Performance Incentive Factor; Docket No. 990002-EG, Energy Conversation Cost Recovery Clause; Docket No. 990003-GU, Purchased Gas Adjustment True-up; and Docket No. 990007-EI, Environmental Cost Recovery Clause.

COMMISSIONER DEASON: Thank you. We are going to take appearances in just a moment. Let me ask Staff, are we going to take appearances for all the dockets at this time?

MR. KEATING: I think that's how we've done it.

COMMISSIONER DEASON: And then parties will indicate on which dockets they are appearing?

MR. KEATING: Yes.

COMMISSIONER DEASON: Very well. We'll take appearances.

MR. BURGESS: I'm Steve Burgess here on behalf of the Public Counsel's Office representing the Citizens of the State of Florida in all the dockets before the Commission.

MR. PALECKI: Michael Palecki on behalf of City Gas Company of Florida, 3111 Mahan Drive, Tallahassee, Florida in the 002 and 003 dockets.

MR. MCGEE: James McGee on behalf of Florida Power Corporation in the 01 and 02 dockets.

MS. KAUFMAN: John McWhirter and Vicki Gordon Kaufman of the McWhirter Reeves law firm on behalf of the Florida Industrial Power Users Group in the 01, 02 and 07 dockets.

MR. CHILDS: Matthew M. Childs with the firm of Steel, Hector and Davis appearing on behalf of Florida Power & Light Company in the 01 and 07 dockets.

MR. STONE: Jeffrey A. Stone and together with me is Russell A. Badders of the law firm of Beggs and Lane, Pensacola, and we're appearing in the 01, 02 and 07 dockets.

MR. WILLIS: Lee L. Willis together with James D. Beasley and Kenneth R. Hart of Ausley & McMullen, P.O. Box 391, Tallahassee, Florida 32302 appearing on behalf of Tampa Electric Company in the 01, 02 and 07 dockets.

MR. KEATING: Cochran Keating appearing on behalf of the Commission Staff in the 01 and 03 dockets.

MS. JAYE: Grace Jaye appearing on behalf of Commission Staff in the 02 and 07 dockets.

COMMISSIONER DEASON: And there are a number of other parties who have been excused from this proceeding because all issues have been stipulated; is that correct?

MR. KEATING: I believe so.

COMMISSIONER DEASON: Very well.

* * * * *

COMMISSIONER DEASON: Call the hearing to order.

MR. STONE: Thank you, Commissioner. Would Ms. Davis please take the stand.

MR. KEATING: Mr. Stone, at this point Staff had had questions for Ms. Davis unless -- if the other parties don't, at this time I think we can stipulate her testimony into the record.

COMMISSIONER DEASON: Do any of the other parties have questions for Ms. Davis? Very well.

MR. STONE: With that, Commissioner, I would ask that we insert Ms. Davis' testimony into the record as though read.

COMMISSIONER DEASON: Somebody is smiling really large. Anyway, go ahead.

MR. STONE: We have two sets of testimony of Ms. Davis to insert into the record. She has an April 1, 1999 set consisting of six pages and an October 1, 1999 set consisting of ten pages. Those would represent the final true-up and the projection filings.

COMMISSIONER DEASON: And you move that testimony at this time?

MR. STONE: Yes, I do.

COMMISSIONER DEASON: Without objection, show then that both sets of testimony will be inserted into the record.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Terry A. Davis
Docket No. 990001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: April 1, 1999

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in Accounts Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I participated in activities related to the cost recovery clauses, budgeting, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and coordination of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail tariff, and review of other regulatory filings submitted by the Company.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes, I have.

Counsel: We ask that Ms. Davis' Exhibit consisting of four schedules be marked as Exhibit No. 23 (TAD-1).

Q. Are you familiar with the Fuel and Purchased Power (Energy) true-up calculations for the periods of April 1998 through September 1998 and October 1998 through December 1998 and the Purchased Power Capacity Cost true-up calculations for the periods of October 1997 through September 1998 and October 1998 through December

1998 set forth in your exhibit?
A. Yes. These documents were prepared under my direction.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?
A. Yes, I have.

Q. What is the amount to be refunded or collected through the fuel cost recovery factor in the period January 2000 through December 2000?
A. A net amount to be collected of $2,450,200 was calculated as shown on Schedule 1, page 1 of my exhibit. This includes $2,694,132 to be collected for April 1998 through September 1998 as shown on page 2 of Schedule 1 and $243,932 to be refunded for October 1998 through December 1998 as shown on page 3 of Schedule 1.

Q. How were these amounts calculated?
A. The $2,694,132 was calculated by taking the difference in the estimated April 1998 through September 1998 under-recovery of $3,743,611 and the actual under-recovery of $6,437,743, which is the sum of the Period-to-Date amounts on lines 7 and 8 shown on Schedule A-2, page 2, of the monthly filing for September 1998. The

$243,932 was calculated by taking the difference in the estimated October through December 1998 over-recovery of $456,058 and the actual over-recovery of $699,990, which is the sum of lines 7 and 8 shown on Schedule A-2, page 2, Period-to-Date of the monthly filing for December 1998. The estimated true-up amounts for these periods were approved in Order No. PSC-98-1715-FOF-EI dated December 18, 1998. Additional details supporting the approved estimated true-up amounts are included on Schedule E1-A filed October 12, 1998.

Q. Ms. Davis, you stated earlier that you are responsible for the Purchased Power Capacity Cost true-up calculation. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedules CCA-1, CCA-2, and CCA-3 of my exhibit relate to the Purchased Power Capacity Cost true-up calculation for the periods October 1997 through September 1998 and October 1998 through December 1998.

Q. What is the amount to be refunded or collected in the period January 2000 through December 2000?

A. An amount to be refunded of $81,124 was calculated as shown in Schedule CCA-1, page 1, of my exhibit. This includes $95,729 to be collected for October 1997 through September 1998 as shown on page 2 of Schedule CCA-1 and $176,853 to be refunded for October 1998 through December 1998 as shown on page 3 of Schedule CCA-1.

Q. How were these amounts calculated?
A. The $95,729 was calculated by taking the difference in the estimated October 1997 through September 1998 under-recovery of $2,467,419 and the actual under-recovery of $2,563,148, which is the sum of lines 11 and 12 under the total column of page 1 of Schedule CCA-2. The $176,853 was calculated by taking the difference in the estimated October through December 1998 under-recovery of $1,237,526 and the actual under-recovery of $1,060,673, which is the sum of lines 11 and 12 under the total column of page 2 of Schedule CCA-2. The estimated true-up amounts for these periods were approved in Order No. PSC-98-1715-FOF-EI dated December 18, 1998. Additional details supporting the approved estimated true-up amounts are included on Schedule CCE-1A filed October 12, 1998.

Q. Please describe Schedules CCA-2 and CCA-3 of your exhibit.
A. Schedule CCA-2 page 1 shows the calculation of the

actual under-recovery of purchased power capacity costs for the period October 1997 through September 1998 and Schedule CCA-2 page 2 shows the calculation of the under-recovery for the period October 1998 through December 1998. Schedule CCA-3 of my exhibit is the calculation of the interest provision on the under-recoveries. Schedule CCA-3 page 1, reflects the period October 1997 through September 1998; and Schedule CCA-3 page 2, reflects the period October 1998 through December 1998. This is the same method of calculating interest that is used in the Fuel and Purchased Power (Energy) Cost Recovery Clause and the Environmental Cost Recovery Clause.

Q. Ms. Davis, does this complete your testimony?
A. Yes, it does.

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony of
Terry A. Davis
Docket No. 990001-EI
Fuel and Purchased Power Cost Recovery
Date of Filing: October 1, 1999

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in Accounts

Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I participated in activities related to the cost recovery clauses, budgeting, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and coordination of the Company’s Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf’s retail tariff, and review of other regulatory filings submitted by the Company.

Q. Have you previously filed testimony before this Commission in Docket No. 990001-EI?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period January 2000 through December 2000. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2000 through December 2000.

Q. Are you familiar with the Fuel and Purchased Power Cost Recovery Clause Calculation for the period of January 2000 through December 2000?

A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Counsel: We ask that Ms. Davis's Exhibit consisting of fourteen schedules, be marked as Exhibit No. 24 (TAD-1).

Q. Ms. Davis, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2000 through December 2000?

A. The fuel cost recovery true-up for this period is an increase of .1373¢/kwh. As shown on Schedule E-1A, this includes a final under-recovery for the April through September 1998 period of $2,694,132, plus a final over-recovery for October through December 1998 period of $243,932, plus the estimated under-recovery of $11,302,259 for January through December 1999 period. The resulting under-recovery is $13,752,459.

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of April 1998 through December 1998?
A. This is shown on Line 32b of Schedule E-1 as a decrease of .0004¢/kwh, thereby penalizing Gulf by $36,679.

Q. Ms. Davis, what is the levelized projected fuel factor for the period January 2000 through December 2000?
A. Gulf has proposed a levelized fuel factor of 1.950¢/kwh. It includes projected fuel and purchased power energy expenses for January 2000 through December 2000 and projected kwh sales for the same period, as well as the true-up and GPIF amount. The levelized fuel factor has not been adjusted for line losses.

Q. How does the levelized fuel factor for the projection period compare with the levelized fuel factor for the current period?
A. The projected levelized fuel factor for 2000 is .288 cents/kwh more or 17.3% higher than the levelized fuel factor for 1999 upon which current fuel factors are based. This increase exceeds the threshold outlined in Order No. PSC-98-0049-FOF-EI dated January 7, 1998. Most of this increase is due to an increase in the price of net purchases and sales of energy. A much smaller

part of this increase is due to increased costs for fuel. Mr. Howell and Mr. Oaks will elaborate on the causes of these increases in their testimonies.

Q. Ms. Davis, how were the line loss multipliers used on Schedule E-1E calculated?

A. They were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest mwh Load Flow Allocators.

Q. Ms. Davis, what fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, OSIII, and OSIV?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 1.974¢/kwh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have also been adjusted for line losses.

Q. Ms. Davis, how were the time-of-use fuel factors calculated?

A. These were calculated based on projected loads and system lambdas for the period January 2000 through December 2000. These factors included the GPIF and true-up, and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 1999 and how would the change affect the cost of 1000 kwh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable through December 1999 is 1.682¢/kwh compared with the proposed factor of 1.974¢/kwh. For a residential customer who uses 1000 kwh in January 2000, the fuel portion of the bill would increase from $16.82 to $19.74.

Q. Ms. Davis, has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984, in Docket No. 830377-EI and Order No. 19548 issued June 21, 1988, in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my Exhibit TAD-1. These costs represent the estimated averages for the period from January 2000 through December 2001.

Q. Ms. Davis, you stated earlier that you are responsible for the calculation of the purchased power capacity cost (PPCC) recovery factors. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedule CCE-1, including CCE-1a and CCE-1b, and Schedule CCE-2 of my exhibit relate to the calculation of the PPCC recovery factors for the period January 2000 through December 2000.

Q. Please describe Schedule CCE-1 of your exhibit.

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the PPCC Recovery Clause. Mr. Howell has provided me with Gulf's projected purchased power capacity transactions under the Southern Company Intercompany Interchange Contract (IIC), Gulf's contract with Solutia, and certain market capacity transactions. Gulf's total projected capacity payments for the period January 2000 through December 2000 are purchases of $12,729,433. The jurisdictional amount is $12,281,702. For the projection period, Gulf's requested recovery before true-up is the difference between the jurisdictional projected purchased power capacity costs and the approved adjustment for former capacity transactions embedded in current base rates. This adjustment amount was fixed in Order No. PSC-93-0047-FOF-EI, dated January 12, 1993, as an annual embedded credit of $1,678,580, or $1,652,000 net of revenue taxes. Thus, the projected recovery amount that would be collected through the PPCC recovery factors in the period January 2000 through December 2000 is $13,933,702. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2000 through December 2000?

A. The true-up for this period is a decrease of $68,182 as shown on Schedule CCE-1a. This includes an estimated under-recovery of $12,942 for January 1999 through December 1999. It also includes a final true-up under-recovery of $95,729 for the period of October 1997 through September 1998, plus a final true-up over-recovery for the period of October through December 1998 of $176,853. The resulting over-recovery is $68,182.

Q. What methodology was used to allocate the capacity payments to rate class?

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology used in Gulf's last full requirements rate case and approved by the Commission in Order No. 23573 issued October 3, 1990, in Docket No. 891345-EI. Although the capacity payments in that cost of service study were allocated to rate class using the demand allocator based on the twelve monthly coincident peaks projected for the test year, for purposes of the PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs to rate class with 12/13th on demand and 1/13th on energy. This allocation is consistent with the treatment accorded to production plant in the cost of service study used in Gulf's last rate case.

Q. How were the allocation factors calculated for use in the PPCC Recovery Clause?

A. The allocation factors used in the PPCC Recovery Clause have been calculated using the 1997 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The calculations of the allocation factors are shown in columns A through I on Page 1 of Schedule CCE-2.

Q. Please describe the calculation of the cents/kwh factors by rate class used to recover purchased power capacity costs.

A. As shown in columns A through D on page 2 of Schedule CCE-2, the 12/13th of the jurisdictional capacity cost to be recovered is allocated to rate class based on the demand allocator, with the remaining 1/13th allocated based on energy. The total revenue requirement assigned to each rate class shown in column E is then divided by that class's projected kwh sales for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each customer's total kwh to calculate the amount to be billed each month.

Q. What is the amount related to purchased power capacity costs recovered through this factor that will be included on a residential customer's bill for 1000 kwh?

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1000 kwh will be $1.67.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?

A. The fuel and capacity factors will be effective beginning with the first Bill Group for January 2000 and continuing through the last Bill Group for December 2000.

Q. Ms. Davis, does this complete your testimony?

A. Yes, it does.

MR. STONE: She also has two exhibits. The exhibit attached to her final true-up testimony dated April 1, 1999 is marked as TAD-1. It consists of four schedules. And then her schedules attached to her projection testimony we have designated in the prehearing order as TAD-2 and it consists of 40 pages of schedules and we would ask that those be marked as exhibits or as a composite exhibit and however the Commission prefers.

COMMISSIONER DEASON: The April exhibits, TAD-1, will be identify as Exhibit 23 and TAD-2, will be identified as Exhibit 24. And you move those at this time?

MR. STONE: Yes, I do.

COMMISSIONER DEASON: Without objection. Hearing no objection, show then Exhibits 23 and 24 are admitted.

(Exhibits 23 and 24 marked for identification and received in evidence.)

MR. STONE: With that we call Mr. Howell to the stand.

WITNESS HOWELL: Good morning.

M.W. HOWELL

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

DIRECT EXAMINATION

BY MR. STONE:

Q Would you please identify yourself for the record?

A My name is M.W. Howell. I'm a transmission and system control manager for Gulf Power Company.

Q Mr. Howell, were you sworn yesterday when the witnesses were sworn?

A Yes.

Q Are you the same M.W. Howell who prefiled direct testimony dated April 1, 1999 consisting of 10 pages?

A Yes.

Q Are you also the same M.W. Howell who prefiled direct testimony dated October 1, 1999, consisting of 18 pages?

A Yes.

Q If I were to ask you the questions contained in those two sets of testimony, would your answers be the same?

A Yes.

Q You have no changes or corrections to those two prefiled sets of testimony?

A No changes.

MR. STONE: I would ask that those two sets of testimony be inserted into the record at though read.

COMMISSIONER DEASON: Without objection, they shall be so inserted.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 990001-EI
Date of Filing: April 1, 1999

Q. Please state your name, business address and occupation.
A. My name is M. W. Howell, and my business address is One Energy Place, Pensacola, Florida 32520. I am Transmission and System Control Manager for Gulf Power Company.

Q. Have you previously testified before this Commission?
A. Yes. I have testified in various rate case, cogeneration, territorial dispute, planning hearing, fuel clause adjustment, and purchased power capacity cost recovery dockets.

Q. Please summarize your educational and professional background.
A. I graduated from the University of Florida in 1966 with a Bachelor of Science Degree in Electrical Engineering. I received my Masters Degree in Electrical Engineering from the University of Florida in 1967, and then joined Gulf Power Company as a Distribution Engineer. I have since served as Relay Engineer, Manager of Transmission,

Manager of System Planning, Manager of Fuel and System Planning, and Transmission and System Control Manager. My experience with the Company has included all areas of distribution operation, maintenance, and construction; transmission operation, maintenance, and construction; relaying and protection of the generation, transmission, and distribution systems; planning the generation, transmission, and distribution systems; bulk power interchange administration; overall management of fuel planning and procurement; and operation of the system dispatch center.

I am a member of the Engineering Committees and the Operating Committees of the Southeastern Electric Reliability Council and the Florida Reliability Coordinating Council, and have served as chairman of the Generation Subcommittee of the Edison Electric Institute System Planning Committee. I have served as chairman or member of many technical committees and task forces within the Southern electric system, the Florida Electric Power Coordinating Group, and the North American Electric Reliability Council. These have dealt with a variety of technical issues including bulk power security, system operations, bulk power contracts, generation expansion, transmission expansion, transmission interconnection requirements, central dispatch, transmission system operation, transient stability, underfrequency operation, generator underfrequency protection, and system production costing.

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

A. I will summarize Gulf Power Company's purchased power recoverable costs for energy purchases and sales that were incurred during the April 1998 through September 1998 recovery period and the October 1998 through December 1998 recovery period. I will then compare these actual costs to their projected levels for the periods and discuss the primary reasons for the differences.

I will also summarize the actual capacity expenses that were incurred during the October 1997 through September 1998 recovery period and the October 1998 through December 1998 recovery period. I will compare these figures to their projected levels and discuss the reasons for the differences.

Q. During the period April 1998 through September 1998, what was Gulf's actual purchased power recoverable cost for energy purchases and how did it compare with the projected amount?

A. Gulf's actual total purchased power recoverable cost for energy purchases, as shown on line 12 of the September 1998 Period-to-Date Schedule A-1 was $20,786,493 for 676,187,675 KWH as compared to the projected amount of $7,424,990 for 329,410,000 KWH. The actual cost per KWH purchased was 3.0741 ¢/KWH as compared to the projected 2.2540 ¢/KWH, or 36% above the projection.

Q. What were the events that influenced Gulf's purchase of energy?

A. During May through September of the recovery period, extremely hot weather caused Gulf's actual territorial and off-system loads, as well as the customer loads of many other utilities in the Southeast United States, to be higher than projected. Because of the unavailability of low cost energy during this hot weather period, Gulf purchased more energy at a higher unit price than was forecasted in order to meet its load obligations.

Q. During the period April 1998 through September 1998, what was Gulf's actual purchased power fuel cost for energy sales and how did it compare with the projected amount?

A. Gulf's actual total purchased power fuel cost for energy sales, as shown on line 18 of the September 1998 Period-to-Date Schedule A-1 was $38,837,325 for 1,771,972,679 KWH as compared to the projected amount of $26,149,800 for 1,282,027,000 KWH. This resulted in a variance above budget of $12,687,525, or 49%. The actual fuel cost per KWH sold was 2.1918 ¢/KWH as compared to 2.0397 ¢/KWH, or 7% above the projection.

Q. What were the events that influenced Gulf's sale of energy?

A. Gulf's energy sales were over the projection due to the hot weather that caused higher territorial and off-system loads across the Southern electric system. Because of higher demand off our system, Gulf's units were able to sell more energy at higher than projected prices during the off-peak hours of each day.

Q. During the period October 1998 through December 1998, what was Gulf's actual purchased power recoverable cost for energy purchases and how did it compare with the projected amount?

A. Gulf's actual total purchased power recoverable cost for energy purchases, as shown on line 12 of the December Period-to-Date Schedule A-1 was $4,409,083 for 224,697,185 KWH as compared to the projected amount of

$2,594,610 for 169,740,000 KWH. The actual cost per KWH purchased was 1.9622 ¢/KWH as compared to the projected 1.5286 ¢/KWH, or 28% above the projection.

Q. What were the events that influenced Gulf's purchase of energy during the October 1998 through December 1998 recovery period?

A. Mild weather during this recovery period led to lower than projected territorial and off-system loads. This caused an increase in the availability of low cost pool energy that allowed Gulf to purchase more economy power through the Southern electric system (SES) power pool in order to meet its load obligations. The actual unit price for these purchases was higher than projected because unplanned maintenance outages for several low cost nuclear generating units resulted in purchases from the next highest cost system units during the October 1998 through December 1998 recovery period.

Q. During the period October 1998 through December 1998, what was Gulf's actual purchased power fuel cost for energy sales and how did it compare with the projected amount?

A. Gulf's actual total purchased power fuel cost for energy sales, as shown on line 18 of the December 1998 Period-to-Date Schedule A-1 was $8,133,197 for 483,438,646 KWH as compared to the projected amount of $8,215,600 for 535,211,000 KWH. This resulted in a variance of $82,403 under budget, or 1%. The actual fuel cost per KWH sold was 1.6824 ¢/KWH as compared to 1.5350 ¢/KWH, or 10% above the projection.

Q. What were the events that influenced Gulf's sale of energy?

A. Gulf's energy sales were lower than projected due to lower territorial and off-system loads across the SES. Because of the availability of lower cost system resources to meet the other operating companies' load requirements, the SES required less energy from Gulf's units. Thus, Gulf sold 10% less KWH than was projected.

Q. How are Gulf's net purchased power fuel costs affected by SES energy sales?

A. As a member of the SES power pool, Gulf Power participates in these sales. Gulf's generating units are economically dispatched to meet the needs of its territorial customers, the system, and off-system customers.

Therefore, SES energy sales provide a market for Gulf's surplus energy and generally improve unit load factors. The cost of fuel used to make these sales is credited against, and therefore reduces, Gulf's fuel and purchased power costs.

Q. During the period October 1997 through September 1998, how did Gulf's actual net purchased power capacity transactions compare with the net projected transactions?

A. The actual net capacity cost for the October 1997 through September 1998 recovery period was $4,685,540. My June 23, 1997 direct testimony during the August 1997 hearings in Docket No. 970001-EI stated that Gulf's net projected purchased power capacity cost for the October 1997 through September 1998 recovery period was $1,841,669. However, as I discussed in my June 22, 1998 direct testimony during the August 1998 hearings, Docket No. 980001-EI, this projected capacity cost was revised in Gulf's first estimated true-up for the October 1997 through September 1998 recovery period to reflect capacity cost increases resulting from revised system load and capacity information used in Southern Companies' Intercompany Interchange Contract (IIC) equalization calculation, as well as revised costs related to the SES market capacity purchases. Gulf included the updated amounts for IIC costs and market capacity purchases in its estimated true-up for the October 1997 through September 1998 recovery period.

These updates resulted in revised projected capacity costs for the October 1997 through September 1998 recovery period of $4,421,141. As mentioned previously, the actual net capacity cost for the October 1997 through September 1998 recovery period was $4,685,540. The variance between the actual net capacity cost and the capacity cost contained in the estimated true-up for October 1997 through September 1998 is $264,399, or only 6% higher. This slightly higher cost was due to a slight increase in available system capacity as opposed to what was projected.

Q. Did Gulf Power Company participate in any other capacity transactions that materially impacted its recoverable capacity costs during the October 1997 through September 1998 recovery period?

A. No.

Q. During the period October 1998 through December 1998, how did Gulf's actual net purchased power capacity transactions compare with the net projected transactions?

A. My direct testimony during the August 1998 hearings in

Docket No. 980001-EI stated that Gulf's net projected purchased power capacity cost for the October 1998 through December 1998 recovery period was $818,888. The actual net capacity cost for the October 1998 through December 1998 recovery period was $815,895. This slight decrease in cost of $2,993 is less than 1% below our projection for the recovery.

Q. Does this conclude your testimony?

A. Yes.

GULF POWER COMPANY

Before the Florida Public Service Commission
Direct Testimony of
M. W. Howell
Docket No. 990001-EI
Date of Filing: October 1, 1999

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

A. My name is M. W. Howell, and my business address is One Energy Place, Pensacola, Florida 32520. I am Transmission and System Control Manager for Gulf Power Company.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in various rate case, cogeneration, territorial dispute, planning hearing, need determination, fuel clause adjustment, and purchased power capacity cost recovery dockets.

Q. Please summarize your educational and professional background.

A. I graduated from the University of Florida in 1966 with a Bachelor of Science Degree in Electrical Engineering. I received my Masters Degree in Electrical Engineering from the University of Florida in 1967, and then joined Gulf Power Company as a Distribution Engineer. I have since served as Relay Engineer, Manager of Transmission, Manager of System Planning, Manager of Fuel and System Planning, and Transmission and System Control Manager. My experience with the Company has included all areas of distribution operation, maintenance, and construction; transmission operation, maintenance, and construction; relaying and protection of the generation, transmission, and distribution systems; planning the generation, transmission, and distribution systems; bulk power interchange administration; overall management of fuel planning and procurement; and operation of the system dispatch center.

