Comprehensive Stipulated Exhibits for Entry into Hearing Record			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
Staff			
1		Exhibit List-Stip- 1	Comprehensive Stipulated Exhibit List
2		Composite Stip-2	FPL's Response to Staff's 4th Set of Interrogatories, No. 34
			FPL's Response to Staff's 5th Set of Interrogatories, Nos. 35-46
			FPL's Response to Staff's 6th Set of Interrogatories, No. 47
			FPL's Response to Staff's 7th Set of Interrogatories, No. 48
			TECO's Response to FIPUG's 1st Set of Interrogatories, No. 6
			FPL's A9 Schedule, 2000-2003
			Gas Daily October 29, 2004, Forecast, p. 5
Testimony Exhibit List			
FPL			
3	G. Yupp	(GJY-1)	Hedging Information
4	G. Yupp	(GJY-2)	Appendix I/Fuel Cost Recovery Forecast Assumptions
5	K. M. Dubin	(KMD-1)	Appendix I and II Fuel Cost Recovery and Capacity Cost Recovery
6	K. M. Dubin	(KMD-2)	Final True-Up Calculation – Jan. 2003 – Dec. 2003
7	K. M. Dubin	(KMD-3)	Appendix I and II /Fuel Cost Recovery and Capacity Cost and Recovery Estimated
8	K. M. Dubin	(KMD-4)	Actual True-Up for Jan. 2004 – Dec. 2004
9	K. M. Dubin	(KMD-5)	Appendix II/Fuel Cost Recovery E Schedules, Levelized Fuel Cost Recovery Factors for Jan. 2005 – Dec. 2005
10	K. M. Dubin	(KMD-6)	Appendix III/Capacity Cost Recovery Factors for Jan. 2005 – Dec. 2005

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 1
COMPANY/ F.P.S.C. Staff
WITNESS: Exhibit List- Stip-1
DATE 11-08-04

Comprehensive Stipulated Exhibits for Entry into Hearing Record			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
11	P. Sonnelitter	(PS-1)	GPIF, Performance Results Jan. 2003 – Dec. 2003
12	P. Sonnelitter	(PS-2)	GPIF, Targets and Ranges, Jan. 2005 – Dec. 2005
13	T. L. Hartman	(TLH-1)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
14	T. L. Hartman	(TLH-2)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
15	T. L. Hartman	(TLH-3)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
16	T. L. Hartman	(TLH-4)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
17	T. L. Hartman	(TLH-5)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
18	T. L. Hartman	(TLH-6)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
19	T. L. Hartman	(TLH-7)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
20	T. L. Hartman	(TLH-8)	Purchase Power Agreements, Economic Analyses, Timeline and Queue for Southern Company Transmission Requests
FPUC			
21	George M. Bachman	(GMB-1)	Composite. Schedules E1-A, E1-B, E1-B1 (for the Marianna and Fernandina Beach Divisions)

Comprehensive Stipulated Exhibits for Entry into Hearing Record			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
22	George M. Bachman	(GMB-2) (revised)	Composite. Schedules E1, E1-A, E2, E7, E8, and E10 (for the Marianna and Fernandina Beach Divisions)
GULF			
23	H. R. Ball	(HRB-1)	Coal Suppliers January 2003 – December 2003
24	H. R. Ball	(HRB-2)	Projected vs. actual fuel cost of generated power March 1995 – December 2005
25	T. A. Davis	(TAD-1)	Calculation of Final True-Up 1/03 – 12/03
26	T. A. Davis	(TAD-2)	Estimated true-up 01/04 – 12/04, Schedules E-1A, E-1B, E-1B-1, CCE-1a, CCE-1b
27	T. A. Davis	(TAD-3)	Projection -1/05 – 12/05, Schedules E-1 through E-11, H1, CCE-1, CCE-1A, CCE-1b, CCE-2
28	L. S. Noack	(LSN-1)	Gulf Power Company GPIF Results January 2005 – December 2003
29	L.S. Noack	(LSN-2)	Gulf Power Company GPIF Targets and Ranges January 2005 – December 2005
30	H. Homer Bell, III	(HHB-1)	Gulf Power Company Projected Purchased Power Contract Transactions January 2005 – December 2005
PEF			
31	Javier Portuondo	(JP-1T)	True-up Variance Analysis, Capacity Cost Recovery True-up, Tiger Bay Amortization, and Schedules A1 – A9 (December 2003).
32	Javier Portuondo	(JP-1R)	Reprojection Assumptions (Parts A-C), Capacity Cost Recovery Reprojections (Part D), and Schedules A1 – A9 (July 2004).
33	Javier Portuondo	(JP-1P)	Forecast Assumptions (Parts A-C), Capacity Cost Recovery Factors (Part D), Hines 2 Depreciation & Return Calculations (Part E), and Schedules E1 – E10 and H1 (2005).

Comprehensive Stipulated Exhibits for Entry into Hearing Record			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
34	Javier Portuondo	(JP-1S)	Updated E Schedules and Hines 2 Depreciation and Return Schedule
35	Pamela R. Murphy	(PRM-1T)	2003 Risk Management Plan Results Summary, and Hedging Information Summary.
36	Pamela R. Murphy	(PRM-1P)	2005 Risk Management Plan.
37	Michael F. Jacob	(MFJ-1T)	GPIF Reward/Penalty Schedules
38	Michael F. Jacob	(MFJ-1P)	GPIF Targets/Ranges Schedules
39	Samuel S. Waters	(SSW-1)	Shady Hills Tolling Agreement
40	Samuel S. Waters	(SSW-3)	Shady Hill Cost/Benefit Summary
TECO			
41	J. Denise Jordan	(JDJ-1)	Fuel Cost Recovery Jan. 2003 – Dec. 2003 Capacity Cost Recovery Jan. 2003 – Dec. 2003
42	J. Denise Jordan	(JDJ-2)	Fuel Cost Recovery, Projected Jan. 2004 – Dec. 2004 Capacity Cost Recovery, Projected Jan. 2004 – Dec. 2004
43	J. Denise Jordan	(JDJ-3)	Fuel Cost Recovery, Projected Jan. 2005 – Dec. 2005 Capacity Cost Recovery, Projected Jan. 2005 – Dec. 2005
44	J. Denise Jordan	(JDJ-4)	Incremental Security Costs
45	David R. Knapp	(WAS-1)[1]	Generating Performance Incentive Factor Results Jan. 2003 – Dec. 2003
46	David R. Knapp	(DRK-1)	Generating Performance Incentive Factor Estimated Jan. 2005 – Dec. 2005
47	Joann T. Wehle	(JTW-1)	Calculation of 2003 Incremental Hedging Operations and Maintenance Costs.

[1] Adopted by Witness David. R. Knapp

Comprehensive Stipulated Exhibits for Entry into Hearing Record			
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**
48	Joann T. Wehle	(JTW-2)	2003 Transportation Benchmark Calculation 2003 Transportation Market Price Application Calculation of 2005 Projected Incremental Hedging Operations and Maintenance Costs.
CHURBUCK/FIPUG			
49	David E. Dismukes	(DED-1)	Contribution of Contracts to Total Purchase Agreement
50	David E. Dismukes	(DED-2)	Merchant Facilities Located in Proximity to Contracted Units
51	David E. Dismukes	(DED-3)	Estimated Natural Gas Transmission Capacity
52	David E. Dismukes	(DED-4)	Merchant Development in SERC Region
53	David E. Dismukes	(DED-5)	Merchant Development in SERC by Subregion
54	David E. Dismukes	(DED-6)	Merchant Development in FRCC Region
55	David E. Dismukes	(DED-7)	Merchant Facilities Under Construction in SERC
56	David E. Dismukes	(DED-8)	Merchant Facilities Under Development in SERC
57	David E. Dismukes	(DED-9)	Merchant Alternatives in SERC
58	David E. Dismukes	(DED-10)	Planned Transmission Additions (Circuit Miles)

EXHIBIT NO. _____

DOCKET NO: 040001-EI

WITNESS: VARIOUS

PARTY: FLORIDA POWER & LIGHT CO.
TAMPA ELECTRIC COMPANY

DESCRIPTION: COMPOSITE EXHIBIT OF STIPULATED DOCUMENTS:

1. FPL'S RESPONSE TO STAFF'S 4TH SET OF INTERROGATORIES (NO. 34);
2. FPL'S RESPONSE TO STAFF'S 5TH SET OF INTERROGATORIES (NOS. 35-46);
3. FPL'S RESPONSE TO STAFF'S 6TH SET OF INTERROGATORIES (NO. 47);
4. FPL'S RESPONSE TO STAFF'S 7TH SET OF INTERROGATORIES (NO. 48);
5. FPL'S SCHEDULE A9, 2000 – 2003;
6. TAMPA ELECTRIC'S RESPONSE TO FIPUG'S 1ST SET OF INTERROGATORIES (NO. 6);
7. *GAS DAILY,* OCTOBER 29, 2004, PAGE 5

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 2
COMPANY/ F.P.S.C. Staff
WITNESS: Composite Stip-2
DATE: 11-08-04

Q. On page 15 of witness Hartman's direct testimony filed in this proceeding, he discusses a cost differential of $60 to $80 million (2004 NPV) between the cost of FPL's self-build option compared to the cost of the proposed contracts. Please describe in detail how this cost differential was calculated.

A. The economic analysis was based on production costing simulations, similar to those normally used by FPL for economic evaluation of power supply alternatives. For the PPAs, the inputs to the analysis were based on the contractual commitments and costs. A self-build generic 4 x 1 combined cycle facility was developed for comparison using currently estimated costs and operational characteristics. For purposes of transmission loss calculations, the self-build facility was assumed to be similar to a plant located at Corbett.

Excluding transmission-related costs on FPL's system, equity adjustment, and ability to arbitrage the firm transmission capacity associated with the PPAs, the analysis indicates a self-build facility could have NPV costs of $107 million lower than the PPAs. Additionally, the PPAs have an equity adjustment of $17 million associated with them, which would increase this differential to $124 million. Finally, our analysis of system costs for the PPAs is based upon marginal losses, and totals $117 million for energy and capacity losses. If we self build a unit instead of using the PPAs, this transmission capacity would likely be used by others to import power into Florida. In this instance, the energy and capacity losses would still occur, but we would recover a portion of this through our tariff rates on transmission. Our tariff rates are based upon average losses, not marginal. Average system losses are 2.19%. Assuming marginal losses of 13% from the border as disclosed in the 2003 RFP, and assuming we recover 2.19% under the tariff, this would increase the differential by $19.7 million, for a total of $144 million. Both the self build unit and the PPAs have redispatch costs associated with loads in South Florida. The PPA redispatch costs are $9 million higher than the self build, due to the fact that the self build unit is assumed closer to the load center. The total cost differential between a self build unit and the PPAs is $153 million, before considering the benefit of retaining transmission in SERC.

We have estimated that the ability to use the firm transmission to purchase economy energy in SERC has a net present value benefit of up to $83 million, with an average estimate of $60 million. Offsetting these benefits against the $153 million cost differential described above yields a net result of a self-build unit a NPV cost of $69 million to $93 million lower than the PPAs. This calculation does not attempt to quantify the other economic benefits (beyond arbitrage) identified in witness Hartman's Direct Testimony.

Q. Please identify whether FPL's existing purchased power contracts with Southern Company contain deadlines for FPL to seek contract renewal or extension.

A. It does not, nor does it imply that renewal or extension is part of the contract.

Q. Please describe any dispatch rights FPL will have for Scherer Unit 3, Harris Unit 1, and Franklin Unit 1 under the proposed contracts.

A. Output of each of the PPA units is fully dispatchable by FPL. Scheduling parameters for each unit are provided in Appendix D of each unit's respective agreement.

Q. Page 5, lines 6-8 of witness Hartman's testimony states that the total capacity under the proposed contracts is 930 MW after allowance for transmission losses. Please identify the amount of these losses, as well as any additional losses resulting from delivery over FPL's system to its load center in Southeast Florida.

A. Per Southern's OASIS system, as of August 2004, capacity losses on Southern's transmission system are 2.0%, or 19.1 MW. These losses are calculated using an average system loss factor. FPL estimates incremental capacity losses are 66 MW attributable to the PPAs, based upon marginal loss calculations. These marginal losses have been reflected in FPL's economic analysis of the PPAs.

Q. Please discuss the conditions under which Southern Company or Southern Power Company could terminate the proposed contracts.

A. See TLH-1 (Sherer) ¶ 5.14.3; ¶ 7.4.6; ¶ 14.2.1: See TLH-2 (Harris) ¶5.15.3; ¶7.4.6; ¶16.2.1 : See TLH-3 (Franklin) ¶5.15.3; ¶7.4.6; ¶16.2.1

Q. Page 6, lines 13-15 of witness Hartman's testimony discusses FPL's right to terminate the proposed contracts if "unable to obtain adequate firm transmission by a date certain..." Please identify the "date certain", and discuss any reasons why FPL would not be able to obtain the required transmission rights.

A. December 1, 2005. We know of no reason why transmission would not be granted. Under Southern's Open Access Transmission Tariff, however, applications for firm transmission can take up to 240 days to be granted. Although it is expected that FPL's transmission rollover request will be granted prior to the end of 2004, the deadline of December 1, 2005 was established to accommodate the longest possible approval schedule, with a small amount of margin.

Q. Pages 7 and 8 of witness Hartman's testimony discuss FPL's securing of transmission rights for the proposed contracts. Please describe who grants the authority to "roll-over" existing transmission rights and how this is done.

A. "Roll-Over" is granted by the transmission owner, in this case, Southern Transmission. A filing was made on Southern's OASIS system to request the roll-over on August 25th. This was followed up with an e-mail confirming the filing, and payment of one month's transmission fees as security. We have also requested that the firm transmission be redirected to the new generating plants, under the PPAs. Southern will examine the feasibility of transmitting power from these facilities to a delivery point on FPL's system. They will then either grant the roll-over and redirect, or indicate that a facilities study is needed.

If a study is required, the facilities study would identify the cost and schedule to perform any system upgrades necessary to provide the requested transmission service. FPL would then be advised of the availability and cost of the transmission service, and given an opportunity to accept or reject Southern's proposal. The process is disclosed in Section 19 of Southern's Open Access Transmission Tariff.

Q. Please discuss whether FPL's proposed contracts use network or point-to-point transmission service. If point-to-point, please identify these locations.

A. The proposed contracts anticipate FPL using firm point to point service. The receipt points are the Harris, Franklin and Scherer plants. The delivery point in each instance is FPL's interconnection with the Southern transmission system.

Q. Please identify the anticipated cost of transmission rights under the proposed contracts.

A. Transmission service is provided at cost of service based rates, under Southern's OATT. At present, the service cost is $1,753.52/MW-Month, plus scheduling fees of $80.60/MW-month.

Q. Page 9, lines 12-14 and 19-22 of witness Hartman's testimony discusses FPL's ability to retain 930 MW of firm transmission within SERC to buy market energy and capacity as a benefit. Please describe how this is a benefit when the transmission capacity is expected to be used up by the proposed contracts. Please include an explanation of how this benefit would be any different if FPL did not have the proposed contracts.

A. The benefit discussed applies to the use of the firm transmission when the facilities under contract are not being dispatched. If the market price for energy is lower than the dispatch cost of the plants, and lower than our own system's marginal cost, we can choose to not dispatch our contract units, and instead purchase cheaper power in the market and bring it to our system using the transmission rights. If the market price is higher than our dispatch cost of the plants under contract, and these dispatch costs are lower than our system's marginal costs, then we dispatch the plants under contract and use the transmission to bring the power to our customers. If the dispatch cost of the plants under contract is lower than the market price, but higher than our own system marginal costs, we would dispatch the plants under contract to the extent we can sell the output into the market. All of these options allow us to lower the cost of energy to our customers by using the firm transmission benefit. If FPL did not have the proposed contracts, we would also not have firm transmission in Southern's territory, and none of these options would apply.

Q. Page 12, lines 1-4 of witness Hartman's testimony states that off-peak power purchases could result in savings of between $36 million and $83 million. Please identify whether these savings are over the contract term or over some other period, and provide the net present value analysis, on an annual and cumulative basis, to determine anticipated savings.

A. The savings are net present value in 2004 dollars of savings anticipated over the term of the contracts. Analysis is provided below:

Conversion of Projected Arbitrage Savings to NPV 2004$ Values

		Minimum Arbitrage		Maximum Arbitrage	
Year	Annual Discount Factor 0.0793	Nominal Annual Arbitrage Savings	NPV Annual Arbitrage Savings	Nominal Annual Arbitrage Savings	NPV Annual Arbitrage Savings
2004	1.000	0	0	0	0
2005	0.927	0	0	0	0
2006	0.858	0	0	0	0
2007	0.795	0	0	0	0
2008	0.737	0	0	0	0
2009	0.683	0	0	0	0
2010	0.633	6,981,073	4,416,407	18,033,360	11,408,370
2011	0.586	13,908,277	8,152,261	31,651,714	18,552,481
2012	0.543	12,930,363	7,022,202	28,350,420	15,396,503
2013	0.503	13,664,620	6,875,717	34,197,875	17,207,569
2014	0.466	12,435,827	5,797,662	27,455,777	12,800,059
2015	0.432	13,911,761	6,009,221	27,862,328	12,035,204
		73,831,921	38,273,470	167,551,474	87,400,186

Q. Page 12, lines 12-14 of witness Hartman's testimony identify the arbitrage value of transmission rights for 2003 as $10.87 million. Please explain whether this value is net of the cost of transmission rights.

A. Yes, in the sense that the incremental cost for arbitrage of the transmission rights is zero. The cost of transmission is associated with the costs of the PPAs and has been reflected in the economic analysis as part of the cost of the PPAs. Since the cost of the transmission must already be paid as part of the PPAs, the ability to arbitrage (and the benefit to our customers) has zero incremental cost associated with it.

Q. Page 15, lines 16-18 of witness Hartman's testimony states that acceleration of FPL's self-build plan could result in savings of between $60 ($69*) million and $80 ($93*) million versus the cost of the proposed contracts. Please identify whether these savings are over the contract term or over some other period, and provide the net present value analysis, on an annual and cumulative basis, to determine anticipated savings.

***These figures have been changed to reflect FPL's correction to page 15 of Hartman's Direct Testimony. The replacement page was filed on October 20, 2004. This change does not affect the conclusions or results reflected in the testimony of Mr. Hartman.**

A. The question paraphrases my testimony. I testified that "if we were to consider only the costs that can be readily quantified," accelerating FPL's self build plan could result in lower costs, but went on to add that "this would ignore a number of the benefits of the PPAs that are not easily quantified but, represent real opportunities and value for our customers."

The purpose of the limited comparison between the contracts and a self-build option was not to provide a full evaluation of one alternative against another for selection purposes. Rather, it was to determine whether the price of the contracts was "reasonable." The result of the comparison confirmed that the price of the proposed PPAs is indeed reasonable.

The cost comparison was performed on a net present value basis, over a period of 30 years. This form of analysis is the most appropriate way to compare the impact on FPL's system from different power-supply alternatives, but it does not yield meaningful year-by-year cost comparisons. Therefore, the following discussion applies to the cumulative net present value difference only.

The table below summarizes the results of FPL's cost comparison:

NET PRESENT VALUE ($ MILLIONS)

	Maximum Arbitrage	Average Arbitrage
System Generation Model Differential	$ (107)	(107)
Equity Adjustment	$ (17)	(17)
Redispatch cost differential	$ (9)	(9)
Energy & Capacity Losses	$ (117)	(117)
	$ (250)	(250)
Potential Benefit of SERC Transmission	$ 83	60
Marginal energy & capacity losses due to wheeling by others	$ 117	117
Transmission loss recovery under tariff	$ (20)	(20)
Net differential between PPA & self build	$ (69)	(93)

Negative numbers reflect self build less costly than PPAs
Numbers may not add due to rounding

The following describes each of the entries in the table:

- System generation model differential. This provides the NPV of the differential production costs on our entire system of having the PPAs in our portfolio versus a self built unit.

- Equity adjustment. This adjustment reflects the cost associated with the balance sheet impact of PPAs in FPL's portfolio, as used by the rating agencies.

- Redispatch cost differential. This differential recognizes the value associated with local grid benefits of a self-built unit in South Florida, which purchased power transmitted from SERC cannot provide.

- Energy and capacity losses. This reflects the cost differential between the marginal losses of capacity and energy on FPL's transmission system associated with the PPAs, and those associated with a self-build alternative in South Florida.

- Potential Benefit of SERC Transmission (arbitrage). FPL will be able to use the firm transmission obtained through the PPAs to purchase economy energy in SERC and wheel it to its customers in Florida, a practice referred to as arbitrage. FPL estimates the value of this arbitrage opportunity at a high of $83 million and an average of $60 million.

- Marginal Energy and Capacity Losses Due to Wheeling By Others/Transmission Recovery Under Tariff. If FPL were to elect a self-build unit instead of the PPAs, the transmission capacity FPL currently utilizes to supply our customers for the existing UPS agreement would become available. In such circumstance, it is reasonable to expect that third parties would utilize the transmission capability to import power from SERC, and the losses associated with such transaction would still be experienced. Since under FPL's transmission tariff transmission customers are responsible for the average transmission losses associated with a transaction instead of the marginal losses, FPL's customers would be responsible for the difference between the marginal losses and the average transmission losses associated with the third party transaction. FPL's average transmission losses under the Tariff are 2.19%. FPL estimates that its customers would have to absorb $117 million in marginal transmission losses, which appears in the table under the heading "Marginal Energy and Capacity Losses Due to Wheeling By Others." This would be partly offset by the recovery of an estimated $19.7 million of these losses through the tariff's average transmission losses recovery procedures. This offset is reflected in the $(20) million entry labeled "Transmission Loss Recovery Under Tariff."

- Net Differential Between PPA and Self-Build. This reflects the arithmetic sum of the gains and losses described above. As shown in the table, the net differential is $69 million based on the high arbitrage estimate and $93 million based on the average arbitrage estimate.

It is important to note that this differential does not reflect any value for the other benefits of the PPAs that are not provided by a self-build alternative. These benefits include retention of some firm coal fired capacity as part of the contracts; the planning flexibility afforded by these short-term contracts, especially when combined with long-term commitments as part of an overall strategy; enhanced system reliability through the geographic diversity of the PPA units, as well as the independent firm gas transportation commitment provided by the PPAs. FPL's position is that these benefits definitely outweigh the cost differential reflected in the table.

Q. **In FPL's response to staff interrogatory #44, you identify the annual and cumulative dollar savings associated with economy energy purchases. Could you please provide the expected amount of economy energy purchases, the average transaction cost of these purchases, and the cost if such energy was generated?**

CONFIDENTIAL

A. The following table presents the information requested for both minimum and maximum projected economy energy purchases, on a non-discounted basis, consistent with our answer in Staff's Interrogatory No. 44.

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Year	Projected Amount of Economy Energy Purchases (GWh) Minimum	Projected Amount of Economy Energy Purchases (GWh) Maximum	Projected Average Transaction Cost of Economy Energy Purchases (000) Minimum	Projected Average Transaction Cost of Economy Energy Purchases (000) Maximum	Avoided Projected Cost of Generation of Economy Energy Purchases (000) Minimum	Avoided Projected Cost of Generation of Economy Energy Purchases (000) Maximum	Projected Value of Economy Energy Purchases (000) Minimum	Projected Value of Economy Energy Purchases (000) Maximum
2010	[redacted]						$ 6,981	$ 18,033
2011							$ 13,908	$ 31,652
2012							$ 12,930	$ 28,350
2013							$ 13,665	$ 34,198
2014							$ 12,436	$ 27,456
2015							$ 13,912	$ 27,862
							$ 73,832	$ 167,551

CONFIDENTIAL

Q. Please provide a side by side comparison of the costs contained in the proposed Harris Unit PPA compared to the costs of FPL's self-build combined cycle alternative. Please provide the same analysis for the proposed Franklin Unit PPA. Costs should be provided for both capacity ($/kw-mo) and energy (¢/kwh). Also, please include the MW size, fuel cost assumption in $/MMBTU, and operating assumptions such as capacity factor, heat rates, etc.

A. The figures requested are provided in the table on page 2 of this response, but should be viewed with caution. Relative cost comparison can be skewed by a number of factors, including how the units are dispatched and how they are operated. These factors would influence start costs and effective heat rate (steady state operation at the most effective output has the best heat rate). In the table below we have assumed the most effective heat rates for the units, a capacity factor slightly lower than we would expect for a self build, and slightly higher than we would expect for Harris and Franklin, but the same values.

Additionally, of course, these figures do not reflect the other aspects of the agreement which bring additional value to the PPAs. These include some firm coal generation , increased reliability due to both geographic diversity and the additional pipeline, the ability to purchase economy energy from the market, as well as the timing flexibility the limited duration PPAs provide to address other generation options, and the ability to preserve firm transmission rights in SERC even beyond the expiration of the PPAs.

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		Self Build	Harris	Franklin
Capacity	MW	1144	600	190
Capacity Payment	$/kW-Month	[redacted]		
Heat Rate	Btu/kWh			
Variable O&M	$/MWh			
Start Charge	$/start			
Fuel Transportation	$/MMBtu			
Assumptions				
	Gas price $/MMBtu	6.00	6.00	6.00
	Capacity Factor	60%	60%	60%
	Starts/year	50	50	50
	Production (MWh)	6,012,864	3,153,600	998,640
Cost Comparison				
	Capacity Cost	[redacted]		
	Variable O&M			
	Start Charges			
	Fuel			
	Fuel Transportation			
	Total Cost			
	Cost/MWh	[redacted]		

[redacted]

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
COMPANY FLORIDA POWER & LIGHT COMPANY
FOR THE MONTHS OF JANUARY THROUGH DECEMBER 2000

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
					COST IF GENERATED		
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS COST cents/KWH	TOTAL $ FOR FUEL ADJ (3) x (4) $	(a) cents/KWH	(b) $	FUEL SAVINGS (6)(b) - (5) $
ACTUAL							
FLORIDA							
Florida Power Corporation	OS	241,565	3 079	7,436,607	3 783	9,138,687	1,702,080
Homestead, City of	OS	10	8 000	800	8 290	829	29
Lake Worth, City of	OS	799	13 089	104,582	13 468	107,609	3,027
New Smyrna Beach Utilities Comm, City of	OS	90	4 000	3,600	4 986	4,487	887
Orlando Utilities Commission	OS	167,125	7 318	12,230,126	7 451	12,453,182	223,056
Reedy Creek Improvement District	OS	2,000	4 916	98,319	5 152	103,042	4,723
Ridge Generating Station	OS	4,520	3 808	172,105	4 732	213,906	41,801
Seminole Electric Co-op	OS	1,260	3 356	42,285	4 514	56,880	14,595
Tallahassee, City of	OS	7,335	3 344	245,285	5 071	371,954	126,669
Tampa Electric	OS	138,663	2 750	3,813,323	3 511	4,868,700	1,055,377
The Energy Authority	OS	474,908	2 924	13,885,007	3 771	17,907,224	4,022,217
NON-FLORIDA							
Allegheny Energy Supply	OS	802	5 765	46,237	7 214	57,860	11,623
American Electric Power Svc Corp	OS	28,923	4 318	1,248,811	4 851	1,403,009	154,198
Aquila Energy Marketing	OS	148	7 478	11,067	10 086	14,927	3,860
Aquila Power Corp	OS	6,452	4 478	288,926	5 541	357,515	68,589
Cargill-Alliant, LLC	OS	46,443	4 062	1,886,352	4 714	2,189,246	302,894
Carolina Power & Light	OS	9,773	3 421	334,383	4 515	441,273	106,890
Coral Power	OS	16,472	8 371	1,378,842	8 727	1,437,439	58,597
DTE Energy Trading	OS	5,949	5 636	335,288	5 380	320,075	(15,213)
Duke Energy Trading	OS	6,171	4 352	268,544	5 719	352,932	84,388
Duke Power	OS	49,130	4 978	2,445,608	5 056	2,483,873	38,265
Dynegy Power Marketing	OS	14,057	4 734	665,497	0 000	737,129	71,632
East Kentucky Power Corp	OS	1,299	1 460	18,963	2 934	38,116	19,153
El Paso Merchant Energy	OS	227	5 419	12,302	6 729	15,274	2,972
Enron Power Marketing	OS	21,652	4 968	1,075,777	5 918	1,281,386	205,609
Entergy Power Marketing	OS	12,147	4 867	591,202	5 355	650,505	59,303
Entergy Services	OS	0	0 000	(18,763)	0 000	0	18,763
Koch Energy Trading	OS	27,776	4 368	1,213,255	4 524	1,256,513	43,258
LG&E Energy Marketing	OS	191,440	3 154	6,037,967	4 062	7,777,190	1,739,223
Louisville Gas & Electric	OS	8,440	2 816	237,636	3 640	307,234	69,598
Morgan Stanley Capital Group	OS	113,002	4 134	4,671,533	4 961	5,605,765	934,232
North Carolina Municipal Power Agency	OS	5,888	1 546	91,008	2 106	123,978	32,970
Oglethorpe Power Corp	OS	75,233	3 330	2,505,336	0 000	3,113,283	607,947
PG&E Energy Trading-Power LP	OS	435	2 481	10,794	3 263	14,192	3,398
PJM Interconnection LLC	OS	2,255	6 491	146,375	4 351	98,113	(48,262)
Reliant Energy Services	OS	3,503	5 389	188,774	6 161	215,835	27,061
Sempra Energy Trading	OS	8,845	4 231	374,235	5 588	494,236	120,001
South Carolina Electric & Gas	OS	7,468	3 219	240,376	4 167	311,155	70,779
Southern Company Energy Marketing	OS	546	2 327	12,707	2 576	14,066	1,359
Southern Company Services	OS	18,719	3 118	583,650	4 458	834,566	250,916
TXU Energy Trading	OS	5,318	4 171	221,814	4 437	235,952	14,138
Tenaska Power Services	OS	3,430	2 631	90,234	3 628	124,442	34,208
Virginia Electric & Power	OS	37,934	4 277	1,622,475	4 553	1,727,266	104,791
Vitol	OS	0	0 000	2,020	0 000	0	(2,020)
Williams Energy Marketing & Trading	OS	451	5 564	25,095	5 965	26,902	1,807
FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		1,038,275	3 663	38,032,039	4 356	45,226,500	7,194,461
NON-FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		730,328	3 952	28,864,320	4 664	34,061,247	5,196,927
TOTAL		1,768,603	3 782	66,896,359	4 483	79,287,747	12,391,388

SCHEDULE A9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
COMPANY: FLORIDA POWER & LIGHT COMPANY
FOR THE MONTHS JANUARY 2001 THROUGH DECEMBER 2001

(1)	(2)	(3)	(4)	(5)	(6)		(7)
					COST IF GENERATED		
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS. COST cents/KWH	TOTAL $ FOR FUEL ADJ. (3) x (4) $	(a) cents/KWH	(b) $	FUEL SAVINGS (6)(b) - (5) $
ACTUAL:							
FLORIDA:							
THE ENERGY AUTHORITY	C	0	0.000	0	0.000	0	0
CITY OF HOMESTEAD	OS	192	2.174	4,174	3.051	5,858	1,684
CITY OF LAKE WORTH	OS	11	2.500	275	3.682	405	130
CITY OF LAKELAND	OS	4,010	7.543	302,482	8.839	354,458	51,976
CITY OF TALLAHASSEE	OS	1,409	1.919	27,044	2.700	38,049	11,005
FLORIDA POWER CORPORATION	OS	414,501	2.398	9,937,847	3.871	16,046,857	6,109,010
JACKSONVILLE ELECTRIC AUTHORITY	OS	0	0.000	3,206	0.000	0	(3,206)
ORLANDO UTILITIES COMMISSION	OS	96,628	5.980	5,778,096	6.295	6,083,119	305,023
REEDY CREEK IMPROVEMENT DISTRICT	OS	55	5.245	2,885	6.282	3,455	570
RIDGE GENERATING STATION, LP	OS	4,986	3.988	198,846	4.279	213,363	14,516
TAMPA ELECTRIC COMPANY	OS	48,816	2.999	1,463,927	3.441	1,679,487	215,560
THE ENERGY AUTHORITY	OS	523,297	3.925	20,537,658	4.419	23,122,379	2,584,721
NON-FLORIDA:							
ALABAMA ELECTRIC COOPERATIVE, INC.	OS	1,919	2.891	55,487	3.406	65,370	9,883
AMERICAN ELECTRIC POWER SERVICE CORPORATION	OS	33,283	5.367	1,786,232	6.602	2,197,280	411,048
AQUILA ENERGY MARKETING CORPORATION	OS	19,987	3.729	745,309	4.809	961,173	215,864
CALPINE ENERGY SERVICES, LP.	OS	420	8.024	33,700	8.074	33,912	212
CARGILL -ALLIANT, LLC	OS	147,876	4.010	5,930,185	4.416	6,530,668	600,483
CAROLINA POWER & LIGHT COMPANY	OS	7,036	3.621	254,761	5.118	360,109	105,348
CORAL POWER LLC	OS	18,138	4.361	789,132	4.969	901,203	112,071
DUKE ENERGY TRADING & MARKETING, LLC	OS	79,172	3.154	2,496,804	3.796	3,005,402	508,598
DUKE POWER, A DIVISION OF DUKE ENERGY CORP.	OS	3,628	3.667	133,050	4.643	168,436	35,386
DYNEGY POWER MARKETING, INC.	OS	22,991	2.828	650,159	3.569	820,456	170,297
EL PASO MERCHANT ENERGY, LP	OS	6,493	3.672	238,438	4.289	278,480	40,042
ENRON POWER MARKETING, INC.	OS	21,166	4.316	913,621	4.985	1,055,188	141,567
ENTERGY-KOCH TRADING, LP	OS	19,853	4.079	809,824	4.603	913,922	104,098
HARDEE POWER PARTNERS LIMITED	OS	1,200	5.800	69,600	8.109	97,308	27,708
L G & E ENERGY MARKETING, INC.	OS	168,370	3.821	6,433,240	4.419	7,439,558	1,006,317
LOUISVILLE GAS & ELECTRIC CO.	OS	100	3.000	3,000	4.272	4,272	1,272
MIRANT AMERICAS ENERGY MARKETING, LP	OS	70	3.000	2,100	3.829	2,680	580
MORGAN STANLEY CAPITAL GROUP, INC.	OS	177,516	5.532	9,820,229	5.759	10,223,027	402,798
NRG POWER MARKETING, INC.	OS	9,524	3.081	293,423	3.818	363,588	70,165
OGLETHORPE POWER CORPORATION	OS	47,744	3.658	1,746,445	4.506	2,161,369	404,924
PG&E ENERGY TRADING-POWER, LP	OS	104	4.188	4,356	4.291	4,463	108
RELIANT ENERGY SERVICES, INC.	OS	12,393	3.127	387,493	4.087	506,552	119,059
SEMPRA ENERGY TRADING CORPORATION	OS	12,478	3.658	456,496	4.603	574,399	117,904
SOUTH CAROLINA ELECTRIC & GAS CO	OS	10,748	4.225	454,117	5.404	580,794	126,677
SOUTHERN COMPANY SERVICES, INC.	OS	22,016	3.763	828,436	4.652	1,024,169	195,733
TENASKA POWER SERVICES CO.	OS	1,229	2.955	36,316	3.486	42,839	6,523
TXU ENERGY TRADING CO.	OS	6,731	3.508	236,114	4.081	274,662	38,548
WILLIAMS ENERGY MARKETING & TRADING	OS	72,337	2.739	1,981,130	3.199	2,313,758	332,628
FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		1,093,904	3.497	38,256,440	4.347	47,547,430	9,290,990
NON-FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		924,521	4.066	37,589,197	4.640	42,895,037	5,305,841
TOTAL		2,018,425	3.758	75,845,637	4.481	90,442,467	14,596,830

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
COMPANY: FLORIDA POWER & LIGHT COMPANY
YTD 2002

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
					COST IF GENERATED		
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS. COST cents/KWH	TOTAL $ FOR FUEL ADJ. (3) x (4) $	(a) cents/KWH	(b) $	FUEL SAVINGS (6)(b) - (5) $
ESTIMATED:							
FLORIDA	OS	30,000	8.100	1,829,945	8.619	2,585,845	755,900
NON-FLORIDA	OS	120,000	3.400	4,080,000	3.848	4,617,600	537,600
TOTAL		150,000	3.940	5,909,945	4.802	7,203,445	1,293,500
ACTUAL:							
FLORIDA:							
THE ENERGY AUTHORITY	C	0	0.000	0	0.000	0	0
CITY OF HOMESTEAD	OS	92	8.674	7,980	9.992	9,193	1,213
CITY OF LAKE WORTH	OS	80	11.583	6,950	11.813	7,088	138
CITY OF LAKELAND	OS	1,900	1.826	34,700	2.092	39,757	5,057
CITY OF TALLAHASSEE (prior month adj)	OS	160	4.033	6,452	4.844	7,750	1,298
FLORIDA POWER CORPORATION	OS	472,735	2.071	9,790,427	3.506	18,584,902	8,794,475
JACKSONVILLE ELECTRIC AUTHORITY	OS	0	0.000	0	0.000	0	0
ORLANDO UTILITIES COMMISSION	OS	70,972	4.723	3,352,278	5.162	3,678,061	325,783
REEDY CREEK IMPROVEMENT DISTRICT	OS	0	0.000	0	0.000	0	0
RIDGE GENERATING STATION, LP	OS	690	3.504	24,175	3.668	25,309	1,134
SEMINOLE ELECTRIC COOPERATIVE, INC.	OS	19,144	3.562	681,945	4.613	883,117	201,172
TAMPA ELECTRIC COMPANY	OS	18,747	2.817	528,049	3.271	613,267	85,218
THE ENERGY AUTHORITY	OS	634,758	3.619	22,973,645	4.376	27,778,966	4,803,321
NON-FLORIDA:							
ALABAMA ELECTRIC COOPERATIVE, INC.	OS	3,831	3.523	134,968	3.997	153,143	18,175
AMERICAN ELECTRIC POWER SERVICE CORPORATION - PRIOR MO ADJ.	OS	7,365	5.209	383,667	8.099	449,167	65,500
AQUILA ENERGY MARKETING CORPORATION	OS	62,124	2.580	1,602,500	3.037	1,886,475	283,975
BP ENERGY COMPANY	OS	42	3.143	1,320	3.521	1,479	159
CALPINE ENERGY SERVICES, L.P.	OS	8,590	2.928	251,308	3.683	333,522	82,214
CARGILL -ALLIANT, LLC	OS	408,937	3.571	14,602,725	4.115	16,828,455	2,225,730
CAROLINA POWER & LIGHT COMPANY (Prior Mo. Adjust.)	OS	2,288	2.713	62,080	3.752	85,839	23,759
CINCINNATI GAS & ELECTRIC CO.	OS	5,492	4.380	240,555	5.679	311,896	71,341
CINERGY CAPITAL & TRADING, INC.	OS	0	0.000	37	0.000	0	(37)
CONOCO, INC.	OS	1,525	3.128	47,699	3.847	58,670	10,971
CONSTELLATION POWER SOURCE, INC.	OS	10,932	6.227	680,685	7.660	837,438	156,753
CORAL POWER LLC	OS	1,677	4.678	78,453	4.766	79,919	1,466
DUKE ENERGY TRADING & MARKETING, LLC	OS	73,006	3.309	2,415,946	4.061	2,979,539	563,593
DUKE POWER, A DIVISION OF DUKE ENERGY CORP.	OS	1,735	4.212	73,085	4.749	82,390	9,305
DYNEGY POWER MARKETING, INC.	OS	45,267	3.752	1,698,442	4.534	2,052,439	353,997
EL PASO MERCHANT ENERGY, LP (prior mo adj)	OS	162	3.163	5,124	3.472	5,624	500
ENRON POWER MARKETING, INC.	OS	0	0.000	0	0.000	0	0
ENTERGY-KOCH TRADING, LP	OS	72,959	3.687	2,835,792	4.403	3,212,640	376,848
EXELON GENERATION COMPANY, LLC	OS	50	2.700	1,350	5.422	2,711	1,361
HARDEE POWER PARTNERS LIMITED	OS	210	4.833	10,150	6.627	13,916	3,766
L G & E ENERGY MARKETING, INC.	OS	220,667	3.398	7,497,500	4.037	8,909,266	1,411,766
MIRANT AMERICAS ENERGY MARKETING, LP	OS	9,144	5.192	474,720	5.512	503,984	29,264
MORGAN STANLEY CAPITAL GROUP, INC.	OS	253,806	3.938	9,969,434	4.511	11,449,311	1,459,877
NORTHERN STATES POWER COMPANY	OS	22	2.964	652	3.473	764	112
NRG POWER MARKETING, INC.	OS	2,316	1.884	43,627	2.916	67,543	23,916
OGLETHORPE POWER CORPORATION	OS	27,404	3.244	888,862	3.843	1,053,029	164,167
RELIANT ENERGY SERVICES, INC. (prior mo adj)	OS	52,280	3.778	1,974,436	4.499	2,351,261	376,825
SELECT ENERGY, INC.	OS	6,400	3.907	250,072	4.396	281,361	31,289
SEMPRA ENERGY TRADING CORPORATION	OS	0	0.000	0	0.000	0	0
SOUTH CAROLINA ELECTRIC & GAS CO	OS	6,950	3.626	251,973	4.167	291,009	39,036
SOUTHERN COMPANY SERVICES, INC.	OS	26,221	3.808	998,587	5.206	1,365,095	366,508
TENASKA POWER SERVICES CO.	OS	7,851	3.026	237,589	3.505	275,170	37,581
TXU ENERGY TRADING CO. (prior mo adj)	OS	642	2.201	14,131	3.197	20,527	6,396
WILLIAMS ENERGY MARKETING & TRADING	OS	120,165	2.990	3,593,477	3.477	4,177,795	584,316
FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		1,219,256	3.068	37,406,801	4.070	49,625,410	12,218,809
NON-FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		1,440,040	3.565	51,340,946	4.175	60,121,377	8,780,431
TOTAL		2,659,296	3.337	88,747,547	4.127	109,746,787	20,999,240
CURRENT MONTH:							
DIFFERENCE		2,509,296	(0.603)	82,837,602	(0.675)	102,543,342	19,705,740
DIFFERENCE (%)		1,672.9	(15.3)	1,401.7	(14.1)	1,423.5	1,523.4
PERIOD TO DATE:							
ACTUAL		2,659,296	3.337	88,747,526	4.127	109,746,780	20,999,255
ESTIMATED		2,353,245	3.553	83,621,741	4.342	102,177,982	18,556,242
DIFFERENCE		306,051	(0.216)	5,125,785	(0.215)	7,568,798	2,443,013
DIFFERENCE (%)		13.0	(6.1)	6.1	(5.0)	7.4	13.2

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
COMPANY: FLORIDA POWER & LIGHT COMPANY
YTD 2003

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
					COST IF GENERATED		
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS COST cents/KWH	TOTAL $ FOR FUEL ADJ (3) x (4) $	(a) cents/KWH	(b) $	FUEL SAVINGS (6)(b) - (5) $
ESTIMATED							
FLORIDA	OS	702,001	3 177	22,301,798	4.224	33,011,523	10,709,728
NON-FLORIDA	OS	1,071,892	3 816	40,898,409	4 196	46,893,849	5,795,440
TOTAL		1,773,893	3 563	63,200,205	4 493	79,705,372	16,505,168
ACTUAL							
FLORIDA:							
THE ENERGY AUTHORITY	C	0	0 000	0	0 000	0	0
ENERGY AUTHORITY, THE	OS	430,999	4 175	17,995,891	5 200	22,410,314	4,414,823
FLORIDA POWER CORPORATION	OS	704,048	2 985	21,016,137	4 615	32,489,219	11,473,082
HOMESTEAD, CITY OF	OS	150	9 500	14,250	10 741	16,112	1,862
JACKSONVILLE ELECTRIC AUTHORITY	OS	0	0 000	0	0 000	0	0
LAKELAND, CITY OF	OS	402	6 192	24,892	9 697	38,983	14,091
LAKE WORTH, CITY OF	OS	0	0 000	0	0 000	0	0
NEW SMYRNA BEACH UTILITIES COMMISSION, CITY OF	OS	0	0 000	0	0 000	0	0
ORLANDO UTILITIES COMMISSION	OS	108,675	5 681	6,173,472	6 355	8,905,991	732,519
REEDY CREEK IMPROVEMENT DISTRICT	OS	0	0 000	0	0 000	0	0
RIDGE GENERATING STATION, LP	OS	748	4 518	33,797	5 517	41,267	7,470
SEMINOLE ELECTRIC COOPERATIVE, INC	OS	50,248	3 790	1,904,241	4 888	2,454,462	550,221
TALLAHASSEE, CITY OF	OS	5,061	5 946	302,125	6 800	345,501	43,375
TAMPA ELECTRIC COMPANY	OS	17,761	3 909	693,896	5 141	912,802	218,705
NON-FLORIDA							
ALABAMA ELECTRIC COOPERATIVE, INC.	OS	805	4 210	33,933	5 789	46,661	12,728
AMERICAN ELECTRIC POWER SERVICE CORPORATION	OS	0	0 000	0	0 000	0	0
AQUILA MERCHANT SERVICES, INC	OS	0	0 000	0	0 000	0	0
BP ENERGY COMPANY	OS	240	6 125	14,700	6 551	15,722	1,022
CALPINE ENERGY SERVICES, L P	OS	24,540	7 263	1,787,154	8 749	2,146,998	359,834
CARGILL POWER MARKETS, LLC	OS	528,180	4 815	25,430,534	5 544	29,281,352	3,850,818
CAROLINA POWER & LIGHT COMPANY	OS	16,589	3 573	592,718	5 042	836,432	243,714
CINCINNATI GAS & ELECTRIC CO	OS	0	0 000	0	0 000	0	0
CONOCO PHILLIPS CO	OS	24,822	2 942	730,348	4 396	1,091,155	360,807
CONSTELLATION POWER SOURCE, INC	OS	0	0 000	0	0 000	0	0
CORAL POWER, LLC	OS	0	0 000	0	0 000	0	0
DUKE ENERGY TRADING & MARKETING, LLC	OS	7,088	4 940	350,168	6 862	486,363	136,194
DUKE POWER, A DIVISION OF DUKE ENERGY CORP	OS	(102)	5 000	(5,100)	5 705	(5,819)	(719)
DYNEGY POWER MARKETING, INC	OS	560	6.085	33,962	7 603	42,577	8,615
EL PASO MERCHANT ENERGY, LP	OS	0	0 000	0	0 000	0	0
ENTERGY-KOCH TRADING, LP	OS	55,358	4 621	2,557,918	5 571	3,083,836	525,919
EXELON GENERATION COMPANY, LLC	OS	0	0 000	0	0 000	0	0
HARDEE POWER PARTNERS LIMITED	OS	547	7 151	39,115	8 764	47,939	8,824
L G & E ENERGY MARKETING, INC.	OS	257,140	3 931	10,108,226	5 010	12,881,749	2,773,522
MIRANT AMERICAS ENERGY MARKETING, LP	OS	0	0 000	0	0 000	0	0
MORGAN STANLEY CAPITAL GROUP, INC.	OS	105,588	4 348	4,590,954	4 997	5,276,748	685,794
NORTHERN STATES POWER COMPANY	OS	0	0.000	0	0 000	0	0
NRG POWER MARKETING, INC.	OS	0	0.000	0	0 000	0	0
OGLETHORPE POWER CORPORATION	OS	9,811	2 397	235,160	3 965	388,960	153,800
PROGRESS VENTURES, INC	OS	88,904	3 585	3,098,054	4 322	3,755,762	657,708
RELIANT ENERGY SERVICES, INC	OS	18,497	5.149	952,411	5 940	1,098,661	146,249
SELECT ENERGY, INC	OS	0	0 000	0	0 000	0	0
SEMPRA ENERGY TRADING CORPORATION	OS	0	0.000	0	0 000	0	0
SOUTH CAROLINA ELECTRIC & GAS CO	OS	0	0 000	0	0 000	0	0
SOUTHERN COMPANY SERVICES, INC	OS	285,290	3 924	10,409,549	4 939	13,102,453	2,692,905
TENASKA POWER SERVICES CO	OS	1,714	6 288	90,640	7 496	128,459	37,818
TRACTEBEL ENERGY MARKETING, INC.	OS	0	0 000	0	0 000	0	0
TXU ENERGY TRADING CO	OS	0	0.000	0	0 000	0	0
VIRGINIA POWER ENERGY MARKETING, INC	OS	0	0 000	0	0 000	0	0
WILLIAMS ENERGY MARKETING & TRADING	OS	0	0 000	0	0.000	0	0
FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		1,318,102	3 654	48,158,501	4.978	65,614,450	17,455,949
NON-FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		1,403,572	4.350	61,050,455	5 251	73,706,007	12,655,553
TOTAL		2,721,674	4.013	109,208,956	5 119	139,320,457	30,111,501
CURRENT MONTH							
DIFFERENCE		0	0	0	0	0	0
DIFFERENCE (%)		0.0	0 0	0 0	0 0	0 0	0 0
PERIOD TO DATE:							
ACTUAL		2,721,674	4 013	109,208,957	5 119	139,320,457	30,111,501
ESTIMATED		1,898,484	3 947	74,936,176	5 224	99,178,091	24,242,816
DIFFERENCE		823,190	0.065	34,272,781	(0.105)	40,141,366	5,868,685
DIFFERENCE (%)		43.4	1 7	45.7	(2 0)	40.5	24 2

6. With regard to TECo's purchased power contract with Hardee Power Partners, Ltd. (HPP), provide the following information:

a. The date of completion of the sale of TECo's affiliate interest in the Hardee Power Station; and

b. List each item of cost in the purchased power contract between TECo and Hardee Power Partners, Ltd (HPP) that has changed since the date the sale was completed, providing:
   i. the effective date of the change in cost;
   ii. the charge before the change in cost; and
   iii. the charge after the change in cost for each item identified.

A. a. The sale of TECO Power Service's interest in Hardee Power Partners, Ltd., closed on September 30, 2003.

b. There were no changes to Tampa Electric's purchased power contract since the completion of the sale.

recent quarter; a year ago it delivered 18.3 million Dt.

The company's interstate gas transmission and storage business reported earnings of $8 million during the period, a 2% increase. Questar Pipeline transported a total of 17.9 million Dt in the latest quarter, down from the 18.3 million Dt a year ago. RAW

EIA: Storage surplus narrows with 26-Bcf injection

U.S. gas storage operators injected a net 26 Bcf during the week ending Oct. 22, raising working gas inventories to 3.249 Tcf with just a week remaining in the traditional refill season, the Energy Information Administration reported Thursday.

The surplus from the year-ago level shrank to 128 Bcf from 157 Bcf, while the surplus over the five-year average narrowed to 210 Bcf from 221 Bcf. EIA's five-year average showed an injection of 35 Bcf and total working gas of 3.039 Tcf.

Estimated working gas in storage

(week ending Oct 22)

	This Week (Bcf)	Last Week (Bcf)	Change (Bcf)
Consuming Region East	1,894	1,880	14
Consuming Region West	422	418	4
Producing Region	933	925	8
Total U.S.	3,249	3,223	26

	This Week Last Yr. (Bcf)	Prior 5 Year Average (Bcf)
Consuming Region East	1,847	1,832
Consuming Region West	396	376
Producing Region	878	832
Total U.S.	3,121	3,039

Source: Energy Information Administration

The build was on the low end of market expectations, which had ranged from the mid-30s to high 40s Bcf. Nevertheless, the report helped spark a rally on the December NYMEX gas futures contract, which broke the $9/MMBtu level before retreating (*see related story, page 2*).

Scott De Pasquale, senior analyst with Energy Security and Analysis in Boston, said that while the NYMEX "is sensitive now to any news," the contract's strong bullish reaction to the storage report was somewhat surprising. "It's difficult to think that that [injection] number was that low," especially given that storage stocks "are still well above the five-year average," he said.

De Pasquale noted that the relatively low injection may not be an indication of weak gas supplies but rather a function of storage levels being so high. "As storage gets full, it gets more difficult to cycle [gas] in," he said.

According to analyst Thomas Driscoll of Lehman Brothers in New York, "the injection rates of the past five weeks indicate that the gas market has gone from being balanced ... to about 2.2 Bcf/day oversupplied," Driscoll said. As a result, "lower prices may be required to correct the oversupply."

Driscoll noted that the National Oceanic and Atmospheric Administration's winter forecasts are calling for warmer-than-normal weather in the West, which "should more than offset cooler-than-normal temperatures forecast in the South/Southeast." If that forecast holds, weather-related demand this winter should be "about 150 to 200 Bcf greater than last year, and about equal to normal."

EIA reported injections for last week of 14 Bcf in the east region, to 1.894 Tcf (1.847 Tcf a year ago), 4 Bcf in the west region, to 422 Bcf (396 Bcf a year ago), and 8 Bcf in the producing region, to 933 Bcf (878 Bcf a year ago).

In the east, stocks are now 62 Bcf above the five-year average, while stocks are 46 Bcf above the five-year average in the west and 101 Bcf above in the producing region.

In the same week a year ago, 55 Bcf was injected to raise stocks to 3.121 Tcf, according to EIA's figures. Two years ago, 11 Bcf was injected to raise storage to 3.172 Tcf.

EIA also announced changes to its storage reporting schedule due to the upcoming Veterans' Day and Thanksgiving holidays. The storage report for the week ending Nov. 5 will be released on Wednesday, Nov. 10, while the report for the week ending Nov. 19 will be released on Wednesday, Nov. 24. MT

NYMEX Henry Hub gas futures contract, Oct 28

	Settlement	High	Low	+/-	Volume*
December, 2004	8.684	9.200	8.620	-9.8	21544
Jan., 2005	9.317	9.800	9.260	-11.8	8936
February	9.352	9.750	9.250	-11.8	3216
March	8.872	9.300	8.820	-12.8	4633
April	7.472	7.610	7.420	-7.8	2255
May	7.122	7.250	7.100	-7.8	669
June	7.144	7.250	7.140	-7.8	279
July	7.172	7.280	7.150	-7.8	390
August	7.192	7.300	7.150	-7.8	308
September	7.157	7.260	7.190	-7.3	209
October	7.187	7.290	7.180	-7.3	272
November	7.522	7.585	7.530	-6.3	242
December	7.827	7.880	7.830	-5.8	475
Jan., 2006	8.067	8.120	8.120	-5.3	529
February	8.047	8.070	8.050	-5.3	455
March	7.787	7.840	7.840	-5.3	786
April	6.627	6.675	6.675	-5.3	60
May	6.412	6.412	6.412	-5.3	86
June	6.437	6.437	6.437	-5.3	7
July	6.447	6.530	6.530	-6.3	7
August	6.462	6.462	6.462	-6.3	10
September	6.432	6.460	6.460	-6.3	9
October	6.467	6.500	6.500	-6.3	7
November	6.797	6.797	6.797	-6.3	7
December	7.087	7.180	7.150	-6.3	9
Jan. 2007	7.312	7.312	7.312	-6.8	427
February	7.287	7.287	7.287	-6.8	402
March	7.062	7.062	7.062	-6.8	177
April	6.062	6.062	6.062	-6.8	3
May	5.832	5.832	5.832	-6.8	3
June	5.847	5.847	5.847	-6.8	3
July	5.857	5.935	5.935	-7.8	3
August	5.872	5.960	5.960	-8.8	3
September	5.837	5.837	5.837	-8.8	3
October	5.862	5.832	5.832	-9.3	3
November	6.202	6.202	6.202	+9.3	3
Volume of contracts (official*)					**46,468**

Front-months open interest Wednesday:
Dec, 16,847 ; Jan, 70,167 ; Feb, 47,102
Total open interest Wednesday: n/a

NYMEX Henry Hub options closings, Oct 28

Strike Price	Calls-Settle Dec.	Jan.	Feb.	Puts-Settle Dec.	Jan.	Feb.
8.60	63.8¢	126.0¢	140.9¢	55.4¢	54.5¢	66.0¢
8.65	61.4¢	123.2¢	138.3¢	58.0¢	56.7¢	68.4¢
8.70	59.2¢	120.4¢	135.7¢	60.8¢	58.9¢	70.8¢
8.75	57.3¢	117.7¢	133.2¢	63.8¢	61.2¢	73.2¢
8.80	55.2¢	115.2¢	130.7¢	66.8¢	63.6¢	75.7¢
8.85	53.3¢	112.6¢	128.2¢	69.9¢	66.0¢	78.2¢
8.90	51.4¢	110.0¢	125.9¢	73.0¢	68.4¢	80.8¢
8.95	49.2¢	107.5¢	123.5¢	76.2¢	70.9¢	83.4¢
9.00	47.9¢	105.1¢	121.2¢	79.5¢	73.5¢	86.1¢

Platts oil prices, Oct 28

	($/b)	($/MMBtu)
Gulf Coast spot		
1% Resid	35.50-35.75	5.67
3% Resid	32.00-32.50	5.13
Crude spot		
WTI (Dec)	50.77-50.79	8.08
New York spot		
No.2	60.77-60.86	10.44
0.3% Resid HP	41.50-41.75	6.62
0.3% Resid LP	45.25-45.75	7.24
0.7% Resid	36.75-37.00	5.87
1% Resid HP	34.00-34.25	5.43

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2003 Hedging Results

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 3
COMPANY/ F.P.&L.
WITNESS: G. Yupp (GJY-1)
DATE: 11-08-04

GJY-1
Docket No. 040001-EI
FPL Witness: Gerard Yupp
Pages 1 – 39
April 1, 2004

CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
TOTAL YEAR 2003	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				
	AVERAGE PERIOD OF HEDGE (Days) - PHYSICAL				
	AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL				

Note: Natural gas option premiums are not included in the Gain/(Loss) figures. Natural gas option premiums are noted separately.

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FPL HEAVY FUEL OIL PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
TOTAL YEAR 2003	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				
	AVERAGE PERIOD OF HEDGE (Days) - PHYSICAL				
	AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
TOTAL YEAR 2003	FIXED PRICE TRANSACTIONS				
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				
	AVERAGE PERIOD OF HEDGE (Days) - PHYSICAL				
	AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL				

Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.

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FPL NATURAL GAS PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
JAN-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL HEAVY FUEL OIL PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
JAN-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
JAN-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
FEB-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL HEAVY FUEL OIL PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
FEB-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
FEB-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
MAR-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL HEAVY FUEL OIL PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	VOLUME WITHDRAW VOLUME	GAIN/(LOSS)
MAR-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
MAR-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL NATURAL GAS PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
APR-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL HEAVY FUEL OIL PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
APR-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
APR-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
MAY-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL HEAVY FUEL OIL PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
MAY-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
MAY-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL NATURAL GAS PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
JUN-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL HEAVY FUEL OIL PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	VOLUME WITHDRAW VOLUME	GAIN/(LOSS)
JUN-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
JUN-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
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FPL NATURAL GAS PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	OPTION PREMIUMS	GAIN/(LOSS)
JUL-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL HEAVY FUEL OIL PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
JUL-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
JUL-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
AUG-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
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	OVER-THE-COUNTER OPTIONS				
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PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	VOLUME WITHDRAW VOLUME	GAIN/(LOSS)
AUG-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
AUG-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
SEP-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	VOLUME WITHDRAW VOLUME	GAIN/(LOSS)
SEP-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

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ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
SEP-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
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	OVER-THE-COUNTER OPTIONS				
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CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
OCT-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

Note: Natural gas option premiums are not included in the Gain/(Loss) figures. Natural gas option premiums are noted separately.

CONFIDENTIAL

FPL HEAVY FUEL OIL PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
OCT-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

CONFIDENTIAL

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
OCT-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.

CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
NOV-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

Note: Natural gas option premiums are not included in the Gain/(Loss) figures. Natural gas option premiums are noted separately.

CONFIDENTIAL

FPL HEAVY FUEL OIL PROCUREMENT

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
NOV-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

CONFIDENTIAL

ELECTRICITY

VOLUME

PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
NOV-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.

CONFIDENTIAL

FPL NATURAL GAS PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	VOLUME SALES	OPTION PREMIUMS	GAIN/(LOSS)
DEC-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

Note: Natural gas option premiums are not included in the Gain/(Loss) figures. Natural gas option premiums are noted separately.

CONFIDENTIAL

FPL HEAVY FUEL OIL PROCUREMENT

PERIOD	INSTRUMENT	VOLUME PURCHASES	SALES	WITHDRAW VOLUME	GAIN/(LOSS)
DEC-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

CONFIDENTIAL

		ELECTRICITY			
		VOLUME			
PERIOD	INSTRUMENT	PURCHASES	SALES	SAVINGS	GAINS
DEC-03	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	OIL INVENTORY HEDGE				
	PHYSICAL POWER OPTION PREMIUMS				
	PHYSICAL POWER (EXERCISED OPTIONS)				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	BROKER FEES				

Note: Physical power option premium volumes represent the total available volume. Physical power option exercised volumes represent the actual volumes called upon.

APPENDIX I

FUEL COST RECOVERY

GJY-2

DOCKET NO. 040001-EI

EXHIBIT_____

PAGES 1-6

SEPTEMBER 9, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 4
COMPANY/ F.P.+L.
WITNESS. G. Yupp (GJY-2)
DATE: 11-08-04

APPENDIX 1

FUEL COST RECOVERY

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3	Projected Availability of Natural Gas	G. Yupp
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5,6	2005 Risk Management Plan	G. Yupp

Florida Power and Light Company
Projected Dispatch Costs and Projected Availability of Natural Gas
January Through December 2005

Heavy Oil	January	February	March	April	May	June	July	August	September	October	November	December
1.0% Sulfur Grade ($/Bbl)	33.00	32.38	31.68	31.47	31.87	32.16	32.27	32.24	31.79	31.01	30.61	29.99
1.0% Sulfur Grade ($/mmBtu)	5.16	5.06	4.95	4.92	4.98	5.03	5.04	5.04	4.97	4.85	4.78	4.69

Light Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.05% Sulfur Grade ($/Bbl)	52.11	51.89	50.89	49.49	48.17	47.23	46.99	47.08	47.34	47.60	47.86	48.12
0.05% Sulfur Grade ($/mmBtu)	8.94	8.90	8.73	8.49	8.26	8.10	8.06	8.08	8.12	8.16	8.21	8.25

Natural Gas Transportation	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT (mmBtu/Day)	760,000	760,000	760,000	859,000	894,000	894,000	894,000	894,000	894,000	859,000	760,000	760,000
Firm Gulfstream (mmBtu/Day)	-	-	-	-	-	350,000	350,000	350,000	350,000	350,000	350,000	350,000
Non-Firm FGT (mmBtu/Day)	150,000	150,000	150,000	110,000	50,000	50,000	50,000	50,000	50,000	110,000	150,000	150,000
Non-Firm Gulfstream (mmBtu/Day)	463,000	463,000	463,000	438,000	413,000	413,000	413,000	413,000	413,000	438,000	463,000	463,000
Total Projected Daily Availability (mmBtu/Day)	1,373,000	1,373,000	1,373,000	1,407,000	1,357,000	1,707,000	1,707,000	1,707,000	1,707,000	1,757,000	1,723,000	1,723,000

Natural Gas Dispatch Price	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT ($/mmBtu)	7.10	7.05	6.88	6.25	6.08	6.10	6.14	6.15	6.12	6.13	6.29	6.47
Firm Gulfstream ($/mmBtu)	-	-	-	-	-	6.06	6.10	6.11	6.07	6.09	6.24	6.42
Non-Firm FGT ($/mmBtu)	7.25	7.21	7.03	6.42	6.31	6.33	6.37	6.38	6.35	6.30	6.44	6.62
Non-Firm Gulfstream ($/mmBtu)	7.47	7.42	7.25	6.65	6.69	6.71	6.75	6.76	6.73	6.59	6.75	6.93

Solid Fuel	January	February	March	April	May	June	July	August	September	October	November	December
Scherer ($/mmBtu)	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59	1.59
SJRPP ($/mmBtu)	2.03	2.03	2.03	2.03	2.03	2.02	2.02	2.02	2.02	2.02	2.02	2.02

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

PLANT/UNIT	PROJECTED FORCED OUTAGE FACTOR (%)	PROJECTED MAINTENANCE OUTAGE FACTOR (%)	PLANNED OUTAGE FACTOR (%)	OVERHAUL DATES	OVERHAUL DATES	OVERHAUL DATES	OVERHAUL DATES
Cape Canaveral 1	1.4	3.6	15.3	02/05/05 - 04/01/05			
Cape Canaveral 2	1.3	3.4	11.5	10/15/05 - 11/25/05			
Cutler 5	1.0	1.2	8.2	10/22/05 - 11/20/05			
Cutler 6	1.3	1.7	11.5	10/22/05 - 12/02/05			
Lauderdale 4	0.9	4.2	3.3	03/19/05 - 03/30/05			
Lauderdale 5	0.9	4.2	19.7	09/24/05 - 12/04/05			
Lauderdale GTs	1.0	7.2	0.0	NONE			
Fort Myers 2 CC	1.0	4.2	1.6	02/12/05 - 02/23/05 **	01/29/05 - 02/09/05 **	01/15/05 - 01/26/05 **	
Ft. Myers 3	1.1	1.7	1.6	02/26/05 - 03/03/05 **	03/05/05 - 03/10/05 **		
Ft. Myers GTs	0.3	1.3	2.1	03/01/05 - 03/28/05 **	04/01/05 - 04/28/05 **	02/01/05 - 02/28/05 **	03/01/05 - 03/07/05 **
Manatee 1	1.1	3.3	20.5	09/17/05 - 11/30/05			
Manatee 2	1.0	3.2	0.0	NONE			
Manatee 3	1.5	0.6	0.0	NONE			
Martin 1	0.8	2.5	17.3	01/29/05 - 04/01/05			
Martin 2	0.9	2.8	0.0	NONE			
Martin 3	1.0	3.9	0.8	03/12/05 - 03/17/05 **			
Martin 4	1.0	4.3	2.5	02/12/05 - 02/17/05 **	03/19/05 - 03/30/05 **		
Martin 8 CC	1.5	0.6	0.0	NONE			
Port Everglades 1	1.8	2.4	15.3	10/01/05 - 11/25/05			
Port Everglades 2	1.9	2.4	22.5	02/26/05 - 05/18/05			
Port Everglades 3	1.3	3.4	5.8	02/05/05 - 02/25/05			
Port Everglades 4	1.2	3.2	0.0	NONE			
Port Everglades GTs	1.9	9.7	0.0	NONE			
Putnam 1	1.0	3.2	9.6	03/12/05 - 04/15/05 **	10/15/05 - 11/18/05 **		
Putnam 2	1.0	3.2	6.8	04/23/05 - 05/27/05 **	04/30/05 - 05/14/05 **		
Riviera 3	2.4	3.4	7.7	03/12/05 - 04/08/05			
Riviera 4	2.8	3.9	8.2	10/08/05 - 11/06/05			
Sanford 3	1.8	2.2	5.8	03/12/05 - 04/01/05			
Sanford 4 CC	1.0	3.3	0.5	02/05/05 - 02/12/05 **			
Sanford 5 CC	1.0	3.7	2.7	05/28/05 - 06/06/05 **	05/14/05 - 05/23/05 **	09/03/05 - 09/12/05 **	06/11/05 - 06/20/05 **
Turkey Point 1	1.4	3.6	0.0	NONE			
Turkey Point 2	1.4	3.6	20.5	02/26/05 - 05/11/05			
Turkey Point 3	1.3	1.3	0.0	NONE			
Turkey Point 4	1.0	1.0	17.8	04/09/05 - 06/13/05			
St. Lucie 1	1.0	1.0	16.4	10/03/05 - 12/02/05			
St. Lucie 2	1.3	1.3	0.0	NONE			
St. Johns River Power P:	1.8	4.0	16.2	02/27/05 - 04/26/05			
St. Johns River Power P:	2.0	4.4	0.0	NONE			
Scherer 4	1.8	4.0	0.0	NONE			

** Partial Planned Outage

2005 Risk Management Plan

1. Identify overall quantitative and qualitative risk management objectives.
   A. FPL's risk management objectives are to effectively execute a well-disciplined and independently controlled fuel procurement strategy to achieve the goals of fuel price stability (volatility minimization), to potentially achieve fuel cost minimization, and to achieve asset optimization. FPL's fuel procurement strategy aims to mitigate fuel price increases and reduce fuel price volatility, while maintaining the opportunity to benefit from price decreases in the marketplace for FPL's customers.

      FPL plans to hedge a percentage of its residual fuel oil and natural gas purchases with a combination of fixed price transactions and options. Additionally, FPL plans to extend its hedging program up to two years beyond the next recovery period. FPL believes that hedging up to three years (next recovery period and an additional two years) into the future will help further achieve the goal of fuel price stability. FPL will approach hedging into the extended period cautiously, similar to its initial approach to implementing its expanded hedging program.

3. Identify and quantify each risk, general and specific, that the utility may encounter with its fuel procurement.
   A. The potential risks that FPL encounters with its fuel procurement are supplier credit, fuel supply and transportation availability, product quality, delivery timing, weather, environmental and supplier failure to deliver. The utility determines acceptable levels of risk for fuel procurement by performing various analyses that include forecasted/expected levels of activity, forecasted price levels and price changes, price volatility, and Value-at-Risk (VaR) calculations. The analyses are then presented to the Exposure Management Committee for review and approval. Approval is given to remain within specified VaR limits. These VaR limits are specified in FPL's policies and procedures that were filed on a confidential basis with the Commission.

4. Describe the utility's oversight of its fuel procurement activities.
   A. The utility has a separate and independent middle office risk management department that provides oversight of fuel procurement activities at the deal level. In addition, an executive-level, Exposure Management Committee meets monthly to review performance and discuss current procurement/hedging activities and monitors daily results of procurement activity.

5. Verify that the utility provides its fuel procurement activities with independent and unavoidable oversight.
   A. Please see response to No. 4.

6. Describe the utility's corporate risk policy regarding fuel procurement activities.
   A. The utility has a written policy and procedures that define VaR, stop -loss, and duration limits for all forward activity by portfolio. FPL's policies and procedures were filed on a confidential basis with the Commission. In addition, individual procurement strategies must be documented and approved by front and middle office management prior to deal execution.

7. Verify that the utility's corporate risk policy clearly delineates individual and group transaction limits and authorizations for all fuel procurement activities.
   A. Please see response to No. 6.

8. Describe the utility's strategy to fulfill its risk management objectives.
   A. Please see response to No. 1.

9. Verify that the utility has sufficient policies and procedures to implement its strategy.
   A. Please see response to No. 6.

13. Describe the utility's reporting system for fuel procurement activities.
   A. The utility has sufficient systems capability for identifying, measuring, and monitoring all types of risk associated with fuel procurement activities. These systems include: deal capture, a database for maintaining current and historical pricing, deal information, and valuation models, and a reporting system that utilizes the information in the trade capture system and the database.

14. Verify that the utility's reporting system consistently and comprehensively identifies, measures, and monitors all forms of risk associated with fuel procurement activities.
   A. Please see response to No. 13.

15. If the utility has current limitations in implementing certain hedging techniques that would provide a net benefit to ratepayers, provide the details of a plan for developing the resources, policies, and procedures for acquiring the ability to use effectively the hedging techniques.
   A. FPL does not believe that there are any such limitations currently.

APPENDIX I

FUEL COST RECOVERY

TRUE UP CALCULATION

KMD-1
DOCKET NO. 040001-EI
FPL WITNESS: K.M. DUBIN
February 23, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO 5
COMPANY/ FP+L
WITNESS. K.M. Dubin (KMD-1)
DATE: 11-08-04

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APPENDIX I

FUEL COST RECOVERY

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PAGE(S)	DESCRIPTION
3	SUMMARY OF NET TRUE UP AMOUNT
4 - 5	CALCULATION OF FINAL TRUE UP AMOUNT
6	CALCULATION OF FINAL TRUE UP VARIANCES

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP FOR THE
PERIOD JANUARY THROUGH DECEMBER 2003

1	End of Period True-up for the period January through December 2003 (from page 4, lines D7 & D8)	$ (302,921,183)
2	Less - Estimated/Actual True-up for the same period *	$ (344,729,859)
3	Net Final True-up for the period January through December 2003	$ 41,808,676

( ) Reflects Underrecovery

* Approved in FPSC Order No. PSC-03-1461-FOF-EI dated December 22, 2003

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

LINE NO.			(1) JAN	(2) FEB	(3) MAR	(4) APR	(5) MAY	(6) JUN
A		**Fuel Costs & Net Power Transactions**						
1	a	Fuel Cost of System Net Generation	$ 202,082,274	$ 166,332,573	$ 338,352,856	$ 220,910,699	$ 290,580,370	$ 301,507,670
	b	Incremental Hedging Costs	38,985	(72,347)	80,832	37,832	25,080	64,444
	c	Nuclear Fuel Disposal Costs	2,045,325	1,810,224	1,585,058	1,830,109	1,438,413	1,705,778
	d	Coal Cars Depreciation & Return	280,827	279,094	277,362	275,629	273,896	272,164
	e	Gas Pipelines Depreciation & Return	179,661	178,205	169,743	168,535	170,561	169,139
	f	DOE D&D Fund Payment	0	0	0	0	0	0
2	a	Fuel Cost of Power Sold (Per A6)	(12,579,178)	(10,953,013)	(2,393,727)	(4,860,362)	(2,233,044)	(3,762,281)
	b	Revenues from Off-System Sales	(4,563,079)	(2,636,240)	(647,973)	(1,097,584)	(463,000)	(637,885)
3	a	Fuel Cost of Purchased Power (Per A7)	20,296,416	12,949,526	26,342,605	22,880,054	28,117,567	24,599,036
	b	Energy Payments to Qualifying Facilities (Per A8)	11,897,821	12,098,222	10,942,372	8,250,698	12,980,622	12,252,734
	c	Cypress Settlement Payment	0	0	0	0	255,797	0
	d	Okeelanta Settlement Amortization including interest	818,207	816,772	814,626	812,971	812,626	809,227
4		Energy Cost of Economy Purchases (Per A9)	2,690,456	5,403,637	9,253,845	6,437,812	7,503,345	9,642,332
5		Total Fuel Costs & Net Power Transactions	$ 223,187,714	$ 186,206,654	$ 384,777,599	$ 255,646,393	$ 339,462,234	$ 346,622,358
6		**Adjustments to Fuel Cost**						
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(2,649,558)	(2,656,228)	(2,619,112)	(4,890,322)	(3,333,364)	(3,919,200)
	b	Reactive and Voltage Control / Energy Imbalance Fuel Revenues	(109,305)	(104,038)	(106,100)	(64,303)	(73,782)	(1,513)
	c	Inventory Adjustments	(97,396)	(25,202)	(70,714)	(51,017)	67,936	(1,124,954)
	d	Non Recoverable Oil/Tank Bottoms	0	60,265	0	0	0	0
7		Adjusted Total Fuel Costs & Net Power Transactions	$ 220,331,455	$ 183,481,452	$ 381,981,674	$ 250,640,752	$ 336,123,023	$ 341,576,691
B		**kWh Sales**						
1		Jurisdictional kWh Sales (RTP @ CBL) (a)	7,569,038,419	7,463,818,224	7,510,229,964	7,396,486,620	7,999,797,862	9,047,332,704
2		Sale for Resale (excluding FKEC & CKW)	35,312,711	39,847,223	39,632,175	45,981,820	46,122,096	42,551,013
3		Sub-Total Sales (excluding FKEC & CKW)	7,604,351,130	7,503,665,447	7,549,862,139	7,442,468,440	8,045,919,958	9,089,883,717
6		**Jurisdictional % of Total Sales (B1/B3)**	99.53562%	99.46896%	99.47506%	99.38217%	99.42676%	99.53189%
C		**True-up Calculation**						
1		Juris Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 202,273,176	$ 200,127,330	$ 201,471,500	$ 228,902,315	$ 251,666,698	$ 284,778,187
2		**Fuel Adjustment Revenues Not Applicable to Period**						
	a 1	Blank Line						
	a 2	Prior Period True-up (Collected)/Refunded This Period	(587,316)	(587,316)	(587,316)	(587,316)	(587,316)	(587,316)
	a 3	2002 Final True-up Refunded per Order PSC-03-0000-AS-EI	0	0	0	(8,051,908)	(8,051,908)	(8,051,908)
	b	GPIF, Net of Revenue Taxes (b)	(578,218)	(578,218)	(578,218)	(578,218)	(578,218)	(578,218)
	c	Oil Backout Revenues, Net of revenue taxes	(2)	(2)	(25)	(0)	(0)	(2)
3		Jurisdictional Fuel Revenues Applicable to Period	$ 201,107,640	$ 198,961,795	$ 200,305,941	$ 219,684,873	$ 242,449,256	$ 275,560,743
4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 220,331,455	$ 183,481,452	$ 381,981,674	$ 250,640,752	$ 336,123,023	$ 341,576,691
	b	Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0	0	0	0	0	0
	c	RTP Incremental Fuel -100% Retail	(43,241)	(46,853)	33,420	95,378	(28,433)	4,846
	d	D&D Fund Payments -100% Retail	0	0	0	0	0	0
	e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	220,374,695	183,528,305	381,948,254	250,545,373	336,151,456	341,571,845
5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.53562 %	99.46896 %	99.47506 %	99.38217 %	99.42676 %	99.53189 %
6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00049(c)) +(Lines C4b,c,d)	$ 219,415,561	$ 182,596,295	$ 380,162,847	$ 249,214,815	$ 334,359,838	$ 340,144,346
7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (18,307,921)	$ 16,365,500	$ (179,856,906)	$ (29,529,943)	$ (91,910,582)	$ (64,583,603)
8		Interest Provision for the Month (Line D10)	(94,270)	(93,296)	(172,231)	(266,978)	(322,706)	(361,539)
9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(7,047,788)	(24,862,663)	(8,003,144)	(187,444,965)	(208,602,661)	(292,196,725)
	b	Deferred True-up Beginning of Period - Over/(Under) Recovery	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)
10	a	Prior Period True-up Collected/(Refunded) This Period	587,316	587,316	587,316	587,316	587,316	587,316
	b	2002 Final True-up Collected/(Refunded) This Period	0	0	0	8,051,908	8,051,908	8,051,908
11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (97,329,839)	$ (80,470,320)	$ (259,912,141)	$ (281,069,837)	$ (364,663,901)	$ (420,969,820)

NOTES

(a) Real Time Pricing (RTP) sales are shown at the Customer Base Load (CBL) KWH. The incremental/decremental kwh sales are excluded. The incremental/decremental RTP fuel revenues (net of revenue taxes) are included in jurisdictional fuel revenues.

(b) Generation Performance Incentive Factor is ((87,049,431) x 98.4280%) - See Order No. PSC-01-1761-FOF-EI.

(c) Per Estimated Schedule E-2, filed November 4, 2002.

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

LINE NO.			(7) JUL	(8) AUG	(9) SEP	(10) OCT	(11) NOV	(12) DEC	(13) TOTAL PERIOD
A		**Fuel Costs & Net Power Transactions**							
1	a	Fuel Cost of System Net Generation	$ 305,103,626	$ 270,721,136	$ 274,410,601	$ 266,663,492	$ 205,477,717	$ 184,750,020	$ 3,026,893,034
	b	Incremental Hedging Costs	23,168	57,164	30,721	22,522	32,540	26,134	367,076
	c	Nuclear Fuel Disposal Costs	1,990,036	2,048,395	2,044,636	1,592,645	1,946,203	1,830,992	21,867,814
	d	Coal Cars Depreciation & Return	270,431	268,699	266,966	265,233	263,501	261,768	3,255,570
	e	Gas Pipelines Depreciation & Return	167,718	166,296	164,874	163,452	162,031	160,609	2,020,823
	f	DOE D&D Fund Payment	0	0	0	0	6,077,275	0	6,077,275
2	a	Fuel Cost of Power Sold (Per A6)	(2,894,541)	(3,528,375)	(3,455,577)	(1,963,701)	(6,052,220)	(17,155,546)	(71,831,565)
	b	Revenues from Off-System Sales	(341,263)	(528,348)	(543,259)	(339,373)	(1,609,471)	(4,420,173)	(17,827,648)
3	a	Fuel Cost of Purchased Power (Per A7)	28,333,960	25,850,471	26,386,610	23,797,923	18,969,882	13,713,574	272,237,624
	b	Energy Payments to Qualifying Facilities (Per A8)	13,492,687	13,448,483	13,179,596	9,259,954	10,341,868	12,627,352	140,772,409
	c	Cypress Settlement Payment	0	0	0	0	0	0	255,797
	d	Okeelanta Settlement Amortization including interest	806,355	806,478	805,922	805,109	803,694	803,148	9,715,135
4		Energy Cost of Economy Purchases (Per A9)	12,520,952	11,098,073	14,380,869	12,759,606	11,765,946	5,752,084	109,208,957
5		Total Fuel Costs & Net Power Transactions	$ 359,473,130	$ 320,408,472	$ 327,671,959	$ 313,026,862	$ 248,178,965	$ 198,349,961	$ 3,503,012,301
6		**Adjustments to Fuel Cost**							
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(3,934,201)	(4,155,922)	(3,808,697)	(3,644,128)	(3,604,089)	(2,771,474)	(41,986,294)
	b	Reactive and Voltage Control / Energy Imbalance Fuel Revenues	5,786	8,575	10,393	(4,138)	(4,027)	(13,006)	(455,459)
	c	Inventory Adjustments	77,271	259,042	45,730	(50,755)	(57,964)	(43,201)	(1,071,224)
	d	Non Recoverable Oil/Tank Bottoms	0	0	0	0	0	0	60,265
7		Adjusted Total Fuel Costs & Net Power Transactions	$ 355,621,985	$ 316,520,167	$ 323,919,384	$ 309,327,842	$ 244,512,884	$ 195,522,280	$ 3,459,559,589
B		**kWh Sales**							
1		Jurisdictional kWh Sales (RTP @ CBL) (a)	9,332,603,999	9,223,379,666	9,347,439,851	8,815,192,252	8,092,460,610	7,703,539,787	99,501,319,958
2		Sale for Resale (excluding FKEC & CKW)	39,109,282	42,889,072	40,994,892	43,068,044	37,996,734	39,111,657	492,616,719
3		Sub-Total Sales (excluding FKEC & CKW)	9,371,713,281	9,266,268,738	9,388,434,743	8,858,260,296	8,130,457,344	7,742,651,444	99,993,936,677
6		**Jurisdictional % of Total Sales (B1/B3)**	99.58269%	99.53715%	99.56335%	99.51381%	99.53266%	99.49485%	99.50735%
C		**True-up Calculation**							
1		Juris Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 293,881,101	$ 330,616,662	$ 340,593,218	$ 321,452,663	$ 294,979,143	$ 280,548,357	$ 3,231,290,350
2		**Fuel Adjustment Revenues Not Applicable to Period**							
	a 1	Blank Line							0.00
	a 2	Prior Period True-up (Collected)/Refunded This Period	(587,316)	(587,316)	(587,316)	(587,316)	(587,316)	(587,316)	(7,047,788)
	a 3	2002 Final True-up Refunded per Order PSC-03-0000-AS-EI	(8,051,908)	(8,051,908)	(8,051,908)	(8,051,908)	(8,051,908)	(8,051,908)	(72,467,176)
	b	GPIF, Net of Revenue Taxes (b)	(578,218)	(578,218)	(578,218)	(578,218)	(578,218)	(578,218)	(6,938,614)
	c	Oil Backout Revenues, Net of revenue taxes	2	(1)	4	0	(2)	0	(28)
3		Jurisdictional Fuel Revenues Applicable to Period	$ 284,663,661	$ 321,399,219	$ 331,375,780	$ 312,235,221	$ 285,761,700	$ 271,330,915	$ 3,144,836,744
4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 355,621,985	$ 316,520,167	$ 323,919,384	$ 309,327,842	$ 244,512,884	$ 195,522,280	$ 3,459,559,589
	b	Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0	0	0	0	0	0	0
	c	RTP Incremental Fuel -100% Retail	37,384	(9,429)	29,218	90,664	(3,444)	20,537	180,048
	d	D&D Fund Payments -100% Retail	0	0	0	0	6,077,275	0	6,077,275
	e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	355,584,601	316,529,596	323,890,166	309,237,178	238,439,054	195,501,743	3,453,302,266
5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.58269 %	99.53715 %	99.56335 %	99.51381 %	99.53266 %	99.49485 %	99.50735 %
6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00049(c)) +(Lines C4b,c,d)	$ 354,311,605	$ 315,209,491	$ 322,663,131	$ 307,975,151	$ 243,514,853	$ 194,630,015	$ 3,444,197,949
7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (69,647,944)	$ 6,189,728	$ 8,712,649	$ 4,260,070	$ 42,246,847	$ 76,700,900	$ (299,361,205)
8		Interest Provision for the Month (Line D10)	(385,649)	(417,576)	(405,679)	(390,854)	(352,832)	(296,367)	(3,559,977)
9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(348,502,644)	(409,897,012)	(395,485,636)	(378,539,442)	(366,031,003)	(315,497,764)	(7,047,788)
	b	Deferred True-up Beginning of Period - Over/(Under) Recovery	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)
10	a	Prior Period True-up Collected/(Refunded) This Period	587,316	587,316	587,316	587,316	587,316	587,316	7,047,788
	b	2002 Final True-up Collected/(Refunded) This Period	8,051,908	8,051,908	8,051,908	8,051,908	8,051,908	8,051,908	72,467,176
11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (482,364,188)	$ (467,952,812)	$ (451,006,618)	$ (438,498,179)	$ (387,964,940)	$ (302,921,183)	$ (302,921,183)

NOTES
(a) Real Time Pricing (RTP) sales are shown at the Customer Base Load (CBL) KWH. The incremental/decremental kwh sales are excluded.
The incremental/decremental RTP fuel revenues (net of revenue taxes) are included in jurisdictional fuel revenues.
(b) Generation Performance Incentive Factor is ((57,849,431) x 90.4280%) - See Order No. PSC-02-1761-POF-EI.
(c) Per Estimated Schedule E-2, filed November 4, 2002.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ACTUAL vs ESTIMATED/ACTUAL
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

LINE NO.			(1) ACTUAL	(2) ESTIMATED / ACTUAL (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
A		**Fuel Costs & Net Power Transactions**				
	1	a Fuel Cost of System Net Generation	$ 3,026,893,034	$ 3,098,365,746	$ (71,472,712)	(2.3) %
		b Incremental Hedging Implementation Costs	367,076	385,994	(18,918)	(4.9) %
		c Nuclear Fuel Disposal Costs	21,867,814	21,908,055	(40,241)	(0.2) %
		d Coal Cars Depreciation & Return	3,255,570	3,255,570	0	0.0 %
		e Gas Pipelines Depreciation & Return	2,020,823	2,020,823	0	0.0 %
		f DOE D&D Fund Payment	6,077,275	6,475,000	(397,725)	(6.1) %
	2	a Fuel Cost of Power Sold (Per A6)	(71,831,565)	(78,009,460)	6,177,895	(7.9) %
		b Revenues from Off-System Sales	(17,827,648)	(13,091,111)	(4,736,537)	36.2 %
	3	a Fuel Cost of Purchased Power (Per A7)	272,237,624	253,413,971	18,823,653	7.4 %
		b Energy Payments to Qualifying Facilities (Per A8)	140,772,409	143,691,143	(2,918,734)	(2.0) %
		c Cypress Settlement Payment	255,797	255,797	0	0.0 %
		d Okeelanta Settlement Amortization including interest	9,715,135	9,708,785	6,350	0.1 %
	4	Energy Cost of Economy Purchases (Per A9)	109,208,957	74,936,176	34,272,781	45.7 %
	5	Total Fuel Costs & Net Power Transactions	$ 3,503,012,301	$ 3,523,316,489	$ (20,304,188)	(0.6) %
	6	**Adjustments to Fuel Cost**				
		a Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (41,986,294)	$ (37,389,545)	$ (4,596,749)	12.3 %
		b Reactive and Voltage Control Fuel Revenue	(455,459)	(459,042)	3,583	(0.8) %
		c Inventory Adjustments	(1,071,224)	(1,301,346)	230,122	(17.7) %
		d Non Recoverable Oil/Tank Bottoms	60,265	60,265	0	0.0 %
	7	Adjusted Total Fuel Costs & Net Power Transactions	$ 3,459,559,589	$ 3,484,226,823	$ (24,667,232)	(0.7) %
B	1	Jurisdictional kWh Sales	99,501,319,958	98,853,280,793	648,039,165	0.7 %
	2	Sale for Resale	492,616,719	454,992,038	37,624,681	8.3 %
	3	Total Sales (Excluding RTP Incremental)	99,993,936,677	99,308,272,831	685,663,846	0.7 %
	4	Jurisdictional Sales % of Total kWh Sales (Line B-6)	N/A	N/A	N/A	N/A
C		**True-up Calculation**				
	1	Juris Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 3,231,290,350	3,215,151,449	$ 16,138,901	0.5 %
	2	**Fuel Adjustment Revenues Not Applicable to Period**				
		a 1 Prior Period True-up (Collected)/Refunded This Period	(7,047,788)	(7,047,788)	0	0.0 %
		a 2 2002 Final True-up Refunded per Order PSC-03-0381-PCO-EI	(72,467,176)	(72,467,176)	0	0.0 %
		b GPIF, Net of Revenue Taxes (b)	(6,938,614)	(6,938,614)	0	0.0 %
		c Oil Backout Revenues, Net of revenue taxes	(28)	(31)	3	(10.7) %
	3	Jurisdictional Fuel Revenues Applicable to Period	$ 3,144,836,744	$ 3,128,697,839	$ 16,138,905	0.5 %
	4	a Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 3,459,559,589	$ 3,484,226,823	(24,667,234)	(0.7) %
		b Nuclear Fuel Expense - 100% Retail	-	-	0	N/A
		c RTP Incremental Fuel -100% Retail	180,048	15,118	164,930	1090.9 %
		d D&D Fund Payments -100% Retail (Line A 1 e)	6,077,275	6,475,000	(397,725)	(6.1) %
		e Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	3,453,302,266	3,477,736,705	(24,434,439)	(0.7) %
	5	Jurisdictional Sales % of Total kWh Sales	N/A	N/A	N/A	N/A
	6	Jurisdictional Total Fuel Costs & Net Power Transactions	$ 3,444,197,949	$ 3,469,917,608	$ (25,719,659)	(0.7) %
	7	True-up Provision for the Period- Over/(Under) Recovery (Line C3 - Line C6)	$ (299,361,205)	$ (341,219,769)	41,858,564	(12.3) %
	8	Interest Provision for the Period	(3,559,977)	(3,510,090)	(49,888)	1.4 %
	9	a True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(7,047,788)	(7,047,788)	0	0.0 %
		b Deferred True-up Beginning of Period - Over/(Under) Recovery	(72,467,176)	(72,467,176)	0	0.0 %
	10	a Prior Period True-up Collected/(Refunded) This Period	7,047,788	7,047,788	0	0.0 %
		b 2002 Final True-up Collected/(Refunded) This Period	72,467,176	72,467,176	(0)	0.0 %
	11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (302,921,183)	$ (344,729,859)	$ 41,808,676	(12.1) %

NOTES **(a) Per Estimated/Actual, Schedule E1b, filed August 12, 2003.**

(b) Generation Performance Incentive Factor is (($7,049,431) x 98.4280%) - See Order No. PSC-02-1761-FOF-EI.

APPENDIX II

CAPACITY COST RECOVERY

TRUE UP CALCULATION

KMD-2
DOCKET NO. 040001-EI
FPL WITNESS: K.M. DUBIN
February 23, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 6
COMPANY/ FP+L
WITNESS. K. M. Dubin (KMD-2)
DATE: 11-08-04

APPENDIX II

CAPACITY COST RECOVERY

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6	CALCULATION OF FINAL TRUE UP VARIANCES

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP FOR THE
PERIOD JANUARY THROUGH DECEMBER 2003

1.	End of Period True-up for the period January through December 2003 (from page 5, lines 17 & 18)	$ 8,998,342
2.	Less - Estimated/Actual True-up for the same period *	16,048,425
3.	Net True-up for the period January through December 2003	$ (7,050,083)

( ) Reflects Underrecovery

* Approved in FPSC Order No. PSC-03-1461-FOF-EI dated December 22, 2003

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

LINE NO.		(1) JAN 2003	(2) FEB 2003	(3) MAR 2003	(4) APR 2003	(5) MAY 2003	(6) JUN 2003
1.	Payments to Non-cogenerators (UPS & SJRPP)	$15,596,426	$15,990,408	$14,684,403	$15,153,064	$14,649,614	$15,005,398
2.	Short Term Capacity Payments	6,245,451	6,245,451	4,361,584	4,490,250	6,995,796	15,128,009
3.	Payments to Cogenerators (QF's)	27,481,162	28,207,963	28,961,670	29,873,286	34,695,552	28,990,956
4a.	SJRPP Suspension Accrual	586,656	586,656	586,656	586,656	586,656	586,656
4b.	Return on SJRPP Suspension Liability	(229,653)	(235,428)	(241,204)	(246,979)	(252,755)	(258,531)
5a.	Cypress Settlement (Capacity)	0	0	0	0	353,244	0
5b.	Okeelanta Settlement (Capacity)	3,078,016	3,072,620	3,064,546	3,058,320	3,057,020	3,044,234
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	113,771	832,709	1,151,391	787,976	769,376	709,694
7.	Tranmission of Electricity by Others	708,540	726,582	967,321	1,113,810	744,916	497,782
8.	Transmission Revenues from Capacity Sales	(853,648)	(676,765)	(153,736)	(226,606)	(243,744)	(329,412)
9.	Total (Lines 1 through 8)	$ 52,726,720	$ 54,750,196	$ 53,382,631	$ 54,589,777	$ 61,355,676	$ 63,374,786
10.	Jurisdictional Separation Factor (a)	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%
11.	Jurisdictional Capacity Charges	52,208,638	54,212,232	52,858,104	54,053,389	60,752,807	62,752,078
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)
13.	Jurisdictional Capacity Charges Authorized	$ 47,463,172	$ 49,466,766	$ 48,112,638	$ 49,307,923	$ 56,007,341	$ 58,006,612
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 45,289,301	$ 44,889,661	$ 44,494,357	$ 44,357,710	$ 47,550,317	$ 52,878,607
15.	Prior Period True-up Provision	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 48,723,919	$ 48,324,279	$ 47,928,975	$ 47,792,328	$ 50,984,935	$ 56,313,225
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	1,260,747	(1,142,487)	(183,663)	(1,515,596)	(5,022,407)	(1,693,387)
18.	Interest Provision for Month	56,326	51,960	46,008	40,687	34,539	25,582
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	41,215,416	39,097,870	34,572,726	31,000,453	26,090,927	17,668,441
20.	Deferred True-up - Over/(Under) Recovery	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 51,774,593	$ 47,249,449	$ 43,677,176	$ 38,767,650	$ 30,345,164	$ 25,242,741

Notes:
(a) Per K. M. Dubin's Testimony Appendix III Page 5, filed November 4, 2002.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffmann's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

LINE NO.		(7) JUL 2003	(8) AUG 2003	(9) SEP 2003	(10) OCT 2003	(11) NOV 2003	(12) DEC 2003	(13) TOTAL
1.	Payments to Non-cogenerators (UPS & SJRPP)	$16,208,389	$14,803,677	$14,029,336	$16,232,538	$15,455,862	$14,017,230	$181,826,345
2.	Short Term Capacity Payments	15,063,510	14,822,310	8,447,380	3,758,876	3,873,799	6,156,400	95,588,816
3.	Payments to Cogenerators (QF's)	28,863,092	28,838,119	28,826,788	28,844,161	29,156,890	29,110,184	351,849,823
4a.	SJRPP Suspension Accrual	586,656	586,656	586,656	586,656	586,656	586,656	7,039,872
4b.	Return on SJRPP Suspension Liability	(264,306)	(270,082)	(275,857)	(281,633)	(287,409)	(293,184)	(3,137,021)
5a.	Cypress Settlement (Capacity)	0	0	0	0	0	0	353,244
5b.	Okeelanta Settlement (Capacity)	3,033,431	3,033,895	3,031,801	3,028,744	3,023,422	3,021,365	36,547,413
6.	Incremental Plant Security Costs-Order No. PSC-02-1761	868,722	1,285,560	1,227,623	738.069	222,684	605,027	9,312,602
7.	Tranmission of Electricity by Others	476,575	512,334	454,678	531,831	489,636	606,800	7,830,805
8.	Transmission Revenues from Capacity Sales	(269,550)	(289,278)	(394,001)	(98,474)	(413,838)	(978,149)	(4,927,201)
9.	Total (Lines 1 through 8)	$64,566,518	$63,323,191	$55,934,404	$53,340,768	$52,107,702	$52,832,329	$ 682,284,698
10.	Jurisdictional Separation Factor (a)	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%	N/A
11.	Jurisdictional Capacity Charges	63,932,101	62,700,990	55,384,803	52,816,652	51,595,702	52,313,209	675,580,705
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(56,945,592)
13.	Jurisdictional Capacity Charges Authorized	$59,186,635	$57,955,524	$50,639,337	$48,071,186	$46,850,236	$47,567,743	$ 618,635,113
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$54,379,742	$53,846,880	$54,260,963	$51,682,946	$47,641,729	$44,779,506	$ 586,051,718
15.	Prior Period True-up Provision	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618	41,215,416
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$57,814,360	$57,281,498	$57,695,581	$55,117,564	$51,076,347	$48,214,124	$ 627,267,134
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(1,372,275)	(674,026)	7,056,243	7,046,378	4,226,111	646,382	8,632,021
18.	Interest Provision for Month	19,509	16,178	16,053	19,172	20,523	19,784	366,321
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	12,566,018	7,778,634	3,686,168	7,323,847	10,954,778	11,766,794	41,215,416
20.	Deferred True-up - Over/(Under) Recovery	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(41,215,416)
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$20,455,357	$16,362,891	$20,000,570	$23,631,501	$24,443,517	$21,675,065	$ 21,675,065

Notes:
(a) Per K. M. Dubin's Testimony Appendix III Page 5, filed November 4, 2002.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per R.L. Hoffman's Testimo
Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

Line No.		(1) ACTUAL	(2) ESTIMATED / ACTUAL (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
1	Payments to Non-cogenerators (UPS & SJRPP)	$ 181,826,345	$ 174,307,675	$ 7,518,670	4.3 %
2	Short Term Capacity Payments	$ 95,588,816	94,397,361	1,191,455	1.3 %
3	Payments to Cogenerators (QF's)	351,849,823	350,923,536	926,287	0.3 %
4a	SJRPP Suspension Accrual	7,039,872	7,039,872	0	0.0 %
4b	Return Requirements on SJRPP Suspension Liability	(3,137,021)	(3,137,021)	0	(0.0) %
5a	Cypress Settlement (Capacity)	353,244	353,244	0	0.0 %
5b	Okeelanta Settlement (Capacity)	36,547,413	36,523,524	23,889	0.1 %
6	Incremental Plant Security Costs-Order No. PSC-02-1761	9,312,602	10,258,750	(946,148)	(9.2) %
7	Transmission of Electricity by Others	7,830,805	8,382,284	(551,479)	(6.6) %
8	Transmission Revenues from Capacity Sales	(4,927,201)	(5,179,411)	252,210	(4.9) %
9	Total (Lines 1 through 8)	$ 682,284,698	$ 673,869,814	$ 8,414,884	1.2 %
10	Jurisdictional Separation Factor	N/A	N/A	N/A	N/A
11	Jurisdictional Capacity Charges	$ 675,580,705	$ 667,248,505	$ 8,332,200	1.2 %
12	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	$ (56,945,592)	(56,945,592)	0	N/A
13	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 618,635,113	$ 610,302,913	$ 8,332,200	1.4 %
14	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 586,051,718	$ 584,746,334	$ 1,305,384	0.2 %
15	Prior Period True-up Provision	41,215,416	41,215,416	0	N/A
16	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 627,267,134	$ 625,961,750	$ 1,305,384	0.2 %
17	True-up Provision for Period - Over/(Under) Recovery (Line 16 - Line 13)	$ 8,632,021	$ 15,658,837	$ (7,026,816)	N/A
18	Interest Provision for Period	366,321	389,587	(23,266)	N/A
19	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	41,215,416	41,215,416	(0)	N/A
20	Deferred True-up - Over/(Under) Recovery	12,676,723	12,676,723	0	N/A
21	Prior Period True-up Provision - Collected/(Refunded) this Period	(41,215,416)	(41,215,416)	0	N/A
22	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 21,675,065	$ 28,725,147	$ (7,050,083)	(24.5) %

Notes:

(a) Per K. M. Dubin's Testimony Appendix II, Page 4, Docket No. 030001-EI, filed August 12, 2003.