I am a member of the Engineering Committees and the Operating Committees of the Southeastern Electric Reliability Council and the Florida Reliability Coordinating Council, and have served as chairman of the Generation Subcommittee of the Edison Electric Institute System Planning Committee. I have served as chairman or member of many technical committees and task forces within the Southern electric system, the Florida Electric Power Coordinating Group, and the North American Electric Reliability Council. These have dealt with a variety of technical issues including bulk power security, system operations, bulk power contracts, generation expansion, transmission expansion, transmission interconnection requirements, central dispatch, transmission system operation, transient stability, underfrequency operation, generator underfrequency protection, and system production costing.

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

A. The purpose of my testimony is to support Gulf Power Company's (Gulf) projection of purchased power recoverable costs for energy purchases and sales for the period January 2000 - December 2000 and Gulf's projection of purchased power capacity costs for the January 2000 - December 2000 recovery period. Also, I will support Gulf's revised capacity cost projection for the January 1999 - December 1999 recovery period that has occurred since the Commission issued Order No.PSC-99-1606-PCO-EI in this docket. Finally, I will address the issues raised by the Commission Staff concerning the regulatory treatment for revenues from non-separated wholesale sales and the elimination of the 20 percent shareholder incentive for certain non-separated wholesale sales.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?
A. Yes. I have one exhibit to which I will refer. This exhibit was prepared under my supervision and direction.

Counsel: We ask that Mr. Howell's Exhibit MWH-1 be marked for identification as Exhibit 25 (MWH-1).

Q. What is Gulf's projected purchased power recoverable cost for energy purchases for the January 2000 - December 2000 recovery period?
A. Gulf's projected recoverable cost for energy purchases, shown on line 12 of Schedule E-1 of the fuel filing, is $31,622,732. These purchases result from Gulf's participation in the coordinated operation of the Southern electric system (SES) power pool, as well as the Solutia and market power purchases. This amount is used by Ms. Davis as an input in the calculation of the fuel and purchased power cost adjustment factor.

Q. What is Gulf's projected purchased power fuel cost for energy sales for the January 2000 - December 2000 recovery period?
A. The projected fuel cost for energy sales, shown on line

18 of Schedule E-1, is $ 43,892,000. These sales also result from Gulf's participation in the coordinated operation of the SES power pool. This amount is used by Ms. Davis as an input in the calculation of the fuel and purchased power cost adjustment factor. As shown on Schedule E-1 of Ms. Davis' testimony, the overall fuel and purchased power cost adjustment factor is 1.950 ¢/KWH. This represents a 17.3% increase over the 1999 recovery period fuel cost adjustment factor.

Q. What impact have Gulf's net energy purchases had on the purchased power cost adjustment factor for the January-December 2000 recovery period?

A. The higher cost of Gulf's net energy purchases account for a significant amount of the increase in the projected factor. The net energy cost for the current recovery period has risen primarily due to the substantial increase in the energy cost of market power purchases experienced by Gulf and all utilities buying from the market since the summer of 1999. The actual cost of these market purchases during the January 1999-December 1999 recovery period has caused Gulf's true-up cost for the current recovery period to increase. In addition, the overall adjustment factor has risen due to Gulf's increased market power purchase cost projection for the January-December 2000 recovery period.

Q. What information is contained in your exhibit?
A. My exhibit lists the long-term power contracts that are included for capacity cost recovery, their associated megawatt amounts, the resulting capacity dollar amounts, and the cost of market capacity purchases.

Q. Which power contracts produce capacity transactions that are recovered through Gulf's purchased power capacity cost adjustment factor?
A. Two power contracts that produce recoverable capacity transactions through Gulf's purchased power capacity adjustment factor are the SES Intercompany Interchange Contract (IIC) and Gulf's cogeneration capacity purchase contract with Solutia, Inc. (Solutia). The Commission has authorized the Company to include capacity transactions under the IIC for recovery through the purchased power capacity cost adjustment factor. Gulf will continue to have IIC capacity transactions during the January 2000 - December 2000 recovery period. The energy transactions under this contract for this recovery period are handled for cost recovery purposes through the fuel cost adjustment factor.

The Gulf Power/Solutia cogeneration capacity contract enables Gulf to purchase 19 megawatts of firm capacity until June 1, 2005. Gulf has included these costs for recovery during the January 2000 - December 2000 recovery period. The energy transactions under this contract have also been approved by the Commission for recovery, and these costs are handled for cost recovery purposes through the fuel cost adjustment factor.

Q. Are there any other arrangements that produce capacity transactions that are recovered through Gulf's purchased power capacity cost adjustment factor?
A. Yes. Gulf and other SES operating companies have purchased market capacity for 2000, and these purchases will continue through May 2002. Gulf will have monthly costs associated with these market purchases for the January 2000 - December 2000 recovery period. Again, the energy transactions related to these purchases are handled for cost recovery purposes through the fuel cost adjustment factor.

Q. Has the SES made any changes to the IIC that were used in the most recent recovery factor adjustment proceedings?
A. Yes. On November 2, 1998 the SES filed IIC Amendment

No. 10. The purpose of this amendment is to improve the methodology for determining generating unit capability ratings as defined in the IIC's Periodic Rate Computation Manual. Because the effective date for implementation of this amendment is January 1, 1999, the SES November 1, 1998 IIC informational filing with the FERC has been updated in 1999 to reflect 1999 capacity resource amounts used for the IIC capacity equalization calculation to determine the capacity transactions and costs for each operating company. These updates are reflected in the projection of IIC capacity transactions among the SES operating companies for the January 2000 - December 2000 recovery period.

Q. What are Gulf's IIC capacity transactions that are projected for the January 2000 - December 2000 recovery period?

A. As shown on my Exhibit MWH-1, capacity transactions under the IIC vary during each month of the recovery period. IIC capacity purchases in the amount of $1,450,690 are projected for the period. IIC capacity sales during the same period are projected to be $2,492,130. Therefore, the Company's net capacity transactions under the IIC for the period are net sales amounting to $1,041,440.

Q. What is the cost of Gulf's capacity purchase from Solutia that is projected for the January 2000 - December 2000 recovery period?
A. As shown on my Exhibit MWH-1, Gulf is projected to pay $746,424, or $62,202 per month, to Solutia for the firm capacity purchase made pursuant to the Commission approved contract.

Q. What is the cost of Gulf's market capacity purchases that is projected for the January 2000 - December 2000 recovery period?
A. As shown on my Exhibit MWH-1, Gulf is projected to pay a total of $13,024,449 for the committed market capacity purchases. Capacity in varying amounts will be purchased during the months of January through December of 2000. The individual suppliers and megawatt amounts are not shown, since this is highly sensitive and confidential information. Public availability of this information would seriously undermine our competitive position and cause our customers increased cost.

Q. What are Gulf's total projected net capacity transactions for the January 2000 - December 2000 recovery period?
A. As shown on my Exhibit MWH-1, the net sales under the

IIC, the Solutia contract purchases, and the committed market capacity purchases will result in a projected net capacity cost of $12,729,433. This figure is used by Ms. Davis as an input into the calculation of the total capacity transactions to be recovered through the purchased power capacity cost adjustment factor for this annual recovery period. As shown on Schedule CCE-2 of Ms. Davis' testimony, the purchased power capacity cost adjustment factor is 0.141 ¢/KWH. This represents a 38.2% increase over the 1999 recovery period cost adjustment factor.

Q. Please explain the reasons for the increase in Gulf's purchased power capacity cost adjustment factor for the January 2000 - December 2000 recovery period.

A. The higher cost of additional short-term purchases needed to meet Gulf's growing customer load is primarily responsible for the increase in the projected capacity cost adjustment factor. Gulf must continue to purchase short-term capacity to ensure adequate reserves for its customers' needs until Gulf's planned combined cycle, Smith Unit No. 3, comes on-line in June 2002. When Gulf's Smith Unit 3 is completed in 2002, the need for short-term market capacity purchases will be eliminated based on today's forecast.

Q. Please describe Gulf's short-term capacity purchase strategy.

A. Since April 1996, Gulf's short-term capacity supply strategy, as indicated in its Ten-Year Site Plan process, has been one of acquiring capacity through market purchases. Gulf and the SES are committed to obtaining the best value for capacity purchases that the market can provide. Past efforts made by SES to obtain this type market capacity have been very beneficial to Gulf and its customers, as relatively cheap short-term capacity helped meet the extremely high demands experienced in the summers of 1998 and 1999. Once again for 2000, Gulf and the SES have pursued the same strategy and have gone to the short-term capacity market to supplement owned capacity resources in order to ensure its territorial customers will have an adequate and reliable supply of electricity.

As I stated earlier, Gulf's customers have enjoyed significant savings in past years because of our ability to buy relatively inexpensive market capacity for their needs. The market has reacted quickly to a temporary shortfall of short-term capacity by significantly raising the price of such capacity. Gulf has been able to secure a two year (June 2000-May 2002) contract for most of its unmet needs. The capacity price is in line with the market, and the associated energy price is at a significant savings over what is available elsewhere.

Q. What changes in Gulf's capacity purchases and/or sales do you presently foresee for the years beyond 2000?

A. Since the majority of our unmet capacity needs will be supplied by this new two year contract until Smith Unit No. 3 comes on-line in 2002, purchased power costs for 2001 would be expected to be in the same vicinity as those projected for 2000. By summer 2002, Gulf will have surplus capacity, and will be in a selling mode, so we would expect net capacity sales, rather than purchases, for 2002.

Q. On July 6, 1999, Gulf notified the Commission that Gulf's actual capacity costs for the recovery period ending December 31, 1999 would be at least ten percent greater than projected capacity costs. Please discuss the reasons for making this notification.

A. This notification, acknowledged by the Commission on August 16, 1999 in Order No.PSC-99-1606-PCO-EI, revealed that actual data for January 1999 through May 1999 and revised data for June 1999 through December 1999 had caused Gulf's estimated capacity cost for the January 1999-December 1999 recovery period to increase from

$7,007,984, as projected in Gulf's October 12, 1998 filing, to $9,369,621. The anticipated increase in cost was a result of additional market capacity purchases made by Gulf and the SES to meet load requirements for the months of June 1999 through September 1999 and revised data used in the IIC capacity cost calculation for June 1999 through December 1999 of the recovery period.

Gulf's additional market capacity purchases resulted from Gulf's need for short-term market capacity for the 1999 summer months, June through September. At the time of its October 12, 1998 projection filing, Gulf projected market capacity purchases for the summer of 1999 to be $1,593,516. With the addition of summer 1999 market capacity purchases, this projection increased to $3,948,590.

Gulf's increased IIC capacity purchase cost projection resulted from updated SES owned capacity resources, DSO capacity, load forecasts, and generating unit availability rates that were contained in the latest SES budget for 1999. At the time of the Company's October 1998 projection filing, Gulf projected its net IIC capacity costs for June 1999 through December 1999 of the recovery period were $315,406. Gulf updated this projection to show that its net IIC capacity costs for June 1999 through December 1999 of the recovery period would be $485,013.

Q. Has Gulf revised its capacity cost projections for the January 1999 - December 1999 recovery period since it notified the Commission on July 6, 1999 that Gulf's actual capacity cost for the recovery period ending December 31, 1999 would be greater than its projected capacity cost?

A. Yes. Since Gulf's July 6, 1999 filing, Gulf has obtained actual capacity cost data for June 1999 through August 1999 that has changed its estimated capacity cost for the January 1999-December 1999 recovery period from $9,369,621 projected in July to its current estimate of $6,907,824.

Q. Please explain the reasons for this decrease in the estimated capacity cost.

A. Gulf's latest January 1999-December 1999 capacity cost projection incorporates actual June 1999-August 1999 costs for both Gulf's market capacity purchases and Gulf's net IIC capacity purchases that are lower than those contained in Gulf's July 6 filing. The lower cost related to Gulf's market capacity purchases result from reduced July 1999 capacity payments by Gulf to two market capacity suppliers according to provisions contained in the related contracts. The provisions specify this reduced capacity payment when the selling parties do not deliver scheduled capacity at the specified amounts. For several days during July, both parties did not deliver capacity scheduled by the SES. Also, in August 1999, Gulf received market capacity revenue related to the Georgia Power Company and Oglethorpe Power Corporation Short-term Non-firm Sales contract due to a re-allocation of June 1999 through August 1999 revenues to all five SES operating companies. Overall, Gulf's actual June 1999-August 1999 market capacity purchase cost was $1,457,720 lower than the cost projected in Gulf's July 6, 1999 notification to the Commission.

Gulf's actual IIC net capacity purchases for June 1999 through August 1999 were lower than projected because of Gulf's higher owned capacity as compared to other SES operating companies' owned capacity. Gulf's higher owned capacity reflects the previously discussed purchase of additional summer 1999 market capacity in 1999. Overall, Gulf's actual June 1999-August 1999 IIC net capacity purchase cost was $1,004,077 lower than the cost projected in Gulf's July 6, 1999 notification to the Commission.

When the cost reductions for market capacity purchases and IIC net purchases are combined, the total net reduction in projected capacity costs for the January 1999-December 1999 recovery period is $2,461,797. These reduced costs more than offset the July 6, 1999 projected cost increase of $2,361,637. Therefore, Gulf's projected capacity cost for January 1999-December 1999 is now $6,907,824 instead of the $7,007,984 as stated in Gulf's original projection filing on October 12, 1998.

Q. What is the appropriate regulatory treatment for transmission revenue received from non-separated wholesale energy sales not made through the Energy Broker Network (EBN)?

A. None of Gulf's economy sales are made through the EBN. FERC Order 888 requires transmission revenues associated with the sale of energy to be recorded in FERC Account No. 447. FERC also requires transmission and ancillary charges to be recorded separately. Gulf credits these amounts to its customers through the fuel clause.

Q. What is the appropriate regulatory treatment for generation-related gain on non-separated wholesale energy sales not made through the EBN?

A. None of Gulf's economy energy sales are made through the

EBN. The profit on all of Gulf's economy energy sales is split 80% to the customer and 20% to the stockholder. The 80% gain is recorded as a credit in FERC Account No. 555, Recoverable Purchase Power Expense, and passed through to the customer as a reduction to expenses for purchased power in the fuel clause.

Q. Should the Commission eliminate the 20 percent shareholder incentive set forth in Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B?

A. No. Ratepayers of a net purchasing utility benefit from a vibrant economy energy market where selling utilities have both direct and indirect incentives to satisfy the market's demand for off-system economy energy. The Commission should not take any action to remove or reduce the existing direct incentives to utilities for participating in this market. If reduced amounts of lower cost economy energy were available from sellers, the net purchasing utility would have to meet its customers' needs for energy from its own higher priced units. The purchasing utility's customers would pay a higher price for energy.

Should there be an elimination of the shared direct incentives associated with economy sales, a net selling utility may not continue to support the administrative cost and effort to actively seek out opportunities for economy energy sales. Any decrease in the amount of economy energy sales would reduce the credit to fuel cost for ratepayers that comes from sharing the direct incentives (80%/20% split of the gain from such sales) that are currently available. By establishing the existing 20% direct shareholder incentive in Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B, the Commission recognized the need for and overall benefit to all of our customers of increased sales of economy energy.

Q. Does this conclude your testimony?

A. Yes.

BY MR. STONE:

Q Mr. Howell, you have exhibit MWH-1 attached to your projection testimony, is that correct?

A Yes.

MR. STONE: I would ask that that be assigned an exhibit number.

COMMISSIONER DEASON: Exhibit 25.

(Exhibit 25 marked for identification.)

MR. STONE: Thank you. Then in the interest of time we will dispense with the summary and tender Mr. Howell for cross examination.

COMMISSIONER DEASON: Ms. Kaufman.

MS. KAUFMAN: Thank you, Mr. Deason.

CROSS EXAMINATION

BY MS. KAUFMAN:

Q Good morning, Mr. Howell.

A Good morning.

Q I'm just going to talk to you for a moment about what we've come to finally refer to as the 80/20 issue.

A Yes, ma'am.

Q Would you agree with me, Mr. Howell, that currently there is a very robust and vibrant wholesale market?

A I would agree that there is a robust market compared to what we have in the past. I would certainly go on to say that in the future this will probably look not as robust.

Q But you'd agree that it's certainly more robust than it was 1984?

A It's more robust.

Q Mr. Howell, if Gulf Power had some excess energy or some excess capacity that was being paid for by its ratepayers that were not -- that was not being used at the time, is it your testimony that in the absence of an incentive to sell that power, that Gulf would not attempt to market that power on behalf of its ratepayers?

A No. And let me do, as I think our custom is here, we answer first and then we elaborate and we have -- as I said in my testimony, we do try to market the power that we have. Gulf, by itself, does not market or make any economy sales. Gulf goes in conjunction with the Southern Company as far as making economy transactions.

In the event that we do have surplus electricity for sale we would market that on the Southern Company basis. In the event that we need power we would try to purchase that on a Southern Company basis. And it often happens that it's really independent of what happens on Gulf Power's system. There are times when we may not have enough generation to even serve our load, and yet, because of the pooling arrangement we have with Southern we are actually making economy sales at a time when we don't have enough generation to serve our load. So it really depends on what's happening on the Southern System and not on Gulf Power Company. And the great bulk of the time the economy transactions which we make actually come out of generating units out of state and we get our portion of the profits from those. So it's not a simple yes or no answer.

Q I understand and I appreciate your explanation. You would agree with me, wouldn't you -- and I think you said it might have been in your direct or in your rebuttal, that utilities certainly have an incentive to keep their rates low for the ratepayers, don't they?

A Yes, ma'am. I believe that was primarily in my rebuttal and we do have an incentive to keep our rates low and that's why I think I tried to make clear in the testimony that certainly in the absence of an incentive, long before we had the incentive we made the best efforts we could to try to market power and benefit our customers. The Commission, though, recognized that if you have an incentive it should cause you to more aggressively I think is the word used in the testimony of one of the witnesses. It should cause you to more aggressively go market those and we would certainly agree with that.

Q In one of your previous answers you were explaining the arrangement that Gulf has with Southern Company. So Gulf does not have its own separate marketing department?

A That's correct. It's a single department for the entire Southern Company.

Q So that if I understood what you said earlier, Southern Company is the one that's really involved in making the purchases and sales?

A Right. On behalf of the operating companies they take all the assets of all the operating companies, all the generation available, and first call on all those resources for the customer load. In the event there is capacity available that we can sell then we would sell that out of those resources and it doesn't matter if it comes out of a Gulf or a Mississippi Power or Georgia Power. It doesn't matter where it comes from. If there's generation available to be sold for a profit, then we would do that on a system basis and Southern Company Services does that on behalf of all the operating companies, and all the operating companies get some share of those profits independent of which generating unit actually picked up to make the sale.

Q Thank you. That's all I have.

COMMISSIONER DEASON: Mr. Burgess.

MR. BURGESS: I just would like to confirm, this is not rebuttal testimony? The testimony that was entered was prepared?

WITNESS HOWELL: That's right, just my direct. But she asked that and I think it probably bridged in there.

MR. BURGESS: I understand.

WITNESS HOWELL: My rebuttal will come later.

MR. BURGESS: I have no questions.

COMMISSIONER DEASON: Staff.

CROSS EXAMINATION

BY MR. KEATING:

Q Does Southern's other affiliates in Alabama and Georgia, do you know if they're allowed to keep and incentive share of the profits from economy sales?

A Counselor, I know it varies among the companies. I don't know exactly what it is, but yes, all of them keep some share of those profits for the stockholder and then the customer, you know, has some share also but I'm not sure what that split is.

Q How would you define economy energy?

A I would define economy energy as you have enough generation to serve your load -- well, let's talk about purchases and sales. If a utility has enough generation to serve its load and it has a surplus that somebody else wants to buy, it would then make that sale as an economy sale. On the contrary, if we have enough generation to serve our load but somebody else happens in that hour to have less costly generation than we do then we would purchase that. So, I think the primary driver is, you need to have enough generation to serve your load, but somebody else could generate it cheaper in that hour or be willing to sell cheaper in that hour than what you could serve your load with.

And, of course, when that happens, your customer -- if you're a purchaser your customer gets all the benefits of that transaction. I think the example that Mr. Wieland gave of, if you're cost is 30 and you have someone who's willing to sell who as an incremental cost of 20, you'll transact at 25. Well, your customer would have had to pay the 30 to generate out of his own resources. You're able to buy it at

25. So he saves that full five cents or five mills and all of that goes to the customer. That's the way I would define economy.

Q Okay. So in the definition I think I could -- would you agree that an economy energy transaction is a short-term nonfirm transaction?

A Yes.

Q Okay. If a utility who sells economy energy should suddenly need that energy to serve its native load can it recall the economy energy?

A Yes. I'm not aware -- there may be. But I'm not aware of any economy transaction that is not considered nonfirm and in the event something happens a utility would recall it even if they had committed for the next hour.

Q Does the utility who purchases the economy energy or is that utility required to have the generation resources on hand in case the economy energy transaction is not consummated?

A Well, I think the answer in the old days is clearly a yes. We're moving into an area where we're not really sure. In the old days, you were suppose to quote what you're incremental cost is; what is it going to cost you in the next hour to generate. And the utility that you were dealing with was suppose to quote you their decremental cost. I'm sorry. You would quote your decremental cost and their incremental.

And so then you're actually looking at cost base rates and you would split the savings. Today, we are really moving a lot towards market based rates and the way market based rates are working, a utility will be willing to sell at a certain rate in the market. Other utilities might be willing to buy at a certain rate in the market, and you could have utilities who don't have enough electricity to serve their customers' needs who may be buying what we call economy energy short term whatever the market price is. Was that responsive to the question?

Q I believe so. Yes.

A Okay.

Q Going to hand an exhibit out right now. It contains Gulf's response to Staff's first set of interrogatories, Interrogatory No. 1. And I just have a couple of quick questions for you about that when you get a chance to look at it.

MR. KEATING: Staff would ask that this exhibit be marked for identification.

COMMISSIONER DEASON: Exhibit 26.

(Exhibit 26 marked for identification.)

Q **(By Mr. Keating)** Mr. Howell, so you can narrow down the area that I'm going to ask you a couple of questions about, I'm looking at your responses to Part C and D of that interrogatory. I believe that's on the last page of this handout.

A Yes, I see it.

Q You've got two columns?

A Yes, sir.

Q One labeled economy sales and one labeled external sales?

A Yes, sir.

Q Could you explain the difference between those two?

A Both of them are what we call -- what we characterize as economy transactions. What we call economy sales are those transactions with utilities with whom we are interconnected. External sales would be economy transactions a system away and let me give an example, if I could.

Let's suppose that the Southern Company is selling economy transactions to Duke. We're directly interconnected so if we sell them power or buy from them we would call that -- we would characterize it or categorize it as an economy transaction.

But if we're say selling or buying with AEP, America Electric Power, we're not directly interconnected with them, but they are interconnected with Duke. We would characterize that as an external transaction, but it's the same basis that we're willing to sell at a certain price, they're willing to buy at a certain price or vice versa. It's just that we're not directly interconnected and that's the difference.

Q Does Gulf apply the 20% shareholder incentive to both types of sales listed here?

A Yes, we do. Like I say, even though we do differentiate based on whether we're directly interconnected or not we still consider them as economy as you indicated, nonfirm hourly transactions. So we do apply the 80/20 split to the gain on both types of economy energy.

Q Under which FERC schedules does Gulf apply the 20% incentive?

A I'm sorry. Repeat that please.

Q Under which FERC schedules under sales, under which FERC schedules would Gulf apply that 20% incentive factor to?

A I don't know what the schedules are. I do know that we have two ways that we make economy transactions with directly interconnected utilities and that's the split the savings concept that Mr. Wieland described. Those are, we have FERC schedules. I don't know what the names of them are. But the great bulk of our transactions now are under market based tariffs and I'm not sure what those tariffs are named. But both of those types of transactions we apply the 80/20 split to. It's any type of hourly, nonfirm transaction.

Q Whether it's split the savings pricing or market?

A Yes, sir. Whether it's split the savings or a market based type of transaction.

Q When Gulf participates in an economy energy transaction, is Gulf exceeding its obligation to provide cost-effective service to its retail ratepayers?

A I'm sorry. I don't understand the question.

Q Do you believe that when Gulf participates in an economy energy transaction that Gulf is exceeding its obligation to provide cost-effective electric service to its ratepayers?

A No, sir, I don't. As I said earlier, I think -- you know, before we have the incentive we engaged in this to try to benefit our customers where the stockholder got no benefit. But, I would hasten to add that I certainly don't think that there is anything wrong with the incentive and we'll cover that I'm sure in great detail in my cross.

Q What incentives does Gulf have to purchase economy energy?

A The incentive we have to purchase economy energy is to offer our customers the greatest benefit because if we go ahead and generate with our resources then it would cost them more than if we purchased lower cost energy from somebody else during that hour so that's the incentive. 100% of the benefit, if you will, of that transaction goes to the customer.

Q So Gulf Power shareholders do not receive any direct financial incentive or benefit from these purchases?

A That's correct.

Q Okay. For your economy sales, what percentage are made in-state versus out-of-state?

A Well, let me answer it this way. Again, Gulf doesn't make any by itself. It makes them through the Southern Company and I really don't know what portion of our transactions are with the Florida companies as opposed to other companies. I just don't have that breakdown.

But I will say this, that we try to maintain contact with all the Florida utilities, all the utilities adjacent to us and one system away to see what they might have for sale or what they might need to purchase. So it may vary hour by hour depending on what the needs of the parties are. But I don't have a feel for how that breaks down. To go further, we're not a member of the broker network, so none of ours are on the broker.

Q Just to clarify, is your projection filing based on Gulf applying the 20% incentive to more types of sales than you're currently applying it to?

A To more types of sales?

Q Right. To any other types of sales that you're not currently applying it to?

A No. No. Our projection is based on, you know, continuing the way we're doing it now. We don't anticipate applying an incentive to any other types of sales.

Q Okay. How does Gulf treat transmission revenues received from nonseparated, nonfirm wholesale sales not --

A We, of course, comply with the Commission order. This was an issue. We put forth our position to the Commission that because we had to return those two transmission customers as ordered by FERC in our tariffs we propose that those should go into operating revenue. We were not successful in convincing the Commission that was the appropriate treatment and the Commission order specified that Gulf should put all of those into the fuel clause and that's what we currently do. Any transmission revenue we receive from nonfirm transmission transactions we do credit the customer 100% of those through the fuel clause.

Q Are transmission costs allocated to the various rate -- are transmission costs allocated to the various rate classes in a rate case on a demand basis?

A I don't have any idea.

Q If the Commission were to approve Staff's position on Issue 9, that is, if Gulf was required to flow transmission revenues from nonseparated wholesale energy sales through the capacity clause, would that decision impact your proposed factors?

A I'm sure it would because whatever those revenues are would flow as a credit through the capacity portion of the clause rather than the energy. It would certainly not impact the overall amount that the customer pays because we're providing 100% of those revenues to the customer. So it would impact -- I do not know. I believe that information is available here this morning if you need it rather than a late-filed, though.

COMMISSIONER CLARK: Mr. Howell, can I ask you a question?

WITNESS HOWELL: Yes, ma'am.

COMMISSIONER CLARK: You indicated most of your economy sales are at market prices?

WITNESS HOWELL: Yes, ma'am.

COMMISSIONER CLARK: But it's not Gulf that's making the sales? It's Southern Company?

WITNESS HOWELL: Yes, ma'am.

COMMISSIONER CLARK: How is it Southern Company is selling at market prices and not cost base prices?

WITNESS HOWELL: Let me give a simple example I think will explain that. Before the advent of market based pricing, which FERC did not allow under prior tariffs, you were required to transact with someone on a split the savings basis if that was what was in your tariff. And you had to quote your incremental price, they had to quote their decremental and you were required to transact at a split the savings price.

With the advent of the changes in the industry, FERC is allowing people to sell at whatever the market will bear, if you will, a market price. So some utilities apparently don't have enough generation and they're willing to pay a pretty high premium for electricity rather than cut their customers off. So, utilities are assessing what the market is; what our customers -- what are utilities willing to pay for electricity and other utilities that have power for sale are charging that. So you've got basically two classes of utilities; those that have surplus power in a particular hour, those that don't have enough in a particular hour.

COMMISSIONER CLARK: Well, let me give you more information about the genesis of the question. If I understand, for instance, that Florida Power & Light and Florida Power Corporation cannot sell at market based rates within their region because they are a dominant transmission provider --

WITNESS HOWELL: Yes, ma'am.

COMMISSIONER CLARK: Now, I would assume Southern Company is a dominant transmission provider in their area.

WITNESS HOWELL: I'm not sure exactly what the -- what all of the requirements are at FERC. I do know this. That in the Southern System we did file our compliance tariffs. Initially each company had a transmission rate. We then -- that was not accepted. We then tried a two zone rate within Southern and that was not accepted and basically what we were left with was we had a single transmission rate for the entire Southern Company; a postage stamp tariff, if you will. And in FERC's eyes that mitigated any market power we had because no longer was someone saying Mississippi had to pay three or four tariffs to get across Southern, they could just pay one.

So in FERC's eyes that mitigated that. That's not the situation in Florida. I'm saying that may be -- I don't know, but that may be why they can't do that. But we do not have that restriction because that's where I would guess over 95% of our transactions are market based transactions.

COMMISSIONER CLARK: Within your region?

WITNESS HOWELL: Well --

COMMISSIONER CLARK: It doesn't matter.

WITNESS HOWELL: It doesn't matter, yes. We can sell -- we comprise the entire subregion, the southern subregion of the SERC area and we're interconnected with just about all the parties in the SERC region. So we have market -- we have the ability to make those market based transactions.

COMMISSIONER CLARK: Thank you.

Q (By Mr. Keating) Would Southern Company sell economy energy if at that time it was implementing load management or interrupting an interruptible customer?

A Well, that's not a simple yes or no. Let me take them separately and address it that way. Okay?

Q Okay.

A If -- we have a lot of load management that is not active load management. Our position is right now that we would not implement the active load management at the same time we're selling off system. Our position at this point is that we have an obligation if we have enough electricity to not sell it off system and then cut customers who are on an interruptible rate. As far as if we would cut firm load, clearly we would never sell off system if we had to cut firm load.

Q Do you believe it is more appropriate to credit transmission revenues to the fuel clause as opposed to the capacity clause? And I'm referring to the revenues, again, from nonseparated nonfirm wholesale sales.

A I don't personally have a position on that. It's my understanding, subject to check, that Gulf Power doesn't have a strong position as to whether it should be credited in the energy or the capacity clause. And, of course, this is all contingent. My feeling is, you know, we should credit those to operating revenues, but we lost that argument.

Q How does Gulf treat generation related gains on those types of sales?

A Which type of sales?

Q Nonseparated nonfirm wholesale energy sales?

A Okay. What we've been talking about is economy. The generation related gain is split 80/20. The stockholder keeps 80% of that gain. The customer keeps 80% of that gain.

MR. STONE: Mr. Howell.

WITNESS HOWELL: I'm sorry. Did I say it wrong?

MR. STONE: I think you may have.

WITNESS HOWELL: Let me start over. Right now the stockholder would like to keep 80% of the gain, but by Commission rule he's only allowed 20% of the gain and 80% is credited to the customer and, subject to check, it's my understanding that that goes through the energy component and not the capacity component, but I'm not the appropriate witness there. But that's my understanding.

Q **(By Mr. Keating)** Do you believe that the fuel clause is the more appropriate place to record generation related gains than the capacity clause?

A Like I said, I don't think -- I personally don't care and I don't think the company has a strong issue with that and that is subject to check. I don't see anybody raising steam over there.

MR. KEATING: Thank you, Mr. Howell. I have no further questions.

COMMISSIONER DEASON: Mr. Howell, I have a question or two.

WITNESS HOWELL: Yes, sir.

COMMISSIONER DEASON: Being that you're not part of Peninsular Florida, you do not participate in the Florida broker system; is that correct?

WITNESS HOWELL: Yes, sir. That's correct.

COMMISSIONER DEASON: Okay. And so the distinction between nonseparated wholesale sales being on the broker or not on the broker, that is a meaningless distinction for you?

WITNESS HOWELL: Yes, sir. That's correct.

COMMISSIONER DEASON: Okay. So, all of your -- what you refer to as economy sales, you apply the 80/20 split to those sales, correct?

WITNESS HOWELL: Yes, sir. The gain.

COMMISSIONER DEASON: The gain?

WITNESS HOWELL: Yes, sir.

COMMISSIONER DEASON: Okay. Now, I'm looking at the exhibit which Staff provided, Exhibit 26, and the last page of that. Even though you make a distinction between economy and external sales, in reality we can just consider both of those columns as what we refer to as economy?

WITNESS HOWELL: Yes, sir. That's correct.

COMMISSIONER DEASON: Okay.

WITNESS HOWELL: It's just that they're characterized differently and we wouldn't want anybody auditing us to be confused by what we may say differently than what's on the books. But they are both economy transactions as I've described with the transmission distinction.

COMMISSIONER DEASON: I'm trying to look at the trends in those numbers. It's kind of hard to ascertain if there's any trend one way or the other. Do you have an opinion on that?

WITNESS HOWELL: Yes, sir. I think the trend is that we're certainly making more. We're certainly making more external sales which is two systems away than we used to because it started from zero. But then very quickly one would point out, well, in 1998 it turned around, so where is it headed.

And I think probably what we're going to see is the lack of a trend and these type of transactions really are driven by, does a utility have surplus capacity or is it temporarily short. And as systems around the southeast and the entire eastern seaboard add generation, they're going to be surplus. As they grow into that generation they're going to be short. And I think we're going to see it kind of go all over the place. I really don't think that there's a trend that's going to develop there.

COMMISSIONER DEASON: Okay. Thank you.

WITNESS HOWELL: Let me go ahead and add, Commissioner, that also if you look at the economy transactions you see that same thing; where we sold 162 million in 1990 and 101 million in '94. It just goes up and down and that's simply because it's dependent upon other utility's need for electricity and our ability to have surplus in the hours that they might need it.

COMMISSIONER DEASON: Well, let me follow that up then. Well, then in your opinion, what impact does the 80/20 split have? If it's primarily driven by what surplus you have and perhaps what deficit your neighbors have, how does the 80/20 split work as an incentive to maximize these sales?

WITNESS HOWELL: I think the way it works as an incentive is, clearly in today's market, as we see all utilities that I'm aware of moving away from split the savings they're going to marketing based transactions. The way you are successful in making transactions in a market based environment is you've got to know the market. If you don't have a Staff who's qualified, who's professional, who is able to track the market and know who needs power, who might have it for sale, then you're not going to be able to engage in that market.

And if we make no profit off these sales -- as I've said before, certainly any utility is going to try to maximize its ability to make economy transactions to the benefit of its customers. 100% of all the benefit of the purchases you make go to your customers anyway. But if we have the incentive of, we might be able to profit some for the stockholder then we can certainly justify a staff that tracks the market and is able to know what is out there. And that's why -- that's what our incentive then is and that's how that incentive works in the market based environment.

And that's our concern about you all possibly adopting a position that you're going to rescind the incentive. We believe the incentive works. I mean, it's an incentive. An incentive is something that modifies behavior to accomplish a goal.

The Commission that said we're going to establish this incentive believed in it and we want you to believe in it, too. If the incentive were removed and we no longer had a justification to track the market, to go after the market and know it, I'm firmly convinced that we would see our ability to make those transactions grow very much smaller, and you give our customers 80% -- I mean 100% of a real small pie, they're not going to benefit as much as if they get 80% of a big pie. And they are going to lose out entirely on all those transactions that in tracking the market we know of where we can go buy somewhere a little bit cheaper than what we can generate. If we lose the ability and the knowledge of that, they're going to lose all that benefit and they get 100% of that benefit.

That's why I guess the core of our disagreement with the other witnesses and the very concern we have is that our customers are going to suffer if the incentive is removed. I'm personally convinced of that. Our company is personally convinced of that. And certainly the stockholder is going to see a small loss in profits, but, if you look at the amount of dollars involved here, it's not that big. But if we lose any incentive to fund this department and we have to keep funding the department out of operating profits right now, I think the customer is really going to lose and that's our big concern.

COMMISSIONER DEASON: Well, how is this department funded? Is it part of Southern Company Services which you receive an allocation and it's included in your base rates?

WITNESS HOWELL: Well, it's not really included in base rates, because right now our rates -- eventually it might be, but right now until we go through a rate case or something it would not be in our base rates. We're just paying this. We've established the department in the last few years as a result of changes in the industry and are able to fund the department out of the 20% gain that we get. I don't think any of the companies have had a base rate increase where they've been able to incorporate those costs into it.

COMMISSIONER DEASON: Then are you saying that if there's an incentive that's adequate return and then you would not seek recovery of these type of cost in base rates?

WITNESS HOWELL: I'm not a rate of return expert. I don't know.

COMMISSIONER DEASON: Okay. Have you given any thought to structuring an incentive which assumes there's going to be a certain base amount of transaction and the incentive would be applied to try to exceed that? Something similar to a GPIF?

WITNESS HOWELL: Yes, sir, I have. And if you go back to what the Staff passed out on Page 3, let me demonstrate that.

I've been around a long time and I maintain that it's very difficult to say what would have happened if. You ask yourself in a football game, what would have happened if.

COMMISSIONER DEASON: Commissioner Clark has been asking herself that question quite a bit.

WITNESS HOWELL: Well, over the years all of us, I'm sure, ask those questions. We don't know what would have happened if. Everybody has an opinion. But I don't think any of us really know what would happen if we remove the incentive as to what level we would have without the incentive.

Right now we see what we have and we see that is varies quite a bit, and we have the incentive now. We've had it every year that the Staff has shown, 1990 through 1998.

What would it have been if we did not have the incentive. I don't think anybody really knows. And that, to me, is the difficulty in establishing some amount. How do you really know what the right amount is.

It would be unfair to the utility if you set the bar too high. It would be unfair to the customer if you set the bar too low. And that's why I'm firmly convinced that you just got to believe in what an incentive is. You just got to believe what human nature does and human nature responds to incentives. You try to get people to behave a certain way, you give them that incentive. And we don't know how, we don't know why, we just know they do it. We try to give incentives to our kids and we all know that have kids, some incentives work and some don't. But you find one that works, but the child does respond to the incentive, especially if it has to do with a car key.

So basic human behavior says, people do respond to incentives. Businesses respond to incentives. And that's why I'm firmly convinced that the incentive is the right thing. It's going to bring about the desired result. It's going to be a win-win situation. And I'm afraid if we remove the incentive, we're going to have not a win-lose, win for the customer, lose for the utility; we are going to have lose-lose. If we can no longer justify tracking the market as closely as we do today, we don't have those opportunities to get the customer lower cost power that we might be aware of and we have to serve it of our own generation, which we have to acknowledge, no utility can always serve its load every hour at the lowest cost out of its own generation. Somebody is going to have some cheaper in some hours. So that would be my answer to that.

COMMISSIONER JACOBS: You indicated earlier that there is some apparent willingness on the part of customers to pay a premium.

WITNESS HOWELL: Utilities -- yes, sir, that are apparently willing to pay whatever the market will bear and, Commissioner, is that what you're referring to when we were talking about paying the market premium?

COMMISSIONER JACOBS: Right.

WITNESS HOWELL: Clearly I think we see a lot of utilities and a lot of hours don't have enough generation to really serve their load.

COMMISSIONER JACOBS: Isn't that going to be the driving force? I mean, at some point there's going to be a margin out there that people are going to pursue and -- well, let me ask you this. How would you characterize the movement of the other companies off broker? Isn't that reflective of that idea?

WITNESS HOWELL: I think so. And I will acknowledge that I'm not that familiar. I was very familiar with the broker when it was -- first came into being, but I'm not that familiar with utilities' actions since then. But the broker, at the time I was very familiar with it, was voluntary. A utility could voluntarily put in a decremental price at an incremental price, but they were not required to.

I think if I were a utility in Florida, and I were -- and I had some capacity available and I kind of knew what I could get because they could track this over time and I knew how much profit I could make off the broker, and if perhaps the market out there offered me greater profits, we all know that's an incentive. That's what I'm talking about. The incentive is to not to sell on the broker. You're not required to. You go out and sell on the market where the gains are higher and I think that may be what has happened in Florida.

COMMISSIONER JACOBS: So then sounds like what we might want to do is look at an incentive which tracks what margin is available as opposed to an automatic situation or incentive.

In other words, if we can look at the market price, prevailing market price and make some determination whether or not companies are going to go to market based pricing, sounds to me then that an alternative incentive such as a hard, fast incentive could be sacrificed.

WITNESS HOWELL: I really think, Commissioner, we have that now because the thing about a market is it varies, the electricity market particularly. It just varies all over the place. It's very high in some hours in the summer and, of course, there really is no market like in the wee hours of the morning on April 1st, when nobody wants to buy any.

But whatever the market price is, it varies each hour and nothing that Gulf or Southern or any Commission or any utility can do can change that. It has to do with the relationship of whatever the loads and demands on the system are, which are mostly weather related, and how much generation the company may have, and what's happened with this forced outages, that type of thing. So nobody can control the market. It is what it is.

And what we do is, whatever that market price is, if we're a seller, we take that gain which is whatever we're able to sell it at above our cost, that's the gain, and we split that right now among -- between the stockholders and the customers. So I think we have the -- I think we have that in place at this time.

COMMISSIONER JACOBS: Okay. Thank you.

COMMISSIONER CLARK: Mr. Howell, do you have an overall sort of view of the prices for these sales since you opened up -- Southern Company opened up their transmission system? Are you able to buy power when you need it?

WITNESS HOWELL: Yes, ma'am. So far we have been able to buy --

COMMISSIONER CLARK: But it is cheaper for you or --

WITNESS HOWELL: Well, we would always generate it with our own resources if we could unless somebody has some cheaper and, yes, ma'am, there are situations where they have it cheaper than we do and that's when we like to buy. On the converse, when we have it cheaper than they do, that's when we like to sell.

COMMISSIONER CLARK: Let me ask the question again maybe more precisely. Since you have gone to the postage stamp rate for your transmission system and you have been allowed to charge --

WITNESS HOWELL: Market rates.

COMMISSIONER CLARK: -- market rates --

WITNESS HOWELL: Yes, ma'am.

COMMISSIONER CLARK: -- is it your experience that the prices when you want to purchase have been lower than they otherwise were before that change?

WITNESS HOWELL: Well, let me answer it this way. I think because we have the transmission system opened up as you characterize it there, yes, ma'am, we are able then to buy power from anybody. But the problem is, before we had -- before we opened up the transmission system capacity was not as short as it is now and it's difficult to go back and compare what happened in the past to what happened now.

But, certainly because we can buy this stuff cheaper, I think -- I don't think that's as big a factor as FERC says, you can't sell it at market prices unless you open up your transmission system. FERC's idea is to improve national efficiency and they don't care if your system is opened up or not if you're a buyer. They do care if you sell. They don't want you to have market power to sell without opening up your system. And I hope that was responsive to the question.

COMMISSIONER CLARK: But having the post -- maybe just having the postage stamp has increased the number of people willing to sell into your market.

WITNESS HOWELL: Probably has, simply because there's just more transactions going on.

COMMISSIONER CLARK: Okay.

WITNESS HOWELL: But if we look at Staff's exhibit they passed out, we've had that open access, I guess, since '96 or so. And you look at those years where the economy transactions were 32, 76 and 52 million, those are really small compared to, say, the three prior years.

So, I find it difficult to track it because the real thing driving that is how much generation do you have and how much generation do they have. And Southern has been in more of a short position compared to prior years. And that's why, even with the market rates that we can charge, we haven't sold as many kilowatt hours, say, in the last three years as we did the prior three.

COMMISSIONER CLARK: Well, let me ask this question. Has Southern seen it to their benefit to buy rather than build?

WITNESS HOWELL: Yes, ma'am. And that varies through time. One of the things that we found, let's say two or three years ago, is that there appeared to be a surplus of power in the southeast. So Southern, and Gulf, of course, gets its share of that, has bought some extremely inexpensive power that would be much cheaper to buy than it would be to build.

Now, what we've seen in the last year or so is that excess or surplus in the southeast is dried up and at this time point in time, it is more expensive to buy than it is to build. Our forecast says that at some point you're going to reach equilibrium and it should be about the same. In fact, I think we'll find in a competitive market that you're always maybe just a little above or a little below capacity compared to the market. But at this point in time today, if you go try to buy power right now for year 2000, it will cost you more than if you had built capacity for the 2000. That not the case two years ago.

COMMISSIONER CLARK: Okay.

COMMISSIONER DEASON: Redirect?

MR. STONE: No redirect.

COMMISSIONER DEASON: Exhibits?

MR. STONE: We move Exhibits 25 and 26 into the record.

COMMISSIONER DEASON: Without objection. Hearing none, Exhibits 25 and 26 are admitted.

MR. KEATING: Staff would move its exhibit. I believe ours was Exhibit 26.

MR. STONE: We adopted it.

MR. KEATING: Thank you.

(Exhibits 25 and 26 received in evidence.)

MR. WILLIS: Call Karen Zwolak.

COMMISSIONER DEASON: Very well.

MR. KEATING: Commissioners, before we bring Ms. Zwolak to the stand, this is a witness that Staff until this morning had intended to ask some questions from and unless the other parties have questions for this witness, we think we can stipulate her testimony into the record.

COMMISSIONER DEASON: Very well.

MR. MCWHIRTER: I got a couple of questions for her.

COMMISSIONER DEASON: Okay. Mr. McWhirter has questions.

MR. KEATING: Okay.

MR. MCWHIRTER: You don't get to talk to a microbiologist every day.

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KAREN O. ZWOLAK

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

DIRECT EXAMINATION

BY MR. WILLIS:

Q Please state your name and address?

A Karen Zwolak. 702 North Franklin Street, Tampa, Florida 33602.

Q Did you prepare and cause to be prefiled on April 1st prepared testimony in this docket?

A Yes, I did.

Q If I ask you the questions contained in that document, would your answers be the same today?

A There are two revisions due to the stipulated issue on the refund that was removed from my exhibits and stricken from my testimony.

Q Well, let's start with the April 1st testimony.

A Uh-huh.

Q Are there any additions and corrections to your April 1st testimony?

A My April 1st testimony there was a revision filed on October 1st correcting the first page of that exhibit.

Q All right. To the exhibit, but no changes to your testimony?

A There was a change to the testimony as well. On Page 4, Line 17, the $11,830,891 should be replaced with the number I have on the revision of $7 million. That number should be $7,700 -- $7,879,936.

Q With that correction, would your answers be the same today?

A Yes, they would.

MR. WILLIS: I ask that Ms. Zwolak's April 1st testimony be inserted into the record as though read.

COMMISSIONER DEASON: Without objection it should be so inserted.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

KAREN O. ZWOLAK

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

A. My name is Karen O. Zwolak. My business address is 702 North Franklin Street, Tampa, Florida 33602. My position is Manager - Energy Issues 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 Arts Degree in Microbiology in 1977 and a Bachelor of Science degree in Chemical Engineering in 1985 from the University of South Florida. I began my engineering career in 1986 at the Florida Department of Environmental Regulation and was employed as a Permitting Engineer in the Industrial Wastewater Program. In 1990, I joined Tampa Electric Company as an engineer in the Environmental Planning Department and was responsible for permitting and compliance issues relating to wastewater treatment and disposal. In 1995, I transferred to Tampa

Electric's Energy Supply Department and assumed the duties of the plant chemical engineer at the F. J. Gannon Station. In this position, I was responsible for boiler chemistry, water management, and maintenance of environmental equipment and general engineering support. In 1997, I was promoted to Manager, Energy Issues in the Electric Regulatory Affairs Department. My present responsibilities include the areas of fuel adjustment, capacity cost recovery, environmental 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 April 1998 through December 1998 period for both the Fuel and Purchased Power Cost Recovery and the Capacity Cost Recovery Clauses.

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE

Q. What is the net true-up amount for the fuel and purchased power cost recovery clause for the period April 1998 through December 1998?

A. The net true-up is an over-recovery of $11,830,891. The actual fuel cost over-recovery, including interest, is

$17,092,004 for the period April 1998 through December 1998. This $17,092,004 amount, less the actual/estimated over-recovery approved in the November 1998 fuel hearings of $5,261,113 results in a final over-recovery for the period of $11,830,891. This over-recovery amount of $11,830,891 will be carried over and applied in the calculation of the fuel recovery factor for the period January 2000 through December 2000.

Q. How much effect will this $11,830,891 over-recovery, in the April 1998 through December 1998 period, have on the January 2000 through December 2000 period?

A. The $11,830,891 over-recovery will cause a 1,000 KWH residential bill to be approximately $0.74 lower.

Q. Have you prepared an Exhibit in this proceeding?

A. Yes. I have prepared exhibit No. (KOZ-1, Fuel and Purchased Power Cost Recovery and Capacity Cost Recovery) which contains four documents. Document No. 1 is entitled "Tampa Electric Company Final Fuel Over-Recovery for the period April 1998 through December 1998" and Document No. 2 is entitled "Tampa Electic Company Calculation of True-Up Amount Actual vs. Original Estimates for the period April

1998 through December 1998. 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-9 for the months of April 1998 through December 1998. Included with the December 1998 monthly filing is a nine-month summary for each of Commission Schedules A6, A7, A8, and A9 for the period April 1998 through December 1998. Document No. 5 provides the true-up amount calculated for the Temporary Base Rate Reduction.