(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

APPENDIX I

FUEL COST RECOVERY

ESTIMATED/ACTUAL TRUE UP CALCULATION

KMD-3
DOCKET NO. 040001-EI
FPL WITNESS: K.M. DUBIN
August 10, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 7
COMPANY/ FP+L
WITNESS. K. M. Dubin (KMD-3)
DATE: 11-08-04

CALCULATION OF THE ESTIMATED/ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2004
SIX MONTHS ACTUAL SIX MONTHS REVISED ESTIMATES

LINE NO.			(1) ACTUAL JAN	(2) ACTUAL FEB	(3) ACTUAL MAR	(4) ACTUAL APR	(5) ACTUAL MAY	(6) ACTUAL JUN
A		**Fuel Costs & Net Power Transactions**						
	1 a	Fuel Cost of System Net Generation	$ 184,452,314	$ 175,787,137	$ 214,008,305	$ 225,837,849	$ 273,633,221	$ 329,439,294
	b	Incremental Hedging Costs	39,539	43,636	95,460	33,158	53,388	50,597
	c	Nuclear Fuel Disposal Costs	2,101,960	1,950,911	1,944,426	1,523,704	1,860,877	1,983,248
	d	Coal Cars Depreciation & Return	260,036	270,239	330,547	378,675	376,456	374,237
	e	Gas Pipelines Depreciation & Return	159,187	157,765	156,343	154,922	153,500	152,078
	f	DOE D&D Fund Payment	-	-	-	-	-	-
	2 a	Fuel Cost of Power Sold (Per A6)	(11,421,993)	(11,341,688)	(11,522,125)	(11,512,453)	(9,166,845)	(7,610,577)
	b	Gains from Off-System Sales	(3,487,436)	(2,828,818)	(2,150,944)	(2,193,430)	(1,561,821)	(784,437)
	3 a	Fuel Cost of Purchased Power (Per A7)	15,140,887	14,698,590	14,110,542	17,432,844	17,161,636	33,206,788
	b	Energy Payments to Qualifying Facilities (Per A8)	12,108,633	11,650,079	10,503,252	12,428,163	10,672,709	12,559,402
	c	Okeelanta Settlement Amortization including interest	802,825	801,251	800,055	799,947	799,908	802,205
	4	Energy Cost of Economy Purchases (Per A9)	4,259,680	3,504,914	3,433,118	6,272,765	7,027,964	3,273,294
	5	Total Fuel Costs & Net Power Transactions	204,415,631	194,694,018	231,708,980	251,156,144	301,010,992	373,446,129
	6	**Adjustments to Fuel Cost**						
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(2,667,940)	(2,628,591)	(2,507,271)	(3,056,227)	(3,064,860)	(3,715,083)
	b	Reactive and Voltage Control / Energy Imbalance Fuel Revenues	(79,263)	(106,143)	(147,636)	4,907	33,674	(40,655)
	c	Inventory Adjustments	(126,576)	(12,827)	(73,126)	34,959	(36,019)	223,329
	d	Non Recoverable Oil/Tank Bottoms	-	-	-	(45,837)	-	-
	7	Adjusted Total Fuel Costs & Net Power Transactions	$ 201,541,853	$ 191,946,456	$ 228,980,948	$ 248,093,946	$ 297,943,787	$ 369,913,720
B		**kWh Sales**						
	1	Jurisdictional kWh Sales	7,668,715,414	7,175,175,525	7,034,440,332	6,799,137,180	7,644,908,043	9,270,486,870
	2	Sale for Resale (excluding FKEC & CKW)	48,691,074	45,861,710	39,221,146	43,391,707	42,455,919	38,691,036
	3	Sub-Total Sales (excluding FKEC & CKW)	7,717,406,488	7,221,037,235	7,073,661,478	6,842,528,887	7,687,363,962	9,309,177,906
	6	**Jurisdictional % of Total Sales (B1/B3)**	99.36907%	99.36489%	99.44553%	99.36585%	99.44772%	99.58438%
C		**True-up Calculation**						
	1	Juris Fuel Revenues (Net of Revenue Taxes)	$ 281,915,788	$ 264,071,397	$ 258,908,817	$ 250,291,507	$ 281,575,254	$ 342,544,711
	2	**Fuel Adjustment Revenues Not Applicable to Period**						
	a	Prior Period True-up (Collected)/Refunded This Period	(28,727,488)	(28,727,488)	(28,727,488)	(28,727,488)	(28,727,488)	(28,727,488)
	b	GPIF, Net of Revenue Taxes (a)	(611,027)	(611,027)	(611,027)	(611,027)	(611,027)	(611,027)
	c	Oil Backout Revenues, Net of revenue taxes	(0)	0	(9)	0	0	(1)
	3	Jurisdictional Fuel Revenues Applicable to Period	$ 252,577,273	$ 234,732,882	$ 229,570,293	$ 220,952,992	$ 252,236,738	$ 313,206,195
	4 a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 201,541,853	$ 191,946,456	$ 228,980,948	$ 248,093,946	$ 297,943,787	$ 369,913,720
	b	Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0	0	0	0	0	0
	c	RTP Incremental Fuel -100% Retail	0	0	0	0	0	0
	d	D&D Fund Payments -100% Retail	0	0	0	0	0	0
	e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	201,541,853	191,946,456	228,980,948	248,093,946	297,943,787	369,913,720
	5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.36907 %	99.36489 %	99.44553 %	99.36585 %	99.44772 %	99.58438 %
	6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00059(c)) +(Lines C4b,c,d)	$ 200,388,424	$ 190,839,915	$ 227,845,667	$ 246,666,105	$ 296,473,119	$ 368,593,627
	7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ 52,188,849	$ 43,892,967	$ 1,724,626	$ (25,713,113)	$ (44,236,381)	$ (55,387,432)
	8	Interest Provision for the Month (Line D10)	(228,553)	(155,711)	(109,881)	(98,757)	(107,179)	(143,639)
	9 a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(344,729,859)	(264,042,075)	(191,577,330)	(161,235,097)	(158,319,479)	(173,935,550)
	b	Deferred True-up Beginning of Period - Over/(Under) Recovery	41,808,676	41,808,676	41,808,676	41,808,676	41,808,676	41,808,676
	10	Prior Period True-up Collected/(Refunded) This Period	28,727,488	28,727,488	28,727,488	28,727,488	28,727,488	28,727,488
	11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (222,233,399)	$ (149,768,654)	$ (119,426,421)	$ (116,510,803)	$ (132,126,874)	$ (158,930,457)

CALCULATION OF THE ESTIMATED/ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2004
SIX MONTHS ACTUAL SIX MONTHS REVISED ESTIMATES

LINE NO.		(7) REVISED EST. JUL	(8) REVISED EST. AUG	(9) REVISED EST. SEP	(10) REVISED EST. OCT	(11) REVISED EST. NOV	(12) REVISED EST. DEC	(13) TOTAL PERIOD
A	**Fuel Costs & Net Power Transactions**							
1	a Fuel Cost of System Net Generation	$ 328,158,233	$ 331,417,022	$ 323,993,606	$ 305,098,671	$ 258,860,614	$ 239,867,115	$ 3,190,553,382
	b Incremental Hedging Costs	34,945	34,945	34,945	34,945	48,775	34,945	539,278
	c Nuclear Fuel Disposal Costs	1,983,357	1,983,357	1,828,859	1,515,688	1,483,193	1,606,560	21,766,140
	d Coal Cars Depreciation & Return	372,017	369,798	367,579	365,359	363,140	360,921	4,189,004
	e Gas Pipelines Depreciation & Return	150,656	75,003	49,341	48,901	48,461	48,021	1,354,179
	f DOE D&D Fund Payment	-	-	-	-	6,671,000	-	6,671,000
2	a Fuel Cost of Power Sold (Per A6)	(7,516,774)	(8,052,651)	(7,885,260)	(7,353,729)	(10,176,498)	(13,080,892)	(116,641,485)
	b Gains from Off-System Sales	(891,900)	(935,800)	(555,650)	(407,450)	(436,000)	(759,000)	(16,992,686)
3	a Fuel Cost of Purchased Power (Per A7)	34,719,157	34,069,259	33,152,675	20,325,358	17,691,216	24,026,493	275,735,445
	b Energy Payments to Qualifying Facilities (Per A8)	13,322,000	13,300,000	12,983,000	13,616,000	11,104,000	13,563,000	147,810,238
	c Okeelanta Settlement Amortization including interest	798,469	797,800	797,132	796,463	795,795	795,126	9,586,975
4	Energy Cost of Economy Purchases (Per A9)	2,719,847	2,929,499	2,907,577	6,336,972	5,771,883	5,977,227	54,414,740
5	Total Fuel Costs & Net Power Transactions	373,850,007	375,988,232	367,673,804	340,377,179	292,225,579	272,439,516	3,578,986,211
6	**Adjustments to Fuel Cost**							
	a Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(3,753,544)	(3,892,284)	(3,953,281)	(3,771,405)	(3,539,694)	(3,239,889)	(39,790,068)
	b Reactive and Voltage Control / Energy Imbalance Fuel Revenues							(335,114.86)
	c Inventory Adjustments							9,740.63
	d Non Recoverable Oil/Tank Bottoms							(45,837.17)
7	Adjusted Total Fuel Costs & Net Power Transactions	$ 370,096,463	$ 372,095,948	$ 363,720,523	$ 336,605,775	$ 288,685,885	$ 269,199,628	$ 3,538,824,932
B	**kWh Sales**							
1	Jurisdictional kWh Sales	9,766,926,607	9,956,053,270	9,877,393,892	9,083,786,926	8,072,305,230	7,940,128,805	100,289,458,094
2	Sale for Resale (excluding FKEC & CKW)	48,561,368	50,429,142	51,331,964	49,729,793	44,385,501	40,270,148	543,020,508
3	Sub-Total Sales (excluding FKEC & CKW)	9,815,487,975	10,006,482,412	9,928,725,855	9,133,516,720	8,116,690,731	7,980,398,953	100,832,478,602
6	**Jurisdictional % of Total Sales (B1/B3)**	99.50526%	99.49604%	99.48300%	99.45552%	99.45316%	99.49539%	N/A
C	**True-up Calculation**							
1	Juris Fuel Revenues (Net of Revenue Taxes)	$ 359,733,073	$ 366,698,941	$ 363,801,778	$ 334,571,838	$ 297,317,190	$ 292,448,899	$ 3,693,879,193
2	**Fuel Adjustment Revenues Not Applicable to Period**							
	a Prior Period True-up (Collected)/Refunded This Period	(28,727,488)	(28,727,488)	(28,727,488)	(28,727,488)	(28,727,488)	(28,727,488)	(344,729,859)
	b GPIF, Net of Revenue Taxes (a)	(611,027)	(611,027)	(611,027)	(611,027)	(611,027)	(611,027)	(7,332,324)
	c Oil Backout Revenues, Net of revenue taxes	0	0	0	0	0	0	(10)
3	Jurisdictional Fuel Revenues Applicable to Period	$ 330,394,558	$ 337,360,425	$ 334,463,262	$ 305,233,323	$ 267,978,674	$ 263,110,384	$ 3,341,817,000
4	a Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 370,096,463	$ 372,095,948	$ 363,720,523	$ 336,605,775	$ 288,685,885	$ 269,199,628	$ 3,538,824,932
	b Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0	0	0	0	0	0	0
	c RTP Incremental Fuel -100% Retail	0	0	0	0	0	0	0
	d D&D Fund Payments -100% Retail	0	0	0	0	6,671,000	0	6,671,000
	e Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	370,096,463	372,095,948	363,720,523	336,605,775	282,014,885	269,199,628	3,532,153,932
5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.50526 %	99.49604 %	99.48300 %	99.45552 %	99.45316 %	99.49539 %	N/A
6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00059(e)) +(Lines C4b,c,d)	$ 368,482,725	$ 370,439,164	$ 362,053,573	$ 334,970,540	$ 287,309,194	$ 267,999,246	$ 3,522,061,299
7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (38,088,167)	$ (33,078,739)	$ (27,590,311)	$ (29,737,217)	$ (19,330,520)	$ (4,888,862)	$ (180,244,299)
8	Interest Provision for the Month (Line D10)	(181,330)	(189,129)	(191,120)	(191,261)	(186,825)	(168,615)	(1,952,000)
9	a True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(200,739,133)	(210,281,141)	(214,821,521)	(213,875,464)	(215,076,454)	(205,866,310)	(344,729,859)
	b Deferred True-up Beginning of Period - Over/(Under) Recovery	41,808,676	41,808,676	41,808,676	41,808,676	41,808,676	41,808,676	41,808,676
10	Prior Period True-up Collected/(Refunded) This Period	28,727,488	28,727,488	28,727,488	28,727,488	28,727,488	28,727,488	344,729,859
11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (168,472,465)	$ (173,012,845)	$ (172,066,788)	$ (173,267,778)	$ (164,057,634)	$ (140,387,623)	$ (140,387,623)

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ESTIMATED/ACTUAL vs ORIGINAL PROJECTIONS
FOR THE PERIOD JANUARY THROUGH DECEMBER 2004

	LINE NO.			(1) ESTIMATED / ACTUAL	(2) ORIGINAL PROJECTIONS (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
A			**Fuel Costs & Net Power Transactions**				
	1	a	Fuel Cost of System Net Generation	$ 3,190,553,382	$ 2,948,212,042	$ 242,341,340	8.2 %
		b	Incremental Hedging Costs	539,278	427,857	111,421	26.0 %
		c	Nuclear Fuel Disposal Costs	21,766,140	21,731,958	34,182	0.2 %
		d	Coal Cars Depreciation & Return	4,189,004	4,413,013	(224,009)	(5.1) %
		e	Gas Pipelines Depreciation & Return	1,354,179	1,816,407	(462,228)	(25.4) %
		f	DOE D&D Fund Payment	6,671,000	6,670,000	1,000	0.0 %
	2	a	Fuel Cost of Power Sold (Per A6)	(116,641,485)	(53,937,966)	(62,703,519)	116.3 %
		b	Gains from Off-System Sales	(16,992,686)	(7,048,624)	(9,944,062)	141.1 %
	3	a	Fuel Cost of Purchased Power (Per A7)	275,735,445	288,786,758	(13,051,313)	(4.5) %
		b	Energy Payments to Qualifying Facilities (Per A8)	147,810,238	148,266,648	(456,410)	(0.3) %
		c	Okeelanta Settlement Amortization including interest	9,586,975	9,578,625	8,350	0.1 %
	4		Energy Cost of Economy Purchases (Per A9)	54,414,740	52,338,486	2,076,254	4.0 %
	5		Total Fuel Costs & Net Power Transactions	$ 3,578,986,211	$ 3,421,255,204	$ 157,731,007	4.6 %
	6		**Adjustments to Fuel Cost**				
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (39,790,068)	$ (41,152,955)	$ 1,362,887	(3.3) %
		b	Reactive and Voltage Control Fuel Revenue	(335,115)		(335,115)	N/A
		c	Inventory Adjustments	9,741		9,741	N/A
		d	Non Recoverable Oil/Tank Bottoms	(45,837)		(45,837)	N/A
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 3,538,824,932	$ 3,380,102,249	$ 158,722,683	4.7 %
B			**Jurisdictional kWh Sales**				
	1		Jurisdictional kWh Sales	100,289,458,094	100,913,606,000	(624,147,906)	(0.6) %
	2		Sale for Resale (excluding FKEC & CKW)	543,020,508	519,832,000	23,188,508	4.5 %
	3		Sub-Total Sales (excluding FKEC & CKW)	100,832,478,602	101,433,438,000	(600,959,398)	(0.6) %
	4		**Jurisdictional % of Total Sales (B1/B3)**	N/A	N/A	N/A	N/A
			True-up Calculation				
C	1		Juris Fuel Revenues (Net of Revenue Taxes)	$ 3,693,879,193	3,716,163,293	$ (22,284,101)	(0.6) %
	2		**Fuel Adjustment Revenues Not Applicable to Period**				
		a 1	Prior Period True-up (Collected)/Refunded This Period	(344,729,859)	(344,729,859)	0	0.0 %
		b	GPIF, Net of Revenue Taxes (b)	(7,332,324)	(7,332,324)	0	0.0 %
		c	Oil Backout Revenues, Net of revenue taxes	(10)	0	(10)	N/A
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 3,341,817,000	$ 3,364,101,110	$ (22,284,101)	(0.7) %
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 3,538,824,932	$ 3,380,102,249	$ 158,722,683	4.7 %
		b	Nuclear Fuel Expense - 100% Retail	0	0	0	N/A
		c	RTP Incremental Fuel -100% Retail	0	0	0	N/A
		d	D&D Fund Payments -100% Retail (Line A 1 f)	6,671,000	6,670,000	1,000	0.0 %
		e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	3,532,153,932	3,373,432,249	158,721,683	4.7 %
	5		Jurisdictional Sales % of Total kWh Sales	N/A	N/A	N/A	N/A
	6		Jurisdictional Total Fuel Costs & Net Power Transactions	$ 3,522,111,210	$ 3,364,101,110	$ 158,010,100	4.7 %
	7		True-up Provision for the Period Over/(Under) Recovery (Line C3 - Line C6)	$ (180,244,299)	$ 0	$ (180,244,299)	N/A
	8		Interest Provision for the Period	(1,952,000)	0	(1,952,000)	N/A
	9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(344,729,859)	(344,729,859)	0	0.0 %
		b	Deferred True-up Beginning of Period - Over/(Under) Recovery	41,808,676	0	41,808,676	N/A
	10		Prior Period True-up Collected/(Refunded) This Period	344,729,859	344,729,859	0	0.0 %
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through D10)	$ (140,387,623)	$ 0	$ (140,387,623)	N/A

NOTES

(a) **Per Original Projections approved by the Commission in Order No. PSC-1461-FOF-EI (December 22, 2003).**

(b) **Generation Performance Incentive Factor is (($7,449,429) x 98.4280%) - See Order No. PSC-03-1461-FOF-EI.**

APPENDIX II

CAPACITY COST RECOVERY

ESTIMATED/ACTUAL TRUE UP CALCULATION

KMD-4
DOCKET NO. 040001-EI
FPL WITNESS: K.M. DUBIN
August 10, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 8
COMPANY/ FP+L
WITNESS: K.M. Dubin (KMD-4)
DATE: 11-08-04

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2004

LINE NO.		(1) JAN 2004 ACTUAL	(2) FEB 2004 ACTUAL	(3) MAR 2004 ACTUAL	(4) APR 2004 ACTUAL	(5) MAY 2004 ACTUAL	(6) JUN 2004 ACTUAL
1.	Capacity Payments to Non-cogenerators (UPS & SJRPP)	$17,271,885	$16,715,070	$15,608,268	$15,512,596	$15,650,658	$16,010,555
2.	Short Term Capacity Payments	6,156,400	6,156,400	3,873,860	3,794,640	7,013,850	16,432,978
3.	Capacity Payments to Cogenerators (QFs)	29,618,332	29,384,726	29,454,264	30,078,378	30,398,617	30,479,099
4a.	SJRPP Suspension Accrual	422,797	422,797	422,797	422,797	422,797	422,797
4b.	Return Requirements on SJRPP Suspension Payments	(298,153)	(302,316)	(306,478)	(310,640)	(314,803)	(318,965)
5.	Okeelanta Settlement	3,020,150	3,014,230	3,009,732	3,009,323	3,009,176	3,017,819
6.	Incremental Plant Security Costs	562,344	654,189	1,001,012	865,299	1,269,330	2,948,484
7.	Transmission of Electricity by Others	817,671	808,943	807,484	649,195	611,848	798,578
8.	Transmission Revenues from Capacity Sales	(687,840)	(654,693)	(634,963)	(581,752)	(542,200)	(1,041,719)
9.	Total (Lines 1 through 8)	$ 56,883,586	$ 56,199,348	$ 53,235,976	$ 53,439,835	$ 57,519,274	$ 68,749,626
10.	Jurisdictional Separation Factor (a)	98.84301%	98.84301%	98.84301%	98.84301%	98.84301%	98.84301%
11.	Jurisdictional Capacity Charges	56,225,448	55,549,127	52,620,041	52,821,541	56,853,782	67,954,199
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)
13.	Jurisdictional Capacity Charges Authorized	$ 51,479,982	$ 50,803,661	$ 47,874,575	$ 48,076,075	$ 52,108,316	$ 63,208,733
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 43,705,699	$ 41,526,132	$ 40,883,478	$ 39,699,773	$ 44,106,141	$ 52,885,350
15.	Prior Period True-up Provision	2,393,762	2,393,762	2,393,762	2,393,762	2,393,762	2,393,762
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 46,099,461	$ 43,919,894	$ 43,277,240	$ 42,093,535	$ 46,499,903	$ 55,279,112
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(5,380,521)	(6,883,767)	(4,597,335)	(5,982,541)	(5,608,412)	(7,929,622)
18.	Interest Provision for Month	15,490	7,770	940	(5,470)	(12,702)	(23,603)
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	28,725,148	20,966,356	11,696,596	4,706,439	(3,675,334)	(11,690,209)
20.	Deferred True-up - Over/(Under) Recovery	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(2,393,762)	(2,393,762)	(2,393,762)	(2,393,762)	(2,393,762)	(2,393,762)
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 13,916,273	$ 4,646,513	$ (2,343,644)	$ (10,725,417)	$ (18,740,292)	$ (29,087,279)

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, filed September 12, 2003.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2004

LINE NO.		(7) JUL 2004 ESTIMATED	(8) AUG 2004 ESTIMATED	(9) SEP 2004 ESTIMATED	(10) OCT 2004 ESTIMATED	(11) NOV 2004 ESTIMATED	(12) DEC 2004 ESTIMATED	(13) TOTAL	LINE NO.
1.	Capacity Payments to Non-cogenerators (UPS & SJRPP)	$15,466,146	$15,466,146	$15,466,146	$15,466,146	$15,466,146	$15,466,146	$189,565,905	1.
2.	Short Term Capacity Payments	16,044,840	16,044,840	9,941,350	4,198,715	4,537,715	6,811,735	101,007,323	2.
3.	Capacity Payments to Cogenerators (QFs)	29,944,669	29,944,669	29,944,669	29,944,669	29,944,669	29,944,669	359,081,428	3.
4a.	SJRPP Suspension Accrual	422,797	422,797	422,797	422,797	422,797	422,797	5,073,564	4a.
4b.	Return Requirements on SJRPP Suspension Payments	(323,128)	(327,290)	(331,452)	(335,615)	(339,777)	(343,940)	(3,852,557)	4b.
5.	Okeelanta Settlement	3,025,369	3,022,122	3,018,875	3,015,628	3,012,381	3,009,134	36,183,937	6b.
6.	Incremental Plant Security Costs	7,435,438	7,568,849	7,563,849	7,563,849	7,563,849	7,477,516	52,474,009	6c.
7.	Transmission of Electricity by Others	596,818	603,794	596,096	686,645	748,280	693,848	8,419,200	7.
8.	Transmission Revenues from Capacity Sales	(504,100)	(504,100)	(486,800)	(425,850)	(527,000)	(704,000)	(7,295,017)	8.
9.	Total (Lines 1 through 8)	$ 72,108,848	$ 72,241,826	$ 66,135,528	$ 60,536,983	$ 60,829,059	$ 62,777,904	$ 740,657,792	9.
10.	Jurisdictional Separation Factor (a)	98.84301%	98.84301%	98.84301%	98.84301%	98.84301%	98.84301%	N/A	10.
11.	Jurisdictional Capacity Charges	71,274,556	71,405,995	65,370,347	59,836,576	60,125,272	62,051,570	732,088,455	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(56,945,592)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 66,529,090	$ 66,660,529	$ 60,624,881	$ 55,091,110	$ 55,379,806	$ 57,306,104	$ 675,142,863	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 55,373,132	$ 56,445,373	$ 55,999,419	$ 51,500,102	$ 45,765,552	$ 45,016,187	$ 572,906,337	14.
15.	Prior Period True-up Provision	2,393,762	2,393,762	2,393,763	2,393,763	2,393,763	2,393,763	28,725,148	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 57,766,894	$ 58,839,135	$ 58,393,182	$ 53,893,865	$ 48,159,315	$ 47,409,950	$ 601,631,485	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(8,762,196)	(7,821,394)	(2,231,699)	(1,197,245)	(7,220,491)	(9,896,155)	(73,511,378)	17.
18.	Interest Provision for Month	(38,421)	(50,306)	(58,586)	(63,205)	(70,593)	(82,809)	(381,495)	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(22,037,196)	(33,231,575)	(43,497,038)	(48,181,086)	(51,835,299)	(61,520,146)	28,725,148	19.
20.	Deferred True-up - Over/(Under) Recovery	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)	(7,050,083)	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(2,393,762)	(2,393,762)	(2,393,763)	(2,393,763)	(2,393,763)	(2,393,763)	(28,725,148)	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ (40,281,658)	$ (50,547,121)	$ (55,231,169)	$ (58,885,382)	$ (68,570,229)	$ (80,942,956)	$ (80,942,956)	22.

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, fi
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket N
Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATE/ACTUAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY THROUGH DECEMBER 2004

Line No.		(1) ESTIMATED / ACTUAL	(2) ORIGINAL PROJECTIONS (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
1.	Capacity Payments to Non-cogenerators (UPS & SJRPP)	$ 189,565,905	$ 177,228,528	$ 12,337,377	7.0 %
2.	Short Term Capacity Payments	101,007,323	84,454,210	16,553,113	19.6 %
3.	Capacity Payments to Cogenerators (QF's)	359,081,428	350,288,484	8,792,944	2.5 %
4a.	SJRPP Suspension Accrual	5,073,564	5,073,564	0	0.0 %
4b.	Return Requirements on SJRPP Suspension Payments	(3,852,557)	(3,852,557)	(0)	0.0 %
5.	Okeelanta Settlement	36,183,937	36,180,354	3,583	0.0 %
6.	Incremental Plant Security Costs	52,474,009	13,673,611	38,800,398	283.8 %
7.	Transmission of Electricity by Others	8,419,200	6,259,386	2,159,814	34.5 %
8.	Transmission Revenues from Capacity Sales	(7,295,017)	(4,235,810)	(3,059,207)	72.2 %
9.	Total (Lines 1 through 8)	$ 740,657,792	$ 665,069,770	$ 75,588,022	11.4 %
9.	Jurisdictional Separation Factor	98.84301%	98.84301%	0	0.0 %
10.	Jurisdictional Capacity Charges	$ 732,088,455	$ 657,374,979	$ 74,713,476	11.4 %
11.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(56,945,592)	(56,945,592)	0	N/A
12.	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 675,142,863	$ 600,429,387	$ 74,713,476	12.4 %
13.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 572,906,337	$ 571,704,239	$ 1,202,097	0.2 %
14.	Prior Period True-up Provision	28,725,148	28,725,148	0	N/A
15.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 601,631,485	$ 600,429,387	$ 1,202,097	0.2 %
16.	True-up Provision for Period - Over/(Under) Recovery (Line 15 - Line 12)	$ (73,511,378)	$0	$ (73,511,378)	N/A
17.	Interest Provision for Period	(381,495)	0	(381,495)	N/A
18.	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	28,725,148	28,725,148	0	N/A
19.	Deferred True-up - Over/(Under) Recovery	(7,050,083)	0	(7,050,083)	N/A
20.	Prior Period True-up Provision - Collected/(Refunded) this Period	(28,725,148)	(28,725,148)	0	N/A
21.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 16 through 20)	$ (80,942,956)	$0	$ (80,942,956)	N/A

Notes: (a) Per K. M. Dubin's Testimony Appendix III, Page 3, Docket No. 030001-EI, filed September 12, 2003.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI.

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES

KMD-5
DOCKET NO. 040001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT _____
PAGES 1-81
SEPTEMBER 9, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 9
COMPANY/ FP+L
WITNESS. K.M. Dubin (KMD-5
DATE: 11-08-04

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES
January 2005 – December 2005

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SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

		(a)		(b)	(c)
		DOLLARS		MWH	¢/KWH
1	Fuel Cost of System Net Generation (E3)	$3,616,133,562		94,398,459	3.8307
2	Nuclear Fuel Disposal Costs (E2)	21,509,414		23,120,944	0.0930
3	Fuel Related Transactions (E2)	11,344,023		0	0.0000
3b	Incremental Hedging Costs (E2)	553,145		0	
4	Fuel Cost of Sales to FKEC / CKW (E2)	(46,912,909)		(1,074,064)	4.3678
5	TOTAL COST OF GENERATED POWER	$3,602,627,235		93,324,395	3.8603
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	230,258,913		11,977,473	1.9224
7	Energy Cost of Sched C & X Econ Purch (Florida) (E9)	24,343,065		646,000	3.7683
8	Energy Cost of Other Econ Purch (Non-Florida) (E9)	26,842,775		573,396	4.6814
9		0		0	0.0000
10		0		0	0.0000
11	Okeelanta/Osceola Settlement (E2)	$9,531,433		0	0.0000
12	Payments to Qualifying Facilities (E8)	160,556,000		7,227,963	2.2213
13	TOTAL COST OF PURCHASED POWER	$451,532,186		20,424,832	2.2107
14	TOTAL AVAILABLE KWH (LINE 5 + LINE 13)			113,749,227	
15	Fuel Cost of Economy Sales (E6)	(115,254,050)		(2,460,000)	4.6851
16	Gain on Economy Sales (E6A)	0		0	0.0000
17	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(1,408,227)		(448,894)	0.3137
18	Fuel Cost of Other Power Sales (E6)	0		0	0.0000
18a	Revenues from Off-System Sales	(11,084,350)		(2,908,894)	0.3811
19	TOTAL FUEL COST AND GAINS OF POWER SALES	($127,746,627)		(2,908,894)	4.3916
19a	Net Inadvertent Interchange	0		0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 13 + 19 + 19a)	$3,926,412,793		110,840,333	3.5424
21	Net Unbilled Sales	(8,002,929)	**	(225,918)	(0.0077)
22	Company Use	11,779,238	**	332,521	0.0114
23	T & D Losses	255,216,832	**	7,204,622	0.2465
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$3,926,412,793		103,529,108	3.7926
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$19,687,819		519,114	3.7926
26	Jurisdictional MWH Sales	$3,906,724,974		103,009,994	3.7926
27	Jurisdictional Loss Multiplier	-		-	1.00065
28	Jurisdictional MWH Sales Adjusted for Line Losses	$3,909,264,345		103,009,994	3.7950
29	FINAL TRUE-UP JAN 03 - DEC 03 $41,808.676 (overrecovery) / EST/ACT TRUE-UP JAN 04 - DEC 04 $182,196,299 underrecovery	140,387,623		103,009,994	0.1363
30	TOTAL JURISDICTIONAL FUEL COST	$4,049,651,968		103,009,994	3.9313
31	Revenue Tax Factor				1.01597
32	Fuel Factor Adjusted for Taxes				3.9941
33	GPIF ***	$6,615,282		103,009,994	0.0064
34	Fuel Factor including GPIF (Line 32 + Line 33)				4.0005
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH				4.001

** For Informational Purposes Only
*** Calculation Based on Jurisdictional KWH Sales

SCHEDULE E - 1A

CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

1. Estimated/Actual over/(under) recovery (January 2004 - December 2004)	$ (182,196,299)
2.Final over/(under) recovery (January 2003 - December 2003)	$ 41,808,676
3.Total over/(under) recovery to be included in the January 2005 - December 2005 projected period (Schedule E1, Line 29)	$ (140,387,623)
4. TOTAL JURISDICTIONAL SALES (MWH) (Projected period)	103,009,994
5. True-Up Factor (Lines 3/4) c/kWh:	(0.1363)

SCHEDULE E - 1C

CALCULATION OF GENERATING PERFORMANCE
INCENTIVE FACTOR AND TRUE - UP FACTOR
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

1. TOTAL AMOUNT OF ADJUSTMENTS:	147,052,976
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$6,615,282
B. TRUE-UP (OVER)/UNDER RECOVERED	$ 140,437,694
2. TOTAL JURISDICTIONAL SALES (MWH)	103,009,994
3. ADJUSTMENT FACTORS c/kWh:	0.1428
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0064
B. TRUE-UP FACTOR	0.1363

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2005 - DECEMBER 2005

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	30.67	32.62
OFF PEAK	69.33	67.38
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$3,926,412,793	$1,280,795,853	$2,645,616,940
2	MWH SALES	103,529,108	31,752,377	71,776,731
3	COST PER KWH SOLD	3.7926	4.0337	3.6859
4	JURISDICTIONAL LOSS FACTOR	1.00065	1.00065	1.00065
5	JURISDICTIONAL FUEL FACTOR	3.7950	4.0363	3.6883
6	TRUE-UP	0.1363	0.1363	0.1363
7				
8	TOTAL	3.9313	4.1726	3.8246
9	REVENUE TAX FACTOR	1.01597	1.01597	1.01597
10	RECOVERY FACTOR	3.9941	4.2392	3.8857
11	GPIF	0.0064	0.0064	0.0064
12	RECOVERY FACTOR including GPIF	4.0005	4.2456	3.8921
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	4.001	4.246	3.892

HOURS:	ON-PEAK	24.62	%
	OFF-PEAK	75.38	%

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

JANUARY 2005 - DECEMBER 2005

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1, GS-1, SL-2		4.001	1.00201	4.009
A-1*	SL-1, OL-1, PL-1		3.949	1.00201	3.957
B	GSD-1		4.001	1.00194	4.008
C	GSLD-1 & CS-1		4.001	1.00097	4.004
D	GSLD-2, CS-2, OS-2 & MET		4.001	0.99390	3.976
E	GSLD-3 & CS-3		4.001	0.95678	3.828
A	RST-1, GST-1	ON-PEAK	4.246	1.00201	4.254
		OFF-PEAK	3.892	1.00201	3.900
B	GSDT-1	ON-PEAK	4.246	1.00194	4.254
	CILC-1(G)	OFF-PEAK	3.892	1.00194	3.900
C	GSLDT-1 &	ON-PEAK	4.246	1.00097	4.250
	CST-1	OFF-PEAK	3.892	1.00097	3.896
D	GSLDT-2 &	ON-PEAK	4.246	0.99513	4.225
	CST-2	OFF-PEAK	3.892	0.99513	3.873
E	GSLDT-3,CST-3,	ON-PEAK	4.246	0.95678	4.062
	CILC -1(T) & ISST-1(T)	OFF-PEAK	3.892	0.95678	3.724
F	CILC -1(D) &	ON-PEAK	4.246	0.99349	4.218
	ISST-1(D)	OFF-PEAK	3.892	0.99349	3.867

* WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

Florida Power & Light Company
2003 Actual Energy Losses by Rate Class

Line No	Rate Class	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	RS-1 Sec	53,362,062	1.07281827	57,247,795	0.932124	3,885,733	1.00201
2							
3	GS-1 Sec	5,858,928	1.07281827	6,285,565	0.932124	426,637	1.00201
4							
5	GSD-1 Pri	65,919	1.04657532	68,989	0.955497	3,070	
6	GSD-1 Sec	22,196,556	1.07281827	23,812,870	0.932124	1,616,315	
7	Subtotal GSD-1	22,262,475	1.07274057	23,881,860	0.932192	1,619,385	1.00194
8							
9	OS-2 Pri	20,360	1.04657532	21,309	0.955497	948	
10	OS-2 Sec	-	1.07281827	-	0.000000	-	
11	Subtotal OS-2	20,360	1.04657532	21,309	0.955497	948	0.97750
12							
13	GSLD-1 Pri	381,079	1.04657532	398,828	0.955497	17,749	
14	GSLD-1 Sec	9,629,926	1.07281827	10,331,161	0.932124	701,235	
15	Subtotal GSLD-1	10,011,005	1.07181931	10,729,989	0.932993	718,983	1.00108
16							
17	CS-1 Pri	55,410	1.04657532	57,990	0.955497	2,581	
18	CS-1 Sec	183,213	1.07281827	196,555	0.932124	13,341	
19	Subtotal CS-1	238,623	1.06672450	254,545	0.937449	15,922	0.99632
20							
21	Subtotal GSLD-1 / CS-1	10,249,628	1.07170069	10,984,534	0.933096	734,905	1.00097
22							
23	GSLD-2 Pri	395,254	1.04657532	413,663	0.955497	18,409	
24	GSLD-2 Sec	1,014,726	1.07281827	1,088,616	0.932124	73,891	
25	Subt GSLD-2	1,409,980	1.06546169	1,502,279	0.938560	92,300	0.99514
26							
27	CS-2 Pri	27,756	1.04657532	29,049	0.955497	1,293	
28	CS-2 Sec	68,799	1.07281827	73,809	0.932124	5,010	
29	Subtotal CS-2	96,556	1.06527437	102,858	0.938725	6,303	0.99497
30							
31	Subtotal GSLD-2 / CS-2	1,506,535	1.06544968	1,605,138	0.938571	98,602	0.99513
32							
33	GSLD-3 Trn	180,521	1.02438901	184,923	0.976192	4,403	0.95678
34							
35	CS-3 Trn	0	1.02438901	0	0.000000	0	0.00000
36							
37	Subtotal GSLD-3 / CS-3	180,521	1.02438901	184,923	0.976192	4,403	0.95678
38							
39	ISST-1 Sec	0	1.07281827	0	0.000000	0	0.00000
40							
41	SST-1 Pri	4,494	1.04657532	4,704	0.955497	209	
42	SST-1 Sec	18,259	1.07281827	19,589	0.932124	1,330	
43	Subtotal SST-1 (D)	22,754	1.06763473	24,293	0.936650	1,539	0.99717
44							
45	SST-1 Trn	144,682	1.02438901	148,211	0.976192	3,529	0.95678
46							
47	CILC-1D Pri	1,082,146	1.04657532	1,132,548	0.955497	50,401	
48	CILC-1D Sec	2,028,149	1.07281827	2,175,835	0.932124	147,686	
49	Subtotal CILC-1D	3,110,295	1.06368772	3,308,383	0.940126	198,088	0.99349
50							
51	CILC-1G Pri	700	1.04657532	733	0.955497	33	
52	CILC-1G Sec	235,235	1.07281827	252,365	0.932124	17,129	
53	Subtotal CILC-1G	235,936	1.07274038	253,098	0.932192	17,162	1.00194
54							
55	Subtotal CILC-1D / CILC-1G	3,346,231	1.06432600	3,561,481	0.939562	215,250	0.99408
56							
57	Subtotal GSD-1 & CILC-1G	22,498,411	1.07274056	24,134,958	0.932192	1,636,547	1.00194
58							
59	CILC-1T Trn	1,468,366	1.02438901	1,504,178	0.976192	35,812	0.95678
60							

Florida Power & Light Company
2003 Actual Energy Losses by Rate Class

Line No	Rate Class	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
61	Subtotal ISST-D & CILC-1D	3,110,295	1.06368772	3,308,383	0.940126	198,088	0.99349
62							
63	MET Pri	93,198	1.04657532	97,539	0.955497	4,341	0.97750
64							
65	Subtotal OS-2, GSLD-2, CS-2, & MET	1,620,094	1.06412671	1,723,985	0.939738	103,891	0.99390
66							
67	OL-1 Sec	109,597	1.07281827	117,578	0.932124	7,981	1.00201
68							
69	SL-1 Sec	426,217	1.07281827	457,254	0.932124	31,036	1.00201
70							
71	Subtotal OL-1 / SL-1	535,815	1.07281827	574,832	0.932124	39,017	1.00201
72							
73	SL-2 Sec	67,673	1.07281827	72,601	0.932124	4,928	1.00201
74							
75	RTP-1 Pri	0	1.04657532	0	0.000000	0	
76	RTP-1 Sec	38,247	1.07281827	41,032	0.932124	2,785	
77	Subtotal RTP-1	38,247	1.07281827	41,032	0.932124	2,785	1.00201
78							
79	RTP-2 Pri	69,791	1.04657532	73,042	0.955497	3,251	
80	RTP-2 Sec	111,877	1.07281827	120,024	0.932124	8,147	
81	Subtotal RTP-2	181,669	1.06273654	193,066	0.940967	11,397	0.99260
82							
83	RTP-3 Trn	0	1.02438901	0	0.000000	0	0.00000
84							
85	Total FPSC	99,339,144	1.07136372	106,428,356	0.933390	7,089,211	1.00065
86							
87	Total FERC Sales	1,511,574	1.02438901	1,548,440	0.976192	36,866	
88							
89	Total Company	100,850,719	1.07065966	107,976,796	0.934004	7,126,077	
90							
91	Company Use	139,794	1.07281827	149,974	0.932124	10,180	
92							
93	Total FPL	100,990,513	1.07066264	108,126,769	0.934001	7,136,257	1.00000
94							
95	**Summary of Sales by Voltage:**						
96							
97	Transmission	3,305,143	1.02438901	3,385,752	0.976192	80,609	
98							
99	Primary	2,196,109	1.04657532	2,298,394	0.955497	102,284	
100							
101	Secondary	95,349,467	1.07281827	102,292,650	0.932124	6,943,183	
102							
103	Total	100,850,719	1.07065966	107,976,796	0.934004	7,126,077	

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2005 - DECEMBER 2005

SCHEDULE E2
Page 1 of 2

LINE NO.		(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$249,062,689	$229,494,456	$248,849,987	$264,235,844	$322,553,153	$340,576,822	$1,654,772,951	A1
1a	NUCLEAR FUEL DISPOSAL	2,033,221	1,836,458	2,033,221	1,587,482	1,515,688	1,738,342	10,744,412	1a
1b	COAL CAR INVESTMENT	357,992	355,784	353,577	351,369	349,162	346,954	2,114,838	1b
1d	GAS LATERAL ENHANCEMENTS	47,580	47,140	46,700	46,260	45,819	45,379	278,878	1d
1e	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0	1e
1g	INCREMENTAL HEDGING COSTS	59,542	35,542	47,707	35,542	49,580	35,542	263,455	1g
2	FUEL COST OF POWER SOLD	(12,813,229)	(11,745,573)	(10,540,691)	(8,393,387)	(7,532,681)	(10,253,775)	(61,279,336)	2
2a	REVENUES FROM OFF-SYSTEM SALES	(750,000)	(885,800)	(787,500)	(736,750)	(672,000)	(1,190,100)	(5,022,150)	2a
3	FUEL COST OF PURCHASED POWER	22,005,184	18,732,575	17,921,994	14,381,067	20,527,668	16,225,115	109,793,603	3
3b	OKEELANTA/OSCEOLA SETTLEMENT	799,033	798,170	797,307	796,444	795,581	794,718	4,781,253	3b
3c	QUALIFYING FACILITIES	13,899,000	12,887,000	13,908,000	13,598,000	13,924,000	13,630,000	81,846,000	3c
4	ENERGY COST OF ECONOMY PURCHASES	5,194,735	4,768,471	5,385,712	5,926,802	6,084,294	2,705,396	30,065,410	4
4a	FUEL COST OF SALES TO FKEC / CKW	(3,354,286)	(3,373,026)	(3,414,130)	(3,662,360)	(3,859,379)	(4,014,266)	(21,677,447)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$276,541,461	$252,951,197	$274,601,884	$288,166,313	$353,780,885	$360,640,127	$1,806,681,867	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	7,871,434	7,643,474	7,321,581	7,506,178	7,862,448	9,376,285	47,581,400	6
7	COST PER KWH SOLD (¢/KWH)	3.5132	3.3094	3.7506	3.8391	4.4996	3.8463	3.7970	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00065	1.00065	1.00065	1.00065	1.00065	1.00065	1.00065	7a
7b	JURISDICTIONAL COST (¢/KWH)	3.5155	3.3115	3.7530	3.8416	4.5026	3.8488	3.7995	7b
9	TRUE-UP (¢/KWH)	0.0782	0.0806	0.0841	0.0820	0.0783	0.0657	0.0776	9
10	TOTAL	3.5937	3.3921	3.8371	3.9236	4.5809	3.9145	3.8771	10
11	REVENUE TAX FACTOR 0.01597	0.0574	0.0542	0.0613	0.0627	0.0732	0.0625	0.0619	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	3.6511	3.4463	3.8984	3.9863	4.6541	3.9770	3.9390	12
13	GPIF (¢/KWH)	0.0070	0.0072	0.0076	0.0074	0.0070	0.0059	0.0070	13
14	RECOVERY FACTOR including GPIF	3.6581	3.4535	3.9060	3.9937	4.6611	3.9829	3.9460	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	3.658	3.454	3.906	3.994	4.661	3.983	3.946	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2005 - DECEMBER 2005

LINE NO.		(h) JULY	(i) AUGUST	(j) ESTIMATED SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) 12 MONTH PERIOD	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$381,888,807	$373,972,172	$343,270,872	$326,700,974	$270,114,226	$265,413,560	$3,616,133,562	A1
1a	NUCLEAR FUEL DISPOSAL	1,983,357	1,983,357	1,919,376	1,453,692	1,410,567	2,014,653	$21,509,414	1a
1b	COAL CAR INVESTMENT	344,747	342,539	340,332	338,124	335,917	333,709	$4,150,206	1b
1d	GAS LATERAL ENHANCEMENTS	44,939	0	0	0	0	0	$323,817	1d
1e	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	6,870,000	0	$6,870,000 $0	1e
1g	INCREMENTAL HEDGING COSTS	66,742	66,742	35,542	35,542	49,580	35,542	$553,145	1g
2	FUEL COST OF POWER SOLD	(9,436,953)	(9,570,193)	(9,216,004)	(7,905,823)	(8,824,500)	(10,429,469)	($116,662,278)	2
2a	REVENUES FROM OFF-SYSTEM SALES	(1,395,800)	(1,422,300)	(576,300)	(427,100)	(842,000)	(1,398,700)	($11,084,350)	2a
3	FUEL COST OF PURCHASED POWER	25,581,676	23,624,151	17,930,638	17,451,974	16,675,160	19,201,711	$230,258,913	3
3b	OKEELANTA/OSCEOLA SETTLEMENT	793,855	792,991	792,128	791,265	790,402	789,539	$9,531,433	3b
3c	QUALIFYING FACILITIES	13,796,000	13,849,000	13,609,000	13,936,000	11,677,000	11,843,000	$160,556,000	3c
4	ENERGY COST OF ECONOMY PURCHASES	2,871,499	2,931,412	2,834,577	4,142,850	4,089,990	4,250,102	$51,185,840	4
4a	FUEL COST OF SALES TO FKEC / CKW	(4,275,422)	(4,431,069)	(4,499,500)	(4,295,460)	(4,035,242)	(3,698,767)	($46,912,909)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$412,263,447	$402,138,802	$366,440,661	$352,222,038	$298,311,100	$288,354,880	$3,926,412,793	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	9,794,123	10,257,836	10,200,267	9,238,929	8,188,913	8,267,640	103,529,108	6
7	COST PER KWH SOLD (¢/KWH)	4.2093	3.9203	3.5925	3.8124	3.6429	3.4878	3.7926	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00065	1.00065	1.00065	1.00065	1.00065	1.00065	1.00065	7a
7b	JURISDICTIONAL COST (¢/KWH)	4.2120	3.9229	3.5948	3.8148	3.6452	3.4900	3.7950	7b
9	TRUE-UP (¢/KWH)	0.0629	0.0600	0.0604	0.0667	0.0752	0.0745	0.0714	9
10	TOTAL	4.2749	3.9829	3.6552	3.8815	3.7204	3.5645	3.8664	10
11	REVENUE TAX FACTOR 0.01597	0.0683	0.0636	0.0584	0.0620	0.0594	0.0569	0.0617	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	4.3432	4.0465	3.7136	3.9435	3.7798	3.6214	3.9281	12
13	GPIF (¢/KWH)	0.0057	0.0054	0.0054	0.0060	0.0068	0.0067	0.0064	13
14	RECOVERY FACTOR including GPIF	4.3489	4.0519	3.7190	3.9495	3.7866	3.6281	3.9345	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	4.349	4.052	3.719	3.950	3.787	3.628	3.935	15

Florida Power & Light Company
9/09/2004

Schedule E 3

Generating System Comparative Data by Fuel Type

		Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05
	Fuel Cost of System Net Generation ($)						
1	Heavy Oil	$33,087,835	$37,458,500	$51,577,745	$69,599,003	$106,072,579	$83,666,800
2	Light Oil	$2,216,880	$803,350	$231,920	$48,330	$2,030,150	$188,920
3	Coal	$8,507,240	$7,707,010	$7,412,740	$6,974,450	$8,398,090	$8,185,290
4	Gas	$198,076,044	$177,057,456	$182,480,002	$181,854,572	$200,527,134	$242,086,322
5	Nuclear	$7,174,690	$6,468,140	$7,147,580	$5,759,490	$5,525,200	$6,449,490
6	***Total***	$249,062,689	$229,494,456	$248,849,987	$264,235,844	$322,553,153	$340,576,822
	System Net Generation (MWH)						
7	Heavy Oil	647,984	773,297	1,047,366	1,406,814	2,166,583	1,704,318
8	Light Oil	14,534	5,108	1,963	443	16,626	1,746
9	Coal	549,042	497,851	477,618	459,315	554,244	540,233
10	Gas	3,333,275	2,995,902	3,200,666	3,384,807	3,793,417	4,691,752
11	Nuclear	2,185,554	1,974,049	2,185,554	1,706,419	1,629,247	1,868,582
12	***Total***	6,730,389	6,246,207	6,913,167	6,957,798	8,160,117	8,806,631
	Units of Fuel Burned						
13	Heavy Oil (BBLS)	1,006,964	1,144,805	1,595,356	2,183,270	3,333,852	2,619,546
14	Light Oil (BBLS)	39,562	14,249	4,215	885	36,680	3,500
15	Coal (TONS)	279,471	253,982	253,056	237,815	276,278	269,216
16	Gas (MCF)	25,351,870	22,688,758	23,805,438	25,443,770	29,012,332	34,751,459
17	Nuclear (MBTU)	24,102,626	21,770,150	24,102,626	19,096,638	18,193,580	20,959,048
	BTU Burned (MMBTU)						
18	Heavy Oil	6,444,569	7,326,754	10,210,278	13,972,926	21,336,650	16,765,090
19	Light Oil	230,646	83,072	24,572	5,158	213,844	20,406
20	Coal	5,351,378	4,852,657	4,663,963	4,386,011	5,285,164	5,151,205
21	Gas	25,351,870	22,688,758	23,805,438	25,443,770	29,012,332	34,751,459
22	Nuclear	24,102,626	21,770,150	24,102,626	19,096,638	18,193,580	20,959,048
23	***Total***	61,481,089	56,721,391	62,806,877	62,904,503	74,041,570	77,647,208

Florida Power & Light Company
9/09/2004

Schedule E 3

Generating System Comparative Data by Fuel Type

		Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05
	Generation Mix (%MWH)						
24	Heavy Oil	9.63%	12.38%	15.15%	20.22%	26.55%	19.35%
25	Light Oil	0.22%	0.08%	0.03%	0.01%	0.20%	0.02%
26	Coal	8.16%	7.97%	6.91%	6.60%	6.79%	6.13%
27	Gas	49.53%	47.96%	46.30%	48.65%	46.49%	53.28%
28	Nuclear	32.47%	31.60%	31.61%	24.53%	19.97%	21.22%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit						
30	Heavy Oil ($/BBL)	32.8590	32.7204	32.3299	31.8783	31.8168	31.9394
31	Light Oil ($/BBL)	56.0356	56.3794	55.0225	54.6102	55.3476	53.9771
32	Coal ($/ton)	30.4405	30.3447	29.2929	29.3272	30.3972	30.4042
33	Gas ($/MCF)	7.8131	7.8038	7.6655	7.1473	6.9118	6.9662
34	Nuclear ($/MBTU)	0.2977	0.2971	0.2965	0.3016	0.3037	0.3077
	Fuel Cost per MMBTU ($/MMBTU)						
35	Heavy Oil	5.1342	5.1126	5.0516	4.9810	4.9714	4.9905
36	Light Oil	9.6116	9.6705	9.4384	9.3699	9.4936	9.2581
37	Coal	1.5897	1.5882	1.5894	1.5902	1.5890	1.5890
38	Gas	7.8131	7.8038	7.6655	7.1473	6.9118	6.9662
39	Nuclear	0.2977	0.2971	0.2965	0.3016	0.3037	0.3077
	BTU burned per KWH (BTU/KWH)						
40	Heavy Oil	9,946	9,475	9,749	9,932	9,848	9,837
41	Light Oil	15,869	16,263	12,518	11,643	12,862	11,687
42	Coal	9,747	9,747	9,765	9,549	9,536	9,535
43	Gas	7,606	7,573	7,438	7,517	7,648	7,407
44	Nuclear	11,028	11,028	11,028	11,191	11,167	11,217
	Generated Fuel Cost per KWH (cents/KWH)						
45	Heavy Oil	5.1063	4.8440	4.9245	4.9473	4.8958	4.9091
46	Light Oil	15.2531	15.7273	11.8146	10.9097	12.2107	10.8202
47	Coal	1.5495	1.5481	1.5520	1.5184	1.5152	1.5151
48	Gas	5.9424	5.9100	5.7013	5.3727	5.2862	5.1598
49	Nuclear	0.3283	0.3277	0.3270	0.3375	0.3391	0.3452
50	***Total***	3.7006	3.6741	3.5997	3.7977	3.9528	3.8673

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Schedule E 3

Generating System Comparative Data by Fuel Type

		Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total
	Fuel Cost of System Net Generation ($)							
1	Heavy Oil	$81,002,720	$84,894,368	$83,052,400	$73,649,915	$37,664,690	$26,834,391	$768,560,945
2	Light Oil	$6,036,540	$4,394,280	$1,663,880	$689,530	$111,750	$68,010	$18,483,540
3	Coal	$8,340,990	$8,343,510	$8,170,830	$8,354,940	$8,327,810	$8,677,420	$97,400,320
4	Gas	$279,078,237	$268,919,464	$243,216,162	$238,368,779	$218,637,616	$222,198,659	$2,652,500,447
5	Nuclear	$7,430,320	$7,420,550	$7,167,600	$5,637,810	$5,372,360	$7,635,080	$79,188,310
6	***Total***	$381,888,807	$373,972,172	$343,270,872	$326,700,974	$270,114,226	$265,413,560	$3,616,133,562
	System Net Generation (MWH)							
7	Heavy Oil	1,628,985	1,707,451	1,686,888	1,517,309	771,735	554,092	15,612,822
8	Light Oil	43,226	32,195	12,607	6,547	1,001	458	136,454
9	Coal	549,508	549,645	538,561	550,462	536,695	559,183	6,362,357
10	Gas	5,210,262	5,068,958	4,628,617	4,576,916	4,202,601	4,078,709	49,165,882
11	Nuclear	2,131,954	2,131,954	2,063,180	1,562,606	1,516,250	2,165,595	23,120,944
12	***Total***	9,563,935	9,490,203	8,929,853	8,213,840	7,028,282	7,358,037	94,398,459
	Units of Fuel Burned							
13	Heavy Oil (BBLS)	2,529,125	2,646,073	2,600,413	2,335,576	1,201,148	861,133	24,057,261
14	Light Oil (BBLS)	110,188	81,092	30,889	13,143	2,107	1,255	337,765
15	Coal (TONS)	274,194	274,328	268,556	274,479	273,224	284,678	3,219,277
16	Gas (MCF)	40,438,751	38,723,054	34,845,441	33,832,175	30,442,219	30,220,774	369,556,040
17	Nuclear (MBTU)	23,967,112	23,967,112	23,193,978	17,690,118	16,831,692	23,886,181	257,760,861
	BTU Burned (MMBTU)							
18	Heavy Oil	16,186,398	16,934,872	16,642,645	14,947,685	7,687,350	5,511,248	153,966,465
19	Light Oil	642,397	472,764	180,081	76,621	12,281	7,315	1,969,157
20	Coal	5,245,828	5,246,001	5,136,962	5,249,295	5,230,722	5,449,722	61,248,908
21	Gas	40,438,751	38,723,054	34,845,441	33,832,175	30,442,219	30,220,774	369,556,040
22	Nuclear	23,967,112	23,967,112	23,193,978	17,690,118	16,831,692	23,886,181	257,760,861
23	***Total***	86,480,486	85,343,803	79,999,107	71,795,894	60,204,264	65,075,240	844,501,431

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Schedule E 3

Generating System Comparative Data by Fuel Type

		Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total
	Generation Mix (%MWH)							
24	Heavy Oil	17.03%	17.99%	18.89%	18.47%	10.98%	7.53%	16.54%
25	Light Oil	0.45%	0.34%	0.14%	0.08%	0.01%	0.01%	0.14%
26	Coal	5.75%	5.79%	6.03%	6.70%	7.64%	7.60%	6.74%
27	Gas	54.48%	53.41%	51.83%	55.72%	59.80%	55.43%	52.08%
28	Nuclear	22.29%	22.46%	23.10%	19.02%	21.57%	29.43%	24.49%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit							
30	Heavy Oil ($/BBL)	32.0280	32.0832	31.9382	31.5339	31.3572	31.1617	31.9472
31	Light Oil ($/BBL)	54.7840	54.1888	53.8664	52.4637	53.0375	54.1912	54.7231
32	Coal ($/ton)	30.4200	30.4144	30.4251	30.4393	30.4798	30.4815	30.2553
33	Gas ($/MCF)	6.9013	6.9447	6.9799	7.0456	7.1821	7.3525	7.1775
34	Nuclear ($/MBTU)	0.3100	0.3096	0.3090	0.3187	0.3192	0.3196	0.3072
	Fuel Cost per MMBTU ($/MMBTU)							
35	Heavy Oil	5.0044	5.0130	4.9903	4.9272	4.8996	4.8690	4.9917
36	Light Oil	9.3969	9.2949	9.2396	8.9992	9.0994	9.2973	9.3865
37	Coal	1.5900	1.5905	1.5906	1.5916	1.5921	1.5923	1.5902
38	Gas	6.9013	6.9447	6.9799	7.0456	7.1821	7.3525	7.1775
39	Nuclear	0.3100	0.3096	0.3090	0.3187	0.3192	0.3196	0.3072
	BTU burned per KWH (BTU/KWH)							
40	Heavy Oil	9,936	9,918	9,866	9,851	9,961	9,946	9,862
41	Light Oil	14,861	14,684	14,284	11,703	12,269	15,972	14,431
42	Coal	9,546	9,544	9,538	9,536	9,746	9,746	9,627
43	Gas	7,761	7,639	7,528	7,392	7,244	7,409	7,517
44	Nuclear	11,242	11,242	11,242	11,321	11,101	11,030	11,148
	Generated Fuel Cost per KWH (cents/KWH)							
45	Heavy Oil	4.9726	4.9720	4.9234	4.8540	4.8805	4.8429	4.9226
46	Light Oil	13.9651	13.6490	13.1981	10.5320	11.1638	14.8493	13.5456
47	Coal	1.5179	1.5180	1.5172	1.5178	1.5517	1.5518	1.5309
48	Gas	5.3563	5.3052	5.2546	5.2081	5.2024	5.4478	5.3950
49	Nuclear	0.3485	0.3481	0.3474	0.3608	0.3543	0.3526	0.3425
50	***Total***	3.9930	3.9406	3.8441	3.9774	3.8432	3.6071	3.8307

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Estimated For The Period of : Jan-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	397	52,423	24.1	95.0	75.0	9,390	Heavy Oil BBLS ->	71,978	6,400,003	460,656	2,368,691	4.5185
2			18,746					Gas MCF ->	207,611	1,000,000	207,611	1,619,028	8.6368
3													
4	TRKY O 2	397	19,653	10.3	93.7	51.4	10,526	Heavy Oil BBLS ->	28,324	6,400,001	181,273	932,151	4.7430
5			10,770					Gas MCF ->	138,969	1,000,000	138,969	1,083,679	10.0624
6													
7	TRKY N 3	717	520,110	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,841,326	1,000,000	5,841,326	1,919,300	0.3690
8													
9	TRKY N 4	717	520,110	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,841,326	1,000,000	5,841,326	1,586,400	0.3050
10													
11	FT LAUD4	443	290,193	88.0	94.7	93.0	7,715	Gas MCF ->	2,238,768	1,000,000	2,238,768	17,458,380	6.0161
12													
13	FT LAUD5	442	275,635	83.8	93.6	88.5	7,906	Gas MCF ->	2,179,029	1,000,000	2,179,029	16,992,476	6.1649
14													
15	PT EVER1	211	5,990	6.4	95.0	45.0	11,424	Heavy Oil BBLS ->	7,823	6,400,020	50,068	258,012	4.3077
16			4,110					Gas MCF ->	65,306	1,000,000	65,306	509,309	12.3925
17													
18	PT EVER2	211	6,608	6.9	94.4	46.3	10,979	Heavy Oil BBLS ->	8,288	6,399,969	53,042	273,318	4.1362
19			4,182					Gas MCF ->	65,424	1,000,000	65,424	510,191	12.1997
20													
21	PT EVER3	383	14,860	8.0	95.1	42.3	12,377	Heavy Oil BBLS ->	25,001	6,400,010	160,004	824,426	5.5481
22			7,991					Gas MCF ->	122,820	1,000,000	122,820	957,752	11.9854
23													
24	PT EVER4	390	9,900	5.9	95.6	34.9	13,779	Heavy Oil BBLS ->	18,129	6,400,014	116,023	597,821	6.0388
25			7,308					Gas MCF ->	121,075	1,000,000	121,075	944,128	12.9191
26													
27	RIV 3	275	6,415	5.4	93.8	40.7	12,625	Heavy Oil BBLS ->	9,064	6,400,018	58,010	298,460	4.6525
28			4,693					Gas MCF ->	82,234	1,000,000	82,234	641,183	13.6619
29													
30	RIV 4	281	121,327	69.1	92.8	79.7	9,100	Heavy Oil BBLS ->	170,311	6,399,999	1,089,988	5,607,933	4.6222
31			23,161					Gas MCF ->	224,919	1,000,000	224,919	1,753,969	7.5730
32													

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Estimated For The Period of : Jan-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	853	618,763	97.5	97.5	100.0	10,844	Nuclear Othr ->	6,709,888	1,000,000	6,709,888	1,909,700	0.3086
35	ST LUC 2	726	526,572	97.5	97.5	100.0	10,844	Nuclear Othr ->	5,710,086	1,000,000	5,710,086	1,759,400	0.3341
37	CAP CN 1	398	24,898	14.7	94.2	62.7	10,536	Heavy Oil BBLS ->	37,237	6,400,002	238,316	1,221,742	4.9070
38			18,635					Gas MCF ->	220,364	1,000,000	220,364	1,718,374	9.2212
40	CAP CN 2	398	35,439	18.6	94.7	68.4	10,251	Heavy Oil BBLS ->	52,587	6,400,003	336,559	1,725,427	4.8687
41			19,490					Gas MCF ->	226,527	1,000,000	226,527	1,766,497	9.0638
43	SANFRD 3	140	2,961	5.6	95.8	41.8	11,755	Heavy Oil BBLS ->	4,129	6,399,985	26,428	116,162	3.9232
44			2,824					Gas MCF ->	41,572	1,000,000	41,572	324,161	11.4804
46	PUTNAM 1	250	16,041	8.6	95.3	56.3	9,645	Gas MCF ->	154,710	1,000,000	154,710	1,206,921	7.5239
48	PUTNAM 2	250	14,316	7.7	95.4	53.2	10,044	Gas MCF ->	143,787	1,000,000	143,787	1,121,559	7.8346
50	MANATE 1	821	150,168	28.2	94.4	54.2	10,279	Heavy Oil BBLS ->	238,560	6,399,999	1,526,785	7,834,481	5.2171
51			22,065					Gas MCF ->	243,636	1,000,000	243,636	1,969,498	8.9259
53	MANATE 2	821	80,168	18.0	95.8	42.2	11,122	Heavy Oil BBLS ->	136,372	6,400,000	872,778	4,478,522	5.5864
54			29,726					Gas MCF ->	349,505	1,000,000	349,505	2,825,960	9.5066
56	CUTLER 5	70	2,684	5.2	97.6	41.3	10,935	Gas MCF ->	29,351	1,000,000	29,351	228,888	8.5272
58	CUTLER 6	142	3,893	3.7	96.6	29.2	11,682	Gas MCF ->	45,477	1,000,000	45,477	354,700	9.1112
60	MARTIN 1	813	38,742	12.8	86.6	41.7	12,168	Heavy Oil BBLS ->	71,207	6,400,003	455,724	2,342,148	6.0456
61			38,451					Gas MCF ->	483,554	1,000,000	483,554	3,770,888	9.8070

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Estimated For The Period of : Jan-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MARTIN 2	804	78,433	22.7	96.3	54.7	10,711	Heavy Oil BBLS ->	127,955	6,400,002	818,912	4,208,730	5.3660
64			57,353					Gas MCF ->	635,439	1,000,000	635,439	4,955,328	8.6400
65													
66	MARTIN 3	465	257,513	74.4	95.1	86.4	7,158	Gas MCF ->	1,843,253	1,000,000	1,843,253	14,374,046	5.5819
67													
68	MARTIN 4	466	274,667	79.2	94.6	89.6	6,884	Gas MCF ->	1,890,900	1,000,000	1,890,900	14,745,568	5.3685
69													
70	MARTIN 8	1,099		0.0	0.0		0						
71													
72	FM GT	624	14,310	3.1	98.4	48.2	15,850	Light Oil BBLS ->	38,904	5,829,992	226,807	2,189,600	15.3014
73													
74	FL GT	768	71	1.9	91.7	30.8	18,675	Light Oil BBLS ->	216	5,829,314	1,257	8,600	12.1813
75			10,542					Gas MCF ->	196,938	1,000,000	196,938	1,535,942	14.5695
76													
77	PE GT	384	154	3.5	88.3	57.3	17,624	Light Oil BBLS ->	443	5,830,662	2,582	18,700	12.1666
78			9,709					Gas MCF ->	171,237	1,000,000	171,237	1,341,514	13.8174
79													
80	SJRPP 1O	130	84,290	87.1	93.1	99.7	9,640	Coal TONS ->	33,219	24,460,311	812,537	1,306,400	1.5499
81													
82	SJRPP 2O	130	84,864	87.7	93.6	99.7	9,500	Coal TONS ->	32,961	24,460,316	806,232	1,296,200	1.5274
83													
84	SCHER #4	648	379,888	78.8	94.2	89.7	9,826	Coal TONS ->	213,292	17,500,004	3,732,609	5,904,600	1.5543
85													
86	FMREP 1	1,451	822,450	76.2	87.1	86.3	6,897	Gas MCF ->	5,672,200	1,000,000	5,672,200	44,278,455	5.3837
87													
88	SNREP4	938	549,897	78.8	95.7	90.7	6,885	Gas MCF ->	3,785,782	1,000,000	3,785,782	29,573,130	5.3779
89													
90	SNREP5	938	507,031	72.7	95.2	87.3	6,809	Gas MCF ->	3,452,432	1,000,000	3,452,432	26,999,502	5.3250
91													
92	MANATE 3	1,105		0.0	0.0		0						
93													

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Estimated For The Period of : Jan-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
94	FM SC	166	29,201	11.8	97.1	81.2	10,926	Gas MCF ->	319,055	1,000,000	319,055	2,515,300	8.6139
95													
96	MR SC	163		0.0	0.0		0						
97													
98	TOTAL	13,446	3,556,626	0.0			8,062				28,673,479	181,385,180	5.0999

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Estimated For The Period of : Feb-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	397	103,636	45.2	95.0	87.3	8,983	Heavy Oil BBLS ->	140,224	6,400,001	897,432	4,586,958	4.4260
2			16,835					Gas MCF ->	184,754	1,000,000	184,754	1,439,169	8.5485
3													
4	TRKY O 2	397	62,538	28.3	83.7	74.1	9,414	Heavy Oil BBLS ->	86,641	6,400,000	554,502	2,834,135	4.5318
5			13,088					Gas MCF ->	157,481	1,000,000	157,481	1,226,709	9.3727
6													
7	TRKY N 3	717	469,777	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,276,049	1,000,000	5,276,049	1,730,300	0.3683
8													
9	TRKY N 4	717	469,777	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,276,049	1,000,000	5,276,049	1,430,100	0.3044
10													
11	FT LAUD4	443	260,154	87.4	94.7	92.3	7,707	Gas MCF ->	2,004,950	1,000,000	2,004,950	15,617,647	6.0032
12													
13	FT LAUD5	442	246,850	83.1	93.6	87.7	7,890	Gas MCF ->	1,947,564	1,000,000	1,947,564	15,170,627	6.1457
14													
15	PT EVER1	211	7,651	10.6	95.0	50.3	11,435	Heavy Oil BBLS ->	9,889	6,399,972	63,287	324,997	4.2479
16			7,320					Gas MCF ->	107,899	1,000,000	107,899	840,458	11.4818
17													
18	PT EVER2	211	10,972	12.5	84.3	57.3	10,244	Heavy Oil BBLS ->	13,486	6,400,007	86,307	443,196	4.0394
19			6,816					Gas MCF ->	95,903	1,000,000	95,903	746,991	10.9595
20													
21	PT EVER3	383	7,610	4.6	23.8	54.2	11,280	Heavy Oil BBLS ->	12,291	6,400,023	78,661	403,929	5.3079
22			4,307					Gas MCF ->	55,766	1,000,000	55,766	434,422	10.0864
23													
24	PT EVER4	390	39,740	20.2	95.6	58.9	11,572	Heavy Oil BBLS ->	66,090	6,399,998	422,973	2,172,028	5.4656
25			13,162					Gas MCF ->	189,225	1,000,000	189,225	1,473,974	11.1991
26													
27	RIV 3	275	125,164	74.7	93.8	84.1	8,444	Heavy Oil BBLS ->	163,640	6,399,999	1,047,294	5,355,646	4.2789
28			12,934					Gas MCF ->	118,828	1,000,000	118,828	925,537	7.1561
29													
30	RIV 4	281	4,972	6.8	92.8	37.6	14,590	Heavy Oil BBLS ->	7,541	6,399,981	48,263	246,759	4.9633
31			7,953					Gas MCF ->	140,309	1,000,000	140,309	1,092,916	13.7427
32													

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Estimated For The Period of : Feb-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	853	558,883	97.5	97.5	100.0	10,844	Nuclear Othr ->	6,060,552	1,000,000	6,060,552	1,721,600	0.3080
34													
35	ST LUC 2	726	475,613	97.5	97.5	100.0	10,844	Nuclear Othr ->	5,157,500	1,000,000	5,157,500	1,586,100	0.3335
36													
37	CAP CN 1	398	12,725	6.5	13.5	76.2	9,785	Heavy Oil BBLS ->	18,693	6,399,999	119,634	610,715	4.7992
38			4,757					Gas MCF ->	51,424	1,000,000	51,424	400,512	8.4201
39													
40	CAP CN 2	398	89,092	39.4	94.7	83.2	9,655	Heavy Oil BBLS ->	129,499	6,399,999	828,792	4,230,955	4.7490
41			16,354					Gas MCF ->	189,246	1,000,000	189,246	1,474,089	9.0135
42													
43	SANFRD 3	140	3,874	9.1	95.8	46.6	11,901	Heavy Oil BBLS ->	5,356	6,399,940	34,277	151,203	3.9035
44			4,653					Gas MCF ->	67,203	1,000,000	67,203	523,476	11.2493
45													
46	PUTNAM 1	250	30	18.8	95.3	69.3	8,937	Light Oil BBLS ->	44	5,828,767	255	2,000	6.6667
47			31,620					Gas MCF ->	282,601	1,000,000	282,601	2,202,397	6.9653
48													
49	PUTNAM 2	250	7	14.7	95.4	64.4	9,318	Light Oil BBLS ->	11	5,831,858	66	500	6.7568
50			24,708					Gas MCF ->	230,220	1,000,000	230,220	1,794,077	7.2613
51													
52	MANATE 1	821	102,033	20.9	94.4	61.0	10,246	Heavy Oil BBLS ->	160,858	6,399,998	1,029,488	5,266,257	5.1613
53			13,194					Gas MCF ->	151,090	1,000,000	151,090	1,218,384	9.2346
54													
55	MANATE 2	821	67,538	15.1	95.8	52.4	10,897	Heavy Oil BBLS ->	112,492	6,400,000	719,951	3,682,852	5.4530
56			15,927					Gas MCF ->	189,580	1,000,000	189,580	1,529,636	9.6042
57													
58	CUTLER 5	70	2,384	5.1	97.6	36.5	13,746	Gas MCF ->	32,771	1,000,000	32,771	255,224	10.7057
59													
60	CUTLER 6	142	4,510	4.7	96.6	33.4	12,067	Gas MCF ->	54,427	1,000,000	54,427	423,932	9.3992
61													
62	MARTIN 1	813		0.0	0.0		0						
63													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
64	MARTIN 2	804	135,753	39.8	96.3	65.1	10,497	Heavy Oil BBLS ->	218,108	6,400,001	1,395,891	7,148,771	5.2660
65			79,332					Gas MCF ->	861,867	1,000,000	861,867	6,713,986	8.4631
67	MARTIN 3	465	252,761	80.9	95.1	89.0	7,117	Gas MCF ->	1,798,872	1,000,000	1,798,872	14,028,815	5.5502
69	MARTIN 4	466	230,290	73.5	84.4	82.7	6,935	Gas MCF ->	1,597,095	1,000,000	1,597,095	12,459,263	5.4103
71	MARTIN 8	1,099		0.0	0.0		0						
73	FM GT	624	5,071	1.2	90.2	44.4	16,320	Light Oil BBLS ->	14,194	5,830,020	82,751	800,800	15.7927
75	FL GT	768	1	0.7	91.7	27.5	19,253	Light Oil BBLS ->	2	5,950,000	12	100	14.2857
76			3,581					Gas MCF ->	68,936	1,000,000	68,936	536,957	14.9967
78	PE GT	384	0	1.4	88.3	54.9	17,863	Light Oil BBLS ->	0		0	0	
79			3,571					Gas MCF ->	63,784	1,000,000	63,784	496,849	13.9146
81	SJRPP 1O	130	72,239	82.7	86.5	99.6	9,639	Coal TONS ->	28,467	24,459,950	696,301	1,106,300	1.5314
83	SJRPP 2O	130	77,637	88.9	93.6	99.7	9,499	Coal TONS ->	30,151	24,459,963	737,495	1,171,800	1.5093
85	SCHER #4	648	347,975	79.9	94.2	89.8	9,825	Coal TONS ->	195,364	17,500,001	3,418,861	5,428,900	1.5601
87	FMREP 1	1,451	723,542	74.2	82.9	84.3	6,920	Gas MCF ->	5,007,216	1,000,000	5,007,216	39,003,902	5.3907
89	SNREP4	938	472,004	74.9	88.9	84.3	6,982	Gas MCF ->	3,295,762	1,000,000	3,295,762	25,721,806	5.4495
91	SNREP5	938	483,104	76.6	95.2	87.5	6,841	Gas MCF ->	3,304,830	1,000,000	3,304,830	25,842,009	5.3492
93	MANATE 3	1,105		0.0	0.0		0						

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
95	FM SC	166	40,194	18.0	91.9	86.3	10,926	Gas MCF ->	439,168	1,000,000	439,168	3,463,530	8.6171
96													
97	MR SC	163		0.0	0.0		0						
98													
99	TOTAL	13,196	3,188,972	0.0			7,983				25,459,035	160,297,047	5.0266

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Estimated For The Period of : Mar-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	397	117,209	45.4	95.0	88.3	8,951	Heavy Oil BBLS ->	158,333	6,399,998	1,013,330	5,123,143	4.3709
2			16,861					Gas MCF ->	186,722	1,000,000	186,722	1,430,373	8.4832
3													
4	TRKY O 2	397		0.0	0.0		0						
5													
6	TRKY N 3	717	520,110	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,841,326	1,000,000	5,841,326	1,912,000	0.3676
7													
8	TRKY N 4	717	520,110	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,841,326	1,000,000	5,841,326	1,580,300	0.3038
9													
10	FT LAUD4	443	166,797	50.6	58.0	92.0	7,711	Gas MCF ->	1,286,135	1,000,000	1,286,135	9,852,575	5.9069
11													
12	FT LAUD5	442	279,836	85.1	93.6	89.8	7,847	Gas MCF ->	2,195,919	1,000,000	2,195,919	16,822,021	6.0114
13													
14	PT EVER1	211	8,202	10.9	95.0	57.4	11,037	Heavy Oil BBLS ->	10,492	6,400,013	67,148	339,938	4.1447
15			8,967					Gas MCF ->	122,352	1,000,000	122,352	937,309	10.4524
16													
17	PT EVER2	211		0.0	0.0		0						
18													
19	PT EVER3	383	65,682	28.4	95.1	72.6	10,496	Heavy Oil BBLS ->	101,499	6,400,003	649,593	3,288,263	5.0064
20			15,242					Gas MCF ->	199,774	1,000,000	199,774	1,530,425	10.0408
21													
22	PT EVER4	390	38,117	18.4	95.6	59.1	11,688	Heavy Oil BBLS ->	63,286	6,399,999	405,031	2,050,318	5.3790
23			15,199					Gas MCF ->	218,127	1,000,000	218,127	1,671,042	10.9944
24													
25	RIV 3	275	1,460	1.7	33.3	42.7	13,664	Heavy Oil BBLS ->	2,056	6,400,029	13,156	66,449	4.5528
26			2,095					Gas MCF ->	35,419	1,000,000	35,419	271,322	12.9491
27													
28	RIV 4	281	138,405	74.0	92.8	83.0	9,012	Heavy Oil BBLS ->	193,154	6,399,999	1,236,186	6,242,972	4.5106
29			16,291					Gas MCF ->	157,936	1,000,000	157,936	1,209,860	7.4264
30													

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Estimated For The Period of : Mar-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUC 1	853	618,763	97.5	97.5	100.0	10,844	Nuclear Othr ->	6,709,888	1,000,000	6,709,888	1,902,500	0.3075
33	ST LUC 2	726	526,572	97.5	97.5	100.0	10,844	Nuclear Othr ->	5,710,086	1,000,000	5,710,086	1,752,800	0.3329
35	CAP CN 1	398		0.0	0.0		0						
37	CAP CN 2	398	96,907	38.0	94.7	83.3	9,658	Heavy Oil BBLS ->	140,686	6,400,000	900,391	4,545,084	4.6902
38			15,623					Gas MCF ->	186,384	1,000,000	186,384	1,427,807	9.1394
40	SANFRD 3	140	531	1.5	34.0	43.1	12,935	Heavy Oil BBLS ->	748	6,400,027	4,785	21,181	3.9897
41			1,052					Gas MCF ->	15,684	1,000,000	15,684	120,120	11.4226
43	PUTNAM 1	250	17,869	9.6	64.5	49.6	9,607	Gas MCF ->	171,671	1,000,000	171,671	1,315,250	7.3605
45	PUTNAM 2	250	25,211	13.6	95.4	68.3	9,135	Gas MCF ->	230,307	1,000,000	230,307	1,764,409	6.9985
47	MANATE 1	821	224,316	38.9	94.4	73.2	10,019	Heavy Oil BBLS ->	348,986	6,399,999	2,233,508	11,261,577	5.0204
48			13,366					Gas MCF ->	147,821	1,000,000	147,821	1,174,215	8.7850
50	MANATE 2	821	168,863	30.5	95.8	66.7	10,578	Heavy Oil BBLS ->	276,178	6,400,001	1,767,541	8,912,097	5.2777
51			17,734					Gas MCF ->	206,225	1,000,000	206,225	1,637,992	9.2363
53	CUTLER 5	70	2,746	5.3	97.6	47.8	12,088	Gas MCF ->	33,190	1,000,000	33,190	254,271	9.2611
55	CUTLER 6	142	6,173	5.8	96.6	49.0	10,865	Gas MCF ->	67,073	1,000,000	67,073	513,887	8.3246
57	MARTIN 1	813		0.0	0.0		0						
59	MARTIN 2	804	187,675	48.3	96.3	72.4	10,426	Heavy Oil BBLS ->	299,939	6,400,000	1,919,608	9,726,803	5.1828
60			101,347					Gas MCF ->	1,093,783	1,000,000	1,093,783	8,378,980	8.2676

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Estimated For The Period of : Mar-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
62	MARTIN 3	465	251,923	72.8	85.9	82.8	7,149	Gas MCF ->	1,800,915	1,000,000	1,800,915	13,796,040	5.4763
64	MARTIN 4	466	229,422	66.2	76.3	74.9	7,006	Gas MCF ->	1,607,315	1,000,000	1,607,315	12,312,965	5.3669
66	MARTIN 8	1,099		0.0	0.0		0						
68	FM GT	624	1,807	0.4	89.1	86.3	12,432	Light Oil BBLS ->	3,854	5,830,042	22,468	217,400	12.0290
70	FL GT	768	138	0.1	91.7	90.3	13,998	Light Oil BBLS ->	320	5,830,053	1,866	12,800	9.2552
71			415					Gas MCF ->	5,878	1,000,000	5,878	45,018	10.8502
73	PE GT	384	17	0.0	88.3	93.1	14,388	Light Oil BBLS ->	41	5,835,381	238	1,700	9.9415
74			51					Gas MCF ->	748	1,000,000	748	5,688	11.0653
76	SJRPP 1O	130		0.0	0.0		0						
78	SJRPP 2O	130	87,134	90.1	93.6	99.8	9,498	Coal TONS ->	33,837	24,459,590	827,637	1,309,800	1.5032
80	SCHER #4	648	390,485	81.0	94.2	89.9	9,825	Coal TONS ->	219,219	17,499,997	3,836,327	6,102,900	1.5629
82	FMREP 1	1,451	865,240	80.1	94.7	89.6	6,882	Gas MCF ->	5,954,284	1,000,000	5,954,284	45,613,362	5.2718
84	SNREP4	938	561,668	80.5	95.7	90.0	6,901	Gas MCF ->	3,876,101	1,000,000	3,876,101	29,693,225	5.2866
86	SNREP5	938	539,723	77.3	95.2	88.3	6,818	Gas MCF ->	3,679,920	1,000,000	3,679,920	28,204,322	5.2257
88	MANATE 3	1,105		0.0	0.0		0						
90	FM SC	166	29,814	12.1	83.0	87.3	10,926	Gas MCF ->	325,758	1,000,000	325,758	2,497,287	8.3762

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Estimated For The Period of : Mar-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
92	MR SC	163		0.0	0.0		0						
93													
94	TOTAL	13,446	3,723,137	0.0			8,007				29,810,181	184,751,987	4.9623

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Estimated For The Period of : Apr-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	43,897	17.5	95.0	74.0	10,059	Heavy Oil BBLS ->	65,603	6,399,999	419,860	2,114,718	4.8175
2			5,827					Gas MCF ->	80,304	1,000,000	80,304	573,628	9.8436
3													
4	TRKY O 2	394		0.0	0.0		0						
5													
6	TRKY N 3	693	486,491	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,587,286	1,000,000	5,587,286	1,825,800	0.3753
7													
8	TRKY N 4	693	129,730	26.0	26.0	100.0	11,485	Nuclear Othr ->	1,489,945	1,000,000	1,489,945	402,400	0.3102
9													
10	FT LAUD4	425	275,838	90.1	94.7	95.2	7,620	Gas MCF ->	2,101,941	1,000,000	2,101,941	15,013,113	5.4427
11													
12	FT LAUD5	424	272,338	89.2	93.6	94.2	7,306	Gas MCF ->	1,989,709	1,000,000	1,989,709	14,211,548	5.2183
13													
14	PT EVER1	210	6,739	5.2	95.0	78.2	10,487	Heavy Oil BBLS ->	10,211	6,400,022	65,349	325,963	4.8368
15			1,078					Gas MCF ->	16,637	1,000,000	16,637	118,819	11.0191
16													
17	PT EVER2	210		0.0	0.0		0						
18													
19	PT EVER3	381	81,100	33.0	95.1	82.1	9,439	Heavy Oil BBLS ->	115,606	6,400,002	739,880	3,690,947	4.5511
20			9,307					Gas MCF ->	113,511	1,000,000	113,511	810,805	8.7115
21													
22	PT EVER4	388	96,424	39.1	95.6	87.3	9,295	Heavy Oil BBLS ->	135,952	6,400,001	870,090	4,340,473	4.5015
23			12,935					Gas MCF ->	146,376	1,000,000	146,376	1,045,478	8.0823
24													
25	RIV 3	273	81,718	50.5	68.8	84.6	10,384	Heavy Oil BBLS ->	130,929	6,400,000	837,944	4,192,141	5.1300
26			17,543					Gas MCF ->	192,778	1,000,000	192,778	1,376,909	7.8489
27													
28	RIV 4	279	11,614	6.5	92.8	79.4	10,615	Heavy Oil BBLS ->	17,912	6,399,982	114,635	573,559	4.9386
29			1,492					Gas MCF ->	24,480	1,000,000	24,480	174,904	11.7228
30													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
31	ST LUC 1	839	588,980	97.5	97.5	100.0	11,025	Nuclear Othr ->	6,493,449	1,000,000	6,493,449	1,838,000	0.3121
33	ST LUC 2	714	501,219	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,525,958	1,000,000	5,525,958	1,693,400	0.3379
35	CAP CN 1	394	54,654	22.0	91.0	78.0	9,760	Heavy Oil BBLS ->	79,669	6,400,003	509,883	2,549,729	4.6652
36			7,889					Gas MCF ->	100,518	1,000,000	100,518	717,932	9.1010
38	CAP CN 2	394	71,026	28.0	94.7	81.2	9,350	Heavy Oil BBLS ->	99,984	6,400,001	639,900	3,199,956	4.5053
39			8,515					Gas MCF ->	103,798	1,000,000	103,798	741,354	8.7060
41	SANFRD 3	138	6,542	8.2	92.6	72.7	9,816	Heavy Oil BBLS ->	9,029	6,400,013	57,787	255,779	3.9097
42			1,593					Gas MCF ->	22,071	1,000,000	22,071	157,659	9.8951
44	PUTNAM 1	239	15,911	9.2	71.5	63.1	8,887	Gas MCF ->	141,403	1,000,000	141,403	1,009,948	6.3474
46	PUTNAM 2	239	14,947	8.7	81.1	70.8	8,962	Gas MCF ->	133,961	1,000,000	133,961	956,820	6.4015
48	MANATE 1	795	259,918	48.9	94.4	69.1	10,048	Heavy Oil BBLS ->	406,388	6,400,000	2,600,885	12,934,639	4.9764
49			20,120					Gas MCF ->	213,016	1,000,000	213,016	1,586,034	7.8828
51	MANATE 2	795	233,104	43.9	95.8	71.1	10,104	Heavy Oil BBLS ->	366,020	6,399,999	2,342,527	11,649,782	4.9977
52			17,915					Gas MCF ->	193,879	1,000,000	193,879	1,442,489	8.0520
54	CUTLER 5	68	1,618	3.3	97.6	78.4	11,439	Gas MCF ->	18,512	1,000,000	18,512	132,189	8.1684
56	CUTLER 6	138	3,712	3.7	96.6	75.8	11,842	Gas MCF ->	43,959	1,000,000	43,959	313,955	8.4576
58	MARTIN 1	803	210,955	56.6	92.7	71.5	10,676	Heavy Oil BBLS ->	345,614	6,400,001	2,211,931	11,013,456	5.2208
59			116,018					Gas MCF ->	1,278,750	1,000,000	1,278,750	9,133,492	7.8725

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
61	MARTIN 2	796	249,123	69.0	96.3	71.6	10,475	Heavy Oil BBLS ->	400,352	6,400,000	2,562,255	12,757,820	5.1211
62			146,139					Gas MCF ->	1,578,200	1,000,000	1,578,200	11,272,314	7.7134
64	MARTIN 3	443	239,681	75.1	95.1	83.8	7,198	Gas MCF ->	1,725,171	1,000,000	1,725,171	12,322,022	5.1410
66	MARTIN 4	443	256,383	80.4	94.6	93.5	6,971	Gas MCF ->	1,787,353	1,000,000	1,787,353	12,766,208	4.9794
68	MARTIN 8	1,080		0.0	0.0		0						
70	FM GT	552	407	0.1	90.7	92.6	11,467	Light Oil BBLS ->	800	5,830,064	4,666	45,000	11.0592
72	FL GT	684	33	0.0	91.7	89.7	14,019	Light Oil BBLS ->	77	5,826,371	446	3,100	9.3939
73			99					Gas MCF ->	1,406	1,000,000	1,406	10,052	10.1435
75	PE GT	348	3	0.0	88.3	92.0	15,348	Light Oil BBLS ->	8	5,846,154	46	300	9.6774
76			9					Gas MCF ->	144	1,000,000	144	1,028	11.1729
78	SJRPP 1O	127	2,774	3.0	12.4	97.7	9,503	Coal TONS ->	1,078	24,456,207	26,359	41,600	1.4997
80	SJRPP 2O	127	81,754	89.4	93.6	99.7	9,321	Coal TONS ->	31,160	24,455,948	762,045	1,205,200	1.4742
82	SCHER #4	643	374,788	81.0	94.2	90.0	9,599	Coal TONS ->	205,578	17,500,005	3,597,607	5,727,600	1.5282
84	FMREP 1	1,423	868,202	84.7	94.7	94.0	6,932	Gas MCF ->	6,018,456	1,000,000	6,018,456	42,986,880	4.9513
86	SNREP4	891	523,430	81.6	95.7	93.9	6,935	Gas MCF ->	3,629,836	1,000,000	3,629,836	25,926,120	4.9531
88	SNREP5	940	538,392	79.5	95.2	91.0	6,880	Gas MCF ->	3,704,260	1,000,000	3,704,260	26,457,710	4.9142
90	MANATE 3	1,080		0.0	0.0		0						

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
92	FM SC	164	7,874	3.3	97.1	91.3	10,584	Gas MCF ->	83,341	1,000,000	83,341	595,232	7.5596
93													
94	MR SC	149		0.0	0.0		0						
95													
96	TOTAL	12,967	4,183,308	0.0			8,285				34,660,412	202,290,990	4.8357

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	85,254	31.4	95.0	78.4	9,864	Heavy Oil BBLS ->	126,916	6,400,001	812,261	4,074,848	4.7796
2			6,667					Gas MCF ->	94,417	1,000,000	94,417	651,052	9.7651
3													
4	TRKY O 2	394	42,935	16.2	60.5	78.5	9,838	Heavy Oil BBLS ->	63,651	6,399,996	407,364	2,043,619	4.7599
5			4,657					Gas MCF ->	60,840	1,000,000	60,840	419,528	9.0085
6													
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,883,100	0.3746
8													
9	TRKY N 4	693		0.0	0.0		0						
10													
11	FT LAUD4	425	293,519	92.8	94.7	98.0	7,534	Gas MCF ->	2,211,250	1,000,000	2,211,250	15,247,943	5.1949
12													
13	FT LAUD5	424	291,731	92.5	93.6	97.6	7,239	Gas MCF ->	2,111,935	1,000,000	2,111,935	14,563,020	4.9919
14													
15	PT EVER1	210	29,418	21.2	95.0	77.0	10,337	Heavy Oil BBLS ->	44,648	6,400,003	285,749	1,423,321	4.8383
16			3,713					Gas MCF ->	56,733	1,000,000	56,733	391,298	10.5375
17													
18	PT EVER2	210	8,135	5.8	39.6	76.1	10,219	Heavy Oil BBLS ->	11,874	6,400,017	75,994	378,486	4.6528
19			1,001					Gas MCF ->	17,359	1,000,000	17,359	119,675	11.9603
20													
21	PT EVER3	381	119,936	46.5	95.1	85.8	9,356	Heavy Oil BBLS ->	170,597	6,400,001	1,091,818	5,438,394	4.5344
22			11,784					Gas MCF ->	140,603	1,000,000	140,603	969,499	8.2270
23													
24	PT EVER4	388	133,516	51.9	95.6	90.8	9,256	Heavy Oil BBLS ->	188,118	6,399,999	1,203,956	5,996,932	4.4915
25			16,194					Gas MCF ->	181,726	1,000,000	181,726	1,253,140	7.7382
26													
27	RIV 3	273	31,517	17.8	93.8	74.7	10,979	Heavy Oil BBLS ->	50,555	6,400,002	323,550	1,614,565	5.1228
28			4,548					Gas MCF ->	72,406	1,000,000	72,406	499,305	10.9786
29													
30	RIV 4	279	131,735	77.7	92.8	87.4	10,021	Heavy Oil BBLS ->	203,577	6,400,000	1,302,891	6,501,823	4.9355
31			29,453					Gas MCF ->	312,297	1,000,000	312,297	2,153,505	7.3118
32													

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Estimated For The Period of : May-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	839	608,613	97.5	97.5	100.0	11,025	Nuclear Othr ->	6,709,895	1,000,000	6,709,895	1,895,600	0.3115
35	ST LUC 2	714	517,926	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,710,153	1,000,000	5,710,153	1,746,500	0.3372
37	CAP CN 1	394	102,911	38.6	94.2	83.5	9,568	Heavy Oil BBLS ->	149,488	6,399,998	956,723	4,766,552	4.6317
38			10,176					Gas MCF ->	125,256	1,000,000	125,256	863,755	8.4884
40	CAP CN 2	394	115,351	43.2	94.7	85.2	9,243	Heavy Oil BBLS ->	162,057	6,400,000	1,037,164	5,167,320	4.4796
41			11,346					Gas MCF ->	133,934	1,000,000	133,934	923,591	8.1405
43	SANFRD 3	138	19,650	22.7	95.8	78.1	9,449	Heavy Oil BBLS ->	26,947	6,399,992	172,463	762,888	3.8823
44			3,685					Gas MCF ->	48,022	1,000,000	48,022	331,135	8.9870
46	PUTNAM 1	239	227	26.3	95.3	81.9	8,617	Light Oil BBLS ->	320	5,829,169	1,867	14,600	6.4204
47			46,470					Gas MCF ->	400,521	1,000,000	400,521	2,763,336	5.9465
49	PUTNAM 2	239	198	21.1	32.3	75.6	9,087	Light Oil BBLS ->	294	5,830,048	1,715	13,400	6.7643
50			37,239					Gas MCF ->	338,490	1,000,000	338,490	2,335,542	6.2717
52	MANATE 1	795	388,647	69.2	94.4	75.8	9,994	Heavy Oil BBLS ->	605,117	6,400,000	3,872,748	19,223,518	4.9463
53			20,477					Gas MCF ->	215,860	1,000,000	215,860	1,586,315	7.7470
55	MANATE 2	795	391,124	70.3	95.8	73.8	10,061	Heavy Oil BBLS ->	613,027	6,400,001	3,923,376	19,474,809	4.9792
56			24,749					Gas MCF ->	260,671	1,000,000	260,671	1,916,548	7.7439
58	CUTLER 5	68	6,007	11.9	97.6	68.3	11,632	Gas MCF ->	69,874	1,000,000	69,874	481,853	8.0217
60	CUTLER 6	138	12,898	12.6	96.6	66.5	12,032	Gas MCF ->	155,185	1,000,000	155,185	1,070,121	8.2969
62	MARTIN 1	803	284,350	72.5	95.9	75.2	10,643	Heavy Oil BBLS ->	464,854	6,400,000	2,975,068	14,800,623	5.2051
63			148,985					Gas MCF ->	1,636,720	1,000,000	1,636,720	11,286,124	7.5754

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
65	MARTIN 2	796	282,105	74.5	96.3	77.3	10,449	Heavy Oil BBLS ->	452,427	6,399,999	2,895,530	14,404,851	5.1062
66			158,988					Gas MCF ->	1,713,451	1,000,000	1,713,451	11,815,236	7.4315
68	MARTIN 3	443	283,281	85.9	95.1	95.3	7,095	Gas MCF ->	2,009,774	1,000,000	2,009,774	13,858,590	4.8922
70	MARTIN 4	443	281,279	85.3	94.6	95.9	6,947	Gas MCF ->	1,953,976	1,000,000	1,953,976	13,473,850	4.7902
72	MARTIN 8	1,080	6,373	0.8	1.0	55.9	6,989	Gas MCF ->	44,541	1,000,000	44,541	307,113	4.8190
74	FM GT	552	11,337	2.8	98.4	58.4	14,049	Light Oil BBLS ->	27,320	5,829,997	159,273	1,526,300	13.4629
76	FL GT	684	231	1.5	91.7	35.8	18,205	Light Oil BBLS ->	687	5,830,180	4,007	27,400	11.8718
77			7,515					Gas MCF ->	137,003	1,000,000	137,003	945,079	12.5762
79	PE GT	348	42	2.6	88.3	62.5	18,390	Light Oil BBLS ->	126	5,830,159	735	5,300	12.6492
80			6,461					Gas MCF ->	118,860	1,000,000	118,860	819,870	12.6891
82	SJRPP 1O	127	84,005	88.9	93.1	99.7	9,460	Coal TONS ->	32,497	24,455,575	794,726	1,256,100	1.4953
84	SJRPP 2O	127	84,580	89.5	93.6	99.7	9,323	Coal TONS ->	32,242	24,455,591	788,505	1,246,300	1.4735
86	SCHER #4	643	385,660	80.6	94.2	90.0	9,599	Coal TONS ->	211,539	17,500,004	3,701,933	5,895,700	1.5287
88	FMREP 1	1,423	928,922	87.7	94.7	96.8	6,903	Gas MCF ->	6,412,056	1,000,000	6,412,056	44,214,983	4.7598
90	SNREP4	891	569,331	85.9	95.7	97.5	6,881	Gas MCF ->	3,917,689	1,000,000	3,917,689	27,062,594	4.7534
92	SNREP5	940	525,935	75.2	84.5	85.4	6,916	Gas MCF ->	3,637,421	1,000,000	3,637,421	25,230,458	4.7973
94	MANATE 3	1,080		0.0	0.0		0						

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
96	FM SC	164	4,591	18.3	97.1	90.5	10,526	Light Oil BBLS ->	7,933	5,829,987	46,249	443,200	9.6537
97			40,034					Gas MCF ->	423,463	1,000,000	423,463	2,973,136	7.4265
98													
99	MR SC	149		0.0	0.0		0						
100													
101	TOTAL	12,728	4,975,342	0.0			8,484				42,208,895	237,694,913	4.7775

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Estimated For The Period of : Jun-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	76,652	29.5	95.0	79.1	9,920	Heavy Oil BBLS ->	114,076	6,399,998	730,088	3,663,639	4.7796
2			6,993					Gas MCF ->	99,640	1,000,000	99,640	690,407	9.8724
3													
4	TRKY O 2	394	87,849	34.0	93.7	83.0	9,797	Heavy Oil BBLS ->	129,795	6,400,001	830,690	4,168,445	4.7450
5			8,509					Gas MCF ->	113,377	1,000,000	113,377	785,640	9.2327
6													
7	TRKY N 3	693	486,491	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,587,286	1,000,000	5,587,286	1,819,000	0.3739
8													
9	TRKY N 4	693	291,892	58.5	58.5	100.0	11,485	Nuclear Othr ->	3,352,356	1,000,000	3,352,356	1,112,300	0.3811
10													
11	FT LAUD4	425	280,398	91.6	94.7	96.7	7,589	Gas MCF ->	2,127,971	1,000,000	2,127,971	14,745,266	5.2587
12													
13	FT LAUD5	424	276,518	90.6	93.6	95.6	7,302	Gas MCF ->	2,019,036	1,000,000	2,019,036	13,990,390	5.0595
14													
15	PT EVER1	210	7,145	6.3	95.0	57.3	11,980	Heavy Oil BBLS ->	11,148	6,400,027	71,344	356,437	4.9888
16			2,452					Gas MCF ->	43,626	1,000,000	43,626	302,293	12.3284
17													
18	PT EVER2	210	13,931	11.2	94.4	66.7	10,702	Heavy Oil BBLS ->	20,565	6,400,010	131,613	657,461	4.7194
19			2,971					Gas MCF ->	49,273	1,000,000	49,273	341,452	11.4936
20													
21	PT EVER3	381	113,209	44.8	95.1	86.6	9,350	Heavy Oil BBLS ->	160,868	6,399,998	1,029,552	5,142,976	4.5429
22			9,593					Gas MCF ->	118,664	1,000,000	118,664	822,303	8.5718
23													
24	PT EVER4	388	121,428	48.3	95.6	90.4	9,265	Heavy Oil BBLS ->	171,072	6,399,999	1,094,862	5,469,161	4.5040
25			13,452					Gas MCF ->	154,837	1,000,000	154,837	1,072,847	7.9753
26													
27	RIV 3	273	118,574	75.5	93.8	83.8	10,418	Heavy Oil BBLS ->	190,462	6,400,000	1,218,956	6,098,281	5.1430
28			29,801					Gas MCF ->	326,869	1,000,000	326,869	2,264,781	7.5997
29													
30	RIV 4	279	11,036	6.9	92.8	61.2	11,936	Heavy Oil BBLS ->	17,374	6,400,010	111,193	556,323	5.0412
31			2,912					Gas MCF ->	55,279	1,000,000	55,279	381,907	13.1154
32													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	839	588,980	97.5	97.5	100.0	11,025	Nuclear Othr ->	6,493,449	1,000,000	6,493,449	1,831,100	0.3109
34													
35	ST LUC 2	714	501,219	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,525,958	1,000,000	5,525,958	1,687,100	0.3366
36													
37	CAP CN 1	394	104,587	39.8	94.2	85.4	9,555	Heavy Oil BBLS ->	151,702	6,400,001	970,892	4,845,939	4.6334
38			8,433					Gas MCF ->	109,019	1,000,000	109,019	755,445	8.9582
39													
40	CAP CN 2	394	114,209	43.3	94.7	86.9	9,228	Heavy Oil BBLS ->	160,209	6,400,000	1,025,340	5,117,709	4.4810
41			8,679					Gas MCF ->	108,634	1,000,000	108,634	752,728	8.6730
42													
43	SANFRD 3	138	9,808	12.9	95.8	68.2	10,141	Heavy Oil BBLS ->	13,640	6,399,981	87,298	385,811	3.9336
44			3,039					Gas MCF ->	42,991	1,000,000	42,991	297,270	9.7812
45													
46	PUTNAM 1	239	40,889	23.8	95.3	80.2	8,737	Gas MCF ->	357,243	1,000,000	357,243	2,475,441	6.0540
47													
48	PUTNAM 2	239	26,962	15.7	95.4	71.5	9,223	Gas MCF ->	248,657	1,000,000	248,657	1,723,053	6.3907
49													
50	MANATE 1	795	280,209	53.6	94.4	68.7	10,096	Heavy Oil BBLS ->	439,658	6,400,000	2,813,811	14,014,897	5.0016
51			26,503					Gas MCF ->	282,678	1,000,000	282,678	1,945,821	7.3419
52													
53	MANATE 2	795	216,201	41.4	95.8	67.4	10,139	Heavy Oil BBLS ->	340,331	6,400,000	2,178,120	10,848,613	5.0178
54			20,877					Gas MCF ->	225,691	1,000,000	225,691	1,553,605	7.4417
55													
56	CUTLER 5	68	1,667	3.4	97.6	52.1	14,134	Gas MCF ->	23,554	1,000,000	23,554	162,933	9.7770
57													
58	CUTLER 6	138	4,370	4.4	96.6	54.8	12,775	Gas MCF ->	55,831	1,000,000	55,831	386,663	8.8475
59													
60	MARTIN 1	803	201,749	55.2	95.9	68.4	10,742	Heavy Oil BBLS ->	332,245	6,400,001	2,126,365	10,624,421	5.2662
61			117,232					Gas MCF ->	1,300,243	1,000,000	1,300,243	8,950,056	7.6345
62													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MARTIN 2	796	227,731	63.6	96.3	70.2	10,494	Heavy Oil BBLS ->	366,401	6,400,000	2,344,966	11,716,696	5.1450
64			136,944					Gas MCF ->	1,481,961	1,000,000	1,481,961	10,200,981	7.4490
66	MARTIN 3	443	260,925	81.8	95.1	92.2	7,148	Gas MCF ->	1,865,036	1,000,000	1,865,036	12,837,834	4.9201
68	MARTIN 4	443	261,790	82.1	94.6	94.1	6,982	Gas MCF ->	1,827,710	1,000,000	1,827,710	12,580,939	4.8057
70	MARTIN 8	1,080	613,784	78.9	96.5	92.6	6,883	Gas MCF ->	4,224,857	1,000,000	4,224,857	29,122,886	4.7448
72	FM GT	552	1,569	0.4	98.4	93.6	11,467	Light Oil BBLS ->	3,085	5,830,033	17,987	172,200	10.9772
74	FL GT	684	154	0.1	91.7	92.1	14,018	Light Oil BBLS ->	357	5,830,020	2,082	14,200	9.2148
75			462					Gas MCF ->	6,558	1,000,000	6,558	45,410	9.8227
77	PE GT	348	23	0.0	88.3	94.3	15,348	Light Oil BBLS ->	58	5,832,180	337	2,400	10.5263
78			68					Gas MCF ->	1,062	1,000,000	1,062	7,376	10.7838
80	SJRPP 1O	127	81,960	89.6	93.1	99.7	9,459	Coal TONS ->	31,701	24,455,202	775,262	1,225,000	1.4946
82	SJRPP 2O	127	82,778	90.5	93.6	99.7	9,321	Coal TONS ->	31,551	24,455,171	771,585	1,219,200	1.4729
84	SCHER #4	643	375,494	81.1	94.2	89.8	9,599	Coal TONS ->	205,963	17,500,002	3,604,358	5,741,200	1.5290
86	FMREP 1	1,423	868,081	84.7	94.7	94.7	6,922	Gas MCF ->	6,008,992	1,000,000	6,008,992	41,637,774	4.7965
88	SNREP4	891	536,418	83.6	95.7	96.6	6,889	Gas MCF ->	3,695,358	1,000,000	3,695,358	25,606,027	4.7735
90	SNREP5	940	500,741	74.0	82.5	86.0	6,915	Gas MCF ->	3,462,763	1,000,000	3,462,763	23,994,326	4.7918
92	MANATE 3	1,080	597,986	76.9	96.5	91.0	6,820	Gas MCF ->	4,078,383	1,000,000	4,078,383	30,019,839	5.0202

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
94	FM SC	164	22,304	9.4	97.1	86.9	10,566	Gas	MCF ->	235,673	1,000,000	235,673	1,633,040	7.3217
95														
96	MR SC	149		0.0	0.0		0							
97														
98	TOTAL	20,210	8,806,630	0.0			8,817					77,647,212	340,577,244	3.8673

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	83,768	33.9	95.0	69.1	10,020	Heavy Oil BBLS ->	126,628	6,400,002	810,419	4,073,915	4.8634
2			15,698					Gas MCF ->	186,193	1,000,000	186,193	1,278,282	8.1431
3													
4	TRKY O 2	394	88,228	38.8	93.7	74.8	9,960	Heavy Oil BBLS ->	132,657	6,399,999	849,004	4,267,863	4.8373
5			25,603					Gas MCF ->	284,691	1,000,000	284,691	1,954,482	7.6339
6													
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,882,600	0.3745
8													
9	TRKY N 4	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,914,000	0.3807
10													
11	FT LAUD4	425	290,097	91.7	94.7	96.9	7,650	Gas MCF ->	2,219,162	1,000,000	2,219,162	15,235,007	5.2517
12													
13	FT LAUD5	424	286,572	90.8	93.6	95.9	7,361	Gas MCF ->	2,109,514	1,000,000	2,109,514	14,482,235	5.0536
14													
15	PT EVER1	210	16,157	14.8	95.0	45.8	11,516	Heavy Oil BBLS ->	25,694	6,400,007	164,441	824,202	5.1013
16			6,894					Gas MCF ->	101,018	1,000,000	101,018	693,425	10.0588
17													
18	PT EVER2	210	22,379	19.3	94.4	54.2	10,721	Heavy Oil BBLS ->	33,667	6,399,999	215,471	1,080,037	4.8262
19			7,835					Gas MCF ->	108,448	1,000,000	108,448	744,503	9.5018
20													
21	PT EVER3	381	118,641	49.5	95.1	84.4	9,440	Heavy Oil BBLS ->	170,451	6,400,001	1,090,883	5,467,959	4.6088
22			21,797					Gas MCF ->	234,791	1,000,000	234,791	1,611,960	7.3955
23													
24	PT EVER4	388	123,921	51.5	95.6	86.4	9,364	Heavy Oil BBLS ->	176,626	6,400,001	1,130,408	5,665,999	4.5723
25			24,861					Gas MCF ->	262,856	1,000,000	262,856	1,804,576	7.2586
26													
27	RIV 3	273	6,822	8.1	93.8	28.3	14,162	Heavy Oil BBLS ->	12,466	6,399,986	79,780	400,173	5.8663
28			9,699					Gas MCF ->	154,179	1,000,000	154,179	1,056,907	10.8971
29													
30	RIV 4	279	92,752	76.0	92.8	85.1	10,290	Heavy Oil BBLS ->	145,650	6,399,999	932,160	4,675,206	5.0405
31			64,976					Gas MCF ->	690,817	1,000,000	690,817	4,742,369	7.2986
32													

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Estimated For The Period of : Jul-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	839	608,613	97.5	97.5	100.0	11,025	Nuclear Othr ->	6,709,895	1,000,000	6,709,895	1,888,500	0.3103
34													
35	ST LUC 2	714	517,926	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,710,153	1,000,000	5,710,153	1,745,200	0.3370
36													
37	CAP CN 1	394	95,086	45.0	94.2	82.0	9,741	Heavy Oil BBLS ->	140,054	6,400,000	896,346	4,485,432	4.7172
38			36,958					Gas MCF ->	389,953	1,000,000	389,953	2,677,079	7.2435
39													
40	CAP CN 2	394	112,724	48.7	94.7	84.7	9,329	Heavy Oil BBLS ->	159,647	6,399,998	1,021,737	5,112,889	4.5358
41			30,166					Gas MCF ->	311,231	1,000,000	311,231	2,136,594	7.0829
42													
43	SANFRD 3	138	14,892	20.6	95.8	57.9	10,004	Heavy Oil BBLS ->	21,134	6,400,008	135,258	600,967	4.0355
44			6,300					Gas MCF ->	76,750	1,000,000	76,750	526,157	8.3524
45													
46	PUTNAM 1	239	55,368	31.1	95.3	74.4	9,021	Gas MCF ->	499,469	1,000,000	499,469	3,428,956	6.1930
47													
48	PUTNAM 2	239	39,618	22.3	95.4	64.4	9,641	Gas MCF ->	381,977	1,000,000	381,977	2,622,306	6.6189
49													
50	MANATE 1	795	264,285	50.6	94.4	57.1	10,201	Heavy Oil BBLS ->	418,583	6,400,000	2,678,930	13,385,088	5.0646
51			34,937					Gas MCF ->	373,463	1,000,000	373,463	2,546,542	7.2889
52													
53	MANATE 2	795	194,253	39.1	95.8	50.0	10,356	Heavy Oil BBLS ->	311,404	6,399,999	1,992,985	9,957,839	5.1262
54			37,203					Gas MCF ->	404,009	1,000,000	404,009	2,754,954	7.4052
55													
56	CUTLER 5	68	4,539	9.0	97.6	31.5	13,773	Gas MCF ->	62,510	1,000,000	62,510	428,650	9.4443
57													
58	CUTLER 6	138	9,482	9.2	96.6	32.0	13,238	Gas MCF ->	125,527	1,000,000	125,527	861,367	9.0838
59													
60	MARTIN 1	803	201,823	56.1	95.9	58.2	10,954	Heavy Oil BBLS ->	338,708	6,400,001	2,167,730	10,870,946	5.3864
61			133,307					Gas MCF ->	1,503,408	1,000,000	1,503,408	10,251,687	7.6903
62													

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Estimated For The Period of : Jul-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MARTIN 2	796	193,256	58.1	96.3	60.4	10,686	Heavy Oil BBLS ->	315,757	6,400,001	2,020,847	10,134,285	5.2440
64			151,050					Gas MCF ->	1,658,473	1,000,000	1,658,473	11,309,136	7.4870
66	MARTIN 3	443	275,210	83.5	95.1	91.7	7,178	Gas MCF ->	1,975,360	1,000,000	1,975,360	13,469,924	4.8944
68	MARTIN 4	443	270,613	82.1	94.6	92.9	7,022	Gas MCF ->	1,900,139	1,000,000	1,900,139	12,957,073	4.7880
70	MARTIN 8	1,080	632,468	78.7	96.6	89.5	6,994	Gas MCF ->	4,423,391	1,000,000	4,423,391	30,227,705	4.7793
72	FM GT	552	43,123	10.5	98.4	51.0	14,853	Light Oil BBLS ->	109,866	5,829,998	640,519	6,023,600	13.9686
74	FL GT	684	90	6.3	91.7	31.2	19,050	Light Oil BBLS ->	280	5,830,418	1,633	11,200	12.4444
75			32,099					Gas MCF ->	611,553	1,000,000	611,553	4,198,391	13.0796
77	PE GT	348	14	12.4	88.3	61.5	18,479	Light Oil BBLS ->	42	5,830,952	245	1,800	12.9496
78			31,579					Gas MCF ->	583,575	1,000,000	583,575	4,006,338	12.6866
80	SJRPP 1O	127	83,320	88.2	93.1	98.3	9,476	Coal TONS ->	32,291	24,451,621	789,572	1,250,100	1.5004
82	SJRPP 2O	127	83,984	88.9	93.6	98.4	9,338	Coal TONS ->	32,074	24,451,591	784,258	1,241,700	1.4785
84	SCHER #4	643	382,204	79.9	94.2	88.7	9,607	Coal TONS ->	209,828	17,500,006	3,671,998	5,849,300	1.5304
86	FMREP 1	1,423	888,753	83.9	94.7	94.4	6,944	Gas MCF ->	6,171,784	1,000,000	6,171,784	42,370,532	4.7674
88	SNREP4	891	546,934	82.5	95.7	93.4	6,961	Gas MCF ->	3,807,481	1,000,000	3,807,481	26,139,060	4.7792
90	SNREP5	940	550,733	78.7	95.2	89.2	6,920	Gas MCF ->	3,811,164	1,000,000	3,811,164	26,164,426	4.7508
92	MANATE 3	1,080	622,043	77.4	96.6	87.5	6,929	Gas MCF ->	4,310,272	1,000,000	4,310,272	31,553,520	5.0726

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
94	FM SC	164	66,871	27.4	97.1	77.3	10,552	Gas MCF ->	705,607	1,000,000	705,607	4,844,175	7.2440
95													
96	MR SC	149		0.0	0.0		0						
97													
98	TOTAL	20,210	9,563,937	0.0			9,042				86,480,500	381,889,116	3.9930

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Estimated For The Period of : Aug-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	84,901	32.6	95.0	69.5	9,996	Heavy Oil BBLS ->	128,039	6,400,002	819,447	4,122,997	4.8562
2			10,564					Gas MCF ->	134,784	1,000,000	134,784	931,197	8.8145
4	TRKY O 2	394	90,396	36.3	93.7	73.7	9,908	Heavy Oil BBLS ->	135,350	6,400,000	866,239	4,358,403	4.8214
5			16,024					Gas MCF ->	188,199	1,000,000	188,199	1,300,400	8.1151
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,879,100	0.3738
9	TRKY N 4	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,914,400	0.3808
11	FT LAUD4	425	291,303	92.1	94.7	97.3	7,620	Gas MCF ->	2,219,610	1,000,000	2,219,610	15,335,844	5.2646
13	FT LAUD5	424	287,557	91.2	93.6	96.2	7,337	Gas MCF ->	2,109,904	1,000,000	2,109,904	14,577,869	5.0696
15	PT EVER1	210	13,483	11.9	95.0	46.8	11,352	Heavy Oil BBLS ->	21,382	6,399,988	136,847	687,047	5.0958
16			5,164					Gas MCF ->	74,839	1,000,000	74,839	517,068	10.0125
18	PT EVER2	210	24,792	19.5	94.4	56.9	10,399	Heavy Oil BBLS ->	37,060	6,399,991	237,186	1,190,702	4.8027
19			5,677					Gas MCF ->	79,660	1,000,000	79,660	550,406	9.6952
21	PT EVER3	381	113,252	44.3	95.1	78.9	9,441	Heavy Oil BBLS ->	162,704	6,400,001	1,041,304	5,227,628	4.6159
22			12,304					Gas MCF ->	144,043	1,000,000	144,043	995,184	8.0882
24	PT EVER4	388	119,904	47.3	95.6	82.6	9,356	Heavy Oil BBLS ->	170,723	6,400,002	1,092,628	5,485,296	4.5747
25			16,674					Gas MCF ->	185,187	1,000,000	185,187	1,279,527	7.6738
27	RIV 3	273	103,341	76.1	93.8	85.0	10,549	Heavy Oil BBLS ->	166,881	6,400,001	1,068,038	5,365,403	5.1919
28			51,293					Gas MCF ->	563,121	1,000,000	563,121	3,890,487	7.5848
30	RIV 4	279	15,058	11.2	92.8	42.0	12,019	Heavy Oil BBLS ->	24,721	6,399,998	158,217	794,867	5.2787
31			8,262					Gas MCF ->	122,064	1,000,000	122,064	841,900	10.1900

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	839	608,613	97.5	97.5	100.0	11,025	Nuclear Othr ->	6,709,895	1,000,000	6,709,895	1,885,000	0.3097
34													
35	ST LUC 2	714	517,926	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,710,153	1,000,000	5,710,153	1,742,000	0.3363
36													
37	CAP CN 1	394	97,394	41.3	94.2	78.4	9,684	Heavy Oil BBLS ->	142,822	6,400,002	914,059	4,579,700	4.7022
38			23,641					Gas MCF ->	257,994	1,000,000	257,994	1,782,562	7.5403
39													
40	CAP CN 2	394	111,094	43.8	94.7	79.9	9,314	Heavy Oil BBLS ->	157,231	6,400,002	1,006,278	5,041,723	4.5383
41			17,324					Gas MCF ->	189,800	1,000,000	189,800	1,311,408	7.5698
42													
43	SANFRD 3	138	16,104	21.2	95.8	61.0	9,887	Heavy Oil BBLS ->	22,655	6,399,992	144,993	675,379	4.1939
44			5,626					Gas MCF ->	69,854	1,000,000	69,854	481,807	8.5647
45													
46	PUTNAM 1	239	118	28.8	95.3	72.0	8,989	Light Oil BBLS ->	173	5,831,116	1,008	7,900	6.7120
47			51,085					Gas MCF ->	459,275	1,000,000	459,275	3,173,433	6.2120
48													
49	PUTNAM 2	239	99	21.1	95.4	63.2	9,627	Light Oil BBLS ->	155	5,828,276	903	7,000	7.1066
50			37,400					Gas MCF ->	360,092	1,000,000	360,092	2,488,097	6.6526
51													
52	MANATE 1	795	267,281	50.3	94.4	63.1	10,158	Heavy Oil BBLS ->	421,638	6,400,000	2,698,484	13,501,967	5.0516
53			30,099					Gas MCF ->	322,307	1,000,000	322,307	2,211,888	7.3487
54													
55	MANATE 2	795	219,031	42.1	95.8	59.8	10,239	Heavy Oil BBLS ->	347,883	6,400,000	2,226,449	11,140,144	5.0861
56			29,986					Gas MCF ->	323,283	1,000,000	323,283	2,218,624	7.3988
57													
58	CUTLER 5	68	4,341	8.6	97.6	37.5	13,008	Gas MCF ->	56,460	1,000,000	56,460	389,700	8.9780
59													
60	CUTLER 6	138	8,940	8.7	96.6	36.9	12,865	Gas MCF ->	115,011	1,000,000	115,011	794,378	8.8858
61													
62	MARTIN 1	803	206,250	55.9	95.9	63.2	10,836	Heavy Oil BBLS ->	342,527	6,400,001	2,192,172	11,009,233	5.3378
63			127,511					Gas MCF ->	1,424,483	1,000,000	1,424,483	9,776,104	7.6669
64													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
65	MARTIN 2	796	225,171	63.6	96.3	66.0	10,567	Heavy Oil BBLS ->	364,458	6,400,000	2,332,531	11,714,050	5.2023
66			151,245					Gas MCF ->	1,645,071	1,000,000	1,645,071	11,289,942	7.4647
68	MARTIN 3	443	264,664	80.3	95.1	91.2	7,173	Gas MCF ->	1,898,477	1,000,000	1,898,477	13,029,043	4.9229
70	MARTIN 4	443	267,319	81.1	94.6	92.7	7,013	Gas MCF ->	1,874,741	1,000,000	1,874,741	12,866,133	4.8130
72	MARTIN 8	1,080	622,638	77.5	96.6	90.7	6,962	Gas MCF ->	4,334,974	1,000,000	4,334,974	29,821,233	4.7895
74	FM GT	552	31,778	7.7	98.4	52.2	14,704	Light Oil BBLS ->	80,146	5,830,001	467,251	4,354,500	13.7029
76	FL GT	684	170	4.6	91.7	31.9	18,897	Light Oil BBLS ->	525	5,830,160	3,062	20,900	12.2869
77			23,296					Gas MCF ->	440,364	1,000,000	440,364	3,042,564	13.0606
79	PE GT	348	31	8.8	88.3	61.7	18,462	Light Oil BBLS ->	93	5,828,294	540	3,900	12.7036
80			22,422					Gas MCF ->	413,976	1,000,000	413,976	2,860,254	12.7565
82	SJRPP 1O	127	82,923	87.8	93.1	98.5	9,473	Coal TONS ->	32,126	24,451,240	785,508	1,244,600	1.5009
84	SJRPP 2O	127	83,634	88.5	93.6	98.6	9,335	Coal TONS ->	31,929	24,451,183	780,690	1,237,000	1.4791
86	SCHER #4	643	383,088	80.1	94.2	89.1	9,606	Coal TONS ->	210,274	17,500,004	3,679,803	5,861,900	1.5302
88	FMREP 1	1,423	905,082	85.5	94.7	94.5	6,936	Gas MCF ->	6,277,353	1,000,000	6,277,353	43,371,700	4.7920
90	SNREP4	891	557,821	84.1	95.7	94.1	6,943	Gas MCF ->	3,873,163	1,000,000	3,873,163	26,760,586	4.7973
92	SNREP5	940	550,853	78.8	95.2	90.4	6,895	Gas MCF ->	3,798,026	1,000,000	3,798,026	26,241,494	4.7638
94	MANATE 3	1,080	610,432	76.0	96.6	88.5	6,903	Gas MCF ->	4,213,737	1,000,000	4,213,737	30,962,657	5.0723

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
96	FM SC	164	52,410	21.5	97.1	79.1	10,555	Gas MCF ->	553,206	1,000,000	553,206	3,825,806	7.2997
97													
98	MR SC	149		0.0	0.0		0						
99													
100	TOTAL	12,728	5,765,914	0.0			8,167				47,092,117	282,045,401	4.8916

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Estimated For The Period of : Sep-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	77,121	29.7	95.0	75.1	9,929	Heavy Oil BBLS ->	115,338	6,400,000	738,160	3,697,459	4.7943
2			7,101					Gas MCF ->	98,092	1,000,000	98,092	680,749	9.5871
3													
4	TRKY O 2	394	85,998	33.8	93.7	79.1	9,821	Heavy Oil BBLS ->	127,665	6,399,999	817,058	4,092,602	4.7590
5			9,811					Gas MCF ->	123,870	1,000,000	123,870	859,617	8.7622
6													
7	TRKY N 3	693	486,491	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,587,286	1,000,000	5,587,286	1,815,100	0.3731
8													
9	TRKY N 4	693	486,491	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,587,286	1,000,000	5,587,286	1,849,200	0.3801
10													
11	FT LAUD4	425	280,002	91.5	94.7	96.6	7,613	Gas MCF ->	2,131,626	1,000,000	2,131,626	14,793,006	5.2832
12													
13	FT LAUD5	424	211,775	69.4	71.8	95.5	7,326	Gas MCF ->	1,551,561	1,000,000	1,551,561	10,767,480	5.0844
14													
15	PT EVER1	210	18,575	15.0	95.0	61.3	10,928	Heavy Oil BBLS ->	28,804	6,399,997	184,347	920,966	4.9581
16			4,158					Gas MCF ->	64,076	1,000,000	64,076	444,616	10.6930
17													
18	PT EVER2	210	24,277	19.0	94.4	67.2	10,292	Heavy Oil BBLS ->	35,899	6,399,991	229,751	1,147,860	4.7282
19			4,474					Gas MCF ->	66,147	1,000,000	66,147	459,018	10.2594
20													
21	PT EVER3	381	106,356	43.0	95.1	84.0	9,393	Heavy Oil BBLS ->	151,787	6,399,999	971,439	4,853,304	4.5633
22			11,503					Gas MCF ->	135,577	1,000,000	135,577	940,831	8.1789
23													
24	PT EVER4	388	114,201	46.4	95.6	87.4	9,305	Heavy Oil BBLS ->	161,545	6,399,999	1,033,888	5,165,321	4.5230
25			15,421					Gas MCF ->	172,238	1,000,000	172,238	1,195,235	7.7507
26													
27	RIV 3	273	21,504	13.3	93.8	61.2	11,492	Heavy Oil BBLS ->	35,131	6,399,996	224,839	1,124,082	5.2274
28			4,652					Gas MCF ->	75,753	1,000,000	75,753	524,605	11.2770
29													
30	RIV 4	279	117,391	76.4	92.8	85.3	10,079	Heavy Oil BBLS ->	182,122	6,400,000	1,165,582	5,827,425	4.9641
31			36,124					Gas MCF ->	381,762	1,000,000	381,762	2,649,088	7.3333
32													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	839	588,980	97.5	97.5	100.0	11,025	Nuclear Othr ->	6,493,449	1,000,000	6,493,449	1,820,700	0.3091
35	ST LUC 2	714	501,219	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,525,958	1,000,000	5,525,958	1,682,600	0.3357
37	CAP CN 1	394	97,091	38.7	94.2	82.9	9,594	Heavy Oil BBLS ->	141,389	6,399,998	904,891	4,514,005	4.6492
38			12,559					Gas MCF ->	147,039	1,000,000	147,039	1,020,442	8.1253
40	CAP CN 2	394	106,709	41.8	94.7	84.5	9,265	Heavy Oil BBLS ->	150,209	6,400,002	961,335	4,795,649	4.4942
41			11,838					Gas MCF ->	137,015	1,000,000	137,015	950,911	8.0326
43	SANFRD 3	138	12,114	16.0	95.8	66.7	9,882	Heavy Oil BBLS ->	16,889	6,399,993	108,088	516,811	4.2663
44			3,751					Gas MCF ->	48,687	1,000,000	48,687	337,280	8.9922
46	PUTNAM 1	239	107	20.5	95.3	74.0	8,884	Light Oil BBLS ->	155	5,831,721	905	7,000	6.5482
47			35,250					Gas MCF ->	313,204	1,000,000	313,204	2,173,590	6.1663
49	PUTNAM 2	239	96	14.5	95.4	66.9	9,406	Light Oil BBLS ->	147	5,828,338	856	6,700	7.0157
50			24,909					Gas MCF ->	234,330	1,000,000	234,330	1,626,223	6.5285
52	MANATE 1	795	148,261	28.5	50.4	66.4	10,122	Heavy Oil BBLS ->	233,169	6,399,999	1,492,281	7,441,746	5.0193
53			15,066					Gas MCF ->	160,844	1,000,000	160,844	1,108,779	7.3593
55	MANATE 2	795	274,147	52.9	95.8	66.5	10,158	Heavy Oil BBLS ->	432,386	6,400,000	2,767,270	13,799,876	5.0337
56			28,695					Gas MCF ->	308,983	1,000,000	308,983	2,130,025	7.4229
58	CUTLER 5	68	3,100	6.3	97.6	46.5	12,944	Gas MCF ->	40,130	1,000,000	40,130	278,153	8.9721
60	CUTLER 6	138	6,460	6.5	96.6	45.7	12,648	Gas MCF ->	81,704	1,000,000	81,704	566,692	8.7725
62	MARTIN 1	803	242,752	66.2	95.9	68.6	10,751	Heavy Oil BBLS ->	400,466	6,400,000	2,562,982	12,782,701	5.2658
63			139,806					Gas MCF ->	1,549,882	1,000,000	1,549,882	10,684,701	7.6425

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Estimated For The Period of : Sep-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
65	MARTIN 2	796	240,392	67.8	96.3	70.4	10,516	Heavy Oil BBLS ->	387,614	6,400,001	2,480,733	12,372,473	5.1468
66			148,217					Gas MCF ->	1,606,010	1,000,000	1,606,010	11,071,591	7.4698
67													
68	MARTIN 3	443	251,851	79.0	95.1	91.7	7,152	Gas MCF ->	1,801,289	1,000,000	1,801,289	12,417,846	4.9306
69													
70	MARTIN 4	443	261,304	81.9	94.6	93.5	6,990	Gas MCF ->	1,826,622	1,000,000	1,826,622	12,592,448	4.8191
71													
72	MARTIN 8	1,080	606,458	78.0	96.5	90.5	6,919	Gas MCF ->	4,196,035	1,000,000	4,196,035	28,986,816	4.7800
73													
74	FM GT	552	12,222	3.1	98.4	54.9	14,325	Light Oil BBLS ->	30,030	5,830,003	175,075	1,627,800	13.3192
75													
76	FL GT	684	160	1.7	91.7	33.1	18,620	Light Oil BBLS ->	486	5,829,835	2,833	19,400	12.1554
77			8,288					Gas MCF ->	154,453	1,000,000	154,453	1,071,831	12.9328
78													
79	PE GT	348	24	3.1	88.3	61.8	18,440	Light Oil BBLS ->	71	5,833,098	412	3,000	12.7660
80			7,654					Gas MCF ->	141,170	1,000,000	141,170	979,723	12.7995
81													
82	SJRPP 1O	127	81,583	89.2	93.1	99.2	9,464	Coal TONS ->	31,578	24,450,890	772,115	1,223,800	1.5001
83													
84	SJRPP 2O	127	82,131	89.8	93.6	99.3	9,326	Coal TONS ->	31,326	24,450,824	765,947	1,214,000	1.4781
85													
86	SCHER #4	643	374,847	81.0	94.2	89.7	9,601	Coal TONS ->	205,651	17,500,001	3,598,900	5,733,100	1.5295
87													
88	FMREP 1	1,423	815,572	79.6	94.7	89.8	6,963	Gas MCF ->	5,679,020	1,000,000	5,679,020	39,411,284	4.8323
89													
90	SNREP4	891	533,946	83.2	95.7	94.8	6,920	Gas MCF ->	3,694,670	1,000,000	3,694,670	25,640,215	4.8020
91													
92	SNREP5	940	497,238	73.5	87.3	84.8	6,944	Gas MCF ->	3,453,028	1,000,000	3,453,028	23,968,988	4.8204
93													
94	MANATE 3	1,080	594,173	76.4	96.5	89.0	6,858	Gas MCF ->	4,074,851	1,000,000	4,074,851	30,130,105	5.0709
95													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type		(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
96	FM SC	164	37,461	15.9	97.1	84.8	10,565	Gas	MCF ->	395,775	1,000,000	395,775	2,754,195	7.3521
97														
98	MR SC	149		0.0	0.0		0							
99														
100	TOTAL	12,728	5,436,812	0.0			8,096					44,018,199	261,644,210	4.8125

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Estimated For The Period of : Oct-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	81,201	29.4	95.0	78.7	9,862	Heavy Oil BBLS ->	120,692	6,400,000	772,427	3,822,760	4.7078
2			5,032					Gas MCF ->	77,978	1,000,000	77,978	547,627	10.8833
3													
4	TRKY O 2	394	94,573	34.5	93.7	83.2	9,739	Heavy Oil BBLS ->	139,519	6,400,002	892,920	4,419,028	4.6726
5			6,444					Gas MCF ->	90,851	1,000,000	90,851	638,021	9.9005
6													
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,873,200	0.3726
8													
9	TRKY N 4	693	502,707	97.5	97.5	100.0	11,485	Nuclear Othr ->	5,773,532	1,000,000	5,773,532	1,907,300	0.3794
10													
11	FT LAUD4	425	288,467	91.2	94.7	96.3	7,597	Gas MCF ->	2,191,436	1,000,000	2,191,436	15,390,134	5.3351
12													
13	FT LAUD5	424		0.0	0.0		0						
14													
15	PT EVER1	210		0.0	0.0		0						
16													
17	PT EVER2	210	21,380	15.5	94.4	78.6	10,068	Heavy Oil BBLS ->	31,108	6,400,009	199,090	982,508	4.5955
18			2,795					Gas MCF ->	44,302	1,000,000	44,302	311,057	11.1295
19													
20	PT EVER3	381	111,255	42.3	95.1	86.3	9,331	Heavy Oil BBLS ->	157,965	6,400,000	1,010,978	4,988,989	4.4843
21			8,732					Gas MCF ->	108,573	1,000,000	108,573	762,445	8.7315
22													
23	PT EVER4	388	121,174	46.3	95.6	89.7	9,253	Heavy Oil BBLS ->	170,628	6,400,002	1,092,020	5,388,937	4.4473
24			12,523					Gas MCF ->	145,069	1,000,000	145,069	1,018,732	8.1346
25													
26	RIV 3	273	122,399	76.1	93.8	85.8	10,414	Heavy Oil BBLS ->	196,318	6,400,001	1,256,436	6,203,339	5.0681
27			32,228					Gas MCF ->	353,860	1,000,000	353,860	2,484,762	7.7099
28													
29	RIV 4	279	7,842	4.6	21.0	80.4	10,798	Heavy Oil BBLS ->	12,125	6,400,013	77,601	383,137	4.8859
30			1,604					Gas MCF ->	24,393	1,000,000	24,393	170,981	10.6603
31													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	ST LUC 1	839	39,265	6.3	6.3	100.0	11,025	Nuclear Othr ->	432,899	1,000,000	432,899	121,100	0.3084
34	ST LUC 2	714	517,926	97.5	97.5	100.0	11,025	Nuclear Othr ->	5,710,153	1,000,000	5,710,153	1,736,200	0.3352
36	CAP CN 1	394	102,967	38.2	94.2	85.8	9,550	Heavy Oil BBLS ->	149,318	6,399,998	955,635	4,709,420	4.5737
37			8,978					Gas MCF ->	113,415	1,000,000	113,415	796,468	8.8715
39	CAP CN 2	394	55,977	20.3	42.7	88.8	9,172	Heavy Oil BBLS ->	78,407	6,400,000	501,804	2,472,933	4.4178
40			3,610					Gas MCF ->	44,707	1,000,000	44,707	314,019	8.6988
42	SANFRD 3	138	12,408	14.7	95.8	76.1	9,628	Heavy Oil BBLS ->	17,041	6,399,995	109,060	530,833	4.2782
43			2,670					Gas MCF ->	36,099	1,000,000	36,099	253,033	9.4787
45	PUTNAM 1	239	29,323	16.5	69.1	70.5	8,735	Gas MCF ->	256,124	1,000,000	256,124	1,798,693	6.1341
47	PUTNAM 2	239	26,594	15.0	95.4	74.1	8,965	Gas MCF ->	238,425	1,000,000	238,425	1,674,389	6.2960
49	MANATE 1	795		0.0	0.0		0						
51	MANATE 2	795	281,519	51.3	95.8	72.4	10,099	Heavy Oil BBLS ->	441,920	6,400,000	2,828,288	13,985,642	4.9679
52			21,779					Gas MCF ->	234,589	1,000,000	234,589	1,637,365	7.5182
54	CUTLER 5	68	3,385	6.7	66.1	72.6	11,769	Gas MCF ->	39,840	1,000,000	39,840	279,473	8.2555
56	CUTLER 6	138	7,606	7.4	65.5	70.5	12,027	Gas MCF ->	91,478	1,000,000	91,478	642,281	8.4442
58	MARTIN 1	803	246,304	63.9	95.9	72.8	10,706	Heavy Oil BBLS ->	404,688	6,400,000	2,590,002	12,706,114	5.1587
59			135,345					Gas MCF ->	1,495,820	1,000,000	1,495,820	10,440,718	7.7141
61	MARTIN 2	796	258,311	68.6	96.3	71.8	10,491	Heavy Oil BBLS ->	415,848	6,400,000	2,661,425	13,056,532	5.0546
62			148,186					Gas MCF ->	1,603,122	1,000,000	1,603,122	11,189,628	7.5511

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
64	MARTIN 3	443	276,568	83.9	95.1	92.4	7,140	Gas MCF ->	1,974,812	1,000,000	1,974,812	13,783,910	4.9839
65													
66	MARTIN 4	443	271,201	82.3	94.6	93.7	6,975	Gas MCF ->	1,891,685	1,000,000	1,891,685	13,203,686	4.8686
67													
68	MARTIN 8	1,080	597,582	74.4	96.6	86.6	6,934	Gas MCF ->	4,143,722	1,000,000	4,143,722	28,955,431	4.8454
69													
70	FM GT	552	5,851	1.4	98.4	92.9	11,467	Light Oil BBLS ->	11,509	5,830,001	67,097	623,900	10.6624
71													
72	FL GT	684	597	0.5	91.7	91.4	14,019	Light Oil BBLS ->	1,385	5,829,975	8,072	55,200	9.2400
73			1,792					Gas MCF ->	25,426	1,000,000	25,426	178,603	9.9661
74													
75	PE GT	348	98	0.2	88.3	93.7	15,348	Light Oil BBLS ->	249	5,830,189	1,452	10,500	10.6925
76			295					Gas MCF ->	4,575	1,000,000	4,575	32,085	10.8947
77													
78	SJRPP 1O	127	83,225	88.1	93.1	99.7	9,461	Coal TONS ->	32,206	24,447,278	787,359	1,250,600	1.5027
79													
80	SJRPP 2O	127	83,858	88.8	93.6	99.7	9,323	Coal TONS ->	31,978	24,447,283	781,785	1,241,700	1.4807
81													
82	SCHER #4	643	383,379	80.2	94.2	90.0	9,599	Coal TONS ->	210,294	17,500,004	3,680,151	5,862,600	1.5292
83													
84	FMREP 1	1,423	898,351	84.9	94.7	94.7	6,922	Gas MCF ->	6,218,799	1,000,000	6,218,799	43,673,667	4.8615
85													
86	SNREP4	891	560,668	84.6	95.7	95.9	6,900	Gas MCF ->	3,868,365	1,000,000	3,868,365	27,166,864	4.8454
87													
88	SNREP5	940	561,150	80.2	95.2	92.6	6,848	Gas MCF ->	3,842,669	1,000,000	3,842,669	26,986,420	4.8091
89													
90	MANATE 3	1,080	628,143	78.2	96.6	89.9	6,834	Gas MCF ->	4,292,536	1,000,000	4,292,536	31,372,807	4.9945
91													
92	FM SC	164	35,868	14.7	97.1	92.3	10,581	Gas MCF ->	379,503	1,000,000	379,503	2,665,159	7.4305
93													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
94	MR SC	149		0.0	0.0		0						
95													
96	TOTAL	12,967	5,546,977	0.0			7,934				44,007,120	264,473,968	4.7679

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	397	97,820	39.1	95.0	87.9	8,981	Heavy Oil BBLS ->	132,249	6,399,999	846,396	4,157,381	4.2500
2			13,837					Gas MCF ->	156,399	1,000,000	156,399	1,121,742	8.1071
3													
4	TRKY O 2	397	50,311	22.6	93.7	69.6	9,689	Heavy Oil BBLS ->	70,112	6,400,003	448,718	2,204,009	4.3808
5			14,212					Gas MCF ->	176,425	1,000,000	176,425	1,265,331	8.9034
6													
7	TRKY N 3	717	503,332	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,652,901	1,000,000	5,652,901	1,830,700	0.3637
8													
9	TRKY N 4	717	503,332	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,652,901	1,000,000	5,652,901	1,864,600	0.3705
10													
11	FT LAUD4	443	280,419	87.9	94.7	92.8	7,691	Gas MCF ->	2,156,826	1,000,000	2,156,826	15,469,259	5.5165
12													
13	FT LAUD5	442		0.0	0.0		0						
14													
15	PT EVER1	211	0	0.1	15.8	22.0	20,771	Heavy Oil BBLS ->	0		0	0	
16			89					Gas MCF ->	1,843	1,000,000	1,843	13,228	14.9128
17													
18	PT EVER2	211	7,482	9.5	94.4	54.9	10,932	Heavy Oil BBLS ->	9,261	6,400,002	59,269	291,141	3.8913
19			6,898					Gas MCF ->	97,921	1,000,000	97,921	702,291	10.1818
20													
21	PT EVER3	383	71,045	29.4	95.1	77.4	10,285	Heavy Oil BBLS ->	109,047	6,400,001	697,900	3,428,524	4.8259
22			10,058					Gas MCF ->	136,217	1,000,000	136,217	976,916	9.7127
23													
24	PT EVER4	390	31,949	15.7	95.6	56.9	11,839	Heavy Oil BBLS ->	53,285	6,399,997	341,025	1,675,263	5.2435
25			12,142					Gas MCF ->	180,969	1,000,000	180,969	1,297,944	10.6895
26													
27	RIV 3	275	6,335	6.5	93.8	45.8	13,087	Heavy Oil BBLS ->	8,844	6,399,991	56,603	277,308	4.3775
28			6,573					Gas MCF ->	112,324	1,000,000	112,324	803,312	12.2221
29													
30	RIV 4	281	80,707	51.6	74.2	79.8	9,163	Heavy Oil BBLS ->	113,634	6,400,001	727,256	3,562,491	4.4141
31			23,639					Gas MCF ->	228,813	1,000,000	228,813	1,640,903	6.9416
32													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	853		0.0	0.0		0						
35	ST LUC 2	726	509,586	97.5	97.5	100.0	10,844	Nuclear Othr ->	5,525,890	1,000,000	5,525,890	1,677,100	0.3291
37	CAP CN 1	398	86,460	34.8	94.2	83.8	9,649	Heavy Oil BBLS ->	125,767	6,399,998	804,906	3,936,662	4.5531
38			13,296					Gas MCF ->	157,685	1,000,000	157,685	1,130,978	8.5060
40	CAP CN 2	398	4,628	2.1	15.8	74.4	10,103	Heavy Oil BBLS ->	6,799	6,400,026	43,513	212,844	4.5994
41			1,470					Gas MCF ->	18,084	1,000,000	18,084	129,673	8.8243
43	SANFRD 3	140	2,748	6.2	95.8	47.3	12,063	Heavy Oil BBLS ->	3,754	6,400,059	24,024	117,500	4.2765
44			3,524					Gas MCF ->	51,633	1,000,000	51,633	369,506	10.4848
46	PUTNAM 1	250	22,685	12.6	66.7	67.1	9,028	Gas MCF ->	204,799	1,000,000	204,799	1,468,893	6.4752
48	PUTNAM 2	250	18,947	10.5	95.4	67.0	9,262	Gas MCF ->	175,480	1,000,000	175,480	1,258,596	6.6428
50	MANATE 1	821		0.0	0.0		0						
52	MANATE 2	821	130,765	25.9	95.8	60.5	10,737	Heavy Oil BBLS ->	216,719	6,400,000	1,387,001	6,846,339	5.2356
53			22,509					Gas MCF ->	258,771	1,000,000	258,771	1,844,465	8.1942
55	CUTLER 5	70	317	0.6	32.5	37.4	14,766	Gas MCF ->	4,680	1,000,000	4,680	33,434	10.5470
57	CUTLER 6	142		0.0	0.0		0						
59	MARTIN 1	813	132,089	36.6	95.9	67.4	11,322	Heavy Oil BBLS ->	228,732	6,400,001	1,463,887	7,125,300	5.3943
60			82,128					Gas MCF ->	961,453	1,000,000	961,453	6,852,822	8.3441
62	MARTIN 2	804	69,398	19.7	96.3	56.7	11,631	Heavy Oil BBLS ->	122,946	6,400,002	786,854	3,829,937	5.5188
63			44,676					Gas MCF ->	539,884	1,000,000	539,884	3,848,063	8.6133

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
65	MARTIN 3	465	257,333	76.9	95.1	88.0	7,122	Gas MCF ->	1,832,779	1,000,000	1,832,779	13,063,338	5.0764
67	MARTIN 4	466	267,314	79.7	94.6	89.5	6,879	Gas MCF ->	1,838,750	1,000,000	1,838,750	13,105,812	4.9028
69	MARTIN 8	1,099	565,339	71.4	96.5	83.9	6,630	Gas MCF ->	3,748,032	1,000,000	3,748,032	26,717,823	4.7260
71	FM GT	624	927	0.2	98.4	92.3	12,165	Light Oil BBLS ->	1,935	5,830,034	11,278	104,900	11.3149
73	FL GT	768	68	0.0	91.7	89.6	13,996	Light Oil BBLS ->	158	5,828,590	922	6,300	9.2240
74			205					Gas MCF ->	2,903	1,000,000	2,903	20,864	10.1825
76	PE GT	384	6	0.0	88.3	92.0	14,388	Light Oil BBLS ->	14	5,841,727	81	600	10.1695
77			18					Gas MCF ->	256	1,000,000	256	1,826	10.3747
79	SJRPP 1O	130	82,353	88.0	93.1	99.6	9,638	Coal TONS ->	32,468	24,446,915	793,740	1,262,000	1.5324
81	SJRPP 2O	130	82,893	88.6	93.6	99.7	9,499	Coal TONS ->	32,208	24,446,956	787,385	1,251,900	1.5103
83	SCHER #4	648	371,448	79.6	94.2	89.7	9,825	Coal TONS ->	208,548	17,499,997	3,649,596	5,813,900	1.5652
85	FMREP 1	1,451	859,088	82.2	94.7	91.1	6,871	Gas MCF ->	5,903,126	1,000,000	5,903,126	42,338,451	4.9283
87	SNREP4	938	530,986	78.6	95.7	92.2	6,841	Gas MCF ->	3,632,691	1,000,000	3,632,691	26,054,445	4.9068
89	SNREP5	938	521,403	77.2	95.2	89.1	6,776	Gas MCF ->	3,533,084	1,000,000	3,533,084	25,340,065	4.8600
91	MANATE 3	1,105	587,122	73.8	96.5	87.3	6,699	Gas MCF ->	3,932,936	1,000,000	3,932,936	28,917,142	4.9252
93	FM SC	166	36,376	15.2	97.1	89.6	10,926	Gas MCF ->	397,459	1,000,000	397,459	2,850,663	7.8366

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
95	MR SC	163		0.0	0.0		0						
96													
97	TOTAL	13,446	4,686,392	0.0			7,649				35,847,824	219,957,877	4.6935

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	397	40,809	17.1	95.0	69.6	9,644	Heavy Oil BBLS ->	56,333	6,400,001	360,533	1,762,798	4.3196
2			9,829					Gas MCF ->	127,803	1,000,000	127,803	940,298	9.5670
3													
4	TRKY O 2	397	14,534	8.2	93.7	47.5	11,166	Heavy Oil BBLS ->	21,132	6,399,995	135,245	661,276	4.5499
5			9,602					Gas MCF ->	134,266	1,000,000	134,266	987,937	10.2888
6													
7	TRKY N 3	717	520,110	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,841,326	1,000,000	5,841,326	1,888,100	0.3630
8													
9	TRKY N 4	717	520,110	97.5	97.5	100.0	11,231	Nuclear Othr ->	5,841,326	1,000,000	5,841,326	1,923,200	0.3698
10													
11	FT LAUD4	443	281,031	85.3	94.7	90.0	7,833	Gas MCF ->	2,201,389	1,000,000	2,201,389	16,196,587	5.7633
12													
13	FT LAUD5	442	193,842	58.9	81.5	80.4	8,154	Gas MCF ->	1,580,633	1,000,000	1,580,633	11,629,412	5.9994
14													
15	PT EVER1	211	903	3.0	95.0	33.3	15,771	Heavy Oil BBLS ->	1,270	6,399,858	8,129	40,057	4.4360
16			3,809					Gas MCF ->	66,175	1,000,000	66,175	486,868	12.7837
17													
18	PT EVER2	211	1,749	3.7	94.4	38.4	13,753	Heavy Oil BBLS ->	2,256	6,400,027	14,436	71,156	4.0686
19			4,042					Gas MCF ->	65,207	1,000,000	65,207	479,709	11.8684
20													
21	PT EVER3	383	21,218	10.9	95.1	54.2	11,704	Heavy Oil BBLS ->	34,210	6,400,001	218,947	1,079,822	5.0892
22			9,792					Gas MCF ->	143,974	1,000,000	143,974	1,059,259	10.8181
23													
24	PT EVER4	390	8,038	5.2	95.6	35.0	14,371	Heavy Oil BBLS ->	14,571	6,400,015	93,256	459,948	5.7219
25			6,982					Gas MCF ->	122,610	1,000,000	122,610	902,086	12.9196
26													
27	RIV 3	275	121,180	69.2	93.8	77.4	8,534	Heavy Oil BBLS ->	159,741	6,400,001	1,022,343	4,949,020	4.0840
28			20,328					Gas MCF ->	185,270	1,000,000	185,270	1,362,932	6.7047
29													
30	RIV 4	281	1,003	2.3	92.8	27.9	18,703	Heavy Oil BBLS ->	1,600	6,400,000	10,240	49,524	4.9361
31			3,770					Gas MCF ->	79,045	1,000,000	79,045	579,798	15.3776
32													

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
33	ST LUC 1	853	598,803	94.4	94.4	100.0	10,844	Nuclear Othr ->	6,493,443	1,000,000	6,493,443	2,094,200	0.3497
35	ST LUC 2	726	526,572	97.5	97.5	100.0	10,844	Nuclear Othr ->	5,710,086	1,000,000	5,710,086	1,729,600	0.3285
37	CAP CN 1	398	38,180	18.3	94.2	73.1	10,188	Heavy Oil BBLS ->	56,111	6,399,996	359,108	1,739,853	4.5570
38			16,025					Gas MCF ->	193,132	1,000,000	193,132	1,421,014	8.8673
40	CAP CN 2	398	58,664	25.1	94.7	79.1	9,853	Heavy Oil BBLS ->	85,772	6,400,003	548,940	2,659,654	4.5337
41			15,617					Gas MCF ->	182,943	1,000,000	182,943	1,346,066	8.6192
43	SANFRD 3	140	464	2.8	95.8	32.1	15,427	Heavy Oil BBLS ->	683	6,399,620	4,374	21,438	4.6193
44			2,416					Gas MCF ->	40,054	1,000,000	40,054	293,870	12.1650
46	PUTNAM 1	250	11,093	6.0	95.3	58.1	9,417	Gas MCF ->	104,461	1,000,000	104,461	768,568	6.9286
48	PUTNAM 2	250	7,927	4.3	95.4	53.9	9,838	Gas MCF ->	77,982	1,000,000	77,982	573,753	7.2381
50	MANATE 1	821	75,267	14.0	94.4	58.9	10,638	Heavy Oil BBLS ->	123,031	6,400,000	787,398	3,859,093	5.1272
51			10,395					Gas MCF ->	123,879	1,000,000	123,879	905,713	8.7131
53	MANATE 2	821	70,585	16.7	95.8	40.6	11,259	Heavy Oil BBLS ->	121,086	6,400,000	774,949	3,797,999	5.3808
54			31,543					Gas MCF ->	374,943	1,000,000	374,943	2,741,175	8.6902
56	CUTLER 5	70	1,049	2.0	97.6	30.0	16,893	Gas MCF ->	17,714	1,000,000	17,714	129,831	12.3813
58	CUTLER 6	142	1,870	1.8	90.4	30.2	12,935	Gas MCF ->	24,192	1,000,000	24,192	177,784	9.5052
60	MARTIN 1	813	70,319	21.7	95.9	49.5	11,853	Heavy Oil BBLS ->	126,569	6,400,002	810,039	3,923,208	5.5792
61			60,879					Gas MCF ->	744,991	1,000,000	744,991	5,446,604	8.9466

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	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MARTIN 2	804	31,178	9.9	96.3	41.9	12,087	Heavy Oil BBLS ->	56,768	6,399,996	363,314	1,759,586	5.6436
64			28,340					Gas MCF ->	356,090	1,000,000	356,090	2,603,332	9.1862
66	MARTIN 3	465	221,233	63.9	95.1	85.1	7,167	Gas MCF ->	1,585,593	1,000,000	1,585,593	11,592,117	5.2398
68	MARTIN 4	466	240,959	69.5	94.6	85.4	6,935	Gas MCF ->	1,670,963	1,000,000	1,670,963	12,216,231	5.0698
70	MARTIN 8	1,099	533,795	65.3	96.6	76.2	6,780	Gas MCF ->	3,619,211	1,000,000	3,619,211	26,460,711	4.9571
72	FM GT	624	458	0.1	98.4	47.8	15,960	Light Oil BBLS ->	1,255	5,830,079	7,315	68,000	14.8374
74	FL GT	768	0	0.0	91.7		13,917	Light Oil BBLS ->	1	6,111,111	6	0	0.0000
75			1					Gas MCF ->	17	1,000,000	17	115	9.6210
77	PE GT	384	0	0.0	88.3		0	Light Oil BBLS ->	0		0	0	
78			0					Gas MCF ->	0	1,000,000	0	0	
80	SJRPP 1O	130	85,736	88.6	93.1	99.5	9,638	Coal TONS ->	33,801	24,446,534	826,322	1,314,300	1.5330
82	SJRPP 2O	130	86,351	89.3	93.6	99.6	9,499	Coal TONS ->	33,551	24,446,552	820,209	1,304,600	1.5108
84	SCHER #4	648	387,095	80.3	94.2	89.7	9,825	Coal TONS ->	217,325	17,500,001	3,803,191	6,058,600	1.5651
86	FMREP 1	1,451	824,412	76.4	94.7	85.8	6,923	Gas MCF ->	5,707,459	1,000,000	5,707,459	41,992,220	5.0936
88	SNREP4	938	502,208	72.0	95.7	86.5	6,938	Gas MCF ->	3,484,461	1,000,000	3,484,461	25,636,644	5.1048
90	SNREP5	938	481,117	68.9	95.2	80.2	6,946	Gas MCF ->	3,341,621	1,000,000	3,341,621	24,585,692	5.1101
92	MANATE 3	1,105	519,071	63.1	96.6	76.5	6,904	Gas MCF ->	3,583,525	1,000,000	3,583,525	26,613,919	5.1272

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Estimated For The Period of : Dec-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
94	FM SC	166	25,734	10.4	97.1	83.0	10,926	Gas MCF ->	281,173	1,000,000	281,173	2,068,701	8.0389
95													
96	MR SC	163		8.4	0.0	98.6	8,766	Gas MCF ->	9	1,000,000	9	402,443	6.6742
97													
98	TOTAL	13,446	4,308,614	0.0	0.0		0						

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Estimated For The Period of : Jan-05 Thru Dec-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	395	944,691	31.2	95.0	78.3	9,563	Heavy Oil BBLS ->	1,356,408	6,400,000	8,681,008	43,569,308	4.6120
2			133,990					Gas MCF ->	1,634,697	1,000,000	1,634,697	11,903,551	8.8839
3													
4	TRKY O 2	395	637,015	21.8	74.4	74.0	9,861	Heavy Oil BBLS ->	934,846	6,400,000	5,983,013	29,981,533	4.7066
5			118,720					Gas MCF ->	1,468,968	1,000,000	1,468,968	10,521,345	8.8623
6			0						0		0	0	0.0000
7													
8	TRKY N 3	703	6,003,740	97.5	97.5	100.0	11,378	Nuclear Othr ->	68,308,914	1,000,000	68,308,914	22,258,300	0.3707
9													
10	TRKY N 4	703	4,949,673	80.4	80.1	100.0	11,355	Nuclear Othr ->	56,203,111	1,000,000	56,203,111	17,484,200	0.3532
11													
12													
13	FT LAUD4	433	3,278,217	86.5	91.6	94.7	7,654	Gas MCF ->	25,091,063	1,000,000	25,091,063	180,354,760	5.5016
14													
15	FT LAUD5	432	2,622,653	69.4	75.2	92.2	7,548	Gas MCF ->	19,794,804	1,000,000	19,794,804	143,207,078	5.4604
16			0						0		0	0	0.0000
17													
18	PT EVER1	210	114,261	8.8	80.5	55.1	11,216	Heavy Oil BBLS ->	171,361	6,400,004	1,096,709	5,500,939	4.8143
19			47,754					Gas MCF ->	720,505	1,000,000	720,505	5,254,692	11.0037
20													
21													
22	PT EVER2	210	141,704	10.2	73.2	59.6	10,573	Heavy Oil BBLS ->	203,462	6,400,000	1,302,158	6,515,866	4.5982
23			46,690					Gas MCF ->	689,644	1,000,000	689,644	4,965,291	10.6345
24			0						0		0	0	0.0000
25													
26	PT EVER3	382	944,161	32.2	89.6	79.1	9,693	Heavy Oil BBLS ->	1,372,024	6,400,001	8,780,957	43,835,161	4.6428
27			132,410					Gas MCF ->	1,654,313	1,000,000	1,654,313	11,871,800	8.9659
28													
29	PT EVER4	389	958,311	33.0	95.6	79.0	9,755	Heavy Oil BBLS ->	1,390,025	6,400,000	8,896,159	44,467,496	4.6402
30			166,854					Gas MCF ->	2,080,294	1,000,000	2,080,294	14,958,709	8.9651
31													

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Estimated For The Period of : Jan-05 Thru Dec-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
32	RIV 3	274	746,428	39.3	86.6	77.5	10,055	Heavy Oil BBLS ->	1,126,086	6,400,000	7,206,949	35,944,867	4.8156
33			196,387					Gas MCF ->	2,273,038	1,000,000	2,273,038	16,102,041	8.1992
34													
35	RIV 4	280	733,841	38.9	85.2	79.1	9,876	Heavy Oil BBLS ->	1,089,721	6,400,000	6,974,211	35,022,020	4.7724
36			219,637					Gas MCF ->	2,442,113	1,000,000	2,442,113	17,392,099	7.9186
37													
38	ST LUC 1	845	6,027,256	81.4	81.5	100.0	10,953	Nuclear Othr ->	66,016,701	1,000,000	66,016,701	18,908,000	0.3137
39													
40													
41	ST LUC 2	719	6,140,275	97.5	97.5	100.0	10,949	Nuclear Othr ->	67,232,131	1,000,000	67,232,131	20,538,000	0.3345
42													
43	CAP CN 1	396	816,954	28.2	79.7	80.6	9,707	Heavy Oil BBLS ->	1,192,249	6,399,999	7,630,392	37,959,749	4.6465
44			161,346					Gas MCF ->	1,865,797	1,000,000	1,865,797	13,284,562	8.2336
45													
46													
47	CAP CN 2	396	971,820	32.7	83.8	82.6	9,439	Heavy Oil BBLS ->	1,383,086	6,400,001	8,851,752	44,282,144	4.5566
48			160,031					Gas MCF ->	1,832,302	1,000,000	1,832,302	13,274,736	8.2951
49													
50	SANFRD 3	139	102,095	11.8	90.3	61.2	10,260	Heavy Oil BBLS ->	142,006	6,399,993	908,836	4,155,953	4.0707
51			41,131					Gas MCF ->	560,619	1,000,000	560,619	4,015,473	9.7627
52													
53	PUTNAM 1	244	373,604	17.5	86.1	70.0	8,954	Gas MCF ->	3,345,480	1,000,000	3,345,480	23,785,425	6.3665
54			482					Light Oil BBLS ->	692	5,830,202	4,035	31,500	6.5353
55													
56	PUTNAM 2	244	298,778	14.0	88.9	66.6	9,350	Gas MCF ->	2,793,707	1,000,000	2,793,707	19,938,824	6.6735
57			400					Light Oil BBLS ->	607	5,829,216	3,540	27,600	6.9086
58													
59	MANATE 1	806	2,160,386	33.5	75.0	65.2	10,128	Heavy Oil BBLS ->	3,395,987	6,400,000	21,734,317	108,723,264	5.0326
60			206,222					Gas MCF ->	2,234,592	1,000,000	2,234,592	16,253,190	7.8814
61			0						0		0	0	0.0000
62													

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Estimated For The Period of : Jan-05 Thru Dec-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
63	MANATE 2	806	2,327,296	37.2	95.8	61.9	10,324	Heavy Oil BBLS ->	3,715,818	6,400,000	23,781,237	118,574,513	5.0949
64			298,644					Gas MCF ->	3,330,129	1,000,000	3,330,129	24,232,837	8.1143
65													
66	CUTLER 5	69	33,836	5.6	89.6	45.3	12,667	Gas MCF ->	428,586	1,000,000	428,586	3,054,599	9.0277
67													
68	CUTLER 6	140	69,916	5.7	85.5	44.5	12,299	Gas MCF ->	859,865	1,000,000	859,865	6,105,760	8.7331
69													
70													
71	MARTIN 1	807	1,835,330	41.5	79.4	65.7	10,881	Heavy Oil BBLS ->	3,055,609	6,400,001	19,555,899	97,198,150	5.2959
72			1,099,661					Gas MCF ->	12,379,303	1,000,000	12,379,303	86,593,195	7.8745
73			0						0		0	0	0.0000
74													
75	MARTIN 2	799	2,178,526	50.4	96.3	67.5	10,581	Heavy Oil BBLS ->	3,528,573	6,400,000	22,582,866	112,830,534	5.1792
76			1,351,815					Gas MCF ->	14,773,350	1,000,000	14,773,350	104,648,517	7.7413
77													
78	MARTIN 3	452	3,092,943	78.1	94.3	89.1	7,149	Gas MCF ->	22,111,331	1,000,000	22,111,331	158,573,525	5.1269
79													
80	MARTIN 4	453	3,112,541	78.5	92.2	89.8	6,961	Gas MCF ->	21,667,249	1,000,000	21,667,249	155,280,177	4.9889
81													
82	MARTIN 8	1,088	4,178,436	43.8	98.0	86.7	6,877	Gas MCF ->	28,734,764	1,000,000	28,734,764	200,599,719	4.8001
83													
84	FM GT	582	128,859	2.5	96.4	52.1	14,609	Light Oil BBLS ->	322,897	5,830,001	1,882,488	17,754,000	13.7778
85													
86	FL GT	719	1,713	1.4	91.7	31.7	18,639	Light Oil BBLS ->	4,493	5,830,017	26,197	179,200	10.4593
87			88,294					Gas MCF ->	1,651,435	1,000,000	1,651,435	11,630,826	13.1728
88													
89	PE GT	363	411	2.6	88.3	58.9	18,311	Light Oil BBLS ->	1,144	5,831,307	6,668	48,200	11.7332
90			81,838					Gas MCF ->	1,499,387	1,000,000	1,499,387	10,552,551	12.8945
91													
92	SJRPP 1O	128	824,409	73.4	78.1	99.2	9,534	Coal TONS ->	321,432	24,452,470	7,859,801	12,480,800	1.5139
93													
94													

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Estimated For The Period of : Jan-05 Thru Dec-05

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
95	SJRPP 2O	128	1,001,597	89.2	93.6	99.4	9,399	Coal TONS ->	384,968	24,453,397	9,413,770	14,939,400	1.4916
97	SCHER #4	645	4,536,350	80.3	94.2	89.7	9,694	Coal TONS ->	2,512,876	17,500,002	43,975,336	69,980,300	1.5427
99	FMREP 1	1,435	10,267,693	81.7	93.2	91.4	6,918	Gas MCF ->	71,030,742	1,000,000	71,030,742	510,893,211	4.9757
101	SNREP4	911	6,445,312	80.8	95.2	92.5	6,914	Gas MCF ->	44,561,358	1,000,000	44,561,358	320,980,717	4.9801
103	SNREP5	939	6,257,420	76.1	92.6	87.7	6,875	Gas MCF ->	43,021,216	1,000,000	43,021,216	310,015,412	4.9544
105	MANATE 3	1,090	4,158,969	43.6	98.0	86.8	6,849	Gas MCF ->	28,486,240	1,000,000	28,486,240	209,569,990	5.0390
107	FM SC	165	424,142	29.7	95.5	100.0	10,695	Gas MCF ->	4,539,180	1,000,000	4,539,180	32,686,225	7.7064
108			4,591					Light Oil BBLS ->	7,933	5,829,987	46,249	443,200	9.6537
110	MR SC	155	0	0.0	0.0	0.0	0		0		0	0	0.0000
112	TOTAL	20,466	94,398,455				8,946				844,501,469	3,616,135,032	3.8307

Company: Florida Power & Light

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : January 2005 thru June 2005

			January 2005	February 2005	March 2005	April 2005	May 2005	June 2005
	Heavy Oil							
1	Purchases:							
2	Units	(BBLS)	902,834	1,139,451	1,744,609	2,274,241	3,406,900	2,705,906
3	Unit Cost	($/BBLS)	32.9684	32.3638	31.6472	31.4338	31.8237	32.1264
4	Amount	($)	29,765,000	36,877,000	55,212,000	71,488,000	108,420,000	86,931,000
5								
6	Burned:							
7	Units	(BBLS)	1,006,963	1,144,807	1,595,357	2,183,270	3,333,847	2,619,546
8	Unit Cost	($/BBLS)	32.8590	32.7204	32.3299	31.8783	31.8169	31.9394
9	Amount	($)	33,087,835	37,458,500	51,577,745	69,599,003	106,072,579	83,666,800
10								
11	Ending Inventory:							
12	Units	(BBLS)	2,654,374	2,649,019	2,798,270	2,889,242	2,962,292	3,048,656
13	Unit Cost	($/BBLS)	32.8081	32.8066	32.1520	31.7834	31.7623	31.8900
14	Amount	($)	87,084,957	86,375,410	89,969,945	91,829,814	94,089,135	97,221,672
15								
16	Light Oil							
17								
18								
19	Purchases:							
20	Units	(BBLS)	31,377	14,249	41	54,662	35,992	3,143
21	Unit Cost	($/BBLS)	57.9087	57.8286	48.7805	55.4864	53.9009	52.8158
22	Amount	($)	1,817,000	824,000	2,000	3,033,000	1,940,000	166,000
23								
24	Burned:							
25	Units	(BBLS)	39,562	14,249	4,215	885	36,680	3,500
26	Unit Cost	($/BBLS)	56.0356	56.3794	55.0225	54.6102	55.3476	53.9771
27	Amount	($)	2,216,880	803,350	231,920	48,330	2,030,150	188,920
28								
29	Ending Inventory:							
30	Units	(BBLS)	527,123	527,121	522,947	576,724	576,037	575,680
31	Unit Cost	($/BBLS)	45.8728	45.9121	45.8385	46.7394	46.6396	46.6298
32	Amount	($)	24,180,607	24,201,214	23,971,090	26,955,739	26,866,135	26,843,821
33								
34	Coal - SJRPP							
35								
36								
37	Purchases:							
38	Units	(Tons)	66,179	58,618	33,837	32,238	64,740	67,775
39	Unit Cost	($/Tons)	38.5168	38.6035	38.5081	38.6500	38.6314	38.6278
40	Amount	($)	2,549,000	2,257,000	1,303,000	1,246,000	2,501,000	2,618,000
41								
42	Burned:							
43	Units	(Tons)	66,179	58,618	33,837	32,238	64,740	63,253
44	Unit Cost	($/Tons)	39.3267	38.8638	38.7088	38.6772	38.6535	38.6407
45	Amount	($)	2,602,599	2,278,117	1,309,788	1,246,875	2,502,429	2,444,138
46								
47	Ending Inventory:							
48	Units	(Tons)	45,217	45,217	45,217	45,217	45,218	49,740
49	Unit Cost	($/Tons)	39.5794	39.1173	38.9630	38.9374	38.9130	38.8770
50	Amount	($)	1,789,663	1,768,768	1,761,788	1,760,632	1,759,587	1,933,740
51								
52	Coal - SCHERER							
53								
54								
55	Purchases:							
56	Units	(MBTU)	3,732,610	3,418,870	3,836,333	3,597,615	3,701,933	3,884,905
57	Unit Cost	($/MBTU)	1.5930	1.5929	1.5929	1.5930	1.5930	1.5931
58	Amount	($)	5,946,000	5,446,000	6,111,000	5,731,000	5,897,000	6,205,000
59								
60	Burned:							
61	Units	(MBTU)	3,732,610	3,418,870	3,836,333	3,597,615	3,701,933	3,604,353
62	Unit Cost	($/MBTU)	1.5819	1.5879	1.5908	1.5920	1.5926	1.5929
63	Amount	($)	5,904,641	5,428,886	6,102,949	5,727,571	5,895,705	5,741,201
64								
65	Ending Inventory:							
66	Units	(MBTU)	2,905,560	2,905,560	2,905,560	2,905,525	2,905,525	3,196,078
67	Unit Cost	($/MBTU)	1.5819	1.5879	1.5908	1.5921	1.5926	1.5929
68	Amount	($)	4,596,301	4,613,779	4,622,231	4,625,772	4,627,375	5,090,902
69								
70	Gas							
71								
72								
73	Burned:							
74	Units	(MCF)	25,351,870	22,688,758	23,805,438	25,443,770	29,012,332	34,751,459
75	Unit Cost	($/MCF)	7.8131	7.8038	7.6655	7.1473	6.9118	6.9662
76	Amount	($)	198,076,044	177,057,456	182,480,002	181,854,572	200,527,134	242,086,322
77								
78	Nuclear							
79								
80								
81	Burned:							
82	Units	(MBTU)	24,102,626	21,770,150	24,102,626	19,096,638	18,193,580	20,959,049
83	Unit Cost	($/MBTU)	0.2977	0.2971	0.2965	0.3016	0.3037	0.3077
84	Amount	($)	7,174,687	6,468,144	7,147,577	5,759,496	5,525,202	6,449,491

Company: Florida Power & Light

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : July 2005 thru December 2005

			July 2005	August 2005	September 2005	October 2005	November 2005	December 2005	Total
	Heavy Oil								
1	Purchases:								
2	Units	(BBLS)	2,610,470	2,646,073	2,450,414	2,335,576	1,001,149	808,825	24,026,448
3	Unit Cost	($/BBLS)	32.2329	32.2240	31.7799	31.0086	30.6068	29.9546	31.7679
4	Amount	($)	84,143,000	85,267,000	77,874,000	72,423,000	30,642,000	24,228,000	763,270,000
5									
6	Burned:								
7	Units	(BBLS)	2,529,125	2,646,073	2,600,414	2,335,576	1,201,149	861,132	24,057,259
8	Unit Cost	($/BBLS)	32.0280	32.0832	31.9381	31.5339	31.3572	31.1618	31.9472
9	Amount	($)	81,002,720	84,894,368	83,052,400	73,649,915	37,664,690	26,834,391	768,560,945
10									
11	Ending Inventory:								
12	Units	(BBLS)	3,129,999	3,130,000	2,979,999	2,980,000	2,780,000	2,727,693	2,727,693
13	Unit Cost	($/BBLS)	32.0175	32.0912	31.9438	31.5473	31.3251	31.0340	31.0340
14	Amount	($)	100,214,601	100,445,520	95,192,516	94,011,047	87,083,662	84,651,330	84,651,330
15									
16	Light Oil								
17									
18									
19	Purchases:								
20	Units	(BBLS)	109,908	80,567	30,403	249	14	0	360,605
21	Unit Cost	($/BBLS)	52.9989	53.0366	53.1855	40.1606	71.4286	0.0000	54.0980
22	Amount	($)	5,825,000	4,273,000	1,617,000	10,000	1,000	0	19,508,000
23									
24	Burned:								
25	Units	(BBLS)	110,188	81,092	30,889	13,143	2,107	1,255	337,765
26	Unit Cost	($/BBLS)	54.7840	54.1888	53.8664	52.4637	53.0375	54.1912	54.7231
27	Amount	($)	6,036,540	4,394,280	1,663,880	689,530	111,750	68,010	18,483,540
28									
29	Ending Inventory:								
30	Units	(BBLS)	575,400	574,875	574,389	561,495	559,403	558,147	558,147
31	Unit Cost	($/BBLS)	46.2846	46.1153	46.0738	45.9219	45.8949	45.8762	45.8762
32	Amount	($)	26,632,187	26,510,551	26,464,302	25,784,900	25,673,722	25,605,670	25,605,670
33									
34	Coal - SJRPP								
35									
36									
37	Purchases:								
38	Units	(Tons)	64,366	64,055	62,905	59,664	64,676	67,352	706,405
39	Unit Cost	($/Tons)	38.7782	38.7636	38.7569	38.9012	38.9016	38.8853	38.7129
40	Amount	($)	2,496,000	2,483,000	2,438,000	2,321,000	2,516,000	2,619,000	27,347,000
41									
42	Burned:								
43	Units	(Tons)	64,366	64,055	62,905	64,186	64,676	67,352	706,405
44	Unit Cost	($/Tons)	38.7119	38.7424	38.7531	38.8310	38.8689	38.8823	38.8165
45	Amount	($)	2,491,730	2,481,644	2,437,766	2,492,407	2,513,888	2,618,801	27,420,182
46									
47	Ending Inventory:								
48	Units	(Tons)	49,740	49,740	49,740	45,218	45,217	45,217	45,217
49	Unit Cost	($/Tons)	38.9540	38.9851	38.9963	39.1050	39.1445	39.1582	39.1582
50	Amount	($)	1,937,571	1,939,121	1,939,678	1,768,251	1,769,999	1,770,617	1,770,617
51									
52	Coal - SCHERER								
53									
54									
55	Purchases:								
56	Units	(MBTU)	3,671,990	3,679,795	3,598,893	3,389,593	3,649,590	3,803,188	43,975,313
57	Unit Cost	($/MBTU)	1.5931	1.5930	1.5930	1.5931	1.5931	1.5931	1.5930
58	Amount	($)	5,850,000	5,862,000	5,733,000	5,400,000	5,814,000	6,059,000	70,054,000
59									
60	Burned:								
61	Units	(MBTU)	3,671,990	3,679,795	3,598,893	3,660,145	3,649,590	3,803,188	43,975,313
62	Unit Cost	($/MBTU)	1.5930	1.5930	1.5930	1.5930	1.5930	1.5930	1.5914
63	Amount	($)	5,849,304	5,861,906	5,733,104	5,862,574	5,813,918	6,058,608	69,980,367
64									
65	Ending Inventory:								
66	Units	(MBTU)	3,196,078	3,196,078	3,196,078	2,905,525	2,905,560	2,905,560	2,905,560
67	Unit Cost	($/MBTU)	1.5930	1.5930	1.5930	1.5930	1.5930	1.5930	1.5930
68	Amount	($)	5,091,218	5,091,365	5,091,433	4,628,607	4,628,622	4,628,629	4,628,629
69									
70	Gas								
71									
72									
73	Burned:								
74	Units	(MCF)	40,438,751	38,723,054	34,845,441	33,832,175	30,442,219	30,220,774	369,556,040
75	Unit Cost	($/MCF)	6.9013	6.9447	6.9799	7.0456	7.1821	7.3525	7.1775
76	Amount	($)	279,078,237	268,919,464	243,216,162	238,368,779	218,637,616	222,198,659	2,652,500,447
77									
78	Nuclear								
79									
80									
81	Burned:								
82	Units	(MBTU)	23,967,112	23,967,112	23,193,979	17,690,116	16,831,692	23,886,181	257,760,861
83	Unit Cost	($/MBTU)	0.3100	0.3096	0.3090	0.3187	0.3192	0.3196	0.3072
84	Amount	($)	7,430,320	7,420,550	7,167,595	5,637,812	5,372,358	7,635,077	79,188,309

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POWER SOLD

Estimated for the Period of : January 2005 thru December 2005

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost Cents / KWH	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
January		OS	275,000		275,000	4.608	5.136	12,671,000	14,125,000	750,000
2005	St.Lucie Rel.		46,084		46,084	0.309	0.309	142,229	142,229	0
Total			321,084	0	321,084	3.991	4.443	12,813,229	14,267,229	750,000
February		OS	260,000		260,000	4.468	5.069	11,617,350	13,180,000	885,800
2005	St.Lucie Rel.		41,624		41,624	0.308	0.308	128,223	128,223	0
Total			301,624	0	301,624	3.894	4.412	11,745,573	13,308,223	885,800
March		OS	225,000		225,000	4.622	5.244	10,399,000	11,800,000	787,500
2005	St.Lucie Rel.		46,084		46,084	0.307	0.307	141,691	141,691	0
Total			271,084	0	271,084	3.888	4.405	10,540,691	11,941,691	787,500
April		OS	175,000		175,000	4.718	5.414	8,256,500	9,475,000	736,750
2005	St.Lucie Rel.		43,865		43,865	0.312	0.312	136,887	136,887	0
Total			218,865	0	218,865	3.835	4.392	8,393,387	9,611,887	736,750
May		OS	150,000		150,000	4.928	5.667	7,391,500	8,500,000	672,000
2005	St.Lucie Rel.		45,328		45,328	0.311	0.311	141,181	141,181	0
Total			195,328	0	195,328	3.856	4.424	7,532,681	8,641,181	672,000
June		OS	200,000		200,000	5.059	5.975	10,117,400	11,950,000	1,190,100
2005	St.Lucie Rel.		43,865		43,865	0.311	0.311	136,375	136,375	0
Total			243,865	0	243,865	4.205	4.956	10,253,775	12,086,375	1,190,100

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POWER SOLD

Estimated for the Period of : January 2005 thru December 2005

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost Cents / KWH	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
July		OS	190,000		190,000	4.893	5.947	9,296,300	11,300,000	1,395,800
2005	St.Lucie Rel.		45,328		45,328	0.310	0.310	140,653	140,653	0
Total			235,328	0	235,328	4.010	4.862	9,436,953	11,440,653	1,395,800
August		OS	190,000		190,000	4.963	6.032	9,429,800	11,460,000	1,422,300
2005	St.Lucie Rel.		45,328		45,328	0.310	0.310	140,393	140,393	0
Total			235,328	0	235,328	4.067	4.929	9,570,193	11,600,393	1,422,300
September		OS	180,000		180,000	5.045	5.683	9,080,400	10,230,000	576,300
2005	St.Lucie Rel.		43,865		43,865	0.309	0.309	135,604	135,604	0
Total			223,865	0	223,865	4.117	4.630	9,216,004	10,365,604	576,300
October		OS	160,000		160,000	4.936	5.497	7,896,800	8,795,000	427,100
2005	St.Lucie Rel.		2,924		2,924	0.309	0.309	9,023	9,023	0
Total			162,924	0	162,924	4.852	5.404	7,905,823	8,804,023	427,100
November		OS	200,000		200,000	4.412	5.105	8,824,500	10,210,000	842,000
2005	St.Lucie Rel.		0		0	0.000	0.000	0	0	0
Total			200,000	0	200,000	4.412	5.105	8,824,500	10,210,000	842,000
December		OS	255,000		255,000	4.029	4.839	10,273,500	12,340,000	1,398,700
2005	St.Lucie Rel.		44,598		44,598	0.350	0.350	155,969	155,969	0
Total			299,598	0	299,598	3.481	4.171	10,429,469	12,495,969	1,398,700
Period		OS	2,460,000	0	2,460,000	4.685	5.421	115,254,050	133,365,000	11,084,350
	St.Lucie Rel.		448,894		448,894	0.314	0.314	1,408,227	1,408,227	0
Total			2,908,894	0	2,908,894	4.011	4.585	116,662,277	133,365,000	11,084,350

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Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2005 thru December 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2005 January	Sou. Co. (UPS + R)		685,874			685,874	1.694		11,618,000
	St. Lucie Rel.		46,084			46,084	0.334		154,000
	SJRPP		255,683			255,683	1.505		3,849,000
	PPAs		76,579			76,579	8.337		6,384,184
Total			1,064,220			1,064,220	2.068		22,005,184
2005 February	Sou. Co. (UPS + R)		602,046			602,046	1.694		10,199,000
	St. Lucie Rel.		41,624			41,624	0.333		138,800
	SJRPP		226,015			226,015	1.505		3,402,000
	PPAs		62,399			62,399	8.001		4,992,775
Total			932,084			932,084	2.010		18,732,575
2005 March	Sou. Co. (UPS + R)		678,293			678,293	1.694		11,490,000
	St. Lucie Rel.		46,084			46,084	0.333		153,400
	SJRPP		131,156			131,156	1.494		1,960,000
	PPAs		56,193			56,193	7.685		4,318,594
Total			911,726			911,726	1.966		17,921,994
2005 April	Sou. Co. (UPS + R)		667,634			667,634	1.694		11,310,000
	St. Lucie Rel.		43,866			43,866	0.338		148,200
	SJRPP		127,848			127,848	1.473		1,883,000
	PPAs		14,658			14,658	7.094		1,039,867
Total			854,006			854,006	1.684		14,381,067
2005 May	Sou. Co. (UPS + R)		690,375			690,375	1.694		11,695,000
	St. Lucie Rel.		45,328			45,328	0.337		152,900
	SJRPP		254,271			254,271	1.483		3,770,000
	PPAs		61,548			61,548	7.977		4,909,768
Total			1,051,522			1,051,522	1.952		20,527,668
2005 June	Sou. Co. (UPS + R)		668,159			668,159	1.694		11,318,000
	St. Lucie Rel.		43,866			43,866	0.337		147,700
	SJRPP		249,689			249,689	1.483		3,702,000
	PPAs		12,680			12,680	8.339		1,057,415
Total			974,394			974,394	1.665		16,225,115
Period Total	Sou. Co. (UPS + R)		3,992,381			3,992,381	1.694		67,630,000
	St. Lucie Rel.		266,852			266,852	0.335		895,000
	SJRPP		1,244,662			1,244,662	1.492		18,566,000
	PPAs		284,057			284,057	7.992		22,702,603
Total			5,787,952			5,787,952	1.897		109,793,603

Date: 9/09/2004
Company: Florida Power & Light

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Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2005 thru December 2005

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total Mwh Purchased	(5) Mwh For Other Utilities	(6) Mwh For Interruptible	(7) Mwh For Firm	(8A) Fuel Cost (Cents/Kwh)	(8B) Total Cost (Cents/Kwh)	(9) Total $ For Fuel Adj (7) x (8A)
2005	Sou. Co. (UPS + R)		682,882			682,882	1.694		11,568,000
July	St. Lucie Rel.		45,328			45,328	0.337		152,700
	SJRPP		252,661			252,661	1.491		3,766,000
	PPAs		129,144			129,144	7.817		10,094,976
Total			1,110,015			1,110,015	2.305		25,581,676
2005	Sou. Co. (UPS + R)		684,561			684,561	1.694		11,597,000
August	St. Lucie Rel.		45,328			45,328	0.336		152,500
	SJRPP		252,093			252,093	1.490		3,756,000
	PPAs		102,869			102,869	7.892		8,118,651
Total			1,084,851			1,084,851	2.178		23,624,151
2005	Sou. Co. (UPS + R)		666,249			666,249	1.694		11,286,000
September	St. Lucie Rel.		43,866			43,866	0.336		147,300
	SJRPP		246,846			246,846	1.488		3,674,000
	PPAs		35,976			35,976	7.848		2,823,338
Total			992,937			992,937	1.806		17,930,638
2005	Sou. Co. (UPS + R)		690,431			690,431	1.694		11,696,000
October	St. Lucie Rel.		45,328			45,328	0.335		151,900
	SJRPP		251,964			251,964	1.493		3,762,000
	PPAs		23,747			23,747	7.757		1,842,074
Total			1,011,470			1,011,470	1.725		17,451,974
2005	Sou. Co. (UPS + R)		666,812			666,812	1.694		11,296,000
November	St. Lucie Rel.		44,597			44,597	0.135		60,000
	SJRPP		249,285			249,285	1.522		3,793,000
	PPAs		17,325			17,325	8.809		1,526,160
Total			978,019			978,019	1.705		16,675,160
2005	Sou. Co. (UPS + R)		666,170			666,170	1.694		11,285,000
December	St. Lucie Rel.		46,084			46,084	0.329		151,400
	SJRPP		259,614			259,614	1.521		3,950,000
	PPAs		40,361			40,361	9.453		3,815,311
Total			1,012,229			1,012,229	1.897		19,201,711
	Sou. Co. (UPS + R)		8,049,486			8,049,486	1.694		136,358,000
Period	St. Lucie Rel.		537,383			537,383	0.318		1,710,800
Total	SJRPP		2,757,125			2,757,125	1.497		41,267,000
	PPAs		633,479			633,479	8.039		50,923,113
Total			11,977,473			11,977,473	1.922		230,258,913

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Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2005 thru December 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2005 January	Qual. Facilities		626,975			626,975	2.217	2.217	13,899,000
Total			626,975			626,975	2.217	2.217	13,899,000
2005 February	Qual. Facilities		580,256			580,256	2.221	2.221	12,887,000
Total			580,256			580,256	2.221	2.221	12,887,000
2005 March	Qual. Facilities		627,218			627,218	2.217	2.217	13,908,000
Total			627,218			627,218	2.217	2.217	13,908,000
2005 April	Qual. Facilities		612,627			612,627	2.220	2.220	13,598,000
Total			612,627			612,627	2.220	2.220	13,598,000
2005 May	Qual. Facilities		626,456			626,456	2.223	2.223	13,924,000
Total			626,456			626,456	2.223	2.223	13,924,000
2005 June	Qual. Facilities		613,698			613,698	2.221	2.221	13,630,000
Total			613,698			613,698	2.221	2.221	13,630,000
Period Total	Qual. Facilities		3,687,230			3,687,230	2.220	2.220	81,846,000
Total			3,687,230			3,687,230	2.220	2.220	81,846,000

Date: 9/09/2004
Company: Florida Power & Light

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Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2005 thru December 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2005 July	Qual. Facilities		625,600			625,600	2.205	2.205	13,796,000
Total			625,600			625,600	2.205	2.205	13,796,000
2005 August	Qual. Facilities		625,964			625,964	2.212	2.212	13,849,000
Total			625,964			625,964	2.212	2.212	13,849,000
2005 September	Qual. Facilities		613,260			613,260	2.219	2.219	13,609,000
Total			613,260			613,260	2.219	2.219	13,609,000
2005 October	Qual. Facilities		627,282			627,282	2.222	2.222	13,936,000
Total			627,282			627,282	2.222	2.222	13,936,000
2005 November	Qual. Facilities		518,322			518,322	2.253	2.253	11,677,000
Total			518,322			518,322	2.253	2.253	11,677,000
2005 December	Qual. Facilities		530,305			530,305	2.233	2.233	11,843,000
Total			530,305			530,305	2.233	2.233	11,843,000
Period Total	Qual. Facilities		7,227,963			7,227,963	2.221	2.221	160,556,000
Total			7,227,963			7,227,963	2.221	2.221	160,556,000

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Economy Energy Purchases

Estimated For the Period of : January 2005 Thru December 2005

	(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
1	January	Florida	C	94,000	3.366	3,164,213	5.071	4,767,010	1,602,797
2	2005	Non-Florida	C	42,036	4.830	2,030,522	5.170	2,173,261	142,739
3									
4	Total			136,036	3.819	5,194,735	5.102	6,940,271	1,745,536
5									
6									
7	February	Florida	C	87,000	3.372	2,933,213	5.080	4,419,450	1,486,237
8	2005	Non-Florida	C	37,968	4.834	1,835,258	5.232	1,986,486	151,228
9									
10	Total			124,968	3.816	4,768,471	5.126	6,405,936	1,637,465
11									
12									
13	March	Florida	C	94,000	3.457	3,249,213	5.113	4,806,310	1,557,097
14	2005	Non-Florida	C	44,913	4.757	2,136,499	5.248	2,357,034	220,535
15									
16	Total			138,913	3.877	5,385,712	5.157	7,163,344	1,777,632
17									
18									
19	April	Florida	C	92,000	3.548	3,264,213	5.037	4,634,500	1,370,287
20	2005	Non-Florida	C	57,048	4.667	2,662,589	5.132	2,927,703	265,114
21									
22	Total			149,048	3.976	5,926,802	5.074	7,562,203	1,635,401
23									
24									
25	May	Florida	C	94,000	3.547	3,334,213	5.089	4,783,650	1,449,437
26	2005	Non-Florida	C	58,950	4.665	2,750,081	5.154	3,038,283	288,202
27									
28	Total			152,950	3.978	6,084,294	5.114	7,821,933	1,737,639
29									
30									
31	June	Florida	C	13,000	4.900	637,000	5.188	674,440	37,440
32	2005	Non-Florida	C	43,464	4.759	2,068,396	5.188	2,254,912	186,516
33									
34	Total			56,464	4.791	2,705,396	5.188	2,929,352	223,956
35									
36									
37	Period	Florida	C	474,000	3.498	16,582,065	5.081	24,085,360	7,503,295
38	Total	Non-Florida	C	284,379	4.741	13,483,345	5.182	14,737,679	1,254,334
39									
40	Total			758,379	3.964	30,065,410	5.119	38,823,039	8,757,629
41									

Date:9/09/2004
Company: Florida Power & Light

Schedule: E9
Page : 2

Economy Energy Purchases

Estimated For the Period of : January 2005 Thru December 2005

	(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
1	July	Florida	C	15,000	4.900	735,000	5.024	753,600	18,600
2	2005	Non-Florida	C	44,913	4.757	2,136,499	5.024	2,256,429	119,930
3									
4	Total			59,913	4.793	2,871,499	5.024	3,010,029	138,530
5									
6									
7	August	Florida	C	15,000	5.000	750,000	5.114	767,100	17,100
8	2005	Non-Florida	C	44,913	4.857	2,181,412	5.114	2,296,851	115,439
9									
10	Total			59,913	4.893	2,931,412	5.114	3,063,951	132,539
11									
12									
13	September	Florida	C	12,000	4.800	576,000	5.208	624,960	48,960
14	2005	Non-Florida	C	48,432	4.663	2,258,577	5.208	2,522,339	263,762
15									
16	Total			60,432	4.691	2,834,577	5.208	3,147,299	312,722
17									
18									
19	October	Florida	C	30,000	4.500	1,350,000	5.278	1,583,400	233,400
20	2005	Non-Florida	C	59,991	4.655	2,792,850	5.278	3,166,325	373,475
21									
22	Total			89,991	4.604	4,142,850	5.278	4,749,725	606,875
23									
24									
25	November	Florida	C	50,000	4.300	2,150,000	4.941	2,470,500	320,500
26	2005	Non-Florida	C	44,640	4.346	1,939,990	4.941	2,205,662	265,672
27									
28	Total			94,640	4.322	4,089,990	4.941	4,676,162	586,172
29									
30									
31	December	Florida	C	50,000	4.400	2,200,000	4.662	2,331,000	131,000
32	2005	Non-Florida	C	46,128	4.444	2,050,102	4.662	2,150,487	100,385
33									
34	Total			96,128	4.421	4,250,102	4.662	4,481,487	231,385
35									
36									
37	Period	Florida	C	646,000	3.768	24,343,065	5.049	32,615,920	8,272,855
38	Total	Non-Florida	C	573,396	4.681	26,842,775	5.116	29,335,772	2,492,997
39									
40	Total			1,219,396	4.198	51,185,840	5.081	61,951,692	10,765,852
41									

SCHEDULE E10

COMPANY: FLORIDA POWER & LIGHT COMPANY

	JAN 04 - DEC 04	PROPOSED JAN 05 - DEC 05	DIFFERENCE FROM CURRENT $	%
BASE	$40.22	$40.22	$0.00	0.00%
FUEL	$37.50	$40.09	$2.59	6.91%
CONSERVATION	$1.45	$1.48	$0.03	2.07%
CAPACITY PAYMENT	$6.25	$7.39	$1.14	18.24%
ENVIRONMENTAL	$0.13	$0.25	$0.12	92.31%
SUBTOTAL	$85.55	$89.43	$3.88	4.54%
GROSS RECEIPTS TAX	$0.88	$0.92	$0.04	4.55%
TOTAL	**$86.43**	**$90.35**	$3.92	4.54%

Company: Florida Power & Light Company

Schedule H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

		PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
		ACTUAL	ACTUAL	ESTIMATED/ACTUAL	PROJECTED			
		JAN - DEC 2002 - 2002 (COLUMN 1)	JAN - DEC 2003 - 2003 (COLUMN 2)	JAN - DEC 2004 - 2004 (COLUMN 3)	JAN - DEC 2005 - 2005 (COLUMN 4)	(COLUMN 2) / (COLUMN 1)	(COLUMN 3) / (COLUMN 2)	(COLUMN 4) / (COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	993,639,285	669,789,553	844,089,611	768,560,945	(32.6)	26.0	(9.0)
2	LIGHT OIL	14,088,154	17,235,168	32,455,806	18,483,540	22.3	88.3	(43.1)
3	COAL	104,731,935	101,539,662	96,020,000	97,400,320	(3.1)	(5.4)	1.4
4	GAS	1,018,816,753	1,205,960,702	2,147,830,095	2,652,500,447	18.4	78.1	23.5
5	NUCLEAR	69,855,439	70,877,908	70,064,262	79,188,310	1.5	(1.2)	13.0
6	OTHER	0	0	0	0	0.0	0.0	0.0
7	TOTAL ($)	2,201,131,566	2,065,402,993	3,190,459,774	3,616,133,562	(6.2)	54.5	13.3
	SYSTEM NET GENERATION							
8	HEAVY OIL	25,802,011	18,708,283	19,071,313	15,612,822	(27.5)	1.9	(18.1)
9	LIGHT OIL	161,593	188,173	252,246	136,454	16.5	34.1	(45.9)
10	COAL	6,266,830	5,977,062	6,024,585	6,362,357	(4.6)	0.8	5.6
11	GAS	24,497,016	34,545,924	41,765,221	49,165,882	41.0	20.9	17.7
12	NUCLEAR	24,069,938	25,295,157	23,399,357	23,120,944	5.1	(7.5)	(1.2)
13	OTHER	0	0	0	0	0.0	0.0	0.0
14	TOTAL (MWH)	80,797,388	84,714,599	90,512,722	94,398,459	4.9	6.8	4.3
	UNITS OF FUEL BURNED							
15	HEAVY OIL (Bbl)	40,994,892	29,790,686	29,326,779	24,057,261	(27.3)	(1.6)	(18.0)
16	LIGHT OIL (Bbl)	381,359	472,694	615,405	337,765	24.0	30.2	(45.1)
17	COAL (TON)	772,666	760,021	703,887	3,219,277	(1.6)	(7.4)	357.4
18	GAS (MCF)	212,955,990	286,112,118	323,457,294	369,556,040	34.4	13.1	14.3
19	NUCLEAR (MMBTU)	262,850,564	276,217,616	256,425,934	257,760,861	5.1	(7.2)	0.5
20	OTHER (TONS)	0	0	0	0	0.0	0.0	0.0
	BTU'S BURNED (MMBTU)							
21	HEAVY OIL	260,958,241	190,168,594	187,396,213	153,966,465	(27.1)	(1.5)	(17.8)
22	LIGHT OIL	2,195,828	2,704,322	3,581,821	1,969,157	23.2	32.5	(45.0)
23	COAL	61,112,685	59,238,746	58,385,812	61,248,908	(3.1)	(1.4)	4.9
24	GAS	222,327,090	296,722,566	328,913,582	369,556,040	33.5	10.9	12.4
25	NUCLEAR	262,850,563	276,217,616	256,425,934	257,760,861	5.1	(7.2)	0.5
26	OTHER	0	0	0	0	0.0	0.0	0.0
27	TOTAL (MMBTU)	809,444,407	825,051,844	834,703,362	844,501,431	1.9	1.2	1.2
	GENERATION MIX (%MWH)							
28	HEAVY OIL	31.93	22.08	21.07	16.54	-	-	-
29	LIGHT OIL	0.20	0.22	0.28	0.14	-	-	-
30	COAL	7.76	7.06	6.66	6.74			
31	GAS	30.32	40.78	46.14	52.08	-	-	-
32	NUCLEAR	29.79	29.86	25.85	24.49	-	-	-
33	OTHER	0.00	0.00	0.00	0.00	-	-	-
34	TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
	FUEL COST PER UNIT							
35	HEAVY OIL ($/Bbl)	24.2381	22.4832	28.7822	31.9472	(7.2)	28.0	11.0
36	LIGHT OIL ($/Bbl)	36.9419	36.4615	52.7389	54.7231	(1.3)	44.6	3.8
37	COAL ($/TON)	34.7820	34.5097	38.7111	30.2553	(0.8)	12.2	(21.8)
38	GAS ($/MCF)	4.7842	4.2150	6.6402	7.1775	(11.9)	57.5	8.1
39	NUCLEAR ($/MMBTU)	0.2658	0.2566	0.2732	0.3072	(3.5)	6.5	12.5
40	OTHER ($/TON)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
	FUEL COST PER MMBTU ($/MMBTU)							
41	HEAVY OIL	3.8077	3.5221	4.5043	4.9917	(7.5)	27.9	10.8
42	LIGHT OIL	6.4159	6.3732	9.0613	9.3865	(0.7)	42.2	3.6
43	COAL	1.7138	1.7141	1.6446	1.5902	0.0	(4.1)	(3.3)
44	GAS	4.5825	4.0643	6.5301	7.1775	(11.3)	60.7	9.9
45	NUCLEAR	0.2658	0.2566	0.2732	0.3072	(3.5)	6.5	12.5
46	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
47	TOTAL ($/MMBTU)	2.7193	2.5034	3.8223	4.2820	(7.9)	52.7	12.0
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL	10,114	10,165	9,826	9,862	0.5	(3.3)	0.4
49	LIGHT OIL	13,589	14,371	14,200	14,431	5.8	(1.2)	1.6
50	COAL	9,752	9,911	9,691	9,627	1.6	(2.2)	(0.7)
51	GAS	9,076	8,589	7,875	7,517	(5.4)	(8.3)	(4.6)
52	NUCLEAR	10,920	10,920	10,959	11,148	0.0	0.4	1.7
53	OTHER	0	0	0	0	0.0	0.0	0.0
54	TOTAL (BTU/KWH)	10,018	9,739	9,222	8,946	(2.8)	(5.3)	(3.0)
	GENERATED FUEL COST PER KWH (c/KWH)							
55	HEAVY OIL	3.8510	3.5802	4.4260	4.9226	(7.0)	23.6	11.2
56	LIGHT OIL	8.7183	9.1592	12.8657	13.5456	5.1	40.5	5.3
57	COAL	1.6712	1.6986	1.5938	1.5309	1.7	(6.2)	(4.0)
58	GAS	4.1589	3.4909	5.1426	5.3950	(16.1)	47.3	4.9
59	NUCLEAR	0.2902	0.2802	0.2994	0.3425	(3.5)	6.9	14.4
60	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
61	TOTAL (c/KWH)	2.7243	2.4381	3.5249	3.8307	(10.5)	44.6	8.7

Note: Scherer coal is reported in MMBTU's only. Scherer coal is not included in TONS.