Q. Please explain Document No. 1.

A. Document No. 1, entitled "Tampa Electric Company Final Fuel Over - Recovery for the period April 1998 through December 1998" shows the calculation of the final fuel over-recovery for the period of $11,830,891 which will be applied to jurisdictional sales during the period January 2000 through December 2000.

Line 1 shows the total company fuel costs of $281,149,525 for the period April 1998 through December 1998. The jurisdictional amount of total fuel costs is $281,501,223 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-recovered fuel costs for the period, shown on line 4. The resulting $16,834,096 over-recovered fuel costs for the period, combined with $257,908 of interest shown on line 5, constitute the actual over-recovery of $17,092,004 shown on line 6. The $17,092,004 less the actual/estimated over-recovery of $5,261,113 shown on line 7, which was approved in the November 1998 fuel hearings, results in the final over-recovery of $11,830,891 shown on line 8.

Q. Please explain Document No. 2.

A. Document No. 2, entitled "Tampa Electric Company Calculation of True-Up Amount Actual vs. Original Estimates for the period April 1998 through December 1998," shows the calculation of the actual over-recovery as compared to the original estimate for the same period.

Q. What was the variance in jurisdictional fuel revenues for the period April 1998 through December 1998?

A. As shown on line C1 of my Document No. 2, the company collected $8,724,480 more jurisdictional fuel revenues than originally estimated.

Q. What was the total fuel and net power transaction cost variance for the period April 1998 through December 1998?

A. As shown on line A7 of Document No. 2, the fuel and net power transactions cost variance is $10,001,582 or 3.4% less than originally projected.

Q. What are the reasons for the total fuel and net power transactions cost being lower by $10,001,582 or 3.4%?

A. The primary reason for the 3.4% decrease is due to an increase in the Net Energy for Load of 283,499 MWH or 2.2%. This 2.2% combined with the decrease in fuel cost (¢/KWH) for Total Fuel and Net Power Transaction of 5.5% from the estimate, accounts for the 3.4% decrease.

CAPACITY COST RECOVERY CLAUSE

Q. What is the net true-up amount for the capacity cost recovery clause for the period April 1998 through December 1998?

A. The net true-up amount is an over-recovery of $442,999. The actual capacity cost under-recovery, including interest, is $732,421 for the period April 1998 through

December 1998 as identified in Document No. 3, pages 2 and 3 of 6. This amount, less the actual/estimated under-recovery approved in the November 1998 fuel hearings of $1,175,420 results in a final over-recovery for the period of $442,999 as identified in Document No. 3, page 6 of 6. This over-recovery amount of $442,999 will be carried over and applied in the calculation of the capacity cost recovery factor for the period January 2000 through December 2000.

Q. How much effect will this $442,999 over-recovery in the April 1998 through December 1998 period, have on the January 2000 through December 2000 period?

A. The $442,999 over-recovery will cause a 1,000 KWH residential bill to be approximately $0.03 lower.

TEMPORARY BASE RATE REDUCTION

Q. What is the actual amount credited to customers through the Temporary Base Rate Reduction?

A. As specified in the stipulation reached in Docket No. 960409-EI approved in Order No. PSC-96-1300-S-EI, issued October 24, 1996, Tampa Electric agreed to provide a temporary base rate reduction to customers in the total amount of $25 million over 15 months starting with the effective date of the first billing cycle from October 1, 1997 through December 31, 1998. The amount actually credited to customers through the Temporary Base Rate Reduction was $25,435,939. This resulted in $435,939 more than the $25 million amount agreed upon in the stipulation.

Q. How will this excess credit to customers be collected?

A. Order No. PSC-96-0670-S-EI states that any over- or under-collection associated with the credit will be handled as a true-up component in the normal course of Tampa Electric's fuel cost recovery proceedings. However, due to the sharing plan approved in this order, Tampa Electric has agreed to refund any revenues contributing to a net ROE in excess of 12.75% for 1998. Because Tampa Electric is within the 100% sharing range for 1998, any additional revenues such as this excess credit to customers of the Temporary Base Rate Reduction would ultimately be refunded to customers. Therefore, Tampa Electric proposes not to recover this excess credit in the true-up. This avoids collecting the excess credit from customers only to turn around and refund it under the deferred revenue calculation formula. In other words, this appears to be the simplest method for handling the excess credit.

Q. Does this conclude your testimony?

A. Yes.

MR. WILLIS: We also requested her 160 page exhibit as the first page of that exhibit was corrected by filing on October 1st be identified.

COMMISSIONER DEASON: It will be identified as Exhibit 27.

(Exhibit 27 marked for identification.)

Q **(By Mr. Willis)** All right. Ms. Zwolak, did you prepare and cause to be prefiled testimony on October 1st in this docket?

A Yes, I did.

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

A The corrections I just mentioned, we have removed the testimony and documents that refer to the refund from the earnings docket.

MR. WILLIS: Commissioner, I request that a correction sheet of Ms. Zwolak's testimony be marked as an exhibit and entered into the record.

COMMISSIONER DEASON: It shall be identified as Exhibit 28.

(Exhibit 28 marked for identification.)

Q **(By Mr. Willis)** With the corrections on Exhibit 28 added to your testimony, would your answers be the same today?

A Yes, they would.

MR. WILLIS: We would request that Ms. Zwolak's October 1st testimony be inserted in the record as though read.

COMMISSIONER DEASON: Without objection it shall be so inserted.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

KAREN O. ZWOLAK

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

A. My name is Karen O. Zwolak. My business address is 702 North Franklin Street, Tampa, Florida 33602. My position is Manager - Energy Issues in the Regulatory Affairs Department of Tampa Electric

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

A. I received a Bachelor of Arts Degree in Microbiology in 1977 and a Bachelor of Science degree in Chemical Engineering in 1985 from the University of South Florida. I began my engineering career in 1986 at the Florida Department of Environmental Regulation and was employed as a Permitting Engineer in the Industrial Wastewater Program. In 1990, I joined Tampa Electric Company as an engineer in the Environmental Planning Department and was responsible for permitting and compliance issues relating to wastewater treatment and disposal. In 1995, I transferred to Tampa Electric's Energy Supply Department and assumed the duties of the plant chemical engineer at the F. J. Gannon Station. In 1997 I was promoted to Manager, Energy Issues in the Electric Regulatory Affairs Department. My present responsibilities include the areas of fuel, capacity, and environmental cost recovery filings and energy issues and rate design.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present to the Commission the proposed total fuel and purchased power cost recovery factors and the proposed capacity cost recovery factors for January 2000 through December 2000. I will also describe significant events that affect the factors. Finally, I will provide an overview of the composite effect from the various cost recovery factors for 2000.

Q. Have you prepared an exhibit to support your testimony?

A. Yes. Exhibit No. 29 (KOZ-2), Document No. 1 is comprised of Schedules H-1 for January - December 1997 through 2000 and Schedules E-1 through E-10 for January 2000 - December 2000. Also contained in this exhibit are

Schedules E-2, E-3, E-5, E-6, E-7, E-8 and E-9 for the current cost recovery period of January through December 1999. These schedules are furnished as support for the projected true-up for this period and consist of eight actual months and four projected months. These schedules are included in Exhibit No. 29 (KOZ-2), Document No. 1 Fuel Projection.

Fuel and Purchased Power Cost Recovery Factors

Q. What is the appropriate value of the fuel adjustment for the year 2000?

A. The appropriate value for the new period is 2.243 cents per kilowatt hour ("kwh") before the normal application of factors that adjust for variations in line losses. Schedule E-1 of Exhibit No. 29 (KOZ-2), Fuel Projection, shows the appropriate values for the total fuel and purchased power cost recovery clause as projected for the period January 2000 through December 2000.

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

A. The GPIF and true-up factors are provided on Schedule E-

1C. Tampa Electric has calculated a GPIF penalty of $276,901 which is to be included in the calculation of the total fuel and purchased power cost recovery fuel factors.

Additionally E-1C indicates the net true-up amount for the January through December 1999 period. The net true-up amount for this period is an under-recovery of $3,666,883. This under-recovery is comprised of a final true-up over-recovery amount of $7,879,936 for the April 1998 through December 1998 period and an estimated under-recovery in the amount of $11,546,819 for the January 1999 through December 1999.

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

A. Schedule E-1D presents Tampa Electric's on-peak and off-peak fuel charge factors for January 2000 through December 2000.

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 summarize the proposed Fuel and Purchased Power Cost Recovery factors by rate schedule for January 2000 through December 2000.

A.

Rate Schedule	Fuel Charge Factor (cents per kwh)	
Average Factor	2.243	
RS, GS and TS	2.259	
RST and GST	3.074	(on-peak)
	1.905	(off-peak)
SL-2, OL-1 and OL-3	2.080	
GSD, GSLD, and SBF	2.247	
GSDT, GSLDT, EV-X and SBFT	3.057	(on-peak)
	1.895	(off-peak)
IS-1, IS-3, SBI-1, SBI-3	2.171	
IST-1, IST-3, SBIT-1, SBIT-3	2.955	(on-peak)
	1.832	(off-peak)

Q. How does Tampa Electric's proposed average fuel charge factor of 2.243 cents per kwh compare to the average fuel charge factor for the January 1999 through December 1999 period?

A. The proposed fuel charge factor is 0.029 cents per kwh (or $0.29 per 1000 kwh) higher than the average fuel charge factor of 2.214 cents per kwh for the January through December 1999 period.

<u>Capacity Cost Recovery Clause</u>

Q. Are you also requesting Commission approval of the projected capacity cost recovery factors for the company's various rate schedules?

A. Yes. The capacity cost recovery factors, prepared under my direction or supervision, are provided in Exhibit No. 29 (KOZ-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 for purchases of power made for retail and all-requirements customers excluding optional provision purchases for interruptible customers.

Q. Please summarize the proposed capacity cost recovery clause factors by rate schedule for January 2000 through December 2000.

A.

Rate Schedule	Capacity Cost Recovery Factor (cents per kwh)
RS	0.271
GS and TS	0.230
GSD, EV-X	0.187
GSLD and SBF	0.169
IS-1, IS-3, SBI-1, SBI-3	0.015
SL-2, OL-1 and OL-3	0.054

These factors are shown in Exhibit No. 29 (KOZ-3), page 3 of 5.

Q. How does Tampa Electric Company's proposed average capacity cost recovery factor of 0.204 cents per kwh compare to the factor for 1999?

A. The proposed capacity cost recovery factor is .048 cents per kwh (or $0.48 per 1000 kwh) higher than the average capacity cost recovery factor of 0.156 cents per kwh for the January through December 1999 period.

Events Affecting the Projection Filing

Q. Are there any events reflected in the calculation of the 2000 Fuel and Purchased Power and Capacity Cost Recovery projections that are not reflected in last year's projections?

A. Yes. There are six events. These are: 1) the stipulation entered into in Docket No. 980001-EI relating to heat content adjustments in the Gatliff Coal contract, 2) the Gannon Unit 6 accident, 3) new purchased power agreements, 4) the advanced in-service date of a 180-megawatt combustion turbine ("CT"), 5) the requested treatment for the FMPA wholesale power supply agreement, and 6) the refund associated with Docket No. 960409-EI.

Q. Please describe the first event, a reduction in the 1999 projections as the result of the stipulation entered into in Docket No. 980001-EI, Order No. PSC-98-1715-FOF-EI issued on December 18, 1998).

A. As the order reflects, Tampa Electric stipulated to reduce its projected fuel and purchased power costs by $6,639,522. This was done to settle an issue raised by Commission Staff regarding Tampa Electric's inclusion of heat content adjustments in comparing Gatliff prices to the benchmark price.

Q. Has the refund been completed?

A. Yes. Tampa Electric adjusted the fuel and purchased power costs by $6,639,522 to reflect purchases from 1993 through 1997 and to also adjust costs to reflect the amount expected to be incurred in 1998. In total, Tampa Electric actually reduced the Fuel and Purchased Power Cost Recovery Clause in 1999 by $7,280,088. The total cost of Gatliff Coal purchased in excess of the benchmark for 1998 was $629,267 as identified in Tampa Electric witness Mark J. Hornick's testimony. The company had estimated the 1998 over-benchmark component to be $610,593 which was included in the adjustment. The difference associated with the true up for 1999 is $18,674 ($629,267 less $610,593) and the adjustment associated with interest for the true up is $9,540 totaling a net adjustment of $9,134. This is included in the calculation for the proposed fuel adjustment factor for the year 2000 and is reflected in Schedule E-1.

Q. Please describe the second event that impacts the company's projection filing.

A. The second event that affects the filing is the April 8, 1999 Gannon Unit 6 accident. Details regarding the accident are discussed in the testimonies of Tampa Electric witnesses Charles R. Black and Mark D. Ward. The company incurred $5,073,526 for replacement fuel and purchased power as a result of the accident. These costs are included in Schedules E-2 and E-8, which reflect actual/estimated costs for the current period January 1999 through December 1999.

Q. Please describe the third event.

A. In an effort to improve system reliability for retail ratepayers in 1999, 2000 and beyond at reasonable and prudent costs, Tampa Electric explored many options. After a review process, the company negotiated five purchased power agreements. The testimony of Tampa Electric Company witness W. L. Brown describes these purchases and demonstrates that the costs associated with these purchased power agreements are prudent and appropriate for recovery through the Fuel and Purchased Power Cost Recovery clause.

Q. Please describe the fourth event that impacts the company's projection filing.

A. The fourth event is the advancement of the in-service date for Tampa Electric's next generation unit, a 180 MW CT. According to the company's Ten-Year Site Plan filed with this Commission in April 1999, this unit was shown to have a commercial in-service date of January 2001. In order to maintain reliability for its native load, the company has decided to accelerate the in-service date to October 2000. The associated natural gas and distillate oil costs are included in generation costs for the year 2000.

Q. Please describe the fifth event that impacts the company's projection filing.

A. The fifth event relates to the company's proposed treatment of its wholesale power supply agreement with FMPA for January 1, 2000 through March 15, 2001. This proposed treatment is described in the testimony of Tampa Electric witness Thomas L. Hernandez. Tampa Electric's Fuel and Purchased Power Cost Recovery Clause factors reflect this proposed treatment for the period January 1, 2000 through December 31, 2000.

Q. Please describe the sixth event that impacts the company's projection filing.

A. The sixth event relates to the refund contemplated in Order No. PSC-96-1300-S-EI from Docket No. 960409-EI. The order specifies that the total refund paid out in 1999 is to be provided to customers at a rate of $2 million per month until the entire refund is exhausted. The refund is to be reflected as a credit on customer's bills calculated by multiplying a levelized factor adjusted for line losses times the actual kwh usage for the period of the refund, as shown in Exhibit 29 (KOZ-4). The refund is to include interest on the unamortized amount of the refund.

Based upon the refunds determined by the Commission in its proposed agency actions ("PAA") from the agenda conferences held on August 31, 1999 and September 7, 1999 for the review of 1997 and 1998 earnings, respectively, the total amount to be refunded is $11,226,598. This amount plus interest will be refunded to customers beginning in January 2000 at a rate of approximately $2 million over a six-month period, assuming there are no protests of the Commission's PAA orders affecting the amount to be refunded.

Cost Recovery Factors

Q. What is the composite effect of Tampa Electric's proposed changes in its various cost recovery factors on a 1000 kwh residential customer?

A. A residential bill for 1000 kwh will increase $0.43 beginning January 2000. These factors are shown in Exhibit 29 (KOZ-2), Document No. 2.

Q. When should the new rates go into effect?

A. The new rates should go into effect concurrent with the first billing cycle in January 2000.

Q. Does this conclude your testimony?

A. Yes it does.

MR. WILLIS: We request that a 48 page Composite Exhibit which is attached to her testimony by identified please.

COMMISSIONER DEASON: Exhibit 29.

(Exhibit 29 marked for identification.)

MR. WILLIS: We would note that the last page of that exhibit has been withdrawn which is -- would be Page 49, as noted in her correction.

BY MR. WILLIS:

Q Could you please summarize your testimony?

A Yes, I could. Good morning, Commissioners. My testimony and exhibits show the calculation of the fuel and purchased power cost recovery clause as well as the capacity cost recovery clause factors to be applied by Tampa Electric in the year 2000. That summarized my testimony. Thank you.

MR. WILLIS: I tender the witness.

COMMISSIONER DEASON: Mr. McWhirter.

CROSS EXAMINATION

BY MR. MCWHIRTER:

Q Ms. Zwolak, would you go to Page 11 of Exhibit 29?

A Exhibit 29? I'm sorry. In my excitement of being excused I left my back-up book behind. Could you tell me again?

Q Yes. Page 11.
A Of the exhibit or the testimony?
Q Of the exhibit.
A Yes.
Q Columns D, E and F of that exhibit provide the net capacity factor, the equivalent availability factor and the net output factor of each of the utility's installed generating stations. Are you familiar with the methodology used to develop those factors?
A No, I'm not. That data is developed from our production department in conjunction with our resource planning department.
Q All right. I will ask no further questions about that. Will you go to Page 8. And this page represents your actual fuel cost on a month by month basis that you use to develop the average fuel cost. Prior to this year we set the fuel factor twice a year. Once for the period of October through March and the second time April through September; is that correct?
A That is correct. Although the page you're referring to, 8, is not actuals.
Q Can you talk into the microphone. I can't hear you.

A I'm sorry. The page you're referring to are not actuals. Those are projections for 2000.

Q I'm not going to ask you to do this calculation, but I have done it and if you think that it's -- I'm misstating the facts then please quickly clarify. But it appears to me if you look at Line 8 it gives your monthly fuel cost for each of the 12 months of the year; is that correct?

A Yes, it does.

Q And if you looked at the former period used for establishing the factor, which would be April through September, is it not fair to say that 65% of your total annual cost is incurred in that period of time?

A I could not tell you the percentages, but the summer months appear to be higher.

Q And then for the other six month period, would take about 35% of your fuel cost; is that right?

A Again, I could not verify your percentages.

Q Would it be fair to say from your basic understanding of the information you put together that when you set the fuel factor twice a year, once for the time when you consumed -- when you have the greatest cost and once for the time when you have less cost, those factors would more closely track cost than if you do it one time a year?

A I really hadn't looked into it in detail, but you may be right.

Q All right. Would you go to Page 36 of your testimony?

A Yes, sir.

Q Now, in your transactions -- this is the power Tampa Electric Company sells to other parties. In your transactions with Hardee Power Partners, for the first eight months of the year the price differential between fuel and your total cost is in the range of 63 to 65 cents a kilowatt hour and then it jumps -- I misspoke myself. It's .63 cents. And then for the last four months of this year it jumps to 2.98 cents or $2.98 cents a megawatt hour. Do you know the underlying reason for that large increase in the capacity charge?

A You're talking about the Hardee Power sale?

Q Look at the Hardee Power sale. It's the line that says contract.

A Right.

Q And the fuel cost remains constant but the total cost jumps up by the amount that I said. Do you know the reason for that?

A Well, one of the reasons could be the Hardee contract, there is an arrangement. There is a purchase for Tampa Electric -- or sales to Hardee but then when there's extra capacity on it I believe that's sold in the wholesale market and it's split between Tampa Electric and Seminole. So that could be the reason the fuel cost may vary like that and some of the months there may be more opportunity to make wholesale sales.

Q And what is the thing that makes it change?

A Pardon? The gains would make the total costs increase and those would be flowed through the fuel clause.

Q I understand that. But what is it that triggers a higher capacity cost for certain months than other months?

A These aren't capacity costs. These are energy costs on this schedule. There are no capacity costs included in this schedule.

Q What is the element that constitutes the difference between fuel cost and total cost?

A The gains.

Q You don't call it capacity charge or other charges? You just you call it gain?

A Our nomenclature has been to call it the gains on the sale.

Q And I don't think I understood your explanation of why the gain is bigger sometimes than other times.

A Because we have opportunity to make sales. There are two sales to -- there is one sale, but one to Seminole if they need it, as well as to if we can broker it on the market if neither Tampa Electric nor Seminole needs the energy. So it can be brokered on the wholesale market and, therefore, you can -- you know, based on the market pricing there are gains resulting that are above and beyond the fuel cost.

Q I see. So you were selling power in September and October to Hardee for resale?

A I don't know if that's the case, but that could be the reason.

Q All right.

MR. MCWHIRTER: That's all the questions that I have.

COMMISSIONER DEASON: Staff still have no questions?

MR. KEATING: No questions.

COMMISSIONER DEASON: Okay. Redirect.

MR. WILLIS: No redirect. I ask for the admission of Exhibits 27, 28 and 29.

COMMISSIONER DEASON: Without objection

Exhibits 27, 28 and 29 are admitted.

(Exhibits 27, 28 and 29 received in evidence.)

MR. WILLIS: I call Tom Hernandez.

- - - - -

THOMAS L. HERNANDEZ

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

DIRECT EXAMINATION

BY MR. WILLIS:

Q State your number and address?

A My name is Thomas L. Hernandez. My business address is 702 North Franklin Street, Tampa, Florida 33602.

Q Did you prepare and cause to be prefiled in this testimony -- in this docket, testimony?

A Yes, I did.

Q If I were to ask you the questions contained in that testimony would your answers be the same today?

A Yes, they would.

MR. WILLIS: I ask that Mr. Hernandez's direct testimony --

WITNESS HERNANDEZ: I do have one change in the direct testimony.

Q (By Mr. Willis) Okay.

A Page 14, Line 6. The number $13.5 million should be $13.2 million, and this reflects the change that's in my exhibit. It's a single page document on that exhibit and this is what drives the change in the text for the year 2000, 2001. It's the last 14 and a half months of the FMPA contract. The correct benefits in 1997 dollars should be $3,406 in terms of thousands of dollars and replaces $3,699. The new total, therefore, is $13,248 in terms of thousands of dollars. And that drove the replacement of the $13.5 million that was in the text of my testimony. So with that change, my testimony is as read.

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

COMMISSIONER DEASON: Without objection, it shall be so inserted.

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
FILED: 10/1/99

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

THOMAS L. HERNANDEZ

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

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

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

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

Q. Have you previously testified before this Commission?

A. Yes. I testified before this Commission in the last annual planning hearing Docket No. 910004-EU. I also provided a description of Tampa Electric's planning process at the FPSC Staff workshop on March 3, 1994. I also submitted testimony in Docket No. 930551-EI which was the numeric conservation goals proceeding for Tampa Electric. I testified in Docket No. 960409-EI regarding the prudence of Polk Unit One and, most recently, I testified in Docket No. 980693-EI regarding the company's flue gas desulfurization system for Big Bend Units 1 and 2.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to urge the Florida Public Service Commission ("Commission") to approve a revision to the current regulatory treatment afforded the company's existing wholesale power sales agreement with the Florida Municipal Power Agency ("FMPA") beginning January 1, 2000 and ending March 15, 2001, the expiration date of the agreement. As discussed below, this transaction creates significant net benefits to ratepayers. While this transaction provides overall net benefits, regulatory treatment of this transaction imposes a significant loss on the company. Tampa Electric urges this Commission to approve a revenue flow-through treatment of this sale, which avoids harming the company while still providing benefits to customers. This treatment would begin at the expiration of the existing rate stipulation agreement approved by Order No. PSC 96-1300-S-EI ("Stipulation") and would be consistent with sound regulatory policy as reflected in previous Commission proceedings.

I will also discuss the appropriate regulatory treatment for the generation-related gains on economy energy transaction which are short-term, cost-based transactions between electric utilities. These sales are made either through the Florida Energy Broker Network ("EBN" or "broker") or outside the broker. I will also discuss the appropriate regulatory treatment for transmission revenue received from such sales not made through the broker. Finally, I will explain why the Commission should not eliminate the 20 percent shareholder incentive established in Order No. 12923, issued January 24, 1984 in Docket 830001-EU-B and why it should consider additional incentives.

Q. Have you prepared an exhibit to support your testimony?

A. Yes I have. My Exhibit No. 3D (TLH-1) was prepared under my direction and supervision and consists of one document.

Regulatory Treatment for FMPA Wholesale Agreement

Q. Please describe the FMPA wholesale power supply agreement.

A. The FMPA wholesale power supply agreement is a letter of commitment dated October 2, 1996, as amended by letter agreements dated November 25, 1997, April 30, 1998, and October 14, 1998 that provides for long-term interchange service by Tampa Electric to FMPA in accordance with the Agreement for Interchange Service dated April 1, 1986, as supplemented by Service Schedule D (Long-Term Interchange Service) dated December 20, 1998 ("Agreement"). The original Agreement provides for the sale of specified amounts of capacity and associated energy from Tampa Electric's Big Bend Units 2 and 3, and Gannon Units 5 and 6 from December 16, 1996 through March 15, 2001.