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

For informational purposes only, the estimated incremental As-Available Energy costs for the next five periods are as follows. In addition, As-Available Energy cost payments will include .0001¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
October 1, 2004 – March 31, 2005	5.41	4.58	4.82
April 1, 2005 – September 30, 2005	4.90	4.67	4.74
October 1, 2005 – March 31, 2006	4.84	4.16	4.36
April 1, 2006 – September 30, 2006	4.71	4.44	4.52
October 1, 2006 – March 31, 2007	4.66	4.06	4.24
April 1, 2007 – September 30, 2007	4.58	4.31	4.39

A MW block size ranging from 36 MW to 40 MW has been used to calculate the estimated As-Available Energy cost.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly As-Available Energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0217
Secondary Voltage Delivery	1.0473

For informational purposes the Company's projected annual generation mix and fuel prices are as follows:

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

	Generation by Fuel Type (%)					Price by Fuel Type ($/MMBTU)			
Year	Nuclear	Oil	Gas	Coal	Purchased Power	Nuclear	Oil	Gas	Coal
2005	21	15	45	6	14	.29	3.94	5.52	1.55
2006	21	13	47	5	14	.28	3.91	5.43	1.58
2007	20	12	49	6	13	.29	3.90	5.43	1.61
2008	21	11	50	5	13	.30	4.03	5.44	1.62
2009	20	10	52	5	13	.39	4.16	5.56	1.63
2010	19	10	57	5	9	.40	4.36	5.61	1.66
2011	19	9	60	5	6	.40	4.36	5.75	1.69
2012	19	7	64	5	6	.41	4.61	5.85	1.72
2013	18	7	64	5	6	.42	4.88	6.02	1.75

NOTE: The Company's forecasts are for illustrative purposes, and are subject to frequent revision. Amounts may not add to 100% due to rounding.

(Continued on Sheet No. 10.102)

(Continued from Sheet No. 10.102)

Customer Rate Schedule	Charge($)	Customer Rate Schedule	Charge($)
GS-1	8.37	CST-1	102.27
GST-1	11.44	GSLD-2	158.05
GSD-1	32.54	GSLDT-2	158.05
GSDT-1	38.58	CS-2	158.05
RS-1	5.25	CST-2	158.05
RST-1	8.32	GSLD-3	371.88
GSLD-1	38.12	CS-3	371.88
GSLDT-1	38.12	CST-3	371.88
CS-1	102.27	GSLDT-3	371.88

B. **Interconnection Charge for Non-Variable Utility Expenses:**

The Qualifying Facility shall bear the cost required for interconnection, including the metering. The Qualifying Facility shall have the option of (i) payment in full for the interconnection costs upon completion of the interconnection facilities (including the time value of money during the construction) and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection costs, (ii) payment of monthly invoices from the Company for actual costs progressively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for the thirty (30) days highest grade commercial paper rate, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the Qualifying Facility.

C. **Interconnection Charge for Variable Utility Expenses:**

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

In lieu of payments for actual charges, the Qualifying Facility may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities necessary for the sale of energy to the Company. The applicable percentages are as follows:

Equipment Type	Charge
Metering Equipment	0.155%
Distribution Equipment	0.251%
Transmission Equipment	0.104%

D. **Taxes and Assessments**

The Qualifying Facility shall be billed monthly an amount equal to any taxes, assessments or other impositions, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility. In the event the Company receives a tax benefit as a result of its purchases of As-Available Energy produced by the Qualifying Facility, the Qualifying Facility shall be entitled to a refund in an amount equal to such benefit.

TERMS OF SERVICE

(1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in the Qualifying Facility's electric generation capability.

(Continue on Sheet No. 10.104)

APPENDIX III

CAPACITY COST RECOVERY

KMD-6
DOCKET NO. 040001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT _____
PAGES 1-5
SEPTEMBER 9, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 10
COMPANY/ FP+L
WITNESS. K. M. Dubin (KMD-6)
DATE: 11-08-04

APPENDIX III
CAPACITY COST RECOVERY

TABLE OF CONTENTS

PAGE(S)	DESCRIPTION	SPONSOR
3	Projected Capacity Payments	K. M. Dubin
4	Calculation of Energy & Demand Allocation % By Rate Class	K. M. Dubin
5	Calculation of Capacity Recovery Factor	K. M. Dubin

FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
JANUARY 2005 THROUGH DECEMBER 2005

	PROJECTED												
	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1. CAPACITY PAYMENTS TO NON-COGENERATORS	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$15,790,290	$189,483,480
2. SHORT TERM CAPACITY PAYMENTS	$5,850,235	$5,850,235	$3,576,215	$3,485,965	$5,984,725	$11,272,940	$11,272,940	$11,272,940	$5,803,850	$1,446,505	$1,726,745	$3,703,645	$71,226,940
3. CAPACITY PAYMENTS TO COGENERATORS	$30,069,137	$30,069,137	$30,069,137	$30,069,137	$30,069,137	$30,069,137	$30,823,832	$30,823,832	$30,823,832	$30,823,832	$25,046,008	$25,046,008	$353,802,166
4a. SJRPP SUSPENSION ACCRUAL	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$393,207	$4,718,484
4b. RETURN REQUIREMENTS ON SJRPP SUSPENSION LIABILITY	($346,104)	($349,955)	($353,805)	($357,656)	($361,506)	($365,357)	($369,207)	($373,058)	($376,908)	($380,759)	($384,609)	($388,460)	($4,407,384)
5b. OKEELANTA SETTLEMENT	$3,005,887	$3,002,640	$2,999,393	$2,996,146	$2,992,899	$2,989,652	$2,986,405	$2,983,158	$2,979,911	$2,976,664	$2,973,417	$2,970,170	$35,856,342
6. INCREMENTAL PLANT SECURITY COSTS	$1,175,804	$1,175,804	$1,175,804	$1,175,804	$972,393	$972,393	$972,393	$972,393	$972,393	$972,393	$972,393	$972,393	$12,482,363
7. TRANSMISSION OF ELECTRICITY BY OTHERS	$624,947	$633,552	$630,309	$640,087	$601,573	$603,462	$507,849	$523,390	$582,789	$591,944	$598,537	$579,780	$7,118,219
8. TRANSMISSION REVENUES FROM CAPACITY SALES	($704,000)	($676,850)	($613,500)	($481,750)	($436,500)	($642,500)	($607,900)	($607,900)	($573,300)	($471,100)	($543,500)	($667,800)	($7,026,600)
9. SYSTEM TOTAL	$55,859,403	$55,888,060	$53,667,050	$53,691,230	$56,006,218	$61,083,224	$61,769,809	$61,778,252	$56,396,064	$52,142,976	$46,572,488	$48,399,234	$663,254,010
10. JURISDICTIONAL % *													98.63289%
11. JURISDICTIONALIZED CAPACITY PAYMENTS													$654,186,598
12. SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET													($56,945,592)
13. FINAL TRUE-UP -- overrecovery/(underrecovery) JANUARY 2003 - DECEMBER 2003 ($7,050,083)		EST \ ACT TRUE-UP -- overrecovery/(underrecovery) JANUARY 2004 - DECEMBER 2004 ($73,892,873)											($80,942,956)
14. TOTAL (Lines 11+12-13)													$678,183,962
15. REVENUE TAX MULTIPLIER													1.01597
16. TOTAL RECOVERABLE CAPACITY PAYMENTS													$689,014,560

*CALCULATION OF JURISDICTIONAL %

	AVG. 12 CP AT GEN.(MW)	%
FPSC	17,676	98.63289%
FERC	245	1.36711%
TOTAL	17,921	100.00000%

* BASED ON 2003 ACTUAL DATA

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2005 THROUGH DECEMBER 2005

Rate Schedule	(1) AVG 12CP Load Factor at Meter (%)	(2) Projected Sales at Meter (kwh)	(3) Projected AVG 12 CP at Meter (kW)	(4) Demand Loss Expansion Factor	(5) Energy Loss Expansion Factor	(6) Projected Sales at Generation (kwh)	(7) Projected AVG 12 CP at Generation (kW)	(8) Percentage of Sales at Generation (%)	(9) Percentage of Demand at Generation (%)
RS1/RST1	63.060%	55,334,940,634	10,017,085	1.09230267	1.07281827	59,364,335,282	10,941,689	53.79073%	59.77947%
GS1/GST1	69.973%	6,075,542,153	991,175	1.09230267	1.07281827	6,517,952,622	1,082,663	5.90599%	5.91508%
GSD1/GSDT1	77.702%	23,085,553,190	3,391,595	1.09220064	1.07274057	24,764,809,488	3,704,302	22.43969%	20.23830%
OS2	93.228%	21,113,200	2,585	1.05829225	1.04657532	22,096,554	2,736	0.02002%	0.01495%
GSLD1/GSLDT1/CS1/CST1	83.923%	10,666,361,079	1,450,879	1.09083728	1.07170069	11,431,146,528	1,582,673	10.35790%	8.64687%
GSLD2/GSLDT2/CS2/CST2	87.158%	1,750,619,663	229,288	1.08297958	1.06544968	1,865,197,160	248,314	1.69008%	1.35665%
GSLD3/GSLDT3/CS3/CST3	86.580%	187,194,635	24,682	1.02969493	1.02438901	191,760,127	25,415	0.17376%	0.13885%
ISST1D	96.676%	0	0	1.09230267	1.07281827	0	0	0.00000%	0.00000%
ISST1T	87.151%	0	0	1.02969493	1.02438901	0	0	0.00000%	0.00000%
SST1T	87.151%	150,031,028	19,652	1.02969493	1.02438901	153,690,136	20,236	0.13926%	0.11056%
SST1D1/SST1D2/SST1D3	96.676%	23,594,871	2,786	1.07224837	1.06763473	25,190,703	2,987	0.02283%	0.01632%
CILC D/CILC G	92.072%	3,469,946,584	430,221	1.08128023	1.06432600	3,693,154,368	465,189	3.34641%	2.54154%
CILC T	94.419%	1,522,653,717	184,093	1.02969493	1.02438901	1,559,789,734	189,560	1.41334%	1.03565%
MET	70.123%	96,643,843	15,733	1.05829225	1.04657532	101,145,061	16,650	0.09165%	0.09097%
OL1/SL1/PL1	565.360%	555,624,734	11,219	1.09230267	1.07281827	596,084,366	12,255	0.54012%	0.06695%
SL2	99.953%	70,174,667	8,015	1.09230267	1.07281827	75,284,665	8,755	0.06822%	0.04783%
TOTAL		103,009,994,000	16,779,008			110,361,636,794	18,303,424	100.00%	100.00%

(1) AVG 12 CP load factor based on actual calendar data.
(2) Projected kwh sales for the period January 2005 through December 2005.
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 2003 demand losses.
(5) Based on 2003 energy losses.
(6) Col(2) * Col(5).
(7) Col(3) * Col(4).
(8) Col(6) / total for Col(6)
(9) Col(7) / total for Col(7)

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
JANUARY 2005 THROUGH DECEMBER 2005

Rate Schedule	(1) Percentage of Sales at Generation (%)	(2) Percentage of Demand at Generation (%)	(3) Energy Related Cost ($)	(4) Demand Related Cost ($)	(5) Total Capacity Costs ($)	(6) Projected Sales at Meter (kwh)	(7) Billing KW Load Factor (%)	(8) Projected Billed KW at Meter (kw)	(9) Capacity Recovery Factor ($/kw)	(10) Capacity Recovery Factor ($/kwh)
RS1/RST1	53.79073%	59.77947%	$28,509,692	$380,205,434	$408,715,126	55,334,940,634	-	-	-	0.00739
GS1/GST1	5.90599%	5.91508%	$3,130,243	$37,620,733	$40,750,976	6,075,542,153	-	-	-	0.00671
GSD1/GSDT1	22.43969%	20.23830%	$11,893,287	$128,718,313	$140,611,600	23,085,553,190	49.73909%	52,939,773	2.66	-
OS2	0.02002%	0.01495%	$10,612	$95,071	$105,683	21,113,200	-	-	-	0.00501
GSLD1/GSLDT1/CS1/CST1	10.35790%	8.64687%	$5,489,802	$54,995,246	$60,485,048	10,666,361,079	64.68915%	22,587,178	2.68	-
GSLD2/GSLDT2/CS2/CST2	1.69008%	1.35665%	$895,760	$8,628,497	$9,524,257	1,750,619,663	66.01990%	3,632,403	2.62	-
GSLD3/GSLDT3/CS3/CST3	0.17376%	0.13885%	$92,093	$883,129	$975,222	187,194,635	70.45754%	363,951	2.68	-
ISST1D	0.00000%	0.00000%	$0	$0	$0	0	0.00000%	0	**	-
ISST1T	0.00000%	0.00000%	$0	$0	$0	0	0.00000%	0	**	-
SST1T	0.13926%	0.11056%	$73,810	$703,167	$776,977	150,031,028	19.42328%	1,058,122	**	-
SST1D1/SST1D2/SST1D3	0.02283%	0.01632%	$12,098	$103,793	$115,891	23,594,871	63.51414%	50,889	**	-
CILC D/CILC G	3.34641%	2.54154%	$1,773,636	$16,164,541	$17,938,177	3,469,946,584	74.11221%	6,413,722	2.80	-
CILC T	1.41334%	1.03565%	$749,088	$6,586,894	$7,335,982	1,522,653,717	78.45936%	2,658,481	2.76	-
MET	0.09165%	0.09097%	$48,575	$578,560	$627,135	96,643,843	58.55491%	226,093	2.77	-
OL1/SL1/PL1	0.54012%	0.06695%	$286,269	$425,841	$712,110	555,624,734	-	-	-	0.00128
SL2	0.06822%	0.04783%	$36,155	$304,222	$340,377	70,174,667	-	-	-	0.00485
TOTAL			$53,001,120	$636,013,440	$689,014,560	103,009,994,000		89,930,612		

Note:There are currently no customers taking service on Schedules ISST1(D) and ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 factor.

(1) Obtained from Page 2, Col(8)
(2) Obtained from Page 2, Col(9)
(3) (Total Capacity Costs/13) * Col (1)
(4) (Total Capacity Costs/13 * 12) * Col (2)
(5) Col (3) + Col (4)
(6) Projected kwh sales for the period January 2005 through December 2005
(7) (kWh sales / 8760 hours)/((avg customer NCP)(8760 hours))
(8) Col (6) / ((7) *730) For GSD-1, only 83.265% of KW are billed due to 10 KW exemption
(9) Col (5) / (8)
(10) Col (5) / (6)

Totals may not add due to rounding.

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Demand Charge (RDD) = (Total col 5)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

Sum of Daily Demand Charge (DDC) = (Total col 5)/(Doc 2, Total col 7)/(21 onpeak days) (Doc 2, col 4) / 12 months

	CAPACITY RECOVERY FACTOR	
	RDC	SDD
	** ($/kw)	** ($/kw)
ISST1D	$0.34	$0.16
ISST1T	$0.32	$0.15
SST1T	$0.32	$0.15
SST1D1/SST1D2/SST1D3	$0.34	$0.16

DOCUMENT NO. 1

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2003

PS -1
DOCKET NO. 040001-EI
FPL Witness: Pamela Sonnelitter
Exhibit No.: _____
Pages 1 - 23
April 1, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 11
COMPANY/ FP+L
WITNESS. P. Sonnelitter (PS-1)
DATE 11-08-04

DOCUMENT NUMBER 1 INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2003

DOCUMENT	INDEX OF MANUAL PAGES	TITLES
1	6.203.001	Index of Manual Pages
	6.203.002	GPIF Reward/(Penalty) Table (Actual)
	6.203.003	GPIF Calculation of Maximum Allowed Incentive Dollars (Actual)
	6.203.004	Derivation of System Actual GPIF Points
	6.203.005	Actual Equivalent Availability and Adjustments Summary
	6.203.006	EAF Adjustment Documentation
	6.203.007	Adjustments to Average Net Operating Heat Rates and Adjustments Summary
	6.203.008 - 6.203.022	GPIF Units Points Tables
	6.203.023	Planned Outages Schedule (Actual)

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ACTUAL)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2003

GENERATNG PERFORMANCE INCENTIVE POINTS (GPIF)		FUEL SAVINGS/(LOSS) ($000)			GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+ 10		59,205.40			22,901.40
+ 9		53,284.86			20,611.26
+ 8		47,364.32			18,321.12
+ 7		41,443.78			16,030.98
+ 6		35,523.24			13,740.84
+ 5		29,602.70			11,450.70
+ 4		23,682.16			9,160.56
+ 3	<---------- 2.89	17,761.62	6,615.282	---------->	6,870.42
+ 2		11,841.08			4,580.28
+ 1		5,920.54			2,290.14
0		0.00			0.00
- 1		(6,121.84)			(2,290.14)
- 2		(12,243.68)			(4,580.28)
- 3		(18,365.52)			(6,870.42)
- 4		(24,487.36)			(9,160.56)
- 5		(30,609.20)			(11,450.70)
- 6		(36,731.04)			(13,740.84)
- 7		(42,852.88)			(16,030.98)
- 8		(48,974.72)			(18,321.12)
- 9		(55,096.56)			(20,611.26)
- 10		(61,218.40)			(22,901.40)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ACTUAL

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2003

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 5,381,760,459	
LINE 2	MONTH OF January	2003	$ 5,443,518,178	
LINE 3	MONTH OF February	2003	$ 5,416,795,989	
LINE 4	MONTH OF March	2003	$ 5,420,129,425	
LINE 5	MONTH OF April	2003	$ 5,429,749,346	
LINE 6	MONTH OF May	2003	$ 5,453,701,108	
LINE 7	MONTH OF June	2003	$ 5,460,622,288	
LINE 8	MONTH OF July	2003	$ 5,479,432,897	
LINE 9	MONTH OF August	2003	$ 5,472,758,595	
LINE 10	MONTH OF September	2003	$ 6,070,337,187	
LINE 11	MONTH OF October	2003	$ 6,046,590,185	
LINE 12	MONTH OF November	2003	$ 6,013,601,919	
LINE 13	MONTH OF December	2003	$ 6,004,027,910	
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 5,622,540,421	
LINE 15	25 BASIS POINTS		0.0025	
LINE 16	REVENUE EXPANSION FACTOR		60.4594%	
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 23,249,240	
LINE 18	JURISDICTIONAL SALES		99,495,660,000	KWH
LINE 19	TOTAL SALES		101,006,875,000	KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.50%	
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS		$ 22,901,397	

JANUARY THROUGH DECEMBER, 2003

DERIVATION OF SYSTEM ACTUAL GPIF POINTS

PLANT/UNIT	PERFORMANCE INDICATOR	WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
Cape Canaveral 2	EAF	0.50	0.00	.0000
Cape Canaveral 2	ANOHR	2.65	0.00	.0000
Lauderdale 4	EAF	0.90	6.40	.0576
Lauderdale 4	ANOHR	3.13	0.00	.0000
Lauderdale 5	EAF	1.01	9.60	.0971
Lauderdale 5	ANOHR	3.76	0.00	.0000
Manatee 2	EAF	0.43	10.00	.0431
Manatee 2	ANOHR	2.88	0.00	.0000
Martin 1	EAF	0.30	10.00	.0297
Martin 1	ANOHR	4.51	0.52	.0234
Martin 2	EAF	0.38	10.00	.0378
Martin 2	ANOHR	5.72	0.00	.0000
Martin 3	EAF	1.34	-10.00	-.1337
Martin 3	ANOHR	1.31	-10.00	-.1313
Martin 4	EAF	1.02	-10.00	-.1015
Martin 4	ANOHR	1.50	-8.49	-.1274
Turkey Point 1	EAF	0.37	4.80	.0179
Turkey Point 1	ANOHR	2.92	0.00	.0000
Turkey Point 2	EAF	0.34	-8.00	-.0274
Turkey Point 2	ANOHR	1.94	0.85	.0165
Turkey Point 3	EAF	9.38	8.67	.8128
Turkey Point 3	ANOHR	5.00	0.00	.0000
Turkey Point 4	EAF	9.41	10.00	.9406
Turkey Point 4	ANOHR	5.35	0.00	.0000
St. Lucie 1	EAF	12.23	10.00	1.2231
St. Lucie 1	ANOHR	1.97	0.00	.0000
St. Lucie 2	EAF	9.65	0.67	.0643
St. Lucie 2	ANOHR	3.28	0.00	.0000
Scherer 4	EAF	3.83	1.20	.0460
Scherer 4	ANOHR	2.99	0.00	.0000
GPIF System Total:		100.00		2.89

ACTUAL EQUIVALENT AVAILABILITY AND ADJUSTMENTS

JANUARY THROUGH DECEMBER, 2003

1	2	3	4	5	6	7	8	9			
	ACTUAL				PLANNED OUTAGE ADJ TO	ADJUSTED ACTUAL		POINTS FROM	ORIGINAL PLANNED	ACTUAL	ACTUAL FUEL SAVINGS/ (LOSS)
UNIT	FOF	MOF	POF	EAF	EA (1)	EA	TARGET EA	TABLES	DATES	DATES	($000)
Cape Canaveral 2	1.7	8.0	7.0	83.2	0.0	89.5	89.5	0.00	-	11/29/2003 - 12/24/2003	0.0
Lauderdale 4	2.1	1.8	4.6	91.5	1.6	93.3	91.7	6.40	04/05/03 - 04/14/03	04/04/2003 - 04/28/2003	341.0
Lauderdale 5	0.1	4.4	4.0	91.5	2.4	92.7	90.3	9.60	10/11/03 - 10/20/03	10/26/2003 - 11/07/2003	574.9
Manatee 2	0.0	1.3	0.0	98.7	3.4	91.1	87.7	10.00	04/26/03 - 05/23/03	NONE	254.9
Martin 1	0.2	0.1	10.6	89.2	4.1	95.9	91.8	10.00	10/18/03 - 10/31/03	4/14/03 - 5/2/03 and 11/2/03 - 11/23/03	175.9
Martin 2	0.4	3.3	7.0	89.4	3.4	86.9	83.5	10.00	11/01/03 - 12/05/03	11/24/2003 - 12/19/2003	223.9
Martin 3	8.3	12.6	0.9	78.1	-15.8	77.0	92.8	-10.00	04/12/03 - 04/17/03	02/16/2003 - 02/22/2003	(791.3)
Martin 4	0.3	9.0	6.3	84.4	-5.7	88.1	93.8	-10.00	10/18/03 - 10/27/03	10/30/2003 - 12/16/2003	(601.2)
Turkey Point 1	1.9	1.8	17.8	78.5	1.2	86.3	85.1	4.80	03/08/03 - 04/11/03	02/14/2003 - 04/20/2003	106.0
Turkey Point 2	1.5	5.2	0.0	93.3	-1.6	93.3	94.9	-8.00	-	NONE	(162.0)
Turkey Point 3	3.8	0.0	8.6	87.6	2.6	88.0	85.4	8.67	03/03/03 - 04/02/03	03/01/2003 - 03/28/2003	4,812.3
Turkey Point 4	0.0	0.0	10.2	89.8	6.4	91.8	85.4	10.00	10/06/03 - 11/05/03	10/01/2003 - 11/05/2003	5,568.7
St. Lucie 1	0.0	0.0	0.0	100.0	6.4	100.0	93.6	10.00	-	NONE	7,241.6
St. Lucie 2	5.8	0.0	14.3	80.0	0.2	85.6	85.4	0.67	04/21/03 - 05/21/03	04/20/2003 - 06/11/2003	380.9
Scherer 4	3.1	3.0	0.0	93.9	0.3	93.9	93.6	1.20	-	NONE	272.2
											18,397.8

(1) EQUIVALENT AVAILABILITY ADJUSTMENT DUE TO PLANNED OUTAGE ACTUAL DURATION VERSUS TARGETED DURATION
SEE 6.203.006 FOR FORMULAS AND CALCULATION DATA

EQUIVALENT AVAILABILITY ADJUSTMENTS
JANUARY THROUGH DECEMBER, 2003

	ACTUAL				TARGETS		ADJUSTED ACTUAL
PLANT / UNIT	PH	EFOH	EMOH	EPOH	POF%	POH	EAF%
Cape Canaveral 2	8760	152.1	699.6	615.9	0.0	0.0	89.5
Lauderdale 4	8760	186.2	157.8	399.3	2.7	236.5	93.3
Lauderdale 5	8760	10.2	386.0	351.1	2.7	236.5	92.7
Manatee 2	8760	2.7	113.0	0.0	7.7	674.5	91.1
Martin 1	8760	18.0	4.8	927.7	3.8	332.9	95.9
Martin 2	8760	33.5	285.6	610.2	9.6	841.0	86.9
Martin 3	8760	722.9	1120.5	78.3	2.2	192.7	77.0
Martin 4	8760	25.2	789.8	553.5	2.2	192.7	88.1
Turkey Point 1	8760	165.0	159.1	1562.7	9.6	841.0	86.3
Turkey Point 2	8760	130.4	454.4	0.0	0.0	0.0	93.3
Turkey Point 3	8760	333.9	0.0	749.0	8.2	718.3	88.0
Turkey Point 4	8760	0.0	0.0	893.6	8.2	718.3	91.8
St. Lucie 1	8760	0.1	0.0	0.9	0.0	0.0	100.0
St. Lucie 2	8760	505.9	0.0	1249.1	8.2	718.3	85.6
Scherer 4	8760	275.7	260.8	0.0	0.0	0.0	93.9

$$\text{ADJ. ACTUAL EAF\%} = 100\% - POF_T - \frac{(EFOH_A + EMOH_A) \times \frac{PH - POH_T}{PH - POH_A}}{PH} \times 100\%$$

ADJUSTMENTS TO AVERAGE NET OPERATING HEAT RATES & ADJUSTMENTS SUMMARY

JANUARY THROUGH DECEMBER, 2003

1	2	3	4	5	6	7	8	9	
		ACTUAL		TARGET (2)	ADJUST.(3)		ADJUST.(5)		
UNIT	HEAT RATE (1) FORMULA	NOF %	ANOHR BTU/KWH	ANOHR AT ACTUAL NOF BTU/KWH	TO ANOHR BTU/KWH	TARGET (4) ANOHR BTU/KWH	ACTUAL ANOHR BTU/KWH	GPIF(6) FROM TABLE	ACTUAL FUEL SAV./(LOSS) $000
Cape Canaveral 2	ANOHR= -22.73 x NOF + 11158	64.9	9696	9682	14	9030	9044	0.00	0.0
Lauderdale 4	ANOHR= -14.39 x NOF + 8796	83.3	7617	7598	19	7435	7454	0.00	0.0
Lauderdale 5	ANOHR= -11.86 x NOF + 8522	82.5	7593	7543	50	7366	7416	0.00	0.0
Manatee 2	ANOHR= -13.04 x NOF + 11034	59.9	10279	10253	26	9862	9888	0.00	0.0
Martin 1	ANOHR= -18.05 x NOF + 11133	56.3	10024	10117	-93	9546	9453	0.52	138.3
Martin 2	ANOHR= -14.40 x NOF + 10872	53.4	10047	10103	-56	9590	9534	0.00	0.0
Martin 3	ANOHR= -1.66 x NOF + 6977	83.4	7018	6838	180	6829	7009	-10.00	(777.4)
Martin 4	ANOHR= -1.81 x NOF + 6918	81.6	6920	6770	150	6753	6903	-8.49	(754.2)
Turkey Point 1	ANOHR= -16.39 x NOF + 10685	64.5	9691	9628	63	9128	9191	0.00	0.0
Turkey Point 2	ANOHR= -7.22 x NOF + 10200	64.3	9647	9735	-88	9512	9424	0.85	97.5
Turkey Point 3	ANOHR= -33.17 x NOF + 14395	99.2	11040	11104	-64	11148	11084	0.00	0.0
Turkey Point 4	ANOHR= -25.79 x NOF + 13650	100.0	11083	11070	13	11119	11132	0.00	0.0
St. Lucie 1	ANOHR= -24.39 x NOF + 13249	102.1	10750	10760	-10	10834	10824	0.00	0.0
St. Lucie 2	ANOHR= -14.93 x NOF + 12323	98.9	10881	10846	35	10843	10878	0.00	0.0
Scherer 4	ANOHR= -19.65 x NOF + 11911	86.2	10184	10218	-34	9992	9958	0.00	0.0
									(1295.8)

1) THESE FORMULAS ARE AS APPROVED BY THE COMMSION IN THE PROJECTED DATA AND REFLECT ON MONTHLY ACTUAL DATA
2) CALCULATED FROM ANOHR FORMULA IN COLUMN 2 USING ACTUAL NOF IN COLUMN 3
3) ADJUSTMENT TO ANOHR=ACTUAL ANOHR - TARGET ANOHR AT ACTUAL NOF (COLUMN 6 = COLUMN 4 - COLUMN 5).
4) AT TARGET NOF AS APPROVED BY THE COMMISION IN PROJECTED DATA.
5) AT TARGET NOF, ADJUSTED ACTUAL ANOHR = TARGET ANOHR + ADJUSTMENTS (COLUMN 8 = COLUMN 7 + COLUMN 6).
6) OBTAINED FROM GPIF POINTS TABLES AS APPROVED BY THE COMMISION IN PROJECTED TARGETS.

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Cape Canaveral 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	293.70	92.5		+10	1569.55	8722	
+9	264.33	92.2		+9	1412.59	8745	
+8	234.96	91.9		+8	1255.64	8768	
+7	205.59	91.6		+7	1098.68	8792	
+6	176.22	91.3		+6	941.73	8815	
+5	146.85	91.0		+5	784.77	8838	
+4	117.48	90.7		+4	627.82	8862	
+3	88.11	90.4		+3	470.86	8885	
+2	58.74	90.1		+2	313.91	8908	
+1	29.37	89.8		+1	156.95	8931	
					0.00	8955	
0	0.00	89.5	<- Adj. Act. EAF= 89.5	0	0.00	9030	<- Adj. Act. HR=9044
					(0.00)	9105	
-1	(-29.37)	89.2		-1	(-156.95)	9128	
-2	(-58.74)	88.9		-2	(-313.91)	9151	
-3	(-88.11)	88.6		-3	(-470.86)	9175	
-4	(-117.48)	88.3		-4	(-627.82)	9198	
-5	(-146.85)	88.0		-5	(-784.77)	9221	
-6	(-176.22)	87.7		-6	(-941.73)	9245	
-7	(-205.59)	87.4		-7	(-1098.68)	9268	
-8	(-234.96)	87.1		-8	(-1255.64)	9291	
-9	(-264.33)	86.8		-9	(-1412.59)	9315	
-10	(-293.70)	86.5		-10	(-1569.55)	9338	
	WEIGHTING FACTOR =	0.50			WEIGHTING FACTOR =	2.65	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Lauderdale 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	532.83	94.2		+10	1850.55	7190	
+9	479.54	94.0		+9	1665.50	7207	
+8	426.26	93.7		+8	1480.44	7224	
+7	372.98	93.5		+7	1295.39	7241	
+6	319.70	93.2	<- Adj. Act. EAF= 93.3	+6	1110.33	7258	
+5	266.41	93.0		+5	925.28	7275	
+4	213.13	92.7		+4	740.22	7292	
+3	159.85	92.5		+3	555.17	7309	
+2	106.57	92.2		+2	370.11	7326	
+1	53.28	92.0		+1	185.06	7343	
					0.00	7360	
0	0.00	91.7		0	0.00	7435	<- Adj. Act. HR=7454
					(0.00)	7510	
-1	(-53.28)	91.5		-1	(-185.06)	7526	
-2	(-106.57)	91.2		-2	(-370.11)	7543	
-3	(-159.85)	91.0		-3	(-555.17)	7560	
-4	(-213.13)	90.7		-4	(-740.22)	7577	
-5	(-266.41)	90.5		-5	(-925.28)	7594	
-6	(-319.70)	90.2		-6	(-1110.33)	7611	
-7	(-372.98)	90.0		-7	(-1295.39)	7628	
-8	(-426.26)	89.7		-8	(-1480.44)	7645	
-9	(-479.54)	89.5		-9	(-1665.50)	7662	
-10	(-532.83)	89.2		-10	(-1850.55)	7679	
	WEIGHTING FACTOR =	0.90			WEIGHTING FACTOR =	3.13	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Lauderdale 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	598.82	92.8		+10	2226.62	7109	
+9	538.94	92.6	<- Adj. Act. EAF= 92.7	+9	2003.96	7128	
+8	479.05	92.3		+8	1781.30	7146	
+7	419.17	92.1		+7	1558.64	7164	
+6	359.29	91.8		+6	1335.97	7182	
+5	299.41	91.6		+5	1113.31	7200	
+4	239.53	91.3		+4	890.65	7218	
+3	179.65	91.1		+3	667.99	7236	
+2	119.76	90.8		+2	445.32	7254	
+1	59.88	90.6		+1	222.66	7272	
					0.00	7291	
0	0.00	90.3		0	0.00	7366	<- Adj. Act. HR=7416
					(0.00)	7441	
-1	(-59.88)	90.1		-1	(-222.66)	7459	
-2	(-119.76)	89.8		-2	(-445.32)	7477	
-3	(-179.65)	89.6		-3	(-667.99)	7495	
-4	(-239.53)	89.3		-4	(-890.65)	7513	
-5	(-299.41)	89.1		-5	(-1113.31)	7531	
-6	(-359.29)	88.8		-6	(-1335.97)	7549	
-7	(-419.17)	88.6		-7	(-1558.64)	7567	
-8	(-479.05)	88.3		-8	(-1781.30)	7585	
-9	(-538.94)	88.1		-9	(-2003.96)	7603	
-10	(-598.82)	87.8		-10	(-2226.62)	7622	
	WEIGHTING FACTOR =	1.01			WEIGHTING FACTOR =	3.76	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Manatee 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	254.94	89.7	<- Adj. Act. EAF= 91.1	+10	1705.88	9607	
+9	229.45	89.5		+9	1535.29	9625	
+8	203.95	89.3		+8	1364.71	9643	
+7	178.46	89.1		+7	1194.12	9661	
+6	152.96	88.9		+6	1023.53	9679	
+5	127.47	88.7		+5	852.94	9697	
+4	101.98	88.5		+4	682.35	9715	
+3	76.48	88.3		+3	511.76	9733	
+2	50.99	88.1		+2	341.18	9751	
+1	25.49	87.9		+1	170.59	9769	
					0.00	9787	
0	0.00	87.7		0	0.00	9862	<- Adj. Act. HR=9868
					(0.00)	9937	
-1	(-25.49)	87.5		-1	(-170.59)	9955	
-2	(-50.99)	87.3		-2	(-341.18)	9973	
-3	(-76.48)	87.1		-3	(-511.76)	9991	
-4	(-101.98)	86.9		-4	(-682.35)	10009	
-5	(-127.47)	86.7		-5	(-852.94)	10027	
-6	(-152.96)	86.5		-6	(-1023.53)	10045	
-7	(-178.46)	86.3		-7	(-1194.12)	10063	
-8	(-203.95)	86.1		-8	(-1364.71)	10081	
-9	(-229.45)	85.9		-9	(-1535.29)	10099	
-10	(-254.94)	85.7		-10	(-1705.88)	10117	
	WEIGHTING FACTOR =	0.43			WEIGHTING FACTOR =	2.88	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Martin 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	175.92	93.8	<- Adj. Act. EAF= 95.9	+10	2671.26	9124	
+9	158.33	93.6		+9	2404.13	9158	
+8	140.74	93.4		+8	2137.01	9193	
+7	123.15	93.2		+7	1869.88	9228	
+6	105.55	93.0		+6	1602.76	9263	
+5	87.96	92.8		+5	1335.63	9297	
+4	70.37	92.6		+4	1068.50	9332	
+3	52.78	92.4		+3	801.38	9367	
+2	35.18	92.2		+2	534.25	9402	
+1	17.59	92.0		+1	267.13	9437	<- Adj. Act. HR=9453
					0.00	9471	
0	0.00	91.8		0	0.00	9546	
					(0.00)	9621	
-1	(-17.59)	91.6		-1	(-338.66)	9656	
-2	(-35.18)	91.4		-2	(-677.32)	9691	
-3	(-52.78)	91.2		-3	(-1015.98)	9726	
-4	(-70.37)	91.0		-4	(-1354.64)	9760	
-5	(-87.96)	90.8		-5	(-1693.30)	9795	
-6	(-105.55)	90.6		-6	(-2031.96)	9830	
-7	(-123.15)	90.4		-7	(-2370.62)	9865	
-8	(-140.74)	90.2		-8	(-2709.28)	9899	
-9	(-158.33)	90.0		-9	(-3047.94)	9934	
-10	(-175.92)	89.8		-10	(-3386.60)	9969	
	WEIGHTING FACTOR =	0.30			WEIGHTING FACTOR =	4.51	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Martin 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	223.86	86.0	<- Adj. Act. EAF= 86.9	+10	3386.60	9160	
+9	201.47	85.8		+9	3047.94	9195	
+8	179.09	85.5		+8	2709.28	9231	
+7	156.70	85.3		+7	2370.62	9266	
+6	134.32	85.0		+6	2031.96	9302	
+5	111.93	84.8		+5	1693.30	9337	
+4	89.54	84.5		+4	1354.64	9373	
+3	67.16	84.3		+3	1015.98	9408	
+2	44.77	84.0		+2	677.32	9444	
+1	22.39	83.8		+1	338.66	9479	
					0.00	9515	<- Adj. Act. HR=9534
0	0.00	83.5		0	0.00	9590	
					(0.00)	9665	
-1	(-22.39)	83.3		-1	(-338.66)	9700	
-2	(-44.77)	83.0		-2	(-677.32)	9736	
-3	(-67.16)	82.8		-3	(-1015.98)	9771	
-4	(-89.54)	82.5		-4	(-1354.64)	9807	
-5	(-111.93)	82.3		-5	(-1693.30)	9843	
-6	(-134.32)	82.0		-6	(-2031.96)	9878	
-7	(-156.70)	81.8		-7	(-2370.62)	9914	
-8	(-179.09)	81.5		-8	(-2709.28)	9949	
-9	(-201.47)	81.3		-9	(-3047.94)	9985	
-10	(-223.86)	81.0		-10	(-3386.60)	10020	
	WEIGHTING FACTOR =	0.38			WEIGHTING FACTOR =	5.72	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Martin 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	791.31	95.3		+10	777.42	6682	
+9	712.18	95.1		+9	699.68	6689	
+8	633.05	94.8		+8	621.94	6696	
+7	553.92	94.6		+7	544.20	6703	
+6	474.79	94.3		+6	466.45	6710	
+5	395.65	94.1		+5	388.71	6718	
+4	316.52	93.8		+4	310.97	6725	
+3	237.39	93.6		+3	233.23	6732	
+2	158.26	93.3		+2	155.48	6739	
+1	79.13	93.1		+1	77.74	6746	
					0.00	6754	
0	0.00	92.8		0	0.00	6829	
					(0.00)	6904	
-1	(-79.13)	92.6		-1	(-77.74)	6911	
-2	(-158.26)	92.3		-2	(-155.48)	6918	
-3	(-237.39)	92.1		-3	(-233.23)	6925	
-4	(-316.52)	91.8		-4	(-310.97)	6932	
-5	(-395.65)	91.6		-5	(-388.71)	6939	
-6	(-474.79)	91.3		-6	(-466.45)	6947	
-7	(-553.92)	91.1		-7	(-544.20)	6954	
-8	(-633.05)	90.8		-8	(-621.94)	6961	
-9	(-712.18)	90.6		-9	(-699.68)	6968	
-10	(-791.31)	90.3	<- Adj. Act. EAF= 77.0	-10	(-777.42)	6975	<- Adj. Act. HR=7009
	WEIGHTING FACTOR =	1.34			WEIGHTING FACTOR =	1.31	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Martin 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	601.20	95.8		+10	888.67	6590	
+9	541.08	95.6		+9	799.80	6599	
+8	480.96	95.4		+8	710.94	6608	
+7	420.84	95.2		+7	622.07	6617	
+6	360.72	95.0		+6	533.20	6625	
+5	300.60	94.8		+5	444.33	6634	
+4	240.48	94.6		+4	355.47	6643	
+3	180.36	94.4		+3	266.60	6652	
+2	120.24	94.2		+2	177.73	6661	
+1	60.12	94.0		+1	88.87	6670	
					0.00	6678	
0	0.00	93.8		0	0.00	6753	
					(0.00)	6828	
-1	(-60.12)	93.6		-1	(-88.87)	6837	
-2	(-120.24)	93.4		-2	(-177.73)	6846	
-3	(-180.36)	93.2		-3	(-266.60)	6855	
-4	(-240.48)	93.0		-4	(-355.47)	6864	
-5	(-300.60)	92.8		-5	(-444.33)	6873	
-6	(-360.72)	92.6		-6	(-533.20)	6881	
-7	(-420.84)	92.4		-7	(-622.07)	6890	
-8	(-480.96)	92.2		-8	(-710.94)	6899	<- Adj. Act. HR=6903
-9	(-541.08)	92.0		-9	(-799.80)	6908	
-10	(-601.20)	91.8	<- Adj. Act. EAF= 88.1	-10	(-888.67)	6917	
	WEIGHTING FACTOR =	1.02			WEIGHTING FACTOR =	1.50	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Turkey Point 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	220.85	87.6		+10	1727.72	8763	
+9	198.77	87.4		+9	1554.95	8792	
+8	176.68	87.1		+8	1382.18	8821	
+7	154.60	86.9		+7	1209.41	8850	
+6	132.51	86.6		+6	1036.63	8879	
+5	110.43	86.4		+5	863.86	8908	
+4	88.34	86.1	<- Adj. Act. EAF= 86.3	+4	691.09	8937	
+3	66.26	85.9		+3	518.32	8966	
+2	44.17	85.6		+2	345.54	8995	
+1	22.09	85.4		+1	172.77	9024	
					0.00	9053	
0	0.00	85.1		0	0.00	9128	<- Adj. Act. HR=9191
					(0.00)	9203	
-1	(-22.09)	84.9		-1	(-172.77)	9232	
-2	(-44.17)	84.6		-2	(-345.54)	9261	
-3	(-66.26)	84.4		-3	(-518.32)	9290	
-4	(-88.34)	84.1		-4	(-691.09)	9319	
-5	(-110.43)	83.9		-5	(-863.86)	9348	
-6	(-132.51)	83.6		-6	(-1036.63)	9377	
-7	(-154.60)	83.4		-7	(-1209.41)	9406	
-8	(-176.68)	83.1		-8	(-1382.18)	9435	
-9	(-198.77)	82.9		-9	(-1554.95)	9464	
-10	(-220.85)	82.6		-10	(-1727.72)	9493	
	WEIGHTING FACTOR =	0.37			WEIGHTING FACTOR =	2.92	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Turkey Point 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	202.55	96.9		+10	1148.16	9284	
+9	182.29	96.7		+9	1033.34	9299	
+8	162.04	96.5		+8	918.53	9314	
+7	141.78	96.3		+7	803.71	9330	
+6	121.53	96.1		+6	688.89	9345	
+5	101.27	95.9		+5	574.08	9360	
+4	81.02	95.7		+4	459.26	9375	
+3	60.76	95.5		+3	344.45	9391	
+2	40.51	95.3		+2	229.63	9406	
+1	20.25	95.1		+1	114.82	9421	<- Adj. Act. HR=9424
					0.00	9437	
0	0.00	94.9		0	0.00	9512	
					(0.00)	9587	
-1	(-20.25)	94.7		-1	(-114.82)	9602	
-2	(-40.51)	94.5		-2	(-229.63)	9617	
-3	(-60.76)	94.3		-3	(-344.45)	9633	
-4	(-81.02)	94.1		-4	(-459.26)	9648	
-5	(-101.27)	93.9		-5	(-574.08)	9663	
-6	(-121.53)	93.7		-6	(-688.89)	9678	
-7	(-141.78)	93.5		-7	(-803.71)	9694	
-8	(-162.04)	93.3	<- Adj. Act. EAF= 93.3	-8	(-918.53)	9709	
-9	(-182.29)	93.1		-9	(-1033.34)	9724	
-10	(-202.55)	92.9		-10	(-1148.16)	9740	
	WEIGHTING FACTOR =	0.34			WEIGHTING FACTOR =	1.94	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Turkey Point 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	5,552.64	88.4		+10	2960.56	10860	
+9	4,997.37	88.1		+9	2664.50	10881	
+8	4,442.11	87.8	<- Adj. Act. EAF= 88.0	+8	2368.45	10902	
+7	3,886.85	87.5		+7	2072.39	10924	
+6	3,331.58	87.2		+6	1776.34	10945	
+5	2,776.32	86.9		+5	1480.28	10966	
+4	2,221.05	86.6		+4	1184.22	10988	
+3	1,665.79	86.3		+3	888.17	11009	
+2	1,110.53	86.0		+2	592.11	11031	
+1	555.26	85.7		+1	296.06	11052	
					0.00	11073	<- Adj. Act. HR=11084
0	0.00	85.4		0	0.00	11148	
					(0.00)	11223	
-1	(-555.26)	85.1		-1	(-373.71)	11245	
-2	(-1,110.53)	84.8		-2	(-747.42)	11266	
-3	(-1,665.79)	84.5		-3	(-1121.12)	11288	
-4	(-2,221.05)	84.2		-4	(-1494.83)	11309	
-5	(-2,776.32)	83.9		-5	(-1868.54)	11330	
-6	(-3,331.58)	83.6		-6	(-2242.25)	11352	
-7	(-3,886.85)	83.3		-7	(-2615.96)	11373	
-8	(-4,442.11)	83.0		-8	(-2989.66)	11394	
-9	(-4,997.37)	82.7		-9	(-3363.37)	11416	
-10	(-5,552.64)	82.4		-10	(-3737.08)	11437	
	WEIGHTING FACTOR =	9.38			WEIGHTING FACTOR =	5.00	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Turkey Point 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	5,568.74	88.4	<- Adj. Act. EAF= 91.8	+10	3167.72	10810	
+9	5,011.86	88.1		+9	2850.94	10834	
+8	4,454.99	87.8		+8	2534.17	10857	
+7	3,898.12	87.5		+7	2217.40	10880	
+6	3,341.24	87.2		+6	1900.63	10904	
+5	2,784.37	86.9		+5	1583.86	10927	
+4	2,227.49	86.6		+4	1267.09	10950	
+3	1,670.62	86.3		+3	950.31	10974	
+2	1,113.75	86.0		+2	633.54	10997	
+1	556.87	85.7		+1	316.77	11020	
					0.00	11044	
0	0.00	85.4		0	0.00	11119	<- Adj. Act. HR=11132
					(0.00)	11194	
-1	(-556.87)	85.1		-1	(-375.29)	11217	
-2	(-1,113.75)	84.8		-2	(-750.58)	11240	
-3	(-1,670.62)	84.5		-3	(-1125.86)	11264	
-4	(-2,227.49)	84.2		-4	(-1501.15)	11287	
-5	(-2,784.37)	83.9		-5	(-1876.44)	11310	
-6	(-3,341.24)	83.6		-6	(-2251.73)	11334	
-7	(-3,898.12)	83.3		-7	(-2627.01)	11357	
-8	(-4,454.99)	83.0		-8	(-3002.30)	11380	
-9	(-5,011.86)	82.7		-9	(-3377.59)	11403	
-10	(-5,568.74)	82.4		-10	(-3752.88)	11427	
	WEIGHTING FACTOR =	9.41			WEIGHTING FACTOR =	5.35	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: St. Lucie 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	7,241.65	96.6	<- Adj. Act. EAF= 100.0	+10	1166.56	10694	
+9	6,517.48	96.3		+9	1049.90	10700	
+8	5,793.32	96.0		+8	933.25	10707	
+7	5,069.15	95.7		+7	816.59	10713	
+6	4,344.99	95.4		+6	699.94	10720	
+5	3,620.82	95.1		+5	583.28	10727	
+4	2,896.66	94.8		+4	466.62	10733	
+3	2,172.49	94.5		+3	349.97	10740	
+2	1,448.33	94.2		+2	233.31	10746	
+1	724.16	93.9		+1	116.66	10753	
					0.00	10759	<- Adj. Act. HR=10824
0	0.00	93.6		0	0.00	10834	
					(0.00)	10909	
-1	(-724.16)	93.3		-1	(-144.64)	10916	
-2	(-1,448.33)	93.0		-2	(-289.27)	10922	
-3	(-2,172.49)	92.7		-3	(-433.91)	10929	
-4	(-2,896.66)	92.4		-4	(-578.54)	10935	
-5	(-3,620.82)	92.1		-5	(-723.18)	10942	
-6	(-4,344.99)	91.8		-6	(-867.82)	10948	
-7	(-5,069.15)	91.5		-7	(-1012.45)	10955	
-8	(-5,793.32)	91.2		-8	(-1157.09)	10962	
-9	(-6,517.48)	90.9		-9	(-1301.72)	10968	
-10	(-7,241.65)	90.6		-10	(-1446.36)	10975	
	WEIGHTING FACTOR =	12.23			WEIGHTING FACTOR =	1.97	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: St. Lucie 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	5,713.31	88.4		+10	1944.49	10650	
+9	5,141.98	88.1		+9	1750.04	10662	
+8	4,570.65	87.8		+8	1555.59	10673	
+7	3,999.32	87.5		+7	1361.14	10685	
+6	3,427.99	87.2		+6	1166.69	10697	
+5	2,856.65	86.9		+5	972.24	10709	
+4	2,285.32	86.6		+4	777.79	10721	
+3	1,713.99	86.3		+3	583.35	10733	
+2	1,142.66	86.0		+2	388.90	10744	
+1	571.33	85.7		+1	194.45	10756	
					0.00	10768	
0	0.00	85.4	<- Adj. Act. EAF= 85.6	0	0.00	10843	<- Adj. Act. HR=10678
					(0.00)	10918	
-1	(-571.33)	85.1		-1	(-231.60)	10930	
-2	(-1,142.66)	84.8		-2	(-463.19)	10942	
-3	(-1,713.99)	84.5		-3	(-694.79)	10954	
-4	(-2,285.32)	84.2		-4	(-926.38)	10965	
-5	(-2,856.65)	83.9		-5	(-1157.98)	10977	
-6	(-3,427.99)	83.6		-6	(-1389.57)	10989	
-7	(-3,999.32)	83.3		-7	(-1621.17)	11001	
-8	(-4,570.65)	83.0		-8	(-1852.76)	11013	
-9	(-5,141.98)	82.7		-9	(-2084.36)	11025	
-10	(-5,713.31)	82.4		-10	(-2315.96)	11037	
	WEIGHTING FACTOR =	9.65			WEIGHTING FACTOR =	3.28	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2003

UNIT: Scherer 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	2,268.31	96.1		+10	1773.03	9724	
+9	2,041.48	95.9		+9	1595.73	9743	
+8	1,814.65	95.6		+8	1418.43	9762	
+7	1,587.82	95.4		+7	1241.12	9782	
+6	1,360.99	95.1		+6	1063.82	9801	
+5	1,134.15	94.9		+5	886.52	9820	
+4	907.32	94.6		+4	709.21	9840	
+3	680.49	94.4		+3	531.91	9859	
+2	453.66	94.1		+2	354.61	9878	
+1	226.83	93.9	<- Adj. Act. EAF= 93.9	+1	177.30	9897	
					0.00	9917	<- Adj. Act. HR=9958
0	0.00	93.6		0	0.00	9992	
					(0.00)	10067	
-1	(-226.83)	93.4		-1	(-177.30)	10086	
-2	(-453.66)	93.1		-2	(-354.61)	10105	
-3	(-680.49)	92.9		-3	(-531.91)	10125	
-4	(-907.32)	92.6		-4	(-709.21)	10144	
-5	(-1,134.15)	92.4		-5	(-886.52)	10163	
-6	(-1,360.99)	92.1		-6	(-1063.82)	10182	
-7	(-1,587.82)	91.9		-7	(-1241.12)	10202	
-8	(-1,814.65)	91.6		-8	(-1418.43)	10221	
-9	(-2,041.48)	91.4		-9	(-1595.73)	10240	
-10	(-2,268.31)	91.1		-10	(-1773.03)	10260	
	WEIGHTING FACTOR =	3.83			WEIGHTING FACTOR =	2.99	

ACTUAL PLANNED OUTAGES

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2003

PLANT/UNIT	ACTUAL PLANNED OUTAGE DATE	REASON FOR OUTAGE
Cape Canaveral 2	11/29/2003 - 12/24/2003	Turbine valves and boiler
Lauderdale 4	04/04/2003 - 04/28/2003	4A CT rotor change out
Lauderdale 5	10/26/2003 - 11/07/2003	Overhaul
Manatee 2	NONE	
Martin 1	4/14/03 - 5/2/03 and 11/2/03 - 11/23/03	Overhaul
Martin 2	11/24/2003 - 12/19/2003	Overhaul
Martin 3	02/16/2003 - 02/22/2003	3A CT overhaul
Martin 4	10/30/2003 - 12/16/2003	4B CT rotor change out
Turkey Point 1	02/14/2003 - 04/20/2003	Turbine generator
Turkey Point 2	NONE	
Turkey Point 3	03/01/2003 - 03/28/2003	Refueling
Turkey Point 4	10/01/2003 - 11/05/2003	Refueling
St. Lucie 1	NONE	
St. Lucie 2	04/20/2003 - 06/11/2003	Refueling
Scherer 4	NONE	

DOCUMENT NO. 1

WITNESS: PAMELA SONNELITTER

DOCKET NO. 040001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2005

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 12
COMPANY/ FP+L
WITNESS: P. Sonnelitter (PS-2)
DATE: 11-08-04

DOCUMENT NUMBER 1 INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2005

DOCUMENT	PAGE NUMBER	TITLE
1	7.201.001	Index
	7.201.002 to 7.201.003	Generating Unit Selection Criteria
	7.201.004	GPIF Reward/(Penalty) Table (Estimated)
	7.201.005	GPIF calculation of Maximum Allowed Dollars (Estimated)
	7.201.006 and 7.201.007	GPIF Target and Range Summary
	7.201.008	GPIF Predicted Unit Heat Rates
	7.201.009	Derivation of Weighting Factors
	7.201.010	Estimated Unit Performance Data
	7.201.011 - 7.201.023	Unit MOF and FOF vs Time Graphs
	7.201.024	Planned Outages Schedule (Estimated)

Table 2.0
POWRSYM Projected System Generation
January Through December, 2005

Name	Capacity (MW)	Service Hours	Net Output MWH	NOF %	% of Total Output	Cumulative % of Total Output	Production Cost ($000)
Ft. Myers Repowered 2	1,435	7,833	10,267,693	91%	10.9	10.9	510,893
Sanford Repowered 4	911	7,654	6,445,312	92%	6.8	17.7	320,981
Sanford Repowered 5	939	7,601	6,257,420	88%	6.6	24.3	310,015
St. Lucie 2	719	8,538	6,140,275	100%	6.5	30.8	20,538
St. Lucie 1	845	7,135	6,027,256	100%	6.4	37.2	18,908
Turkey Point 3	703	8,538	6,003,740	100%	6.4	43.6	22,258
Turkey Point 4	703	7,017	4,949,673	100%	5.2	48.8	17,484
Scherer 4	645	7,844	4,536,350	90%	4.8	53.6	69,980
Martin 8	1,088	4,681	4,178,436	82%	4.4	58.1	200,600
Manatee 3	1,090	4,685	4,158,969	81%	4.4	62.5	209,570
Martin 2	799	6,542	3,530,341	68%	3.7	66.2	217,479
Lauderdale 4	433	8,003	3,278,217	95%	3.5	69.7	180,355
Martin 4	453	7,662	3,112,541	90%	3.3	73.0	155,280
Martin 3	452	7,679	3,092,943	89%	3.3	76.3	158,574
Martin 1	807	5,534	2,934,991	66%	3.1	79.4	183,791
Manatee 2	806	5,268	2,625,941	62%	2.8	82.1	142,807
Lauderdale 5	432	6,595	2,622,653	92%	2.8	84.9	143,207
Manatee 1	806	4,501	2,366,608	65%	2.5	87.4	124,976
Cape Canaveral 2	396	3,464	1,131,851	83%	1.2	88.6	57,557
Port Everglades 4	389	3,665	1,125,166	79%	1.2	89.8	59,426
Turkey Point 1	395	3,485	1,078,681	78%	1.1	91.0	55,473
Port Everglades 3	382	3,564	1,076,572	79%	1.1	92.1	55,707
St. Johns River 2	128	7,854	1,001,597	99%	1.1	93.2	14,939
Cape Canaveral 1	396	3,069	978,300	81%	1.0	94.2	51,244
Riviera 4	280	4,309	953,477	79%	1.0	95.2	52,414
Riviera 3	274	4,445	942,814	77%	1.0	96.2	52,047
St. Johns River 1	128	6,478	824,409	99%	0.9	97.1	12,481
Turkey Point 2	395	2,583	755,734	74%	0.8	97.9	40,503
Ft. Myers SC 3	165	1,540	428,733	84%	0.5	98.3	33,129
Putnam 1	244	2,193	374,086	70%	0.4	98.7	23,817
Putnam 2	244	1,845	299,178	67%	0.3	99.0	19,966
Port Everglades 2	210	1,503	188,394	60%	0.2	99.2	11,481
Port Everglades 1	210	1,398	162,015	55%	0.2	99.4	10,756
Sanford 3	139	1,687	143,226	61%	0.2	99.6	8,171
Ft. Myers GT 1-12	582	425	128,859	52%	0.1	99.7	17,754
Ft. lauderdale GT 1-24	719	395	90,008	32%	0.1	99.8	11,810
Port Everglades GT 1-1:	363	385	82,248	59%	0.1	99.9	10,601
Cutler 6	140	1,125	69,916	44%	0.1	100.0	6,106
Cutler 5	69	1,085	33,836	45%	0.0	100.0	3,055
Total	20,311		94,398,455		100.0	100.0	3,616,135

FLORIDA POWER & LIGHT COMPANY
UNITS TO BE USED TO DETERMINE THE
GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2005

Lauderdale Unit 4

Lauderdale Unit 5

Manatee Unit 1

Manatee Unit 2

Martin Unit 1

Martin Unit 2

Martin Unit 3

Martin Unit 4

Scherer Unit 4

St. Lucie Unit 1

St. Lucie Unit 2

Turkey Point Unit 3

Turkey Point Unit 4

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2005

Generating Performance Incentive Points (GPIF)	Fuel Savings/(Loss) ($000)	Generating Performance Incentive Factor ($000)
+ 10	71,721	25,569
+ 9	64,549	23,012
+ 8	57,377	20,455
+ 7	50,205	17,898
+ 6	43,033	15,342
+ 5	35,861	12,785
+ 4	28,689	10,228
+ 3	21,516	7,671
+ 2	14,344	5,114
+ 1	7,172	2,557
0	0	0
- 1	(7,175)	(2,557)
- 2	(14,350)	(5,114)
- 3	(21,525)	(7,671)
- 4	(28,700)	(10,228)
- 5	(35,875)	(12,785)
- 6	(43,050)	(15,342)
- 7	(50,225)	(17,898)
- 8	(57,400)	(20,455)
- 9	(64,576)	(23,012)
- 10	(71,751)	(25,569)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	6,029,044,746
LINE 2	MONTH OF JANUARY	2005	$	6,158,490,202
LINE 3	MONTH OF FEBRUARY	2005	$	6,143,724,921
LINE 4	MONTH OF MARCH	2005	$	6,154,980,006
LINE 5	MONTH OF APRIL	2005	$	6,163,547,843
LINE 6	MONTH OF MAY	2005	$	6,179,880,106
LINE 7	MONTH OF JUNE	2005	$	6,197,832,313
LINE 8	MONTH OF JULY	2005	$	6,423,964,998
LINE 9	MONTH OF AUGUST	2005	$	6,430,544,904
LINE 10	MONTH OF SEPTEMBER	2005	$	6,423,676,130
LINE 11	MONTH OF OCTOBER	2005	$	6,398,663,851
LINE 12	MONTH OF NOVEMBER	2005	$	6,380,648,929
LINE 13	MONTH OF DECEMBER	2005	$	6,525,480,148
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 13 DIVIDED BY 13)		$	6,277,729,000
LINE 15	25 BASIS POINTS			0.0025
LINE 16	REVENUE EXPANSION FACTOR			60.4594%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$	25,958,449
LINE 18	JURISDICTIONAL SALES			103,009,995,124 KWH
LINE 19	TOTAL SALES			104,577,999,841 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			98.50%
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS		$	25,569,237

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

Plant / Unit	Weighting Factor (%)	EAF Target (%)	EAF Range Max. (%)	EAF Range Min. (%)	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Lauderdale 4	0.71	92.7	94.7	90.7	509.0	-509.0
Lauderdale 5	0.48	75.5	77.5	73.5	344.6	-344.6
Manatee 1	0.45	74.6	76.6	72.6	320.1	-320.1
Manatee 2	0.51	96.0	98.0	94.0	368.7	-368.7
Martin 1	0.44	76.0	78.5	73.5	318.1	-318.1
Martin 2	0.35	92.9	95.4	90.4	254.2	-254.2
Martin 3	1.20	92.2	95.2	89.2	859.7	-859.7
Martin 4	1.10	92.5	95.0	90.0	785.8	-785.8
Scherer 4	4.89	95.5	97.5	93.5	3,503.7	-3,503.7
St. Lucie 1	12.44	77.2	80.2	74.2	8,919.5	-8,919.5
St. Lucie 2	12.79	93.6	96.6	90.6	9,173.4	-9,173.4
Turkey Point 3	12.43	93.6	96.6	90.6	8,913.0	-8,913.0
Turkey Point 4	10.45	75.8	78.8	72.8	7,492.8	-7,492.8
	58.23				41,762.8	-41,762.8

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

Plant / Unit	Weighting Factor (%)	ANOHR TARGET BTU/KWH	NOF	ANOHR RANGE BTU/KWH	BTU/KWH	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Lauderdale 4	7.63	7,515	94.7	7,212	7,818	5,474.0	-5,474.0
Lauderdale 5	1.74	7,511	92.2	7,371	7,651	1,246.7	-1,246.7
Manatee 1	2.98	10,274	65.2	10,023	10,524	2,134.2	-2,134.2
Manatee 2	5.12	10,248	61.9	9,910	10,587	3,672.5	-3,672.5
Martin 1	3.62	9,994	65.7	9,778	10,210	2,596.0	-2,596.0
Martin 2	4.36	9,964	67.5	9,746	10,183	3,129.8	-3,129.8
Martin 3	1.68	6,977	89.1	6,849	7,105	1,206.0	-1,206.0
Martin 4	3.14	6,926	89.8	6,750	7,101	2,254.7	-2,254.7
Scherer 4	1.07	10,151	89.7	9,965	10,336	765.0	-765.0
St. Lucie 1	0.77	10,846	100.0	10,793	10,899	550.3	-552.6
St. Lucie 2	0.04	10,866	100.0	10,790	10,942	25.2	-25.3
Turkey Point 3	5.93	11,043	100.0	10,787	11,299	4,253.4	-4,268.8
Turkey Point 4	3.70	11,078	100.3	10,868	11,287	2,650.8	-2,662.3
	41.77					29,958.6	-29,987.8

PROJECTED UNIT HEAT RATE EQUATIONS
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

				ANOHR Equation					
Plant/Unit	ANOHR	NOF	MW	a coef.	b coef.	Bounds	First	Last	Exclusions
Lauderdale 4	7,515	94.7	433	8573	-11.17	303	07-01	06-04	Mar-04, Apr-04
Lauderdale 5	7,511	92.2	432	8131	-6.73	140	07-01	06-04	Nov-03, Dec-03, Jan-04
Manatee 1	10,274	65.2	806	10648	-5.73	250	07-01	06-04	Nov-02, Apr-03, May-03
Manatee 2	10,248	61.9	806	10822	-9.27	339	07-01	06-04	Nov-01, Feb-04, Mar-04, Apr-04
Martin 1	9,994	65.7	807	10189	-2.97	216	07-01	06-04	Oct-02, Feb-03
Martin 2	9,964	67.5	799	10234	-3.99	218	07-01	06-04	Nov-02, Jan-03, Feb-04, May-04
Martin 3	6,977	89.1	452	7336	-4.03	128	07-01	06-04	Aug-03, Sep-03
Martin 4	6,926	89.8	453	7145	-2.44	176	07-01	06-04	Jun-02, Jul-02, Nov-02, Nov-03
Scherer 4	10,151	89.7	645	10878	-8.12	186	07-01	06-04	No exclusions
St. Lucie 1	10,846	100.0	845	15106	-42.61	53	07-01	06-04	Oct-02, Apr-04
St. Lucie 2	10,866	100.0	719	13016	-21.50	76	07-01	06-04	Dec-01, Apr-03, May-03, Jun-03
Turkey Point 3	11,043	100.0	703	13204	-21.60	256	07-01	06-04	Oct-01, Mar-03
Turkey Point 4	11,078	100.3	703	14739	-36.48	210	07-01	06-04	Jul-02, Jan-03, Oct-03

DERIVATION OF WEIGHT FACTORS

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

PRODUCTION COSTING SIMULATION
FUEL COST ($000)

Unit	Performance Indicator	At Target (1)	At Maximum Improvement (2)	Savings (3)	Factor (% Of Savings)
Lauderdale 4	EAF	3,616,135	3,615,626	509.0	0.71
Lauderdale 4	ANOHR	3,616,135	3,610,661	5,474.0	7.63
Lauderdale 5	EAF	3,616,135	3,615,790	344.6	0.48
Lauderdale 5	ANOHR	3,616,135	3,614,888	1,246.7	1.74
Manatee 1	EAF	3,616,135	3,615,815	320.1	0.45
Manatee 1	ANOHR	3,616,135	3,614,001	2,134.2	2.98
Manatee 2	EAF	3,616,135	3,615,766	368.7	0.51
Manatee 2	ANOHR	3,616,135	3,612,463	3,672.5	5.12
Martin 1	EAF	3,616,135	3,615,817	318.1	0.44
Martin 1	ANOHR	3,616,135	3,613,539	2,596.0	3.62
Martin 2	EAF	3,616,135	3,615,881	254.2	0.35
Martin 2	ANOHR	3,616,135	3,613,005	3,129.8	4.36
Martin 3	EAF	3,616,135	3,615,275	859.7	1.20
Martin 3	ANOHR	3,616,135	3,614,929	1,206.0	1.68
Martin 4	EAF	3,616,135	3,615,349	785.8	1.10
Martin 4	ANOHR	3,616,135	3,613,880	2,254.7	3.14
Scherer 4	EAF	3,616,135	3,612,631	3,503.7	4.89
Scherer 4	ANOHR	3,616,135	3,615,370	765.0	1.07
St. Lucie 1	EAF	3,616,135	3,607,215	8,919.5	12.44
St. Lucie 1	ANOHR	3,616,135	3,615,585	550.3	0.77
St. Lucie 2	EAF	3,616,135	3,606,962	9,173.4	12.79
St. Lucie 2	ANOHR	3,616,135	3,616,110	25.2	0.04
Turkey Point 3	EAF	3,616,135	3,607,222	8,913.0	12.43
Turkey Point 3	ANOHR	3,616,135	3,611,882	4,253.4	5.93
Turkey Point 4	EAF	3,616,135	3,608,642	7,492.8	10.45
Turkey Point 4	ANOHR	3,616,135	3,613,484	2,650.8	3.70
	TOTAL			71,721.4	100.00

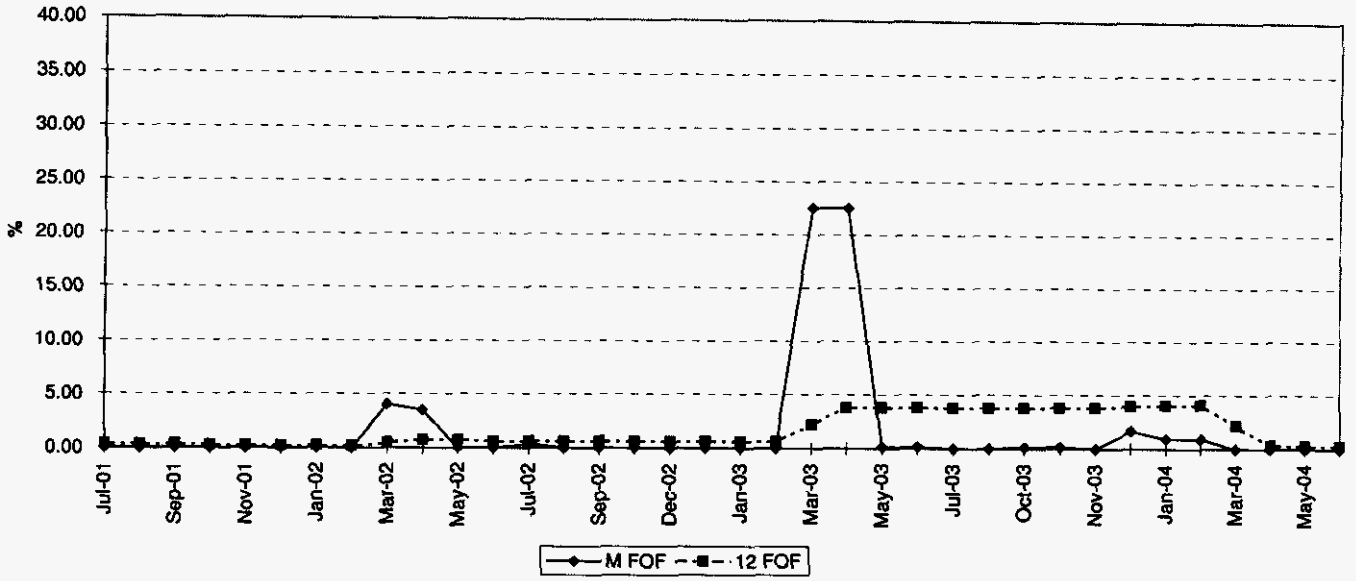
(1) FUEL ADJUSTMENT - ALL UNITS PERFORMANCE AT TARGET
(2) ALL OTHER UNITS PERFORMANCE AT TARGET
(3) EXPRESSED IN REPLACEMENT ENERGY COSTS.

ESTIMATED UNIT PERFORMANCE DATA
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2005

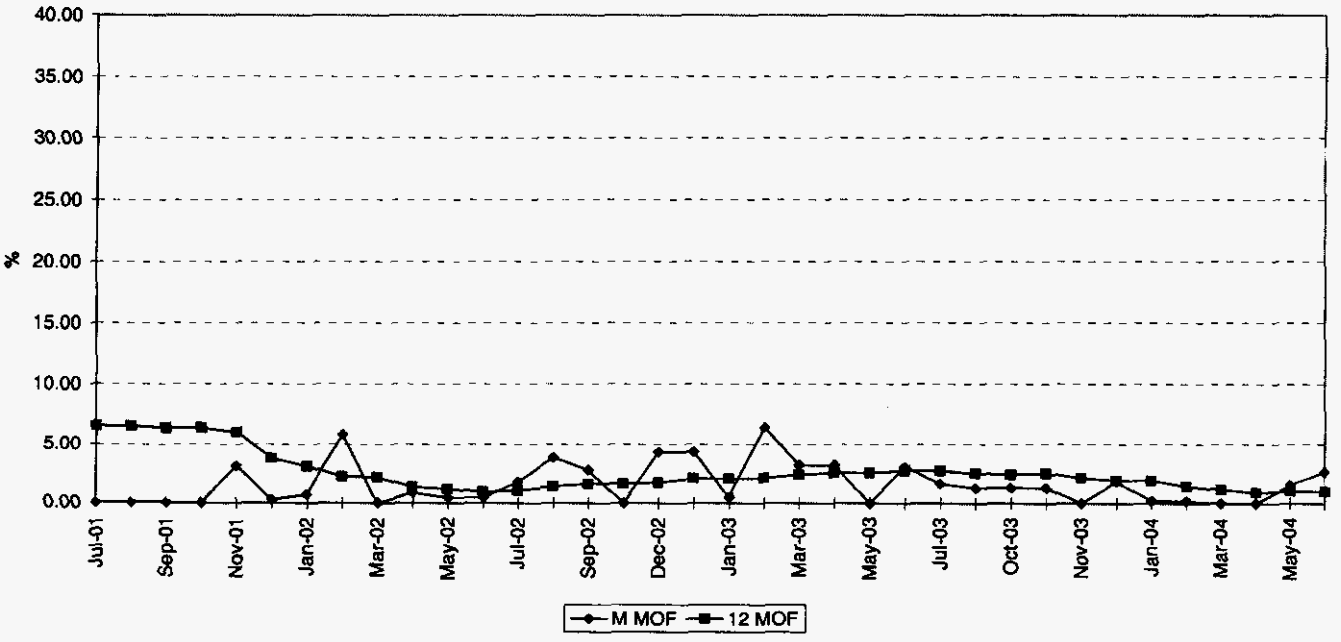
Plant/Unit	EAF	EPOF	EUOF	PH	SH	RSH	UH	EPOH	EFOH	EMOH	NET_GEN
Lauderdale 4	92.7	3.3	4.0	8760	8003	118	639	289	175	175	3,278,217
Lauderdale 5	75.5	19.7	4.8	8760	6595	19	2146	1726	175	245	2,622,653
Manatee 1	74.6	20.5	4.9	8760	4501	2034	2225	1796	254	175	2,366,608
Manatee 2	96.0	0.0	4.0	8760	5268	3142	350	0	175	175	2,625,941
Martin 1	76.0	17.3	6.7	8760	5534	1124	2102	1515	412	175	2,934,991
Martin 2	92.9	0.0	7.1	8760	6542	1596	622	0	175	447	3,530,341
Martin 3	92.2	0.8	7.0	8760	7679	398	683	70	263	350	3,092,943
Martin 4	92.5	2.5	5.0	8760	7662	441	657	219	175	263	3,112,541
Scherer 4	95.5	0.0	4.5	8760	7844	522	394	0	175	219	4,536,350
St. Lucie 1	77.2	16.4	6.4	8760	6759	0	2001	1440	280	280	6,027,256
St. Lucie 2	93.6	0.0	6.4	8760	8199	0	561	0	280	280	6,140,275
Turkey Point 3	93.6	0.0	6.4	8760	8199	0	561	0	280	280	6,003,740
Turkey Point 4	75.8	17.8	6.4	8760	6639	0	2121	1560	280	280	4,949,673

EPOF = equivalent planned outage factor. EPOF=(EPOH/PH)*100
EUOF = equivalent unavailable outage factor. EUOF=((EFOH+EMOH)/PH)*100
PH = period hours
SH = service hours
RSH = reserve shutdown
UH = unavailable hours . UH=PH-SH-RSH
EPOH = equivalent planned outage hours
EFOH = equivalent forced outage hours
EMOH = equivalent maintenance outage hours

PFL 4
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



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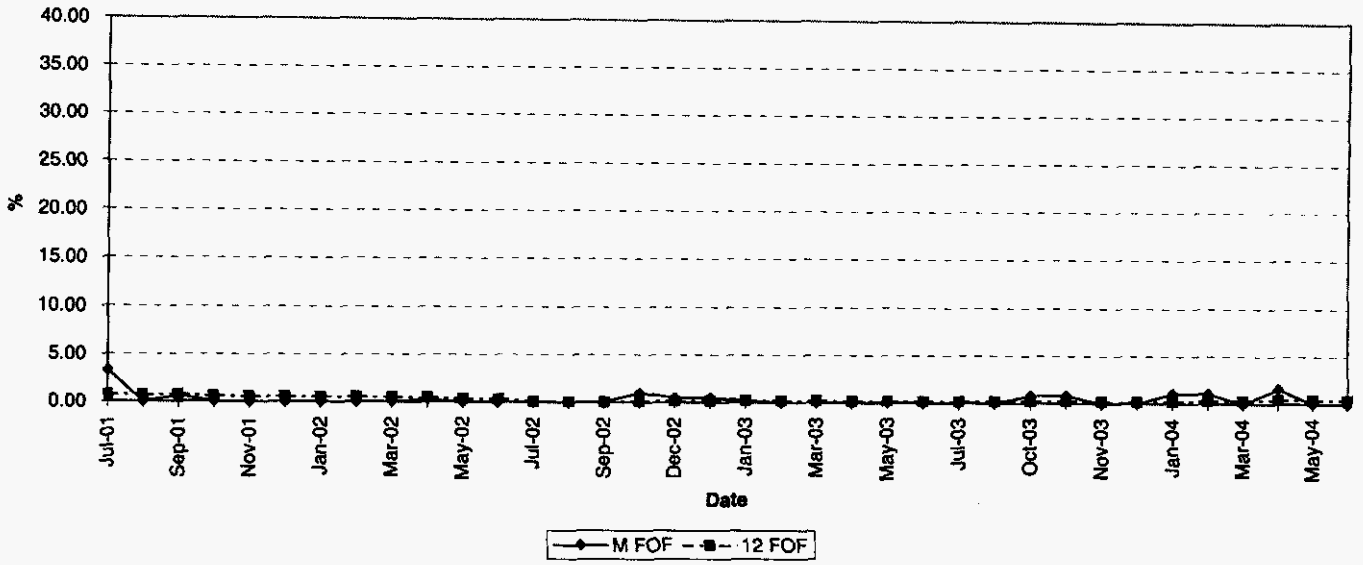

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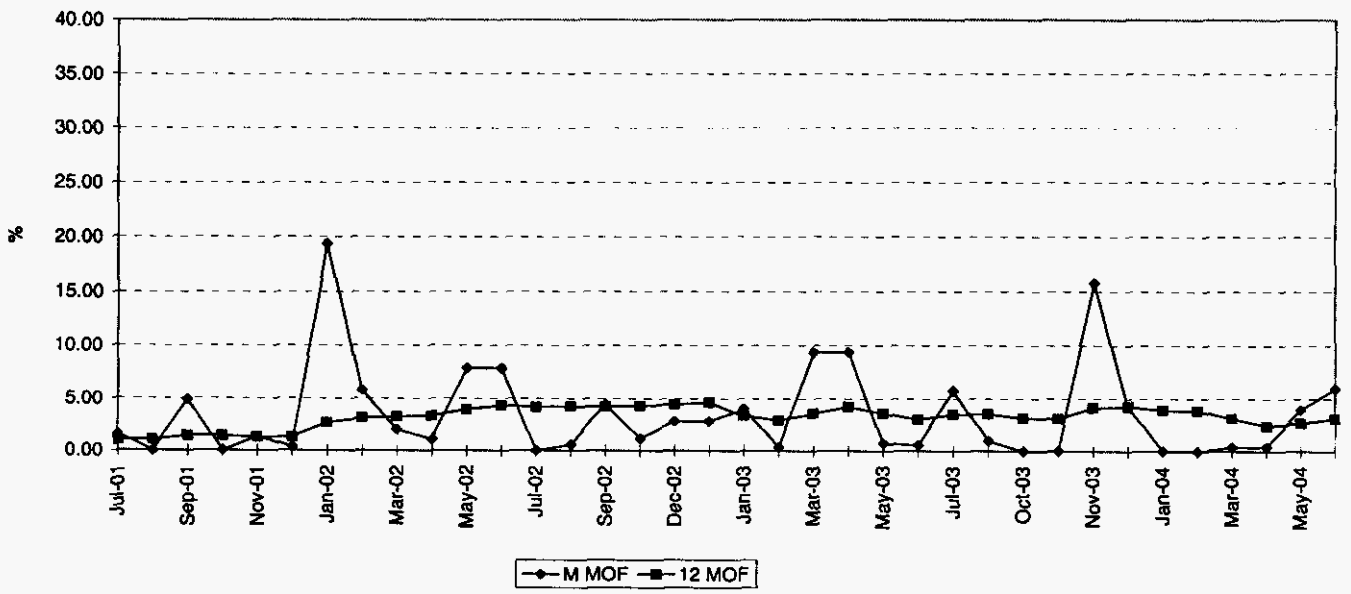

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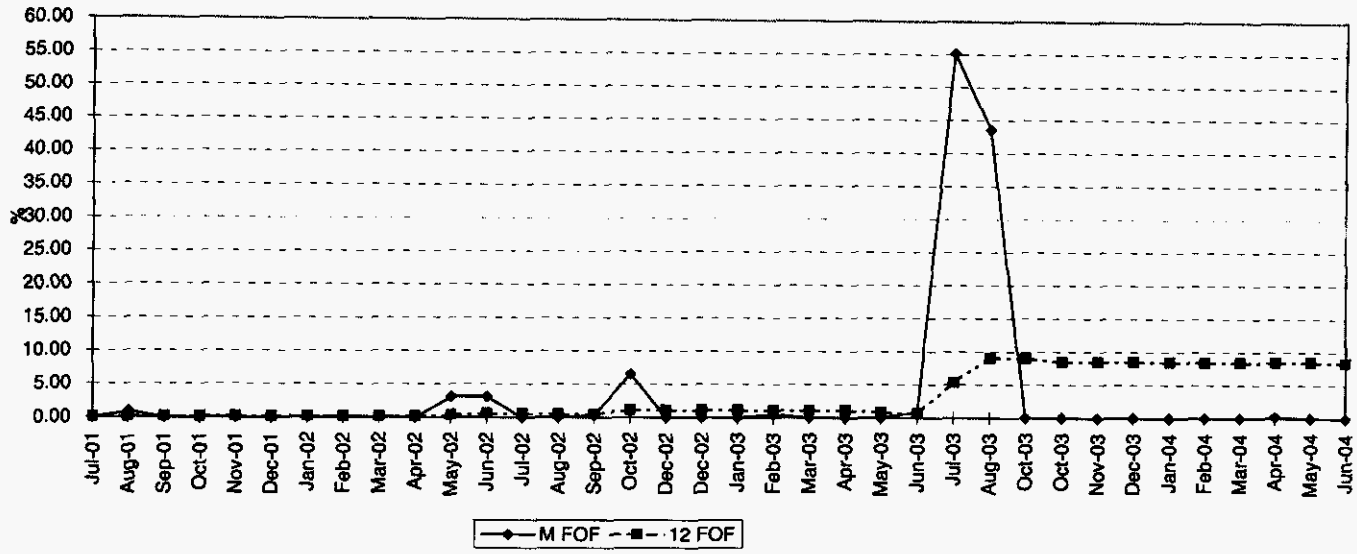

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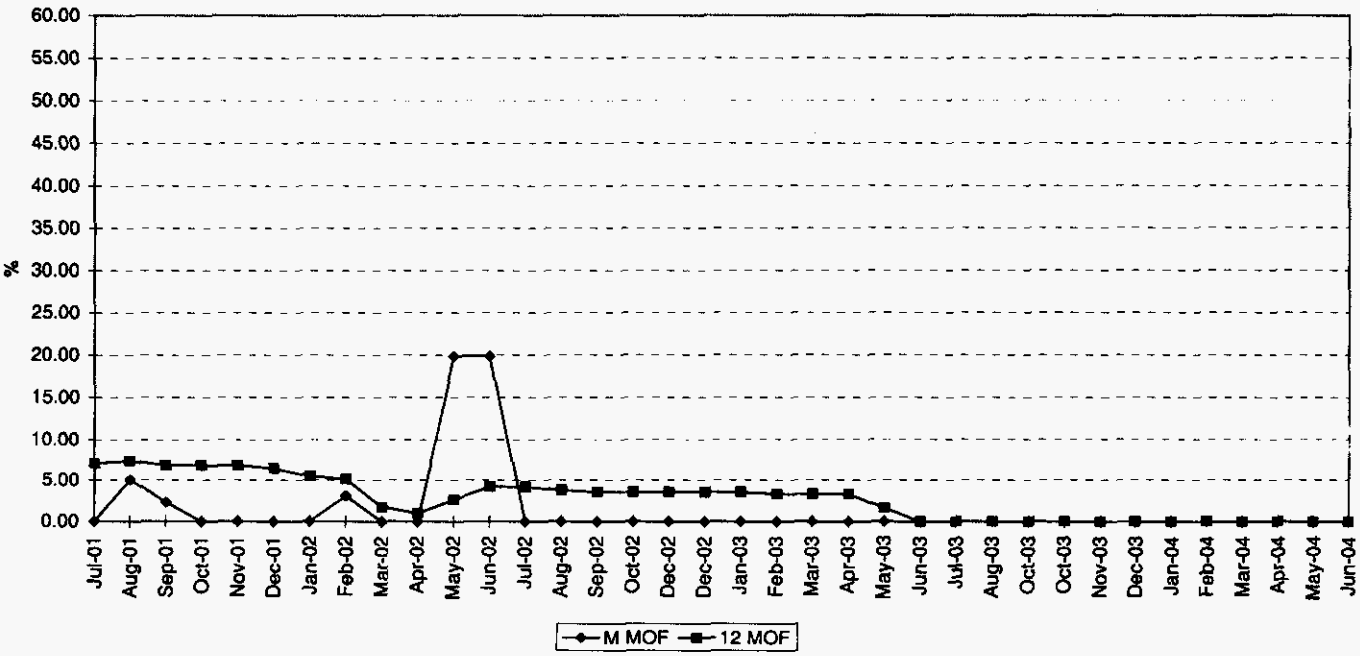

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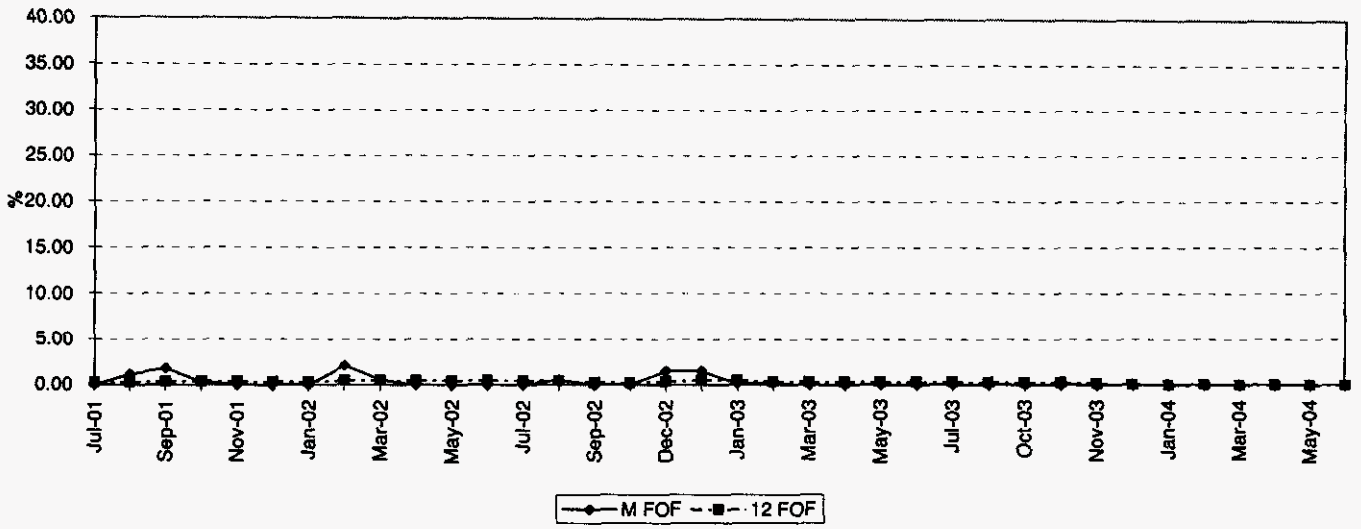

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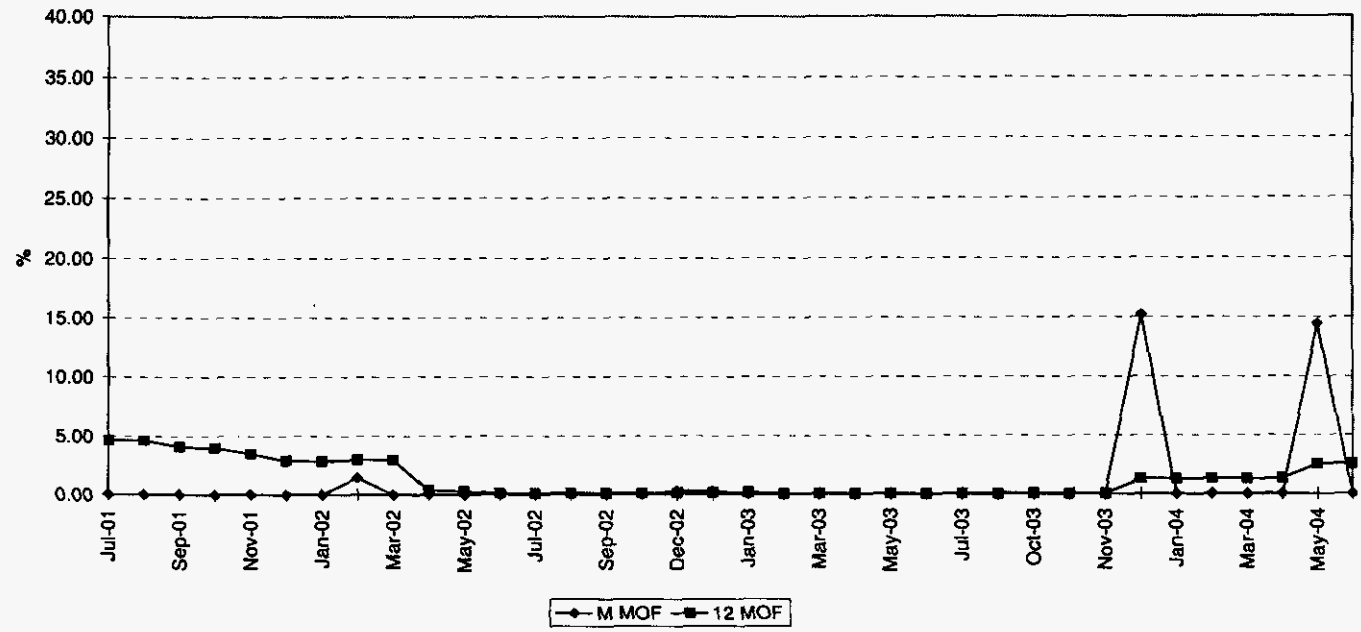

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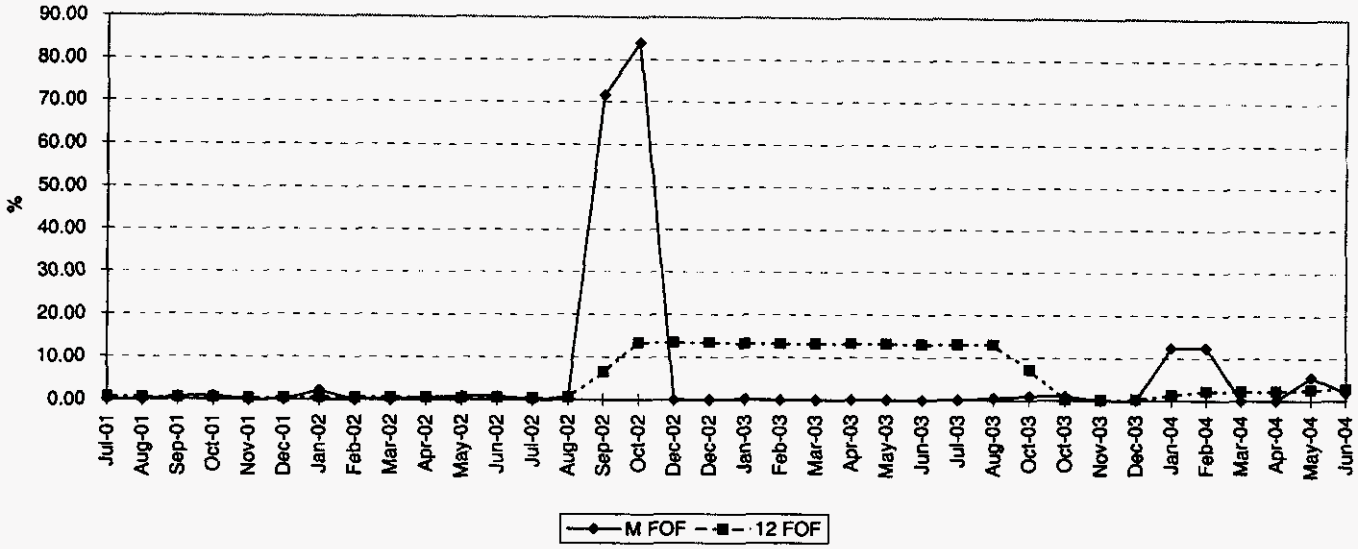

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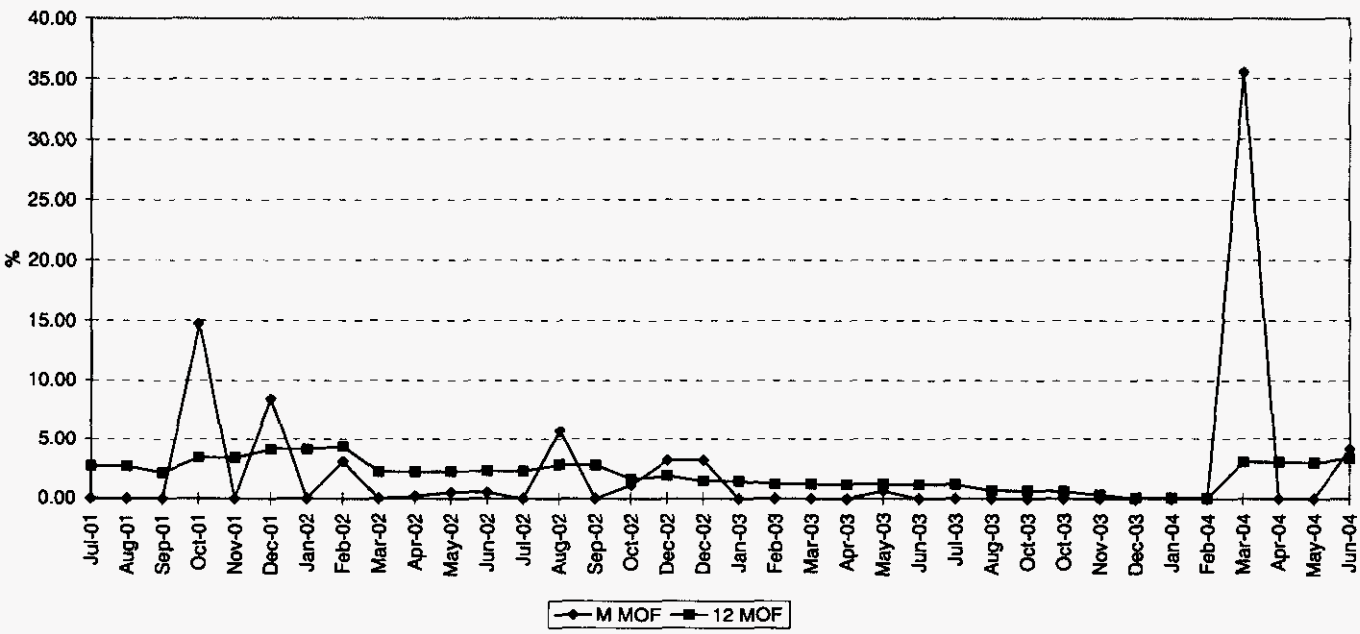

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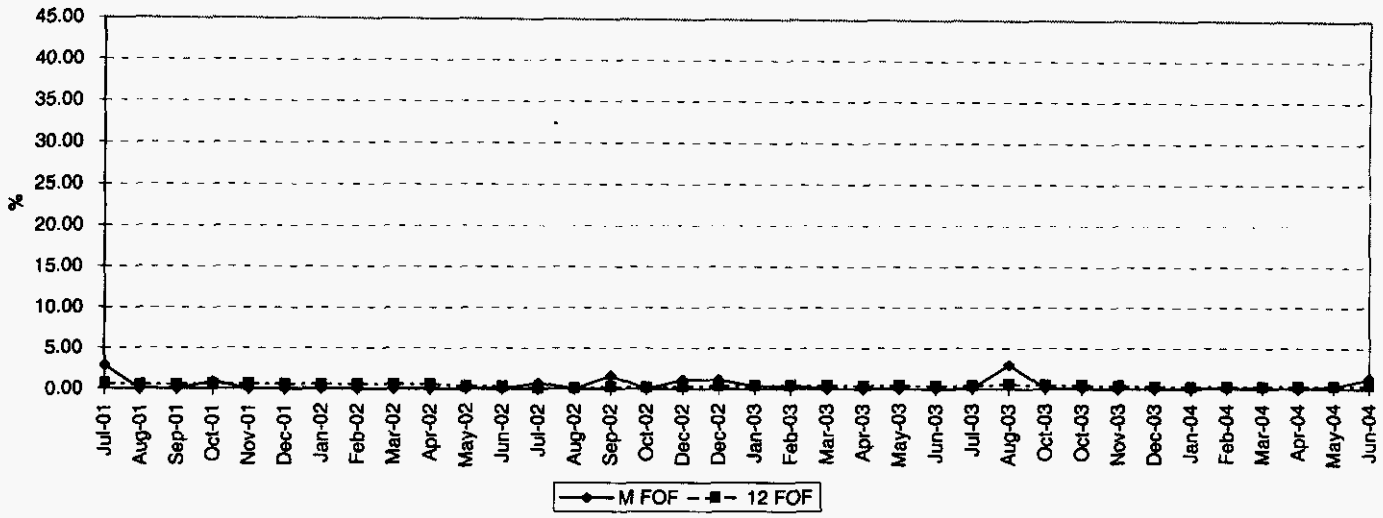

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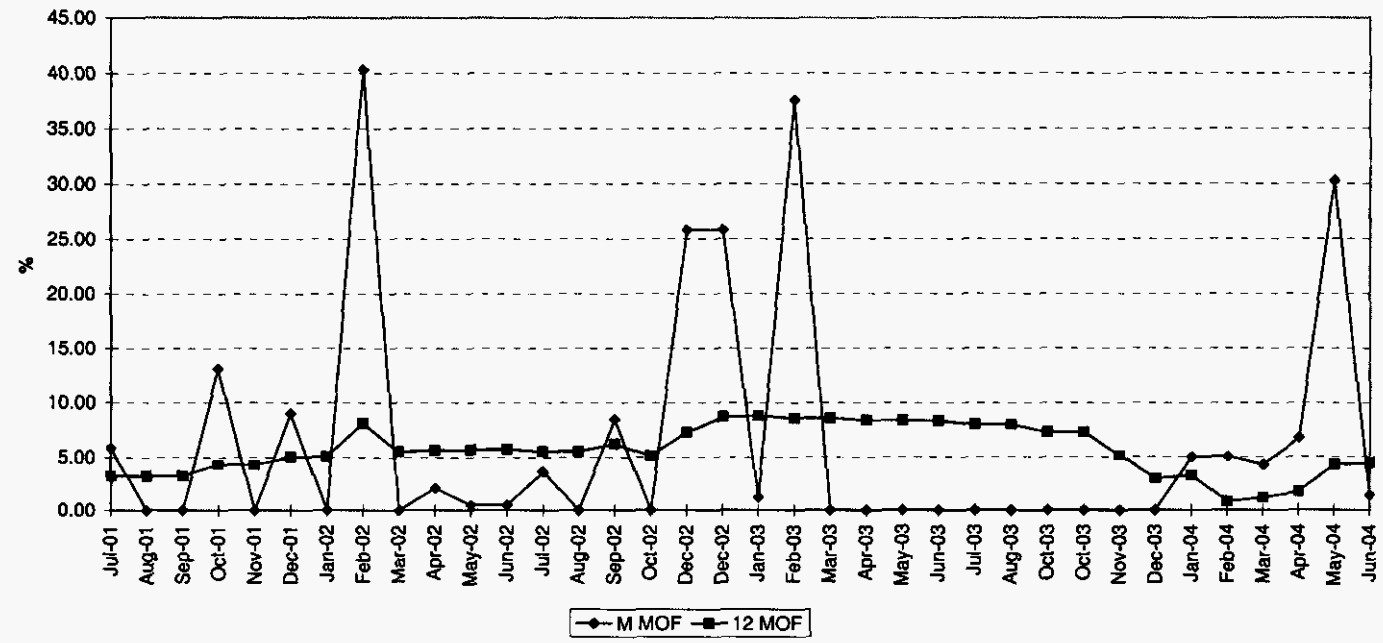

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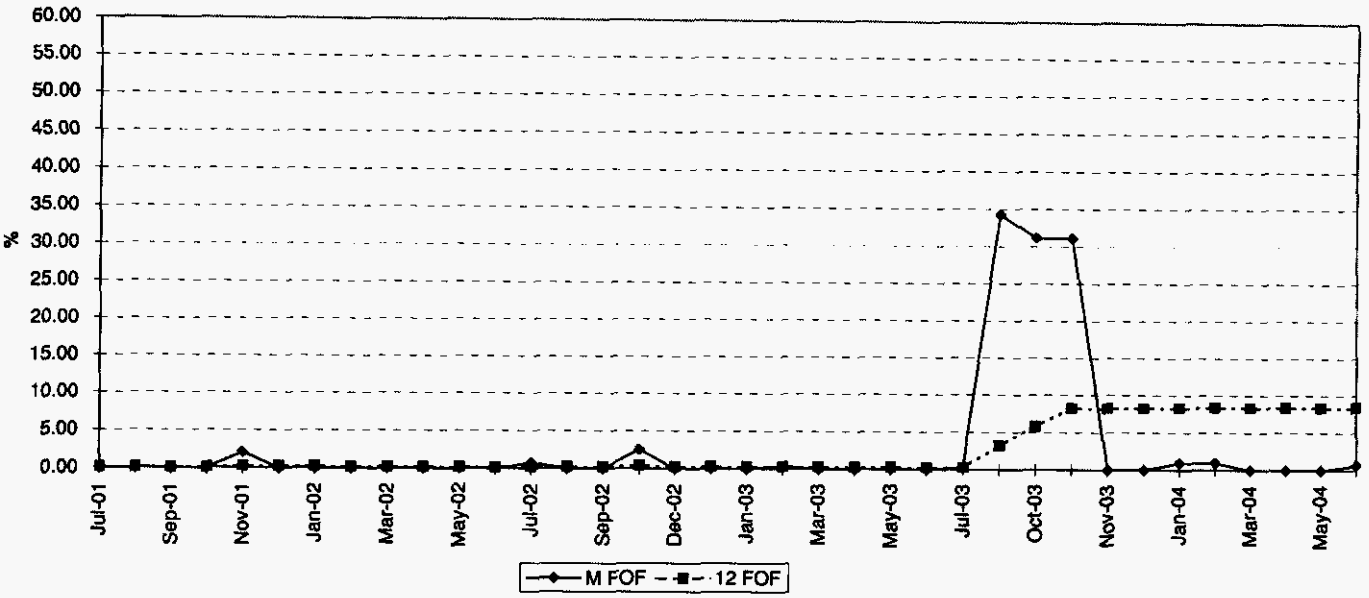

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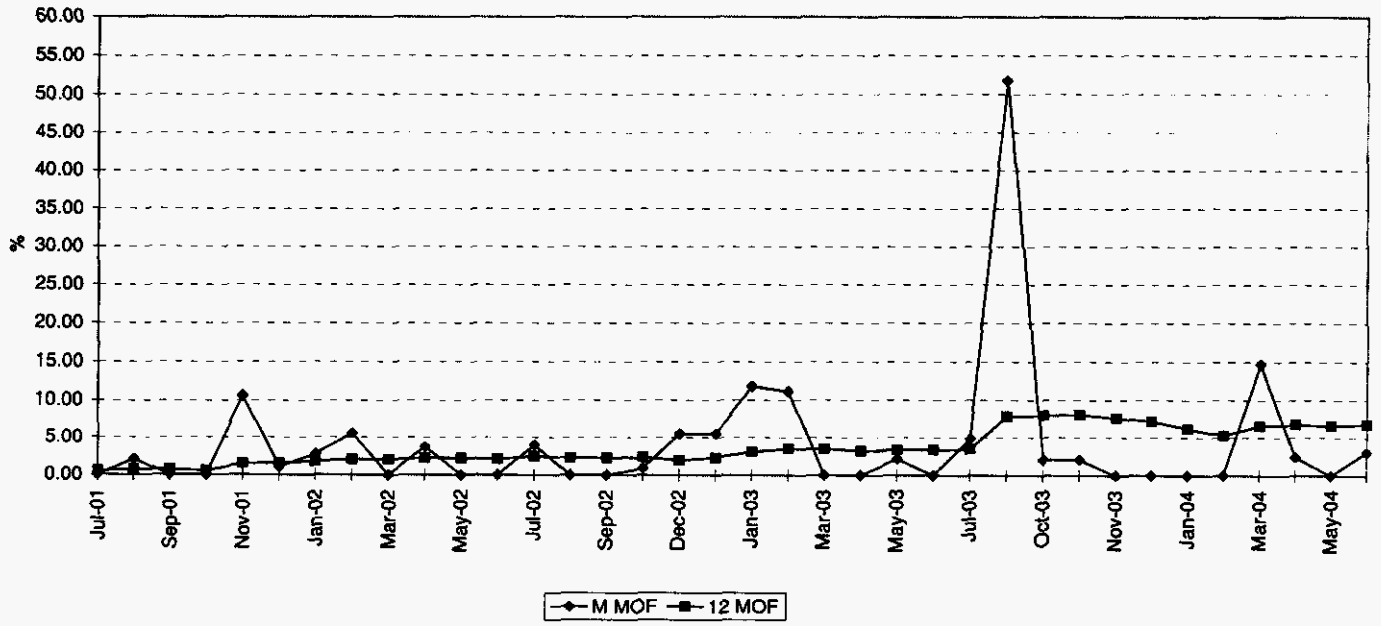

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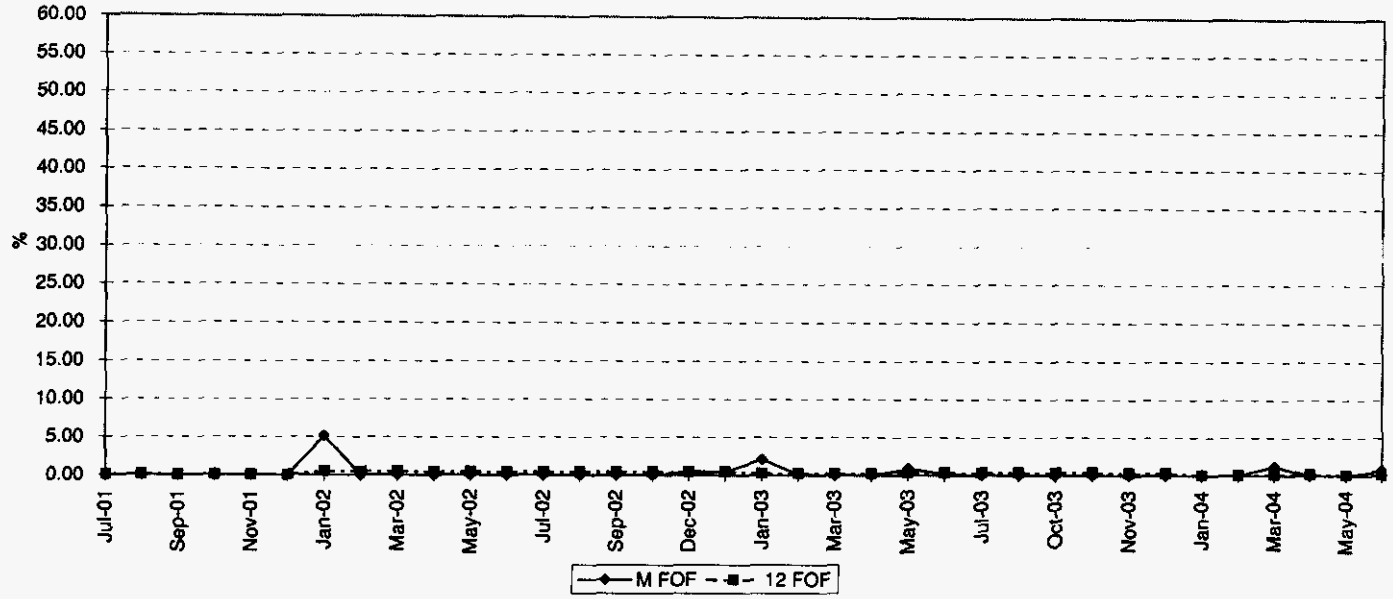

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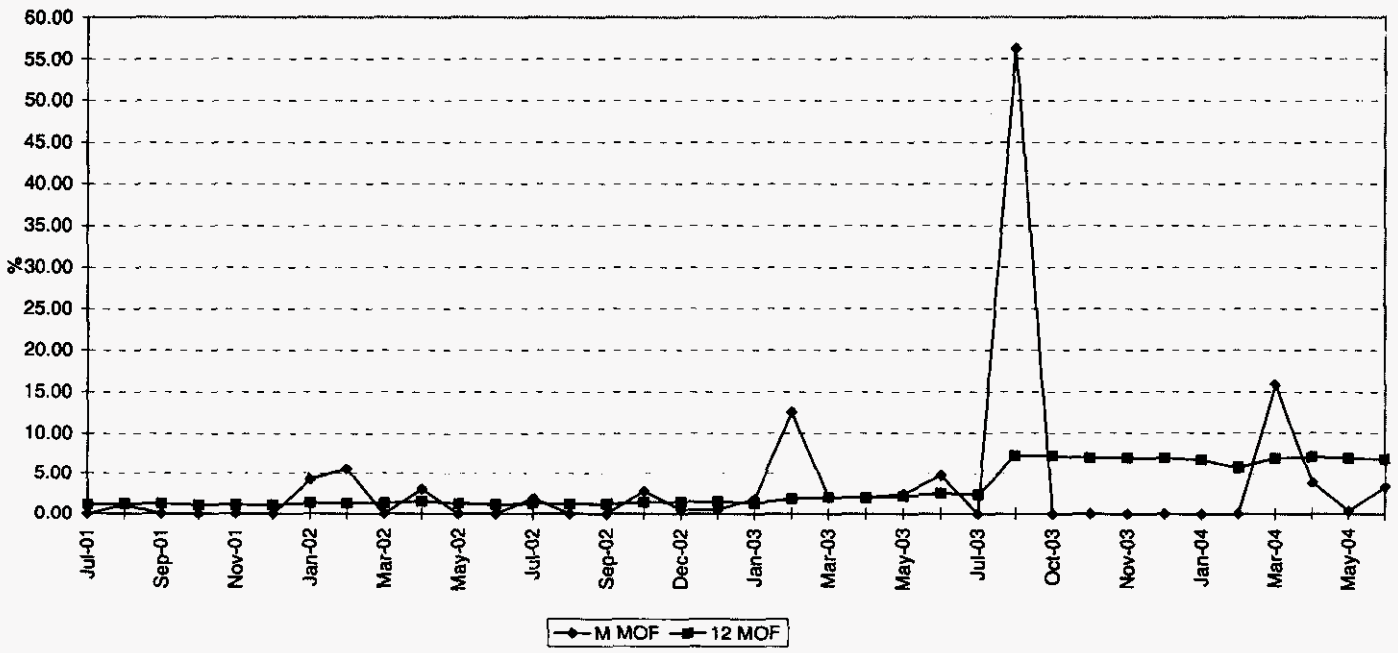

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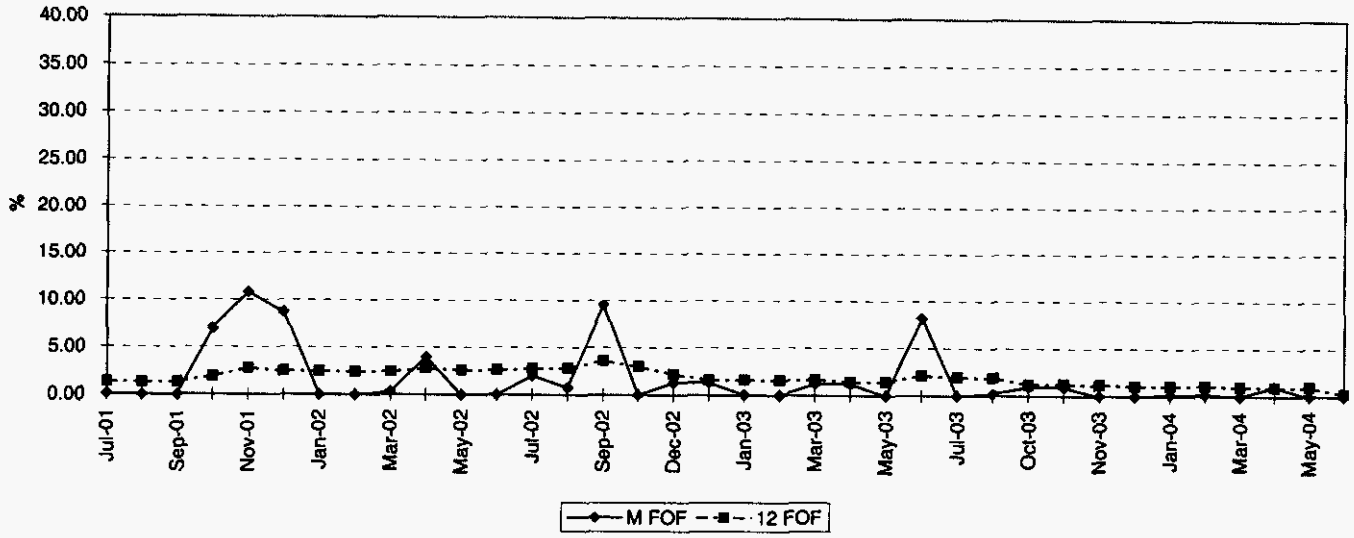

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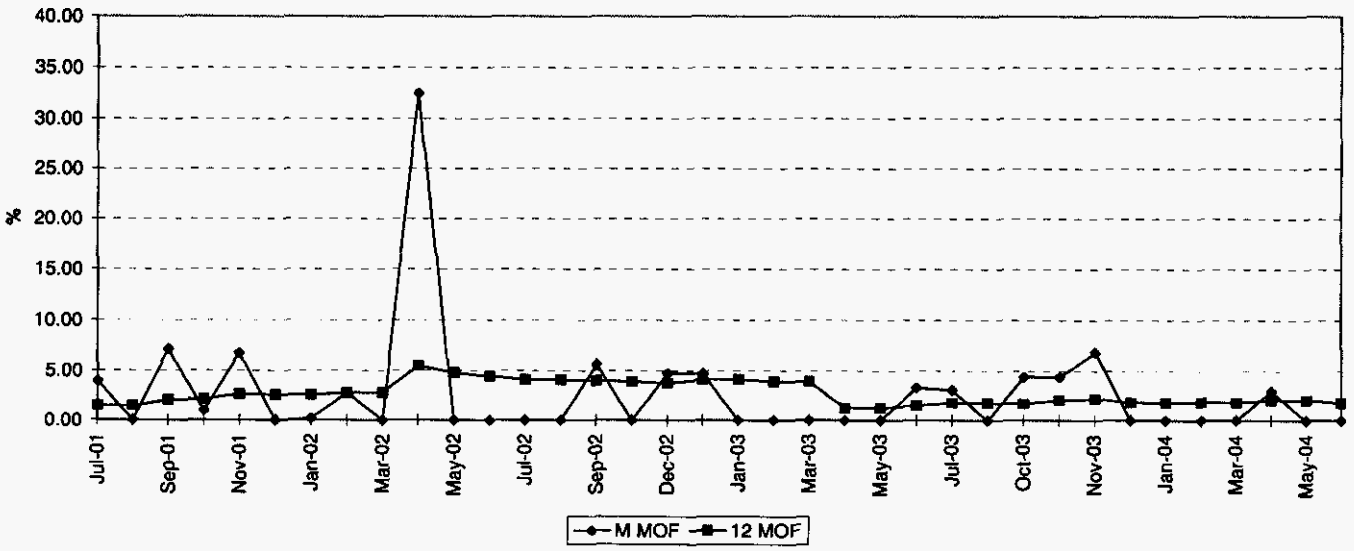

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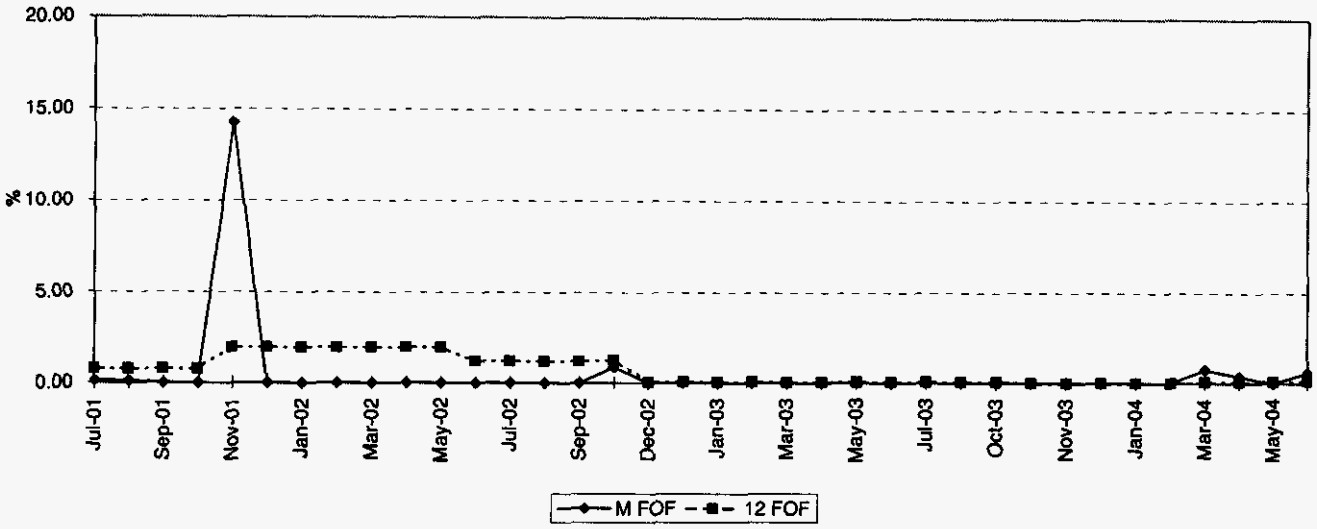

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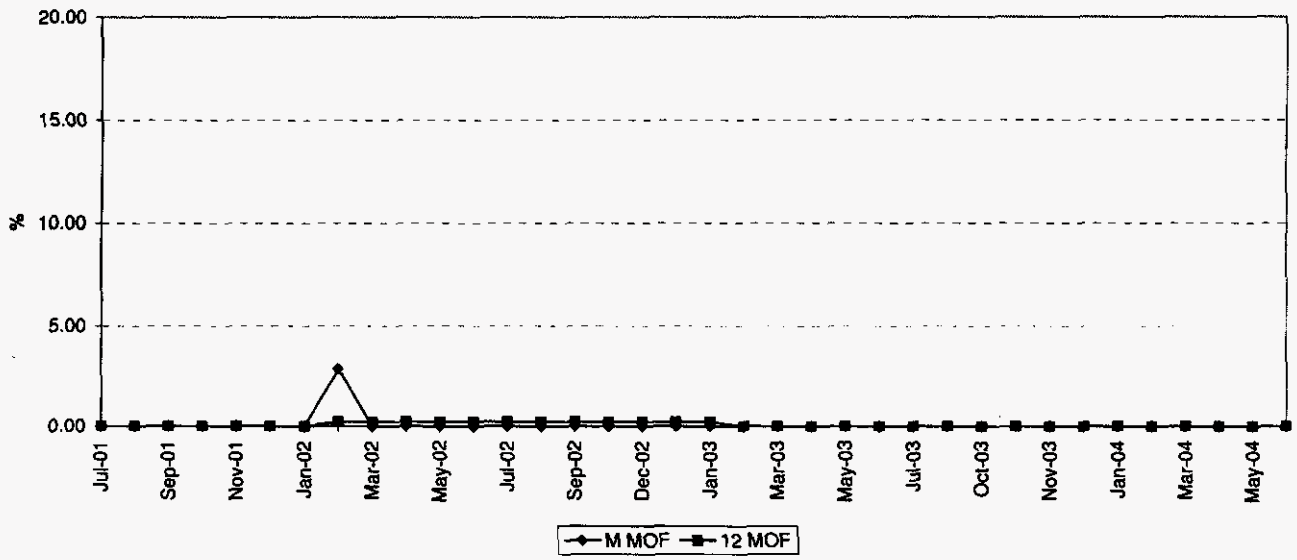

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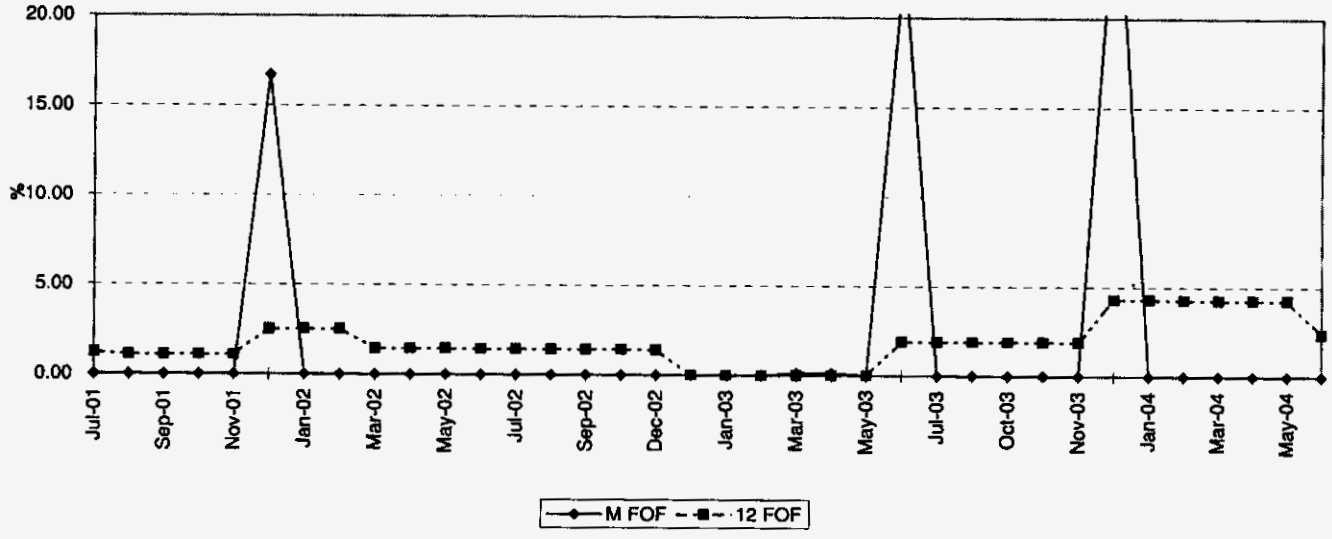

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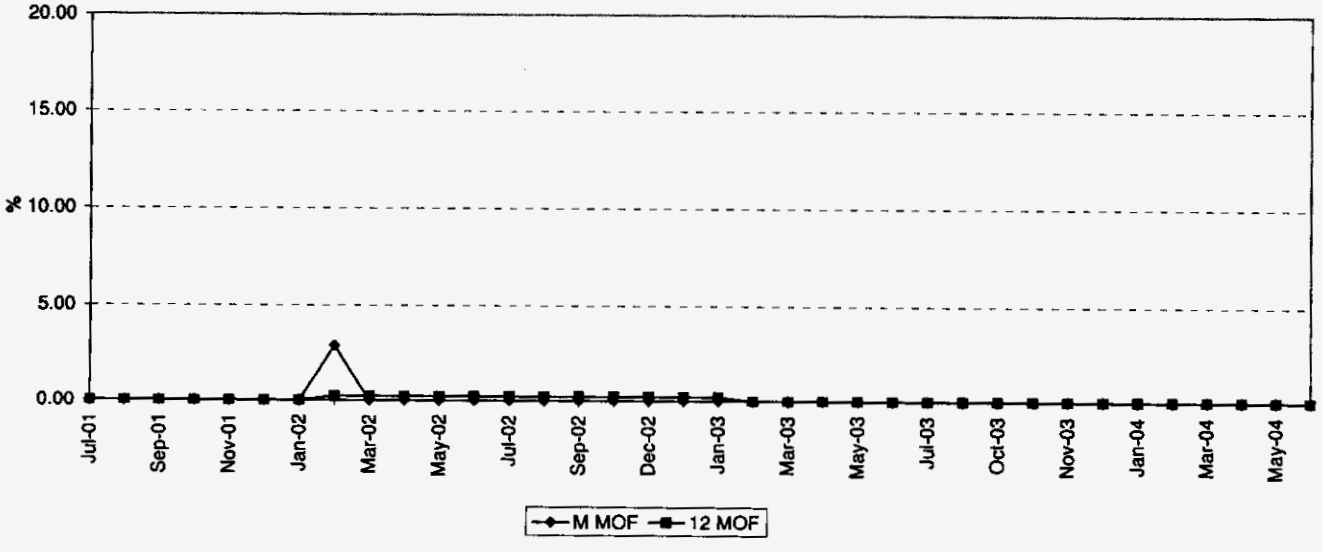

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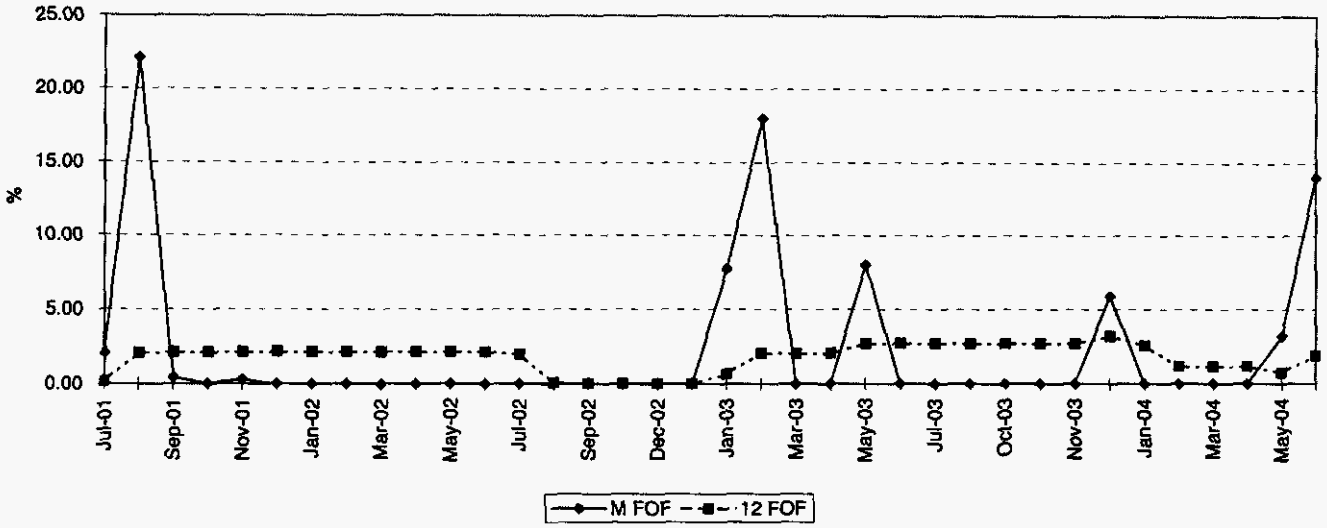

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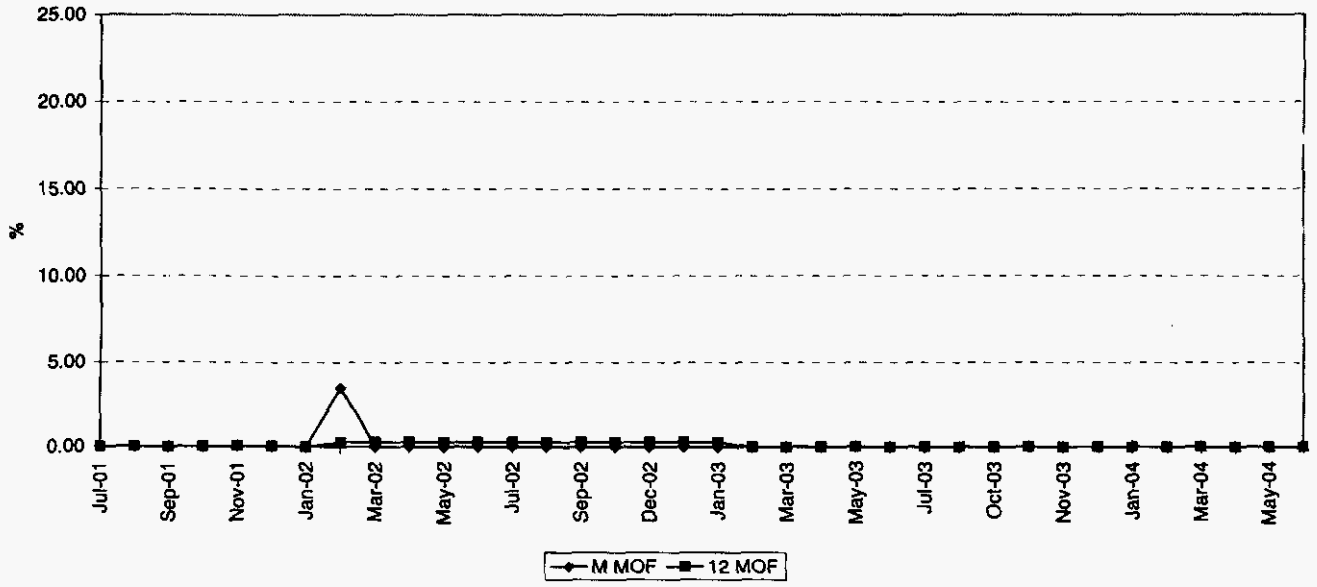

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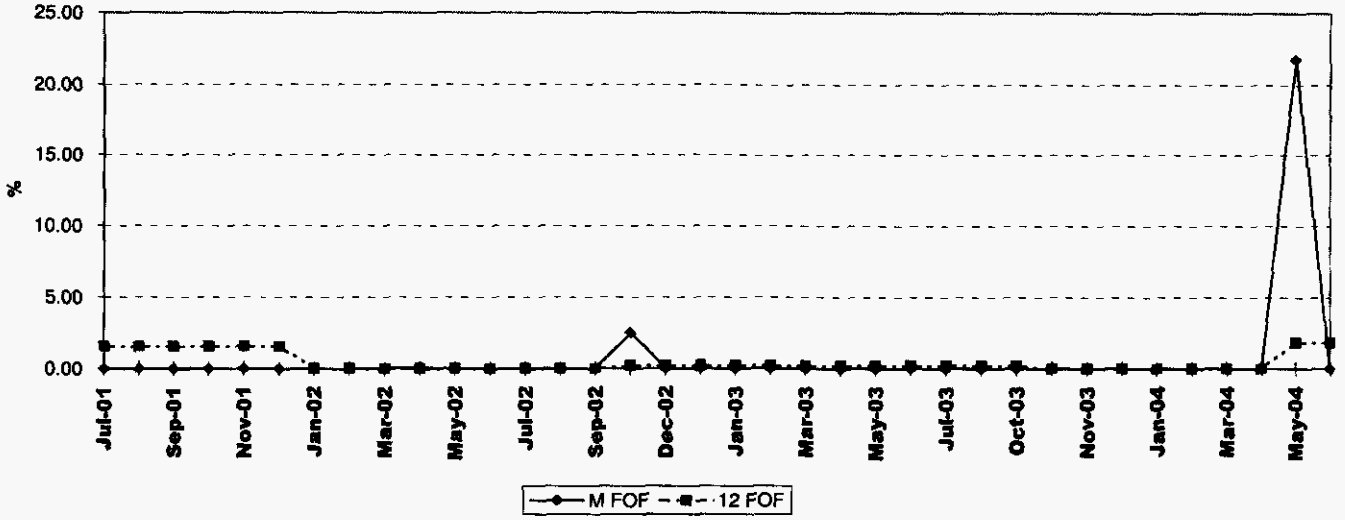

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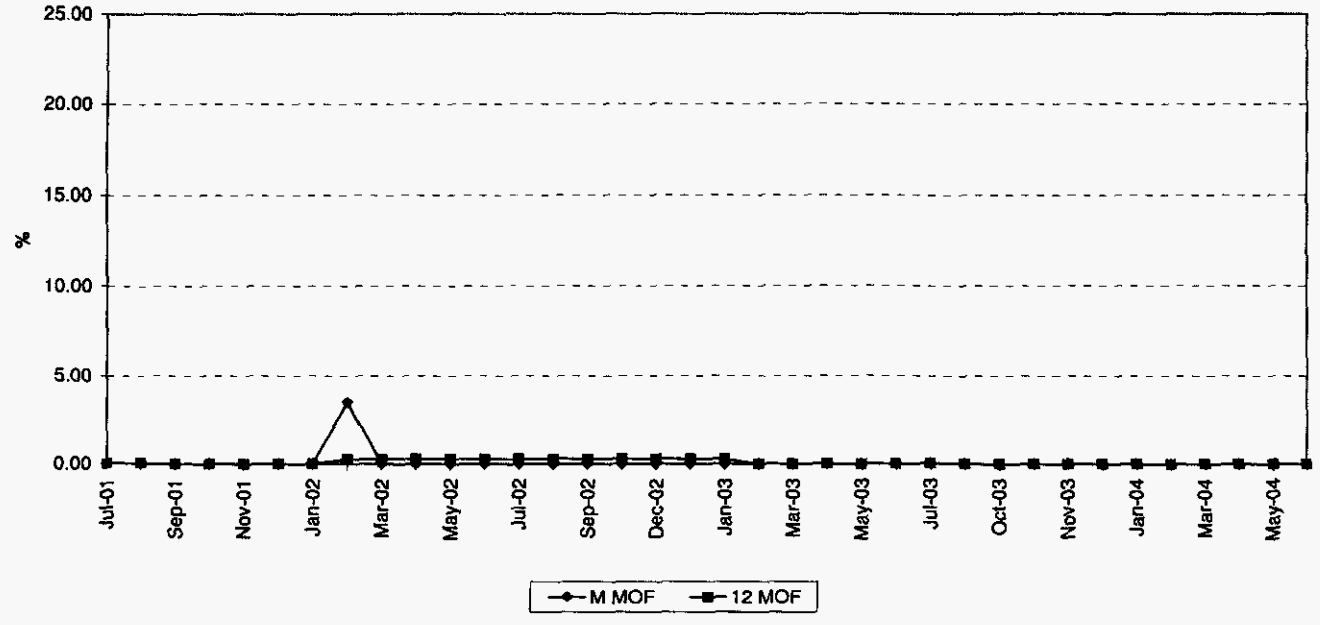

PLANNED OUTAGE SCHEDULE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY THROUGH DECEMBER, 2005

PLANT/UNIT	PLAN OUTAGE*	REASON FOR OUTAGE	LR MW**
Lauderdale 4	03/19/2005 - 03/30/2005	A CT COMBUSTOR INSPECTION (CI) / B CT CI	443
Lauderdale 5	09/24/2005 - 12/04/2005	A CT MAJOR OH / B CT CI / STEAM (ST) GEN STATOR REWIND (GS	442
Manatee 1	09/17/2005 - 11/30/2005	GSR / REBURN UPGRADE	802
Manatee 2	NONE		
Martin 1	01/29/2005 - 04/01/2005	ST TURB IP/ MINOR BOILER/GENERATOR ROTOR REPLACEMENT	813
Martin 2	NONE		
Martin 3	03/12/2005 - 03/17/2005	B CT COMBUSTOR INSPECTION - 50% CURT	233
Martin 4	02/12/2005 - 02/17/2005	A CT COMBUSTOR INSPECTION - 50% CURT	233
Martin 4	03/19/2005 - 03/30/2005	B CT HOT PATH - 50% CURT	233
Scherer 4	NONE		
St. Lucie 1	10/03/2005 - 12/02/2005	Refueling/reactor vessel head replacement	839
St. Lucie 2	NONE		
Turkey Point 3	NONE		
Turkey Point 4	04/09/2005 - 06/13/2005	Refueling/reactor vessel head replacement	693

*Dates are estimated from breaker open to breaker close
**Load Reduction MW are based on the unit's MW rating during the specified outage period

EXECUTION COPY

CONTRACT FOR THE

PURCHASE OF CAPACITY AND ENERGY

BETWEEN

SOUTHERN COMPANY SERVICES, INC.

AND

FLORIDA POWER & LIGHT COMPANY

FROM

PLANT SCHERER UNIT NO. 3

DATED AS OF AUGUST 11, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 13
COMPANY/ F.P.+L.
WITNESS: J.L. Hartman (TLH-1)
DATE: 11-08-04

TLH-1
DOCKET NO. 040001-EI
FPL WITNESS: T. HARTMAN
EXHIBIT ____
SEPTEMBER 9, 2004

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EXECUTION COPY

CONTRACT FOR THE PURCHASE OF CAPACITY AND ENERGY BETWEEN SOUTHERN COMPANY SERVICES, INC., AS AGENT FOR GEORGIA POWER COMPANY AND GULF POWER COMPANY, AND FLORIDA POWER & LIGHT COMPANY

This CONTRACT FOR THE PURCHASE OF CAPACITY AND ENERGY is made and entered into as of this 11th day of August, 2004 ("Effective Date"), between **SOUTHERN COMPANY SERVICES, INC.**, an Alabama corporation having its principal office and place of business at 600 North 18th Street, Birmingham, Alabama 35203, acting as agent (in such capacity hereinafter referred to as "SCS") for Georgia Power Company (hereinafter referred to as "Georgia Power"), a Georgia corporation having its principal office and place of business at 241 Ralph McGill Boulevard NE, Atlanta, Georgia 30308, and Gulf Power Company (hereinafter referred to as "Gulf Power" and collectively with Georgia Power referred to as "Seller"), a Maine corporation having its principal office and place of business at One Energy Place, Pensacola, Florida 32520, and **FLORIDA POWER & LIGHT COMPANY** (hereinafter referred to as "FPL" or "Buyer"), a Florida corporation having its principal office and place of business at 700 Universe Boulevard, Juno Beach, Florida 33408. Seller and Buyer are hereafter referred to individually and collectively as a "Party" or the "Parties," respectively.

RECITALS:

Buyer desires to purchase and Seller desires to sell, capacity and energy in accordance with this Agreement.

Subject to the terms and conditions of this Agreement, Seller will provide and sell to Buyer, and Buyer will accept and purchase from Seller, capacity and energy from the Facility or from other resources as provided in this Agreement.

NOW THEREFORE, in consideration of the foregoing recitals and the mutual covenants and agreements hereinafter set forth, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1

DEFINITIONS

The following terms shall have the respective meanings set forth below.

"**Affiliate**" means, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly (through one or more intermediaries) controls, is controlled by, or is under common control with, such corporation, partnership, or other entity.

"After-Tax Basis" – means, with respect to any payment under Section 12.2 to any Person, the amount of such payment ("Base Payment") supplemented by a further payment ("Additional Payment") to that Person so that the sum of the Base Payment plus the Additional Payment shall, after deduction of the amount of all Federal, state and local income taxes required to be paid by such Person in respect of the receipt or accrual of the Base Payment and the Additional Payment (taking into account the net present value of any reduction in such income taxes resulting from tax benefits realized by the recipient as a result of the payment or the event giving rise to the payment), be equal to the amount required to be received. Such calculations shall be made on the basis of the highest generally applicable Federal, state and local income tax rates applicable to the Person for whom the calculation is being made for all

relevant periods, and shall take into account the deductibility of state and local income taxes for Federal income tax purposes.

"**Agreement**" means this Contract for the Purchase of Capacity and Energy, including, to the extent applicable, any appendices hereto and any amendments that the Parties may execute now or at any time in the future.

"**Alternate Delivery Point(s)**" means, when Seller designates an Alternate Resource(s) pursuant to Section 5.5 or Section 5.6 (including a Replacement Resource), the applicable point(s) of delivery designated by Seller.

"**Alternate Resource(s)**" means any resource or resources other than the Facility (whether such other resources are owned, purchased or otherwise controlled by Seller, or that are otherwise available to Seller) that Seller designates pursuant to Section 5.5 or Section 5.6.

"**Available Capacity**" means, at any given time, the Contract Capacity less the sum of: (i) the Force Majeure Capacity at such time; and (ii) the Outage Capacity at such time.

"**Billing Month**" means each Month during the Term beginning with the second Month of the first Contract Year and includes the Month immediately following the expiration or early termination of this Agreement.

"**Btu**" means British Thermal Units.

"**Business Day**" means any Day on which Federal Reserve Member Banks in New York, New York are open for business. A Business Day shall begin at 0800 CPT and end at 1700 CPT.

"**Buyer**" has the meaning set forth in the introductory paragraph hereof.

"Buyer Delivery Point(s)" means, for any hour of any Delivery Day, the point(s) on the Southern Company Transmission System to which Buyer intends to transmit energy delivered by Seller under this Agreement.

"Buyer Percentage" means 19.57 percent.

"Central Prevailing Time" or **"CPT"** means the local time at any point in Birmingham, Alabama.

"Change in Law" means the adoption, enactment, promulgation or issuance of, a change in, or a new or changed interpretation by a Government Agency of, any Law after February 6, 2004.

"Commercially Reasonable" or **"Commercially Reasonable Efforts"** means, with respect to any purchase, sale, decision, or other action made, attempted or taken by a Party, such efforts as a reasonably prudent business would undertake for the protection of its own interest under the conditions affecting such purchase, sale, decision, or other action, including without limitation, electric system reliability and stability, the amount of notice of the need to take such action, the duration and type of the purchase or sale or other action, and the commercial environment in which such purchase, sale, decision, or other action occurs.

"Contemporaneous Agreements" means: (i) this Agreement; (ii) the Contract for the Purchase of Capacity and Energy from Plant Franklin Unit No. 1 dated as of August 11, 2004 between Southern Company Services, Inc. (acting as agent for Southern Power Company) and Buyer; and (iii) the Contract for the Purchase of Capacity and Energy from Plant Harris Unit No. 1 dated as of August 11, 2004 between Southern Company Services, Inc. (acting as agent for Southern Power Company) and Buyer.

"**Contest**" means with respect to any Person, a contest of any Governmental Approval or Law, acts or omissions by any Government Agency, a requirement of any Government Agency, or any related matters, so long as the contesting Party could not reasonably be expected to be prevented from performing its material obligations under this Agreement pending the outcome of such contest.

"**Contract Capacity**" means, for the applicable calendar year, the product of: (i) the Buyer Percentage; and (ii) the applicable Total Facility Capacity, rounded down to the nearest whole MW.

"**Contract Year**" means: (i) for the first Contract Year, the Service Commencement Date through the next date that is May 31; and (ii) for each Contract Year thereafter, each twelve (12) Month period beginning June 1 and ending May 31; provided, however, the last Contract Year shall end on the date that this Agreement terminates or expires.

"**Day**" means the period of time beginning at hour ending 0100 CPT and ending at hour ending 2400 CPT.

"Delivery Day" means any Day for which Buyer Schedules energy to be delivered in accordance with this Agreement.

"**Delivered Energy**" means, for any hour, the amount of energy (expressed in MWh) delivered by Seller in accordance with this Agreement and shall equal the sum of energy delivered by Seller to the Delivery Point pursuant to Buyer's Schedule and any energy provided and/or procured by Seller to resolve energy imbalances at the Delivery Point. Delivered Energy shall not exceed Scheduled Energy for any hour.

"Delivered Energy Credit" means, for any hour, to the extent such difference is positive, the difference of: (i) Delivered Energy for such hour; less (ii) Available Capacity plus

the portion of Delivered Energy provided from an Alternate Resource(s) designated for such hour pursuant to Section 5.5.1 in response to a Force Majeure Event.

"**Delivery Excuse**" means: (i) an Event of Default by Buyer; (ii) the interruption of transmission service procured by Buyer or the unavailability of transmission service to Buyer beyond the Delivery Point(s); or (iii) any directive from the applicable transmission provider and/or the control area operator to cease deliveries of energy from the Facility.

"**Delivery Point**" means the Facility Delivery Point when Seller designates the Facility as the source of Delivered Energy and/or the Alternate Delivery Point(s) (as applicable) to which Seller shall deliver energy to Buyer hereunder.

"**Effective Date**" has the meaning set forth in the introductory paragraph hereof.

"**Electric Metering Equipment**" means electric meters and associated equipment, including metering transformers and back-up meters.

"**EFMH**" or "**Equivalent Force Majeure Hour**" shall occur in any hour (or portion of an hour) in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point is occurring or is continuing. During such an hour, EFMH shall equal the ratio of: (A)(i) Force Majeure Capacity for such hour; less (ii) the amount of electric capacity associated with an Alternate Resource(s), whether available or unavailable, that has been designated for such hour pursuant to Section 5.5.1 in response to the Force Majeure Event causing the Force Majeure Capacity to exist; to (B) the Contract Capacity.

"**EUH**" or "**Equivalent Unavailable Hour**" shall occur in any hour (or portion of an hour) in which there is Unavailable Capacity. For such an hour, EUH shall equal the ratio of: (i) Unavailable Capacity for such hour; to (ii) the Contract Capacity for such hour.

"**Event of Default**" has the meaning set forth in Section 14.1.

"**Facility**" means Seller's coal fired steam turbine electric generating unit known as Plant Robert W. Scherer Unit No. 3 (as may be modified) and all appurtenant facilities located near Juliette, Georgia which directly interconnects to the Georgia Integrated Transmission System.

"Facility Delivery Point" means the substation where the Facility interconnects to the Georgia Integrated Transmission System (or other applicable transmission system) at the transmission system voltage.

"**FERC**" means the Federal Energy Regulatory Commission, or any successor to its functions.

"Florida Interface" means the transmission interface between the Southeastern Electric Reliability Council (or its successor) region and the Florida Reliability Coordinating Council (or its successor) region as such regions exist on the Effective Date.

"Force Majeure Capacity" means, for any hour in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, the product of: (i) the portion of the Total Facility Capacity that is not available from the Facility as a result of such Force Majeure Event; and (ii) the Buyer Percentage.

"**Force Majeure Event**" has the meaning set forth in Section 13.1.

"**Forced Outage**" means any condition or circumstance in which the generating capability of the Facility is eliminated or reduced (in whole or in part) for any reason, including an actual or threatened component failure. A Forced Outage does not include those times that the Facility's capability is reduced (in whole or in part) due to a Force Majeure Event, Delivery Excuse, or during Scheduled Outages or Maintenance Outages. In addition, a Forced Outage

shall not occur solely because of Seller's ability to sell capacity and/or energy from the Facility to a third party or an Affiliate(s).

"Georgia Integrated Transmission System" or **"GITS"** means the electric transmission systems owned individually by Georgia Power, Georgia Transmission Corporation, the Municipal Electric Authority of Georgia and the City of Dalton, Georgia, and operated as an integrated transmission system, as well as any successor transmission system.

"Georgia Power" has the meaning set forth in the introductory paragraph hereof.

"Government Agency" means any federal, state, local, territorial or municipal government and any department, commission, board, court, bureau, agency, instrumentality, judicial or administrative body thereof.

"Governmental Approval" means any authorization, consent, approval, license, ruling, permit, exemption, variance, order, judgment, decree, declarations of or regulation of any Government Agency relating to the Facility or to the execution, delivery or performance of this Agreement.

"Guarantor" has the meaning set forth in Section 14.1.

"Guaranty" means a guaranty or other instrument guaranteeing a Party's obligations under this Agreement as contemplated under Article 18.

"Gulf Power" has the meaning set forth in the introductory paragraph hereof.

"IIC" means the Southern Company System Intercompany Interchange Contract among the electric operating companies of Southern Company (or any successor arrangement), as the same may be changed or amended from time to time.

"Imaged Agreement" has the meaning set forth in Section 19.17.

"Increased Generation Costs" means [redacted]

[redacted]

"**kW**" means kilowatt(s).

"**kWh**" means kilowatt hour(s).

"**Law**" means any act; statute; law; requirement; ordinance; order; ruling or rule; regulation; standards and/or criteria contained in any permit, license or other approval; legislative or administrative action; or a decree, judgment or order of any Government Agency imposed, whether in effect now or at any time in the future.

"Long Term Firm Transmission Service" means firm point-to-point (or other equivalent) transmission service for a term of one year or more.

"Maintenance Outage" has the meaning set forth in Section 4.2.

"Minimum Schedule Amount" has the meaning set forth in Appendix D.

"MMBtu" means one million Btu.

"Month" means a calendar month.

"Monthly Capacity Payment" means the payment for Contract Capacity to be made by Buyer to Seller pursuant to Section 6.1.

"Monthly Energy Payment" means the payment for Delivered Energy to be made by Buyer to Seller pursuant to Section 6.2.

"Monthly Start Payment" means the payment for Successful Starts to be made by Buyer to Seller pursuant to Section 6.3.

"Moody's" has the meaning set forth in Section 17.1.

"MW" means megawatt(s).

"MWh" means megawatt hour(s).

"NERC" means the North American Electric Reliability Council, or any successor to its functions.

"OATT" means the Open Access Transmission Tariff of Southern Companies or a successor tariff governing transmission on the Southern Company Transmission System, as the same may be changed or amended from time to time.

"Operating Committee" has the meaning set forth in Section 4.5.

"Operating Procedures" has the meaning set forth in Section 4.4.

"Outage Capacity" means, for any hour in which a Forced Outage occurs or is continuing, the product of: (i) the portion of the Total Facility Capacity that is not available from the Facility as a result of such Forced Outage; and (ii) the Buyer Percentage.

"Person" means any individual, corporation, limited liability corporation, partnership, joint venture, trust, unincorporated organization, Government Agency or other entity.

"Plant" means Seller's Plant Robert W. Scherer Units 1 through 4 and all appurtenant facilities located near Juliette, Georgia, as such plant and facilities may be modified and/or expanded from time to time (including the addition of generating units).

"Prior Business Day" means the Business Day immediately prior to a Delivery Day.

"Prime Rate" means, for any Day on which the calculation of an interest amount begins under this Agreement, the "Prime Rate" specified for such Day (or, if such Day is not a Business Day, on the first Business Day following such Day) under the "Money Rate" table of the *Wall Street Journal*. In the event that the *Wall Street Journal* ceases to report a Prime Rate, the Prime Rate shall be the prime rate (or its functional equivalent) charged by the Federal Reserve Bank of Atlanta, Georgia.

"Prudent Industry Practices" means any of the practices, methods, standards and acts (including the practices, methods and acts engaged in or approved by a significant portion of the electric power industry in the United States) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, could have been expected to accomplish the desired result consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts generally conform to operation and maintenance

standards recommended by equipment suppliers and manufacturers, applicable design limits and applicable Governmental Approvals and Laws.

"Redirect Deadline" means the deadline established by the applicable transmission provider for requesting the redirect of transmission service under the applicable transmission tariff.

"S&P" has the meaning set forth in Section 17.1.

"Schedule" means the right of Buyer to request the delivery of Scheduled Energy in accordance with this Agreement. Any form of the term Schedule (e.g., "Scheduled," "Schedules" or "Scheduling") shall refer to the exercise of such right by Buyer.

"Schedule Shut-Down" means any time Buyer goes from having some energy Scheduled to having no energy Scheduled.

"Schedule Start" means each time that Buyer goes from not having any energy Scheduled to having some amount of energy Scheduled.

"Scheduled Energy" means the amounts of energy, expressed in whole MWh, Scheduled by Buyer to be delivered by Seller in accordance with this Agreement.

"Scheduled Outage" means maintenance and/or outages conducted and/or taken by Seller pursuant to Section 4.1.

"Scheduling Parameters" has the meaning set forth in Appendix D.

"SEARUC" means the Southeastern Association of Regulatory Utility Commissioners.

"Seller" has the meaning set forth in the introductory paragraph hereof.

"Service Commencement Date" means June 1, 2010; provided, however, that such date may be extended by Seller due to a Force Majeure Event for a period equal to the period of delay caused by said Force Majeure Event.

"**Southern Company**" means the Southern Company, a publicly held corporation, organized and existing under the laws of the State of Delaware and having its principal place of business in Atlanta, Georgia.

"**Southern Company Transmission**" means the functional transmission division of Southern Company and its affiliates, as well as any successor transmission service provider.

"**Southern Company Transmission System**" means the integrated transmission systems of the electric operating companies of Southern Company, as such systems may be modified or expanded from time-to-time, as well as any successor transmission system(s).

"**Successful Start**" means each time that Seller goes from delivering no energy to delivering an amount of energy at least equal to the Minimum Scheduling Amount during [redacted] of Buyer's Schedule (or such lesser amount of time for which Buyer has requested at least the Minimum Scheduling Amount); provided, however, if Seller interrupts the delivery of energy during Buyer's Schedule (other than pursuant to Buyer's request or a Delivery Excuse), a Successful Start shall not be deemed to have occurred when delivery is resumed pursuant to the same Schedule.

"**Taxes**" means any or all ad valorem, property, occupational, severance, emissions, generation, first use, conservation, energy, transmission, utility, gross receipts, privilege, sales, use, excise and other taxes, governmental charges, licenses, fees, permits and assessments; provided, however, the term Taxes shall not include taxes based on net income or net worth.

"**Term**" has the meaning set forth in Section 2.1.

"**Total Facility Capacity**" means, for each calendar year, the full load capacity rating (or equivalent rating) of the Facility (including the portions of the Facility owned by Gulf Power and Georgia Power) for such year as set forth in the applicable informational filing(s) under the

IIC made at FERC, adjusted to transmission voltage level. Total Facility Capacity (as may be modified) shall be effective for each applicable calendar year beginning on January 1 of such year.

"Unavailable Capacity" means, for any hour: (i) Outage Capacity for such hour; less (ii) the Delivered Energy Credit; less (iii) if positive, the difference of the available portion of capacity associated with an Alternate Resource(s) that has been designated for such hour pursuant to Section 5.5.1 in response to the Forced Outage causing Outage Capacity to exist, less the Delivered Energy Credit; plus (iv) the unavailable portion of capacity associated with an Alternate Resource(s) designated for such hour pursuant to Section 5.5.1 in response to a Force Majeure Event.

ARTICLE 2

TERM OF AGREEMENT

2.1 Term. Subject to the survival provisions herein, this Agreement shall continue in full force and effect from the Effective Date until the end of the Service Term, or on such earlier date on which this Agreement is terminated in accordance with its terms ("Term").

2.2 Service Term. Subject to early termination of this Agreement as provided hereunder, Seller's obligation to provide and sell and Buyer's obligation to accept and purchase Contract Capacity and Scheduled Energy shall extend from the Service Commencement Date through December 31, 2015 ("Service Term").

2.3 Survival. All provisions of this Agreement that expressly or by implication come into or continue in force and effect following the expiration or termination of this Agreement shall remain in effect and be enforceable following such expiration or termination.

2.4 Effect of Termination. Subject to the exercise of a non-defaulting Party's rights under Section 14.2, in the event that this Agreement is terminated, the rights and obligations of the Parties hereunder shall continue unaffected until the termination is effective in accordance with the terms and conditions thereof. Any termination of this Agreement shall not relieve Buyer of its obligation to pay any unpaid invoices for any Contract Capacity made available and Delivered Energy prior to the effective date of such termination, relieve Seller of its obligation to provide Contract Capacity and to deliver Scheduled Energy prior to the effective date of such termination, or relieve either Party of any of its other liabilities or obligations accruing prior to termination.

ARTICLE 3

SALE AND PURCHASE OF CAPACITY AND ENERGY

3.1 Sale and Purchase of Capacity. Subject to the terms and conditions of this Agreement, beginning on the Service Commencement Date and until the end of the Service Term, Seller shall make available and sell to Buyer, and Buyer shall accept and purchase, the Contract Capacity.

3.2 Sale and Purchase of Energy. Subject to the terms and conditions of this Agreement, beginning on the Service Commencement Date and until the end of the Service Term, Seller shall deliver and sell to Buyer, and Buyer shall accept and purchase from Seller, energy up to the Contract Capacity as and when Scheduled by Buyer.

ARTICLE 4

FACILITY MAINTENANCE

4.1 Scheduled Outages. Commencing in 2010 and each year thereafter, Seller shall submit to Buyer, before February 1, a schedule of Facility outages during which maintenance

and/or the installation of equipment required by Law or Prudent Industry Practices will be performed for the next Contract Year ("Scheduled Outages"). Such maintenance and outages shall be scheduled in accordance with Prudent Industry Practices. Prior to or during any Contract Year, Seller may reschedule any Scheduled Outages in accordance with Prudent Industry Practices.

4.2 Maintenance Outages. [redacted]

4.3 Permits and Compliance with Laws.

4.3.1 Subject to the right of Contest, each Party shall acquire and maintain in effect all Governmental Approvals necessary for it to perform its obligations under this Agreement.

4.3.2 Subject to the right of Contest, each Party shall at all times comply with all Laws and Governmental Approvals applicable to such Party that are necessary for such Party to perform its obligations under this Agreement.

4.4 Operating Procedures. Buyer and Seller shall begin to develop written Operating Procedures no later than six (6) months before the Service Commencement Date.

Such Operating Procedures shall be completed no later than thirty (30) Days before the Service Commencement Date. The Operating Procedures shall establish the protocol under which the Parties shall perform their respective responsibilities under this Agreement, including method of Day-to-Day communications, key personnel lists, and logging and tracking of hours of EUH and EFMH, Scheduled Outages, Maintenance Outages and hours of Delivery Excuse.

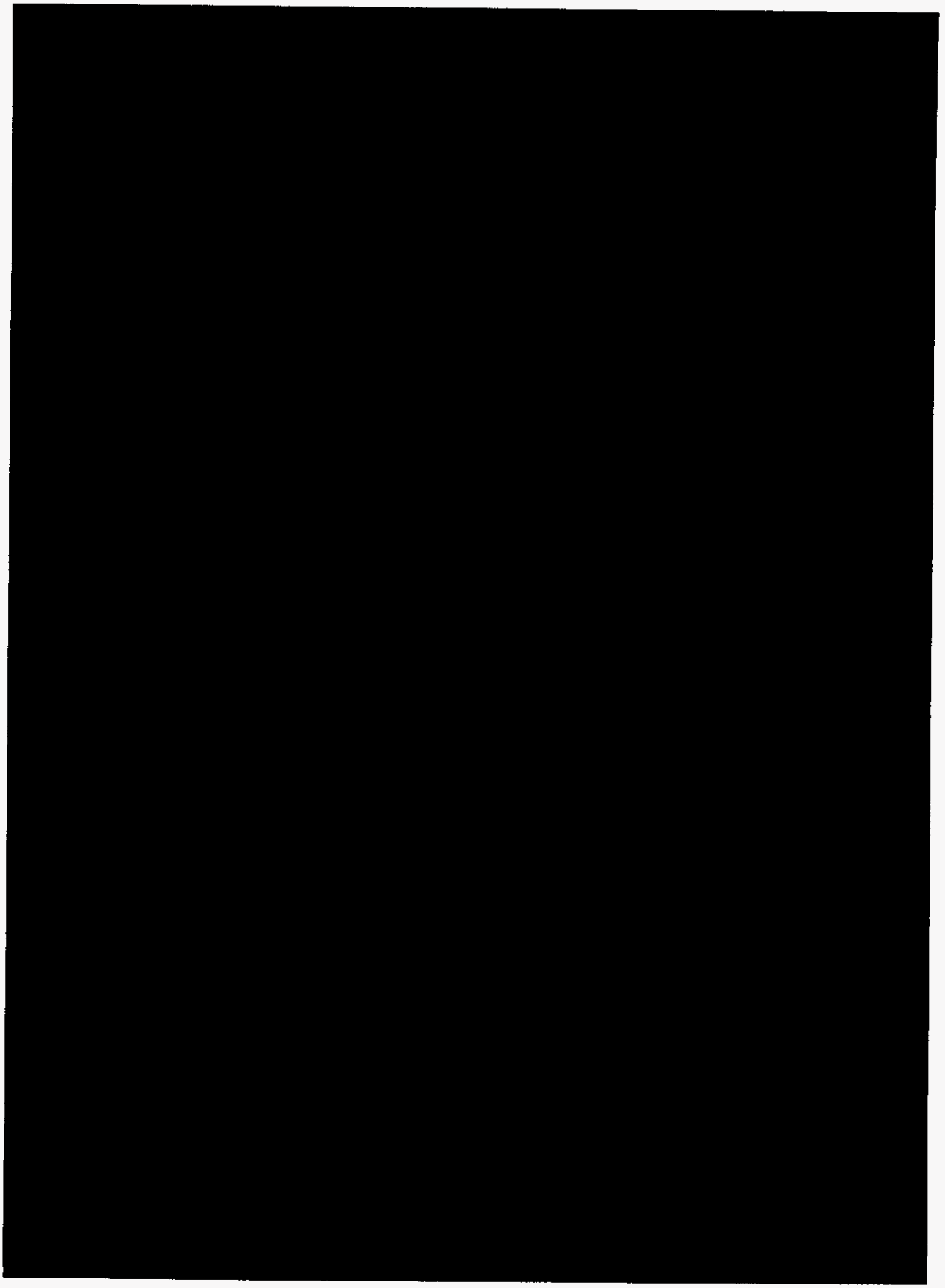
4.5 Operating Committee. The Parties shall form a committee to act in matters relating to the performance of their respective obligations under this Agreement ("Operating Committee"). Each Party shall appoint one representative and one alternate representative to serve on the Operating Committee. The Parties shall notify each other in writing of such appointments and any changes thereto. The Operating Committee shall have no authority to modify the terms or conditions of this Agreement. Beginning in 2009, the Operating Committee shall meet no less than two times per calendar year (which meetings may be by telephone), and all of its decisions must be the unanimous decision of the representatives. Within a reasonable time after the conclusion of each meeting of the Operating Committee, the representatives of each Party shall exchange written summaries of such meeting, including a description of issues discussed and decisions made.

ARTICLE 5

SCHEDULING AND THE PROVISION OF CAPACITY AND ENERGY

5.1 Scheduling.

5.1.1 [redacted]

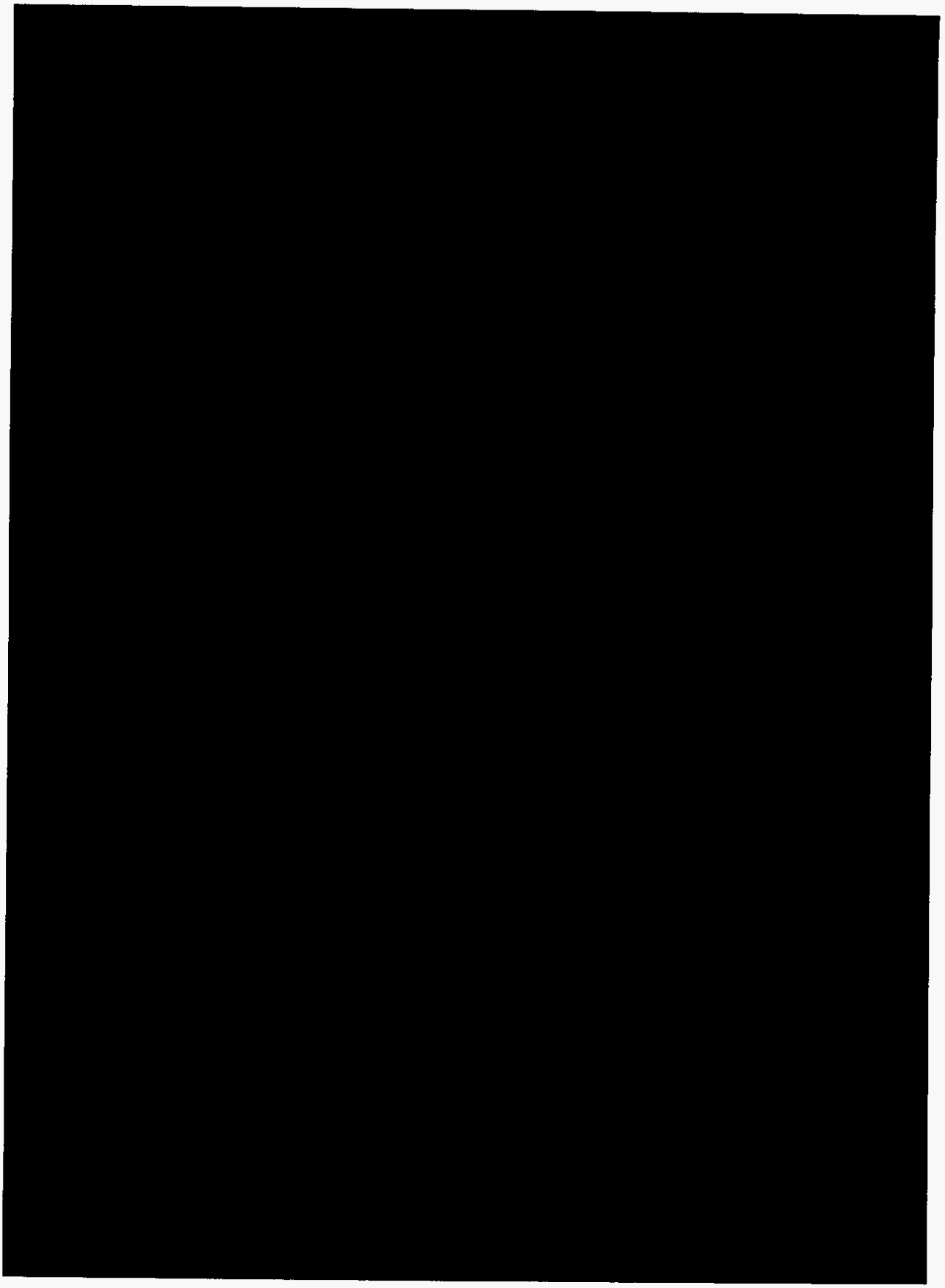


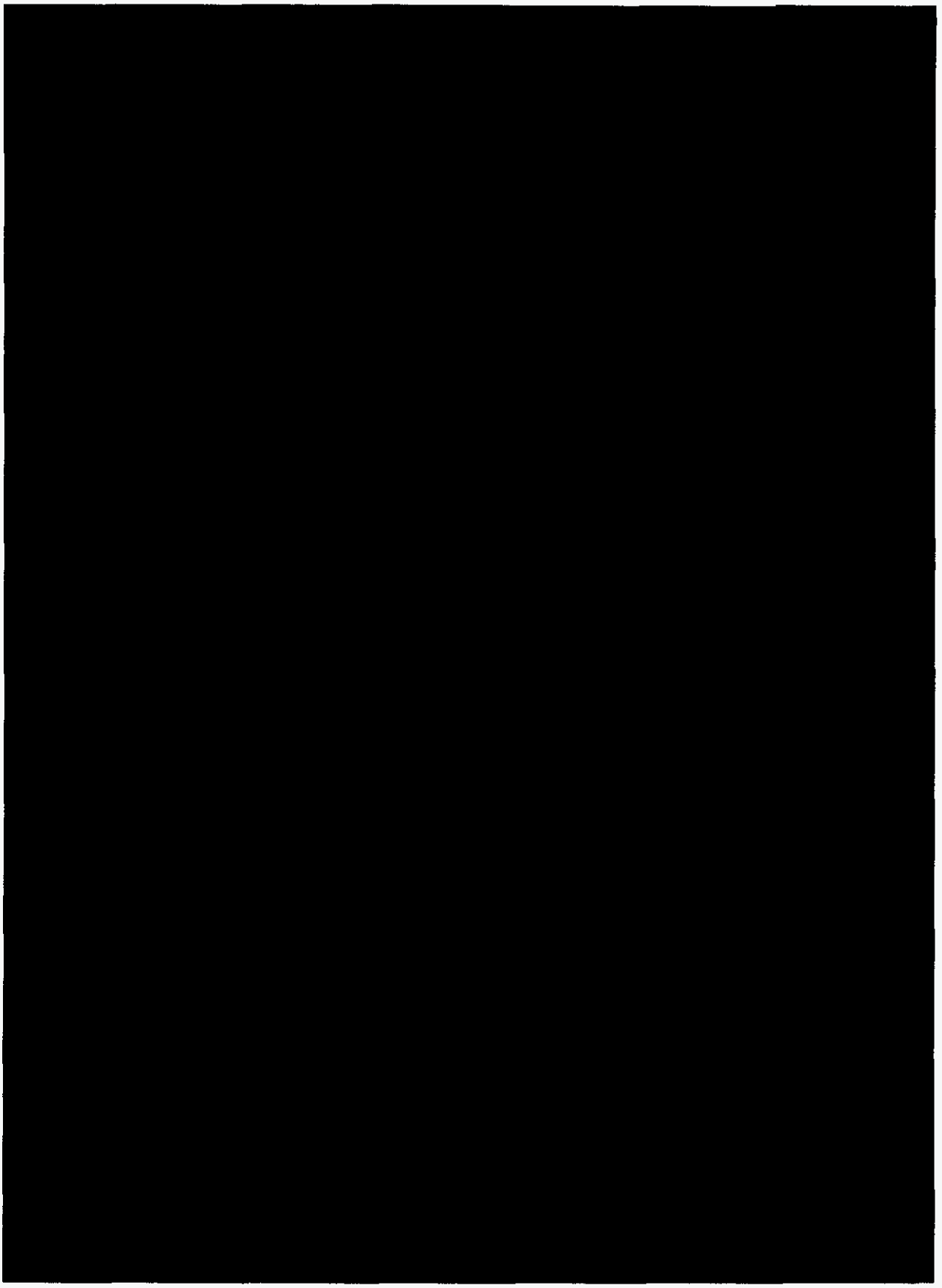
5.2 **Transmission and Scheduling Requirements.** Buyer shall be responsible for complying with all transmission reservation, scheduling and tagging requirements associated with energy provided hereunder at and after the Delivery Point.

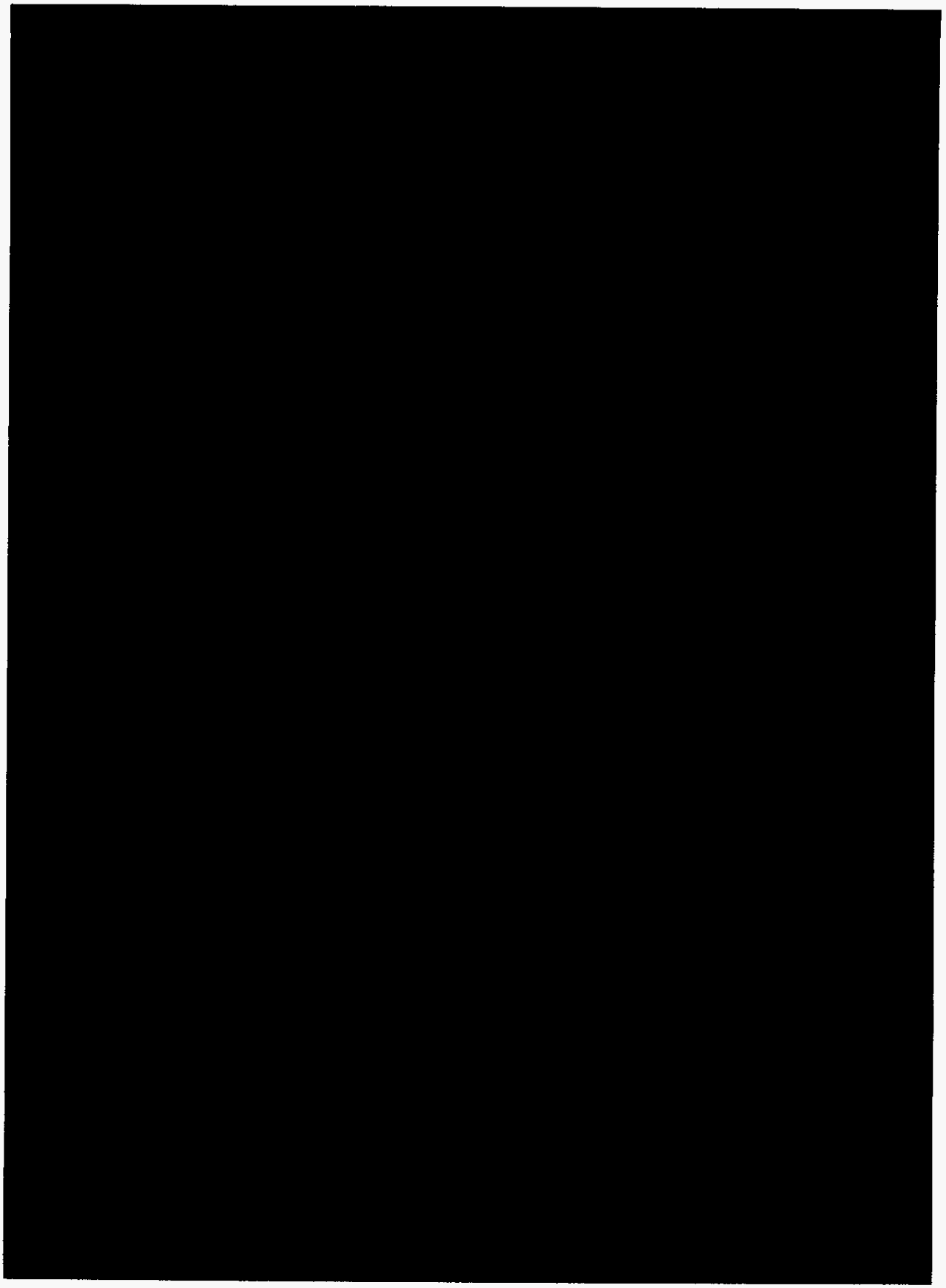
5.3 **Costs and Expenses.** Except as specifically provided hereunder, all costs and expenses associated with Delivered Energy at and after the Delivery Point shall be the sole responsibility of Buyer. Except as specifically provided hereunder, all costs and expenses associated with Delivered Energy prior to the Delivery Point shall be the responsibility of Seller. Any penalties associated with Delivered Energy shall be the responsibility of the Party whose action or inaction caused the penalty to be assessed.

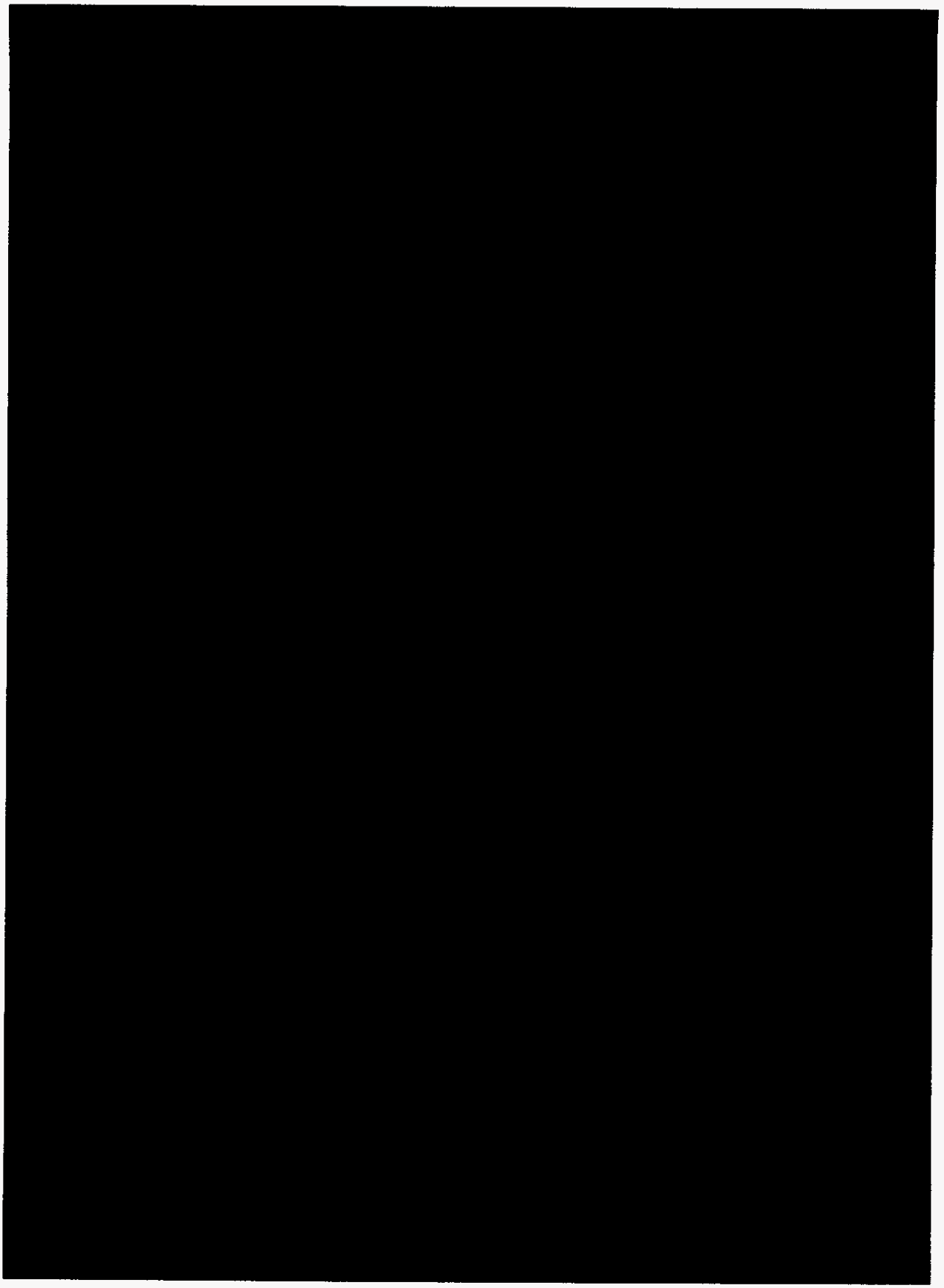
5.4 **Delivery of Energy.** Subject to the terms of this Agreement and the Scheduling Parameters, energy provided by Seller pursuant to Buyer's Schedule shall be deemed to be delivered at the Delivery Point.

5.5 [redacted]









[redacted]

5.7 Seller's Rights to the Facility. To the extent Buyer has not submitted a Schedule requesting energy associated with the full Contract Capacity, and/or to the extent Scheduled Energy is being provided from Alternate Resources, Seller shall have the right to dispatch the Facility to utilize for its own purposes energy from the Facility not Scheduled and/or replaced with Alternate Energy.

5.8 Title and Risk of Loss. Seller shall be deemed to be in exclusive control of the Delivered Energy prior to the Delivery Point. Buyer shall be deemed to be in exclusive control of the Delivered Energy at and after the Delivery Point. Custody, title and risk of loss of Contract Capacity and Delivered Energy shall transfer from Seller to Buyer at the Delivery Point.

5.9 Force Majeure Event.

5.9.1 For any hour in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, Seller shall only be obligated to deliver to Buyer the lesser of: (i) Scheduled Energy; or (ii) energy associated with the difference of the Contract Capacity less Force Majeure Capacity. In addition, to the extent of such Force Majeure Event, Seller may elect in its sole discretion pursuant to the procedures under Section 5.5 (but shall not be required) to deliver Scheduled Energy from Alternate Resources.

5.9.2 For any hour during which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, Seller shall be required to accumulate EFMH (as applicable) for such hour. [redacted]

5.10 Forced Outages and Unavailable Capacity.

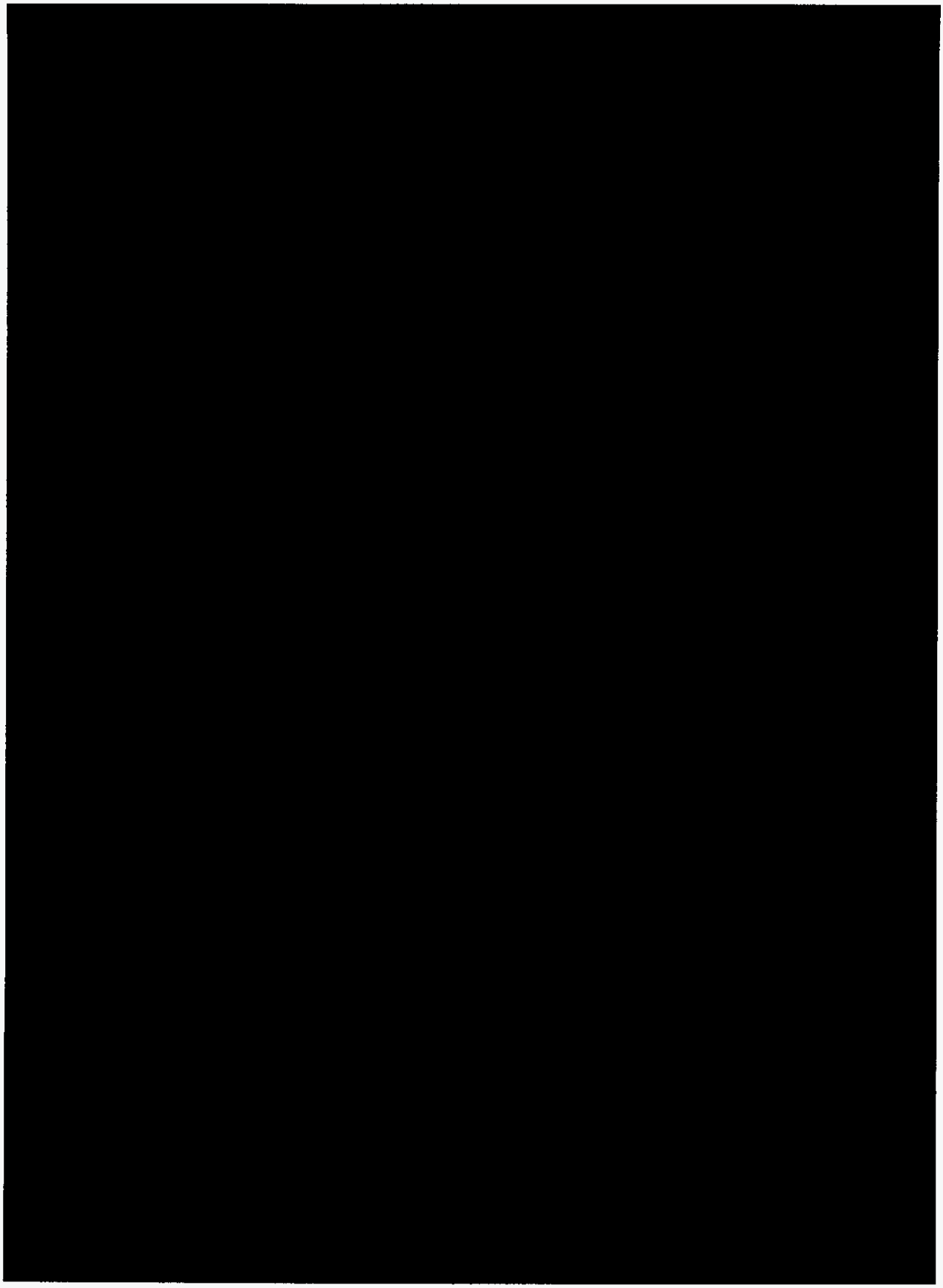
5.10.1 Seller shall notify Buyer as soon as reasonably practicable of: (i) the occurrence of any Forced Outage that is expected to result in Outage Capacity and the estimated duration of such outage; (ii) the cessation of such Forced Outage; and (iii) if requested by Buyer within 30 Days after the outage and if known to Seller, the cause of such outage.

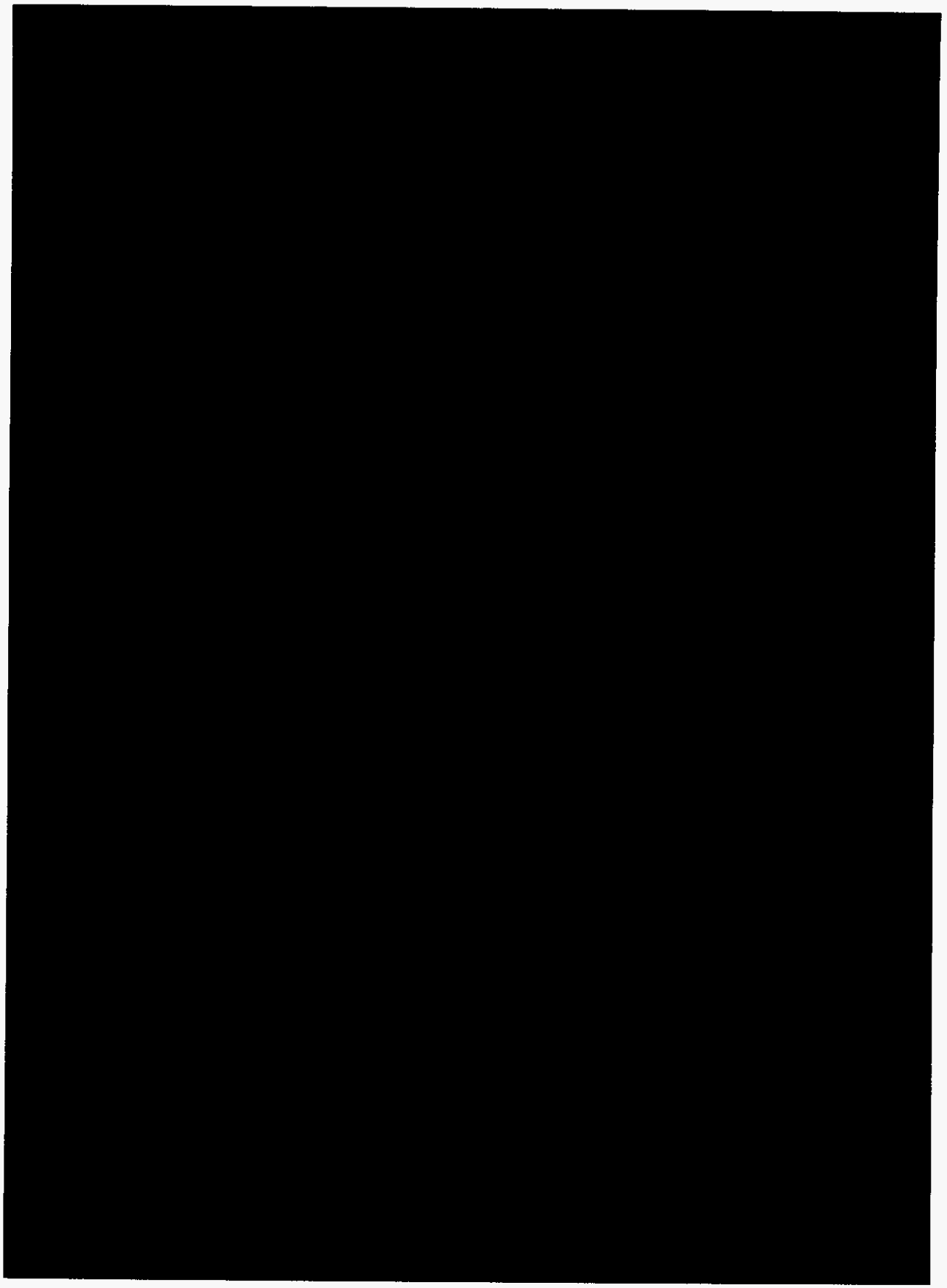
5.10.2 For any hour during which there is Unavailable Capacity, Seller shall be required to accumulate EUH (as applicable) for such hour. [redacted] Seller's sole and exclusive liability and Buyer's sole and exclusive remedy for Seller's failure to provide capacity and/or energy from any resource under this Agreement shall be the [redacted]

5.11 Delivery Excuse. For any hour in which a Delivery Excuse is occurring or is continuing, Seller shall not be obligated to deliver, and Buyer shall not be entitled to receive, or submit a Schedule for, Scheduled Energy. In such event, Seller shall not be required to accumulate EFMH or EUH. Buyer shall not be relieved of its performance obligations during a Delivery Excuse, including its obligation to pay Seller the Monthly Capacity Payment.

5.12 Scheduled and Maintenance Outages. Buyer shall not have the right to submit a Schedule for any period of time during which maintenance is being performed and/or outages are taken consistent with Sections 4.1 and 4.2.

5.13 [redacted]





[redacted]

ARTICLE 6

PAYMENTS

6.1 **Capacity Payment.** Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Capacity Payment for the Contract Capacity. The calculation of the Monthly Capacity Payment is set forth in Appendix A.

6.2 **Energy Payment.** Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Energy Payment. The calculation of the Monthly Energy Payment is set forth in Appendix B.

6.3 **Start Payment.** Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Start Payment. The calculation of the Monthly Start Payment is set forth in Appendix C.

6.4 Additional Payments. In addition to the payments specified in this Article 6, the Parties shall pay all amounts due pursuant to the other provisions of this Agreement.

ARTICLE 7

TRANSMISSION SERVICE

7.1 Buyer Obligations. Buyer, or its designee, shall have the sole and exclusive responsibility at all times to arrange, obtain, contract and pay for any and all transmission service and ancillary services required (including service under any applicable transmission tariff) to deliver any energy hereunder from and beyond the Delivery Point. Buyer assumes all risk associated with the availability, adequacy and cost of such transmission service and ancillary services.

7.2 Seller Obligations. Seller, or its designee, shall have the sole and exclusive responsibility at all times to arrange, obtain, contract, and pay for any and all transmission service required to deliver energy hereunder to the Delivery Point.

7.3 Imbalances and Penalties. Upon receiving notice of any interruption of the delivery of energy under this Agreement for any reason (e.g., a Forced Outage or a Force Majeure Event), Buyer shall promptly notify the applicable transmission provider and/or system operator in order to avoid any energy imbalances. Any penalties or imbalances (including associated costs) resulting from actions or inactions of Buyer (including the failure to provide required notice to the applicable transmission provider and/or system operator), its designee or any third party to which Buyer may be supplying the capacity and energy provided hereunder will be the responsibility of Buyer as between the Parties. Any penalties or imbalances (including associated costs) resulting from actions or inactions of Seller or its designee will be the responsibility of Seller as between the Parties. If either Party incurs any costs associated

with penalties or imbalances that are the responsibility of the other Party under this Section, such other Party shall provide prompt reimbursement of such costs.

7.4 Buyer's Request for Transmission Service.

7.4.1 Within [redacted] after the Effective Date, Buyer shall request from Southern Company Transmission (including by submitting such request on Southern Company Transmission's OASIS and completing any required application(s)) 165 MW of Long Term Firm Transmission Service from the Facility Delivery Point to the Florida Interface, such service to commence on June 1, 2010 ("Requested Service"). As entered into Southern Company Transmission's OASIS, such request shall designate the point of delivery as "FPL." In addition, from the Effective Date, Buyer shall make and/or continue Commercially Reasonable Efforts to have Southern Company Transmission provide Buyer with an offer to provide the Requested Service no later than [redacted] ("Transmission Deadline"); provided, however, the Transmission Deadline shall automatically be extended on a Month to Month basis until either Party provides timely notice to the other that it does not desire for the Transmission Deadline to be extended under this Agreement and in Section 7.4.1 of both of the other Contemporaneous Agreements. Such notice must be provided no later than 5 Days prior to the then existing Transmission Deadline (as may be extended). Notwithstanding the foregoing, the Transmission Deadline in this Agreement shall be extended only to the same extent as such deadline is also extended under Section 7.4.1 of both of the other Contemporaneous Agreements.

7.4.2 No later than 2 Business Days after the earlier of: (i) the Transmission Deadline; (ii) Southern Company Transmission's notice to Buyer that it will not be able to provide any of the Requested Service to Buyer; or (iii) Southern Company Transmission's

notice to Buyer that it will be able to provide some or all of the Requested Service to Buyer, Buyer shall notify Seller ("Transmission Notice") of the total amount of the Requested Service that Southern Company Transmission is able to provide to Buyer at any price and cost ("SCT Service"). In the event that the total cost ("Total Cost") of any portion of the SCT Service is higher than the embedded rate for Long Term Firm Transmission Service under the OATT ("Tariff Rate"), the Transmission Notice shall specify the amount of SCT Service offered at a Total Cost higher than the Tariff Rate and include any and all documentation of such Total Cost provided to Buyer by Southern Company Transmission. For purposes of this Section 7.4, "Total Cost" shall mean those costs that would be imposed on Buyer directly by the applicable transmission provider for the Requested Service.

7.4.3 Within 2 Business Days after its receipt of the Transmission Notice, Seller may offer to sell to Buyer (including by reassignment) up to 165 MW of Long Term Firm Transmission Service from the Facility Delivery Point to the Florida Interface on any applicable transmission system, such service to commence on June 1, 2010 ("Seller Service"). Such offer shall set forth the amount of Seller Service and the price for such service. For purposes of this Agreement the sum of the Seller Service and the SCT Service shall be referred to as the "Available Service."

7.4.4 [redacted]

[redacted]

7.4.5 Once the procedures in Sections 7.4.1 through 7.4.4 have been completed (as applicable), Buyer may elect to reduce the Contract Capacity for the Service Term by an amount up to the sum of: [redacted]

Buyer shall notify Seller of such election within three (3) Business Days after the later of the date of (if applicable) the Reduction Notice, receipt of Seller's offer under Section 7.4.3 or the Transmission Notice ("Election Deadline"). In addition, after the procedures in Sections 7.4.1 through 7.4.4 have been completed (as applicable), if Available Service of at least [redacted] MW is not available to Buyer so that Buyer is in effect able to procure Long Term Firm Transmission Service from the Facility at a Total Cost equal to or less than the Tariff Rate (taking into account any offset of Excess Cost by Seller), Buyer may provide notice to Seller that it will terminate this Agreement. Such notice must be provided no later than the Election Deadline.

7.4.6 If Buyer elects, pursuant to Section 7.4.5, to reduce the Contract Capacity by an amount greater than [redacted] MW, Seller shall be entitled to either: [redacted] Seller shall provide Buyer with notice of its election of either (i) or (ii) no later than 2 Business Days after its receipt of Buyer's notice to reduce the Contract Capacity. If Seller accepts the reduction in Contract Capacity, the Parties shall mutually agree on modifications to this Agreement in order to reflect such reduction.

7.4.7 In the event that either Party provides notice to the other Party under this section 7.4 that it has elected to terminate this Agreement, this Agreement and the other

Contemporaneous Agreements shall immediately terminate. Upon such termination, no Party shall have any further obligation under any of the Contemporaneous Agreements except for any liabilities and/or obligations accruing prior to such termination. The Parties acknowledge that the other Contemporaneous Agreements contain a provision similar to this Section 7.4.7 and that this Agreement is subject to termination as provided in such similar provisions.

7.4.8 Nothing in this Section 7.4 shall be construed as requiring Buyer to actually purchase any transmission service.

7.4.9 The MW amounts set forth in this Section 7.4 refer to MW amounts at the Facility Delivery Point. As appropriate and/or required, such amounts shall be adjusted consistent with the OATT (or other applicable transmission tariff) to reflect transmission losses to the Florida Interface (e.g., including for purposes of submitting the required transmission service request through Southern Company's OASIS and/or other required application(s) for such service).

7.5 Regional Transmission Organizations.

7.5.1 In the event that a Regional Transmission Organization(s) or similar organization ("RTO") is formed and such formation materially changes the scheduling requirements and/or costs associated with the delivery of energy to and/or from the Delivery Point, Seller shall be solely responsible for complying with all scheduling requirements and paying all such costs to the Delivery Point (including but not limited to all congestion and/or basis costs). In addition, Buyer shall be solely responsible for complying with all scheduling requirements and paying all such costs at and beyond the Delivery Point to any other point(s) of delivery (including but not limited to all congestion and/or basis costs). Seller agrees to indemnify and hold harmless Buyer for any costs and expenses incurred by Buyer that are

Seller's responsibility under this Section 7.5.1. Buyer agrees to indemnify and hold harmless Seller for any costs and expenses incurred by Seller that are Buyer's responsibility under this Section 7.5.1.

7.5.2 [redacted]

ARTICLE 8

ELECTRIC METERING

8.1 Metering. At no cost to Buyer, Seller shall be responsible for performing, or causing to be performed, the installation, maintenance, testing and calibration of the Electric Metering Equipment owned by Seller and/or its Affiliates at the Delivery Point(s).

8.2 Industry Standards. All Electric Metering Equipment owned by Seller and/or its Affiliates at the Delivery Point(s), shall be operated, maintained and tested by and/or on behalf of Seller in accordance with Prudent Industry Practices.

8.3 Records. The Parties shall maintain accurate and detailed records relating to the metering of energy at the Delivery Point(s) for one year or for such longer period as may be required by an applicable Government Agency or Law. All records shall be available for inspection by either Party upon reasonable notice.

8.4 Meter Errors. If the Electric Metering Equipment at the Delivery Point(s) fails to register, or if the measurement made by a metering device is found upon testing to vary by more than 0.5% from the measurement made by the standard meter used in a test, an adjustment shall be made correcting all measurements of energy made by the Electric Metering Equipment during: (i) the actual period when inaccurate measurements were made, if that period can be determined to the mutual satisfaction of the Parties; or (ii) if such actual period cannot be determined to the mutual satisfaction of the Parties, the latter half of the period from the date of the last test of the Electric Metering Equipment to the date such failure is discovered or such test is made (each being an "Adjustment Period"). If the Parties are unable to agree on the amount of the adjustment to be applied to the Adjustment Period, the amount of the adjustment shall be determined: (i) by correcting the error if the percentage of error is ascertainable by calibration, tests or mathematical calculation; or (ii) if not so ascertainable, by estimating on the basis of deliveries under similar conditions during the period since the last test.

ARTICLE 9

BILLING AND PAYMENT

9.1 Timing and Method of Payment. Seller will submit to Buyer, as promptly as practicable after the first of each Billing Month, an invoice (by mail, facsimile or electronic means) for the amounts due under the terms of this Agreement for the preceding Month. Amounts due pursuant to such invoice shall be due and payable on [redacted] ("Payment Due Date"). Such invoice shall include adjustments (either a charge or a credit, as applicable) as expressly provided pursuant to Appendix B. If the Payment Due Date falls on a Day that is not a Business Day, the Payment Due Date shall be the next Business Day. Payment shall be made, on or before the due date, to Seller in accordance with the invoice in immediately available funds through wire transfer, or other mutually agreeable method.