The amounts of contracted capacity made available under the Agreement ranged from 35 megawatts in 1997 to 105 megawatts through December 15, 1999. For the period December 16, 1999 through March 15, 2001, the contracted base capacity will be 150 megawatts. The Agreement provides that capacity would be available to FMPA any time generating resources from Big Bend Units 2 and 3, and Gannon 5 and 6 are available.

In March 1998, Tampa Electric began serving FMPA through third-party resources. The Agreement was formally amended to reflect that FMPA's capacity needs could be met with power supplied from third party purchased power agreements instead of Tampa Electric's generating resources.

Q. Why is making wholesale sales important to Tampa Electric?

A. Making cost effective wholesale sales which provide revenues greater than incremental costs of making such sales is good for the company's retail customers as well as its shareholders. Since its 1985 rate case, when this Commission gave the company an incentive to keep retail prices down by increasing wholesale revenues, the company worked hard to optimize those sales. The current and anticipated levels of such wholesale revenue has been one of several significant variables that the company has managed which have resulted in reduced prices to customers in spite of the pressure of increasing costs. Retail customers benefit through low prices and shareholders benefit in the increase in probability of the company earning its allowed rate of return.

Q. Has the Commission provided the company incentives to enter into transactions like the FMPA sale?

A. Yes, most definitely. In the company's 1985 rate order, the Commission reduced retail revenue requirements by $37 million based on Tampa Electric's existing sale of capacity and energy to Florida Power and Light Company. In that proceeding, the Commission challenged the company to make up the deficit in revenue requirements by making up to $37 million in wholesale sales. The Commission treated the wholesale sales by allowing the company to credit 100% of the non-fuel revenue from such sales above the line in the retail jurisdiction. In 1987, the Commission approved a proposal by the company to credit fuel revenues based on the incremental fuel cost from off-system sales to the retail customer fuel adjustment clause ("Fuel Clause") which had the effect of encouraging wholesale sales. In the company's 1992 rate case, the Commission separated certain of the company's wholesale sales at system average cost, certain others at unit embedded cost, while still other sales were not separated from the retail jurisdiction. For some sales that were not separated from the retail jurisdiction, net revenues were shared 80/20. There are good, sound policy reasons for this.

Q. What regulatory treatment has the Commission prescribed for the costs and revenues associated with the Agreement during the stipulation?

A. During the February 1997 fuel adjustment hearing, an issue was raised regarding cost recovery of non-fuel revenues associated with sales such as the Agreement. The Commission opened Docket No. 970171-EU to establish the regulatory treatment of costs and revenues associated with such sales. In its Order No. PSC-97-0262-FOF-EI issued March 11, 1997 the Commission set out its basic policy with respect to the regulatory treatment for the recovery of fuel costs of long-term, firm, wholesale power sales. Under this policy a utility is required to credit average system fuel costs through the Fuel Clause unless it demonstrates, on a case-by-case basis, that each new sale provides net benefits to retail ratepayers in which case incremental costs can be credited.

During the hearing conducted in August 1997 in Docket No. 970171-EU, Tampa Electric demonstrated that the sale to FMPA contributed net present value benefits of $9 million (1997 dollars) to the company's retail customers as shown in my exhibit. In making its decision in this docket, the Commission concluded that solely because of the terms of the Stipulation, Tampa Electric was required to separate the capital and operating and maintenance costs ("O&M") of the FMPA sales from the retail jurisdiction at average embedded cost. Furthermore, in light of the fact that the Commission, in Order No. PSC-97-1273 FOF-EI, recognized that the FMPA sale provided overall net benefits to retail ratepayers, the company was permitted to credit the Fuel Clause and Environmental Cost Recovery Clause ("ECRC") with revenue amounts equal to the system incremental fuel and SO_2 allowance costs, respectively, resulting from the FMPA sale. In the event that fuel revenues received under the contract were less than the differential costs for fuel and SO_2, the company was ordered to reduce retail operating revenues by the amount of shortfall.

Q. Did Tampa Electric follow the Commission's order for treating the costs and revenues associated with the FMPA wholesale power supply agreement?

A. Yes. To the extent that Tampa Electric's retail resources were being used to supply FMPA, from the inception of the agreement and continuing through December 31, 1999, Tampa Electric has and will continue to separate the capital and O&M costs (excluding fuel and SO_2) associated with the FMPA sale from the retail jurisdiction at average embedded costs. In addition, whenever such retail generating resources were used to serve the sale the company credited the Fuel Clause with incremental fuel revenues and credited the ECRC with incremental SO_2 allowance revenues associated with the sale as described in the hearing in Docket No. 970171-EU. (The fuel and SO_2 costs were documented in the company's 1997 and 1998 Fuel Clause and ECRC filings.) Finally, if there was a shortfall between incremental fuel revenues and SO_2 revenues and incremental costs, the company made up the difference with additional credits from retail revenues.

Q. What was the effect of separating the sale at average system embedded costs?

A. This separation treatment resulted in the allocation of costs that exceeded the non-fuel revenues from the sale by approximately $0.7 to $2.1 million per month. The net result of this regulatory treatment was that although the FMPA sale was shown to provide net benefits to ratepayers, the company was losing approximately $0.7 to $2.1 million per month serving the Agreement.

The FMPA sale is an incremental or opportunity sale. Tampa Electric has no obligation to wholesale customers to make these kinds of sales and would only do so in those cases where net benefits accrue to the general body of ratepayers and the company's shareholders are not harmed. Separating FMPA sales on an average cost basis, creates a tremendous disincentive to Tampa Electric to make these types of sales in the future. The resulting loss of benefits to our general body of ratepayers under that treatment would be in no one's best interest.

Q. How did Tampa Electric serve the FMPA sale after February 1998?

A. In March 1998, Tampa Electric began serving FMPA partially through third party resources. The third party resources consisted of purchased power agreements with Florida Power Corporation and PECO Energy Company and by April 28, 1998, the total amount of third-party supplied purchase power equaled the entire amount of contracted capacity to be supplied to FMPA under the Agreement. Therefore, since April 28, 1998, none of Tampa Electric's generating units have been used to serve the sale.

Q. How did Tampa Electric treat the costs and revenues associated with the FMPA wholesale power supply agreement after February 1998?

A. In every month that Tampa Electric was not serving FMPA directly from its own generating resources, the purchase power costs and sales revenues were excluded from the retail jurisdiction. The amount of energy required to serve the FMPA sale equaled the amount of energy purchased from third-party suppliers. Therefore, in each of those months the FMPA sale was served totally by third-party purchases and the fuel cost recovery factor was not affected in any way.

Q. Why is Tampa Electric seeking different regulatory treatment for the FMPA wholesale power supply agreement for the period of January 1, 2000 through March 15, 2001?

A. When the Commission made its decision in Order No. PSC-97-1273-FOF-EU, it established the regulatory treatment for the duration of the Stipulation or through December 31, 1999. During its discussion at the agenda conference when the decision was made, the Commission made it clear that Tampa Electric could seek alternative treatment after the Stipulation ended. We are now requesting different treatment since the benefits to ratepayers far exceed those contemplated in the original economic benefit analysis with Tampa Electric forced to make up this difference at a substantial loss to shareholders.

Q. What is Tampa Electric's proposed treatment for the FMPA wholesale power supply agreement for the period January 1, 2000 through March 15, 2001?

A. The company is proposing a revenue flow-through treatment that credits all revenues received from the FMPA sale to retail customers through the ECRC and Fuel Clause. The company will credit the ECRC with revenues to offset the incremental SO_2 costs. The SO_2 allowance costs will be determined by using the market price for SO_2 allowances and the weighted average SO_2 emission rate for Big Bend

Units 2 and 3 and Gannon Units 5 and 6. All remaining revenues will be credited to the Fuel Clause.

Q. Why is this proposed treatment appropriate?

A. The proposed FMPA treatment provides customers benefits derived from this type of wholesale sale, and eliminates the absolute disincentive that is created by the separation treatment required during the Stipulation. Tampa Electric's proposed regulatory treatment of the Agreement is fair and reasonable, and sends an appropriate signal rather than discouraging utilities from seeking future opportunities to reduce their costs of providing service.

Q. What are the overall total benefits for retail ratepayers resulting from the FMPA agreement?

A. The appropriate way to review the overall total benefits of the Agreement is to review what was known and reasonably assumed at the time the Agreement was signed. As stated above, and shown in my exhibit, the company originally projected net present value benefits of $9 million (1997 dollars) for the contract period. These benefits were determined based upon a cost benefit analysis of this wholesale power transaction during the period 1997 through 2001. In evaluating the benefits realized from the current regulatory treatment and those benefits to be obtained under the proposed regulatory treatment from January 1, 2000 through the end of the Agreement, the company has determined that $13.~~8~~2 million (1997 dollars) net benefits will be achieved as shown in my exhibit.

Q. Why should the Commission approve your proposed regulatory treatment of the FMPA sale?

A. It should be approved as a matter of sound regulatory policy consistent with the Commission's Order in Docket No. 970171-EU as well as a matter of basic fairness. The proposed regulatory treatment will provide additional net benefits for the remainder of the contract and these benefits will be passed through to customers without penalizing the company. The separation treatment based upon average embedded costs imposed during the Agreement, on the other hand, does in effect provide a severe penalty to the company.

It is simply unreasonable and unfair to continue to require a regulatory treatment which provides a financial penalty and disincentive for entering into a transaction which has reasonable expectations of providing net benefits to customers. The reason separation was required initially was related to the Stipulation. The Stipulation term ends December 31, 1999 and accordingly separation treatment should end.

Economy Sales Transactions

Q. Please describe the appropriate regulatory treatment for generation costs associated with economy sales?

A. For generation costs, revenues sufficient to cover the fuel costs associated with Schedules C and X transactions are credited through the Fuel Clause and revenues sufficient to cover the associated SO_2 credits are credited through the ECRC. Revenues are also credited to operating revenues to cover incremental variable O&M costs incurred by the company.

Q. How are the gains from economy energy sales treated for regulatory purposes?

A. Gains are realized by the company selling the energy as a result of the "split the savings" methodology used to calculate the transaction price of economy energy. The gain is simply the difference between the transaction price and the associated incremental fuel, O&M and SO_2 costs of the seller. This Commission has long had a policy of encouraging these transactions by providing incentives for the utilities to engage in economy sales. On January 24, 1984, the Commission entered its Order No. 12923, Docket No. 830001-EU-B authorizing utilities to retain 20 percent of their gains on economy sales while providing net benefit to ratepayers. In its order the Commission agreed with Staff witness testimony that a positive incentive is desirable for the purpose of maximizing the benefits of the Energy Broker Network: "We believe Staff's witness was correct in stating that "a positive incentive will preserve current levels of economy sales and may result in increased sales and that a 20 percent incentive is large enough to maximize the amount of economy sales and provide a net benefit to ratepayers." The Supreme Court of Florida affirmed the Commissions position in Citizens v. Public Service Commission, 464 So 2d 1194 (Fla. 1985). It was clear both then and now that the Commission provided an incentive to engage in economy sales type transactions.

Q. What is the appropriate regulatory treatment for the generation-related gain on Schedule C and X transactions not made through the broker?

A. The treatment should be the same as if it were made through the broker. The broker is merely a computerized-based, telephonically-linked, system driven by hardware and software. In essence, it is a tool that facilitates Schedule C transactions for those utilities that wish to use the system. There is no logical reason for making any distinction between types of economy sales based solely on the type of tools used by the buyer and seller to communicate their offers and document the transactions. Any generation-related gains associated with economy sales transactions should be treated the same way whether the broker is used or not since the policy of incenting such transactions clearly should apply to both broker and non-broker transactions. Accordingly, eighty percent of those gains assigned to the retail jurisdiction should be credited to ratepayers through the fuel clause. The company should retain 20 percent of the gain from a non-broker transaction.

Q. What is the appropriate regulatory treatment for transmission revenues received from non-separated economy sales?

A. Transmission revenues from economy sales should be separated on an energy basis. Eighty percent of those revenues should be credited to retail ratepayers through the Fuel Clause. The company should retain the remaining 20 percent.

Q. Should the Commission eliminate the 20 percent shareholder incentive set forth in Order No. 12923, issued January 24, 1984 in Docket No. 830001-EU-B?

A. Definitely not. In fact the Commission should increase the incentive to give greater encouragement to utilities to enter into these types of transactions. Elimination of the 20 percent shareholder incentive will negatively impact both sellers and purchasers since fewer transactions will occur in the absence of incentives. The shareholder incentive encourages sellers to offer their as-available energy within the state and provides mutual benefits for customers of both sellers and buyers.

Q. Why should utilities be incented to ensure there are mutual benefits for customers of both sellers and purchasers of energy?

A. Utilities should be incented to carry reserve margins in excess of their minimum planning margins to serve two purposes: one is to meet contingency needs of the state when individual and statewide loads are higher than expected due to extreme weather conditions or when generating unit availability is less than expected. The second purpose is to balance the market and business risk of those utilities that depend on the market for reliability purposes with those utilities that help meet market needs. It is appropriate for the Commission to provide incentives to utilities that have acknowledged the need for additional capacity and have modified their resource plans accordingly. Particularly, when such incentives will maximize benefits to their retail customers.

Q. Please summarize the appropriate regulatory treatment for the generation-related gains on economy energy transactions, the appropriate regulatory treatment for transmission revenues received from economy sales, and why the Commission should not eliminate the 20 percent shareholder incentive.

A. Tampa Electric enters into hourly or multi-hour, cost-based, "split the savings" economy wholesale energy transactions. These transactions can be made utilizing the broker or not utilizing the broker. The transactions result in "share the savings", of which eighty percent of the energy-based generation gains and transmission revenues are returned to ratepayers as a credit to the Fuel Clause. The remaining 20 percent is retained by the company. The 20 percent is critical in incenting and benefiting sellers, purchasers and ratepayers. Both sellers and buyers are able to offset and reduce fuel costs to ratepayers with sellers retaining a portion of the gains within the company. The Commission should seriously consider enhancing incentives for those utilities willing to provide generation resources to serve the needs of its ratepayers and the Florida market due to unexpected slumps in supply-side resources and/or customer demand. Therefore, although the wholesale market has changed considerably over the past few years, the incentives continue to serve an important purpose and continue to send a correct and positive message to wholesale market participants.

Q. Does this conclude your testimony?

A. Yes, it does.

MR. WILLIS: We request that his exhibit, as he has corrected it, be marked.

COMMISSIONER DEASON: It should be identified as Exhibit 30.

(Exhibit 30 marked for identification.)

Q **(By Mr. Willis)** Please summarize your testimony.

A Good morning, Commissioners. My direct testimony in this proceeding supports Tampa Electric's proposed regulatory treatment of its wholesale power supply agreement with the Florida Municipal Power Agency or sometimes referred to as FMPA for the period January 1, 2000 through March 15, 2001.

This Commission has a policy relating to long-term firm wholesale power sales that requires a utility to separate production plant and operating expenses associated with the sale from the retail jurisdictions cost responsibility unless the utility shows on a case by case basis that the sale generates net benefits to retail customers in which case separation is not required and the revenues of the sale are flowed through the fuel adjustment clause. Tampa Electric made such a demonstration in a hearing conducted with this Commission in August 1997. We showed then that the sale to FMPA contributes net present value benefits of approximately $9 million in 1997 dollars to the company's retail customers. However, because of the existence of a rate stipulation entered into between Tampa Electric, FIPUG and OPC, the Commission required Tampa Electric to separate the FMPA sale at average system embedded costs. This separation treatment resulted in the allocation of the costs that exceeded the nonfueling revenues from the sale by approximately $700,000 to $2.1 million per month; a direct loss to the company even though the FMPA sale was shown to provide net benefits to our ratepayers.

When the Commission made that decision it was made clear that Tampa Electric could seek alternative treatment after the stipulation ended. We are now proposing such treatment that will continue to benefit our customers and at the same time avoid a substantial loss to the company since the stipulation ends December 31st of this year.

Our proposal is simply to flow back 100% of the total revenues received from FMPA back to retail customers through the fuel and environmental cost recovery clauses. The proposed FMPA treatment provides our customers with benefits derived from this sale and eliminates an absolute disincentive created by the separation treatment required during the stipulation.

Our proposed regulatory treatment is both fair and reasonable, particularly since the projected benefits to customers from this agreement is approximately $4.5 million dollars higher than the original $9 million estimate in terms of benefits projected back in the 1997 proceeding.

We urge you to approve our proposed regulatory treatment as a matter of basic fairness. It will provide additional net benefits to our customers and at the same time curtail a severe penalty to Tampa Electric.

My direct testimony also describes the appropriate regulatory treatment of gains from economy energy sales which Tampa Electric defines as Schedule C and Schedule X sales. This Commission has a long standing policy of encouraging these transactions by providing incentives for the utilities to engage in economy sales transactions.

The 80/20 split of gains on economy sales was instituted by this Commission in 1984 with the Commission agreeing with Staff that positive incentives are desirable for purposes of maximizing economy sales transactions. This incentive is appropriate for all economy sales whether they are made on or off the Florida energy broker network commonly referred to as the broker. There simply is no basis for differentiating between the two transactions because the broker is merely a computerized tool that facilitates Schedule C and X transactions. The nature of this transaction is the same. Transmission revenues and generated related gains from economy sales should be separated on an energy basis and shared by retail ratepayers in the company on the same 80/20 basis.

Finally, my testimony urges the Commission not to eliminate the 20% shareholder incentive the Commission adopted in 1984. Such an action would negatively impact both sellers and purchasers of short-term energy within Florida. This incentive encourages utilities that may otherwise not do so, to sell energy within this state and help improve overall Peninsular Florida reliability as well as economics. If any change at all is made with respect to incentives the incentives should be expanded to cover all types of off system sales. Although the wholesale market has changed considerably over the past few years, the incentives continue to serve an important purpose and this incentive continues to send a correct and positive message to wholesale market participants. To remove the incentive on economy sales would be the exact opposite action that the Commission should take in this proceeding. That concludes my summary.

MR. WILLIS: Tender the witness.

COMMISSIONER DEASON: Mr. McWhirter.

CROSS EXAMINATION

BY MR. MCWHIRTER:

Q Mr. Hernandez, you're aware that FIPUG has filed a position in this case that the FMPA sale continue to be separated, is that -- you're aware of that?

A Yes, I am.

Q And I'd like to ask you some questions about the FMPA sale, if I may. This contract lasts for one more year and three months?

A Technically, it's one year and two and a half months. The contract ends March 15, 2001.

Q Will this contract be continued or will it be terminated and the capacity that's dedicated to that contract returned to the use of your retail customers at the conclusion of the contract?

A This contract or purchase or sales agreement concludes at the end of the day on March 15, 2001.

Q I understand that it ends. My question is, are you aware of whether the intention of your company is to continue it beyond that date?

A No, I am not aware of that intent.

Q Okay. As I understand your testimony in this case, every dime that is collected under that contract will be flowed directly through to retail customers through the cost recovery clauses; is that correct?

A Yes, specifically the fuel and environmental cost recovery clauses.

Q If we have a separation of that sale after January 1st, you would be required to pay average fuel costs but Tampa Electric would keep the rest of the money?

A We would effectively -- if we separated we would effectively take the approximately $44 million of revenues that we're proposing to credit and keep 100% of those revenues and then credit back to the fuel clause the cost associated with serving that sale out of those assigned units, that's correct.

Q So it would -- it appears to me after asking you these questions and after looking at your deposition, that although our philosophy is in favor of separating contracts for more than one year -- that are of more than one year duration, in this particular case customers will be better off for the duration of this particular contract if it is not separated?

A That's correct.

Q All right. Actually, I was making a statement there for the record.

A I'm agreeing with you.

MR. MCWHIRTER: But I want to tell the Commission, we've addressed this issue and we conclude, after giving it thorough study, that although it's philosophically against what we like to see monetarily on this specific case at this specific time the customers are better off and we're going to withdraw our objection to the separation aspect.

However, we don't want to leave Mr. Hernandez at peace on that subject. Our concern is principally with capacity available and a lot of my clients are nonfirm customers who have been interrupted and for whom purchased power was purchased this year.

Q **(By Mr. Mcwhirter)** If the FMPA contract was separated we would still not have that capacity available for your nonfirm load, would we?

A That's correct.

Q But if the contract is not continued we will have it after March of 2001?

A After March 15th year 2001, that's correct.

Q Now, you enter into a variety of sales. You've already committed 150 megawatts to the FMPA transaction and you've committed 145 megawatts to first call on the Big Bend facilities, and with respect to the Hardee Power Station, Seminole has first call on all the capacity that's in place up to date but not the new capacity you're going to -- you're talking about in this case; is that correct?

A I'll say yes, but it's qualified and let me qualify the sale. The Big Bend 4 sale, the 145 megawatt sale to Seminole, which ends year 2003, is capped by an energy. It is not restrictive of the capacity. There is a restriction in terms of the actual usage of that capacity and that was predescribed in the original agreement that was set in place or became effective January 1, 1993.

On the Hardee capacity that Mr. McWhirter was referring to, the original agreement had a sale from Hardee Power Partners to Tampa Electric and to Seminole Electric and this was the shared resource concept. The capacity is available to Seminole only to the extent that they have unavailable capacity associated with Seminole 1 and Seminole 2 in a -- there are 14 megawatts allocation of Crystal River 3, the nuclear plant for FPC.

If those three resources are up and running, then all of that capacity, the 295 megawatts nominal rating at the Hardee facility is available first to Tampa Electric. And then to the extent that -- as was discussed before by Ms. Zwolak, to the extent that neither Tampa Electric nor Seminole needs it for its own native system requirements, it is then given back to Hardee Power Partners to sell on the market. And then to the extent that there's any gains from those sales, 40% of the gains goes to Tampa Electric's customers, 60% of the gains goes to Seminole customers. So it's a qualified availability of that capacity, both Big Bend 4 and the Hardee capacity.

The newest purchased power, the Hardee CT-2B purchase, which was considered in the original agreement, does have a different configuration. In this case, there is no restriction by Tampa Electric in terms of access to the capacity. There's no requirement or contingency that if Seminole 1 or Seminole 2 or Crystal River 3 were down, Tampa Electric still has the first call on that capacity. So there is no contingency requirement on that. So that is a subtle difference in the agreement. That was agreed to by Seminole Electric and Tampa Electric as well as Hardee Power Partners in this new contract.

Q Let me see if I can summarize your response to my last question. My question was, with respect to 145 megawatts of Big Bend 4, if Tampa Electric's retail customers had a need for the power and Seminole claimed that power, which one would have priority?

A If the energy allocation on Big Bend 4 was used up, Tampa Electric would. If there was still energy remaining up to the cap then Seminole Electric could take that capacity.

Q All right. If it hadn't consumed the appropriate amount of energy from it?

A That's correct.

Q All right. Now, with respect to -- what is the present size of the Hardee Power Plant? Is it --

A It's nominal rated 295 megawatts, and that's comprised of Unit 1, which is a combined cycle unit. Has a nominal rating of 220 megawatts. CT-2A, which is the first CT set up for the second combined cycle, if built, has a nominal rating of 75 megawatts. So that comprises 295 megawatts.

Q With respect to that 295 megawatts, if Tampa Electric has a need for the power and Seminole has a need for the power, which one gets it?

A Tampa Electric would unless Seminole 1 or

Seminole 2 are forced outage or planned outage.

Q Are you familiar with the petition that your company filed with the Federal Energy Regulatory Commission?

A In what matter?

Q In the approval of the new contract in which it stated the background of the old contracts?

A I did not review the contract, but my understanding is the contract was submitted to FERC and it was approved by FERC.

Q If you have not examined the contract, are you absolutely sure that Seminole does not have a first claim on that Hardee capacity irrespective of whether its other plants are down?

A I'm sure, based on discussions I've had with other officers at Tampa Electric.

Q But you haven't examined the contract yourself?

A No, I did not read the contract in detail.

MR. MCWHIRTER: Mr. Chairman, I'd like to request a late-filed exhibit in this case. I didn't think this would come up but the late-file exhibit would be the petition filed by Hardee Power Partners with the Federal Energy Regulatory Commission in which, as a background, the petitioners explained the relationship between Tampa Electric and Seminole with respect to claims on that capacity.

MR. WILLIS: Commissioner, that petition is attached to Mr. Brown's testimony.

MR. MCWHIRTER: Good.

COMMISSIONER DEASON: There's no need for a late-filed exhibit then.

MR. MCWHIRTER: I was looking for it a minute ago. If it's attached to Mr. Brown's testimony, I didn't see it.

MR. WILLIS: It's attached to his rebuttal testimony.

MR. MCWHIRTER: Would you furnish me with a copy of it please?

MR. WILLIS: Commissioner, any further questions with respect to this should be addressed to Mr. Brown who testifies on this subject. I've given Mr. McWhirter some latitude to inquire into a subject that was not covered in Mr. Hernandez's direct testimony.

MR. MCWHIRTER: I will accept that offer. I've got what I want now, but obviously Mr. Brown would be more familiar with it than Mr. Hernandez.

COMMISSIONER DEASON: Very well.

Q **(By Mr. Mcwhirter)** In your deposition in this case, Mr. Hernandez, you were asked questions about your various types of sales and you mentioned a variety, Schedule A, B, C, X. I don't think you mentioned L but you mentioned J.

A D and Js, that's correct.

Q And J are not -- are wholesale nonfirm sales that are made on the spot market to gain the opportunities that are available to you at that time. The concern that I have with respect to those sales is the relationship and priority between the wholesale nonfirm customer and the retail nonfirm customer. When you entered into a contract like that, which of those customers has priority?

A Just to clarify, Schedule Js, by the way Tampa Electric has used Schedule Js in the past, could be firm or nonfirm. They are negotiated sales. We don't consider them as a economy type transactions. Schedule Js are typically one year or less. We've entered into transactions that could be recallable. We've entered into transactions that are firm. And a lot of that judgment depends upon what's happening in the market, what our available resources are to serve that sale, and so it's a qualified circumstantial type situation where it depends on what our supply and demand resource issue is whether or not we make a firm or nonfirm.

Q All right. Now, that you've explained that, would you answer my question, which is, if you have a Schedule J nonfirm sale and you have a nonfirm retail customer, which of those customers takes priority in the event that you have a forced outage of your other equipment and you need the power and you won't have enough power to serve both contracts?

A Since you characterize it as a nonfirm transaction, I believe we would serve our retail requirements -- total retail. We do have the ability related to nonfirm customer to exercise load management. We have a provision in our tariff that I believe it was sometime in the early 90's that we modified that tariff to allow us to use that as a resource if there were -- to realize opportunity sales. We don't do that often. We do not have that same capability in our interruptible tariff.

Q All right. Let me ask you the question perhaps another way. You have a Schedule J opportunity sale that's made on Wednesday for a Thursday delivery. On Thursday morning you have a power outage. You don't have enough power to serve that Schedule J sale but you do have enough power to serve all your retail firm load, but you don't have enough power if you serve the Schedule J to serve your interruptible customers. Would the Schedule J be served or would the interruptible customers be served?

A My understanding is that a nonfirm Schedule J would be recalled so that we can serve the interruptible customers.

Q All right. Are you absolutely certain that that's your company's position? It would give us comfort to have that under oath in this case.

A I'm not involved with the day to day transactions, so to the best of my knowledge I would say that that's what we would do.

Q All right. And are you a stater of company policy that -- to bind your company on a thing like that?

MR. WILLIS: Commissioner, I'm going to object to further lines of questions. This -- along this line. This is outside the scope of Mr. Hernandez's direct testimony. It's not on any issue that's pending before --

COMMISSIONER DEASON: I will sustain the objection. The witness has answered the question to the best extent that he has.

MR. MCWHIRTER: All right.

Q **(By Mr. Mcwhirter)** I'd look to go on to your testimony with respect to incentives. You get an -- customers get 80% of your nonseparated sales and the company gains 20%. And I would ask you if there may not be some other incentives. When you generate electricity I understand that the generators use fuel to do that, they burn coal?

A Is that a question?

Q Yes. Is that correct?

A Yes. In order to generate electricity we need to consume fuel.

Q Now, does Tampa Electric have an affiliated coal company that sells coal to Tampa Electric Company?

A We do. This is the last year of that contract. Very small amount of coal.

Q Does that company make a profit when it sells coal?

A I wouldn't know what their profit is.

Q You wouldn't -- I didn't ask you the amount of the profit. Is it in the general business design that it makes a profit on the sale of coal?

A I will hope that there would be some type of profit margin.

Q Now, Tampa Electric owns a lot of barges that transport coal. Do those barges make a profit when they transport the coal from the mines down to Florida?

A Again, I don't know what the amount would be but I would assume there would be some type of margin.

Q All right. Now, as I understand it, Tampa Electric has a trading room in which you have employees who engage in these wholesale transactions, opportunity transactions. Do those people receive any kind of brokerage fee for making the sale?

A I don't know.

Q If they did and if the fuel company made profit on fuel and if the transportation company made a profit on the transportation, would it not be fair to say that there is, in fact, an incentive to the parent corporation for these sales to be made?

A That's a difficult question to answer because, as we've talked before, there's an issue about the balance of supply and demand and having the resources available to make these short-term opportunity sales that you're talking about. Just to clarify something you said in the beginning and then I'll get back to what you just asked me.

The 80/20% split is only made on the economy sales transactions. There are other nonseparated transactions like the Schedule J that 100% of those benefits or margins go back. I think that's something for the Commission to consider in terms of opening up the incentives to other types of sales.

But at this time, what Tampa Electric has done and what's in our current projection, the 20% margin share that goes back to the shareholders only applies to the Schedule C and X transactions.

The scenario you're setting up related to other additional incentives for moving more fuel or burning more fuel, that really from a business planning perspective opportunity sales are just that. They're not a firm commitment to make the transaction. We're not obligated to continue those transactions if we enter into them. They are simply opportunity or as available sales.

So for any one of our operating companies to plan on that as a firm transaction, that's not what we do. We do not assume that we're going to be able to make these opportunity sales. We make an estimate related to business planning purposes but there is no guarantee. It's subject to our retail load. It's subject to our unit or resource availability. And also a willing market; a market that would support entering into a wholesale transaction.

So it's difficult to say if that really

truly is an incentive for us from a corporate point of view.

Q Thank you for that explanation. You heard Ms. Zwolak testify that she thought it was a fair estimate without independent calculation that 65% of your fuel cost is incurred in the summer months and 35% in the winter months. If Mr. Taylor's hypothesis is correct that setting one fuel factor that charges more than actual cost during the off peak period and less for fuel cost during the on peak period, would Tampa Electric be opposed to providing an optional seasonal rate that closely tracked costs in each season? For instance, one that would cover the eight off shoulder months -- I mean, the eight shoulder months and one that would cover the four peak months?

A Just the way you started that out in terms of the percentages, I would have to subject to check on what that allocation of cost and what that relationship of costs and energy is. But, conceptually, Tampa Electric would consider developing a seasonal, if you will, on-peak off-peak seasonal rate patterned similarly to the time of day rate as reflected in concept Schedule -- I think it's Schedule E1-D of Ms. Zwolak's exhibit.

And the concept there, there's a one page in her exhibit. The concept there is that you walk through using the levelized fuel factor on an annual basis and you simply would make an offering that based on energy consumption and production costs, along the lines of higher costs and higher energy over the summer months versus lower production costs and lower energy usage generally over the winter months, at least this is true for our system, and you can come up with a relationship of cost and usage related to the summer season, the four months that were discussed yesterday, May, June, July and August, relative to the other months of the year.

So conceptually, we would consider developing a seasonal time of use or seasonal utilization rate that keys off the existing projected levelized annualized fuel cost recovery factor, but effectively once we did the math I would envision that you'd have a scaler, a multiplier if you will, greater than one for the summer months and a scaler less than one for the winter months. And that conceptually is similar to the concept of an on-peak off-peak rate.

If you look at the schedule in Ms. Zwolak's exhibit you'll see that the factor for on-peak usage to better reflect the on-peak production cost is higher than the levelized factor and that the off-peak factor is somewhat less than that.

So conceptually what Tampa Electric would consider is develop a seasonal rate patterned off the same concept.

Q If you did such a rate it would be cost based and it wouldn't discriminate against any other customers, would it?

A That's correct, because we're still taking the same system projected cost. It would be an optional type program. It would have to consider at some time the mechanics of running through the numbers, but conceptually it seems reasonable to be able to develop an offering like that.

Q So if a company or a customer desired to have a flat rate for budgeting purposes they could have that, but if someone wanted to adjust their consumption pattern so that they could take advantage of the seasonal rate they could do that as well?

A That's correct. I would envision this almost like a passive conservation program; the price elasticity issue. The higher the price, the less likely you would use to the extent you can modify your consumption behavior and shift usage from the summer to the winter if a customer could do so. And it's the same concept in the on-peak off-peak rate.

Q Could you do that before the beginning of this new era, collection?

A Resources as they are, what we would try to do -- what we would do is put together a filing for this Commission on or before January 1st, subject to Commission review and approval, and what I'd like to do is consider it as maybe a pilot program to see what kind of market penetration we would have.

But effectively once we run the numbers, bring it back to this Commission, and subject to your review and approval. And to the extent that you're willing to allow us to have this pilot program, we would be willing to enter into that and allow customers to try a seasonal rate.

MR. MCWHIRTER: I tender the witness.

COMMISSIONER DEASON: Mr. Burgess.

CROSS EXAMINATION

BY MR. BURGESS:

Q Mr. Hernandez, I have some questions about the FMPA sale. Is it correct that at this point that TECO has found another source to supply that particular agreement; to supply the energy associated with that particular agreement?

A Just to clarify, when you say at this point, do you mean for this year or for next year?

Q For this year. Let's start with 1999.

A For 1999, that's correct. 100% of the resources used to serve the sale are from third party purchases.

Q Is that a single third party?

A No, there's two parties.

Q Can you tell me who they are?

A PECO Energy and Florida Power Corporation.

Q What's the treatment, the fuel adjustment treatment for that for the cost and revenues associated with that at this point?

A There are no costs associated with the sale or the purchases in the fuel adjustment filings.

Q Is -- if for some reason either PECO or Power Corp. or both were unable to meet their obligations under the sale, is Tampa Electric still obligated to meet some portion of it or to meet the requirements of the FMPA sale?

A To the extent there was a shortfall, we would either utilize one of our assigned resources or have an additional short-term third party purchase to cover, but that has not been the case to date.

Q But the answer is, yes, contractually you're still under the obligation to be the guarantor of this energy; is that correct?

A That's correct, with the option to either utilize our resources or third party purchases. That's correct.

Q Okay. Now, as I understand it, what you're saying with regard to the year 2000 is your -- Tampa Electric would like to the Commission to adopt the proposition that the entirety of the revenue go through fuel adjustment as revenue credit and fuel adjustment; is that correct?

A With the slight change, that's correct. The portion -- a small portion of that -- those revenues would be credited through the environmental cost recovery clause.

Q And is the $44 million that you gave, is that the sum of the amount that would go through fuel adjustment and environmental?

A That's correct, for the full 14 and a half months of the transactions.

Q For the full 14 and a half months. Okay. I would like to understand the dollar impact of the other changes that TECO would like and so I want to stay on consistent ground; either the entire 14 and a half months or the 12 months of the year 2000. Do you have the amount that would be associated with the full 14 and a half for the other aspects of this or would it be better to run them through as an annualized figure for the year 2000?

A I believe I have it. I can answer questions in both ways. The confusion is, we're seeking the regulatory treatment for the 14 and a half months so this won't be as much of an issue in the next fuel adjustment proceeding next year for the balance of the two and a half months of the agreement. But relative to the fuel factors, there is only a portion of the revenues that apply to the credits. In this, the year 2000 factors, it's $36 million out of the $44 million.

Q Okay. So $36 million. Can you tell me then, as I understand it, what you're recommending then is that the O&M costs and the carrying cost is a plant cost associated with this would then be unseparated for the year 2000 as a result of your flowing through the file adjustment clause all of this revenue; is that correct?

A That's correct and the environmental clause.

Q And the environmental, correct. For the year 2000, can you tell me how much would be associated with the O&M costs that would otherwise be separated if the Commission determines that it wants to continue with the separation factor that it imposed in applying the last stipulation?

A If you give me a moment I believe I do have that.

Q Thank you.

A I apologize. I have this in different dollar bases. It's in 1999 dollars. But I do have the answer.

Q I don't understand what you mean. You have it in 1999 dollars.

A I have it in current year dollars versus year 2000 dollars. It's the time value of the dollars.

Q Okay. So you're simply looking for, it's just discounted back one year?

A That's correct.

Q Is the $36 million discounted back one year?

A No, it is not.

Q Okay. Would you give me the O&M expenses?

A Well, I do -- I'm sorry. I do have it in a rate bill. I'll give you the total dollars. The O&M dollars are $3,390,150. And that corresponds to a rate of $2.10 per megawatt hour in the year 2000.

Q Okay. Can you tell me what the average fuel costs that are anticipated as necessary to serve this contract for the year 2000?

A Yes, I can. I need to clarify that the number that I just read you is for the full 14 and a half months. It's not for the calendar year. I apologize.

Q Okay. Do you have that number for a calendar year?

A Not directly in front of me.

Q Okay.

A The weighted -- let's see. You just asked me about the fuel cost?

Q Yes.

A The fuel cost, and I will give this again in the 14 and a half months. That's how I've got the information in front of me. The projected system average fuel and purchased power costs -- and this is right off the Line 20 in Ms. Zwolak's testimony if you were to use the number. This is not the incremental fuel cost but it's what we used in my late-filed exhibit.

Using the system average fuel and purchased power cost rates of $20.87 per megawatt hour, so that includes average fuel plus all of the purchased power that's in our projected fuel filing, you come up with a number for the 14 and a half months of $33,557,257. The actual incremental fuel cost associated with the sale, just for comparison, is $27,942,048.

Q Okay.
A I'm sorry. The rate for that is \$17.38. And that number, just to help clarify, is the assigned units, the Big Bend 2 and 3, and Gannon 5 and 6 weighted average incremental fuel costs associated with making the sale.
Q And Mr. Hernandez, as I recall there was an exhibit attached, I believe, to your deposition wherein some of these costs were displayed and there was an entry for SO2; is that correct?
A That's correct.
Q Can you tell me what that is please?
A Okay. Again in 1999 dollars, the amount for the SO2 allowance -- and this is a replacement value of the SO2, which is much higher than the actual SO2 costs incurred by internalized costs -- the value is \$2,558,140.
Q All right. And I think, unless I'm missing a component, the final piece of the effect would be the carrying costs associated with the capital assets involved in providing this sale. Do you have that?
A If you give me a moment, I believe I do. The carrying costs associated with the existing separation methodology would be calculated by using the current rate of \$18.50 per kW month times 150

megawatts. That's the amount of the sale for the year 2000, times 12 months, and that value is $33.3 million.

Q Okay. Now -- and that's what you're telling me the return costs, the overall rate of return plus the depreciation associated with that portion of plant or is -- tell me where the depreciation expense associated with that portion of plant would be. Would that be in the O&M expenses you gave earlier or is that included in this number that you've just given?

A I believe it's included in the 18.50 but I'd have to check.

Q Okay. Now, then do I have it correct then that what you're saying -- and again, part of the problem is, I think we have jumped a little bit from 12 months to 14 and a half months, but correct me if I'm wrong. And we have also mixed a little bit between the year 2000 and the year 1999 as far as dollars. But conceptually what I understand you're suggesting is that you would flow back $44 million, the entire amount of the revenue in fuel adjustment for the FMPA sale to the benefit of the retail customers, and in the base rate effect would be $33 million -- I'm sorry. The base rate effect would be $33 million additional carrying costs associated from the nonseparation, the $2.5 million of O&M expense and the $3.39 million of the SO2. Is that correct or have I mischaracterized something?

A I'm -- just to qualify or to better understand it, $33.3 million that we calculated is based on separation, not nonseparation.

Q That's what I'm speaking of. But what you're asking basically in this proposition is that where the Commission separated this out before, what you are suggesting is that it not be separated?

A That's correct. But the impact on the cost recovery clauses, the $33.3 million, is simply a loss to the company; that those resources were part of the reserves that were in place at the time that we made the deal back in 1996. So to the extent that those resources were there, the sale was based on an incremental type consideration.

From the company's perspective there wasn't a consideration that this was a good deal for ratepayers and customers and company, the ratepayers alike to the extent that we had to separate the sale. And the $33.3 million, therefore, if that was -- if we continued the separation, becomes a huge expense to the company with no benefit to the ratepayers because then the company retains 100% of those revenues. And the $44 million, again, is spread over the 14 and a half months. It's $36 million approximately in the year 2000 and approximately $8 million in the first quarter.

So when you annualize that you don't get the same rate reduction and that was the way that it was described in my Late-filed Exhibit No. 2 attached to my deposition.

Q I'm trying to figure out -- I'm trying to get from you the dollar impact of the change in the separation that would be associated with what you're seeking that would be effected by the change in plant separation.

A Impact to the customer?

Q The impact on your base rates. The impact on your base rates earnings?

A That's the $33.3 million.

Q Okay. That's the $33.3?

A Right.

Q And that's just from the plant side? That's not the O&M side?

A That's correct.

Q Okay. So you would have the $33 million, the $3.39 million and the $2.5 million would be the impact reduction on your base rate earnings as a result of that; is that correct?

A I believe that's correct.

Q Okay. And then I think you said the average fuel cost that would be associated with serving this contract would be $33.5 million; is that correct?

A No. The weighted average incremental fuel cost associated with serving the sale is that other number. I had simply gave you the system average because I believe that's what you asked me.

Q You said the incremental was $27.9 million and the weighted average cost for that amount of fuel for the same period was $33.5 million?

A No. Those are two different numbers. The weighted average, $27.9 million, is taking the incremental fuel cost from the four identified sources that will be serving the sale; that's Gannon 5 and 6, Big Bend 2 and 3. So that's the true incremental fuel cost associated with serving the sale; the fuel cost component.

When you ask the question related to what would the system number be, in our late filed -- in my Late-filed Exhibit No. 2, we showed that even if you looked at the total system average not just those four units fuel average, which would be maybe something closer to $19 versus the $17.38 weighted average -- if you even stepped it up and included that all the units on our system average fuel cost, plus all of the purchases that are in our projected, that's where you come up with the rate of $20.87 per megawatt hour. That's what drives the $33.5 million number.

Q And that's for the same period?

A It's for the same period, right. And simply we did it that way to demonstrate that even if you included the total system, fuel and purchased power cost, you still get net benefits to the ratepayers. We're somewhere -- in an actual basis somewhere in between.

Q Now, that's assuming nothing is captured in base rates; is that correct?

A Captured by base rates in terms of?

Q In terms of some type of earnings limitation imposed by the Commission on base rates for the year 2000?

A That's correct.

Q Mr. Hernandez, you do have rebuttal testimony and I have some specifics on the 80/20 split with regard to that, but before we get into that I just have a general question or some general questions on it.

I understand your point for the need for an incentive. I guess my question is, isn't this incentive all one way? That is, there is no downside to it?

A We're referring to economy sales or making cost systems --

Q Yes. The 80/20 split on economy sales.

A I don't understand when you say there is no downside.

Q Well, let me start from this proposition. You agree that because you've been given a proper return, a reasonable return on your investment -- because Tampa Electric's been given a reasonable return on its investment, a reasonable effort to keep prices as low as possible is expected in exchange; is that correct?

A I would agree with that.

Q And what you're suggesting, though, is that some specific incentive is helpful for the purpose of assuring as much aggressiveness as prudent for each company to make as much sales to keep the prices as low as possible; is that correct?

A To an extent. And this gets back to the supply. I can't say yes or no without talking a little bit. This whole issue of reserves and what you compile in terms of available supply side resources, if we were simply to say, we're going to carry a 30% reserve margin, certainly we're going to mitigate any of the reliability issues that we have for either firm or the nonfirm customers, but it comes at a price. It comes at a price in terms that we would probably seek rate base relief because we simply can't carry 30% reserves without some impact on price.

But, if you were in that situation and you had now available resources to get on the market, you know, arguably is the 80% or even 100% of that margin enough to offset what the customers would realize in terms of the base rate effect. So there's a fine balance there in terms of maintaining the adequate reliability criteria; what is the appropriate criteria; what are the resources that you need to have and at what price; what is the cost and, therefore, what is the price. So these type of transactions, these nonfirm transactions, are clearly driven by what resources you put in place, the availability of those resources, either your existing system or the purchased power arrangements that you have and your ability to work the market.

I agree with some of the comments that Mr. Howell earlier, with most of them, in fact. There are some differences between our two companies, Tampa

Electric and Gulf, in terms of how we enter into the market and what we characterize as economy transactions perhaps. But, effectively, by having an incentive there actually is a reliability benefit but you've got to balance the cost and the price issue between not only our ratepayers but also the other ratepayers, the wholesale market players that are, in turn, buying power or selling power to met someone else's firm commitments, and then, of course, our shareholders.

I mean, if we were to price ourselves out of the market effectively by carrying a 20% or 30% supply side margin, that's not the right thing to do for our ratepayers and wouldn't be the right thing for our shareholders because we tend to -- that would expose ourself to the extent that the wholesale market continues to change in this state. And it is a dynamic and robust market right now. But, it's difficult to say that, you know, what that amount of resources should be, and should there be an incentive. I think having a carrot versus a stick or disincentive makes a big difference.

So to the extent those remarks by Mr. Howell, I totally agree with and fully support that the Commission should retain an incentive, and not just for the economy transactions. We should consider it for all types of transactions.

Q I don't think you understood the question.

A I will try again then.

Q The point that I'm making is -- and I will simply offer this and you tell me. Is it not correct that given that you're receiving a reasonable return before you make any economy sales that you -- a company could make less than optimum effort at making economy sales; less than reasonable effort; less than what the Commission should reasonably expect a regulated utility to make, and yet get more than a reasonable return because every sale adds to the profit of the company?

A Well, margin aside --

Q Is that correct?

A There's a benefit to the company in the corporation for making these types of transactions. The effective credits that go back in the lowering of the retail rates. There is a benefit to that, as was discussed before.

But to the extent that this market is very dynamic, the fact that we've had to add additional resources since our last rate case, it's not so much knowing the market, it's working the market. And that works both on the wholesale side when you're making sales, but also when you're buying and so -- I mean, there is no guarantee that you're going to make these opportunity sales. You've got to expend the resources. You got to spend the dollars to provide the information to the folks that make these types of transactions. And there is, I would say, a difference in the effort. It's not to say that we wouldn't make or seek to make cost-effective transactions, either buying capacity and energy or selling capacity or energy, but would we have the same level of resources dedicated to that in the absence of an incentive, I'd say there would be a difference.

Q Well, I'm not sure whether you answered the question. My question -- are you telling me that the answer might be no because you've got assets and expenses devoted to it that were encountered subsequent to your last rate case? I'm trying to understand how it can be anything other than yes for every sale that a company makes, even if the effort is below that that's reasonable or reasonably expected, yes, you get higher than a reasonable return because you are already receiving a reasonable return to the establishment of your base rates?

A But doesn't that depend on where we are at in terms of the range? I mean, if we're below our ceiling and we still have that opportunity to go up, for Tampa Electric to 12.7 -- 12.75% on return, then we have the ability to or shouldn't we be allowed the ability to be aggressive or as aggressive as we can in these sales and enjoy some type of return for that effort?

Q You're asking me a question?

A I think I did.

MR. BURGESS: Should I be under oath, Commissioner?

COMMISSIONER DEASON: Let me ask this question and this is a question. How is the 20% that is retained by shareholders for economy sales under the broker, how is that accounted for? Is that above or below the line for regulatory purposes?

WITNESS HERNANDEZ: Below the line.

COMMISSIONER DEASON: So then how would it impact your earnings for your determination of your range if it booked below the line?

WITNESS HERNANDEZ: It doesn't. I spoke incorrectly.

Q **(By Mr. Burgess)** When you say that you have expenses associated with examining these -- and I agree that a great deal more effort has been put into trying to establish the optimum amount of these sales to be made and discovering where the markets are. But what is the accounting for these expenses for these particular departments that you're speaking of that do this examination? What account does it go into?

A I don't know what the specific FERC account is. I'm sorry.

Q Do you know whether it's an account that would be an above the line expense for the purpose of establishment of base rates?

A I believe it is an above the line expense.

Q And so for any surveillance purposes, any stipulation that involves earnings, they would be accounted for and paid for through base rates; is that correct?

A I believe that's correct.

Q Okay. Thank you, Mr. Hernandez.

COMMISSIONER DEASON: Staff, how much do you have for this witness?

MR. KEATING: I'd estimate about 20 minutes.

COMMISSIONER DEASON: Okay. We're going to take a recess. We will reconvene at 20 minutes after 11:00.

MR. KEATING: Okay.

(Brief recess.)

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COMMISSIONER DEASON: Call the hearing back to order. Staff, you may inquire.

CROSS EXAMINATION

BY MR. KEATING:

Q Mr. Hernandez, how does TECO treat transmission revenues received from nonseparated nonfirm wholesale energy sales not made through the broker?

A Transmission revenues, you said?

Q Yes.

A They're credited back. These are noneconomy sales?

Q Excuse me?

A These are noneconomy, nonseparated sales?

Q These are the economy sales, nonbroker.

A Economy sales nonbroker, the company retains 20% of those revenues and flows 80% back through the fuel clause.

Q You flow back 20% of the transmission revenues from those sales? My question related only of the transmission revenues.

A On economy transactions a broker or off broker the company retains 20% of those revenues. Off broker or on broker noneconomy transactions, 100% of those revenues are flowed back through the fuel clause.