9.2 Late Payment. Amounts that are owed Seller shall, if not remitted within the time period specified under Section 9.1, be subject to a late payment charge equal to the interest calculated pursuant to Section 19.7, accrued and payable on a Monthly basis with respect to the unpaid amount. Such late payment charge shall accrue from the due date of such amount until the date on which it is paid.

9.3 Disputed Billings. In the event that either Party has a bona fide dispute with any invoice submitted hereunder, such Party shall inform the other Party in writing of its grounds for disputing such invoice. [redacted]

[redacted]

9.4 **Adjustments.** If any overcharge or undercharge in any form whatsoever shall at any time be found and the invoice therefor has been paid, the Party that has been paid the overcharge shall refund the amount of the overcharge to the other Party, and the Party that has been undercharged shall pay the amount of the undercharge to the other Party, within thirty (30) Days after final determination thereof; provided, however, that no retroactive adjustment shall be made for any overcharge or undercharge unless written notice of the same is provided to the other Party within a period of 12 Months from the date of the invoice in which such overcharge or undercharge was first included. Any such adjustments shall be made with interest calculated in accordance with Section 19.7 from the date that the undercharge or overcharge actually occurred.

9.5 **Audit Rights.** Subject to Section 8.3, the Parties shall keep complete and accurate records of their operations under this Agreement and shall maintain such data for a period of at least [redacted] years after the completion of the relevant Billing Month hereunder; provided, however, records relating to a disputed matter shall be retained until the dispute is resolved. Such records shall be available for inspection and audit by the other Party upon reasonable request during any regular Business Day.

ARTICLE 10

REGULATORY

10.1 Initial Approval of the Florida Public Service Commission.

10.1.1 No later than [redacted] after the Effective Date, Buyer shall make a filing with the Florida Public Service Commission ("FPSC") seeking approval for Buyer to recover from its customers all payments required to be made to Seller under the Contemporaneous Agreements without material modification or condition with respect to such agreements ("FPSC Approval"). After making such filing, Buyer shall utilize diligent efforts to obtain the FPSC Approval for the Contemporaneous Agreements by no later than [redacted] after the Effective Date ("Approval Deadline"). Seller agrees to reasonably assist and support Buyer's efforts to obtain the FPSC Approval. Buyer shall promptly notify Seller when it receives the FPSC Approval.

10.1.2 If FPSC Approval for the Contemporaneous Agreements is not received by the Approval Deadline, but the date of the Transmission Notice under Section 7.4.2 has not yet occurred and the FPSC has not yet issued an order denying the Buyer's request for FPSC Approval ("FPSC Denial"), the Approval Deadline shall automatically be extended until the date of the Transmission Notice. During this extended period, Buyer shall keep Seller closely informed as to the progress of its efforts to obtain FPSC Approval and Buyer shall continue diligent efforts to obtain FPSC Approval.

10.1.3 If FPSC Approval is not received by the Approval Deadline (as extended under Section 10.1.2) or if an FPSC Denial is issued prior to the Approval Deadline, Buyer shall provide notice to Seller within 30 Days after the Approval Deadline or the FPSC Denial (whichever occurs first) that it desires to either: (i) terminate all (but not less than all) of

the Contemporaneous Agreements, in which case all of the Contemporaneous Agreements shall immediately terminate; or (ii) continue all (but not less than all) of the Contemporaneous Agreements regardless of FPSC Approval. If Buyer elects option (ii) under the foregoing sentence, all of the Contemporaneous Agreements shall continue in full force and effect for the Term notwithstanding any subsequent action or inaction of the FPSC (including the subsequent issuance of a FPSC Denial or failure to issue an FPSC Approval).

10.1.4 The Parties acknowledge that the other Contemporaneous Agreements contain provisions that are substantially similar to Sections 10.1.1 through 10.1.3 above and that this Agreement may be subject to termination as provided in such similar provisions.

10.1.5 After the procedures in Sections 10.1.1, 10.1.2, and 10.1.3 (as applicable) have been completed, except as provided under Section 10.3, at no time shall this Agreement be subject to termination or modification due to any action or inaction of any Government Agency or Buyer's inability to recover from its customers amounts to be paid to Seller pursuant this Agreement whether such inability is due to action of any Government Agency or otherwise.

10.2 Changes in Agreement. Except for any changes pursuant to Section 10.3, absent the agreement of all Parties to the proposed change, the standard of review for changes to this contract proposed by a Party, a non-Party or the FERC acting sua sponte shall be the "public interest" standard of review set forth in United Gas Pipeline Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. (1956) (the "Mobile-Sierra" doctrine).

10.3 Federal Energy Regulatory Commission.

10.3.1 The Parties anticipate that this Agreement is not required to be filed and accepted by FERC because it is a market-based contract. Therefore, this Agreement shall not be contingent on FERC acceptance. Having freely negotiated and agreed upon the economic bargain among them as set forth hereunder, Seller and Buyer waive all rights under Sections 205 and 206 of the Federal Power Act to effect a change in the Agreement. Moreover, it is the Parties' mutual intent that FERC be precluded, to the fullest extent permitted by law, from altering this Agreement in any way. Notwithstanding the foregoing, if at any time FERC takes some action that reduces the economic benefit of this Agreement to either Party ("Impacted Party") as contemplated on the Effective Date ("Original Economic Benefit"), Impacted Party shall be deemed to have retained rights under Section 205 to file for changes in the Agreement, but only to the extent required to restore the Original Economic Benefit.

10.3.2 Impacted Party may exercise its Section 205 rights provided under Section 10.3.1 if at any time it reasonably determines in its sole discretion that it may be able to have some or all of the Original Economic Benefit restored. Before exercising such rights, Impacted Party shall negotiate with the other Party in an effort to reach mutual agreement regarding amendments to this Agreement (including amendments regarding those provisions addressing the determination of payments between the Parties and adjustments to capacity payments due to unavailability) that would restore some or all of the Original Economic Benefit. Impacted Party shall file any resulting amendments for acceptance by FERC, and the other Party shall actively support such filing(s). If the Parties are unable to agree upon such amendment(s), Impacted Party shall be entitled to make unilateral filing(s) at FERC to modify the Agreement in order to restore some or all of the Original Economic Benefit. In this latter

event, the other Party shall actively support Impacted Party's right to recover the Original Economic Benefit, including by making filings at FERC (provided that the non-impacted Party shall retain the right to challenge the amount of and/or the methodology for calculating the Original Economic Benefit).

10.3.3 Any amendment(s) or unilateral filing(s) contemplated hereunder shall restore the Original Economic Benefit (or any allowed portion thereof) for the remainder of the Term, including any portion of the Original Economic Benefit associated with prior periods (with interest). Such amendment(s) or filing(s) by the Impacted Party shall not require the other Party to bear more of an economic burden than originally contemplated in this Agreement on the Effective Date. Nothing in this Agreement is intended to or shall restrict the number of times that a Party may exercise the above-described Section 205 rights during the Term or within any specific time frame.

ARTICLE 11

CHANGE IN LAW

11.1 Increased Generation Costs. The Parties acknowledge that during the Term of this Agreement, Changes in Law that increase Seller's cost of providing capacity and/or energy hereunder could occur. Any Increased Generation Costs will be paid by Buyer through an additional payment or surcharge each Month ("Change in Law Surcharge"). Once Seller has incurred Increased Generation Costs, Buyer shall pay for all Increased Generation Costs through the Change in Law Surcharge, as provided below.

11.2 Determination. If Seller determines that a Change in Law will or has resulted in Increased Generation Costs and that Buyer is responsible for such costs under this Agreement, Seller shall, within six (6) Months after identifying such costs, notify Buyer of: (a) the

applicable Change in Law giving rise to the Increased Generation Costs; and (b) the resulting Increased Generation Costs. Provided, however, the failure by Seller to provide such notice within such time period shall not under any circumstance result in an Event of Default, nor shall such failure prejudice or affect in any way Seller's right to receive reimbursement from Buyer for any Increased Generation Costs under this Agreement. Provided further, such notice by Seller shall include reasonable documentation of the applicable Change in Law and resulting Increased Generation Costs. Within sixty (60) Days after receipt of such notice, Buyer will: (i) make a good faith determination of whether the Increased Generation Costs result from a Change in Law as specified in this Agreement; (ii) make a good faith determination of whether the Increased Generation Costs are determined in accordance with this Agreement; and (iii) provide Seller written notice of its determination. In the event that Buyer does not provide written notice of its determination within such time period, Buyer shall be deemed to have concurred that the specified Increased Generation Costs result from a Change in Law. If Buyer does not concur, the Parties shall commence discussions in an effort to address and resolve the basis for Buyer's disagreement. If the Parties are unable to resolve their disagreement within thirty (30) Days after commencing such discussions, the Parties shall submit the issue to arbitration under the procedures set forth in Section 16.2. The arbitrators shall determine whether a Change in Law has occurred and, if so, the amount of the resulting Increased Generation Costs.

11.3 Initiation of Surcharge. In the event that Increased Generation Costs result from a Change in Law, Seller shall provide Buyer with written notice of a Change in Law Surcharge or an increase in an existing Change in Law Surcharge to recover Increased Generation Costs. No earlier than thirty (30) Days thereafter, Seller may initiate a Change in

Law Surcharge (or, if applicable, an increase in an existing Change in Law Surcharge) consistent with such notice. Provided, however, Seller shall reduce any Change in Law Surcharge to the extent that any costs included in such surcharge are not incurred. After the end of the Term, Seller shall not be entitled to initiate a Change in Law Surcharge, an increase in an existing Change in Law Surcharge, or any other additional charge intended to recover costs resulting from a Change in Law unless: (i) Seller has provided Buyer with notice of the applicable Change in Law, surcharge or increase prior to the expiration of the Term; and (ii) the costs Seller seeks to recover were incurred during the Service Term as a result of such Change in Law.

11.4 Timing. Any Change in Law Surcharge (or increase in an existing Change in Law Surcharge) hereunder due to Increased Generation Costs shall recognize the timing of the Increased Generation Costs (including the recovery through such payments of amounts associated with the Increased Generation Costs in prior periods, with interest) for which Buyer is responsible under this Agreement.

ARTICLE 12

LIABILITY ALLOCATION; LIMITATIONS ON LIABILITY

12.1 Costs, Taxes and Charges. Except as otherwise provided in this Agreement, in addition to all other amounts due and payable under this Agreement: (i) Seller shall be responsible for all costs, Taxes, and charges of any kind prior to the Delivery Point relating to the delivery of energy and provision of capacity under this Agreement, transmission, and/or related services (by way of clarification of the foregoing, Taxes prior to the Delivery Point include: ad valorem taxes); and (ii) Buyer shall be responsible for all costs, Taxes, and charges of any kind at and after the Delivery Point relating to the delivery of energy and provision of

capacity under this Agreement, transmission, and/or related services (by way of clarification of the foregoing, Taxes at and after the Delivery Point include: any Taxes incurred in connection with sales of the Delivered Energy). Each Party shall provide the other Party upon written request a certificate of exemption or other reasonably satisfactory evidence of exemption if any exemption from or reduction of any Tax is applicable. Each Party shall exercise Commercially Reasonable Efforts to obtain and to cooperate in obtaining any exemption from or reduction of any Tax. In addition, each Party shall be responsible for paying its own income taxes and net worth taxes on it or its property.

12.2 Indemnification. Unless otherwise agreed in writing by the Parties, Seller and Buyer shall each defend, indemnify and save harmless, on an After-Tax Basis, the other and their respective officers, directors, servants, agents, employees and representatives from and against any and all claims, demands, costs or expenses (including reasonable attorneys' fees) for loss, damage or injury to any person, property or interest arising out of or in any way related to this Agreement to the extent such loss, damage or injury occurs on its own side of the Delivery Point, irrespective of negligence, whether actual or claimed, of the other. Nothing in this Agreement shall create a contractual relationship between one Party and the customers of the other Party, nor shall it create a duty of any kind to such customers.

12.3 Limitation of Liability.

12.3.1 THERE ARE NO WARRANTIES UNDER THIS AGREEMENT EXCEPT TO THE EXTENT SPECIFICALLY SET FORTH HEREIN. THE PARTIES HEREBY SPECIFICALLY DISCLAIM AND EXCLUDE ALL IMPLIED WARRANTIES, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR A PARTICULAR PURPOSE.

12.3.2 SUBJECT TO SECTION 14.2, NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES SUFFERED BY THAT PARTY OR BY ANY CUSTOMER OF THAT PARTY, FOR LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, WHETHER BY VIRTUE OF ANY STATUTE, IN TORT OR CONTRACT, UNDER ANY PROVISION OF INDEMNITY OR OTHERWISE. THE PARTIES INTEND THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING, WITHOUT LIMITATION, THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, THAT OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT, AND THAT THE LIQUIDATED DAMAGES CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

12.3.3 In the event that any provision of this Section 12.3 is held to be invalid or unenforceable, this Section shall be void and of no effect solely to the extent of such invalidity or unenforceability, and no claim arising out of such invalidity or lack of enforceability shall be made by one Party against the other or its officers, agents, or employees. Notwithstanding the foregoing, this Section 12.3 shall not limit or negate the right of either Party to be fully indemnified as provided in Section 12.2 or limit the remedies set forth in this Agreement for an Event of Default.

12.3.4 Without prejudice to the obligations and liabilities of an entity pursuant to an Eligible Guaranty, neither any Affiliate of a Party nor any stockholder, officer, director or employee of a Party or of any Affiliate of a Party (collectively, the "Nonrecourse Persons") shall have any liability to the other Party for the payment of any sums now or hereafter owing by such Party or for the performance of any of the obligations of such Party contained herein, and each of the Parties hereto agrees that all of the obligations of the other Party under this Agreement shall be obligations solely of such other Party and recourse in enforcing said obligations shall only be had against the assets of such other Party; provided that the foregoing provision shall not constitute a waiver, release or discharge of any of the terms, covenants or conditions of this Agreement or any Eligible Guaranty and the same shall continue until fully paid, discharged, observed or performed.

ARTICLE 13

FORCE MAJEURE EVENT

13.1 Force Majeure Event Defined.

13.1.1 As used herein, an Event of Force Majeure with respect to a Party means an occurrence, non-occurrence, or set of circumstances that is beyond the reasonable control of such Party and is not caused by the fault or negligence of such Party, including but not limited to acts of God, strike, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, sabotage, or terrorism, which, by the exercise of due diligence, it is unable to overcome.

13.1.2 Notwithstanding anything contained in Section 13.1.1, the term Force Majeure shall not include any of the following:

(i) the inability of Buyer, for any reason, to obtain or maintain adequate transmission service from and after the Delivery Point;

(ii) a change or circumstance in market conditions that affect the cost, price, or demand for capacity and/or energy from the Facility;

(iii) a change or circumstance in market conditions or otherwise that affects the economic value of this Agreement to any Party;

(iv) an increase in costs or expenses to any Party as a result (either directly or indirectly) of such Party's performance under this Agreement;

(v) a change in Law, action or inaction by any Governmental Agency or the inability to comply with any Law; or

(vi) any event or circumstance that qualifies as a Delivery Excuse.

13.2 Applicability of Force Majeure Event. Neither Party shall be in breach or liable for any delay or failure in its performance under this Agreement (except for such Party's performance of its payment obligations hereunder, which shall not be excused by any Force Majeure Event) to the extent such performance is prevented or delayed due to a Force Majeure Event, provided that:

13.2.1 The non-performing Party shall give the other Party written notice within three (3) Business Days of the commencement of the Force Majeure Event, with available details to be supplied within fifteen (15) Days after the commencement of the Force Majeure Event further describing the particulars of the occurrence of the Force Majeure Event;

13.2.2 The delay in performance shall be of no greater scope and of no longer duration than is directly caused by the Force Majeure Event;

13.2.3 The Party whose performance is delayed or prevented shall proceed with Commercially Reasonable Efforts to overcome the events or circumstances preventing or delaying performance and shall, as requested (but not more often than weekly), provide written progress reports to the other Party during the period that performance is delayed or prevented describing actions taken and to be taken to remedy the consequences of the Force Majeure Event, the schedule for such actions and the expected date by which performance shall no longer be affected by the Force Majeure Event; and

13.2.4 When the performance of the Party claiming the Force Majeure Event is no longer being delayed or prevented, that Party shall give the other Party written notice to that effect.

13.3 Effect of Force Majeure Event.

13.3.1 Except for the obligation of either Party to make any required payments under this Agreement, the Parties shall be excused from performing their respective obligations under this Agreement and shall not be liable in damages or otherwise if and to the extent that they are unable to so perform or are prevented from performing by a Force Majeure Event.

13.3.2 To the extent Seller is unable to provide Contract Capacity or Scheduled Energy from the Facility due to a Force Majeure Event, Seller shall be excused from performance hereunder and shall not be required to provide capacity and/or energy from other resources (including Alternate Resources) in order to satisfy Buyer's Schedule; provided, however, to the extent Seller does provide capacity and/or energy at its sole option to satisfy Buyer's Schedule consistent with this Agreement, [redacted]

[redacted]

13.4 [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

ARTICLE 14

EVENT OF DEFAULT

14.1 **Event of Default.** The occurrence of any one or more of the following events with respect to a Party shall constitute an "Event of Default" attributable to such Party under this Agreement:

14.1.1 The failure by a Party to make payment to the other Party for amounts due under this Agreement after said amounts have become due and payable and such failure is not cured within fifteen (15) Days after receiving written notice of such failure from the Party to which such payments are due;

14.1.2 A Party or any Person guaranteeing such Party's obligations hereunder (a "Guarantor") shall: (i) admit in writing its inability to pay its debts as such debts become due; (ii) make a general assignment or an arrangement or composition with or for the benefit of its creditors; (iii) take any action for the purpose of effectuating any of the foregoing; or (iv) fail to comply with the terms and conditions of its Guaranty;

14.1.3 A proceeding or case shall be commenced by a Party or against a Party with the consent of such Party or by its Guarantor or against its Guarantor with the consent of such Guarantor, in any court of competent jurisdiction, seeking: (i) its liquidation, reorganization of its debts, dissolution or winding-up, or the composition or readjustment of its

debts; (ii) the appointment of a receiver, custodian, liquidator or the like of the Party or its Guarantor or of all or any substantial part of its assets or the assets of its Guarantor; or (iii) similar relief in respect of such Party or its Guarantor under any law relating to bankruptcy, insolvency, reorganization of its debts, winding-up, composition or adjustment of debt;

14.1.4 A proceeding or case shall be commenced without the consent of a Party against such Party or without the consent of its Guarantor against such Guarantor, in any court of competent jurisdiction, seeking: (i) its liquidation, reorganization of its debts, dissolution or winding-up, or the composition or readjustment of its debts; (ii) the appointment of a receiver, custodian, liquidator or the like of the Party or its Guarantor or of all or any substantial part of its assets or the assets of its Guarantor; or (iii) similar relief in respect of such Party or its Guarantor under any law relating to bankruptcy, insolvency, reorganization of its debts, winding-up, composition or adjustment of debt, unless such proceeding or case is dismissed within sixty (60) days of the filing thereof;

14.1.5 The failure of any Party to comply with the requirements of Article 18 regarding creditworthiness and/or security;

14.1.6 The failure of a Party to comply with the requirements of Article 17 regarding assignment;

14.1.7 Any representation or warranty made by a Party under Article 15 proves to have been false or misleading in any material respect when made and such representation or warranty is not made true within thirty (30) Days after such Party has obtained actual knowledge thereof or has been provided notice thereof by the other Party; provided, however, that the cure must also remove any adverse effect on the Non-Defaulting Party;

14.1.8 A Party or its Guarantor shall fail to pay when due (subject to any applicable cure or grace period), whether by acceleration or otherwise, any principal or interest on indebtedness aggregating in excess of [redacted] in principal amount; or any indebtedness aggregating in excess of [redacted] shall be declared due and payable or be required to be prepaid (other than by a regularly scheduled payment) prior to the stated maturity of such indebtedness; or

14.1.9 [redacted]

[redacted]

14.1.10 The material failure by a Party to comply with any material provision of this Agreement if such failure is not the result of a Force Majeure Event or is not otherwise excused in accordance with this Agreement, and such failure continues uncured for thirty (30) Days after written notice thereof from the other Party; provided, however, if such failure is not capable of being cured within such period of thirty (30) Days with the exercise of reasonable diligence, then such cure period shall be extended for an additional reasonable period of time (not to exceed ninety (90) Days), so long as the Party is exercising reasonable diligence to cure such failure. Provided, however, this Section 14.1.10 shall not apply to: (i) any event described in Sections 14.1.1 through 14.1.9; (ii) any event described in Sections 5.9 and 5.10 for which a remedy is expressly provided in those Sections; or (iii) Seller's failure to provide capacity and/or energy pursuant to any provision of this Agreement.

The Party in default or the Party to whom an Event of Default is attributable as provided in this Section 14.1 shall be referred to as the "Defaulting Party" and the other Party shall be referred to as the "Non-Defaulting Party."

14.2 Exclusive Remedies.

14.2.1 Upon and after the occurrence of an Event of Default, the Non-Defaulting Party's sole and exclusive remedy (whether arising in contract, tort or otherwise) shall be to suspend its performance under this Agreement and declare an Early Termination Date with the relevant remedies as provided below.

14.2.2 If an Event of Default has occurred, the Non-Defaulting Party shall have the right, in its sole discretion, by no more than twenty (20) Days notice to the Defaulting Party, to designate a Day no earlier than the Day such notice is effective as the date on which the Agreement shall terminate ("Early Termination Date"). Subject to Sections 19.3 and 19.15, this Agreement shall terminate on the Early Termination Date and neither Party shall have any further liability or obligation to the other hereunder, except (i) the Defaulting Party shall pay to the Non-Defaulting Party on demand [redacted] in liquidated damages and (ii) as provided in Sections 14.2.3 or 14.2.4 below. The exercise by a Party of its rights under this Section 14.2 shall be the sole and exclusive remedy of such Party for an Event of Default by or attributable to the other Party. The Parties acknowledge and agree that in the event of termination of this Agreement due to an Event of Default, all or a portion of the amount of damages arising therefrom are not susceptible to an accurate determination. The Parties further acknowledge and agree that the liquidated damages set forth above are not intended as a penalty and represent a fair and reasonable approximation of all or a portion of the damages a Non-Defaulting Party may incur in each particular case.

14.2.3 With respect to an Event of Default by or attributable to Buyer, within fifteen (15) Days after Seller's notice under Section 14.2.2, the Parties shall each select an independent party to determine the Seller's Damages. Within thirty (30) Days after such notice,

the two independent parties shall select a third independent party to determine the Seller's Damages. Within sixty (60) Days after such notice, the three (3) independent parties shall provide the Parties with their respective estimates of the Seller's Damages. The actual Seller's Damages shall equal the arithmetic average of the three estimates. If one Party disputes the actual Seller's Damages, within five (5) Business Days of notice of the Seller's Damages determined by the independent parties, such Party may submit the dispute for resolution pursuant to the arbitration procedures of Article 16 and the arbitration order or finding regarding the Seller's Damages shall be conclusive, provided, however, in no event shall the Seller's Damages be less than [redacted] at any time whether or not arbitrated. Subject to such qualification, the Seller's Damages will be paid by Buyer to Seller within three (3) Business Days after being determined by the independent parties unless disputed and arbitrated pursuant to the terms of this Agreement in which event it shall be paid within three (3) Business Days of the relevant arbitration finding or order. As used herein, "Seller's Damages" [redacted]

14.2.4 With respect to an Event of Default by or attributable to Seller, within fifteen (15) Days after Buyer's notice under Section 14.2.2, the Parties shall each select an independent party to determine the Buyer's Damages. Within thirty (30) Days after such notice,

the two independent parties shall select a third independent party to determine the Buyer's Damages. Within sixty (60) Days after such notice, the three (3) independent parties shall provide the Parties with their respective estimates of the Buyer's Damages. The actual Buyer's Damages shall equal the arithmetic average of the three estimates. If one Party disputes the actual Buyer's Damages, within five (5) Business Days of notice of the Buyer's Damages determined by the independent parties, such Party may submit the dispute for resolution pursuant to the arithmetic procedures of Article 16 and the arithmetic order or finding regarding the Buyer's Damages shall be conclusive, provided, however, in no event shall the Buyer's Damages be less than [redacted] at any time whether or not arbitrated. Subject to such qualification, the Buyer's Damages will be paid by Seller to Buyer within three (3) Business Days after being determined by the independent parties unless disputed and arbitrated pursuant to the terms of this Agreement in which event it shall be paid within three (3) Business Days of the relevant arbitration finding or order. As used herein, "Buyer's Damages" means [redacted]

ARTICLE 15

REPRESENTATIONS AND WARRANTIES

15.1 Execution. Each Party represents and warrants to the other Party as of the Effective Date that: (i) it has all the necessary corporate and legal power and authority and has been duly authorized by all necessary corporate action to enable it to lawfully execute, deliver and perform under this Agreement; and (ii) it is a valid legal entity duly organized and validly existing in good standing under the laws of the state of its formation and is, to the extent required, qualified to do business in the state where it is organized;

15.2 Permits. Each Party represents and warrants to the other Party that as of the Effective Date it has all permits, licenses or approvals necessary to lawfully perform its obligations contained herein in the manner prescribed by this Agreement.

15.3 Binding Obligations. Each Party represents and warrants to the other Party that as of the Effective Date this Agreement is the valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting enforcement generally, and by equitable principles regardless of whether such principals are considered in a proceeding at law or in equity.

15.4 Execution and Consummation. Each Party represents and warrants to the other Party that as of the Effective Date the execution and delivery of this Agreement, the consummation of the transactions contemplated hereby and the fulfillment of and compliance with the provisions of this Agreement do not and will not conflict with any of the terms, conditions or provisions of its organizational documents or any law applicable to it or result in a

breach or default under any evidence of its indebtedness or any other agreement or instrument to which it is a party or by which it or any of its property is bound which has a reasonable likelihood of materially and adversely affecting the consummation of the transactions contemplated hereby or the performance by the Party of any of its obligations under this Agreement.

15.5 Actions and Proceedings. Each Party represents and warrants to the other that as of the Effective Date there is no pending or, to the knowledge of such Party, threatened action or proceeding affecting such Party before any Government Agency that has a reasonable likelihood of materially adversely affecting or reasonably threatening the ability of such Party to perform its obligations under this Agreement or the validity or enforceability of this Agreement against it and that there are no bankruptcy proceedings pending or being contemplated by it or, to its knowledge, threatened against it.

15.6 Absence of Certain Events. Each Party represents and warrants to the other Party that as of the Effective Date no Event of Default attributable to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement.

ARTICLE 16

DISPUTE RESOLUTION

16.1 Senior Officers.

16.1.1 Each of the Parties will designate in writing to the other Parties a representative who will be authorized to resolve any dispute arising under this Agreement and,

unless otherwise expressly provided herein, to exercise the authority of such Party to make decisions by mutual agreement.

16.1.2 If such designated representatives are unable to resolve a dispute under this Agreement, such dispute will be referred by each Party's representative, respectively, to a designated senior officer.

16.1.3 The Parties hereto agree: (i) to attempt to resolve all disputes arising hereunder promptly; and (ii) to provide each other with reasonable access during normal business hours to any and all non-privileged and non-confidential records, information and data pertaining to any such dispute. Non-privileged and non-confidential information shall be made available to a Party pursuant to a confidentiality agreement consistent with the confidentiality provisions of this Agreement.

16.2 Arbitration.

16.2.1 All disputes arising under, out of, or in relation to any provision of this Agreement that are not resolved pursuant to Section 16.1 within 30 Days after either Party's receipt of notice referring the dispute to the senior officers of the Parties (and in any event within the time which legal or equitable proceedings based on such claim, dispute, or controversy would not be barred by the applicable statute of limitations) will be submitted upon written request of any Party to binding arbitration. Each Party will have the right to designate an arbitrator of its choice, who need not be from the American Arbitration Association ("AAA") panel of arbitrators but who (a) will be an expert in the independent power electric generation field and (b) will not be and will not have been previously an employee or agent of or consultant or counsel to either Party or any of its Affiliates and will not have a direct or indirect interest in either Party or any of its Affiliates or the subject matter of the arbitration. Such designation will

be made by notice to the other Party and to the AAA within ten (10) Days or, in the case of payment disputes, five (5) Days after the date of the giving of notice of the demand for arbitration. The arbitrators designated by the Parties will designate a third arbitrator, who will have a background in legal and judicial matters (and who will act as chairman), within ten (10) Days or, in the case of payment disputes, five (5) Days after the date of the designation of the last of the arbitrators to be designated by the Parties, and the arbitration will be decided by the three arbitrators. If the two arbitrators cannot or do not select a third independent arbitrator within such period, either Party may apply to the AAA for the purpose of appointing any person listed with the AAA as the third independent arbitrator under the expedited rules of the AAA. Such arbitration will be held in alternating locations of the home offices of the Parties, commencing with Buyer's home office, or in any other mutually agreed upon location. The rules of the AAA will apply to the extent not inconsistent with the rules herein specified. Each Party will bear its own expenses (including attorneys' fees) with respect to the arbitration. The arbitrators will designate the Party to bear the expenses of the arbitrators or the respective amounts of such expense to be borne by each Party.

16.2.2 Subject to Section 14.2, the arbitrators conducting an arbitration proceeding under this Section shall have no authority to award to any Party consequential, incidental, punitive, exemplary or indirect damages or any lost profits or business interruption damages, whether by virtue of any Law or otherwise. Provided further, the fact that any arbitration proceeding is conducted hereunder and the decision of the arbitrators shall be deemed Confidential Information under Section 19.2; provided further, notwithstanding any provision in Article 19, Confidential Information, to the extent relevant, may be disclosed by

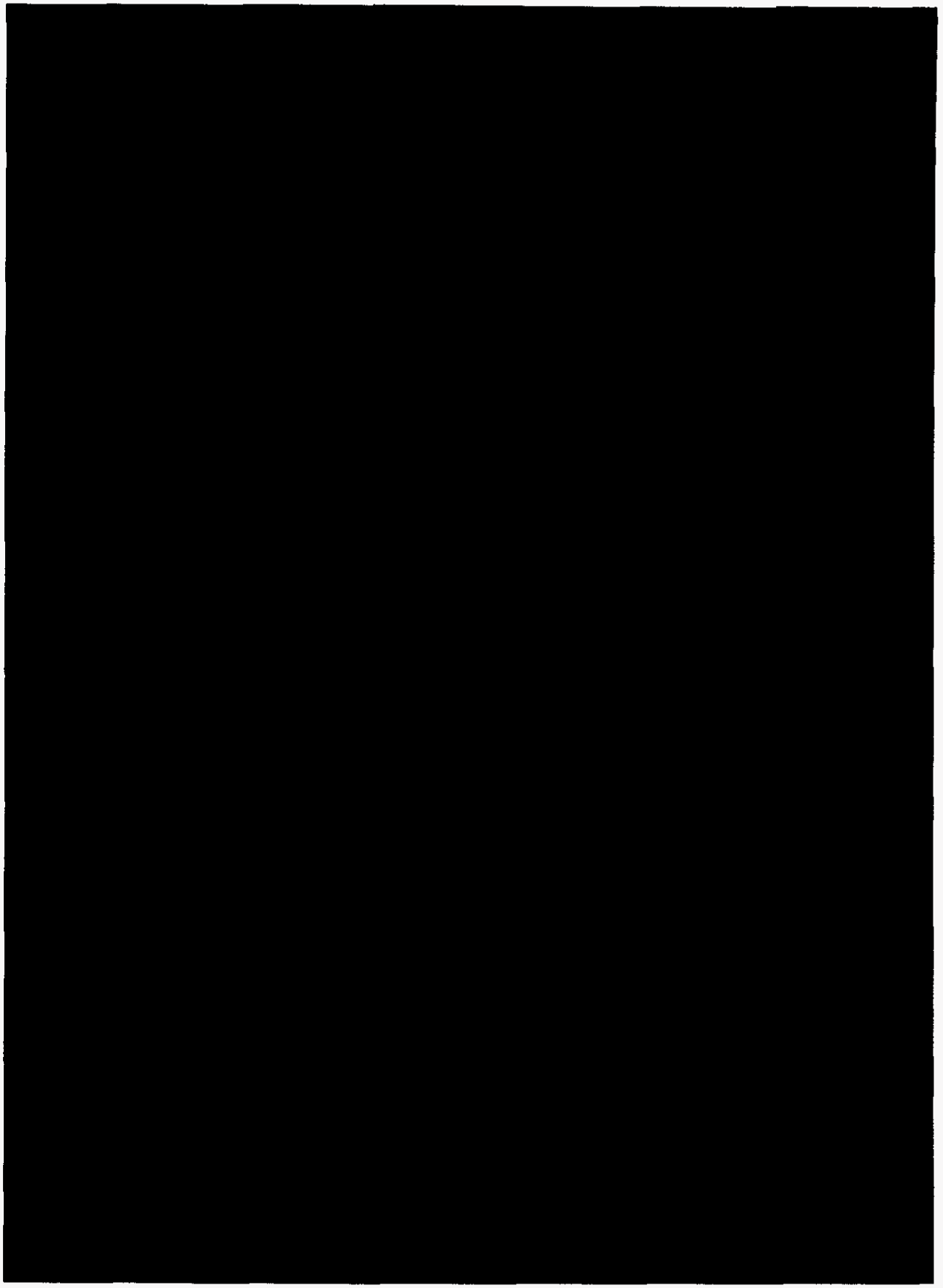
any Party to the arbitrators conducting the arbitration and any court of competent jurisdiction enforcing the arbitrators' award.

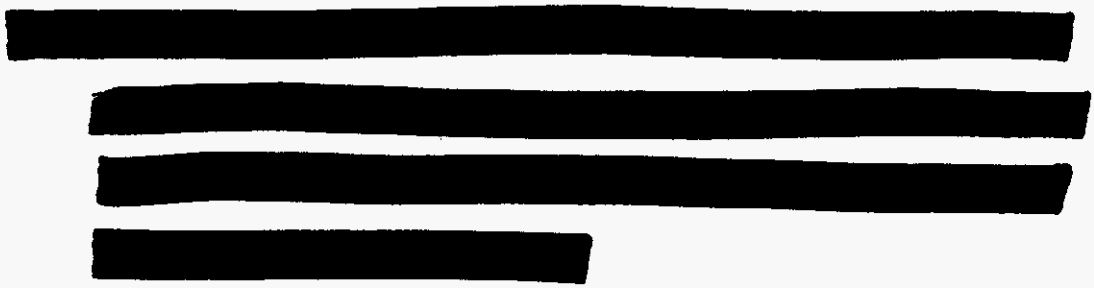
16.3 **Binding Nature of Proceedings.** Each Party understands that this Agreement contains an agreement to arbitrate with respect to specified disputes. After signing this Agreement, each Party understands that it will not be able to bring a lawsuit concerning any dispute that may arise that is covered by this arbitration provision. Instead, each Party agrees to submit any such dispute to arbitration pursuant to Section 16.2. Any award of the arbitrator may be enforced by the Party in whose favor such award is made in any court of competent jurisdiction.

ARTICLE 17

ASSIGNMENT

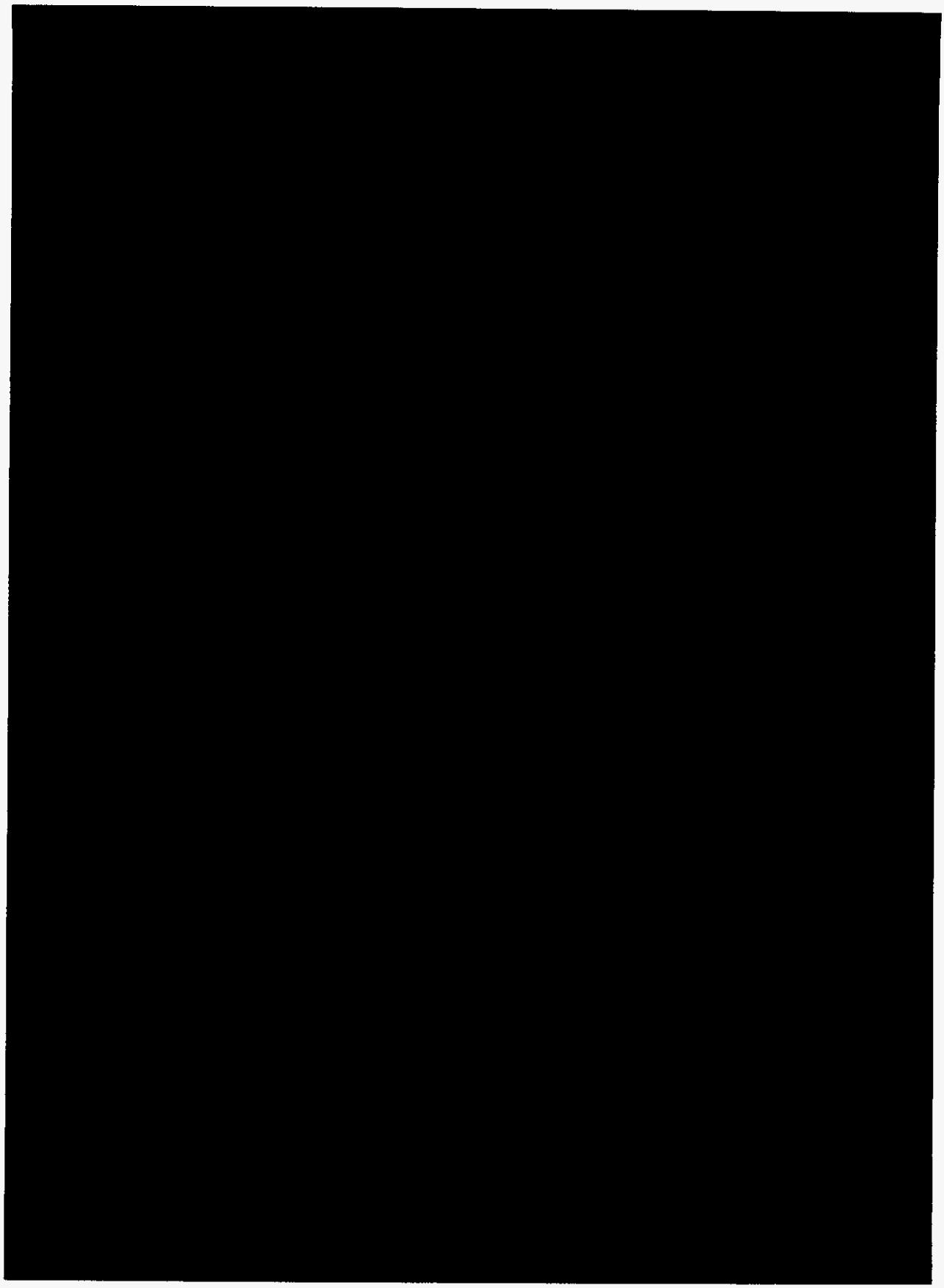
17.1 **Assignment.** Either Party may assign outright or collaterally this Agreement and its rights and obligations hereunder subject to the written consent of the other Party (which consent shall not be unreasonably withheld); provided that either Party may assign outright this Agreement and its rights and obligations hereunder without the consent of the other Party to any person with at [redacted]

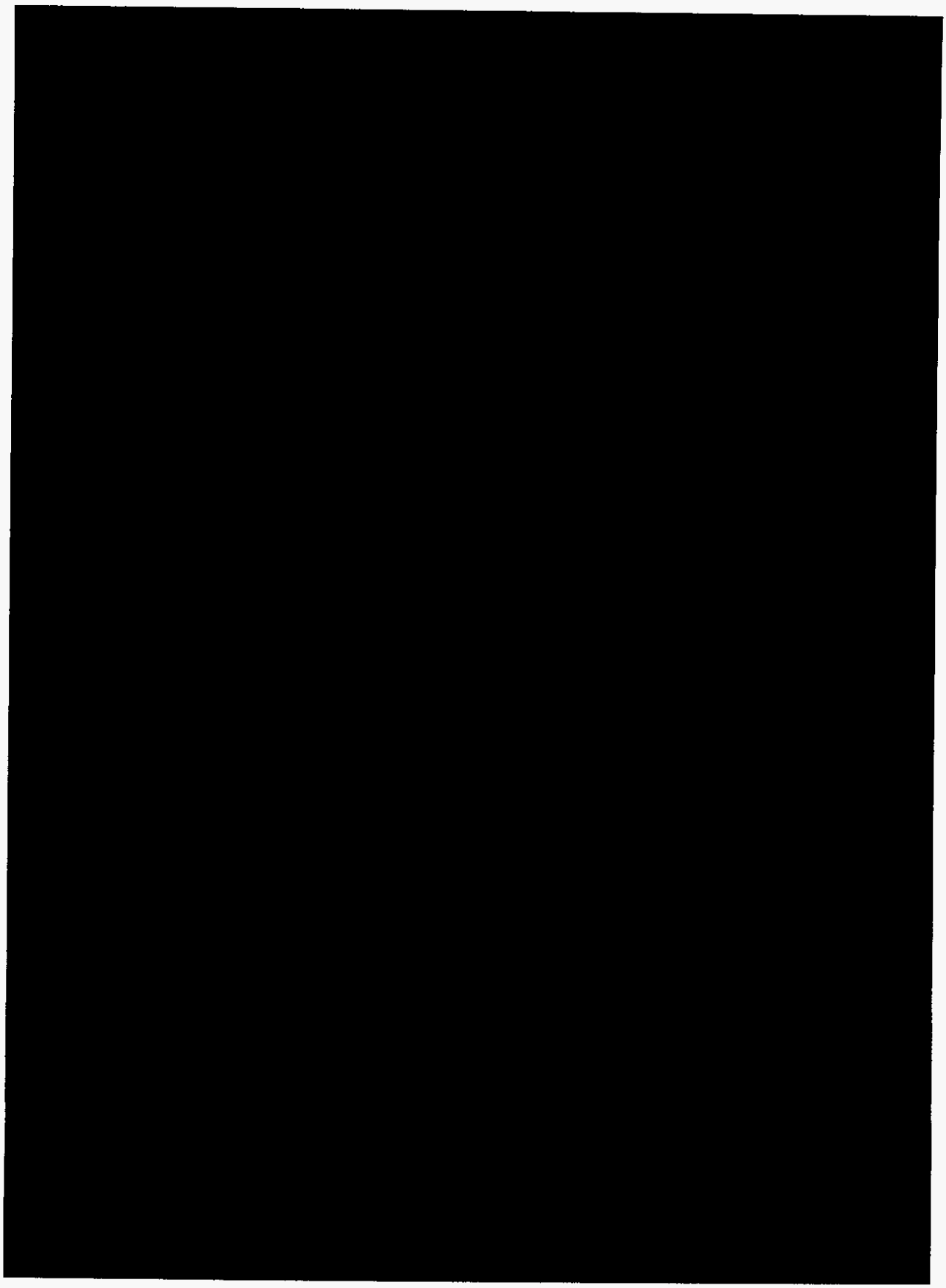


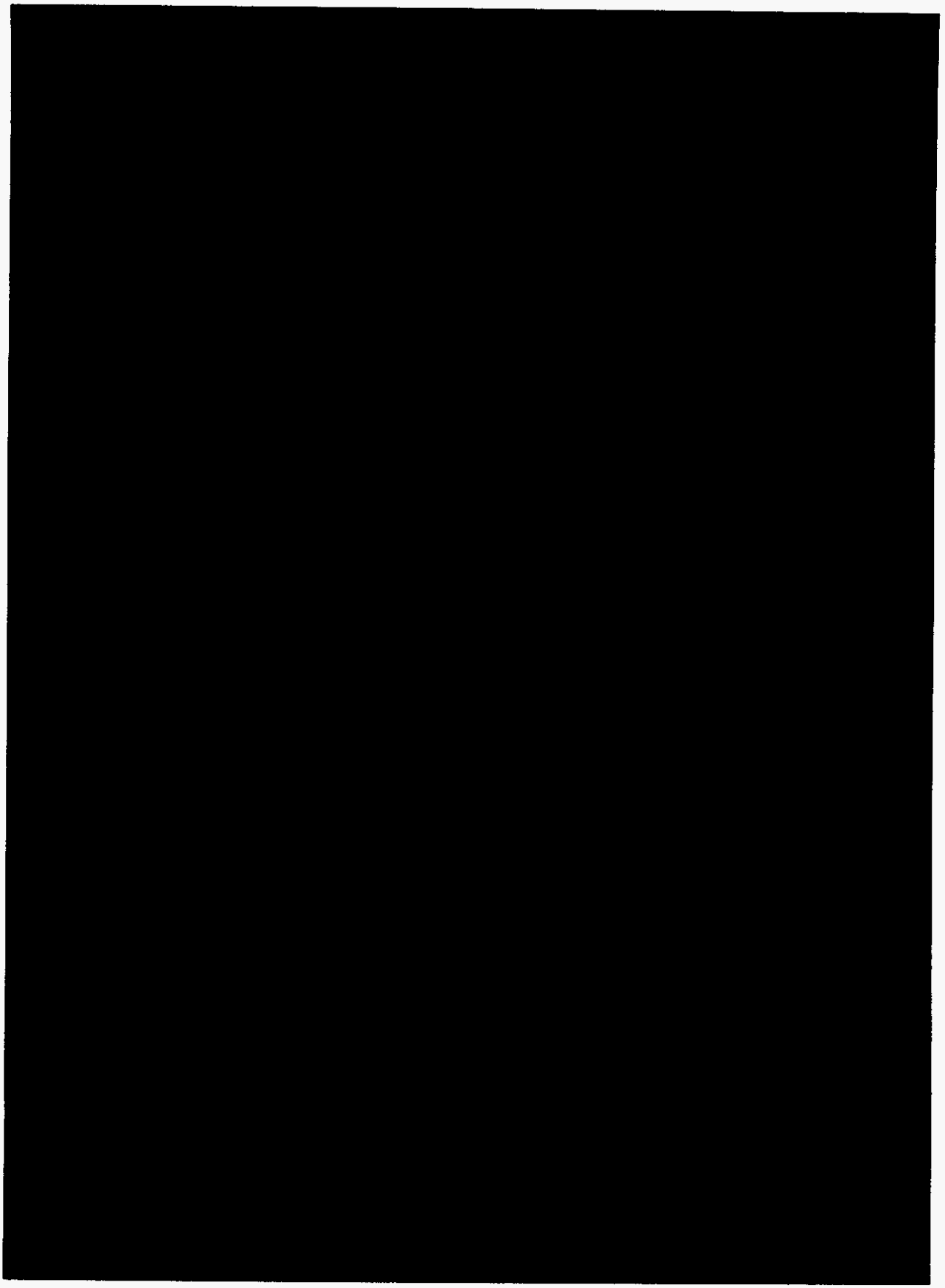


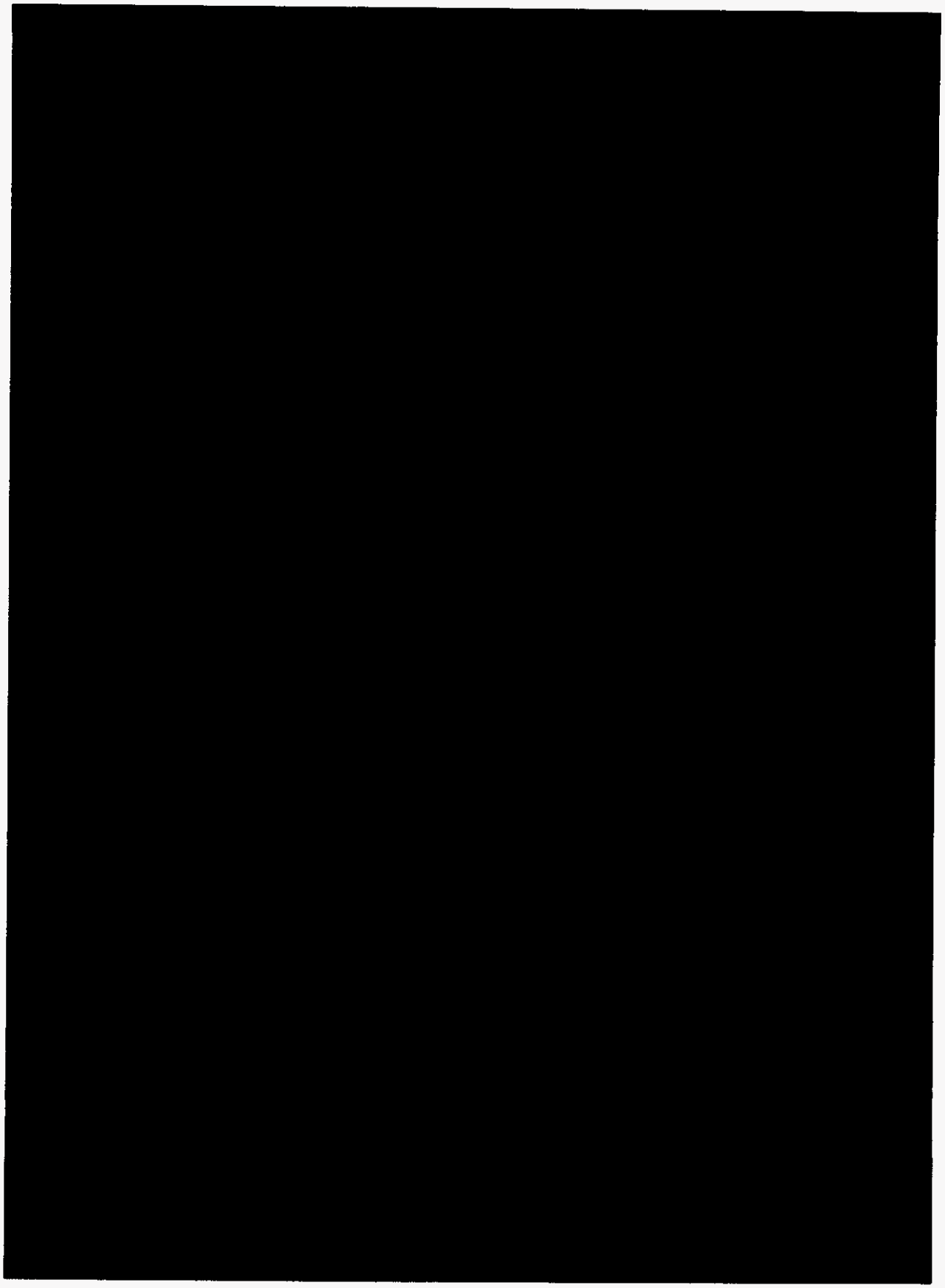
who has the legal power and authority, licenses and technical ability to perform and satisfy the obligations of the assigning Party under this Agreement (an "Eligible Assignee"). The assigning Party will notify the other Party in writing prior to any assignment with respect to which consent is not required hereunder. No assignment by a Party of this Agreement or its rights or obligations hereunder shall relieve the assigning Party of liability for its obligations under this Agreement without the written release of the other Party. Such release shall not be withheld if the Assignment Conditions (defined below) are satisfied.

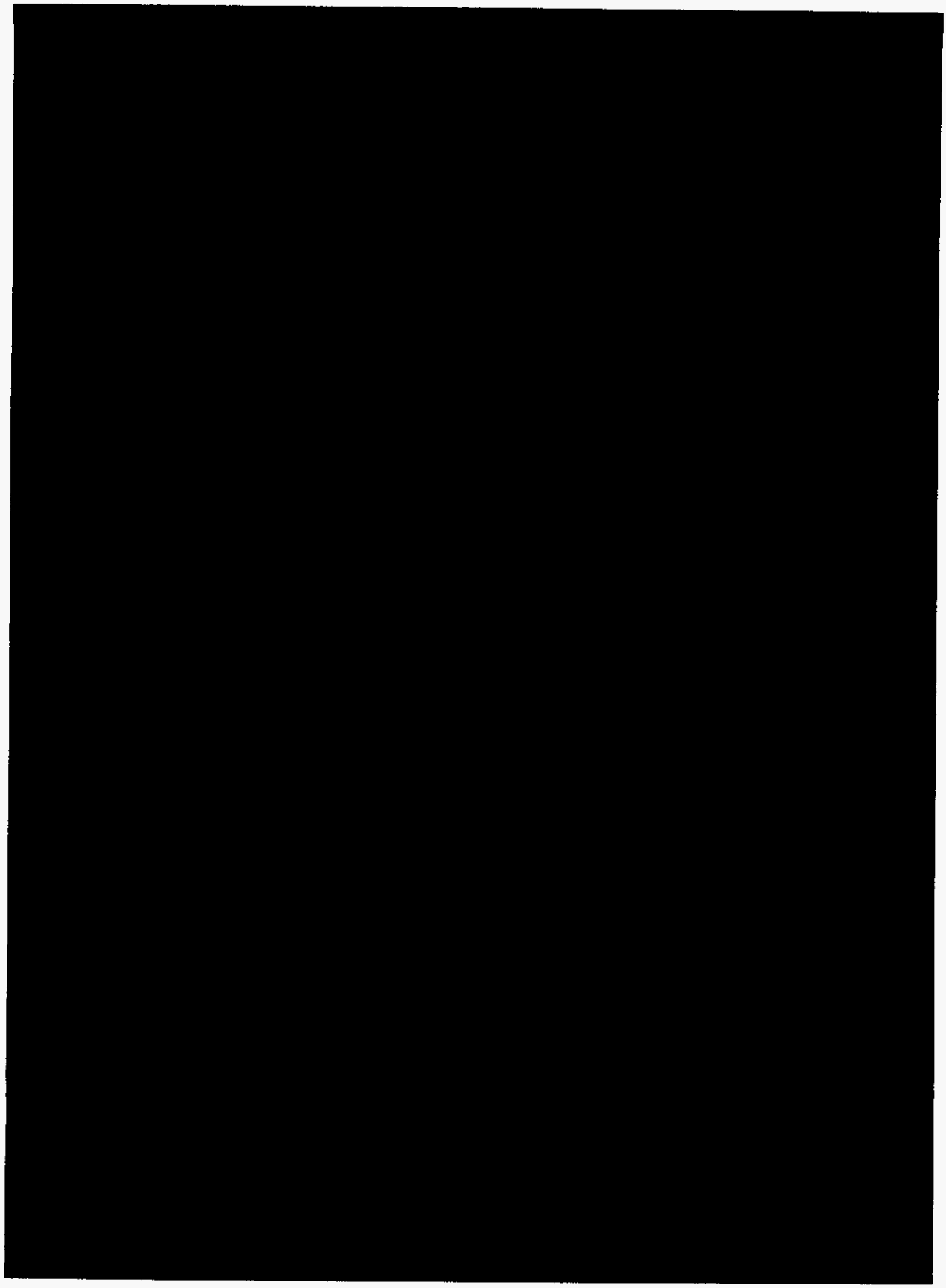
17.2 Assignment Conditions. The non-assigning Party's obligation to recognize or perform for any person claiming rights in this Agreement by outright assignment or through collateral assignment (an "Assignee") shall be subject to such Assignee: (i) establishing that it satisfies the qualifications of an Eligible Assignee; (ii) having cured all existing Events of Default under this Agreement; and (iii) having executed and delivered to the non-assigning Party an assignment and assumption agreement whereby the Assignee assumes and agrees to satisfy all conditions and pay and perform all obligations in favor of the non-assigning Party then existing and/or thereafter arising under this Agreement (the "Assignment Conditions"). Any attempted assignment, directly or indirectly, by way of merger or otherwise, which is not in compliance with the terms hereof shall be void and ineffective.

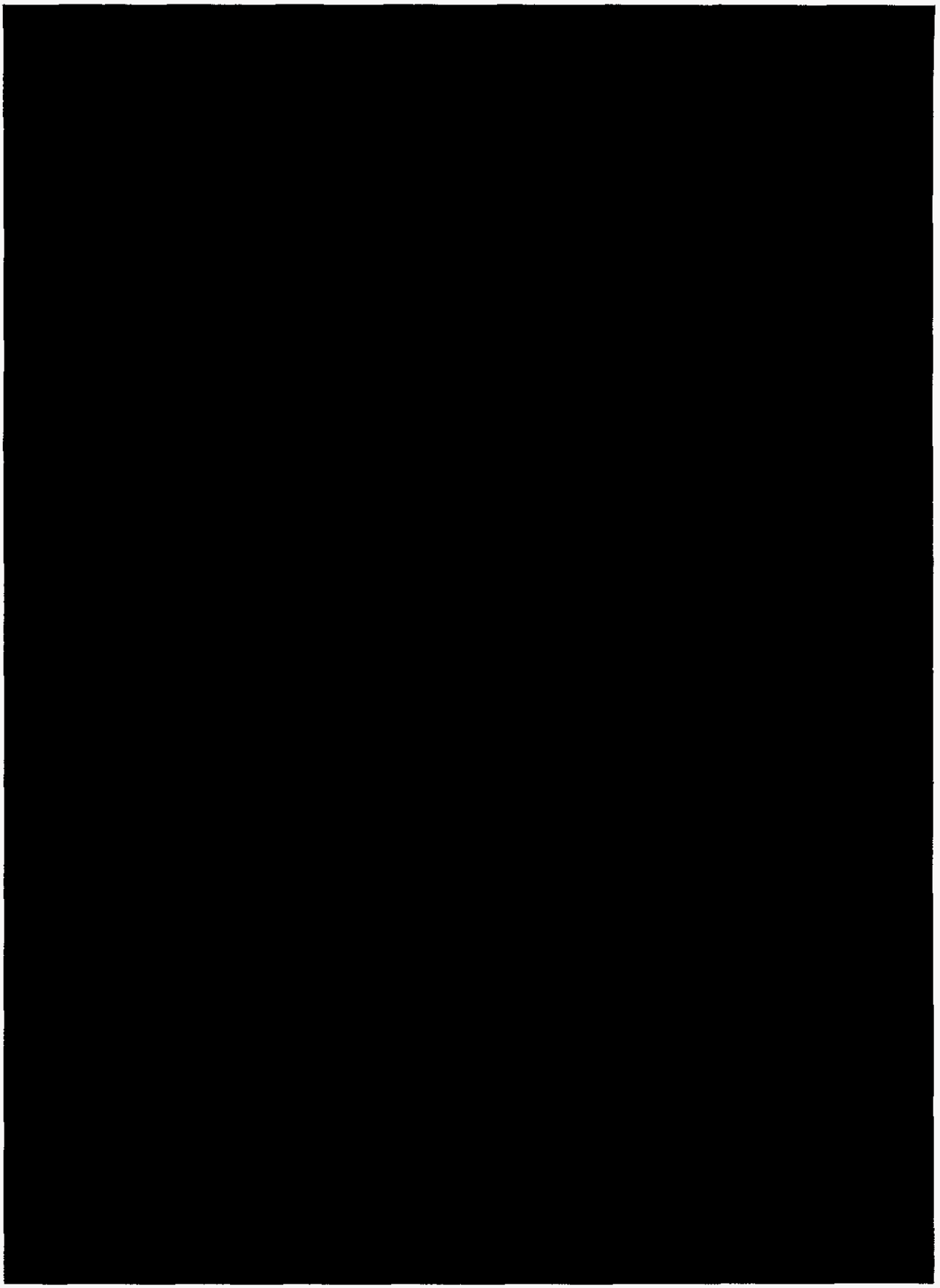


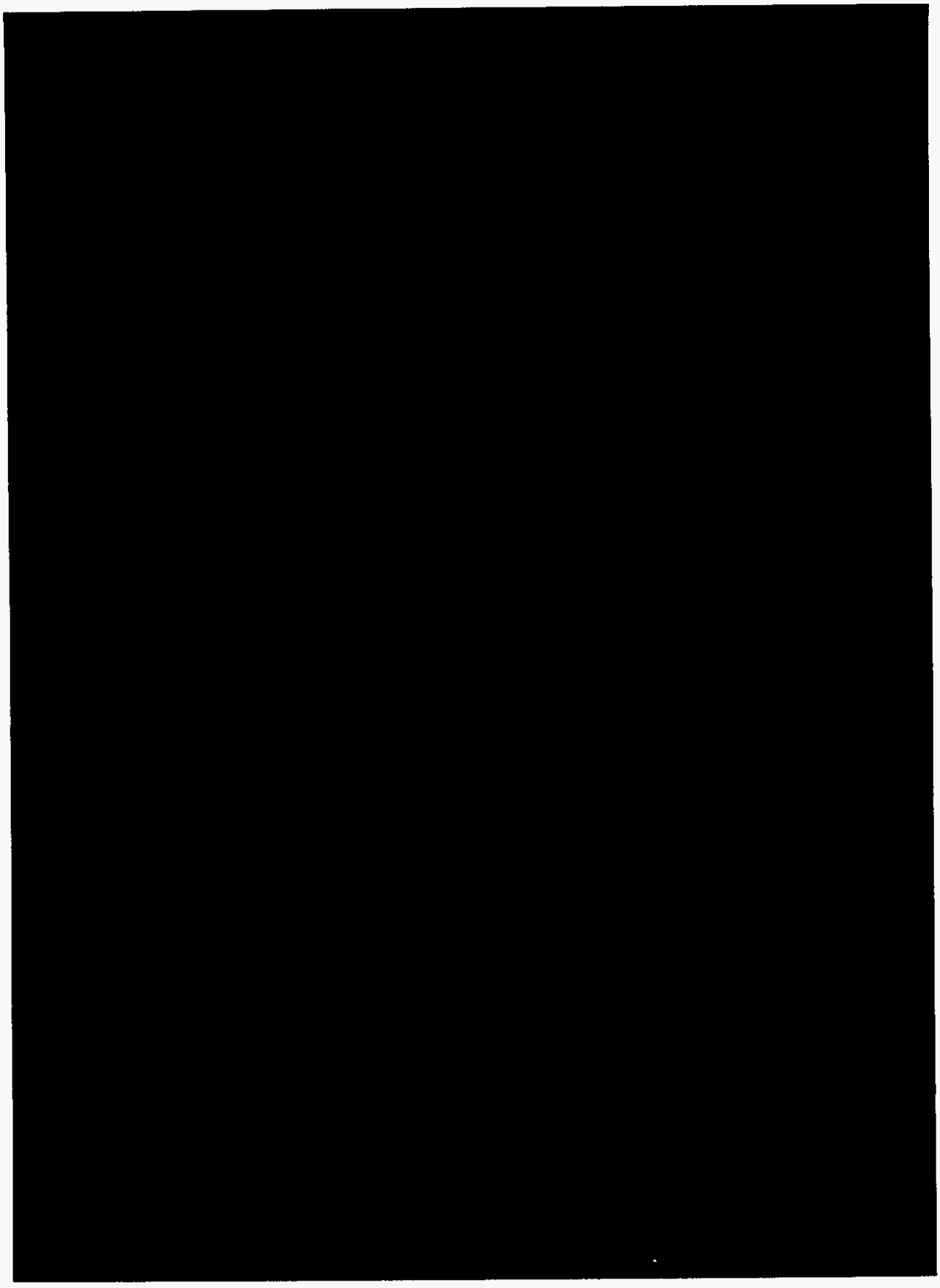


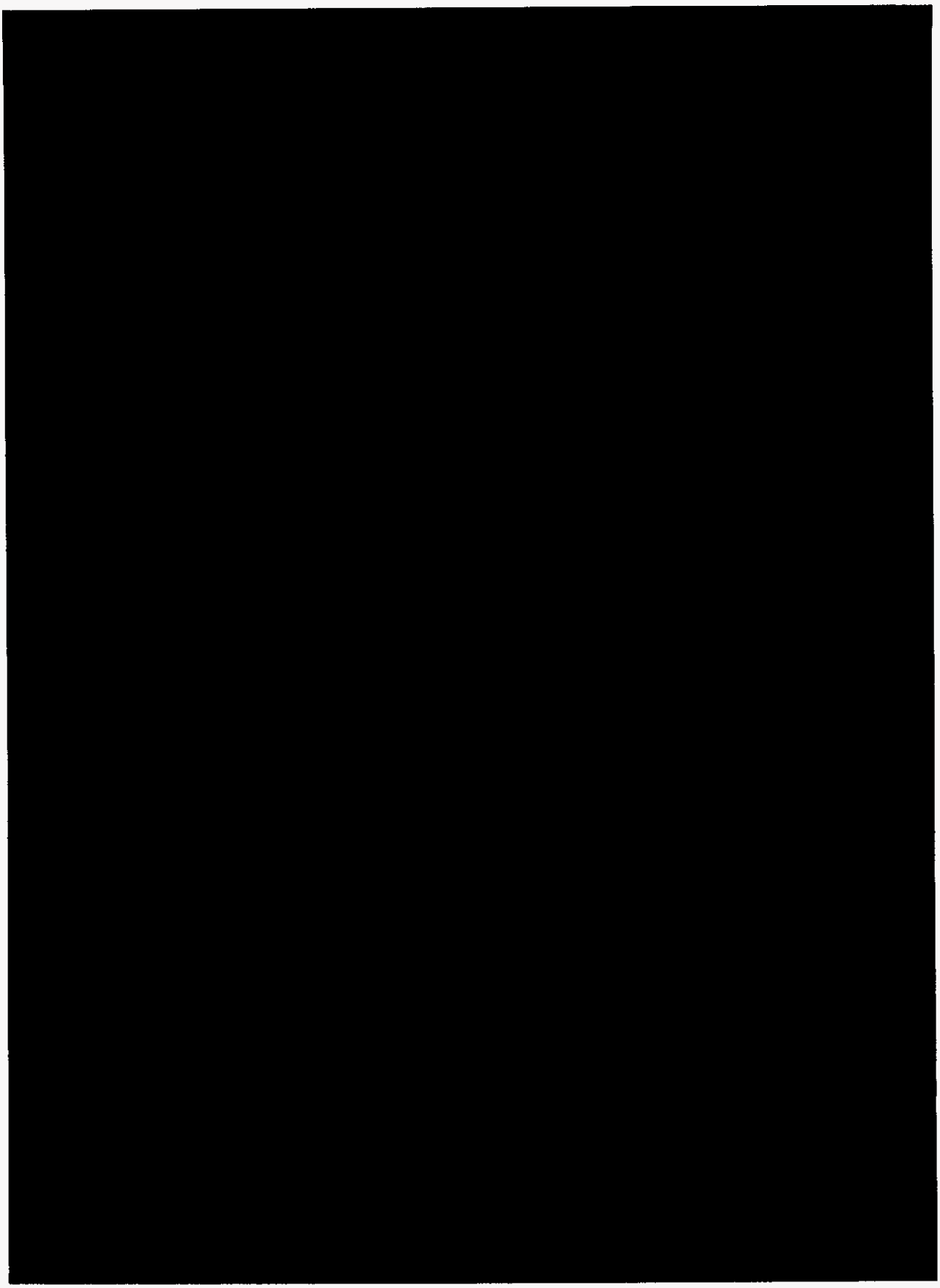


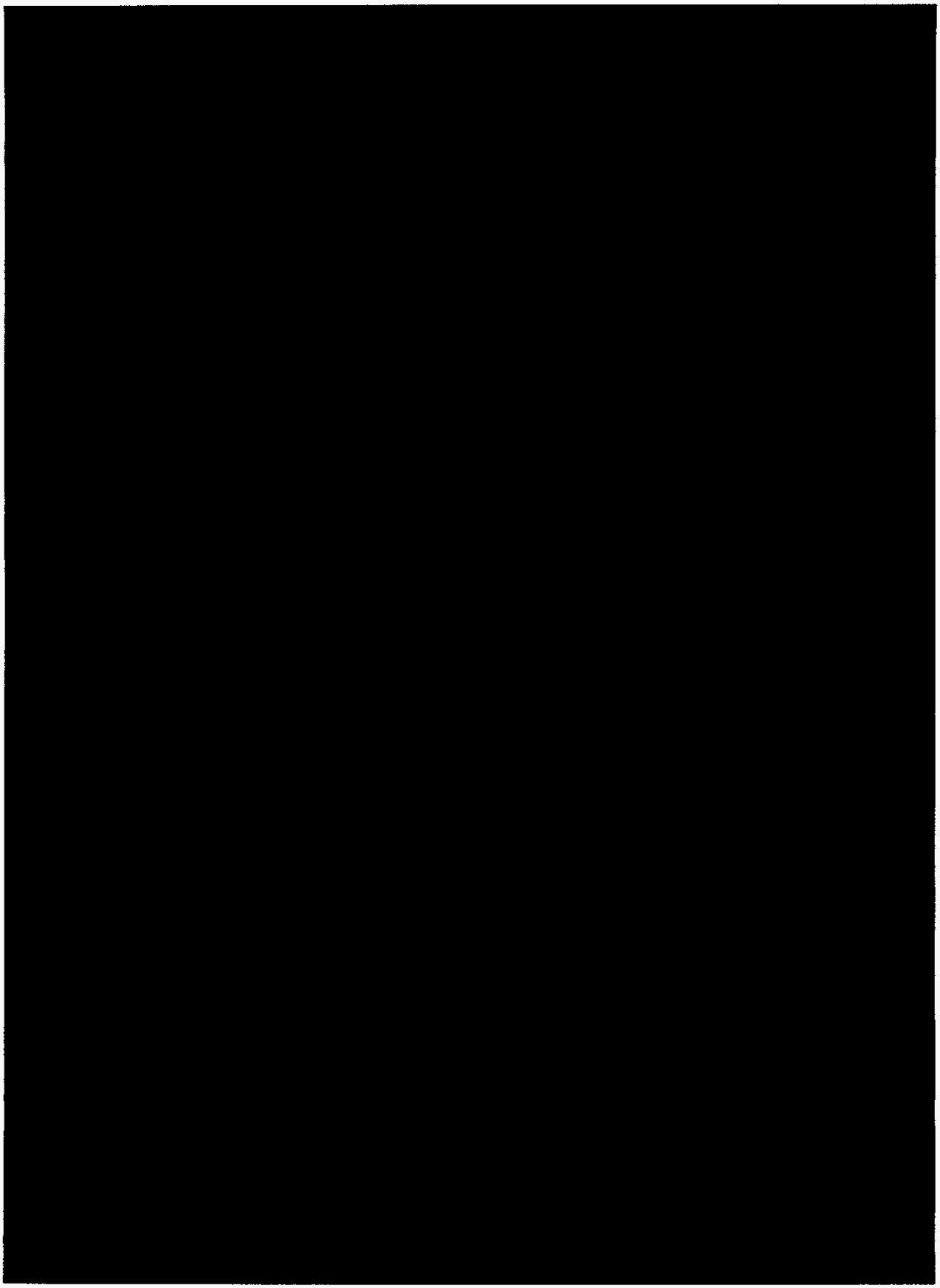












ARTICLE 19

MISCELLANEOUS

19.1 Governing Law; Waiver of Jury Trial. THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAW OF THE STATE OF FLORIDA, EXCLUSIVE OF ITS CONFLICTS OF LAW PROVISIONS, AND, TO THE EXTENT APPLICABLE, BY THE FEDERAL LAW OF THE UNITED STATES OF AMERICA. BY CHOOSING TO HAVE THIS AGREEMENT GOVERNED BY AND CONSTRUED UNDER THE LAW OF THE STATE OF FLORIDA, THE PARTIES ARE IN NO WAY SUBMITTING TO OR INCORPORATING INTO THIS AGREEMENT ANY FLORIDA STATUTE, REGULATION, OR ORDER, OR ANY OF THE SAME INVOLVING THE GENERATION, SALE, PURCHASE OR TRANSMISSION OF ELECTRIC CAPACITY OR ELECTRIC ENERGY IN, OR FOR CONSUMPTION IN, THE STATE OF FLORIDA. EACH PARTY HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT.

19.2 Confidentiality.

19.2.1 Scope of Protection.

(i) For purposes of this Section 19.2: (a) "Seller Confidential Information" means the terms of this Agreement and all drafts of the same, together with any documents, data or drafts labeled or otherwise expressly identified as "Confidential" by Seller

when provided to Buyer; (b) "Buyer Confidential Information" means the terms of this Agreement and all drafts of the same, together with any documents, data or drafts labeled or otherwise expressly identified as "Confidential" by Buyer when provided to Seller; and (c) "Confidential Information" means collectively the Seller Confidential Information and the Buyer Confidential Information.

(ii) Seller shall not disclose to third parties any Buyer Confidential Information; provided that nothing contained herein shall prohibit Seller from providing any such Buyer Confidential Information to its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons in connection with the acquisition of all or a significant portion of the assets or stock of Georgia Power or Gulf Power or any of their Affiliates or in connection with the analysis, issuance or rating of any debt or equity securities or other financing activities by Georgia Power or Gulf Power or any of their Affiliates who in the reasonable judgment of Seller should have access to such Buyer Confidential Information and are bound by an obligation to maintain such confidentiality provided that Seller shall be responsible for any use or disclosure of such Buyer Confidential Information by any of its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons inconsistent with this Section 19.2; provided further that nothing contained herein shall prohibit Seller from providing Buyer Confidential Information to the NERC or SEARUC solely to the extent that (i) Seller determines in its reasonable discretion that the provision of such information is required to enhance and/or maintain reliability; (ii) such entity is obligated to

maintain such confidentiality; and (iii) Seller has notified Buyer of its intention to release such information no less than five (5) Business Days prior to the release subject to the requirements of applicable law and regulation.

(iii) Buyer shall not disclose to third parties any Seller Confidential Information; provided that nothing contained herein shall prohibit Buyer from providing any such Seller Confidential Information to its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons in connection with the acquisition of all or a significant portion of the assets or stock of Buyer or any of its Affiliates or in connection with the analysis, issuance or rating of any debt or equity securities or other financing activities by Buyer or any of its Affiliates who in the reasonable judgment of Buyer should have access to such Seller Confidential Information and are bound by an obligation to maintain such confidentiality provided that Buyer shall be responsible for any use or disclosure of such Seller Confidential Information by any of its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons inconsistent with this Section 19.2; provided further that nothing contained herein shall prohibit Buyer from providing Seller Confidential Information to the NERC or SEARUC solely to the extent that (i) Buyer determines in its reasonable discretion that the provision of such information is required to enhance and/or maintain reliability, (ii) such entity is obligated to maintain such confidentiality, and (iii) Buyer has notified Seller of its intention to release such information no less than five (5) Business Days prior to the release subject to the requirements of applicable law and regulation.

(iv) Notwithstanding the foregoing, either Party may disclose Confidential Information (i) to the extent relevant, to the independent parties determining Seller's Damages or Buyer's Damages (as appropriate), and (ii) to its and its Affiliates' employees, officers, directors, accountants, counsel and other advisors who need to know such information in connection with the performance of their duties or services for the disclosing Party or its Affiliates; provided, however, that such Persons shall be required to maintain the confidentiality of such information consistent with the requirements of this Agreement..

19.2.2 Required and Other Disclosure.

(i) Notwithstanding anything in this Section 19.2 to the contrary, if Buyer is required by applicable law or regulation, or in the course of administrative or judicial proceedings or investigations, to disclose to third parties, Seller Confidential Information or otherwise intends to disclose Seller Confidential Information to FERC or its staff (other than at the request or requirement of FERC or its staff) or pursuant to the request or requirement of any appropriate state regulatory commission or body, Buyer may make disclosure of such Seller Confidential Information; provided, however, that all reasonable steps are taken by Buyer to assure continued confidential treatment by the relevant administrative, regulatory or judicial agencies or other recipient and provided further that as soon as Buyer learns of the disclosure request or requirement or otherwise intends to disclose any Seller Confidential Information pursuant hereto and prior to making disclosure, Buyer shall, to the extent permitted by law, notify Seller of the requirement, request or intention and the terms thereof and any Party may challenge the disclosure requirement, request or intention or seek a protective order or other appropriate remedy. Buyer, at Seller's expense, shall cooperate with Seller to the maximum extent practicable to minimize the disclosure of the Seller Confidential Information consistent

with applicable law. Buyer shall cooperate with Seller to obtain proprietary or confidential treatment of such Seller Confidential Information by the Person to whom such Seller Confidential Information will be disclosed (and if practicable, reasonably prior to any such disclosure). If, in the absence of a protective order or other appropriate remedy or the receipt of a waiver by Seller, Buyer is nonetheless, in the written opinion of counsel, legally compelled to disclose Seller Confidential Information or otherwise may become subject to contempt or other censure or penalty, Buyer may, in such instance but not otherwise, without liability hereunder, disclose that portion of the Seller Confidential Information which and to whom such counsel advises Buyer is legally required to be disclosed (but none other), provided that Buyer exercises Commercially Reasonable Efforts to preserve the confidentiality of the Seller Confidential Information, including by cooperating with Seller to obtain an appropriate protective order or other reliable assurance that the Seller Confidential Information shall be accorded confidential treatment. Seller shall be liable for all reasonable legal costs incurred by Buyer in cooperating with Seller to obtain such an appropriate protective order or confidential treatment.

(ii) Notwithstanding anything in this Section 19.2 to the contrary, if Seller is required by applicable law or regulation, or in the course of administrative or judicial proceedings or investigations, to disclose to third parties, Buyer Confidential Information or otherwise intends to disclose Buyer Confidential Information to FERC or its staff (other than at the request or requirement of FERC or its staff) or pursuant to the request or requirement of any appropriate state regulatory commission or body, Seller may make disclosure of such Buyer Confidential Information; provided, however, that all reasonable steps are taken by Seller to assure continued confidential treatment by the relevant administrative, regulatory or judicial agencies or other recipient and provided further that as soon as Seller learns of the disclosure

request or requirement or otherwise intends to disclose any Buyer Confidential Information pursuant hereto and prior to making disclosure, Seller shall, to the extent permitted by law, notify Buyer of the requirement, request or intention and the terms thereof and any Party may challenge the disclosure requirement, request or intention or seek a protective order or other appropriate remedy. Seller, at Buyer's expense, shall cooperate with Buyer to the maximum extent practicable to minimize the disclosure of the Buyer Confidential Information consistent with applicable law. Seller shall cooperate with Buyer to obtain proprietary or confidential treatment of such Buyer Confidential Information by the Person to whom such Buyer Confidential Information will be disclosed (and if practicable, reasonably prior to any such disclosure). If, in the absence of a protective order or other appropriate protective remedy or the receipt of a waiver by Buyer, Seller is nonetheless, in the written opinion of counsel, legally compelled to disclose Buyer Confidential Information or otherwise may become subject to contempt or other censure or penalty, Seller may, in such instance but not otherwise, without liability hereunder, disclose that portion of the Buyer Confidential Information which and to whom such counsel advises Seller is legally required to be disclosed (but none other), provided that Seller exercises Commercially Reasonable Efforts to preserve the confidentiality of the Buyer Confidential Information, including, without limitation, by cooperating with Buyer to obtain an appropriate protective order or other reliable assurance that the Buyer Confidential Information shall be accorded confidential treatment. Buyer shall be liable for all reasonable legal costs incurred by Seller in cooperating with such Buyer to obtain an appropriate protective order or confidential treatment.

(iii) Nothing in this Section 19.2 shall prohibit or otherwise limit the use or disclosure of Confidential Information if such Confidential Information: (i) was

previously known to the disclosing or using Party unrelated to this Agreement without an obligation of confidentiality; (ii) was developed by or for the disclosing or using Party unrelated to this Agreement using nonconfidential information; (iii) was acquired by the disclosing or using Party from a third party which is not, to the disclosing or using Party's knowledge, under an obligation of confidence with respect to such information; (iv) is or becomes publicly available other than through a manner inconsistent with this Section 19.2; or (v) is provided or made available for inspection by Seller or Buyer under public records or public disclosure laws but only to the extent required to be so provided or made available.

(iv) The provisions of this subsection shall supercede any contrary provisions of this Section 19.2 regarding the disclosure of information to FERC or its staff pursuant to the request or requirement of FERC or its staff. In providing Buyer Confidential Information to FERC or its staff pursuant to the request or requirement of FERC or its staff, Seller shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. To the extent permitted by law, Seller shall promptly notify Buyer when it is required or requested by FERC or its staff to disclose Buyer Confidential Information. Seller shall not be prohibited to make or liable for the disclosure to FERC or its staff of any Buyer Confidential Information pursuant to the request or requirement of FERC or its staff consistent with this subsection. In providing Seller Confidential Information to FERC or its staff pursuant to the request or requirement of FERC or its staff, Buyer shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. To the extent permitted by law, Buyer shall promptly notify Seller when it is required or requested by FERC or its staff to

disclose Seller Confidential Information. Buyer shall not be prohibited to make or liable for the disclosure to FERC or its staff of any Seller Confidential Information pursuant to the request or requirement of FERC or its staff consistent with this subsection. Notwithstanding the foregoing, the Parties acknowledge that any request of FERC for confidential treatment of information may be denied by FERC in whole or in part.

(v) The Parties agree to seek confidential treatment of the Confidential Information from the FPSC to the maximum extent possible pursuant to Chapter 366.093, Florida Statutes, and Rule 25-22.006 of the Florida Administrative Code; however, notwithstanding the foregoing, the Parties acknowledge that a request for confidential treatment of Confidential Information may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the FPSC to such information. In the event any Confidential Information will need to be disclosed in connection with the application for the FPSC Approval, Buyer shall consult and cooperate with Seller prior to such disclosure, including, without limitation, in determining the extent to which confidential treatment will be sought for such terms, conditions and provisions.

(vi) Seller may file this Agreement with the Securities and Exchange Commission ("Commission") as may be necessary under the Public Utility Holding Company Act and the rules and regulations thereunder in connection with Seller's application to the Commission for such orders and approvals as may be required for financing and/or the issuance and sale of interests in or debt issued or to be issued by Seller and/or its Affiliates. Seller shall request confidential treatment of the Buyer Confidential Information in this Agreement in connection with such filing; however, the Parties acknowledge that such request may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the

Commission to such information. In addition, Seller may disclose such Buyer Confidential Information as required by the Commission pursuant to the Securities and Exchange Act of 1934, as amended, and any rule or regulation promulgated thereunder.

(vii) Except for filings with the Commission or other regulatory authorities, any public statement and/or press release by a Party hereto concerning this Agreement (except statements or releases by the Non-Defaulting Party after an Event of Default) shall be reviewed and agreed upon by the Parties before release, which agreement shall not be unreasonably withheld or delayed.

The obligations under this Section 19.2 with respect to any Party shall survive until the earlier of [redacted]

19.3 Survivorship of Obligations. Termination of this Agreement shall not discharge any Party from any obligation it owes the other Party under this Agreement by reason of any transaction, loss, cost, damage, expense or liability occurring, accruing or arising prior to such termination. It is the intent of the Parties that any such obligation owed (whether the same shall be known or unknown as of the termination or cancellation of this Agreement) will survive the termination or cancellation of this Agreement in favor of the Party to which such obligation is owed. The Parties also intend that the indemnification and limitation of liability provisions contained in Sections 12.2 and 12.3 shall remain operative and in full force and effect and that any specific survivability provisions in any other sections be given full effect.

19.4 No Third Party Beneficiaries. This Agreement is not intended to, and shall not, create rights, remedies or benefits of any character whatsoever in favor of any Persons, corporations, associations, or entities other than the Parties and their permitted successors and assigns, and the rights and obligations of each of the Parties under this Agreement are solely for

the use and benefit of, and may be enforced solely by the Parties, their permitted successors and assigns.

19.5 Section Headings Not to Affect Meaning. The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and shall in no way modify or restrict any of the terms and provisions thereof. References to "Articles", "Sections" and "Appendices" in this Agreement shall mean the Articles, Sections and Appendices of this Agreement unless otherwise expressly noted.

19.6 Computation of Time. In computing any period of time prescribed or allowed by this Agreement, the designated period of time shall begin to run on the Day immediately following the Day of the act, event or default that precipitated the running of the designated period of time. The designated period shall expire on the last Day of the period so computed unless that Day is not a Business Day, in which event the period shall run until the end of the next Business Day.

19.7 Interest. Whenever the provisions of this Agreement require the calculation of an interest rate, such rate shall be computed at an annual rate equal to the Prime Rate as of the date on which the calculation begins, but not to exceed the maximum rate which may be lawfully charged. Interest on obligations arising under this Agreement shall be compounded daily and be calculated based on a 360 day year.

19.8 Entire Agreement. [redacted] this Agreement constitutes the entire agreement between the Parties relating to the subject matter hereof and supersedes any other agreements, written or oral, between the Parties concerning such subject matter. The Parties have entered into this Agreement in reliance upon the representations and mutual

understandings contained herein and not in reliance upon any oral or written representation or information provided by one Party to another Party not contained or incorporated herein.

19.9 Counterparts. This Agreement may be executed simultaneously in multiple counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

19.10 Amendments. This Agreement may only be amended by written agreement signed by duly authorized representatives of the Parties.

19.11 Waivers. Waivers of the provisions of this Agreement or excuses of any violations of this Agreement shall be valid only if in writing and signed by an authorized officer of the Party issuing the waiver or excuse. A waiver or excuse issued under one set of circumstances shall not extend to other occurrences under similar circumstances.

19.12 No Partnership Created. Any provision of this Agreement to the contrary notwithstanding, the Parties do not intend to create hereby any joint venture, partnership, association taxable as a corporation, or other entity for the conduct of any business for profit. If it should appear that one or more changes to this Agreement would be required in order not to create an entity referenced in the preceding sentence, the Parties agree to negotiate promptly and in good faith with respect to such changes.

19.13 Character of Sale. The sale of capacity and energy hereunder shall not constitute a sale, lease, transfer or conveyance to Buyer or any other party of any contractual rights or ownership interests in any generating unit or other equipment comprising the Facility, nor does the sale of capacity and energy hereunder constitute a dedication of ownership of any generating unit or other equipment comprising the Facility.

19.14 Notices. Any notice, demand, request, statement, or correspondence provided for in this Agreement, or any notice which a Party may desire to give to the other, shall be in writing (unless otherwise expressly provided by this Agreement) and shall be considered duly delivered when received by hand delivery, first-class mail, facsimile, or by overnight delivery, at the address(es) and to the attention of the person(s) listed below; provided, however, if actual delivery occurs at a time other than between the hours of 0800 and 1700 CPT on a Business Day (each a "Business Hour"), delivery shall be deemed to have occurred in the next Business Hour after actual delivery.

(i) **To Seller:**

Vice President, Business Development
Southern Company Generation and Energy Marketing
Bin 935
270 Peachtree Street, NW
Atlanta, Georgia 30303

Telephone: 404-506-0346
Facsimile: 404-506-0399

With a copy to:

Senior Vice President and General Counsel
Georgia Power Company
241 Ralph McGill Boulevard
Atlanta, Georgia 30308

Telephone: 404-506-2700
Facsimile: 404-506-7985

And

Vice President, Chief Financial Officer and Comptroller
Gulf Power Company
1 Energy Place
Pensacola, Florida 32520

Telephone: 850-444-6385
Facsimile: 850-444-6744

And

Vice President, Fleet Operations and Trading
Southern Company Services, Inc.
600 North 18th Street, GS-8259
Birmingham, Alabama 35203

Telephone: 205-257-6139
Facsimile: 205-257-4441

(ii) **To Buyer:**

Vice President, Energy Marketing and Trading
Florida Power & Light Company
700 Universe Boulevard
EMT/JB
Juno Beach, Florida 33408

Telephone: 561-691-7878
Facsimile: 561-691-7759

With a copy to:

Director, Resource Assessment and Planning
Florida Power & Light Company
9250 West Flagler Street
Miami, Florida 33174

Telephone: 305-552-3622
Facsimile: 305 552-2905

Either Party may change the information set forth in this Section 19.14 by giving written notice to the other Party in the manner prescribed by this Section.

19.15 Survival. Any provision(s) of this Agreement that expressly comes into or remains in force following the termination or expiration of this Agreement shall, subject to the express terms of the relevant provision, survive the termination or expiration of this Agreement.

19.16 Construction. The language used in this Agreement is the product of both Parties' efforts. Accordingly, each Party irrevocably waives the benefit of any rule of contract

construction that disfavors the drafter of a contract or the drafter of specific language in a contract.

19.17 Imaged Agreement. Any original executed Agreement, schedule confirmation or other related document may be photocopied and stored on computer tapes and disks (the "Imaged Agreement"). The Imaged Agreement, if introduced as evidence on paper, the schedule confirmation, if introduced as evidence in automated facsimile form, the transaction tape, if introduced as evidence in its original form and as transcribed onto paper, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings, will be admissible as between the Parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the transaction tape, the schedule confirmation or the Imaged Agreement (or photocopies of the transcription of the transaction tape, the schedule confirmation or the Imaged Agreement) on the basis that such were not originated or maintained in documentary form under either the hearsay rule, the best evidence rule or other rule of evidence.

19.18 Severability. If any provision or provisions of this Agreement or the application thereof to any Person or circumstance or in any jurisdiction is found by a court of competent jurisdiction to be illegal, invalid, unlawful, void or unenforceable as written for any reason, then it is the intent of each of the Parties that any such provision or provisions shall be given force and effect to the fullest possible extent that they are legal, valid and enforceable, that the remainder of this Agreement and the application of such provision or provisions to other Persons or circumstances or in other jurisdictions shall be deemed valid and enforceable to the fullest extent possible and continue in force and effect. If the determination that any provision

or provisions hereof are illegal, invalid, unlawful, void or unenforceable (even after such provision or provisions are given force and effect to the fullest extent possible) results in a significant material deviation from the Parties' original intent or economic expectations regarding this Agreement, the Parties shall negotiate to (and/or the applicable court, in its discretion, may) replace any such illegal, invalid, unlawful, void or unenforceable provision or provisions with valid provision(s) which result in the least deviation from the Parties' intent and economic expectations.

19.19 Agency of Southern Company Services, Inc. Seller hereby designates Southern Company Services, Inc. to serve as its agent for purposes of the implementation and administration of this Agreement. Seller may designate a new agent from time to time under this Agreement by giving Buyer sixty (60) Days written notice in which event Southern Company Services, Inc.'s role, as agent, shall cease and the newly-designated agent shall be substituted for the sole purpose of serving and acting as agent for Seller hereunder.

19.20 Include. As used herein, the words "include" or "including" shall be deemed to be followed by the words "without limitation."

19.21 Examples. Examples of calculations pursuant to the provisions of this Agreement are set forth in Appendix G. Such calculations are for example purposes only and are not intended to, and shall not, modify any of the terms of this Agreement. To the extent there is a conflict between any of these examples and the other terms of this Agreement, such other terms shall govern. Moreover, such examples shall be given no weight in interpreting or construing the provisions of this Agreement.

[The Next Page is the Signature Page.]

IN WITNESS WHEREOF, Seller and Buyer have caused this Agreement to be executed in duplicate by their respective duly authorized officers as of the Effective Date.