Q In a rate case, is it correct that transmission costs are allocated to the various rate classes on a demand basis?

A I believe that's true.

Q How does TECO record generation related gains on nonseparated nonfirm wholesale sales that are not made through the broker?

A On economy transactions that fall under that category the company retains 20%. And economy, again, for Tampa Electric is Schedule C and Schedule X transactions only. Other nonfirm nonseparated transactions that are off the broker, 100% of those gains are credited back on the generation side through the fuel clause.

COMMISSIONER CLARK: Do I understand there is a bit of inconsistency among the companies as to how that is treated?

WITNESS HERNANDEZ: I think it's more of a definition of what we each characterize as economy, Commissioner Clark.

COMMISSIONER CLARK: Well, you say C and X are economy.

WITNESS HERNANDEZ: Yes. For Tampa Electric that's true.

COMMISSIONER CLARK: And you split 20/80 for those sales?

WITNESS HERNANDEZ: Yes, we do.

COMMISSIONER CLARK: And it's J and O something?

WITNESS HERNANDEZ: We don't -- well, all other nonfirm or these as available transactions, either on the broker or off the broker are credited back 100% of the gain, both on the transmission as well as the generation gain, credited back to the fuel clause.

COMMISSIONER CLARK: You have to talk to me in terms of schedules.

WITNESS HERNANDEZ: Okay. All other schedules except for C and X, 100% of the gains generation and transmission revenues are credited back through the fuel clause.

COMMISSIONER CLARK: Does FP&L have the same C and X schedules?

WITNESS HERNANDEZ: I'm not the best person to ask, but I believe their Schedule Cs and Xs are comparable to ours in terms of the concept, but I'm not sure.

COMMISSIONER CLARK: Well, then let's forget the schedules. Do you think all economy sales are being treated the same? If they have the same characteristics, are they being treated the same with respect to the 20/80 split?

WITNESS HERNANDEZ: For Tampa Electric, yes, ma'am.

COMMISSIONER CLARK: For all companies, do you know?

WITNESS HERNANDEZ: I don't know. I don't know.

COMMISSIONER CLARK: Does it make sense to treat them all the same?

WITNESS HERNANDEZ: It may.

COMMISSIONER CLARK: Why would you not treat them the same?

WITNESS HERNANDEZ: I really don't know what the circumstances would be for the other companies in terms of how they make those transactions, so, again, I can only speak for Tampa Electric.

COMMISSIONER CLARK: Can you think of any circumstances why it wouldn't be appropriate?

WITNESS HERNANDEZ: No. I believe transactions -- C and X type transactions that are made on the broker as well as off the broker should be treated the same, and so, therefore, a 20% incentive should be retained by the investor-owned utilities that make those transactions.

COMMISSIONER CLARK: What is a J transaction?

WITNESS HERNANDEZ: A Schedule J transaction is typically a transaction that's one year or less. That could be firm or nonfirm. It's a negotiated contract that's different than the split the savings concept, that's attributed to what we characterize as economy transactions. It's simply a negotiated reservation or capacity charge; a negotiated energy charge that includes fuel and O&M and it's a willing seller and a willing buyer, generally off broker, I believe.

COMMISSIONER CLARK: How is it different from a C or X transaction?

WITNESS HERNANDEZ: Well, it's still cost based type transaction. By negotiating what the transaction price would be we can effectively get a greater margin relative to the incremental cost to make the Schedule J sale and then flow 100% back to the ratepayer. I'm not answering your question, am I?

COMMISSIONER CLARK: The difference is that one is -- Mr. McWhirter, I think you need to quit fiddling with that.

MR. MCWHIRTER: I will step out.

COMMISSIONER CLARK: The difference is that one is based on incremental and decremental costs and the other is based on what you negotiate?

WITNESS HERNANDEZ: That's correct.

COMMISSIONER CLARK: Are you arguing that the one you negotiate should be treated the same with respect to the 20/80 split and, in effect, that those should be subject to the shareholders getting 20%?

WITNESS HERNANDEZ: I think the Commission should consider that. To the extent that because it's a negotiated transaction, it's not as simple as just identifying what your avoided costs are if you're a buyer, or identifying what your incremental costs are if you're a seller.

In either case, in any type of transaction, you should know what those are. But a negotiated transaction is such that you've got to the utilize, again, the knowledge of the market. You've got to work the market to raise the transaction price and to use those same numbers as before, that Mr. Wieland talked about and Mr. Howell talked about; the $20 seller cost; the $30 buyer. In the economy transaction, you simply take the two, add them together and divide by two. So the transaction price there would be $25 per megawatt hour.

In a negotiated J transaction, if my incremental cost is still $20 but I can negotiated a $27 transaction price versus what I would have gotten on the broker at split the savings or off the broker split the savings, I just raised the bar in terms of the margin for our company and or our ratepayers. And the way that we're handling this right now, that full margin and this example, the $7 per megawatt hour, would be credited back 100%.

COMMISSIONER CLARK: If that's the case why do you as a company ever negotiate a J contract? You're not going to get any.

WITNESS HERNANDEZ: That's a good question. Part of it has to do with the benefits that the ratepayers receive. But arguably, if have you to work harder for those negotiated contracts, this Commission should consider an incentive back to the company for its shareholders to enter into those type of transactions because it's not simply matching the high to low. You've got to work the market.

COMMISSIONER CLARK: Can you tell me how much you have subject to a J contract and how much you have subject to a C and X contract?

WITNESS HERNANDEZ: Energy? I don't know.

Again --

COMMISSIONER CLARK: You threw in energy. Why is that important?

WITNESS HERNANDEZ: Because C and X, it's typically not a capacity.

COMMISSIONER CLARK: Okay. J has the capacity.

WITNESS HERNANDEZ: More energy driven. The J is more of a capacity type contract with some energy tied to it and I don't have a feel for what our current obligations or what our current market opportunities are.

COMMISSIONER CLARK: Thank you.

Q **(By Mr. Keating)** Mr. Hernandez, I've got an exhibit I'd like you to take a look at. I just have a few questions on that.

MR. KEATING: It's a composite exhibit. Consists of TECO's response to Staff's First Set of Interrogatories No. 10, TECO's Late-filed Deposition Exhibit No. 2 to Mr. Hernandez's deposition and the Late-filed Exhibit No. 5 to Mr. Hernandez's deposition. Staff would ask that that be marked for identification.

COMMISSIONER DEASON: Exhibit 31.

(Exhibit No. 31 marked for identification.)

Q **(By Mr. Keating)** Mr. Hernandez, turning to the first page of that exhibit. I realize that this is not a response that you sponsored, but are you familiar with these figures or --

A Yes, I am.

Q Do you know what percentage of these economy sales are broker sales versus off broker sales?

A It changes from year to year. Between 1990 and 1998 the numbers range from 62% on broker up to 95% on broker, and the difference, the balance of the percentage being off-broker type transactions.

Q For 1998, do you know what that percentage was?

A 62% were made on broker.

Q And for the purchases, do you -- can you break those down into percentage of on broker and off broker economy transactions?

A Every year? I'm sorry.

Q For 1998.

A For 1998, 62% of the 744,079 megawatt hours were on broker, and then 38% of that number would be --

Q I going on to the next column. I'm sorry I didn't make that clear. The next column entitled Economy Megawatt Hour Purchases.

A Okay. I'm sorry.

Q Can you break those down into off broker and on broker transactions?

A It ranges, again, between that period, roughly 75% up to 97%.

Q On broker?

A Made on broker.

Q And for 1998 do you know what the breakdown is?

A 97% on broker.

Q Okay. I believe you stated before that Tampa Electric applies a 20% incentive factor only on economy sales made under Schedules C and X; is that correct?

A That's correct. Made either on broker or off broker.

Q Okay. Why doesn't TECO apply the incentive to market based economy energy sales?

A Market based priced economy?

Q Yes.

A I guess by definition we -- a market based priced transaction doesn't fit our definition of what our incremental cost is. In that sense a market based priced transaction would -- I guess I would envision this as being an off broker type transaction, and at this point we've made some of those sales, but we flowed 100% of those margins back because my understanding is we don't have the ability as yet to retain 20% of those margins.

Q Okay. So does TECO believe that the Commission's 1985 order approving the 20% incentive does not apply to market based priced economy sales or market based priced sales? As I understand it, you're saying that market based priced transactions are not, under your definition of an economy transaction, an economy transaction?

A Yes. And the reason why -- I will clarify the last point. The reason why I say in my opinion that that would not be an economy type transaction, because by definition, we would be selling at a cost higher than our incremental cost. And an economy type transaction, we would simply be putting out there our incremental costs of fuel in the associated O&M and SO2 allowance cost, and that's what gets used to determine the transactions price with the buyer, again, under decremental or avoided costs.

In a market based priced transaction, you're hopefully something much greater than your incremental cost. Now, if this Commission determined that by the order that came out in the 1985 proceeding that we should be allowed a 20% margin, we would certainly agree to that.

Q Do you think that that order did apply to market based priced transactions?

A We haven't interpreted that at this point.

Q When Tampa Electric participates in an economy energy transaction, is it exceeding its obligation to provide cost-effective electric service to its retail ratepayers?

A Is Tampa Electric exceeding our obligation?

Q Yes.

A I'm sorry. Could you rephrase it -- or repeat the question?

Q Yes. When Tampa Electric participates in an economy energy transaction, is TECO exceeding its obligation to provide cost-effective service to its retail ratepayers?

A I would say that if it were exceeding -- again, as we discussed earlier, I believe that's -- to the extent that we've got available resources and there is a willing buyer, I think we should do so, to some level.

Q What incentives does TECO have to purchase economy energy?

A To reduce the production costs that we would otherwise incur by utilizing our own resources. To the extent that there is lower cost available resources the customers benefit by providing that incremental energy with the lower cost incremental resource.

Q Do TECO's shareholders receive any direct financial incentive for making economy purchases?

A Not at this time, no.

Q Okay. Do they intend to apply an incentive?

A If the Commission is willing to consider that, we would certainly entertain those thoughts. That's not our intent in our filing.

Q Does Tampa Electric recover the capital and fixed O&M costs of its generating resources through its base rates?

A I'm sorry. I couldn't hear the first part of the question.

Q Does Tampa Electric recover the capital and fixed O&M costs of its generating resources through its base rates?

A Yes, it does.

Q Are these the same generation resources from which TECO would make an economy energy sale?

A Yes, they are.

Q Okay. Can Tampa Electric sell economy energy at market based rates?

A I believe, as I was saying earlier, my definition of selling economy wouldn't fit, a market based priced transaction wouldn't fit. Tampa Electric does have the ability to engage in market price based transactions within and without -- outside the state. I'm sorry.

Q What percentage of these transactions are made in state versus out of state?

A I'm not sure.

COMMISSIONER CLARK: Mr. Hernandez, to your knowledge, does FP&L make Schedule J sales in Florida?

WITNESS HERNANDEZ: I'm not sure if they have Schedule J transactions. I don't know.

COMMISSIONER CLARK: If they did have a Schedule J, would it be the same as yours?

WITNESS HERNANDEZ: I'm not sure.

COMMISSIONER CLARK: I thought in your testimony you indicated that they did have Schedule J and that was just -- maybe it was your rebuttal -- some confusion as to what the comparison --

WITNESS HERNANDEZ: I believe in my -- either my rebuttal testimony I was really focusing on Tampa Electric as what we consider to be economy transactions, the C and X. I might have referred to

Schedule J, but it would be specific to Tampa Electric.

Q **(By Mr. Keating)** Mr. Hernandez, for the 1999 recovery period how much revenue will TECO receive from out of state economy sales?

A Again, I'm not sure how much of the economy sales that we're making out of state. I don't know.

Q Do you know how much -- what level of purchases -- economy purchases TECO would make from out of state?

A I believe most of the purchases are from within the state, but again, I'm not sure on the exact proportion.

Q How does TECO treat the revenues from out of state economy sales?

A They would be treated just the same as if there was an in state transaction, either on broker or off broker. We would retain 20% of the margin.

Q How would the remainder of the gain that's credited to the ratepayers be credited?

A The gain would be the same. 80% of that gain would be credited back to the fuel cost recovery clause.

Q I'm going to go on to some questions about the FMPA sale. Could you describe the current regulatory treatment as ordered by the Commission in 1997 for your contract with FMPA?

A The Commission ordered Tampa Electric to separate the FMPA sale during the stipulation period.

Q Is there a capacity charge associated with the sale of wholesale energy and capacity to FMPA?

A Yes, there is.

Q Is there a transmission charge associated with that sale?

A Yes, there is.

Q On Page 10 of your prefiled testimony you refer to the FMPA wholesale sale as an incremental or opportunity sale; is that correct?

A Yes. On Line 10 of my testimony, that's correct. Page 10.

Q Can you explain what you mean by an incremental or opportunity sale in this context?

A Sure. What I mean by that is that an incremental sale or an opportunity sale is one, in my opinion, does not change the resource expansion plan. It does not require additional resources. It's simply using the available reserves, if you will, or supply side resources in excess of the company's prescribed reliability criteria.

So, for example, for Tampa Electric at the time that this transaction was entered into in 1996, Tampa Electric had reserves projected approximately 20%. And so, our criteria at that time was 15% and so we effectively had 5% reserve margin that would be there in excess of our minimum to make opportunity sales.

Opportunity sales can be configured in either a nonfirm or firm. To the extent that you enter into a firm transaction, as long as you're above your minimum planning criteria, the company should be encouraged to make these type of transactions. This transaction was priced on an incremental cost basis, again, with the thought that to the extent the resources above our minimum were available that we would charge an appropriate amount to recover both the fuel and variable operating costs and some gain.

And that initially our concept was to share the gain 40% to the shareholders and 60% to the ratepayers with no separation. And in subsequent proceeding, the Commission determined that we needed to separate and that therein lied the economics and why that type of treatment didn't work for us during the stipulation period.

Q Could you refer to Exhibit TLH-1 attached to your prefiled testimony.

A Should we refer to the amended or revised document?

Q Yes. Could you tell me what information is shown on this exhibit?

A In the revised document we're showing, as of October of this year, what the cumulative benefits associated with this transaction going back to the retail ratepayers. For the first section of data, we cover the period of 1997 through 1999. And for 1999 it's an actual slash estimate; an estimate, if you will, for the balance of 1999 at the time that we prepared these numbers.

What that reflects, in 1997 dollars the net benefits back to the retail ratepayers were $9.8 million approximately in 1997 dollars. That compares to what Tampa Electric talked about in the 1997 proceeding of approximately $9 million in benefits. And that's why we put this in 1997 dollars so we could compare on a common dollar basis.

The point of doing that was to demonstrate that while we had estimated $9 million for the whole transaction -- from 1997 through March 15th of year 2001, while we estimated $9 million benefits, we've already accrued $9.8 million benefits.

The next line goes to the balance of the transaction, the last 14 and a half months, from January, 2000, to March 15, 2001. The corrected number there is $3.4 million net benefit to the ratepayers and that's even using the more prescriptive number of -- using system average fuel and purchased power as the rate to -- if we were to credit back against those total revenues versus what the real cost is and that's the incremental fuel cost associated with those units -- fuel and SO2 allowance, I'm sorry, associated with the Gannon 5 and 6 and the Big Bend 2 and 3 units.

So we used a number that generated a very conservative reforecast of the balance of the transaction benefits. The next column simply takes those -- estimates a total net benefit by combining the $9.8 million with $3.4 million and you get to the $13.2 million net benefit for the entire transaction. And, again, on -- the next line shows the original net benefit estimate for the whole period of $9 million.

Q Thank you. Can the net benefit to retail ratepayers for the 2000 to 2001 period be described as the difference between the revenues received from FMPA and the incremental cost of SO2 emission allowances and fuel to provide the 150 megawatts of capacity and energy to FMPA?

A It would. What we showed here was not the incremental unit fuel cost. The benefits would be much greater. This is, again, the system average but that's how it -- conceptually, that's how it would work.

Q Is it possible that the incremental cost of fuel and SO2 allowances will exceed the revenues received by TECO under this contract?

A I do have that figure for you, if you like. The incremental fuel cost -- and I believe I spoke of this earlier -- using the weighted average fuel cost from those assigned units would be $27.9 million. And the associated SO2 expense, the $2.56 million, is based off of those four units serving the sale. It's also using a much higher figure for the SO2 allowance as a credit. We're utilizing -- and it's in footnote No. 3 -- a market replacement value of those SO2 allowance costs of $225 per ton.

The internalized cost -- what I mean by internalized cost is the actual cost associated with fuel blending or scrubbing -- is much less than that. So we again used a much more conservative number by using a higher replacement value. So we've got conservatism built into these numbers that reflects a higher replacement value of the SO2 allowance cost and includes the total system average fuel in excess of the incremental unit fuel associated with serving the sale. And we're utilizing the total purchases that are in our projection. So, it's pretty safe to say that this is a very conservative approach that still yields benefits.

Q Does that amount include O&M costs?

A It's got -- yes, it's got O&M using, again, the variable O&M rate prescribed by the Commission by the methodology that came up with, and this is in Footnote No. 2, $2.10 per megawatt hour in the year 2000, and $2.15 in 2001. It's the same value that we would use for economy type transactions.

Q So is it possible that these costs will exceed the revenues received by TECO under the contract?

A Only to the extent that our fuel -- incremental unit fuel cost would be higher than what we think they're going to be. To the extent -- and again, this gets back to the contract. By utilizing the four units that I described before, Gannon 5 and 6 and Big Bend 2 and 3, if those four units or all four units are unavailable, we are not committed to make the sale. So we would not be forced to utilize a higher re -- higher cost resource, for example, a combustion turbine to serve the sale.

Q You wouldn't be required to, but could you?

A No. We would not be required to. If those four units are all off line for either planned maintenance or forced outage, that sale stops. So we would not be forced to utilize other higher cost resources to make the sale.

Q You mentioned that the incremental fuel cost may be higher than estimated and that would perhaps be the only possibility that costs would exceed the revenues received by TECO under the contract?

A The other piece would be purchased power costs but most of those are contracted. The other as available purchases would be of economy type or to the extent that if we had additional forced outages, unplanned outages in our system, that we don't have any control over.

Q Is TECO going to monitor the fuel costs to ensure that they don't exceed -- so that we don't have a situation where costs exceed the revenues?

A Well, at this point in time the fuel contracts are already in place. The reason why I hesitate as to why there would be any variances is that the incremental cost is really a function of two components. It's the fuel cost, which is pretty much set for next year, but it's also a component of the incremental heat rate. So to the extent that there were slight variations in what we think the heat rate is going to be off those units versus if we got warmer temperatures or changes in cooling water temperature that effects those heat rates, the incremental costs could be higher or lower. It's a projection, but we think our projections are pretty close.

Q Well, let me ask if TECO can give the assurance that if its incremental cost of fuel and SO2 allowances and O&M exceed the revenues that TECO receives from FMPA contract, will TECO make the ratepayers whole by crediting that difference through the fuel clause from operating revenues?

A That isn't in our proposal. And, again, reflecting on the benefits already accrued, we don't think it's very likely that there's a need for that type of guarantee. Again, we took a conservative approach but I would say that our fuel and incremental heat rate numbers for those units are probably within a percentage or two. The purchased power agreements that are already in place that are part of our presentation or filing is -- are already in place so we feel fairly confident that our system fuel and purchased power proxy more than covers that issue, that variance between what the incremental cost from the units would be.

Q Well, if it's -- I guess if it's not that likely, if you believe that it's not that likely that you're estimates are going to be that far off, why would there be any problem with agreeing to make the ratepayers whole in the unlikely event that those costs are higher than the revenues received?

A Well, again, I don't know. We could have problems with our unit availability. Just -- our best guess right now, our best forecast is based on the best information that we have right now. It's tough for me to sit here and say that the world can't turn upside down next year. But we feel fairly confident about all the assumptions that went into our projected rates here. Our proposal considers not only the $3.4 million benefit, which again is higher if you really look at the incremental fuel costs, but also in consideration of the $9.8 million. So when you look at that type of benefit that's already been accrued, as well as what's estimated, I struggle as to what the need for a commitment on a make whole is.

Q Could you turn to the second page of the exhibit that I handed out, the Staff exhibit. The second -- on to the third page. It's the table titled

Impact on 1000 Kilowatt Hour Residential Bill, Current and Proposed Treatment for FMPA Contract.

A Yes, I've got it.

Q Okay. Could you explain what the numbers in Columns 1 and 2 -- sorry. Strike that. Could you explain what the numbers under the second and third columns in that table show us, and those are the columns titled Total FMPA Revenues Credited, and the third column titled Less System Average Fuel and Purchased Power?

A Yes, I will. The middle column titled Total FMPA Revenues Credited is simply taking the approximately $36 million in the year 2000 and splitting it between the environmental and the fuel cost recovery clauses. So that's a total revenue, 100% revenue credit and -- which is already included in our projected cost recovery factors.

Relative to what's titled the current FMPA treatment to the extent that that we did not flow 100% of the revenues and we were to credit -- to pull out, I'm sorry, the revenues, effectively the difference would be, on a revenue perspective, $2.12 higher. We're showing this as a negative to indicate the benefits associated with flowing the revenues, but relative to our projected fuel cost filings, just looking at the revenues, the factor would be up $2.12.

The third column, that's titled Less System Average Fuel and Purchased Power again goes to using a very conservative proxy on both the SO2 replacement costs as well as using the combined aggregate system average fuel as well as the total purchased power that's in our projection. This is right off of Line 20 in the Schedule E-1s in Ms. Zwolak's testimony, but effectively incorporates that $20.87 combined system fuel and purchased power production cost type number, and applied to the total FMPA energy associated with the 150 megawatts and 100% load factor. And if you took those revenues and pulled out these higher costs, then effectively you still generate a benefit of 35 cents per 1,000 kWh.

Q So which number on the table represents the impact on a 1,000 kilowatt hour residential bill?

A They both do. The middle column reflects just the revenues without any crediting of what the incremental costs are. The third column reflects a crediting, if you would, if we were to separating what would that reduction be in terms of expense. Where we're really at, if you look at the incremental fuel out of the assigned units it's something that's closer to 50, 55 cents. That's the difference.

COMMISSIONER DEASON: Could you repeat that? You're comparing the 35 to 55?

WITNESS HERNANDEZ: Commissioner Deason, the 55 -- the 50 to 55, it's approximately that number, is if you looked at what the true incremental fuel costs of the four units assigned to the transaction, that's Gannon 5 and 6, Big Bend 2 and 3 versus using the higher rate of the combined total system average fuel, not incremental fuel, but average fuel, and the total purchases associated with our total system. And so we use that number just to indicate that there's still net benefits even if you consider average fuel and total purchases.

COMMISSIONER DEASON: Why do you have zero for current treatment?

WITNESS HERNANDEZ: Because in the absence of knowing where we're going to actually end up in terms of earnings for year 2000 and subject to a review, that ultimately wouldn't get probably resolved until 2001. There would be a zero impact to the fuel -- well, actually all the cost recovery clauses. To the extent that we pulled all of the $44 million of revenues, the bill would actually increase by the amount that we're showing here. We show it as zero because we showed the benefits as a negative, but our projections already include those benefits. Another way would to have been shown a zero differential in Column 1 -- I'm sorry, Column 2 and shown a positive increase on the bill. We chose to represent it a different way.

Q **(By Mr. Keating)** Just for clarification, does Column 3 reflect the difference between the revenues collected and the estimated cost of the transaction to the ratepayers based on system average fuel?

A Yes.

Q Okay. Finally, on the last page of that exhibit that I handed to you, this exhibit depicts the incremental cost of the FMPA sales; is that correct?

A Yes.

Q Do you know what the revenues are for that same period, the January 2000 through March 2001?

A It's roughly $44 million.

Q I just have a few more questions. Could you briefly describe the purchased power agreement that TECO has with Hardee Power Partners?

A To the best I can, I'm just aware of -- I don't know the details of the contract. The agreement is for a purchase of 75 megawatts nominal capacity generated from a GE-7EA machine. It fits into the existing infrastructure, the space, if you will, at the existing Hardee site. It's characterized as a CT-2B which sits right next to its sister unit, CT-2A, configured in a way that to the extent the economics makes sense for Tampa Electric and we opt to complete the second phase build-out of the second combined cycle unit, that unit facilitates that ultimate build-out. We have not yet committed for the full build-out of a combined cycle unit. We simply indicated to Seminole Electric and to Hardee Power Partners our intent to do a phased construction of that combined cycle by first putting in the CT-2B. The nominal 75 megawatts capacity is expected to be available around mid-May of next year.

It is -- because it lines up with the existing agreement that was reviewed by this Commission back in 1989 and 1990, it effectively is required only in an amendment to the existing agreement simply because of the utilization of the resources we talked about. Tampa Electric has an unconstrained first call. Seminole has a secondary call. Different configuration than the first 295 megawatts in capacity.

The agreement commences with the commercial operation date, as I mentioned, of mid-May of next year and goes through the end of -- it's a 12 year deal. Let me get the numbers right. To the end of 2012, I believe, if that's right. But effectively it lines up with the existing agreement in terms of the terms and conditions.

The capacity and energy payments were prescribed by the original agreement and were modified slightly due to the supplemental sale to Seminole Electric to the extent that Tampa Electric doesn't need it. So there's slight variations. Again, all that was reviewed by FERC; a cost based transaction and approved by FERC, and as in place and we're expecting to have that capacity available for our system by mid-May of next year.

Q And when did TECO enter into that contract?

A There were discussions earlier this year. I believe that contract or amendment is in Mr. Brown's testimony, but Mr. Brown can answer that question.

Q Okay. How would you describe the wholesale power market in terms of pricing when TECO entered into the Hardee Power Partners contract?

A The pricing of the market?

Q Yes.

A I'd say, again, because of the things you've heard earlier, because of the situation with capacity, physical capacity in the state of Florida as well as a tightening operating and planning reserves, at least during the next couple of years, market pricing for short term purchases are definitely higher than what they were expected to be a couple of years ago. The benefit of utilizing the Hardee Purchased Power Agreement is that if you were to compare the terms and conditions that were established back in '89 and '90 and that became effective in 1993 with the commercial operation date of the first combined cycle in CT-2A, the rates are even slightly lower when you do a rate comparison.

So, relative to the market I think it's a great deal.

Q So how has the market price for wholesale power changed since TECO entered into the wholesale agreement with FMPA?

A Well, certainly for Tampa Electric's system, our planning reserves got tighter, principally due to greater load growth, retail load growth than what we expected for year 2000. The capacity in our existing system is comparable to what we thought it was going to be. It's simply that that growth in retail has driven our reserve margins closer to our minimum. That had one impact.

From a state perspective, looking at the state operating reserves and the planning reserves, they have come down as well. Tampa Electric, probably relative to its size probably had a greater impact of the higher retail load growth but certainly our condition in our system as well as the external conditions, the Florida market, have created a situation where the market prices are higher and capacity is a little more scarce.

Q Could you explain why -- TECO's seeking cost recovery for four other purchased power agreements; is that correct?

A I'm sorry. Is TECO?

Q Is TECO seeking recovery of costs under four other purchased power agreements?

A Yes, we are.

Q And those agreements range from seven months to 15 months in length; is that correct?

A Subject to check, I believe that's correct.

Q Okay. Why has TECO entered into the shorter term contracts while at the same time entering into a 12 year contract with Hardee Power Partners?

A Again, part of it was timing. Secondary issue was the existence of an available infrastructure and agreement. The contract, as you'll hear later from our witness Mark Ward -- the 12 year duration of the contract is cost-effective on the same basis that this Commission reviewed and approved the original agreement, and that's on a cumulative present worth revenue requirements. If you look on a short-term basis, the rates that are being charged are certainly less than what we think the market is over the next several years.

As the capacity in the state gets built up, either through other resources that are being added in the state, that will help suppress the market prices after the next three to four years, but that has all been factored into the cost-effectiveness study, as you'll hear later.

Q Just two more questions. If the Commission were to approve Staff's position on Issue 9 -- and this is jumping back. That is, if TECO is required to flow transmission revenues from their nonseparated nonbroker wholesale sales through the capacity clause, would that decision impact your proposed factors?

A For Tampa Electric the amounts of money that we're talking about are approximately $100,000, $110,000. It would not have a significant impact. It would be on the order of less than -- close to a penny, but not anything more. And that would just simply be a shift from the fuel to the capacity cost recovery clauses.

Q And just to clarify, is your projection filing based on TECO applying the 20% shareholder incentive to any other types of sales other than what it currently applies the 20% incentive to?

A No.

Q Thank you.

MR. KEATING: I have no further questions.

COMMISSIONER DEASON: Redirect.

MR. WILLIS: I just have a couple.

REDIRECT EXAMINATION

BY MR. WILLIS:

Q Mr. Hernandez, does this Commission have a policy which has encouraged sales such as the FMPA sale?

A Yes, it does.

Q Is Tampa Electric sale to FMPA consistent with that policy?

A Yes, it is.

Q Is making cost-effective wholesale sales which provide revenues greater than incremental costs of making such sales good for retail customers?

A Absolutely.

Q In 1985 did this Commission give Tampa

Electric a specific incentive to make off-system sales?

A In 1995?

Q In 1985.

A Yes, it did. And that was coincident with the construction of the Big Bend 4 unit that came in line in February of that year, I believe. The Commission basically awarded Tampa Electric for the next three years or so to sell its available capacity in access of what it needed for our retail reserve margin criteria at the time to sell to the market and to receive revenues to offset the construction of that unit until our system grew into it.

Q Has Tampa Electric worked hard to optimize off-system sales?

A Absolutely. Up until the last couple of years, as our system continued to grow into our supply side resources, Tampa Electric at one point, probably had over 50% or close to it of the economy sales market in the state of Florida.

Q Is Tampa Electric Company's proposal with respect to FMPA fair to all concerned?

A Yes, it is.

COMMISSIONER CLARK: Mr. Willis, can I interrupt you just a minute? I do have a question I want to ask and it may be that it's appropriate to do redirect.

Mr. Hernandez, can you explain to me how it is that there's apparently a disparity in treatment with respect to economy sales in the sense that FPC and FPL, as I understand some of the testimony, they only apply the split the savings when it is broker, the hour to hour sale as I understand it. Yet, you and Gulf have done it on other economy sales. Where was the breakdown in understanding? Why was there not uniformity to your knowledge?

WITNESS HERNANDEZ: I'm reluctant to speak for the other companies, Commissioner Clark, but in my opinion it's the same resources being utilized, in a certain extent off broker transactions where you're not using an automated system and you got to actually physically contact, either by phone or go talk with people in order to entire into those type of transactions. Even though they're still split the savings, it takes more work.

COMMISSIONER CLARK: Do you have a specific order where it was indicated that it was acceptable for beyond broker sales?

WITNESS HERNANDEZ: No. But at the same time I can't recall one that said you couldn't or shouldn't do that.

MR. WILLIS: Commissioner Clark, the orders with respect to that refer to the type of transaction as opposed to the medium by which the transaction is consummated and that's how -- we can find those if you want.

COMMISSIONER CLARK: That would be helpful and if you could address it when you come back on rebuttal.

MR. STONE: Commissioner Clark, if I may, if you were to look at Exhibit 26, Gulf has provided a narrative in response to that interrogatory that may be helpful in that regard.

COMMISSIONER CLARK: Okay.

BY MR. WILLIS:

Q With respect to questions that Commissioner Clark asked you, should there be a difference in treatment with respect to the incentive by virtue of the medium by which the deal is struck as opposed to the basic fundamentals of the transaction?

A No, there should not be a difference.

Q Okay. Going back to the FMPA transaction, would separation provide a severe penalty to Tampa Electric?

A Yes, it would.

MR. WILLIS: No further questions, and I would move the admission of Exhibit 30.

COMMISSIONER DEASON: Without objection Exhibit 30 is admitted.

(Exhibit 30 received in evidence.)

MR. KEATING: Staff would move the admission of Exhibit 31.

COMMISSIONER DEASON: Without objection Exhibit 31 is admitted.

(Exhibit 31 received in evidence.)

COMMISSIONER DEASON: Let's go forward.

MR. WILLIS: We call Mr. Black.

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CHARLES R. BLACK

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

DIRECT EXAMINATION

BY MR. WILLIS:

Q Would you please state your name and address.

A My name is Charles R. Black. My address is 702 North Franklin Street, Tampa, Florida. Zip code, 33602.

Q Did you prepare and cause to be prefiled in this docket prepared direct testimony of Charles R. Black?

A Yes, I did.

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

A No.

Q If I were to ask you the questions contained in that document, would your answers be the same today?

A Yes, they would.

MR. WILLIS: We request that Mr. Black's testimony be inserted in the record as though read.

COMMISSIONER DEASON: Without objection it shall be so inserted.

TAMPA ELECTRIC COMPANY
DOCKET NO. 990001-EI
FILED: 10/1/99

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

CHARLES R. BLACK

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

A. My name is Charles R. Black. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am Vice President-Energy Supply for Tampa Electric Company ("Tampa Electric" or "company").

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

A. I graduated from the University of South Florida in August 1973 with a Bachelor of Science degree in Engineering, majoring in Chemical Engineering. I am a Registered Professional Engineer in the State of Florida. I began my career with Tampa Electric in September 1973 as a staff engineer in the Production Department. Between 1973 and 1989, I held various engineering and management positions in the Production Department, Power Plant Engineering Department, and the Budget Department.

In March of 1989, I joined our affiliated company, TECO Power Services as Director Engineering and Construction. In December of 1990, I was elected Vice President of Engineering and Construction. In December of 1991, I returned to Tampa Electric as Vice President of Project Management. In December 1996 I assumed my present role as Vice President, Energy Supply.

Q. Have you previously testified before this Commission?

A. Yes. I testified in support of the prudence of Polk Unit One in Docket No. 960409-EI and in support of cost estimates associated with the proposed flue gas desulfurization system in Docket No. 980693-EI.

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

A. The purpose of my testimony is to provide support for a Commission determination that Tampa Electric had in place reasonable procedures and requirements that should have prevented the accident during the maintenance outage of F. J. Gannon ("Gannon") Unit 6, and the company acted prudently in its actions following the accident on April 8, 1999. I will provide an overview of events related to the Gannon Unit 6 accident, an overview of system recovery for Gannon Units 1 through 6, and a current assessment of Gannon Unit 6.

Q. Have you prepared an exhibit to support your testimony?

A. Yes I have. My Exhibit No. 32 (CRB-1) was prepared under my direction and supervision and consists of two documents.

Q. Please describe the Gannon Unit 6 accident.

A. On April 8, 1999, an explosion occurred on the turbine/generator floor at Tampa Electric's Gannon Unit 6, a 375-megawatt generator. At the time of the accident, Gannon Unit 6 was not operational and was in the third week of an eight week planned maintenance outage. The accident occurred as hydrogen, used to cool the unit's generator during normal operations, exploded when one of four generator maintenance access covers was removed prior to purging the hydrogen from the unit. The accident resulted in three fatalities and injuries to 45 employees and sub-contractors. The explosion damaged Units 5 and 6 and caused the immediate emergency shutdown of the five Gannon units that were operating at the time of the accident.

Q. Does Tampa Electric have sufficient safety practices and procedures in place to prevent against accidents such as the one which occurred at Gannon Station?

A. Yes. One of the company's highest priorities is to provide a safe and healthy work environment for all employees and assure that employees have the knowledge, skills, and equipment to perform their jobs safely. The company has in place rigorous and specific procedures for maintenance outage activities. These safety procedures are designed to be in compliance with OSHA and industry standards, including ANSI standards, National Electric Safety Code and others.

In this case, prior to beginning any work, the company's safe work practices require the supervisor of the crew to conduct a job briefing with the crew before the start of each job. The briefing requires the supervisor to cover the hazards associated with the job, work procedures, special precautions, energy source controls, and personal protective equipment requirements for maintenance procedures that are to be performed.

Further, the company's safe work practices require that before work is performed on a generator it should have been purged of hydrogen and then tested and proper clearance should have been obtained in accordance with the tagging procedures applicable to Energy Supply. Employees undergo safety training routinely on all topics associated with the various power plant maintenance activities and the company's safe work practices.

Q. Was the crew assigned to Gannon Unit 6 experienced and trained?

A. Yes. The crew foreman and his maintenance crew were highly experienced. All but one member of the crew were journeyman power plant mechanics who had worked together for many years. The journeymen were in a specially designated job classification that denoted and provided extra compensation for their specialized skills in heavy-duty power plant maintenance work. As of April 1999, the number of years that the members of the crew had performed in the classification of power plant maintenance mechanic ranged from 6.5 years to 21 years. For the crew assigned to this job, the work they were to perform on Unit 6 was routine.

Q. Did Tampa Electric have training procedures in place to ensure employees are properly trained?

A. Yes. Company employees are provided various forms of training. Core training includes annual safety and environmental training. This training covers tagging procedures as well as confined space procedures and hazardous material training. The company also provides periodic CPR and first-aid training. In addition to core training, the company requires periodic refresher training, safety meetings, and on-the-job training.

Q. Was the employee who removed the access cover of the generator properly trained?

A. Yes. The employee who removed the access cover was a production apprentice for six years. He had completed an outage at the company's Big Bend facility before he was assigned to the outage at Gannon. He had attended an annual two-day, safety and environmental refresher-training program and tagging procedures training within the year prior to the accident and other safety programs on specific topics throughout the years. He had extensive hours of on-the-job training and routinely attended safety meetings.

Q. Who made the decision to open the access cover of the generator?

A. From the best the company has ascertained, the employee who opened the access cover made the decision based on his belief that it was safe to do so.

Q. Did the company act prudently in performing maintenance on Gannon Unit 6 on April 8, 1999?

A. Yes. The maintenance being performed when the explosion occurred was planned spring maintenance. Gannon Unit 6 was taken out of service on March 26, 1999 for inspection and maintenance of the boiler, turbine and generator. Details of the planned maintenance activities have been provided to Staff in response to Interrogatory No. 35b and are included as Document 1 of my exhibit. This type of scheduled major maintenance is typically performed routinely in preparation for high system demands in the summer months. Gannon Unit 6 was originally scheduled to return to service on May 23, 1999.

Q. Once the explosion occurred at Unit 6, how were Units 1 through 5 impacted?

A. Due to the quick response of the Gannon Station employees operating Units 1 through 5, they were able to implement a safe and orderly shutdown procedure and the company was able to minimize the amount of damage to the other units. Unit 5 sustained damage primarily due to the explosion from Unit 6 while the other four units suffered little or no damage. Units 1 through 3 went back in service on April 10 and Unit 4 was back in service on April 12. Unit 5 was returned to service on May 16.

Q. Please describe the procedures Tampa Electric employed for overall system restoration as a result of the Gannon 6 accident.

A. The company's immediate response and concern was for the safety of employees. After the explosion, the units were shutdown without any significant problems. The operators initially purged the hydrogen from the remaining generators to minimize the risk of any further fire or explosions. To ensure the units could be returned to service safely, the damage assessment teams from within and outside the company began inspections as early as two hours after the accident. Units 1 though 4 were safely returned to service as soon as these inspections were complete.

Gannon Unit 5 received more direct physical damage to the electrical equipment since it is located adjacent to Unit 6. All safety systems worked properly and the operators responded to ensure the safety of the employees and equipment. No damages occurred to the boiler or turbine as a result of the explosion. Detailed inspections were made on all of the equipment and structures immediately following the accident. Motors, switchgear, cables, and other equipment were repaired or sent out for inspection and cleaning. Equipment was secured to minimize damage from the elements. Details of the additional maintenance and repair activities beyond those contemplated in the outage have been provided to Staff in response to Interrogatory No. 35c and is provided in Document 2 of my exhibit.

Q. What is the current status and assessment of Gannon Unit 6?

A. Gannon Unit 6 returned to full service on June 22, 1999. All of the originally planned maintenance was performed in addition to those activities that needed to be performed as the result of the explosion. Since the unit was returned to service, it has operated normally.

Q. Please summarize your testimony.

A. My testimony demonstrates that Tampa Electric Company took reasonable precautions to guard against an explosion of hydrogen gas during the maintenance outage of Gannon Unit 6, and the company acted prudently in performing maintenance on April 8, 1999. The company had sufficient safety practices and procedures in place to prevent against accidents such as the one that occurred. The crew assigned to Gannon Unit 6 were experienced and trained. The employee who opened the access cover made the decision based on his belief that it was safe to do so. After the accident occurred, the company was able to restore its system by taking prudent and reasonable actions to ensure the safety of its employees while completing all necessary maintenance and restoration of its units.

Q. Does this conclude your testimony?

A. Yes, it does.

Q (**By Mr. Willis**) Did you have an exhibit which was prepared in support of your testimony, Mr. Black?

A Yes.

MR. WILLIS: Commissioner, I request that the documents attached to Mr. Black's prepared direct testimony be marked as a composite exhibit.

COMMISSIONER DEASON: That will be Exhibit 32.

(Exhibit 32 marked for identification.)

MR. WILLIS: I would just like to point out, with respect to Exhibit 32, just to avoid confusion, there is a document that was premarked CAB -- CRB-2 that should have been CRB-1 because there is a separate CRB-2 in his rebuttal testimony.

Q (**By Mr. Willis**) Would you please summarize your testimony.

A Yes. Good afternoon, Commissioners. As you are all well aware on April 8, 1999 an unfortunate accident occurred during a maintenance outage of Tampa Electric's Gannon Unit No. 6. The accident occurred as hydrogen used to cool the generators during normal operation exploded when one of the four generator maintenance access covers was removed prior to the hydrogen being purged from that unit.

The accident resulted in three fatalities and injuries to 45 employees and subcontractors. The explosion damaged Units 5 and 6 and caused the immediate emergency shut down of all five Gannon units that were operating at the time of the accident.

My testimony describes the reasonable precautions that Tampa Electric took to guard against an explosion of hydrogen gas during the maintenance outage of Gannon 6 and explains that the company acted prudently in performing maintenance on that unit.

Safety is one of the company's highest priorities and we continually work to ensure that employees have the knowledge, skills and equipment to perform their job safely.

In the case of Gannon Unit No. 6, Tampa Electric had in place rigorous procedures for the maintenance outage activity as well as safe work practices requiring the crew supervisor to provide a detailed job briefing prior to the start of each job.

Our employees undergo safety training routinely on all topics associated with the various power plant maintenance activities and the company's safe work practices.

Our employees undergo annual core training covering tagging procedures, confined space procedures and hazardous material training. This core training is augmented by periodic refresher training, safety meetings and on-the-job training. Tampa Electric also provides CPR and first aid training for our employees.

The crew foreman and maintenance crew performing the Gannon Unit 6 maintenance were highly qualified and experienced. The employee who actually removed the access cover had been a production apprentice for six years and had attended an annual two day safety and environmental refresher training program within the year prior to the accident. He had extensive hours of on-the-job training, and routinely attended safety meetings.

From the best information we have it appears that the employee who opened the access cover made the decision to do so based on his belief that it was safe to open the cover.

Tampa Electric acted prudently in performing maintenance on Gannon 6 on April 8th. That maintenance was planned spring maintenance performed on a routine basis. Once the accident occurred our employees responded quickly to implement a safe and orderly shut down of the units that were operating.

Units 1 through 4 were returned to service as soon as damage assessment teams had determined that it was safe to do so. Units 1 through 3 were returned to service on April 10th. Unit 4 was back in service on April 12th. Unit 5 returned to service May 16th, and Gannon 6 returned to full service on the 22nd of June, 1999.

It is unfortunate that this accident occurred despite the reasonable precautions Tampa Electric took to avoid this type of occurrence. Our safety practices and procedures were sufficient and the crew assigned to the Gannon Unit No. 6 were experienced and well trained.

Finally, our post accident response was prudent and expedited with all six units being brought back into service as soon as we could safely do so. That concludes my summary.

MR. WILLIS: I tender the witness.

COMMISSIONER DEASON: Ms. Kaufman. Mr. McWhirter.

CROSS EXAMINATION

BY MR. MCWHIRTER:

Q Mr. Black, let me ask you a multiple choice question. Was the explosion caused by A, an act of God; B, the nonfeasance of an employee, or the act of an employee of Tampa Electric Company?

A The choice would be B.

Q Do you know of any act by any customer of Tampa Electric Company that contributed to this explosion?

A No, sir.

Q Have there been any other explosions at the Gannon plant before this one?

A What type? I'm not sure I understand the question. You mean similar to the hydrogen explosion?

Q No. No. Just any explosions at all.

A There had been a steam line that created a release of steam in the plant, I believe, back in 1994.

Q Any before that?

A Not that I'm aware of.

Q You personally investigated or supervised the investigation of this unfortunate accident?

A My role was associated with the restoration of the unit and the return of those units safely and the care of the employees. I did not personally head up the investigation.

Q From your personal observation of the circumstances -- and if you don't know from your personal observation or it wasn't reported to you in the due course of your function -- was the accident caused by the fact that the man was unscrewing the top of this generator and hydrogen escaped and exploded? That was the cause of it?

A Based on the physical evidence that we reviewed it appears the cause of the accident was associated with the removal of an access cover on the generator and that access cover being removed prior to the time that hydrogen had been purged from the generator. When the cover had been removed it allowed the hydrogen to escape into the plant and at some point the hydrogen and air mixture found an ignition source and the explosion occurred.

Q And at Page 9 on your testimony at Line 23, you say the accident was the result of an unfortunate miscommunication by a valued and dedicated employee and was certainly not any willful misconduct of anyone.

A I'm sorry. I'm not with you. Could you repeat the reference again?

Q On Page 9, Line 22. That's your testimony?

A I think you may be looking at my rebuttal testimony.

MR. WILLIS: That's the rebuttal testimony, Mr. McWhirter.

MR. MCWHIRTER: Rebuttal. Okay. I apologize. Can I ask him about that at this time or would you prefer I wait?

COMMISSIONER DEASON: If he's going to be coming back for rebuttal, we'll just wait.

MR. MCWHIRTER: I'd rather waive rebuttal and get it all over now.

MR. HART: We would not.

Q **(By Mr. Mcwhirter)** All right. Well, then I won't ask you that question until later. I perceive from the general tenor of your testimony that it is your opinion that any damages caused by this accident should be placed upon the consumers of Tampa Electric rather than the company. What is the rationale for that opinion?

A The request that the company has made is to recover the fuel and purchased power associated with the accident. Those costs are recoverable under the regulatory arrangement that we have with the Commission. We've not requested that all the costs, direct costs and other costs associated with the accidents, be recovered; simply that we believe the company did act in a prudent way and we had prudent procedures in place and we've managed the business, both the operation and maintenance of the business, in a prudent fashion and under the rules of the Commission fuel and purchased power is a recoverable expense and that's my rationale.

MR. MCWHIRTER: I have no further questions of the witness.

COMMISSIONER DEASON: Mr. Burgess.

CROSS EXAMINATION

BY MR. BURGESS:

Q Yes, sir. Mr. Black, you just indicated that all not the costs are being sought for recovery. Do you mean that some of the costs are being accounted for below the line in base rates?

A I'm not sure as to the above the line below the line treatment, but there were direct costs associated with the accident that we've incurred.

Q That you're not seeking to be recovered through any type of rate recovery?

A Not that I'm aware of.

Q Well, is it your understanding that the only way to -- that they would not be included in rates would be is if they were included as some type of below the line treatment?

A No. By virtue of saying they're not being asked to be recovered I'm not saying that they're not covered by base rates. I'm saying they're not specifically being asked for recovery like the fuel and purchased power.

Q You mean they're not just included in the fuel?

A That's correct.

Q Okay. Thank you. Is it your understanding that these Gannon units have been in the Tampa Electric rate base?

A Yes.

Q Since they've been in service?

A Yes.

Q And is it your understanding that -- are you aware at all of the stipulations that have been entered into surrounding the earnings of Tampa Electric Company over the last several years?

A Generally familiar with it, yes, sir.

Q Is it your understanding that Tampa Electric Company has earned between $11.75 and $12.75 in the last several years pursuant to those stipulations?

A That's my general understanding.

Q So then both in theory and in fact TECO has collected between $11.75 and $12.75 return to cover the risk associated with its investment in the Gannon Unit; is that correct?

A That's the return that we've earned, yes, sir.

MR. BURGESS: Thank you, Mr. Black. That's all that I have.

COMMISSIONER DEASON: Staff.

MR. KEATING: Staff has no questions. We would like to have an exhibit identified. I believe TECO can stipulate with Staff to have this exhibit moved into the record.

This exhibit is composed of the deposition of Mr. Black. It does not include the exhibits to that deposition, only the text transcript and it also includes TECO's response to Staff's Second Set of Interrogatories Nos. 21 through 27 concerning the explosion at Gannon.

COMMISSIONER DEASON: It will be identified as Exhibit 33.

(Exhibit 33 marked for identification.)

COMMISSIONER DEASON: Commissioners, questions? Redirect.

MR. WILLIS: No redirect. I move admission of Exhibit 32, I believe it was.

COMMISSIONER DEASON: Without objection Exhibit 32 is admitted.

(Exhibit 32 received in evidence.)

MR. KEATING: Staff would move 33.

COMMISSIONER DEASON: Without objection Exhibit 33 is admitted.

(Exhibit 33 received in evidence.)

MR. WILLIS: We call Mr. Brown.

COMMISSIONER DEASON: We're going to recess for lunch at this time. We will reconvene at 1:00.

(Thereupon, lunch recess was taken at 12:30 p.m.)

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(Transcript continues in sequence in Volume 4.)

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