SOUTHERN COMPANY SERVICES, INC.
As Agent for
Georgia Power Company and
Gulf Power Company

BY: _____

NAME: William N. McKenzie

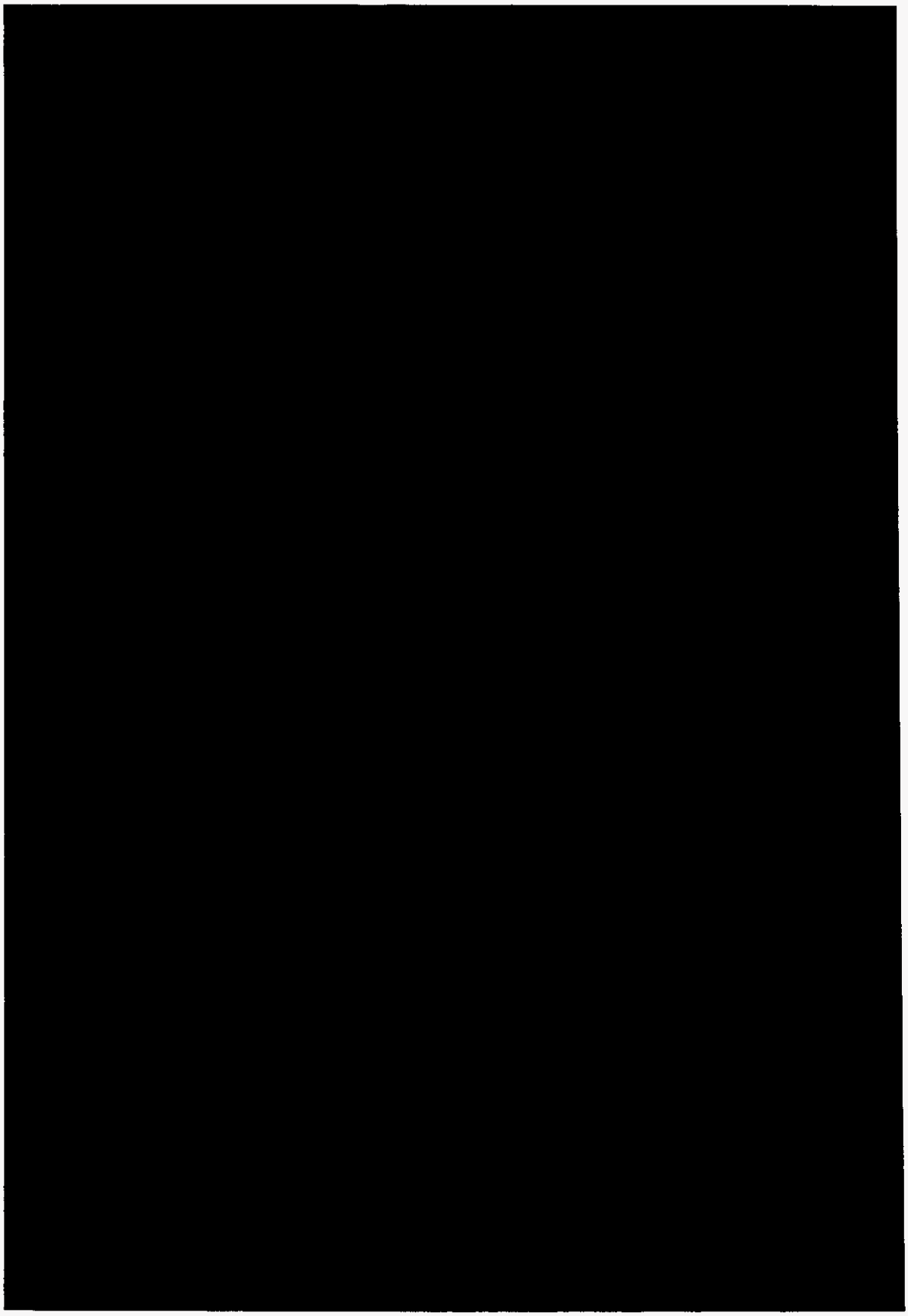
TITLE: Vice President

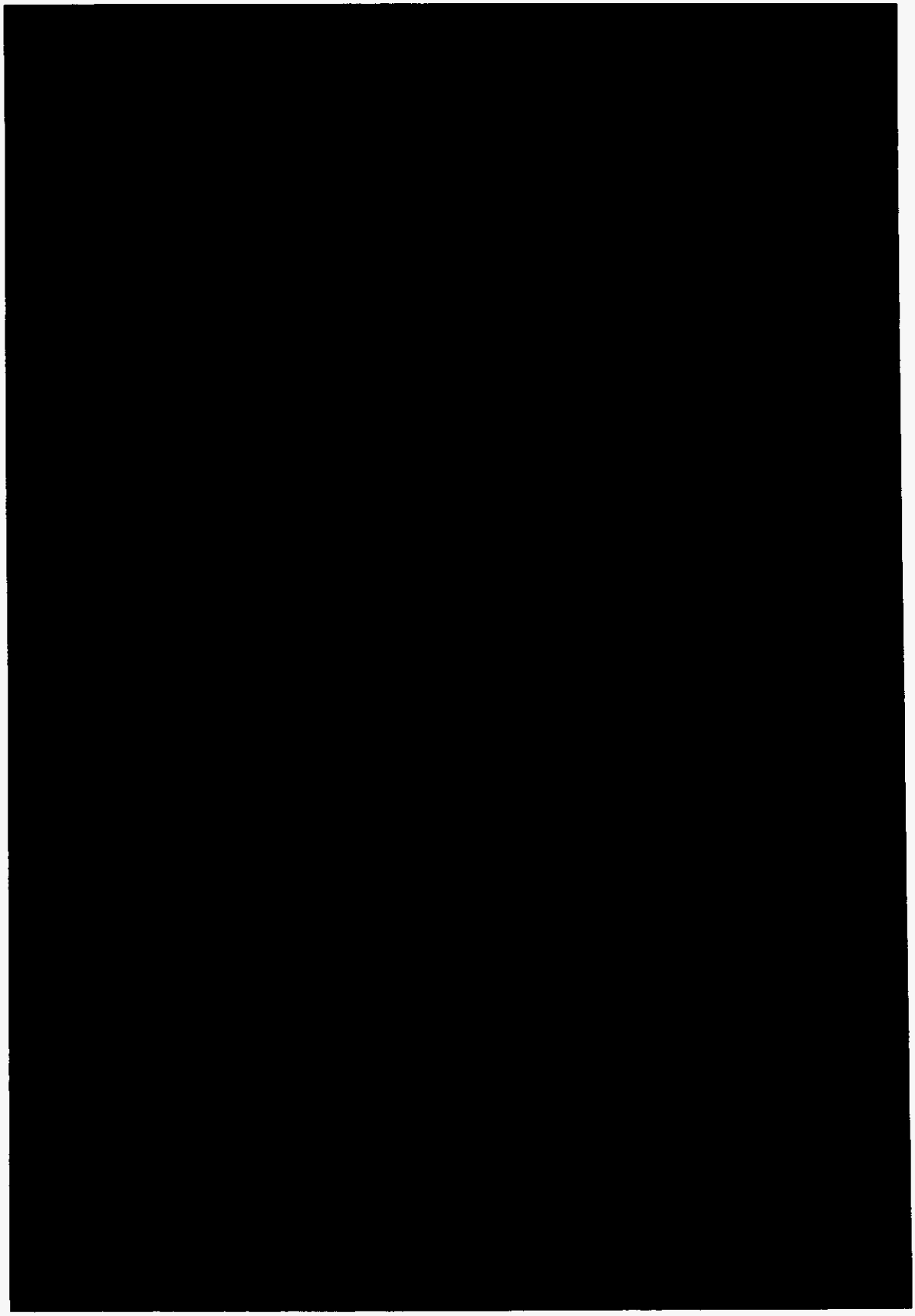
FLORIDA POWER & LIGHT COMPANY

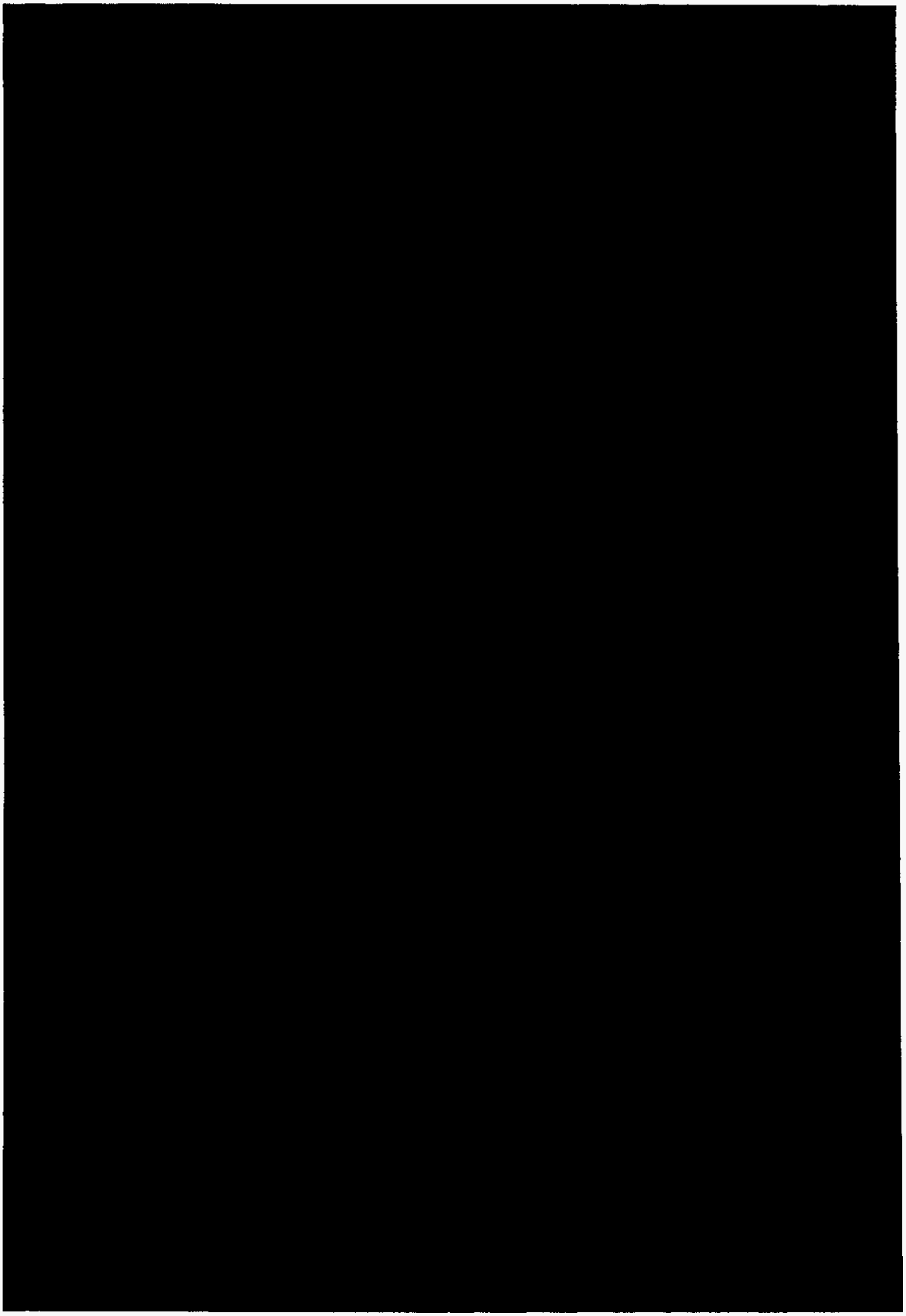
BY: _____

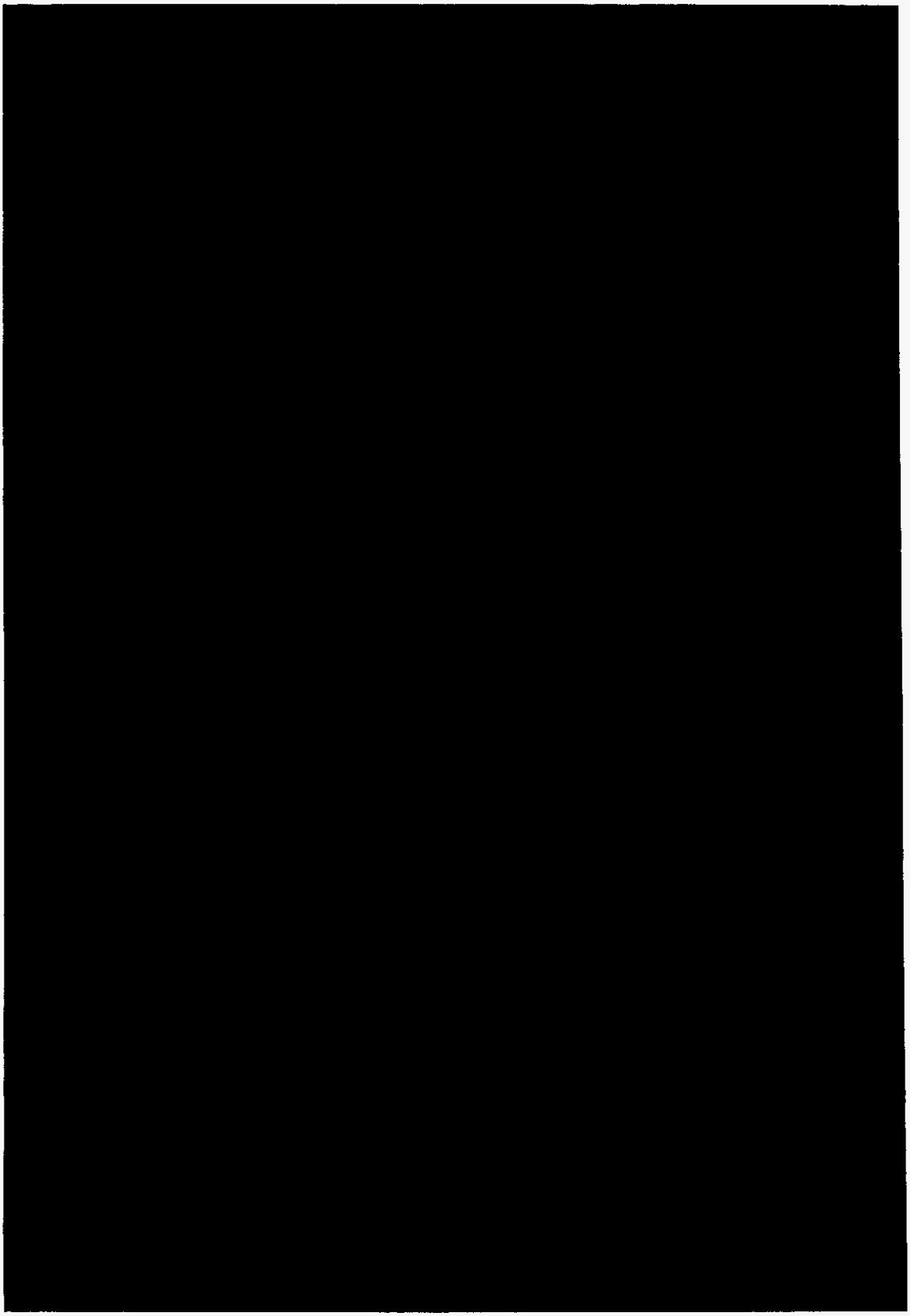
NAME: Terry L. Morrison

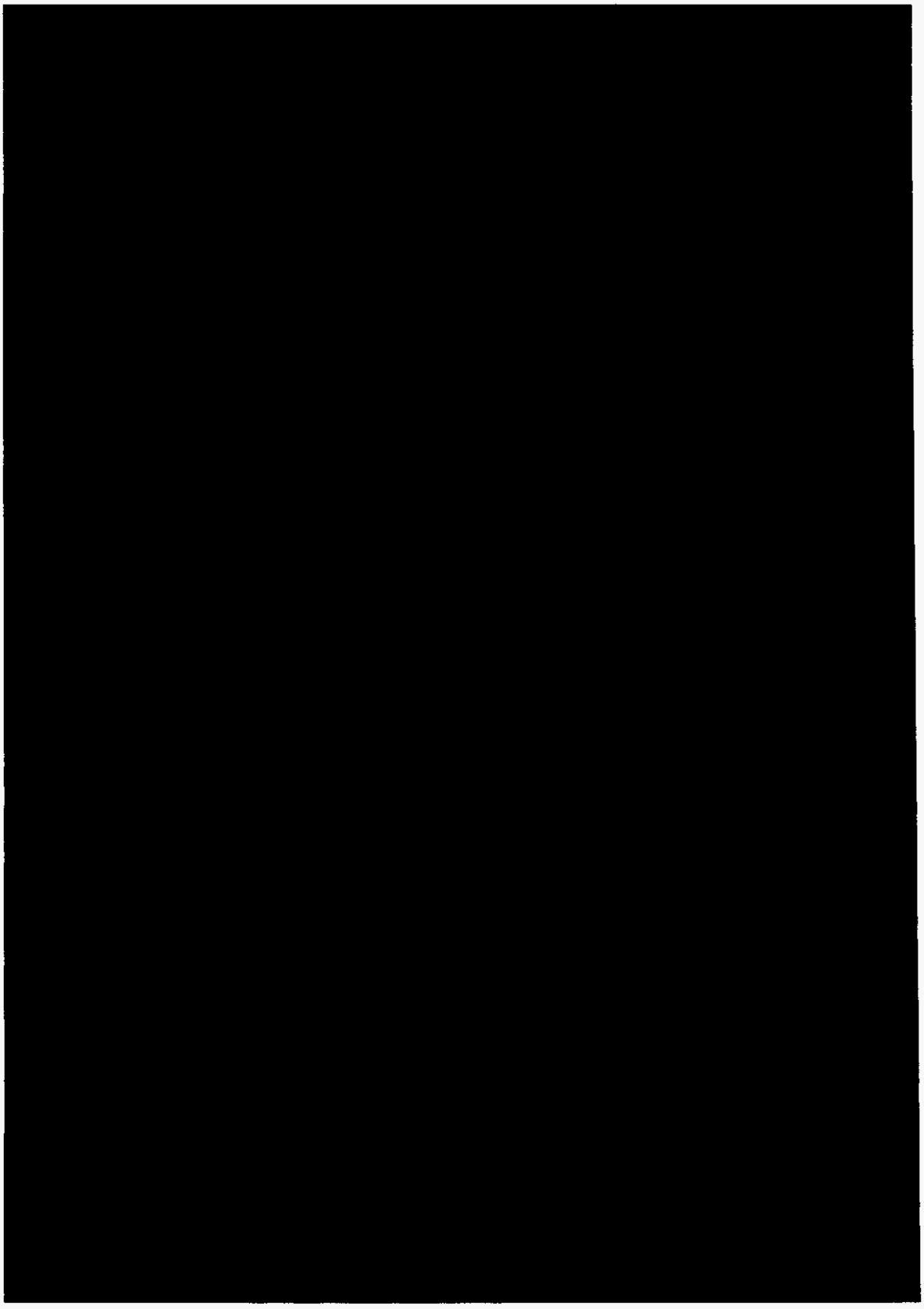
TITLE: Vice President

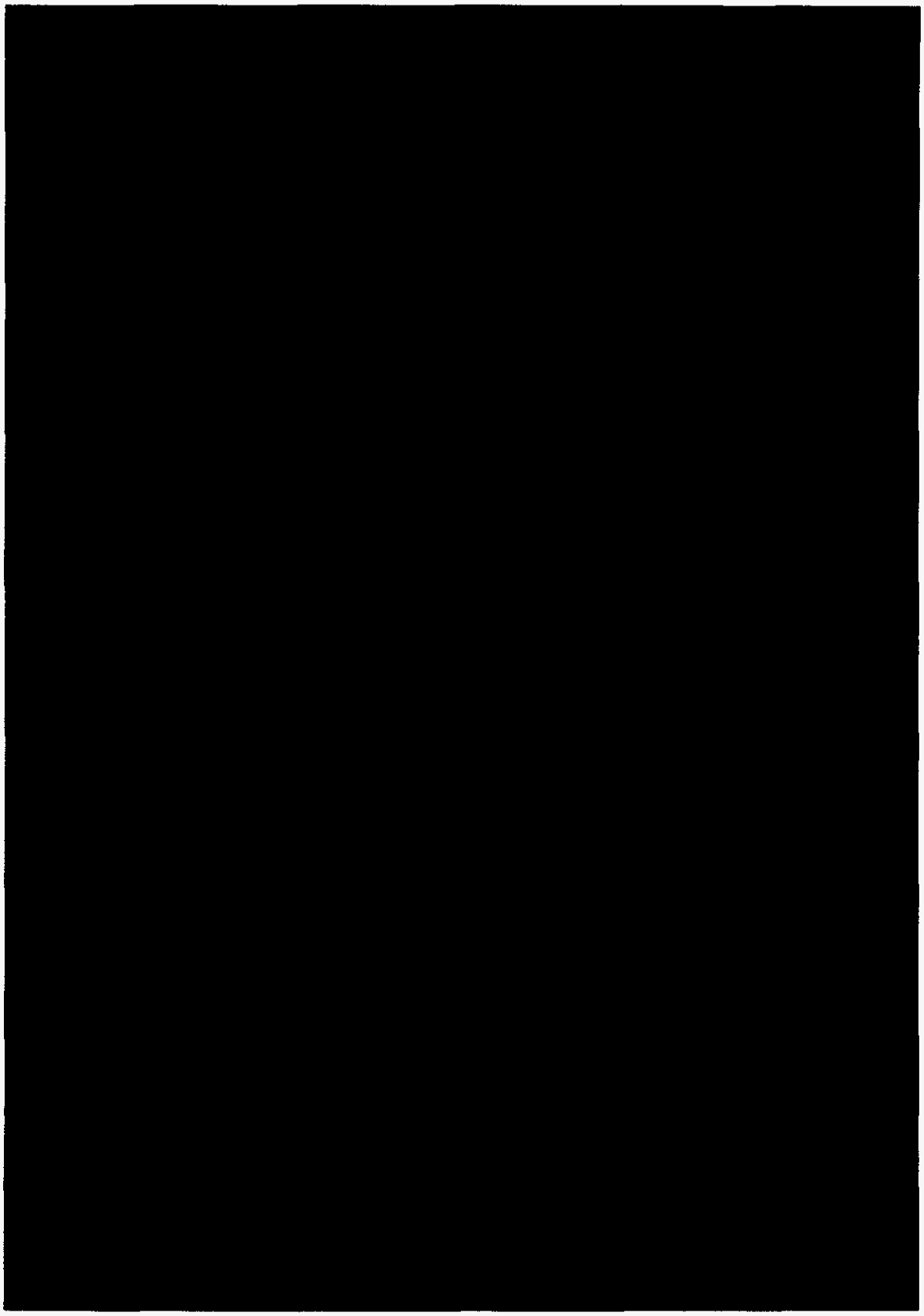


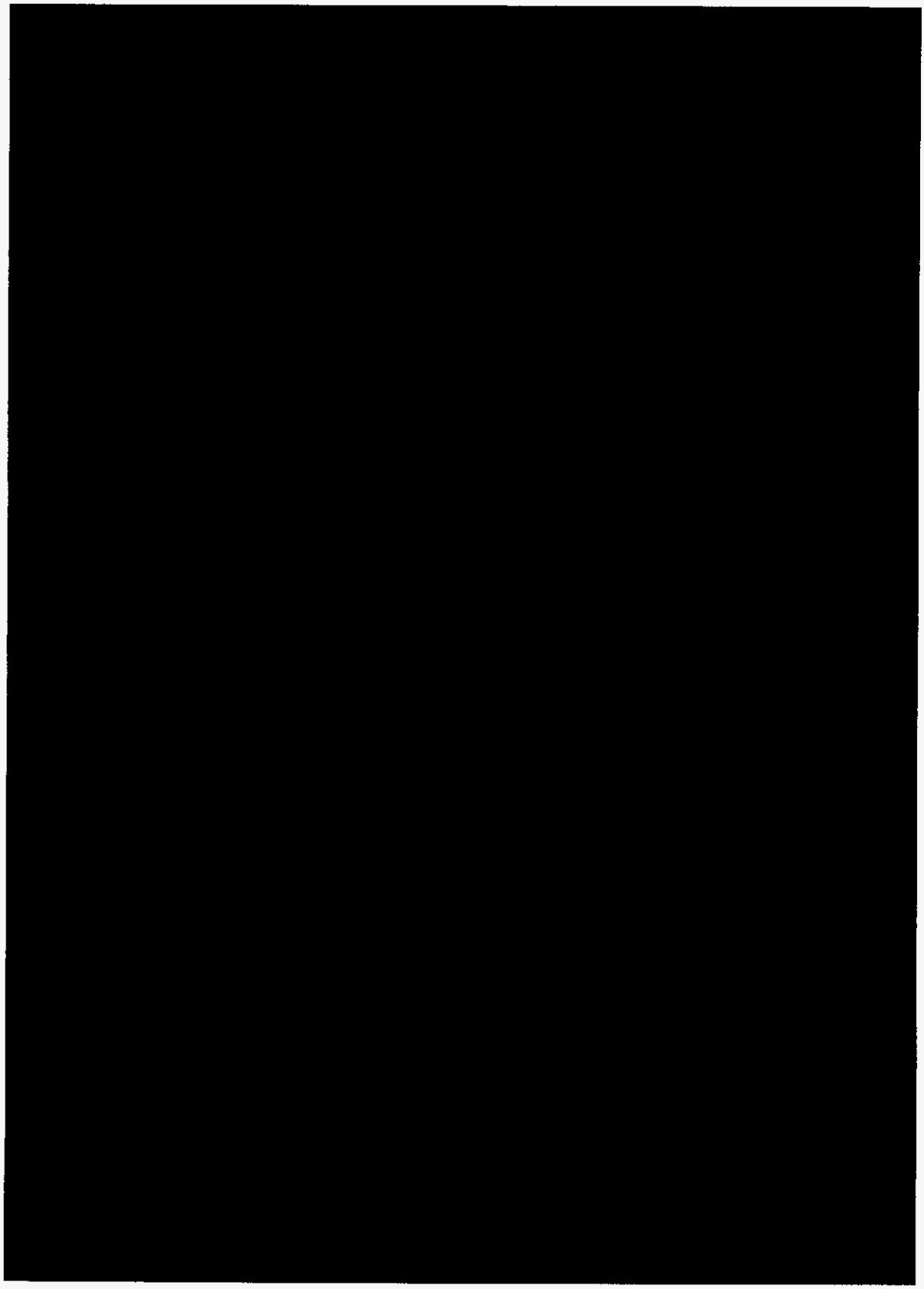


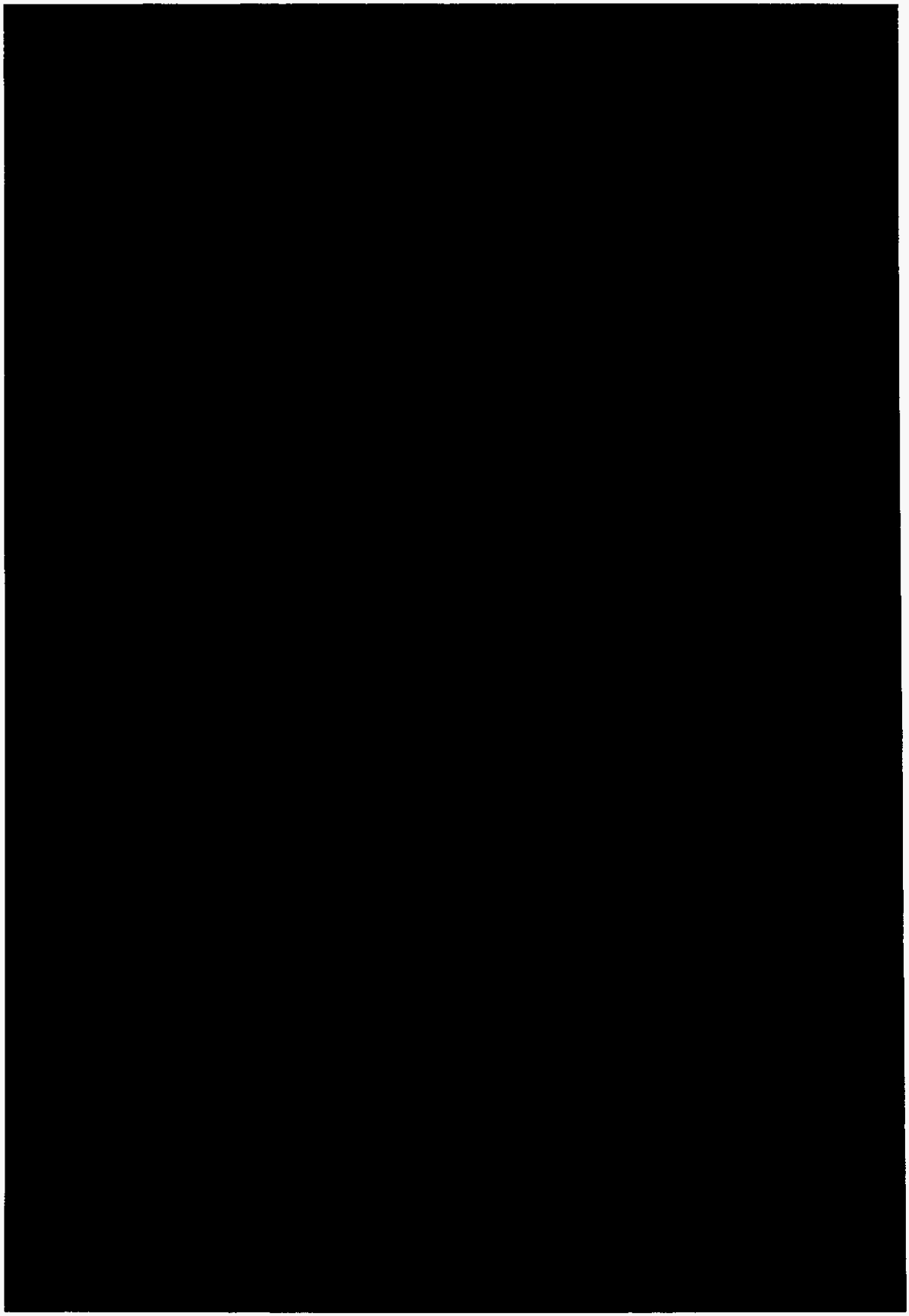


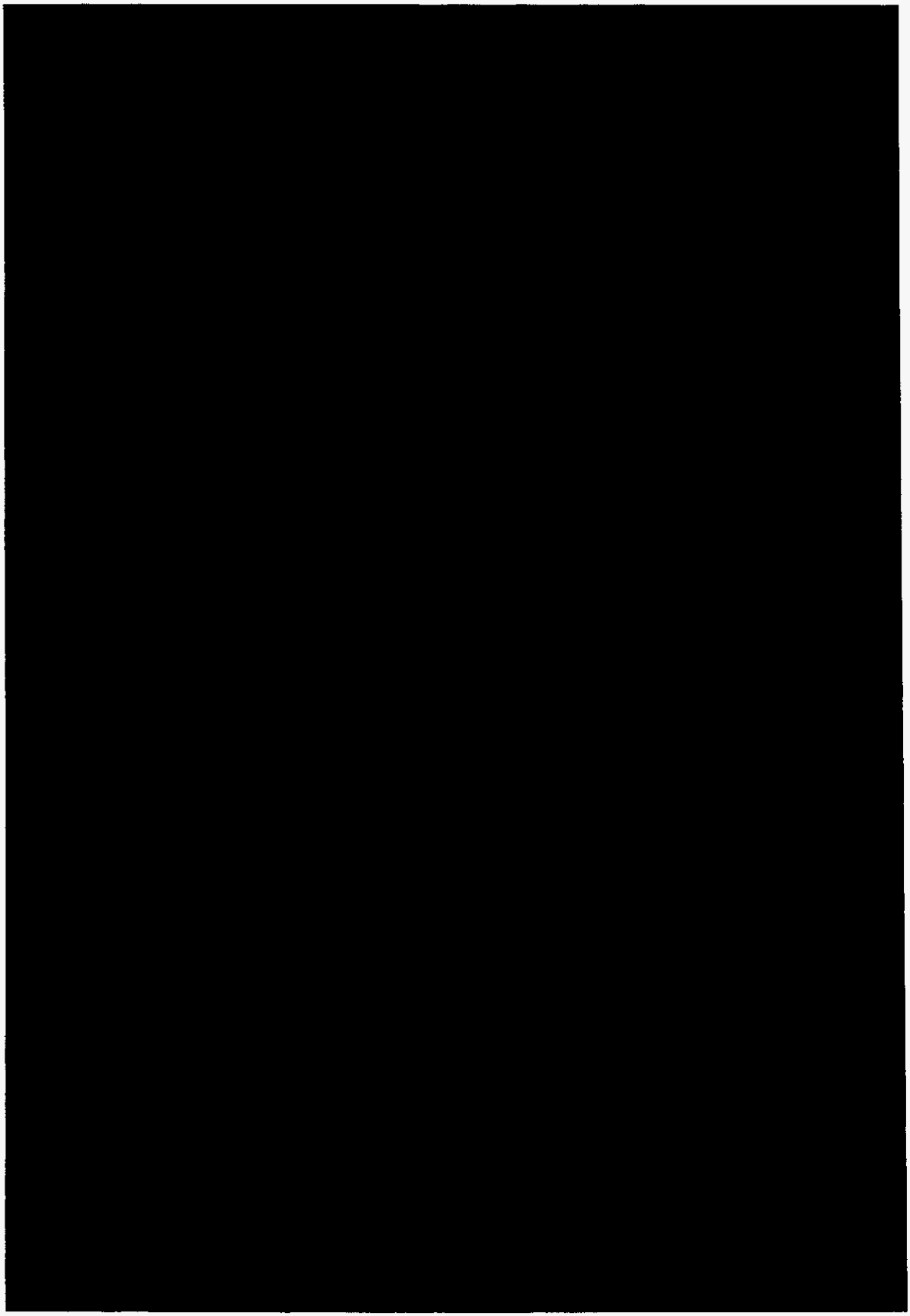


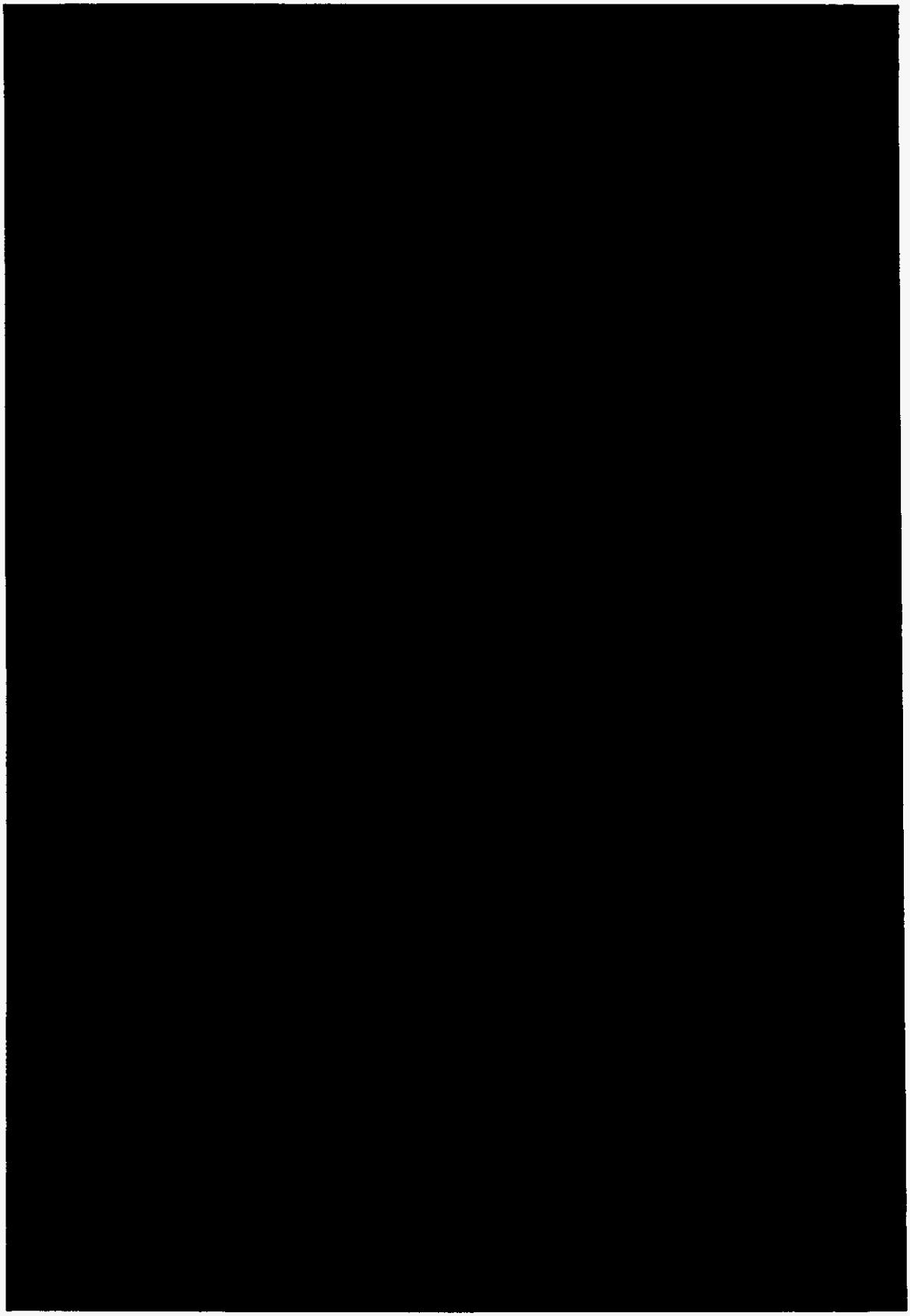


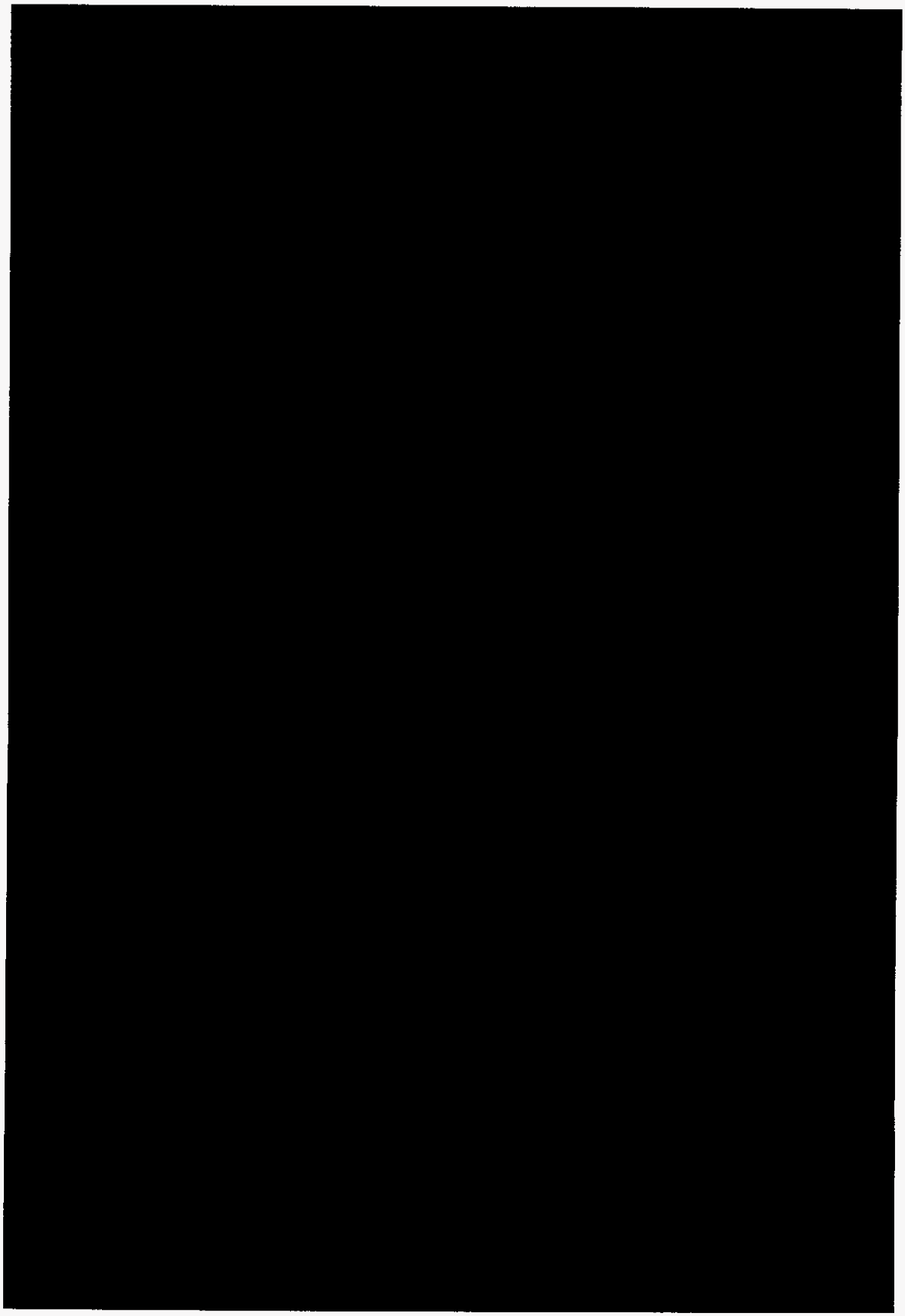


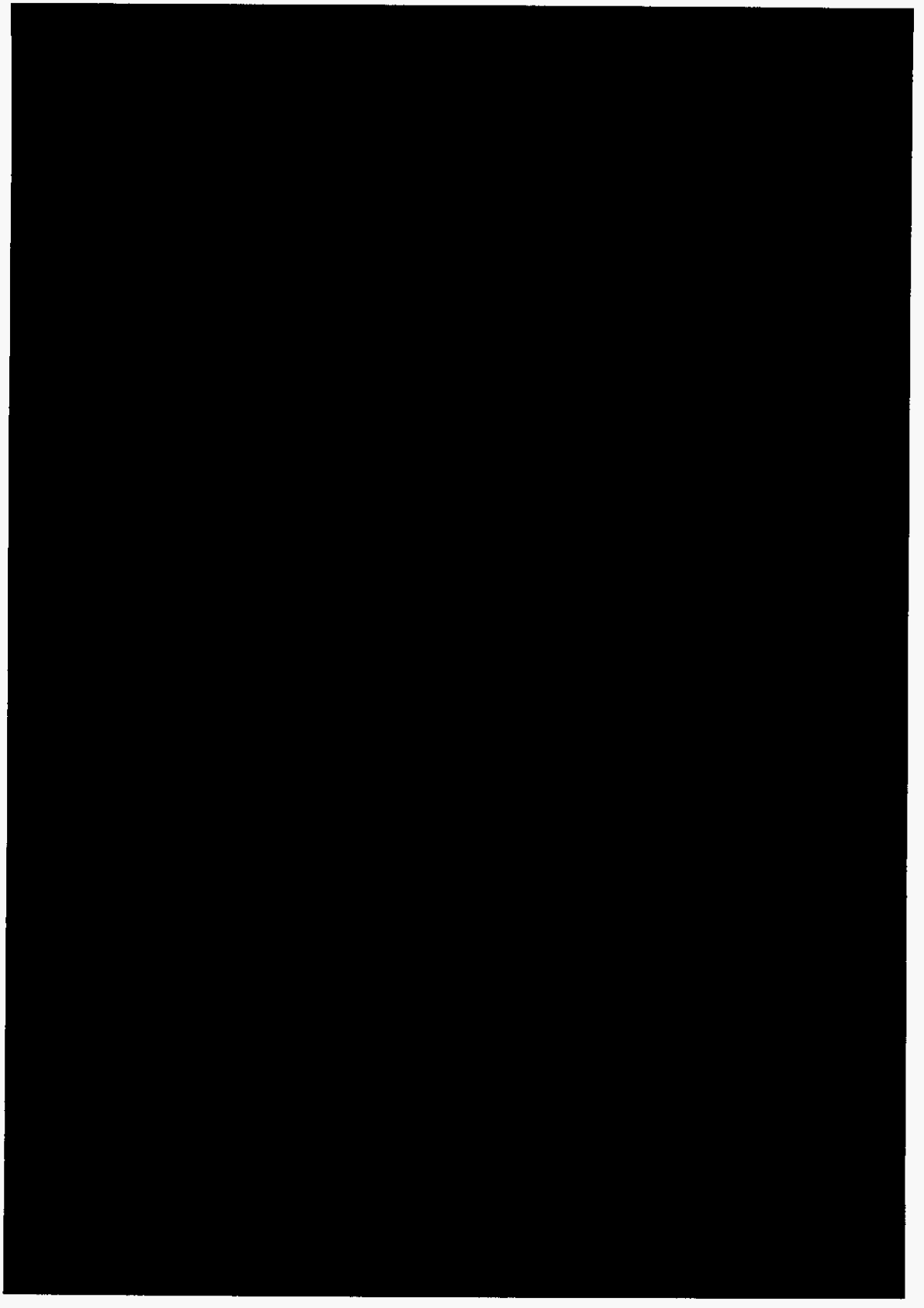


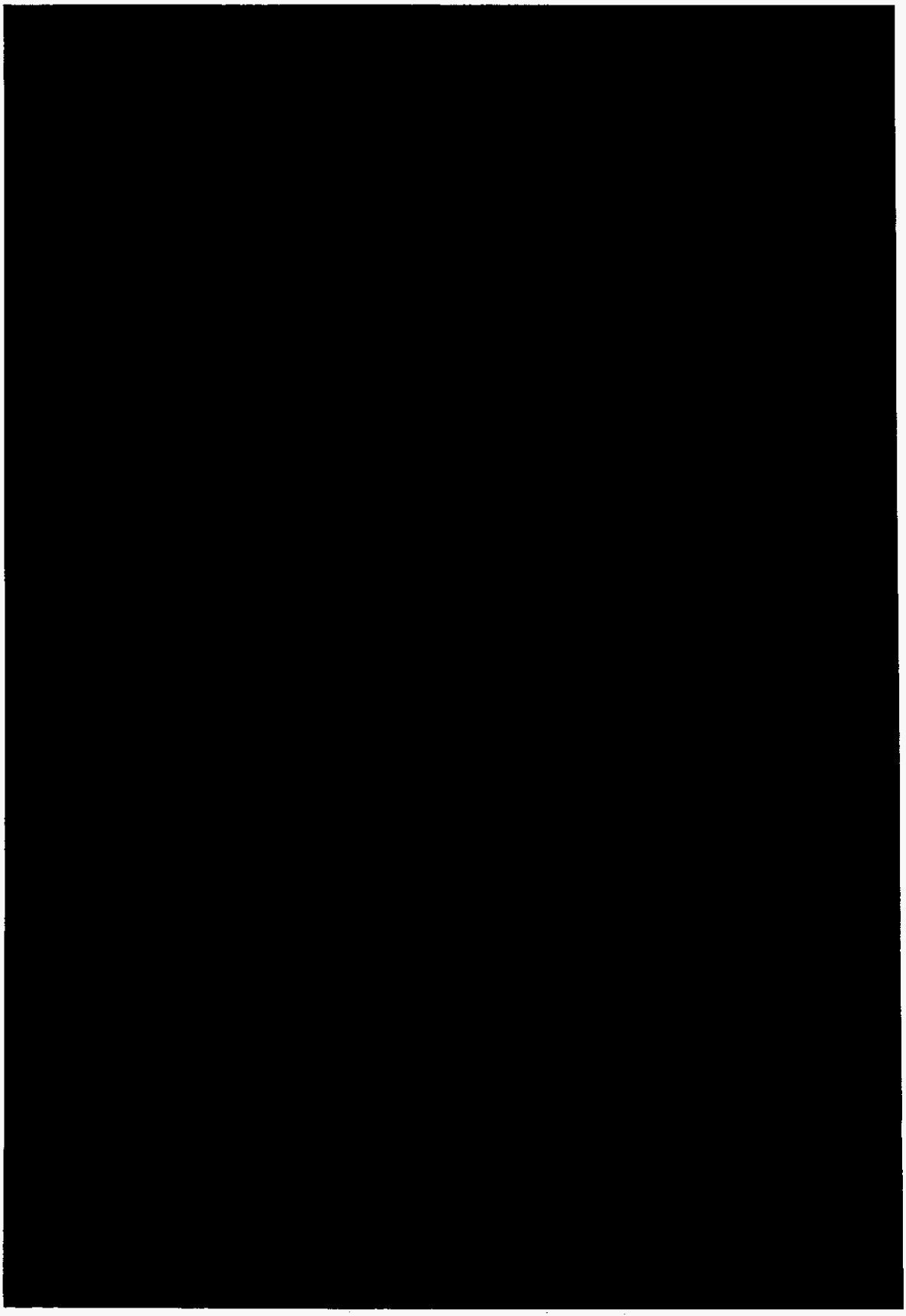


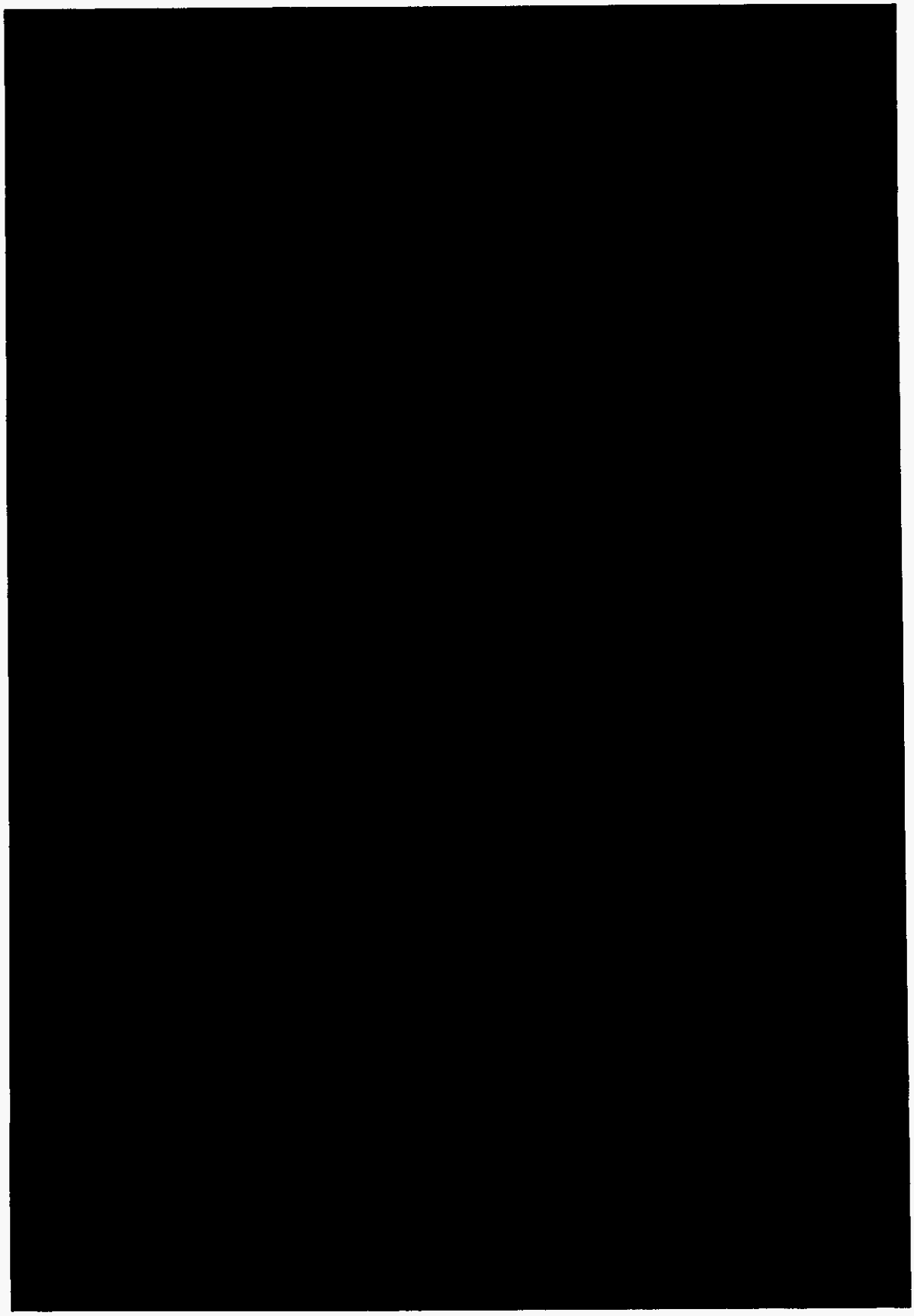


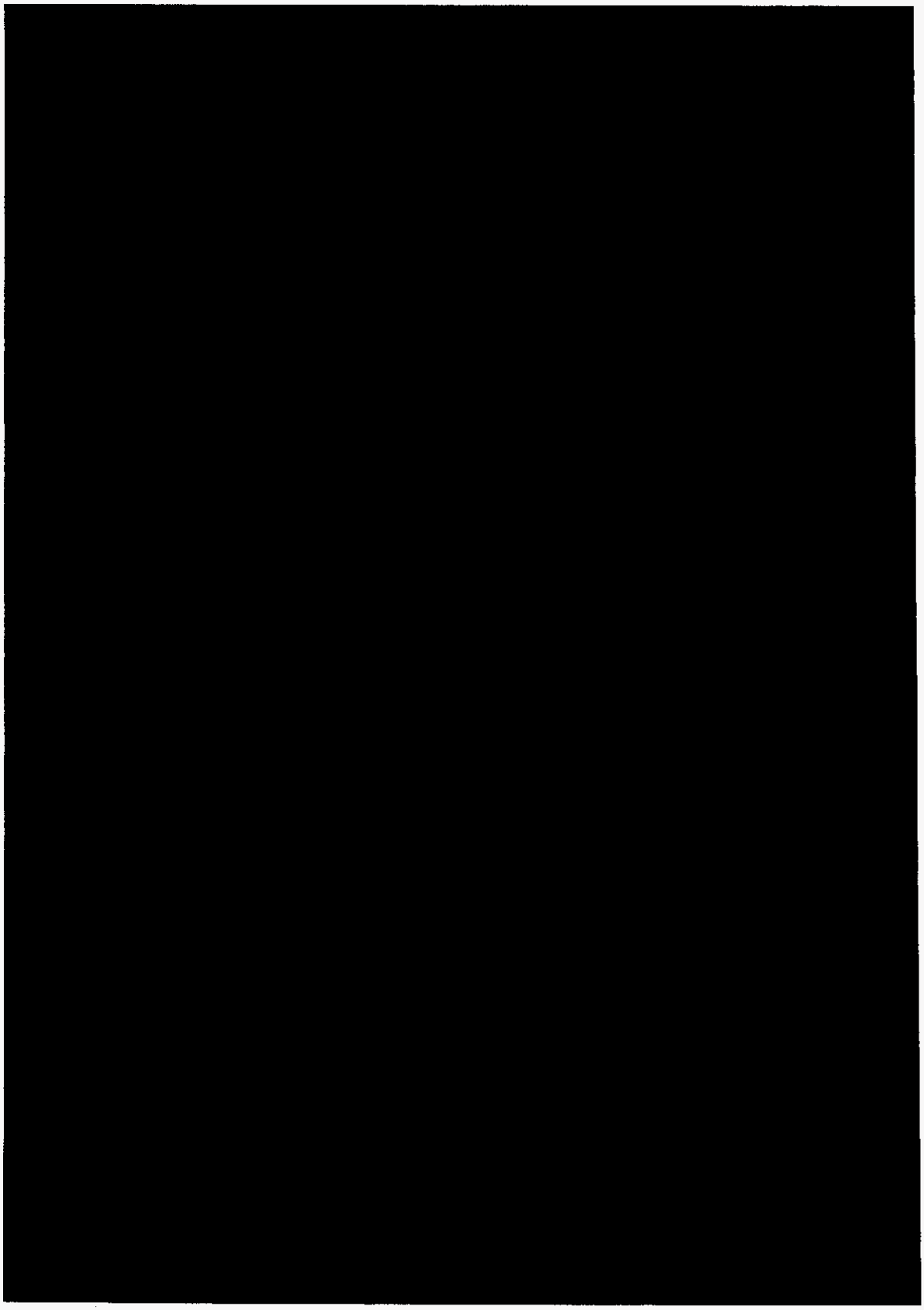


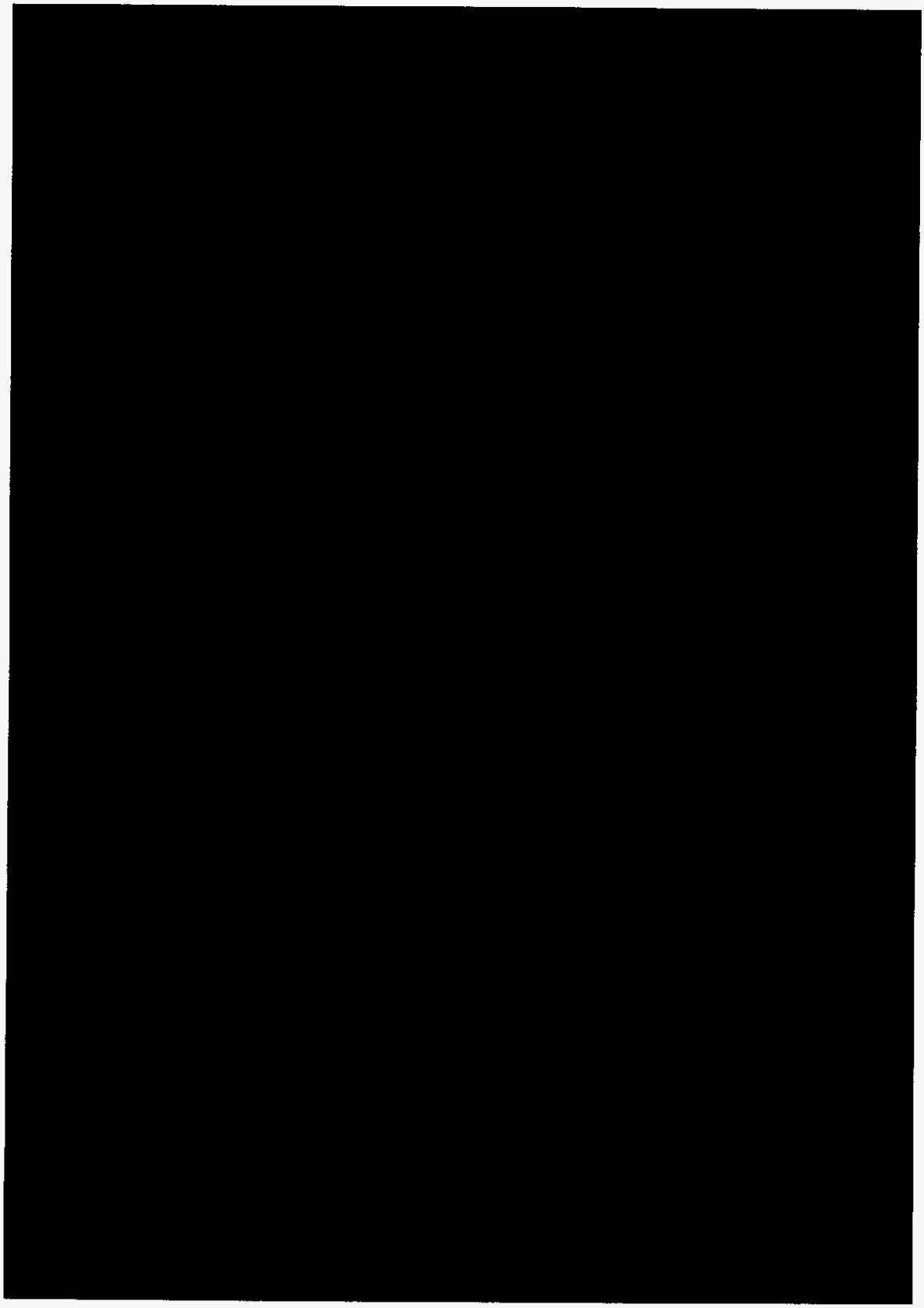


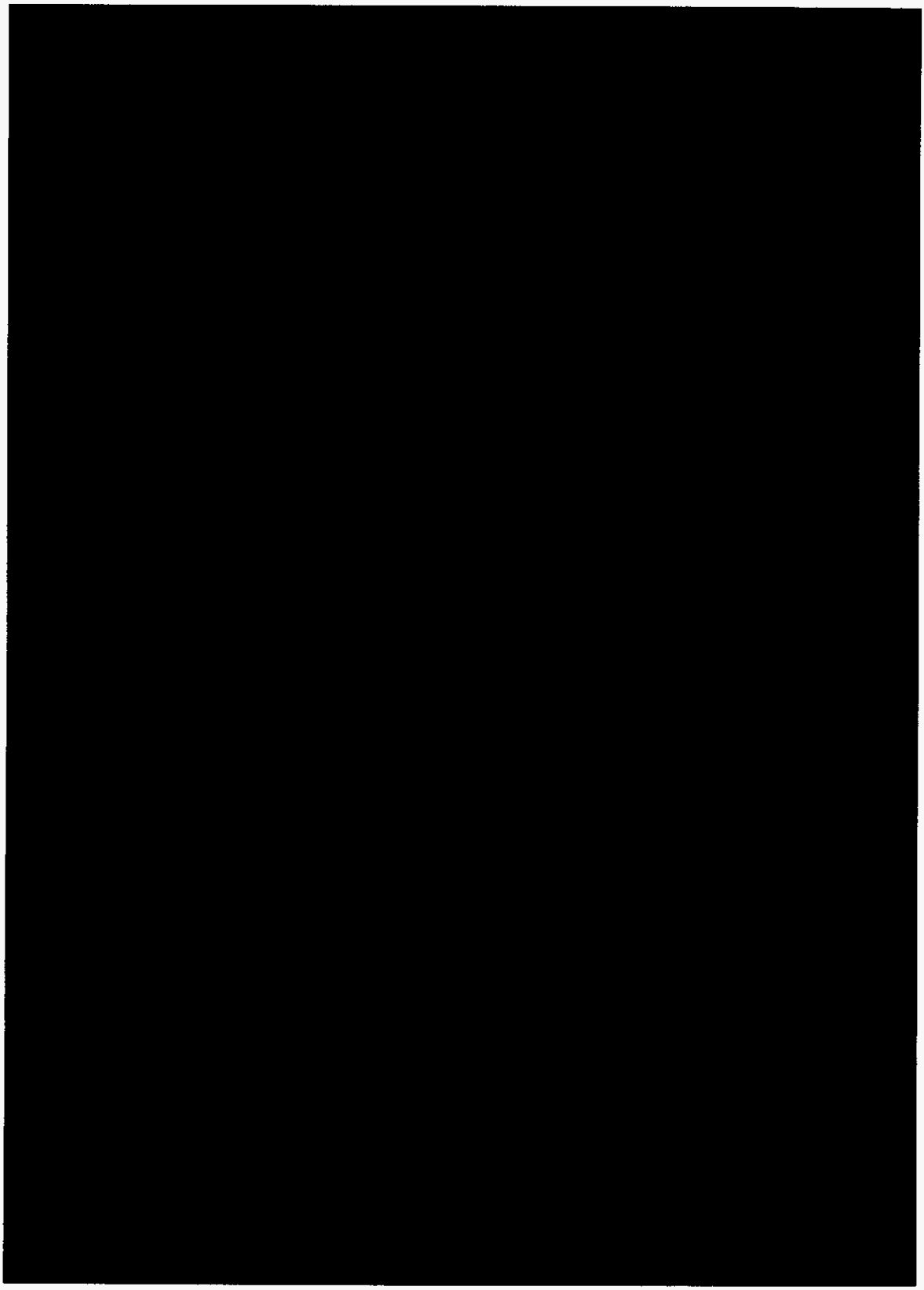


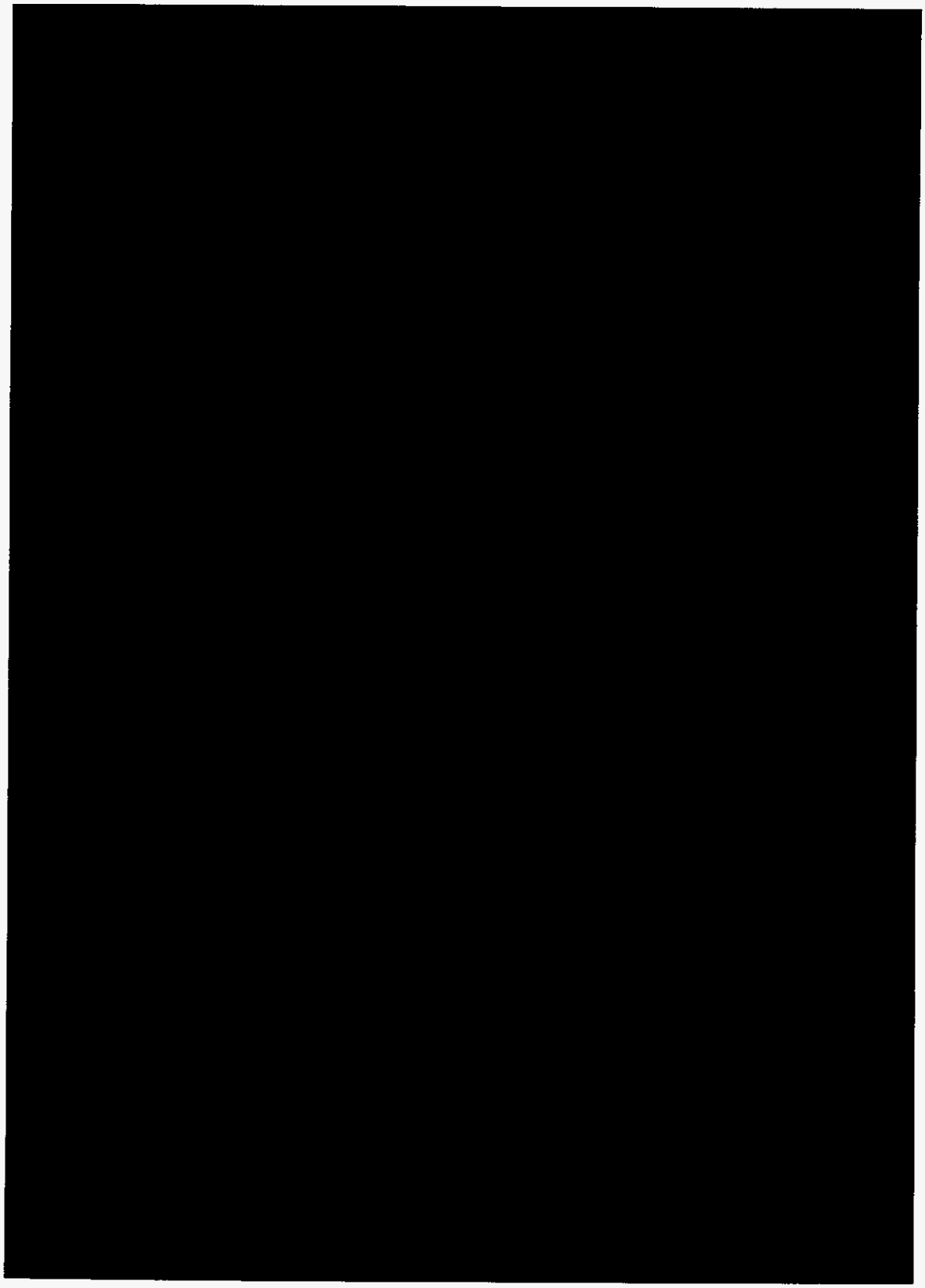


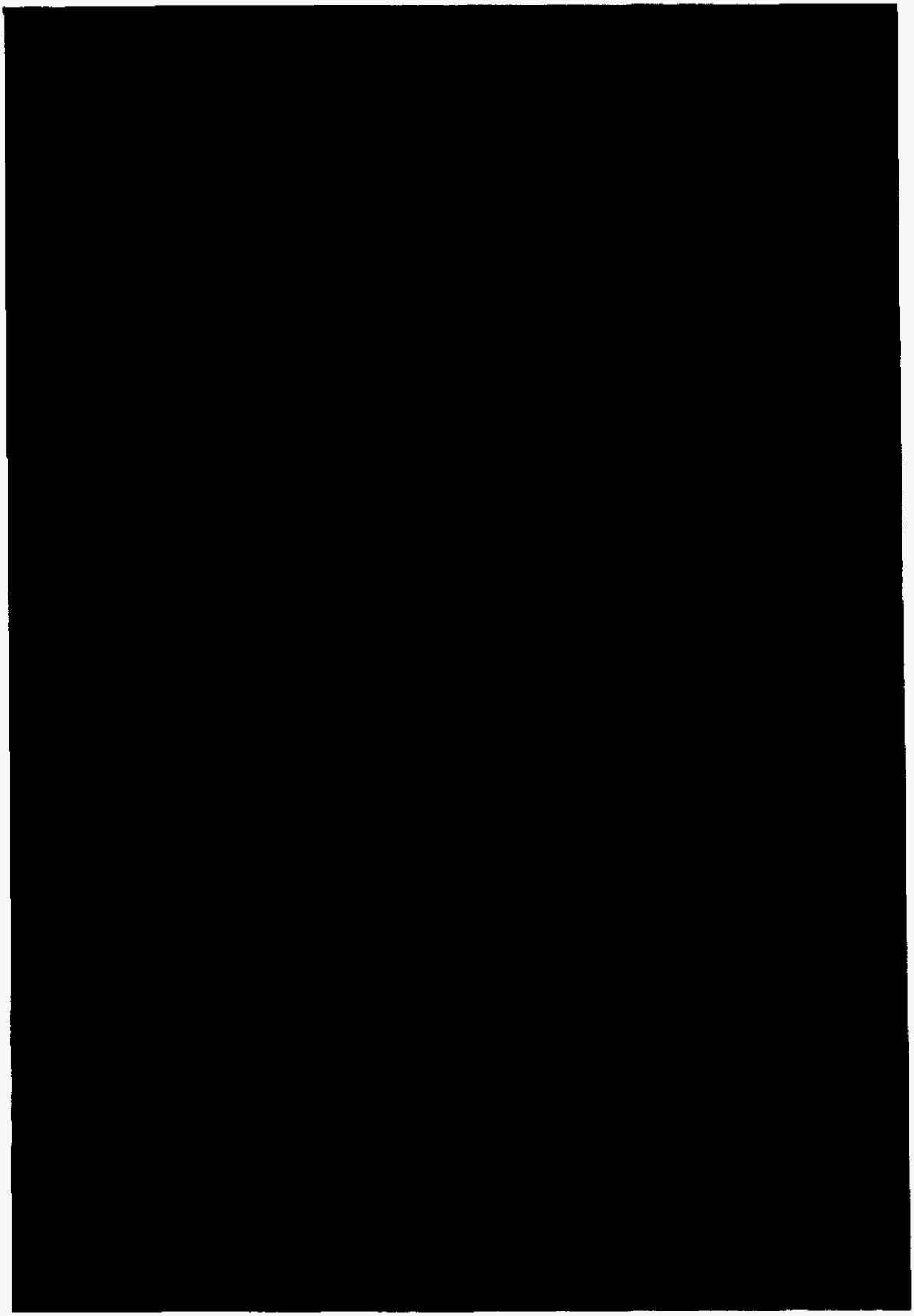


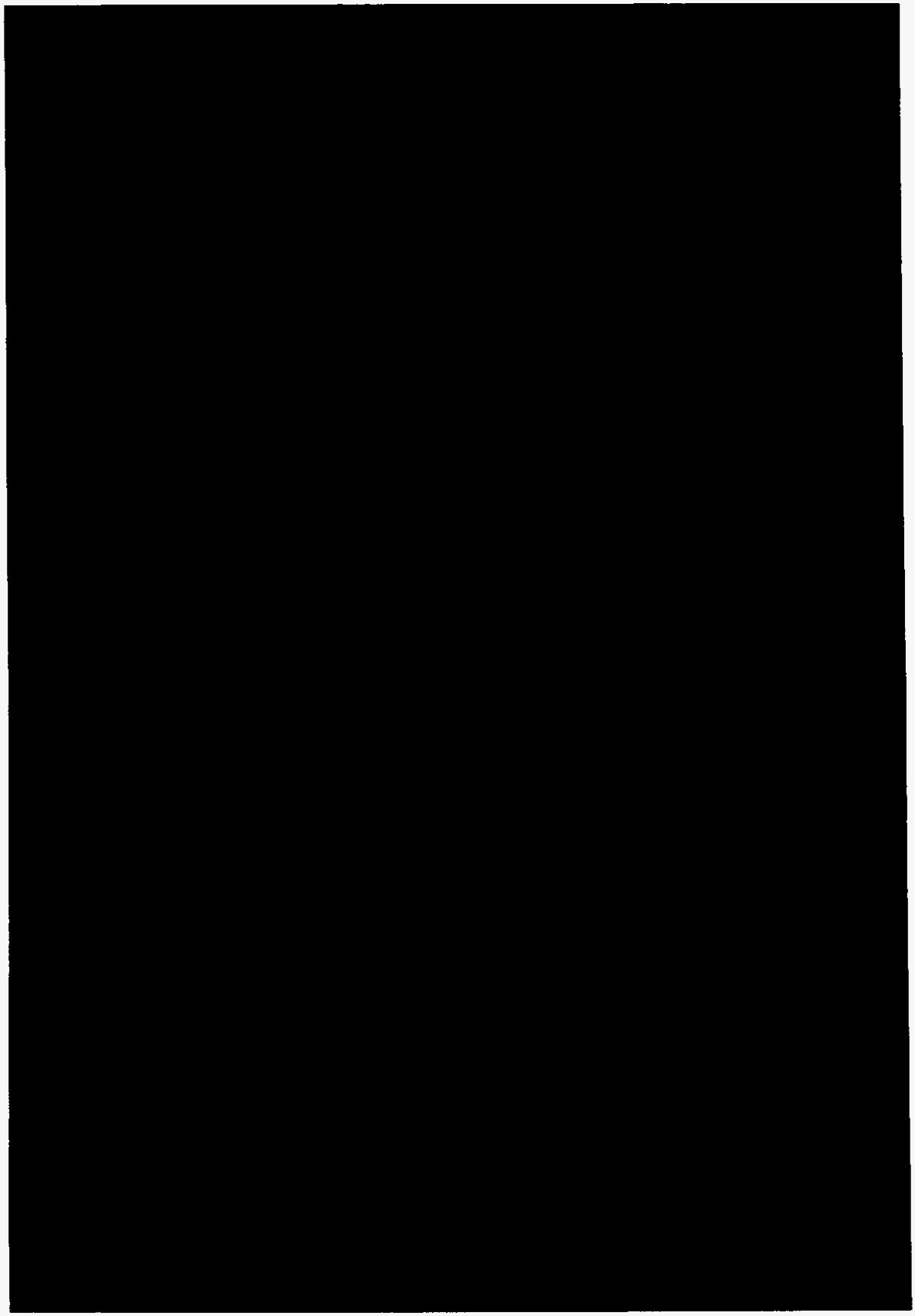


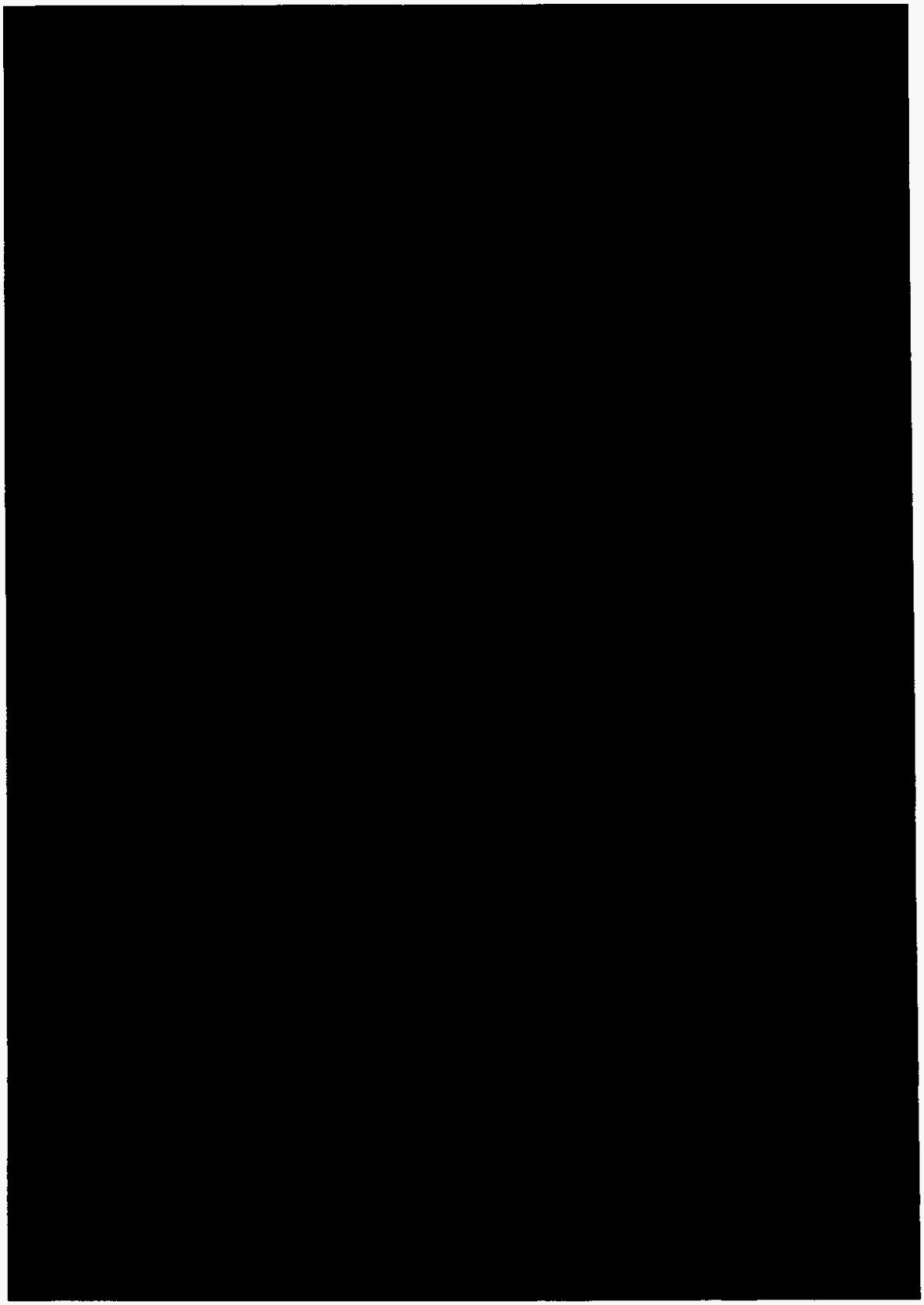


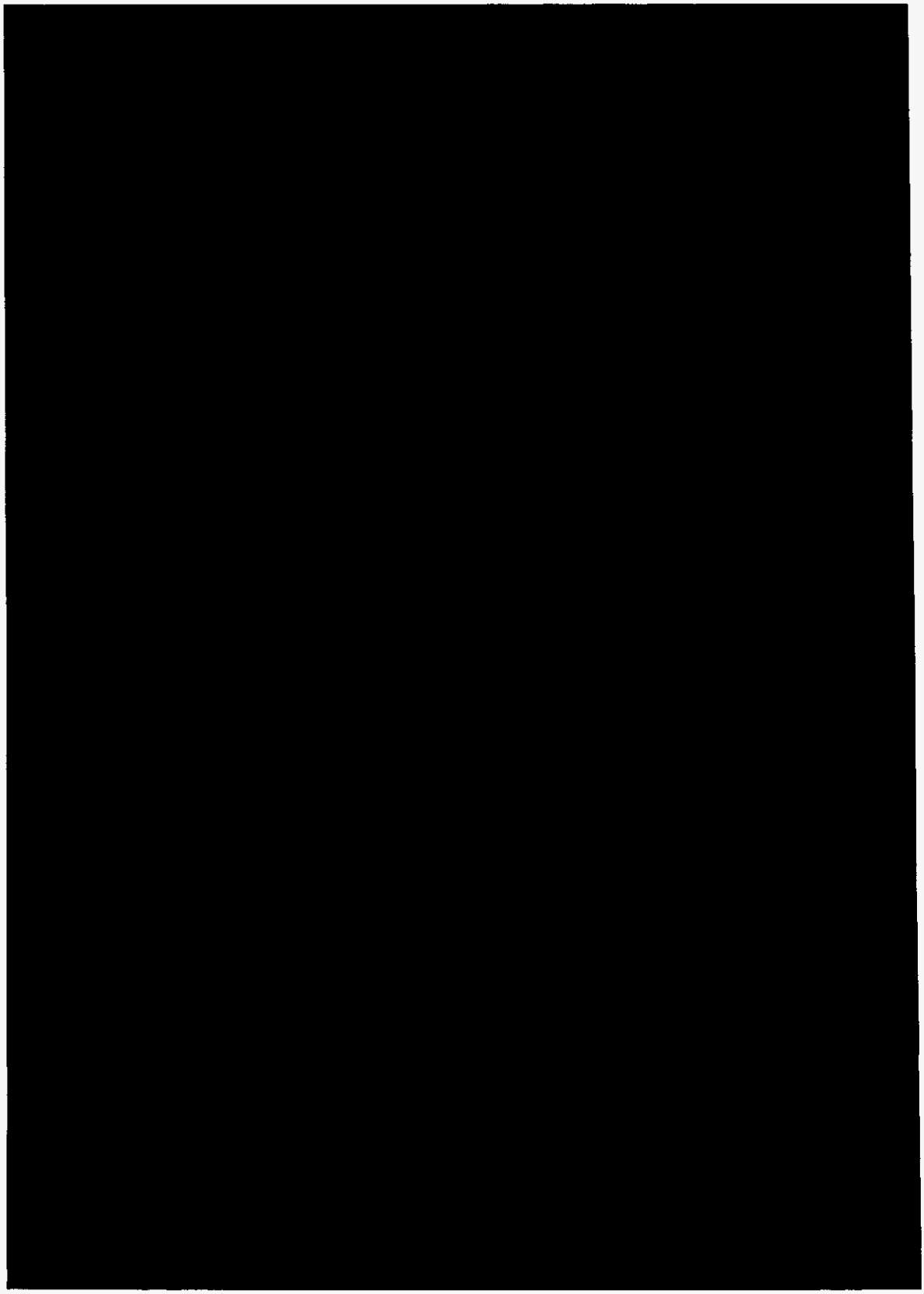


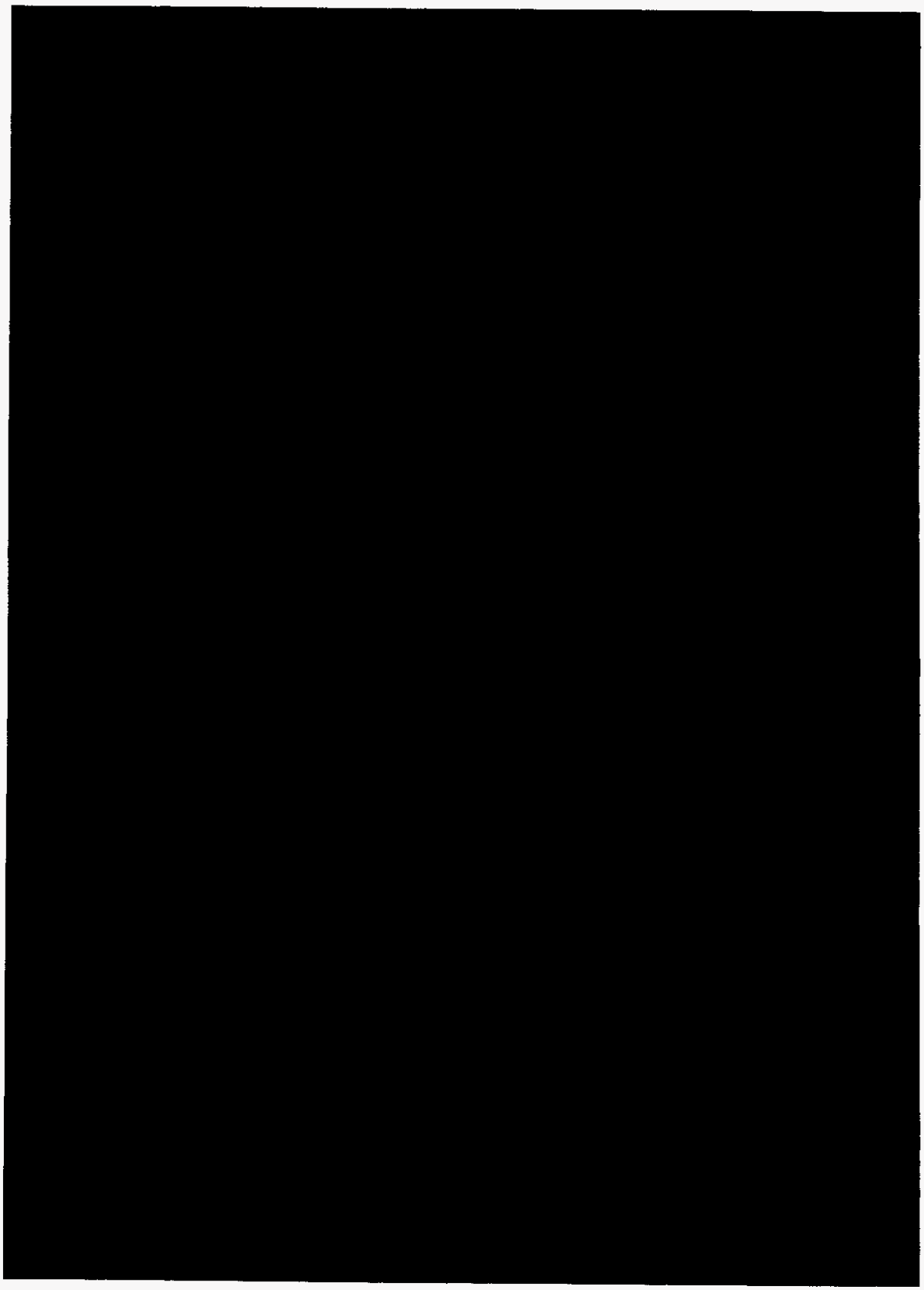












EXECUTION COPY

CONTRACT FOR THE

PURCHASE OF CAPACITY AND ENERGY

BETWEEN

SOUTHERN COMPANY SERVICES, INC.

AND

FLORIDA POWER & LIGHT COMPANY

FROM

PLANT HARRIS UNIT NO. 1

DATED AS OF AUGUST 11, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 14
COMPANY/ F.P.+L.
WITNESS: T.L. Hartman
DATE: 11-08-04

TLH-2
DOCKET NO. 040001-EI
FPL WITNESS: T. HARTMAN
EXHIBIT ____
SEPTEMBER 9, 2004

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EXECUTION COPY

CONTRACT FOR THE PURCHASE OF CAPACITY AND ENERGY BETWEEN SOUTHERN COMPANY SERVICES, INC. AND FLORIDA POWER & LIGHT COMPANY

This CONTRACT FOR THE PURCHASE OF CAPACITY AND ENERGY is made and entered into as of this 11th day of August, 2004 ("Effective Date"), between **SOUTHERN COMPANY SERVICES, INC.**, an Alabama corporation having its principal office and place of business at 600 North 18th Street, Birmingham, Alabama 35203, acting as agent (in such capacity hereinafter referred to as "SCS") for Southern Power Company, a Delaware corporation having its principal office and place of business at 600 North 18th Street, Birmingham, Alabama 35203 (hereinafter referred to as "Southern Power" or "Seller") and **FLORIDA POWER & LIGHT COMPANY** (hereinafter referred to as "FPL" or "Buyer"), a Florida corporation having its principal office and place of business at 700 Universe Boulevard, Juno Beach, Florida 33408. Seller and Buyer are hereafter referred to individually and collectively as a "Party" or the "Parties," respectively.

RECITALS:

Buyer desires to purchase and Seller desires to sell, capacity and energy in accordance with this Agreement.

Subject to the terms and conditions of this Agreement, Seller will provide and sell to Buyer, and Buyer will accept and purchase from Seller, capacity and energy from the Facility or from other resources as provided in this Agreement.

NOW THEREFORE, in consideration of the foregoing recitals and the mutual covenants and agreements hereinafter set forth, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1

DEFINITIONS

The following terms shall have the respective meanings set forth below.

"1-on-1 Operating Mode" means any time a Schedule requests energy for any hour in an amount between and including [redacted] (whether or not such energy is supplied from an Alternate Resource(s)).

"2-on-1 Operating Mode" means any time a Schedule requests energy for any hour in an amount equal to or greater than [redacted] MW (whether or not such energy is supplied from an Alternate Resource(s)).

"Affiliate" means, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly (through one or more intermediaries) controls, is controlled by, or is under common control with, such corporation, partnership, or other entity.

"After-Tax Basis" means, with respect to any payment under Section 14.2 to any Person, the amount of such payment ("Base Payment") supplemented by a further payment ("Additional Payment") to that Person so that the sum of the Base Payment plus the Additional Payment shall, after deduction of the amount of all Federal, state and local income taxes required to be paid by such Person in respect of the receipt or accrual of the Base Payment and the Additional Payment (taking into account the net present value of any reduction in such income taxes resulting from tax benefits realized by the recipient as a result of the payment or

the event giving rise to the payment), be equal to the amount required to be received. Such calculations shall be made on the basis of the highest generally applicable Federal, state and local income tax rates applicable to the Person for whom the calculation is being made for all relevant periods, and shall take into account the deductibility of state and local income taxes for Federal income tax purposes.

"Agreement" means this Contract for the Purchase of Capacity and Energy, including, to the extent applicable, any appendices hereto and any amendments that the Parties may execute now or at any time in the future.

"Alternate Delivery Point(s)" means, when Seller designates an Alternate Resource(s) pursuant to Section 5.6 or Section 5.7 (including a Replacement Resource), the applicable point(s) of delivery designated by Seller.

"Alternate Resource(s)" means any resource or resources other than the Facility (whether such other resources are owned, purchased or otherwise controlled by Seller, or that are otherwise available to Seller) that Seller designates pursuant to Section 5.6 or Section 5.7.

"Available Capacity" means, at any given time, the Contract Capacity less the sum of: (i) the Force Majeure Capacity at such time; and (ii) the Outage Capacity at such time.

"Billing Month" means each Month during the Term beginning with the second Month of the first Contract Year and includes the Month immediately following the expiration or early termination of this Agreement.

"Btu" means British Thermal Units.

"Business Day" means any Day on which Federal Reserve Member Banks in New York, New York are open for business. A Business Day shall begin at 0800 CPT and end at 1700 CPT.

"Buyer" has the meaning set forth in the introductory paragraph hereof.

"Buyer Delivery Point(s)" means, for any hour of any Delivery Day, the point(s) on the Southern Company Transmission System to which Buyer intends to transmit energy delivered by Seller under this Agreement.

"Central Prevailing Time" or **"CPT"** means the local time at any point in Birmingham, Alabama.

"Change in Law" means the adoption, enactment, promulgation or issuance of, a change in, or a new or changed interpretation by a Government Agency of, any Law after February 6, 2004.

"Commercially Reasonable" or **"Commercially Reasonable Efforts"** means, with respect to any purchase, sale, decision, or other action made, attempted or taken by a Party, such efforts as a reasonably prudent business would undertake for the protection of its own interest under the conditions affecting such purchase, sale, decision, or other action, including without limitation, electric system reliability and stability, the amount of notice of the need to take such action, the duration and type of the purchase or sale or other action, and the commercial environment in which such purchase, sale, decision, or other action occurs.

"Contemporaneous Agreements" means: (i) this Agreement; (ii) the Contract for the Purchase of Capacity and Energy from Plant Franklin Unit No. 1 dated as of August 11, 2004 between Southern Company Services, Inc. (as agent for Seller) and Buyer; and (iii) the Contract for the Purchase of Capacity and Energy from Plant Scherer Unit No. 3 dated as of August 11, 2004 between Southern Company Services, Inc. (as agent for Georgia Power Company and Gulf Power Company) and Buyer.

"Contest" means with respect to any Person, a contest of any Governmental Approval or Law, acts or omissions by any Government Agency, a requirement of any Government Agency, or any related matters, so long as the contesting Party could not reasonably be expected to be prevented from performing its material obligations under this Agreement pending the outcome of such contest.

"Contract Capacity" means the lesser of: (i) 600 MW; or (ii) the Total Facility Capacity, or such other amount as expressly provided in this Agreement.

"Contract Year" means: (i) for the first Contract Year, the Service Commencement Date through the next date that is May 31; and (ii) for each Contract Year thereafter, each 12 Month period beginning June 1 and ending May 31; provided, however, the last Contract Year shall end on the date that this Agreement terminates or expires.

"Day" means the period of time beginning at hour ending 0100 CPT and ending at hour ending 2400 CPT.

"Delivery Day" means any Day for which Buyer Schedules energy to be delivered in accordance with this Agreement.

"Delivered Energy" means, for any hour, the amount of energy (expressed in MWh) delivered by Seller in accordance with this Agreement and shall equal the sum of: (i) energy delivered by Seller to the Delivery Point pursuant to Buyer's Schedule (including Ramp Energy provided at the Facility Delivery Point in connection with such Schedule); and (ii) any energy provided and/or procured by Seller to resolve energy imbalances at the Delivery Point. Delivered Energy shall not exceed Scheduled Energy for any hour.

"Delivered Energy Credit" means, for any hour, to the extent such difference is positive, the difference of: (i) Delivered Energy for such hour; less (ii) Available Capacity plus

the portion of Delivered Energy provided from an Alternate Resource(s) designated for such hour pursuant to Section 5.6.1 in response to a Force Majeure Event.

"Delivery Excuse" means: (i) an Event of Default by Buyer; (ii) the interruption of transmission service procured by Buyer or the unavailability of transmission service to Buyer beyond the Delivery Point(s); (iii) any directive from the applicable transmission provider and/or control area operator to cease deliveries of energy from the Facility; (iv) SNG's failure to schedule or to deliver scheduled quantities of Gas to the Facility (but only if, for the period of such failure, Seller has complied with Section 9.1 and has utilized Commercially Reasonable Efforts to utilize available transportation capacity as required by Section 9.2.1 to satisfy Buyer's Schedule); or (v) a circumstance described in Section 9.2.6 and/or Section 9.3.2.

"Delivery Point" means the Facility Delivery Point when Seller designates the Facility as the source of Delivered Energy and/or the Alternate Delivery Point(s) (as applicable) to which Seller shall deliver energy to Buyer hereunder.

"Effective Date" has the meaning set forth in the introductory paragraph hereof.

"Electric Metering Equipment" means electric meters and associated equipment, including metering transformers and back-up meters.

"EFMH" or **"Equivalent Force Majeure Hour"** shall occur in any hour (or portion of an hour) in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point is occurring or is continuing. During such an hour, EFMH shall equal the ratio of: (A)(i) Force Majeure Capacity for such hour; less (ii) the amount of electric capacity associated with an Alternate Resource(s), whether available or unavailable, that has been designated for such hour pursuant to Section 5.6.1 in response to the Force Majeure Event causing the Force Majeure Capacity to exist; to (B) the Contract Capacity.

"EUH" or **"Equivalent Unavailable Hour"** shall occur in any hour (or portion of an hour) in which there is Unavailable Capacity. For such an hour, EUH shall equal the ratio of: (i) Unavailable Capacity for such hour; to (ii) the Contract Capacity for such hour.

"Event of Default" has the meaning set forth in Section 16.1.

"Facility" means Seller's Gas fired combined cycle electric generating unit known as Plant Harris Unit No. 1 (as may be modified) and all appurtenant facilities, located near Autaugaville, Alabama which directly interconnects to the Southern Company Transmission System.

"Facility Delivery Point" means the substation where the Facility interconnects to the Southern Company Transmission System (or other applicable transmission system) at the transmission system voltage.

"FERC" means the Federal Energy Regulatory Commission, or any successor to its functions.

"Florida Interface" means the transmission interface between the Southeastern Electric Reliability Council (or its successor) region and the Florida Reliability Coordinating Council (or its successor) region as such regions exist on the Effective Date.

"Force Majeure Capacity" means, for any hour in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, the portion of the Contract Capacity that is not available from the Facility as a result of such Force Majeure Event. Force Majeure Capacity shall be calculated as follows:

Force Majeure Capacity = Contract Capacity – Unaffected Contract Capacity

Where:

Unaffected Contract Capacity = the lesser of TCUFM or 600 MW

TCUFM = Total Capacity Unaffected by Force Majeure = Total Facility Capacity – TAC

TAC = Total Affected Capacity = the total amount of capacity that is not available from the Facility as a result of the Force Majeure Event.

"Force Majeure Event" has the meaning set forth in Section 15.1.

"Gas" means natural gas.

"Government Agency" means any federal, state, local, territorial or municipal government and any department, commission, board, court, bureau, agency, instrumentality, judicial or administrative body thereof.

"Governmental Approval" means any authorization, consent, approval, license, ruling, permit, exemption, variance, order, judgment, decree, declarations of or regulation of any Government Agency relating to the Facility or to the execution, delivery or performance of this Agreement.

"Guarantor" has the meaning set forth in Section 16.1.

"Guaranty" means a guaranty or other instrument guaranteeing a Party's obligations under this Agreement as contemplated under Article 20.

"Imaged Agreement" has the meaning set forth in Section 21.17.

"Increased Generation Costs" [redacted]

[redacted]

"kW" means kilowatt(s).

"kWh" means kilowatt hour(s).

"Law" means any act; statute; law; requirement; ordinance; order; ruling or rule; regulation; standards and/or criteria contained in any permit, license or other approval; legislative or administrative action; or a decree, judgment or order of any Government Agency imposed, whether in effect now or at any time in the future.

"Long Term Firm Transmission Service" means firm point-to-point (or other equivalent) transmission service for a term of one year or more.

"Maintenance Outage" has the meaning set forth in Section 4.2.

"Major Maintenance" means the performance of a hot gas path inspection for the combustion turbines at the Facility.

"Major Maintenance Off-Peak Performance Period" means any Off-Peak Performance Period in which Major Maintenance occurs.

"MMBtu" means one million Btu.

"Month" means a calendar month.

"Monthly Capacity Payment" means the payment for Contract Capacity to be made by Buyer to Seller pursuant to Section 6.1.

"Monthly Energy Payment" means the payment for Delivered Energy to be made by Buyer to Seller pursuant to Section 6.2.

"Monthly Fuel Transportation Payment" means the payment for fuel transportation to be made by Buyer to Seller pursuant to Section 6.4.

"Monthly Start Payment" means the payment for Successful Starts to be made by Buyer to Seller pursuant to Section 6.3.

"Moody's" has the meaning set forth in Section 19.1.

"MW" means megawatt(s).

"MWh" means megawatt hour(s).

"NERC" means the North American Electric Reliability Council, or any successor to its functions.

"Normal Off-Peak Performance Period" means any Off-Peak Performance Period in which Major Maintenance does not occur.

"OATT" means the Open Access Transmission Tariff of Southern Companies or a successor tariff governing transmission on the Southern Company Transmission System, as the same may be changed or amended from time to time.

"Off-Peak Performance Period" means the period of time consisting of all hours during the Months of October, November, December, January, February, March and April in succession. If this Agreement terminates or expires during such period on a Day other than the last Day of such period, such Off-Peak Performance Period shall be deemed to end on the Day of such termination or expiration. If the Service Commencement Date occurs during such period on a Day other than the first Day of such period, such Off-Peak Performance Period shall be deemed to begin on the Service Commencement Date.

"Operating Committee" has the meaning set forth in Section 4.5.

"Operating Mode" means either 1-on-1 Operating Mode or 2-on-1 Operating Mode.

"Operating Procedures" has the meaning set forth in Section 4.4.

"Outage" means any condition or circumstance in which the generating capability of the Facility is eliminated or reduced (in whole or in part) for any reason, including an actual or threatened component failure and during Scheduled Outages and Maintenance Outages. An Outage does not include those times that the Facility's capability is reduced (in whole or in part)

due to a Force Majeure Event or a Delivery Excuse. In addition, an Outage shall not occur solely because of Seller's ability to sell capacity and/or energy from the Facility to a third party or an Affiliate(s).

"Outage Capacity" means, for any hour in which an Outage occurs or is continuing, the portion of the Contract Capacity that is not available from the Facility as a result of such Outage. Outage Capacity shall be calculated as follows:

Outage Capacity = Contract Capacity – Unaffected Contract Capacity

Where:

Unaffected Contract Capacity = the lesser of TCUO or 600 MW

TCUO = Total Capacity Unaffected by Outage = [the sum of: (A) the lesser of: (i) Total Facility Capacity; or (ii) 600 MW; and (B) Unused Excess Capacity] – TAC

Unused Excess Capacity = to the extent it is positive, the difference of TCUFM as determined under the definition of "Force Majeure Capacity" hereunder, less 600 MW.

TAC = Total Affected Capacity = the total amount of capacity that is not available from the Facility as a result of the Outage.

"Peak Performance Period" means the period of time consisting of all hours during the Months of May, June, July, August and September in succession. If this Agreement terminates or expires during such period on a Day other than the last Day of such period, such Peak Performance Period shall be deemed to end on the Day of such termination or expiration. If the Service Commencement Date occurs during such period on a Day other than the first Day of such period, such Peak Performance Period shall be deemed to begin on the Service Commencement Date.

"Performance Period" shall mean either a Peak Performance Period or an Off-Peak Performance Period.

"Person" means any individual, corporation, limited liability corporation, partnership, joint venture, trust, unincorporated organization, Government Agency or other entity.

"Plant" means Seller's Plant Harris located near Autaugaville, Alabama, which currently consists of the Facility and a combined cycle electric generating unit known as Plant Harris Unit No. 2 and all appurtenant facilities, as such plant and facilities may be modified and/or expanded from time to time (including the addition of generating units).

"Prior Business Day" means the Business Day immediately prior to a Delivery Day.

"Prime Rate" means, for any Day on which the calculation of an interest amount begins under this Agreement, the "Prime Rate" specified for such Day (or, if such Day is not a Business Day, on the first Business Day following such Day) under the "Money Rate" table of the *Wall Street Journal*. In the event that the *Wall Street Journal* ceases to report a Prime Rate, the Prime Rate shall be the prime rate (or its functional equivalent) charged by the Federal Reserve Bank of Atlanta, Georgia.

"Prudent Industry Practices" means any of the practices, methods, standards and acts (including the practices, methods and acts engaged in or approved by a significant portion of the electric power industry in the United States) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, could have been expected to accomplish the desired result consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts generally conform to operation and maintenance standards recommended by equipment suppliers and manufacturers, applicable design limits and applicable Governmental Approvals and Laws.

"Ramp Energy" has the meaning set forth in Section 5.2.

"Redirect Deadline" means the deadline established by the applicable transmission provider for requesting the redirect of transmission service under the applicable transmission tariff.

"S&P" has the meaning set forth in Section 19.1.

"SNG" means Southern Natural Gas Company.

"Schedule" means the right of Buyer to request the delivery of Scheduled Energy in accordance with this Agreement. Any form of the term Schedule (e.g., "Scheduled," "Schedules" or "Scheduling") shall refer to the exercise of such right by Buyer.

"Schedule Shut-Down" means any time Buyer goes from having some energy Scheduled to having no energy Scheduled.

"Schedule Start" means each time that Buyer goes from not having any energy Scheduled to having some amount of energy Scheduled (in either 1-on-1 Operating Mode or 2-on-1 Operating Mode).

"Scheduled Energy" means the amounts of energy, expressed in whole MWh, Scheduled by Buyer to be delivered by Seller in accordance with this Agreement, including amounts of Ramp Energy Buyer is required to accept and receive hereunder.

"Scheduled Outage" means maintenance and/or outages conducted and/or taken by Seller pursuant to Section 4.1.

"Scheduling Parameters" has the meaning set forth in Appendix D.

"SEARUC" means the Southeastern Association of Regulatory Utility Commissioners.

"Seller" has the meaning set forth in the introductory paragraph hereof.

"Service Commencement Date" means June 1, 2010; provided, however, that such date may be extended by Seller due to a Force Majeure Event for a period equal to the period of delay caused by said Force Majeure Event.

"Southern Company" means the Southern Company, a publicly held corporation, organized and existing under the laws of the State of Delaware and having its principal place of business in Atlanta, Georgia.

"Southern Company Transmission" means the functional transmission division of Southern Company and its affiliates, as well as any successor transmission service provider.

"Southern Company Transmission System" means the integrated transmission systems of the electric operating companies of Southern Company, as such systems may be modified or expanded from time-to-time, as well as any successor transmission system(s).

"Southern Power" has the meaning set forth in the introductory paragraph.

"Taxes" means any or all ad valorem, property, occupational, severance, emissions, generation, first use, conservation, energy, transmission, utility, gross receipts, privilege, sales, use, excise and other taxes, governmental charges, licenses, fees, permits and assessments; provided, however, the term Taxes shall not include taxes based on net income or net worth.

"Term" has the meaning set forth in Section 2.1.

"Total Facility Capacity" means, for each Contract Year, the generating capability of the Facility as declared by Seller under Article 8.

"Unavailable Capacity" means, for any hour: (i) Outage Capacity for such hour; less (ii) the Delivered Energy Credit; less (iii) if positive, the difference of the available portion of capacity associated with an Alternate Resource(s) that has been designated for such hour pursuant to Section 5.6.1 in response to the Outage causing Outage Capacity to exist, less the

Delivered Energy Credit; plus (iv) the unavailable portion of capacity associated with an Alternate Resource(s) designated for such hour pursuant to Section 5.6.1 in response to a Force Majeure Event.

ARTICLE 2

TERM OF AGREEMENT

2.1 Term. Subject to the survival provisions herein, this Agreement shall continue in full force and effect from the Effective Date until the end of the Service Term, or on such earlier date on which this Agreement is terminated in accordance with its terms ("Term").

2.2 Service Term. Subject to early termination of this Agreement as provided hereunder, Seller's obligation to provide and sell and Buyer's obligation to accept and purchase Contract Capacity and Scheduled Energy shall extend from the Service Commencement Date through December 31, 2015 ("Service Term"). Provided, however, Buyer shall be entitled to unilaterally extend the Service Term to December 31, 2017 by providing Seller with written notice on or before January 31, 2010. Upon Buyer's providing such notice, the Service Term shall be deemed to be extended through December 31, 2017.

2.3 Survival. All provisions of this Agreement that expressly or by implication come into or continue in force and effect following the expiration or termination of this Agreement shall remain in effect and be enforceable following such expiration or termination.

2.4 Effect of Termination. Subject to the exercise of a non-defaulting Party's rights under Section 16.2, in the event that this Agreement is terminated, the rights and obligations of the Parties hereunder shall continue unaffected until the termination is effective in accordance with the terms and conditions thereof. Any termination of this Agreement shall not relieve Buyer of its obligation to pay any unpaid invoices for any Contract Capacity made available and

Delivered Energy prior to the effective date of such termination, relieve Seller of its obligation to provide Contract Capacity and to deliver Scheduled Energy prior to the effective date of such termination, or relieve either Party of any of its other liabilities or obligations accruing prior to termination.

ARTICLE 3

SALE AND PURCHASE OF CAPACITY AND ENERGY

3.1 Sale and Purchase of Capacity. Subject to the terms and conditions of this Agreement, beginning on the Service Commencement Date and until the end of the Service Term, Seller shall make available and sell to Buyer, and Buyer shall accept and purchase, the Contract Capacity.

3.2 Sale and Purchase of Energy. Subject to the terms and conditions of this Agreement, beginning on the Service Commencement Date and until the end of the Service Term, Seller shall deliver and sell to Buyer, and Buyer shall accept and purchase from Seller, energy up to the Contract Capacity as and when Scheduled by Buyer.

ARTICLE 4

FACILITY MAINTENANCE

4.1 Scheduled Outages. Commencing in 2010 and each year thereafter, Seller shall submit to Buyer, before February 1, a schedule of Facility outages during which maintenance and/or the installation of equipment required by Law or Prudent Industry Practices will be performed for the next Contract Year ("Scheduled Outages"); [redacted] [redacted] Within 30 Days after receiving Seller's proposed schedule for Scheduled Outages, Buyer may request, in writing, that Seller reschedule any such Scheduled Outages.

Following receipt of such request, Seller shall inform Buyer as to whether it can accommodate Buyer's request and, if so, shall further advise Buyer of the good faith estimated costs that will be incurred by Seller in connection with accommodating the request of Buyer to reschedule the Scheduled Outages. Buyer shall then within 14 Days of the receipt of the estimated costs provided by Seller determine whether Seller should reschedule the Scheduled Outages. Without regard to any prior estimate, Buyer shall reimburse Seller for all Commercially Reasonable costs related to such change in schedule if Seller makes such change. While Seller must use Commercially Reasonable Efforts to accommodate a request of Buyer to re-schedule any Scheduled Outages, Seller may elect to decline rescheduling, if, in Seller's Commercially Reasonable judgment, it would cause a failure on the part of Seller to observe Prudent Industry Practices, or if the proposed reschedule would cause Seller to incur costs which Buyer is unwilling to reimburse. Prior to or during any Contract Year, Seller may modify a schedule of Scheduled Outages to reschedule such outages with the prior written consent of Buyer, which consent shall not be unreasonably withheld, conditioned or delayed.

4.2 [redacted]

[redacted]

4.3 Permits and Compliance with Laws.

4.3.1 Subject to the right of Contest, each Party shall acquire and maintain in effect all Governmental Approvals necessary for it to perform its obligations under this Agreement.

4.3.2 Subject to the right of Contest, each Party shall at all times comply with all Laws and Governmental Approvals applicable to such Party that are necessary for such Party to perform its obligations under this Agreement.

4.4 Operating Procedures. Buyer and Seller shall begin to develop written Operating Procedures no later than 6 months before the Service Commencement Date. Such Operating Procedures shall be completed no later than 30 Days before the Service Commencement Date. The Operating Procedures shall establish the protocol under which the Parties shall perform their respective responsibilities under this Agreement, including method of Day-to-Day communications, amounts of Ramp Energy to be received by Buyer under Section 5.2, key personnel lists, and logging and tracking of hours of EUH and EFMH, Scheduled Outages, Maintenance Outages, and hours of Delivery Excuse.

4.5 Operating Committee. The Parties shall form a committee to act in matters relating to the performance of their respective obligations under this Agreement ("Operating Committee"). Each Party shall appoint one representative and one alternate representative to serve on the Operating Committee. The Parties shall notify each other in writing of such appointments and any changes thereto. The Operating Committee shall have no authority to modify the terms or conditions of this Agreement. Beginning in 2009, the Operating Committee shall meet no less than two times per calendar year (which meetings may be by telephone) and all of its decisions must be the unanimous decision of the representatives. Within a reasonable time after the conclusion of each meeting of the Operating Committee, the representatives of each Party shall exchange written summaries of such meeting, including a description of issues discussed and decisions made.

ARTICLE 5

SCHEDULING AND THE PROVISION OF CAPACITY AND ENERGY

5.1 Scheduling.

[redacted]

[redacted]

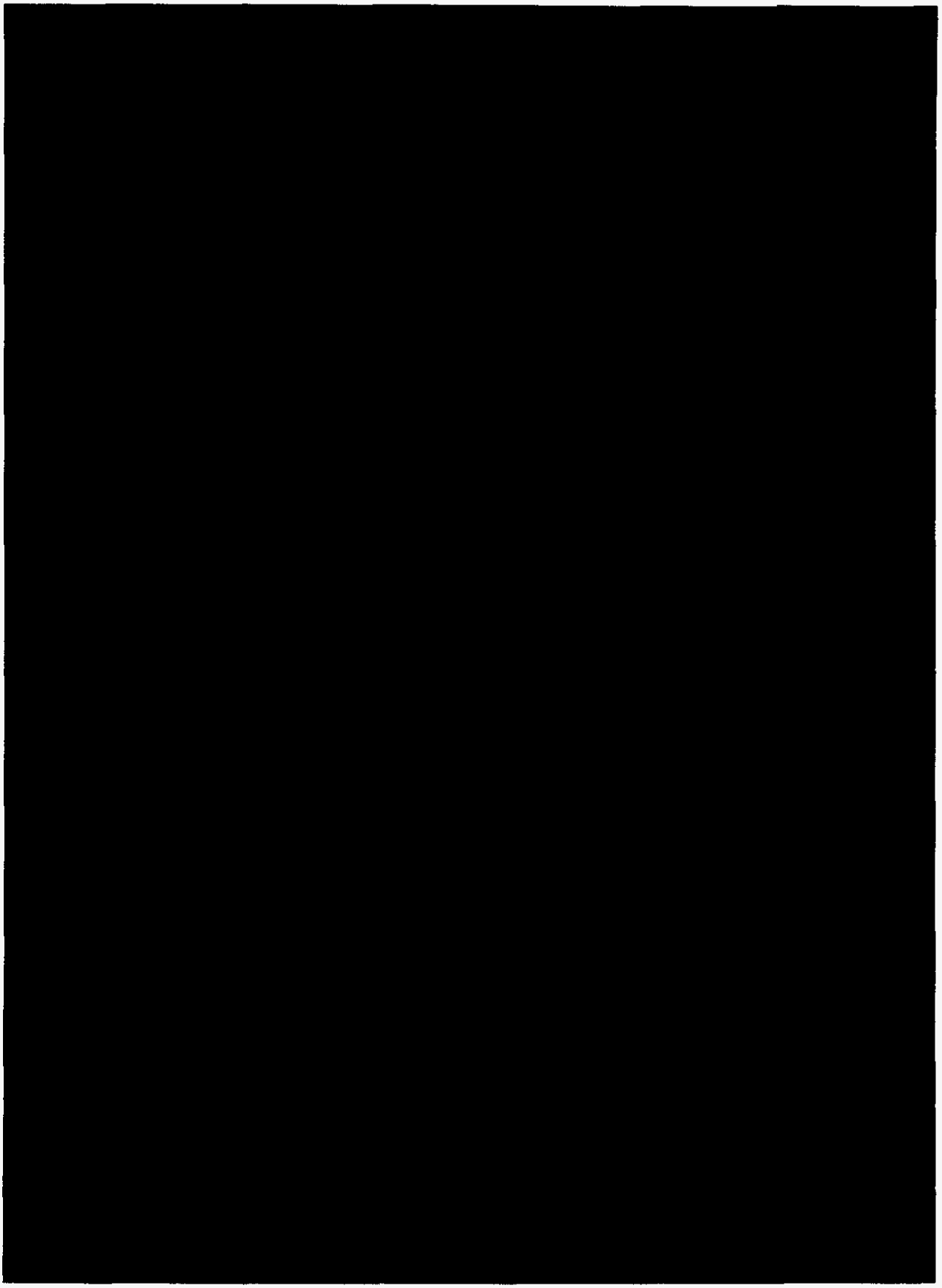
5.2 Ramp Energy. Buyer shall receive and accept at the Facility Delivery Point all energy produced by the Facility during ramping (both starting and shutting down) in connection with satisfying Buyer's Schedule ("Ramp Energy"). The Operating Procedures established pursuant to Section 4.4 shall provide for a procedure whereby Seller, for transmission scheduling purposes, shall provide Buyer with prior notice of the hourly Ramp Energy to be provided for each Schedule. Provided, however, Buyer shall not be required to accept and receive Ramp Energy in an amount greater than [redacted] MWh while the Facility is starting or greater than [redacted] MWh while the Facility is shutting down. For purposes hereof (including Appendix B), Ramp Energy shall be deemed to be Delivered Energy. The Operating Procedures established pursuant to Section 4.4 shall provide for a methodology (consistent with the Facility's manufacturer's recommendations and Prudent Industry Practices) for determining the amounts of Ramp Energy that must be accepted and received by Buyer under this Section 5.2. Ramp Energy shall not be provided to the extent energy is supplied to Buyer from an Alternate Resource(s).

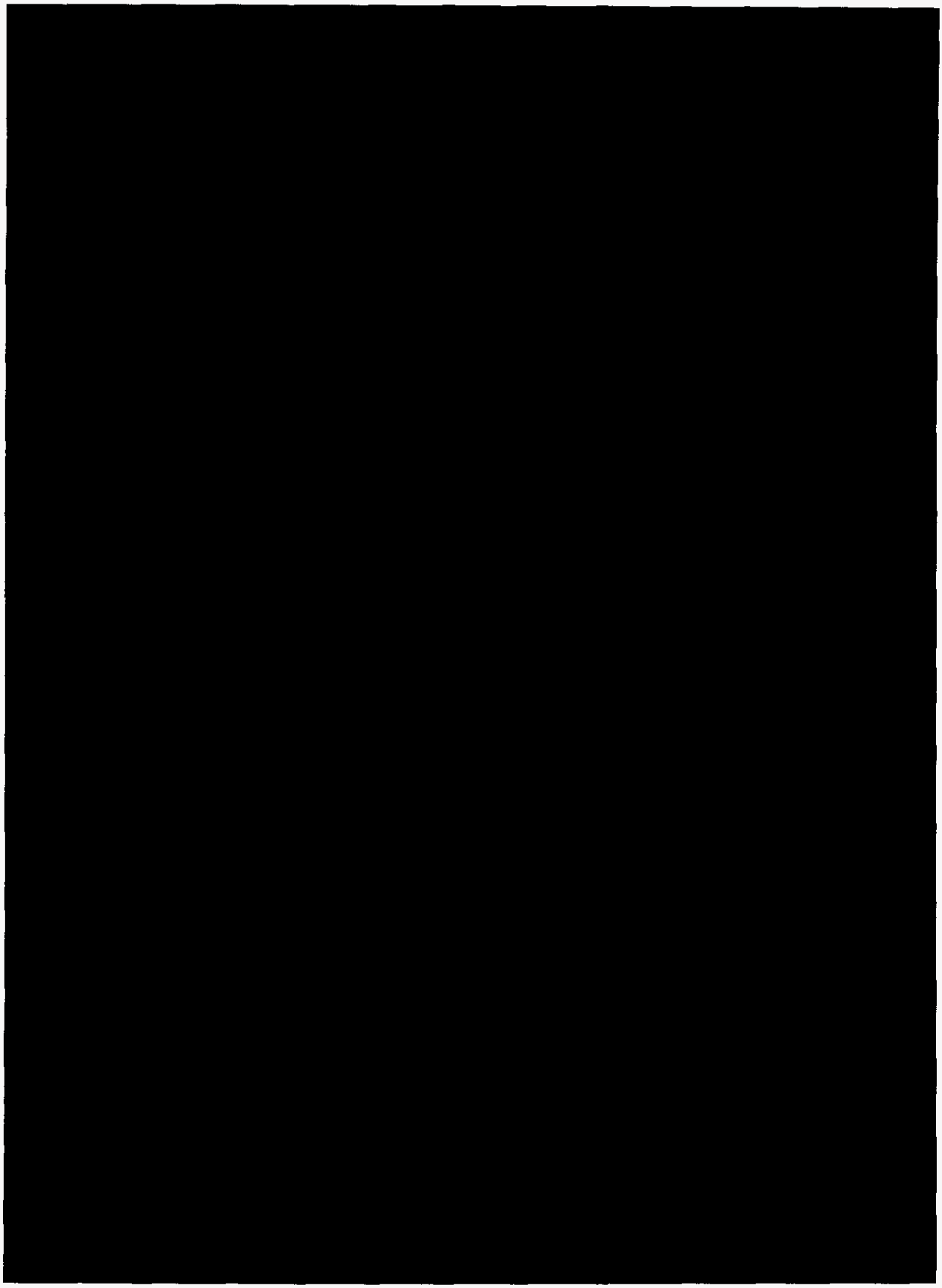
5.3 Transmission and Scheduling Requirements. Buyer shall be responsible for complying with all transmission reservation, scheduling and tagging requirements associated with energy provided hereunder at and after the Delivery Point.

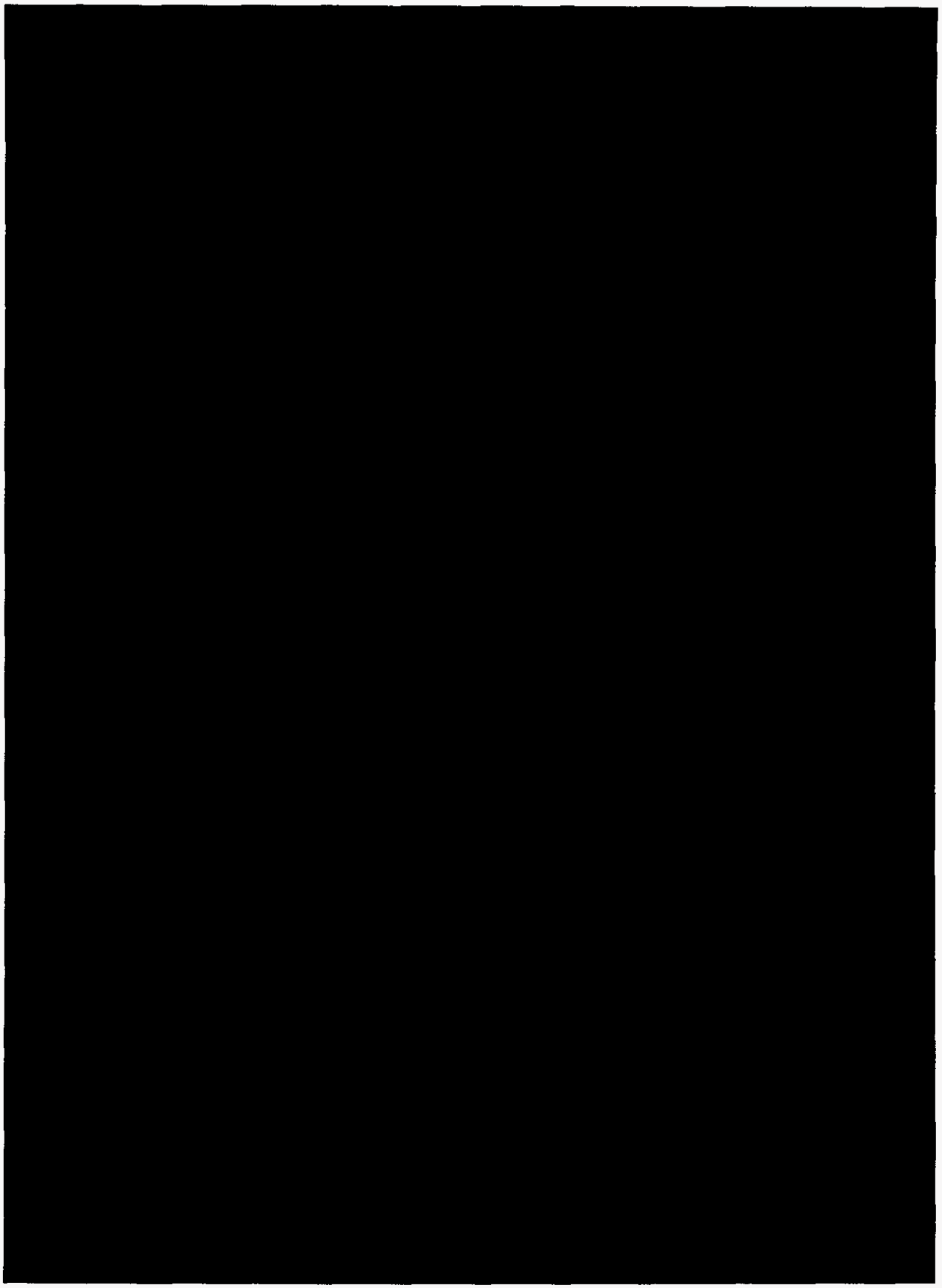
5.4 Costs and Expenses. Except as specifically provided hereunder, all costs and expenses associated with Delivered Energy at and after the Delivery Point shall be the sole responsibility of Buyer. Except as specifically provided hereunder, all costs and expenses associated with Delivered Energy prior to the Delivery Point shall be the responsibility of Seller. Any penalties associated with Delivered Energy shall be the responsibility of the Party whose action or inaction caused the penalty to be assessed.

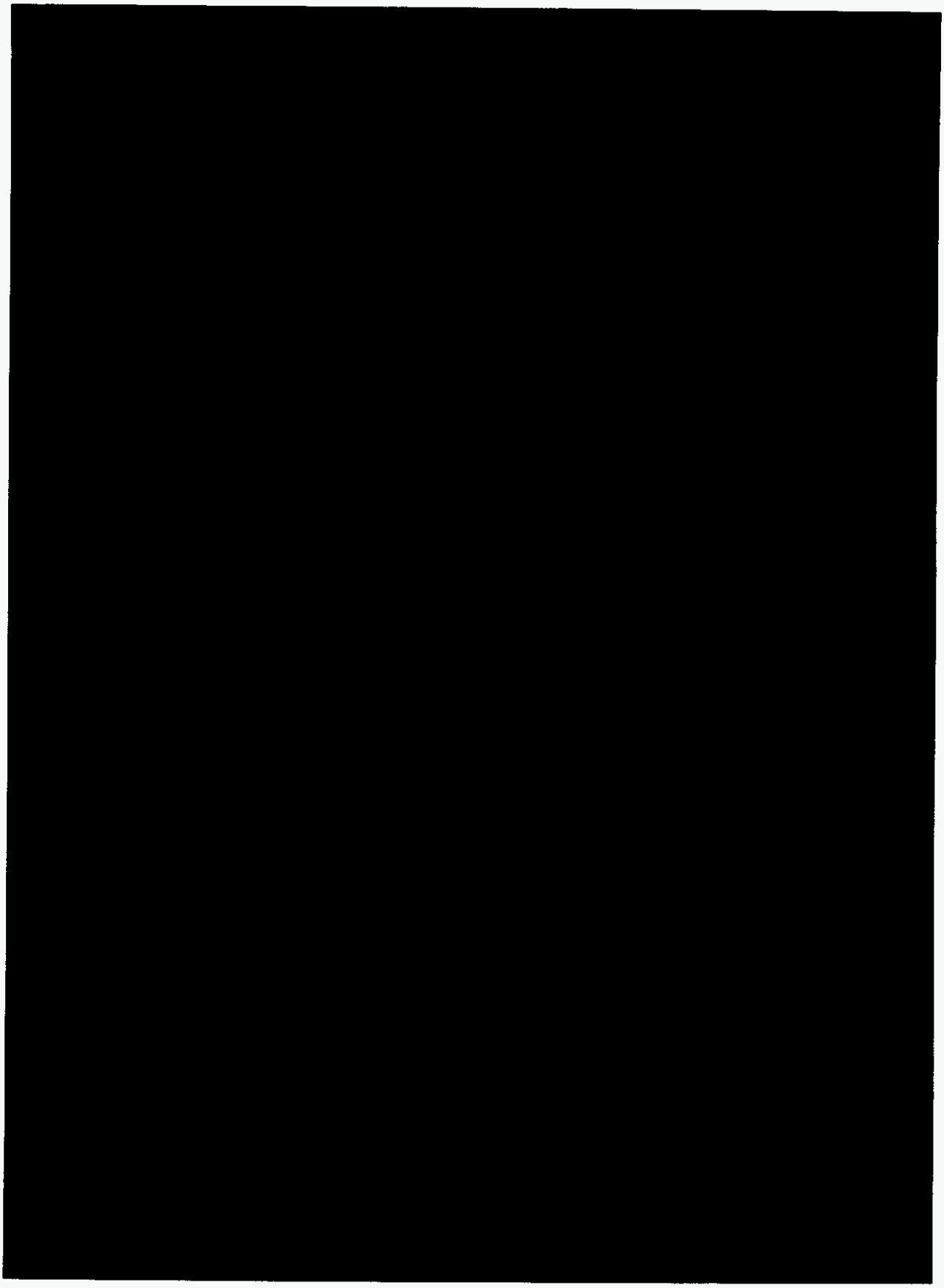
5.5 Delivery of Energy. Subject to the terms of this Agreement and the Scheduling Parameters, energy provided by Seller pursuant to Buyer's Schedule shall be deemed to be delivered at the Delivery Point.

5.6 [redacted]









5.8 Seller's Rights to the Facility. To the extent Buyer has not submitted a Schedule requesting energy associated with the full Contract Capacity, and/or to the extent Scheduled Energy is being provided from Alternate Resources, Seller shall have the right to dispatch the Facility to utilize for its own purposes energy from the Facility not Scheduled and/or replaced with Alternate Energy.

5.9 Title and Risk of Loss. Seller shall be deemed to be in exclusive control of the Delivered Energy prior to the Delivery Point. Buyer shall be deemed to be in exclusive control of the Delivered Energy at and after the Delivery Point. Custody, title and risk of loss of Contract Capacity and Delivered Energy shall transfer from Seller to Buyer at the Delivery Point.

5.10 Force Majeure Event.

5.10.1 For any hour in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, Seller shall only be obligated to deliver to Buyer the lesser of: (i) Scheduled Energy; or (ii) energy associated with the difference of the Contract Capacity less Force Majeure Capacity. In addition, to the

extent of such Force Majeure Event, Seller may elect in its sole discretion pursuant to the procedures under Section 5.6 (but shall not be required) to deliver Scheduled Energy from Alternate Resources.

5.10.2 For any hour during which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, Seller shall be required to accumulate EFMH (as applicable) for such hour. [redacted]

5.11 Outages and Unavailable Capacity.

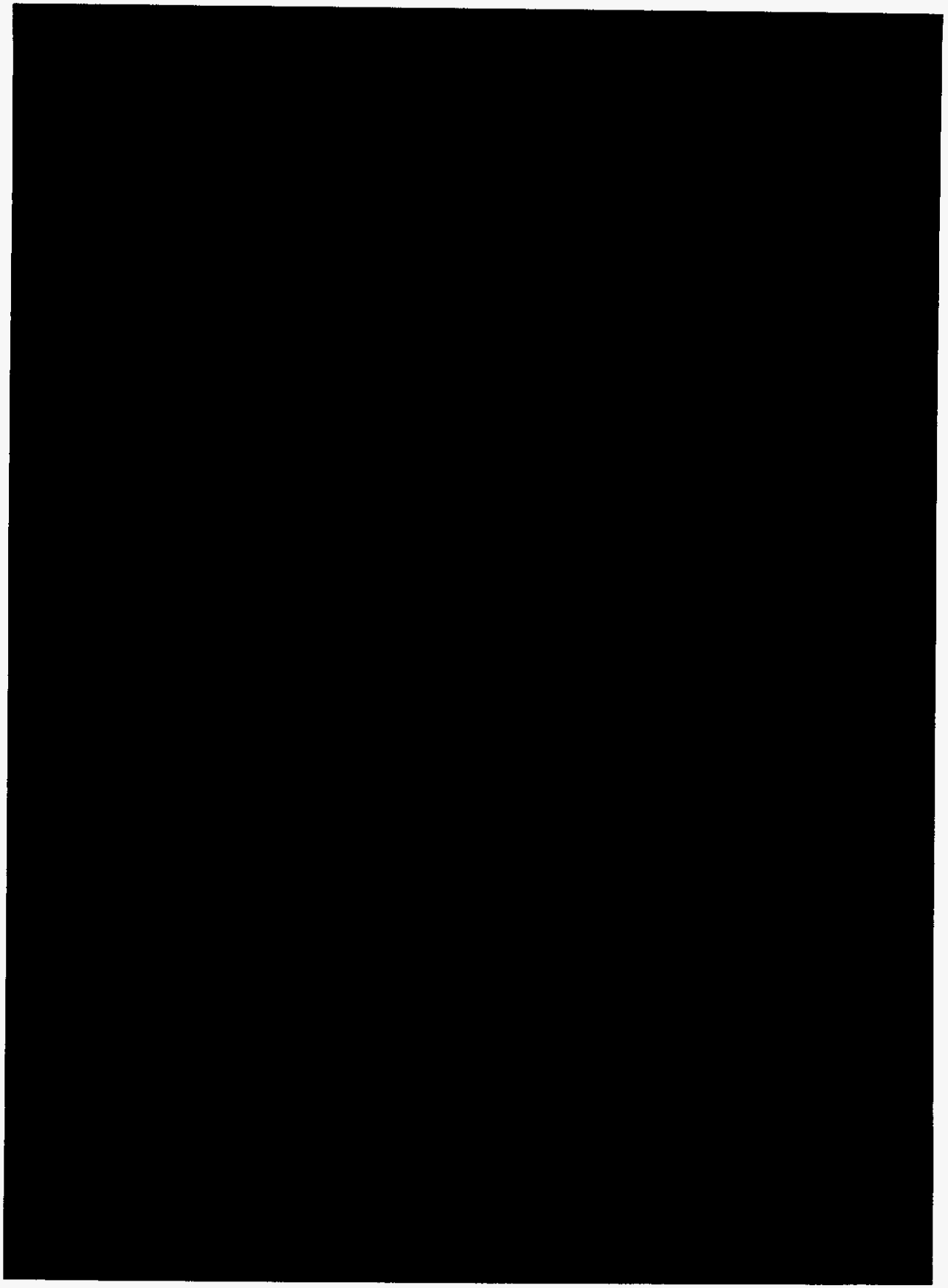
5.11.1 Seller shall notify Buyer as soon as reasonably practicable of: (i) the occurrence of any Outage that is expected to result in Outage Capacity and the estimated duration of such Outage; (ii) the cessation of such Outage; and (iii) if requested by Buyer within 30 Days after the Outage and if known to Seller, the cause of such Outage.

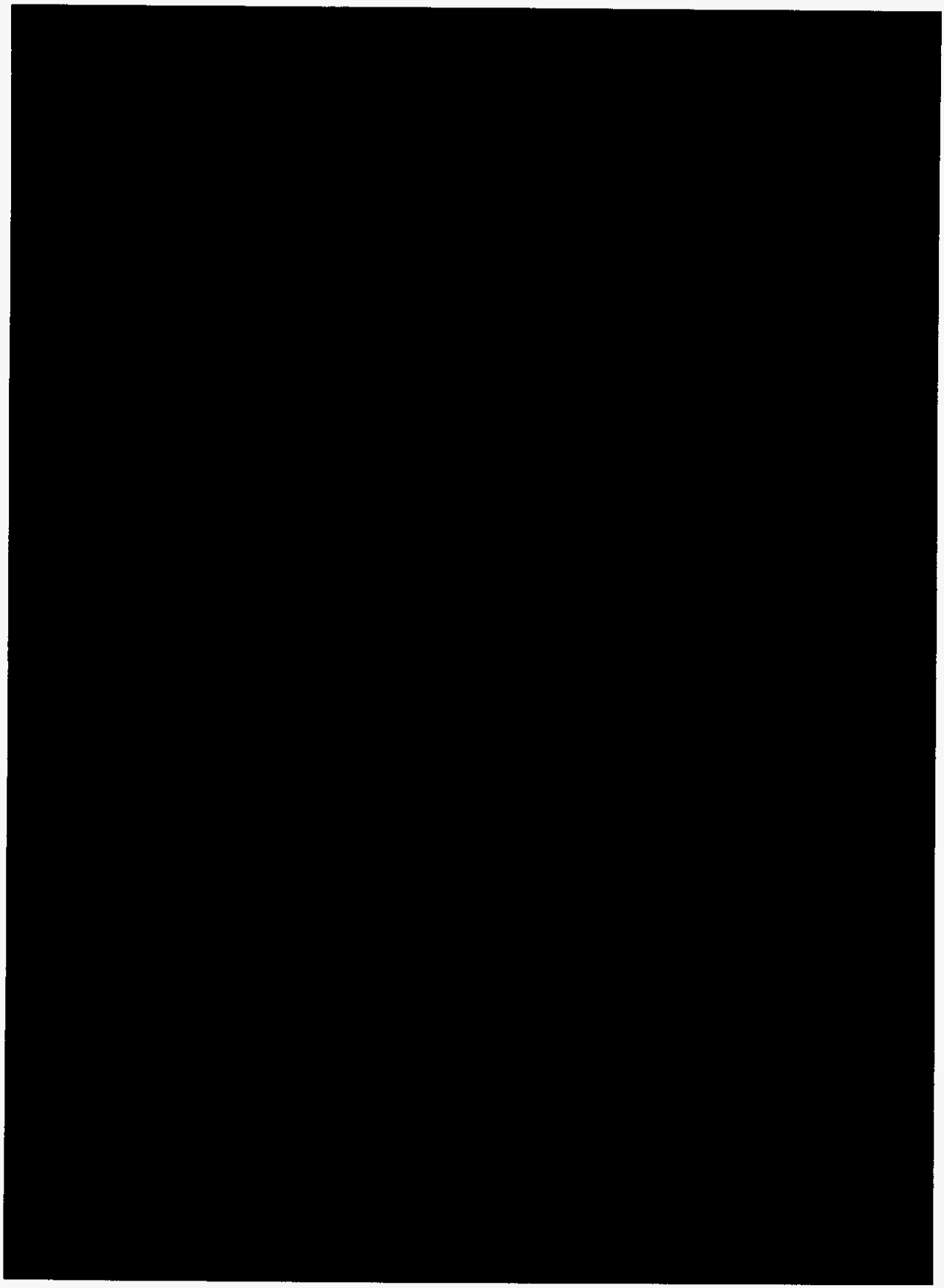
5.11.2 For any hour during which there is Unavailable Capacity, Seller shall be required to accumulate EUH (as applicable) for such hour. [redacted] Seller's sole and exclusive liability and Buyer's sole and exclusive remedy for Seller's failure to provide capacity and/or energy from any resource under this Agreement shall [redacted]

5.12 Delivery Excuse. For any hour in which a Delivery Excuse is occurring or is continuing, Seller shall not be obligated to deliver, and Buyer shall not be entitled to receive or submit a Schedule for, Scheduled Energy. In such event, Seller shall not be required to accumulate EFMH or EUH. Buyer shall not be relieved of its performance obligations during a Delivery Excuse, including its obligation to pay Seller the Monthly Capacity Payment.

5.13 Scheduled and Maintenance Outages. Buyer shall not have the right to submit a Schedule for any period of time during which maintenance is being performed and/or outages are taken consistent with Sections 4.1 and 4.2.

5.14 [redacted]





ARTICLE 6

PAYMENTS

6.1 Capacity Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Capacity Payment for the Contract Capacity. The calculation of the Monthly Capacity Payment is set forth in Appendix A.

6.2 Energy Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Energy Payment. The calculation of the Monthly Energy Payment is set forth in Appendix B.

6.3 Start Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Start Payment. The calculation of the Monthly Start Payment is set forth in Appendix C.

6.4 Fuel Transportation Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Fuel Transportation Payment. The calculation of the Monthly Fuel Transportation Payment is set forth in Section 9.2.2.

6.5 Additional Payments. In addition to the payments specified in this Article 6, the Parties shall pay all amounts due pursuant to the other provisions of this Agreement.

ARTICLE 7

TRANSMISSION SERVICE

7.1 Buyer Obligations. Buyer, or its designee, shall have the sole and exclusive responsibility at all times to arrange, obtain, contract and pay for any and all transmission service and ancillary services required (including service under any applicable transmission

tariff) to deliver any energy hereunder from and beyond the Delivery Point. Buyer assumes all risk associated with the availability, adequacy and cost of such transmission service and ancillary services.

7.2 Seller Obligations. Seller, or its designee, shall have the sole and exclusive responsibility at all times to arrange, obtain, contract, and pay for any and all transmission service required to deliver energy hereunder to the Delivery Point.

7.3 Imbalances and Penalties. Upon receiving notice of any interruption of the delivery of energy under this Agreement for any reason (e.g., an Outage or a Force Majeure Event), Buyer shall promptly notify the applicable transmission provider and/or system operator in order to avoid any energy imbalances. Any penalties or imbalances (including associated costs) resulting from actions or inactions of Buyer (including the failure to provide required notice to the applicable transmission provider and/or system operator), its designee or any third party to which Buyer may be supplying the capacity and energy provided hereunder will be the responsibility of Buyer as between the Parties. Any penalties or imbalances (including associated costs) resulting from actions or inactions of Seller or its designee will be the responsibility of Seller as between the Parties. If either Party incurs any costs associated with penalties or imbalances that are the responsibility of the other Party under this Section, such other Party shall provide prompt reimbursement of such costs.

7.4 Buyer's Request for Transmission Service.

7.4.1 Within [redacted] Days after the Effective Date, Buyer shall request from Southern Company Transmission (including by submitting such request on Southern Company Transmission's OASIS and completing any required application(s)) 600 MW of Long Term Firm Transmission Service from the Facility Delivery Point to the Florida Interface, such

service to commence on June 1, 2010 ("Requested Service"). As entered into Southern Company Transmission's OASIS, such request shall designate the point of delivery as "FPL." In addition, from the Effective Date, Buyer shall make and/or continue Commercially Reasonable Efforts to have Southern Company Transmission provide Buyer with an offer to provide the Requested Service no later than [redacted] ("Transmission Deadline"); provided, however, the Transmission Deadline shall automatically be extended on a Month to Month basis until either Party provides timely notice to the other that it does not desire for the Transmission Deadline to be extended under this Agreement and in Section 7.4.1 of both of the other Contemporaneous Agreements. Such notice must be provided no later than 5 Days prior to the then existing Transmission Deadline (as may be extended). Notwithstanding the foregoing, the Transmission Deadline in this Agreement shall be extended only to the same extent as such deadline is also extended under Section 7.4.1 of both of the other Contemporaneous Agreements.

7.4.2 No later than 2 Business Days after the earlier of: (i) the Transmission Deadline; (ii) Southern Company Transmission's notice to Buyer that it will not be able to provide any of the Requested Service to Buyer; or (iii) Southern Company Transmission's notice to Buyer that it will be able to provide some or all of the Requested Service to Buyer, Buyer shall notify Seller ("Transmission Notice") of the total amount of the Requested Service that Southern Company Transmission is able to provide to Buyer at any price and cost ("SCT Service"). In the event that the total cost ("Total Cost") of any portion of the SCT Service is higher than the embedded rate for Long Term Firm Transmission Service under the OATT ("Tariff Rate"), the Transmission Notice shall specify the amount of SCT Service offered at a Total Cost higher than the Tariff Rate and include any and all documentation of such Total Cost

provided to Buyer by Southern Company Transmission. For purposes of this Section 7.4, "Total Cost" shall mean those costs that would be imposed on Buyer directly by the applicable transmission provider for the Requested Service.

7.4.3 Within 2 Business Days after its receipt of the Transmission Notice, Seller may offer to sell to Buyer (including by reassignment) up to 600 MW of Long Term Firm Transmission Service from the Facility Delivery Point to the Florida Interface on any applicable transmission system, such service to commence on June 1, 2010 ("Seller Service"). Such offer shall set forth the amount of Seller Service and the price for such service. For purposes of this Agreement the sum of the Seller Service and the SCT Service shall be referred to as the "Available Service."

7.4.4 [redacted]

7.4.5 Once the procedures in Sections 7.4.1 through 7.4.4 have been completed (as applicable), Buyer may elect to reduce the Contract Capacity for the Service Term by an amount up to the sum of: [redacted]

Buyer shall notify Seller of such election within 3 Business Days after the later of the date of (if applicable) the Reduction Notice, receipt of Seller's offer under Section 7.4.3 or the Transmission Notice ("Election Deadline"). In addition, after the procedures in Sections 7.4.1 through 7.4.4 have been completed (as applicable), if Available Service of at least [redacted]MW is not available to Buyer so that Buyer is in effect able to procure Long Term Firm Transmission Service from the Facility at a Total Cost equal to or less than the Tariff Rate (taking into account any offset of Excess Cost by Seller), Buyer may provide notice to Seller that it will terminate this Agreement. Such notice must be provided no later than the Election Deadline.

7.4.6 If Buyer elects, pursuant to Section 7.4.5, to reduce the Contract Capacity by an amount greater than [redacted]MW, Seller shall be entitled to either: [redacted] Seller shall provide Buyer with notice of its election of either (i) or (ii) no later than 2 Business Days after its receipt of Buyer's notice to reduce the Contract Capacity. If Seller accepts the reduction in Contract Capacity, the Parties shall mutually agree on modifications to this Agreement in order to reflect such reduction.

7.4.7 In the event that either Party provides notice to the other Party under this section 7.4 that it has elected to terminate this Agreement, this Agreement and the other Contemporaneous Agreements shall immediately terminate. Upon such termination, no Party shall have any further obligation under any of the Contemporaneous Agreements except for any liabilities and/or obligations accruing prior to such termination. The Parties acknowledge that the other Contemporaneous Agreements contain a provision similar to this Section 7.4.7 and that this Agreement is subject to termination as provided in such similar provisions.

7.4.8 Nothing in this Section 7.4 shall be construed as requiring Buyer to actually purchase any transmission service.

7.4.9 The MW amounts set forth in this Section 7.4 refer to MW amounts at the Facility Delivery Point. As appropriate and/or required, such amounts shall be adjusted consistent with the OATT (or other applicable transmission tariff) to reflect transmission losses to the Florida Interface (e.g., including for purposes of submitting the required transmission service request through Southern Company's OASIS and/or other required application(s) for such service).

7.5 Regional Transmission Organizations.

7.5.1 In the event that a Regional Transmission Organization(s) or similar organization ("RTO") is formed and such formation materially changes the scheduling requirements and/or costs associated with the delivery of energy to and/or from the Delivery Point, Seller shall be solely responsible for complying with all scheduling requirements and paying all such costs to the Delivery Point (including but not limited to all congestion and/or basis costs). In addition, Buyer shall be solely responsible for complying with all scheduling requirements and paying all such costs at and beyond the Delivery Point to any other point(s) of delivery (including but not limited to all congestion and/or basis costs). Seller agrees to indemnify and hold harmless Buyer for any costs and expenses incurred by Buyer that are Seller's responsibility under this Section 7.5.1. Buyer agrees to indemnify and hold harmless Seller for any costs and expenses incurred by Seller that are Buyer's responsibility under this Section 7.5.1.

7.5.2 [redacted]

[redacted]

ARTICLE 8

TOTAL FACILITY CAPACITY AND COMMENCEMENT OF SERVICE

8.1 Declaration of the Total Facility Capacity. Through notice to Buyer, Seller shall declare the Total Facility Capacity for each Contract Year pursuant to the procedures set forth in Section 8.2.

8.2 Declaration Prior to Each Contract Year.

8.2.1 Except as provided in Section 8.3.1.1 and 8.3.1.2, within 90 Days prior to the beginning of each Contract Year, Seller shall declare the Total Facility Capacity for such Contract Year. Such declaration shall be based on the demonstrated generating capability of the Facility as determined in accordance with Appendix E.

8.2.2 After Seller's declaration under Section 8.2.1, Buyer shall have the right to require a test to re-demonstrate the capability of the Facility as follows:

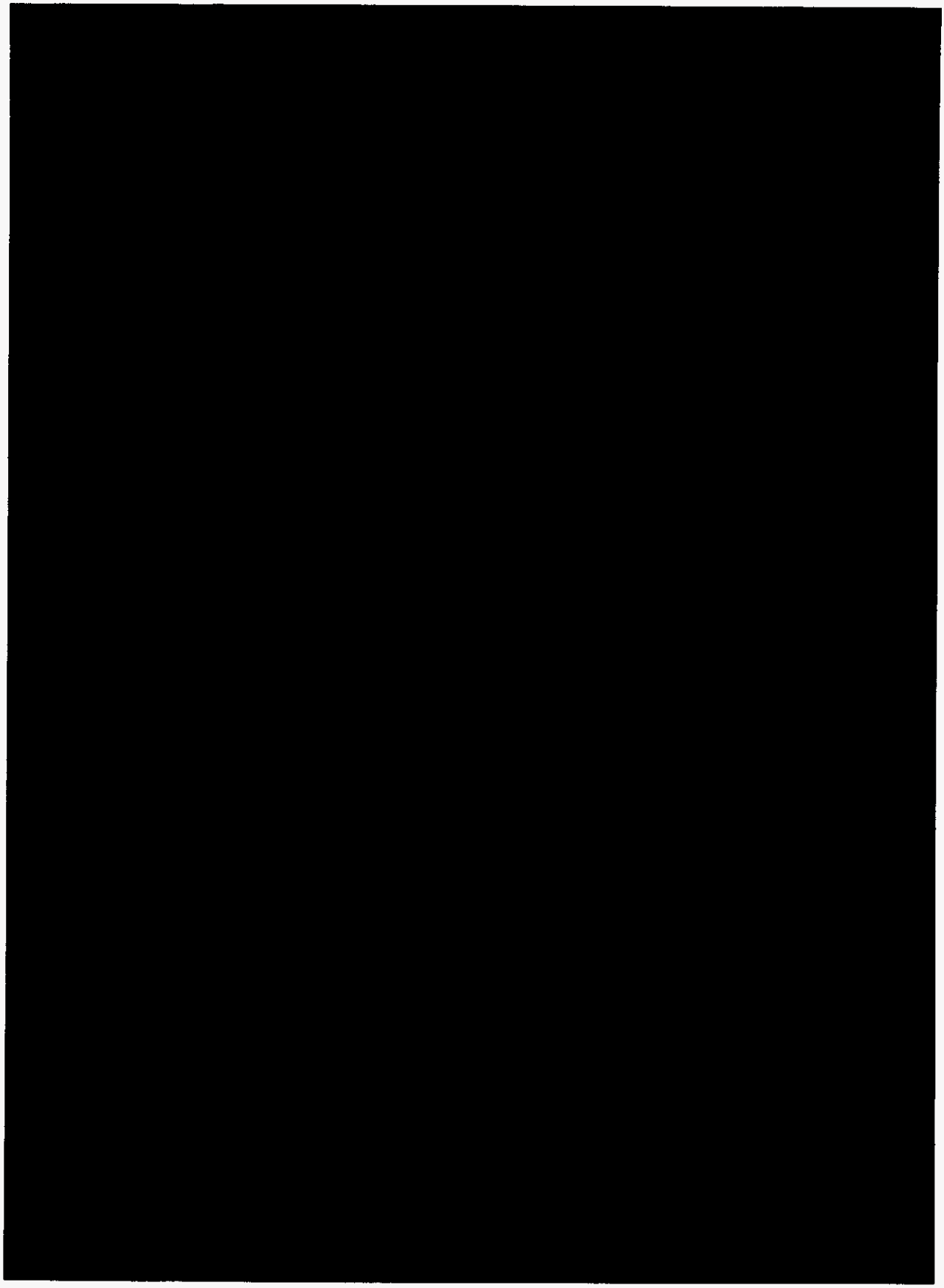
8.2.2.1 After Seller's declaration of the Total Facility Capacity for the first Contract Year, Buyer may by notice to Seller ("Test Notice") require Seller to conduct a test to re-demonstrate the capability of the Facility. Buyer shall provide any such Test Notice no later than 30 Days after the Service Commencement Date ("Initial Testing Deadline"). If Buyer timely provides the Test Notice, Seller shall conduct a test of the Facility in accordance with Appendix E within 30 Days after the Test Notice on a Day selected by Seller and provide Buyer with prior notice of such test. Buyer shall pay Seller all costs of testing (including Gas and operation and maintenance costs), and Buyer shall be entitled to utilize all energy produced during testing for its own purposes.

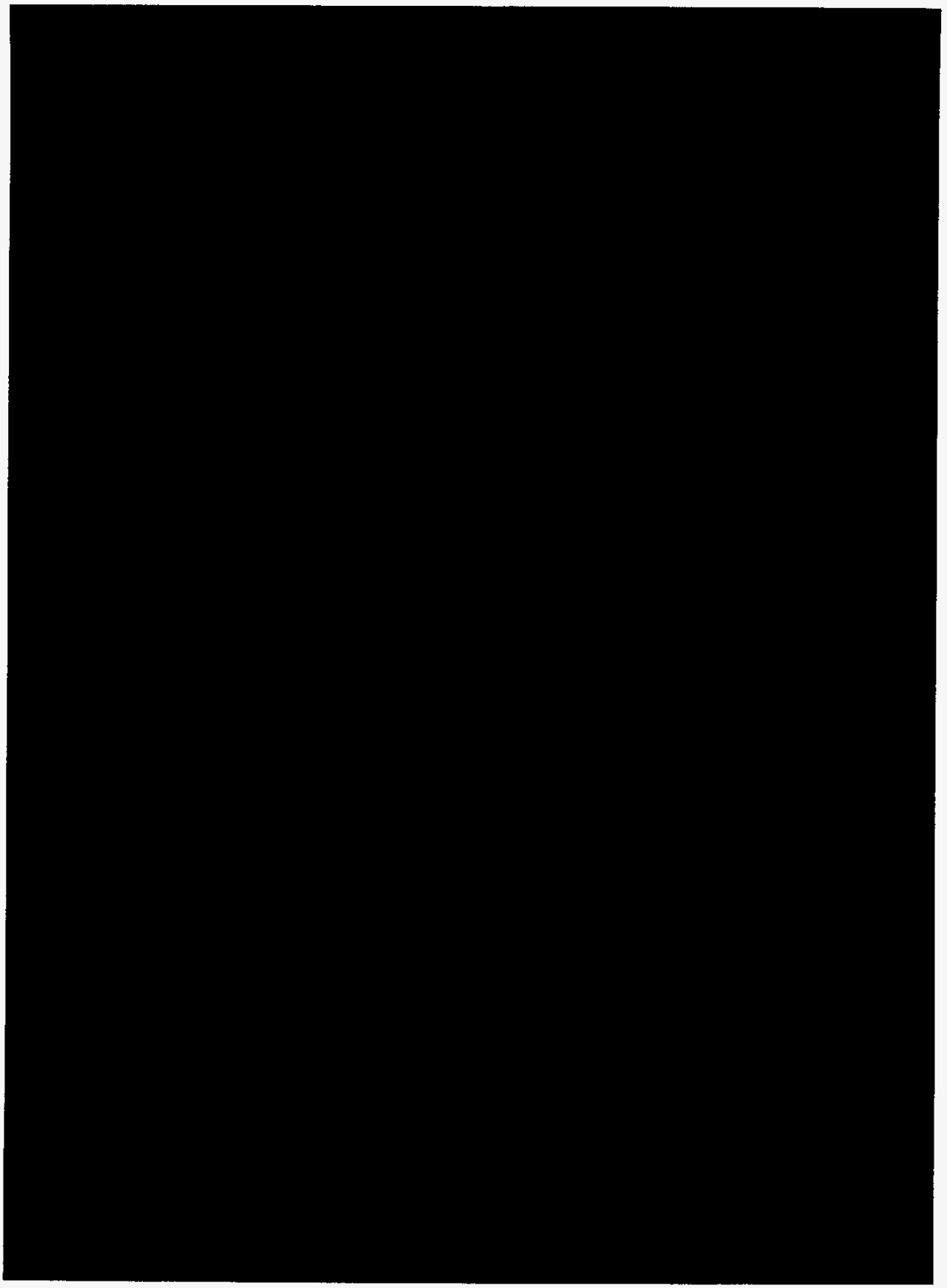
8.2.2.2 After the Initial Testing Deadline, if at any time Buyer has reasonable grounds for disputing Seller's declared amount of Total Facility Capacity (e.g., the delivery of energy by Seller in amounts less than Scheduled Energy), Buyer may provide to Seller a Test Notice to require Seller to conduct a test to re-demonstrate the capability of the Facility. Upon receipt of such notice, Seller shall conduct a test of the Facility in accordance with Appendix E within 30 Days after the Test Notice on a Day selected by Seller and provide Buyer with prior notice of such test. Buyer shall pay Seller all costs of testing (including Gas and operation and maintenance costs), and Buyer shall be entitled to utilize all energy produced during testing for its own purposes.

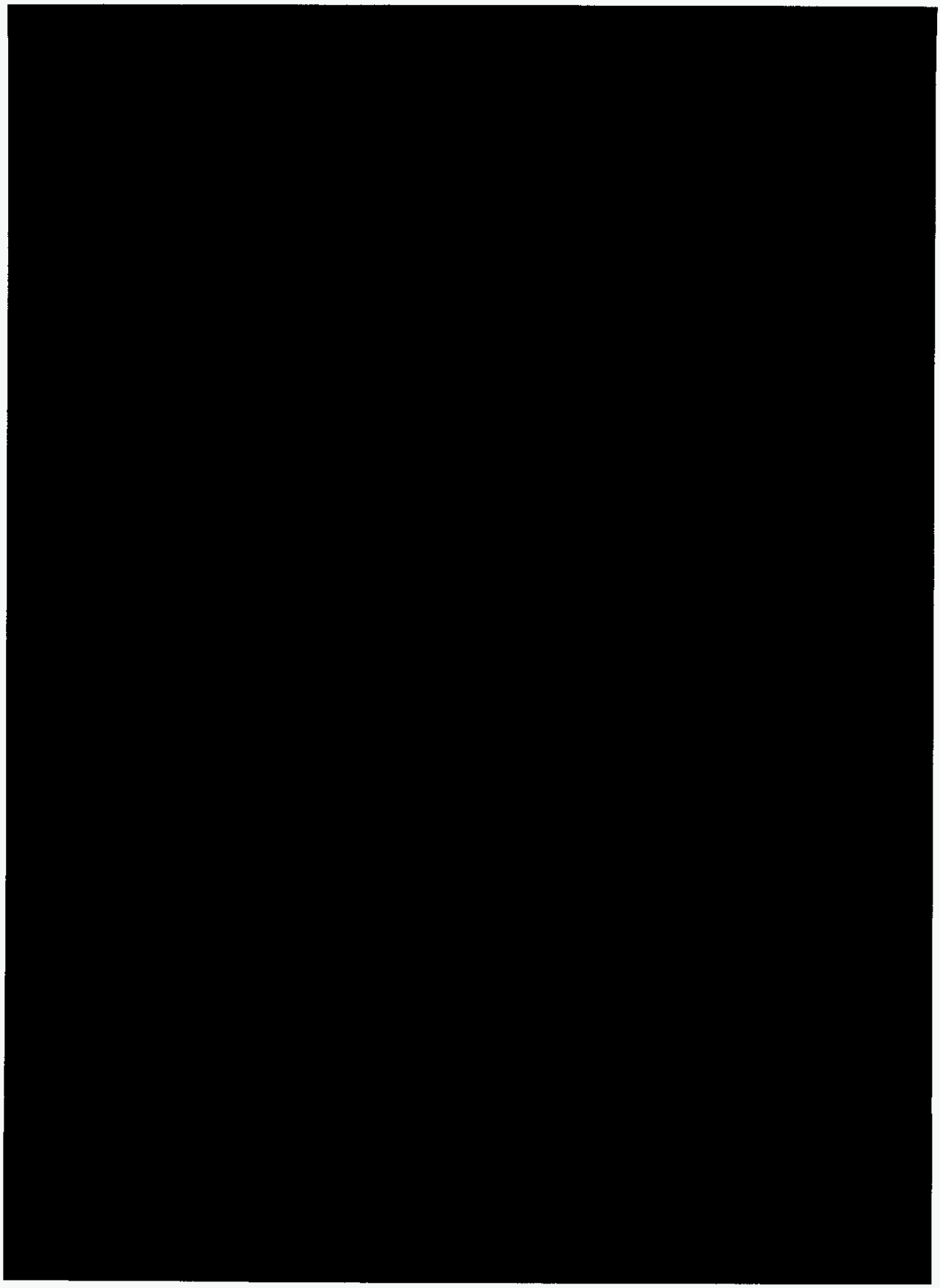
8.2.3 In the event that a test required by Buyer pursuant to Section 8.2.2 indicates that the generating capability of the Facility is different than the Total Facility Capacity declared pursuant to Section 8.2.1, Seller may (at its sole option) conduct additional test(s) of the Facility in accordance with Appendix E, such test(s) to be completed no later than 30 Days after the test conducted pursuant to Section 8.2.2. If Seller does not elect to conduct

such additional test(s), the Total Facility Capacity shall be re-set pursuant to Section 8.2.4 to an amount equal to the generating capability demonstrated by the test conducted pursuant to Section 8.2.2. If Seller does elect to conduct additional testing, Seller shall provide Buyer prior notice of the Day(s) of such test(s) and the Total Facility Capacity shall be re-set pursuant to Section 8.2.4 to an amount equal to the generating capability demonstrated through such additional test(s). If such test(s) is performed coincident with Buyer's Schedule for any Day(s), Buyer shall pay Seller the costs of testing (including Gas and operation and maintenance costs) that are the responsibility of Buyer through the application of the Monthly Energy Payment for all Delivered Energy provided to Buyer. To the extent such test(s) is performed during a time period in which energy will not be delivered to Buyer pursuant to a Schedule, Seller shall be responsible for all costs of testing (including Gas and operation and maintenance costs) and shall be entitled to utilize all energy produced during testing for its own purposes.

8.2.4 If the Total Facility Capacity is set pursuant to a test conducted under Section 8.2.2 or Section 8.2.3 as a result of a Test Notice provided by Buyer on or before the Initial Testing Deadline, the Total Facility Capacity shall be adjusted retroactively to the Service Commencement Date. In all other cases when the Total Facility Capacity is set pursuant to a test conducted under Section 8.2.2 or Section 8.2.3, the Total Facility Capacity shall be adjusted retroactively to the date of the applicable Test Notice. All capacity billing under Section 6.1 shall (if necessary and as soon as practicable) be retroactively adjusted as appropriate (with interest at the Interest Rate) to reflect such adjustment of the Total Facility Capacity.







[redacted]

ARTICLE 9

FUEL ARRANGEMENTS

9.1 Seller's Commitment. Subject to the provisions of this Agreement, Seller will use Commercially Reasonable Efforts to provide to the Facility the volume of Gas needed to provide Scheduled Energy.

9.2 Gas Transportation Arrangement and Charges.

9.2.1 Subject to the provisions of this Agreement, Seller will utilize up to [redacted] MMBtu per day of firm transportation capacity on the pipeline system of SNG from SNG's Zone 0 to Zone 2 under SNG's Contract Number FSNG284 constructed under South System I, Phase II expansion that was placed in service on June 1, 2003 for deliveries to Point Code 808000, Plant Harris, as amended ("SNG Contract") as necessary to provide Scheduled Energy under this Agreement. To the extent energy is supplied to Buyer from the Facility, Seller shall afford Buyer's Schedule priority with regard to the use of such transportation capacity that is available; provided, however, if a portion of the total amount of transportation capacity procured by Seller to the Plant is unavailable for any hour(s), Seller shall be permitted to reduce on a pro rata basis the amount of transportation capacity that it will utilize in order to satisfy Buyer's Schedule.

9.2.2 Buyer shall pay to Seller a Monthly Fuel Transportation Payment which shall be an amount equal to the product resulting from multiplying [redacted] MMBtu by the sum of: [redacted]

9.2.3 [redacted]

9.2.4 Buyer acknowledges that Seller may have the right pursuant to Exhibit E of the SNG Contract to terminate that contract; however, Seller shall exercise that right with respect to the transportation capacity necessary to provide Scheduled Energy under this Agreement only if Buyer and Seller agree on mutually acceptable replacement transportation arrangements.

9.2.5 Buyer acknowledges that SNG may impose imbalance, cash-out and other types of charges, including penalty charges, pursuant to its FERC approved tariff under certain conditions ("Penalty Charges"). Buyer agrees to be responsible for and pay or reimburse Seller for any Penalty Charges billed to Seller by SNG that result from any action or failure to act of Buyer under this Agreement. The Parties agree to cooperate in order to attempt to minimize Penalty Charges.

9.2.6 In the event that accommodating Buyer's Schedule would require Gas transportation capacity in addition to that set forth in Section 9.2.1, Seller shall make Commercially Reasonable Efforts to obtain (if available) additional capacity at Buyer's expense and Buyer shall reimburse Seller based on SNG's interruptible transportation rate from Zone 0 to Zone 2 in effect at the time. To the extent Seller is unable to obtain such additional capacity at or below such interruptible transportation rate and such capacity is available, Seller shall make Commercially Reasonable Efforts to provide Buyer the option of having Seller purchase such additional capacity at the higher rate. If Buyer desires to have Seller purchase such additional capacity at the higher rate, Seller shall make Commercially Reasonable Efforts to obtain such capacity to accommodate Buyer's Schedule and Buyer shall reimburse Seller for all associated costs. To the extent that Buyer does not desire to have Seller purchase such additional capacity at the higher rate or Seller is unable to obtain such capacity, Seller shall have a Delivery Excuse to that extent.

9.3 Interruption of Gas Supplies

9.3.1 In the event that Gas supplies are interrupted due to any circumstance affecting Seller's Gas suppliers that qualifies as an event of force majeure as defined in the North American Energy Standards Board's Base Contract for Sale and Purchase of Natural Gas:

A. Seller shall use Commercially Reasonable Efforts to arrange for alternate Gas supplies to overcome such an interruption. If alternate Gas supplies are available, Seller shall offer to Buyer, and Buyer shall have the option to immediately accept, such alternate Gas supplies at the price quoted by Seller.

B. If Seller is unable to arrange for alternate Gas supplies or if Buyer does not accept such alternate Gas supplies pursuant to subparagraph A above, Buyer may

arrange to sell alternate gas supplies to Seller at the Gas Price (as defined in Appendix B) by delivering such Gas to SNG at a point on its pipeline at which Seller can schedule receipts of such Gas under the SNG Contract. Buyer shall cooperate with Seller and SNG in order to ensure that such supplies are nominated, scheduled and delivered to SNG for transportation under the SNG Contract and under the terms of SNG's FERC approved tariff. Buyer shall be responsible for any Penalty Charges resulting from any difference between the volume scheduled for delivery by Buyer to and receipt by SNG and the actual volume delivered by Buyer to and received by SNG.

9.3.2 In the event that there is no arrangement for alternate Gas supplies under Section 9.3.1, the interruption of Gas supplies described in Section 9.3.1 shall constitute a Delivery Excuse as defined in this Agreement.

9.3.3 Notwithstanding any other provision of this Agreement, Seller shall not be obligated to obtain or use any Gas storage services in order to provide Gas under this Agreement.

9.4 Scheduling Changes. In the event that Buyer requests a Schedule change pursuant to Section 5.1.2 after the Scheduling Deadline, Seller shall quote a price for supplying incremental Gas needed to accommodate an increase in Scheduled Energy (subject to Gas availability and the ability to schedule delivery of Gas) or for selling excess Gas resulting from a decrease in Scheduled Energy, as appropriate. Upon receipt of Seller's quote, Buyer shall immediately exercise one of the following options: (i) not changing the existing Schedule: (ii) proceeding with the requested Scheduling Change and the increase or decrease in Gas supplies based on the quoted price (to buy the incremental Gas supply, or to sell the excess Gas supply, as applicable), or (iii) proceeding with the increase (if applicable) in Scheduled Energy and

notifying Seller that Buyer will supply the required incremental Gas supply utilizing the procedures set forth in Section 9.3.1B.

ARTICLE 10

ELECTRIC METERING

10.1 Metering. At no cost to Buyer, Seller shall be responsible for performing, or causing to be performed, the installation, maintenance, testing and calibration of the Electric Metering Equipment owned by Seller and/or its Affiliates at the Delivery Point(s).

10.2 Industry Standards. All Electric Metering Equipment owned by Seller and/or its Affiliates at the Delivery Point(s), shall be operated, maintained and tested by and/or on behalf of Seller in accordance with Prudent Industry Practices.

10.3 Records. The Parties shall maintain accurate and detailed records relating to the metering of energy at the Delivery Point(s) for one year or for such longer period as may be required by an applicable Government Agency or Law. All records shall be available for inspection by either Party upon reasonable notice.

10.4 Meter Errors. If the Electric Metering Equipment at the Delivery Point(s) fails to register, or if the measurement made by a metering device is found upon testing to vary by more than 0.5% from the measurement made by the standard meter used in a test, an adjustment shall be made correcting all measurements of energy made by the Electric Metering Equipment during: (i) the actual period when inaccurate measurements were made, if that period can be determined to the mutual satisfaction of the Parties; or (ii) if such actual period cannot be determined to the mutual satisfaction of the Parties, the latter half of the period from the date of the last test of the Electric Metering Equipment to the date such failure is discovered or such test is made (each being an "Adjustment Period"). If the Parties are unable to agree on the amount

of the adjustment to be applied to the Adjustment Period, the amount of the adjustment shall be determined: (i) by correcting the error if the percentage of error is ascertainable by calibration, tests or mathematical calculation; or (ii) if not so ascertainable, by estimating on the basis of deliveries under similar conditions during the period since the last test.

ARTICLE 11

BILLING AND PAYMENT

11.1 Timing and Method of Payment. Seller will submit to Buyer, as promptly as practicable after the first of each Billing Month, an invoice (by mail, facsimile or electronic means) for the amounts due under the terms of this Agreement for the preceding Month. Amounts due pursuant to such invoice shall be due and payable on [redacted] ("Payment Due Date"). If the Payment Due Date falls on a Day that is not a Business Day, the Payment Due Date shall be the next Business Day. Payment shall be made, on or before the due date, to Seller in accordance with the invoice in immediately available funds through wire transfer, or other mutually agreeable method.

11.2 Late Payment. Amounts that are owed Seller shall, if not remitted within the time period specified under Section 11.1, be subject to a late payment charge equal to the interest calculated pursuant to Section 21.7, accrued and payable on a Monthly basis with respect to the unpaid amount. Such late payment charge shall accrue from the due date of such amount until the date on which it is paid.

11.3 Disputed Billings. In the event that either Party has a bona fide dispute with any invoice submitted hereunder, such Party shall inform the other Party in writing of its grounds for disputing such invoice. Notwithstanding such dispute, [redacted]

[redacted]

11.4 Adjustments. If any overcharge or undercharge in any form whatsoever shall at any time be found and the invoice therefor has been paid, the Party that has been paid the overcharge shall refund the amount of the overcharge to the other Party, and the Party that has been undercharged shall pay the amount of the undercharge to the other Party, within 30 Days after final determination thereof; provided, however, that no retroactive adjustment shall be made for any overcharge or undercharge unless written notice of the same is provided to the other Party within a period of 12 Months from the date of the invoice in which such overcharge or undercharge was first included. Any such adjustments shall be made with interest calculated in accordance with Section 21.7 from the date that the undercharge or overcharge actually occurred.

11.5 Audit Rights. Subject to Section 10.3, the Parties shall keep complete and accurate records of their operations under this Agreement and shall maintain such data for a period of at least [redacted] years after the completion of the relevant Billing Month hereunder; provided, however, records relating to a disputed matter shall be retained until the dispute is

resolved. Such records shall be available for inspection and audit by the other Party upon reasonable request during any regular Business Day.

ARTICLE 12

REGULATORY

12.1 Initial Approval of the Florida Public Service Commission.

12.1.1 No later than [redacted] Days after the Effective Date, Buyer shall make a filing with the Florida Public Service Commission ("FPSC") seeking approval for Buyer to recover from its customers all payments required to be made to Seller under the Contemporaneous Agreements without material modification or condition with respect to such agreements ("FPSC Approval"). After making such filing, Buyer shall utilize diligent efforts to obtain the FPSC Approval for the Contemporaneous Agreements by no later than [redacted] Days after the Effective Date ("Approval Deadline"). Seller agrees to reasonably assist and support Buyer's efforts to obtain the FPSC Approval. Buyer shall promptly notify Seller when it receives the FPSC Approval.

12.1.2 If FPSC Approval for the Contemporaneous Agreements is not received by the Approval Deadline, but the date of the Transmission Notice under Section 7.4.2 has not yet occurred and the FPSC has not yet issued an order denying the Buyer's request for FPSC Approval ("FPSC Denial"), the Approval Deadline shall automatically be extended until the date of the Transmission Notice. During this extended period, Buyer shall keep Seller closely informed as to the progress of its efforts to obtain FPSC Approval and Buyer shall continue diligent efforts to obtain FPSC Approval.

12.1.3 If FPSC Approval is not received by the Approval Deadline (as extended under Section 12.1.2) or if an FPSC Denial is issued prior to the Approval Deadline,

Buyer shall provide notice to Seller within 30 Days after the Approval Deadline or the FPSC Denial (whichever occurs first) that it desires to either: (i) terminate all (but not less than all) of the Contemporaneous Agreements, in which case all of the Contemporaneous Agreements shall immediately terminate; or (ii) continue all (but not less than all) of the Contemporaneous Agreements regardless of FPSC Approval. If Buyer elects option (ii) under the foregoing sentence, all of the Contemporaneous Agreements shall continue in full force and effect for the Term notwithstanding any subsequent action or inaction of the FPSC (including the subsequent issuance of a FPSC Denial or failure to issue an FPSC Approval).

12.1.4 The Parties acknowledge that the other Contemporaneous Agreements contain provisions that are substantially similar to Sections 12.1.1 through 12.1.3 above and that this Agreement may be subject to termination as provided in such similar provisions.

12.1.5 After the procedures in Sections 12.1.1, 12.1.2, and 12.1.3 (as applicable) have been completed, except as provided under Section 12.3, at no time shall this Agreement be subject to termination or modification due to any action or inaction of any Government Agency or Buyer's inability to recover from its customers amounts to be paid to Seller pursuant this Agreement whether such inability is due to action of any Government Agency or otherwise.

12.2 Changes in Agreement. Except for any changes pursuant to Section 12.3, absent the agreement of all Parties to the proposed change, the standard of review for changes to this contract proposed by a Party, a non-Party or the FERC acting sua sponte shall be the "public interest" standard of review set forth in United Gas Pipeline Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. (1956) (the "Mobile-Sierra" doctrine).

12.3 Federal Energy Regulatory Commission.

12.3.1 The Parties anticipate that this Agreement is not required to be filed and accepted by FERC because it is a market-based contract. Therefore, this Agreement shall not be contingent on FERC acceptance. Having freely negotiated and agreed upon the economic bargain among them as set forth hereunder, Seller and Buyer waive all rights under Sections 205 and 206 of the Federal Power Act to effect a change in the Agreement. Moreover, it is the Parties' mutual intent that FERC be precluded, to the fullest extent permitted by law, from altering this Agreement in any way. Notwithstanding the foregoing, if at any time FERC takes some action that reduces the economic benefit of this Agreement to either Party ("Impacted Party") as contemplated on the Effective Date ("Original Economic Benefit"), Impacted Party shall be deemed to have retained rights under Section 205 to file for changes in the Agreement, but only to the extent required to restore the Original Economic Benefit.

12.3.2 Impacted Party may exercise its Section 205 rights provided under Section 12.3.1 if at any time it reasonably determines in its sole discretion that it may be able to have some or all of the Original Economic Benefit restored. Before exercising such rights, Impacted Party shall negotiate with the other Party in an effort to reach mutual agreement regarding amendments to this Agreement (including amendments regarding those provisions addressing the determination of payments between the Parties and adjustments to capacity payments due to unavailability) that would restore some or all of the Original Economic Benefit. Impacted Party shall file any resulting amendments for acceptance by FERC, and the other Party shall actively support such filing(s). If the Parties are unable to agree upon such amendment(s), Impacted Party shall be entitled to make unilateral filing(s) at FERC to modify the Agreement in order to restore some or all of the Original Economic Benefit. In this latter

event, the other Party shall actively support Impacted Party's right to recover the Original Economic Benefit, including by making filings at FERC (provided that the non-impacted Party shall retain the right to challenge the amount of and/or the methodology for calculating the Original Economic Benefit).

12.3.3 Any amendment(s) or unilateral filing(s) contemplated hereunder shall restore the Original Economic Benefit (or any allowed portion thereof) for the remainder of the Term, including any portion of the Original Economic Benefit associated with prior periods (with interest). Such amendment(s) or filing(s) by the Impacted Party shall not require the other Party to bear more of an economic burden than originally contemplated in this Agreement on the Effective Date. Nothing in this Agreement is intended to or shall restrict the number of times that a Party may exercise the above-described Section 205 rights during the Term or within any specific time frame.

ARTICLE 13

CHANGE IN LAW

13.1 Increased Generation Costs. The Parties acknowledge that during the Term of this Agreement, Changes in Law that increase Seller's cost of providing capacity and/or energy hereunder could occur. Any Increased Generation Costs will be paid by Buyer through an additional payment or surcharge each Month ("Change in Law Surcharge"). Once Seller has incurred Increased Generation Costs, Buyer shall pay for all Increased Generation Costs through the Change in Law Surcharge, as provided below.

13.2 Determination. If Seller determines that a Change in Law will or has resulted in Increased Generation Costs and that Buyer is responsible for such costs under this Agreement, Seller shall, within 6 Months after identifying such costs, notify Buyer of: (a) the applicable

Change in Law giving rise to the Increased Generation Costs; and (b) the resulting Increased Generation Costs. Provided, however, the failure by Seller to provide such notice within such time period shall not under any circumstance result in an Event of Default, nor shall such failure prejudice or affect in any way Seller's right to receive reimbursement from Buyer for any Increased Generation Costs under this Agreement. Provided further, such notice by Seller shall include reasonable documentation of the applicable Change in Law and resulting Increased Generation Costs. Within 60 Days after receipt of such notice, Buyer will: (i) make a good faith determination of whether the Increased Generation Costs result from a Change in Law as specified in this Agreement; (ii) make a good faith determination of whether the Increased Generation Costs are determined in accordance with this Agreement; and (iii) provide Seller written notice of its determination. In the event that Buyer does not provide written notice of its determination within such time period, Buyer shall be deemed to have concurred that the specified Increased Generation Costs result from a Change in Law. If Buyer does not concur, the Parties shall commence discussions in an effort to address and resolve the basis for Buyer's disagreement. If the Parties are unable to resolve their disagreement within 30 Days after commencing such discussions, the Parties shall submit the issue to arbitration under the procedures set forth in Section 18.2. The arbitrators shall determine whether a Change in Law has occurred and, if so, the amount of the resulting Increased Generation Costs.

13.3 Initiation of Surcharge. In the event that Increased Generation Costs result from a Change in Law, Seller shall provide Buyer with written notice of a Change in Law Surcharge or an increase in an existing Change in Law Surcharge to recover Increased Generation Costs. No earlier than 30 Days thereafter, Seller may initiate a Change in Law Surcharge (or, if applicable, an increase in an existing Change in Law Surcharge) consistent

with such notice. Provided, however, Seller shall reduce any Change in Law Surcharge to the extent that any costs included in such surcharge are not incurred. After the end of the Term, Seller shall not be entitled to initiate a Change in Law Surcharge, an increase in an existing Change in Law Surcharge, or any other additional charge intended to recover costs resulting from a Change in Law unless: (i) Seller has provided Buyer with notice of the applicable Change in Law, surcharge or increase prior to the expiration of the Term; and (ii) the costs Seller seeks to recover were incurred during the Service Term as a result of such Change in Law.

13.4 Timing. Any Change in Law Surcharge (or increase in an existing Change in Law Surcharge) hereunder due to Increased Generation Costs shall recognize the timing of the Increased Generation Costs (including the recovery through such payments of amounts associated with the Increased Generation Costs in prior periods, with interest) for which Buyer is responsible under this Agreement.

ARTICLE 14

LIABILITY ALLOCATION; LIMITATIONS ON LIABILITY

14.1 Costs, Taxes and Charges. Except as otherwise provided in this Agreement, in addition to all other amounts due and payable under this Agreement: (i) except for any Taxes included in the Gas Charges, Seller shall be responsible for all costs, Taxes, and charges of any kind prior to the Delivery Point relating to the delivery of energy and the provision of capacity under this Agreement, transmission, and/or related services (by way of clarification of the foregoing, Taxes prior to the Delivery Point include: ad valorem taxes); and (ii) Buyer shall be responsible for all costs, Taxes, and charges of any kind at and after the Delivery Point relating to the delivery of energy and the provision of capacity under this Agreement, transmission,

and/or related services (by way of clarification of the foregoing, Taxes at and after the Delivery Point include: any Taxes incurred in connection with sales of the Delivered Energy). Each Party shall provide the other Party upon written request a certificate of exemption or other reasonably satisfactory evidence of exemption if any exemption from or reduction of any Tax is applicable. Each Party shall exercise Commercially Reasonable Efforts to obtain and to cooperate in obtaining any exemption from or reduction of any Tax. In addition, each Party shall be responsible for paying its own income taxes and net worth taxes on it or its property.

14.2 Indemnification. Unless otherwise agreed in writing by the Parties, Seller and Buyer shall each defend, indemnify and save harmless, on an After-Tax Basis, the other and their respective officers, directors, servants, agents, employees and representatives from and against any and all claims, demands, costs or expenses (including reasonable attorneys' fees) for loss, damage or injury to any person, property or interest arising out of or in any way related to this Agreement to the extent such loss, damage or injury occurs on its own side of the Delivery Point, irrespective of negligence, whether actual or claimed, of the other. Nothing in this Agreement shall create a contractual relationship between one Party and the customers of the other Party, nor shall it create a duty of any kind to such customers.

14.3 Limitation of Liability.

14.3.1 THERE ARE NO WARRANTIES UNDER THIS AGREEMENT EXCEPT TO THE EXTENT SPECIFICALLY SET FORTH HEREIN. THE PARTIES HEREBY SPECIFICALLY DISCLAIM AND EXCLUDE ALL IMPLIED WARRANTIES, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR A PARTICULAR PURPOSE.

14.3.2 SUBJECT TO SECTION 16.2, NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES SUFFERED BY THAT PARTY OR BY ANY CUSTOMER OF THAT PARTY, FOR LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, WHETHER BY VIRTUE OF ANY STATUTE, IN TORT OR CONTRACT, UNDER ANY PROVISION OF INDEMNITY OR OTHERWISE. THE PARTIES INTEND THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING, WITHOUT LIMITATION, THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, THAT OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT, AND THAT THE LIQUIDATED DAMAGES CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

14.3.3 In the event that any provision of this Section 14.3 is held to be invalid or unenforceable, this Section shall be void and of no effect solely to the extent of such invalidity or unenforceability, and no claim arising out of such invalidity or lack of enforceability shall be made by one Party against the other or its officers, agents, or employees. Notwithstanding the foregoing, this Section 14.3 shall not limit or negate the right of either Party to be fully indemnified as provided in Section 14.2 or limit the remedies set forth in this Agreement for an Event of Default.

14.3.4 Without prejudice to the obligations and liabilities of an entity pursuant to an Eligible Guaranty, neither any Affiliate of a Party nor any stockholder, officer, director or employee of a Party or of any Affiliate of a Party (collectively, the "Nonrecourse Persons") shall have any liability to the other Party for the payment of any sums now or hereafter owing by such Party or for the performance of any of the obligations of such Party contained herein, and each of the Parties hereto agrees that all of the obligations of the other Party under this Agreement shall be obligations solely of such other Party and recourse in enforcing said obligations shall only be had against the assets of such other Party; provided that the foregoing provision shall not constitute a waiver, release or discharge of any of the terms, covenants or conditions of this Agreement or any Eligible Guaranty and the same shall continue until fully paid, discharged, observed or performed.

ARTICLE 15

FORCE MAJEURE EVENT

15.1 Force Majeure Event Defined.

15.1.1 As used herein, an Event of Force Majeure with respect to a Party means an occurrence, non-occurrence, or set of circumstances that is beyond the reasonable control of such Party and is not caused by the fault or negligence of such Party, including but not limited to acts of God, strike, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, sabotage, or terrorism, which, by the exercise of due diligence, it is unable to overcome.

15.1.2 Notwithstanding anything contained in Section 15.1.1, the term Force Majeure shall not include any of the following:

(i) the inability of Buyer, for any reason, to obtain or maintain adequate transmission service from and after the Delivery Point;

(ii) a change or circumstance in market conditions that affect the cost, price, or demand for capacity and/or energy from the Facility;

(iii) a change or circumstance in market conditions or otherwise that affects the economic value of this Agreement to any Party;

(iv) an increase in costs or expenses to any Party as a result (either directly or indirectly) of such Party's performance under this Agreement;

(v) a change in Law, action or inaction by any Governmental Agency or the inability to comply with any Law; or

(vi) any event or circumstance that qualifies as a Delivery Excuse.

15.2 Applicability of Force Majeure Event. Neither Party shall be in breach or liable for any delay or failure in its performance under this Agreement (except for such Party's performance of its payment obligations hereunder, which shall not be excused by any Force Majeure Event) to the extent such performance is prevented or delayed due to a Force Majeure Event, provided that:

15.2.1 The non-performing Party shall give the other Party written notice within 3 Business Days of the commencement of the Force Majeure Event, with available details to be supplied within 15 Days after the commencement of the Force Majeure Event further describing the particulars of the occurrence of the Force Majeure Event;

15.2.2 The delay in performance shall be of no greater scope and of no longer duration than is directly caused by the Force Majeure Event;

15.2.3 The Party whose performance is delayed or prevented shall proceed with Commercially Reasonable Efforts to overcome the events or circumstances preventing or delaying performance and shall, as requested (but not more often than weekly), provide written progress reports to the other Party during the period that performance is delayed or prevented describing actions taken and to be taken to remedy the consequences of the Force Majeure Event, the schedule for such actions and the expected date by which performance shall no longer be affected by the Force Majeure Event; and

15.2.4 When the performance of the Party claiming the Force Majeure Event is no longer being delayed or prevented, that Party shall give the other Party written notice to that effect.

15.3 Effect of Force Majeure Event.

15.3.1 Except for the obligation of either Party to make any required payments under this Agreement, the Parties shall be excused from performing their respective obligations under this Agreement and shall not be liable in damages or otherwise if and to the extent that they are unable to so perform or are prevented from performing by a Force Majeure Event.

15.3.2 To the extent Seller is unable to provide Contract Capacity or Scheduled Energy from the Facility due to a Force Majeure Event, Seller shall be excused from performance hereunder and shall not be required to provide capacity and/or energy from other resources (including Alternate Resources) in order to satisfy Buyer's Schedule; provided, however, to the extent Seller does provide capacity and/or energy at its sole option to satisfy Buyer's Schedule consistent with this Agreement, [redacted]

[redacted]

[redacted]

ARTICLE 16

EVENT OF DEFAULT

16.1 **Event of Default.** The occurrence of any one or more of the following events with respect to a Party shall constitute an "Event of Default" attributable to such Party under this Agreement:

16.1.1 The failure by a Party to make payment to the other Party for amounts due under this Agreement after said amounts have become due and payable and such failure is not cured within 15 Days after receiving written notice of such failure from the Party to which such payments are due;

16.1.2 A Party or any Person guaranteeing such Party's obligations hereunder (a "Guarantor") shall: (i) admit in writing its inability to pay its debts as such debts become due; (ii) make a general assignment or an arrangement or composition with or for the benefit of its creditors; (iii) take any action for the purpose of effectuating any of the foregoing; or (iv) fail to comply with the terms and conditions of its Guaranty;

16.1.3 A proceeding or case shall be commenced by a Party or against a Party with the consent of such Party or by its Guarantor or against its Guarantor with the consent of such Guarantor, in any court of competent jurisdiction, seeking: (i) its liquidation, reorganization of its debts, dissolution or winding-up, or the composition or readjustment of its

debts; (ii) the appointment of a receiver, custodian, liquidator or the like of the Party or its Guarantor or of all or any substantial part of its assets or the assets of its Guarantor; or (iii) similar relief in respect of such Party or its Guarantor under any law relating to bankruptcy, insolvency, reorganization of its debts, winding-up, composition or adjustment of debt;

16.1.4 A proceeding or case shall be commenced without the consent of a Party against such Party or without the consent of its Guarantor against such Guarantor, in any court of competent jurisdiction, seeking: (i) its liquidation, reorganization of its debts, dissolution or winding-up, or the composition or readjustment of its debts; (ii) the appointment of a receiver, custodian, liquidator or the like of the Party or its Guarantor or of all or any substantial part of its assets or the assets of its Guarantor; or (iii) similar relief in respect of such Party or its Guarantor under any law relating to bankruptcy, insolvency, reorganization of its debts, winding-up, composition or adjustment of debt, unless such proceeding or case is dismissed within 60 days of the filing thereof;

16.1.5 The failure of any Party to comply with the requirements of Article 20 regarding creditworthiness and/or security;

16.1.6 The failure of a Party to comply with the requirements of Article 19 regarding assignment;

16.1.7 Any representation or warranty made by a Party under Article 17 proves to have been false or misleading in any material respect when made and such representation or warranty is not made true within 30 Days after such Party has obtained actual knowledge thereof or has been provided notice thereof by the other Party; provided, however, that the cure must also remove any adverse effect on the Non-Defaulting Party;

16.1.8 A Party or its Guarantor shall fail to pay when due (subject to any applicable cure or grace period), whether by acceleration or otherwise, any principal or interest on indebtedness aggregating in excess of [redacted] in principal amount; or any indebtedness aggregating in excess of [redacted] shall be declared due and payable or be required to be prepaid (other than by a regularly scheduled payment) prior to the stated maturity of such indebtedness; or

[redacted]

16.1.10 The material failure by a Party to comply with any material provision of this Agreement if such failure is not the result of a Force Majeure Event or is not otherwise excused in accordance with this Agreement, and such failure continues uncured for 30 Days after written notice thereof from the other Party; provided, however, if such failure is not capable of being cured within such period of 30 Days with the exercise of reasonable diligence, then such cure period shall be extended for an additional reasonable period of time (not to exceed 90 Days), so long as the Party is exercising reasonable diligence to cure such failure. Provided, however, this Section 16.1.10 shall not apply to: (i) any event described in Sections 16.1.1 through 16.1.9; (ii) any event described in Sections 5.10, 5.11 and 8.3 for which a remedy is expressly provided in those Sections; or (iii) Seller's failure to provide capacity and/or energy pursuant to any provision of this Agreement.

The Party in default or the Party to whom an Event of Default is attributable as provided in this Section 16.1 shall be referred to as the "Defaulting Party" and the other Party shall be referred to as the "Non-Defaulting Party".

16.2 Exclusive Remedies.

16.2.1 Upon and after the occurrence of an Event of Default, the Non-Defaulting Party's sole and exclusive remedy (whether arising in contract, tort or otherwise) shall be to suspend its performance under this Agreement and declare an Early Termination Date with the relevant remedies as provided below.

16.2.2 If an Event of Default has occurred, the Non-Defaulting Party shall have the right, in its sole discretion, by no more than 20 Days notice to the Defaulting Party, to designate a Day no earlier than the Day such notice is effective as the date on which the Agreement shall terminate ("Early Termination Date"). Subject to Sections 21.3 and 21.15, this Agreement shall terminate on the Early Termination Date and neither Party shall have any further liability or obligation to the other hereunder, except (i) the Defaulting Party shall pay to the Non-Defaulting Party on demand [redacted] in liquidated damages and (ii) as provided in Sections 16.2.3 or 16.2.4 below. The exercise by a Party of its rights under this Section 16.2 shall be the sole and exclusive remedy of such Party for an Event of Default by or attributable to the other Party. The Parties acknowledge and agree that in the event of termination of this Agreement due to an Event of Default, all or a portion of the amount of damages arising therefrom are not susceptible to an accurate determination. The Parties further acknowledge and agree that the liquidated damages set forth above are not intended as a penalty and represent a fair and reasonable approximation of all or a portion of the damages a Non-Defaulting Party may incur in each particular case.

16.2.3 With respect to an Event of Default by or attributable to Buyer, within 15 Days after Seller's notice under Section 16.2.2, the Parties shall each select an independent party to determine the Seller's Damages. Within 30 Days after such notice, the two independent

parties shall select a third independent party to determine the Seller's Damages. Within 60 Days after such notice, the three (3) independent parties shall provide the Parties with their respective estimates of the Seller's Damages. The actual Seller's Damages shall equal the arithmetic average of the three estimates. If one Party disputes the actual Seller's Damages, within 5 Business Days of notice of the Seller's Damages determined by the independent parties, such Party may submit the dispute for resolution pursuant to the arithmetic procedures of Article 18 and the arithmetic order or finding regarding the Seller's Damages shall be conclusive, provided, however, in no event shall the Seller's Damages be less than [redacted] at any time whether or not arbitrated. Subject to such qualification, the Seller's Damages will be paid by Buyer to Seller within 3 Business Days after being determined by the independent parties unless disputed and arbitrated pursuant to the terms of this Agreement in which event it shall be paid within 3 Business Days of the relevant arbitration finding or order. As used herein, "Seller's Damages" [redacted]

16.2.4 With respect to an Event of Default by or attributable to Seller, within 15 Days after Buyer's notice under Section 16.2.2, the Parties shall each select an independent party to determine the Buyer's Damages. Within 30 Days after such notice, the two

independent parties shall select a third independent party to determine the Buyer's Damages. Within 60 Days after such notice, the 3 independent parties shall provide the Parties with their respective estimates of the Buyer's Damages. The actual Buyer's Damages shall equal the arithmetic average of the three estimates. If one Party disputes the actual Buyer's Damages, within 5 Business Days of notice of the Buyer's Damages determined by the independent parties, such Party may submit the dispute for resolution pursuant to the arithmetic procedures of Article 18 and the arithmetic order or finding regarding the Buyer's Damages shall be conclusive, provided, however, in no event shall the Buyer's Damages be less [redacted] at any time whether or not arbitrated. Subject to such qualification, the Buyer's Damages will be paid by Seller to Buyer within 3 Business Days after being determined by the independent parties unless disputed and arbitrated pursuant to the terms of this Agreement in which event it shall be paid within 3 Business Days of the relevant arbitration finding or order. As used herein, "Buyer's Damages" means [redacted]

ARTICLE 17

REPRESENTATIONS AND WARRANTIES

17.1 Execution. Each Party represents and warrants to the other Party as of the Effective Date that: (i) it has all the necessary corporate and legal power and authority and has been duly authorized by all necessary corporate action to enable it to lawfully execute, deliver and perform under this Agreement; and (ii) it is a valid legal entity duly organized and validly existing in good standing under the laws of the state of its formation and is, to the extent required, qualified to do business in the state where it is organized;

17.2 Permits. Each Party represents and warrants to the other Party that as of the Effective Date it has all permits, licenses or approvals necessary to lawfully perform its obligations contained herein in the manner prescribed by this Agreement.

17.3 Binding Obligations. Each Party represents and warrants to the other Party that as of the Effective Date this Agreement is the valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or other similar laws affecting enforcement generally, and by equitable principles regardless of whether such principals are considered in a proceeding at law or in equity.

17.4 Execution and Consummation. Each Party represents and warrants to the other Party that as of the Effective Date the execution and delivery of this Agreement, the consummation of the transactions contemplated hereby and the fulfillment of and compliance with the provisions of this Agreement do not and will not conflict with any of the terms, conditions or provisions of its organizational documents or any law applicable to it or result in a breach or default under any evidence of its indebtedness or any other agreement or instrument to

which it is a party or by which it or any of its property is bound which has a reasonable likelihood of materially and adversely affecting the consummation of the transactions contemplated hereby or the performance by the Party of any of its obligations under this Agreement.

17.5 Actions and Proceedings. Each Party represents and warrants to the other that as of the Effective Date there is no pending or, to the knowledge of such Party, threatened action or proceeding affecting such Party before any Government Agency that has a reasonable likelihood of materially adversely affecting or reasonably threatening the ability of such Party to perform its obligations under this Agreement or the validity or enforceability of this Agreement against it and that there are no bankruptcy proceedings pending or being contemplated by it or, to its knowledge, threatened against it.

17.6 Absence of Certain Events. Each Party represents and warrants to the other Party that as of the Effective Date no Event of Default attributable to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement.

ARTICLE 18

DISPUTE RESOLUTION

18.1 Senior Officers.

18.1.1 Each of the Parties will designate in writing to the other Parties a representative who will be authorized to resolve any dispute arising under this Agreement and, unless otherwise expressly provided herein, to exercise the authority of such Party to make decisions by mutual agreement.

18.1.2 If such designated representatives are unable to resolve a dispute under this Agreement, such dispute will be referred by each Party's representative, respectively, to a designated senior officer.

18.1.3 The Parties hereto agree: (i) to attempt to resolve all disputes arising hereunder promptly; and (ii) to provide each other with reasonable access during normal business hours to any and all non-privileged and non-confidential records, information and data pertaining to any such dispute. Non-privileged and non-confidential information shall be made available to a Party pursuant to a confidentiality agreement consistent with the confidentiality provisions of this Agreement.

18.2 Arbitration.

18.2.1 All disputes arising under, out of, or in relation to any provision of this Agreement that are not resolved pursuant to Section 18.1 within 30 Days after either Party's receipt of notice referring the dispute to the senior officers of the Parties (and in any event within the time which legal or equitable proceedings based on such claim, dispute, or controversy would not be barred by the applicable statute of limitations) will be submitted upon written request of any Party to binding arbitration. Each Party will have the right to designate an arbitrator of its choice, who need not be from the American Arbitration Association ("AAA") panel of arbitrators but who (a) will be an expert in the independent power electric generation field and (b) will not be and will not have been previously an employee or agent of or consultant or counsel to either Party or any of its Affiliates and will not have a direct or indirect interest in either Party or any of its Affiliates or the subject matter of the arbitration. Such designation will be made by notice to the other Party and to the AAA within 10 Days or, in the case of payment disputes, 5 Days after the date of the giving of notice of the demand for arbitration. The

arbitrators designated by the Parties will designate a third arbitrator, who will have a background in legal and judicial matters (and who will act as chairman), within 10 Days or, in the case of payment disputes, 5 Days after the date of the designation of the last of the arbitrators to be designated by the Parties, and the arbitration will be decided by the three arbitrators. If the two arbitrators cannot or do not select a third independent arbitrator within such period, either Party may apply to the AAA for the purpose of appointing any person listed with the AAA as the third independent arbitrator under the expedited rules of the AAA. Such arbitration will be held in alternating locations of the home offices of the Parties, commencing with Buyer's home office, or in any other mutually agreed upon location. The rules of the AAA will apply to the extent not inconsistent with the rules herein specified. Each Party will bear its own expenses (including attorneys' fees) with respect to the arbitration. The arbitrators will designate the Party to bear the expenses of the arbitrators or the respective amounts of such expense to be borne by each Party.

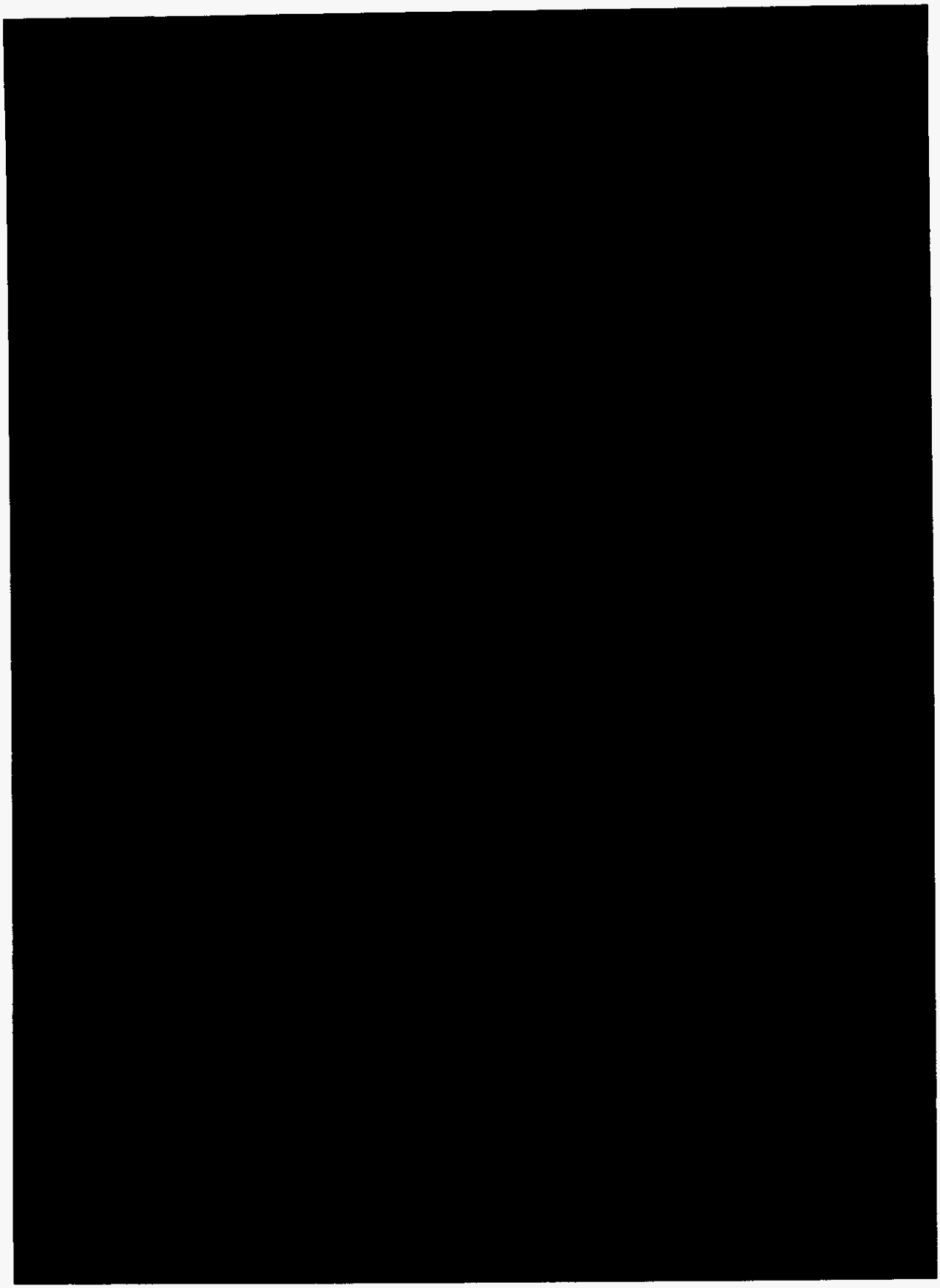
18.2.2 Subject to Section 16.2, the arbitrators conducting an arbitration proceeding under this Section shall have no authority to award to any Party consequential, incidental, punitive, exemplary or indirect damages or any lost profits or business interruption damages, whether by virtue of any Law or otherwise. Provided further, the fact that any arbitration proceeding is conducted hereunder and the decision of the arbitrators shall be deemed Confidential Information under Section 21.2; provided further, notwithstanding any provision in Article 21, Confidential Information, to the extent relevant, may be disclosed by any Party to the arbitrators conducting the arbitration and any court of competent jurisdiction enforcing the arbitrators' award.

18.3 Binding Nature of Proceedings. Each Party understands that this Agreement contains an agreement to arbitrate with respect to specified disputes. After signing this Agreement, each Party understands that it will not be able to bring a lawsuit concerning any dispute that may arise that is covered by this arbitration provision. Instead, each Party agrees to submit any such dispute to arbitration pursuant to Section 18.2. Any award of the arbitrator may be enforced by the Party in whose favor such award is made in any court of competent jurisdiction.

ARTICLE 19

ASSIGNMENT

19.1 Assignment. Either Party may assign outright or collaterally this Agreement and its rights and obligations hereunder subject to the written consent of the other Party (which consent shall not be unreasonably withheld); provided that either Party may assign outright this Agreement and its rights and obligations hereunder without the consent of the other Party to any person with [redacted]



[redacted]

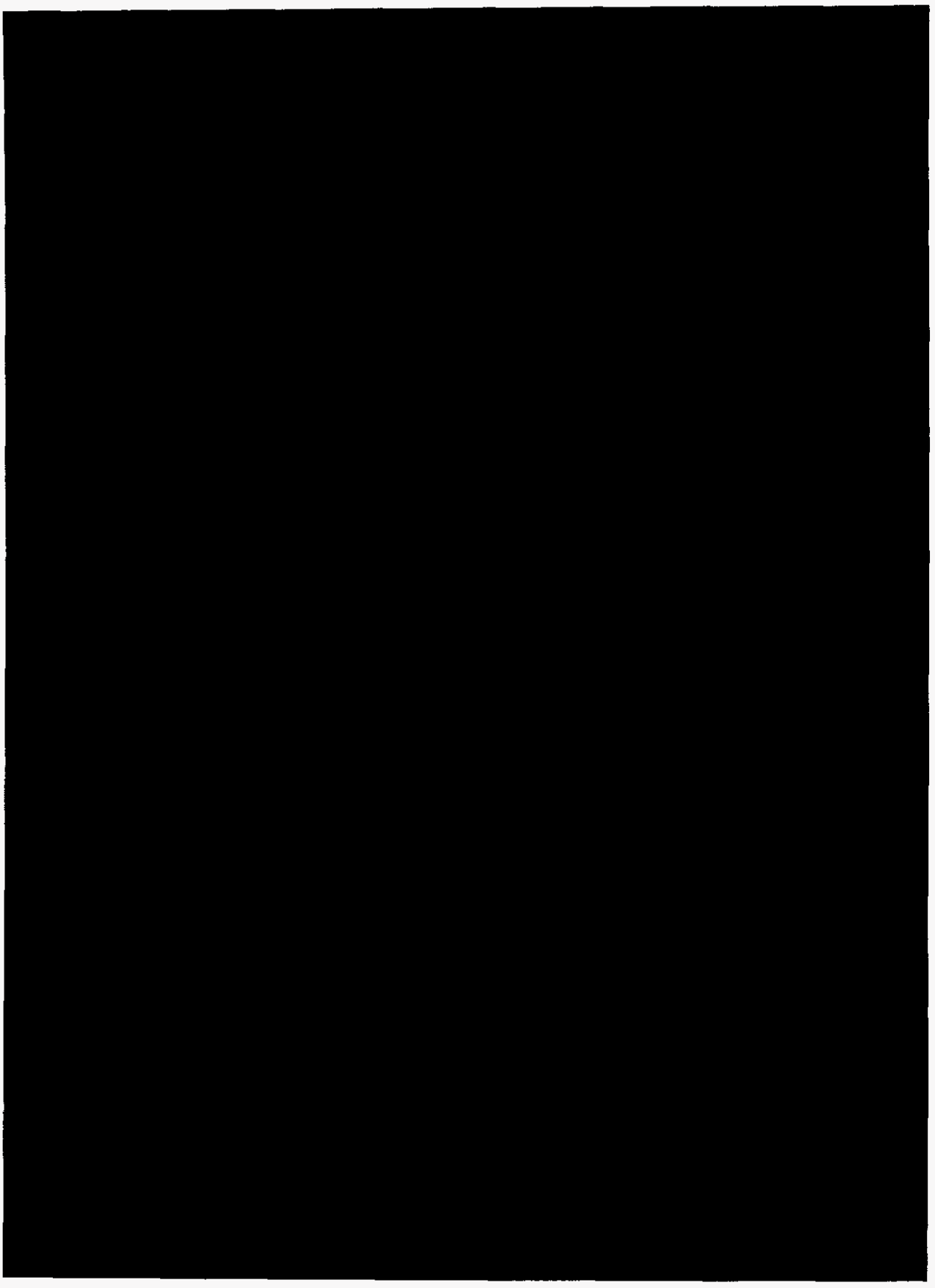
who has the legal power and authority, licenses and technical ability to perform and satisfy the obligations of the assigning Party under this Agreement (an "Eligible Assignee"). The assigning Party will notify the other Party in writing prior to any assignment with respect to which consent is not required hereunder. No assignment by a Party of this Agreement or its rights or obligations hereunder shall relieve the assigning Party of liability for its obligations under this Agreement without the written release of the other Party. Such release shall not be withheld if the Assignment Conditions (defined below) are satisfied.

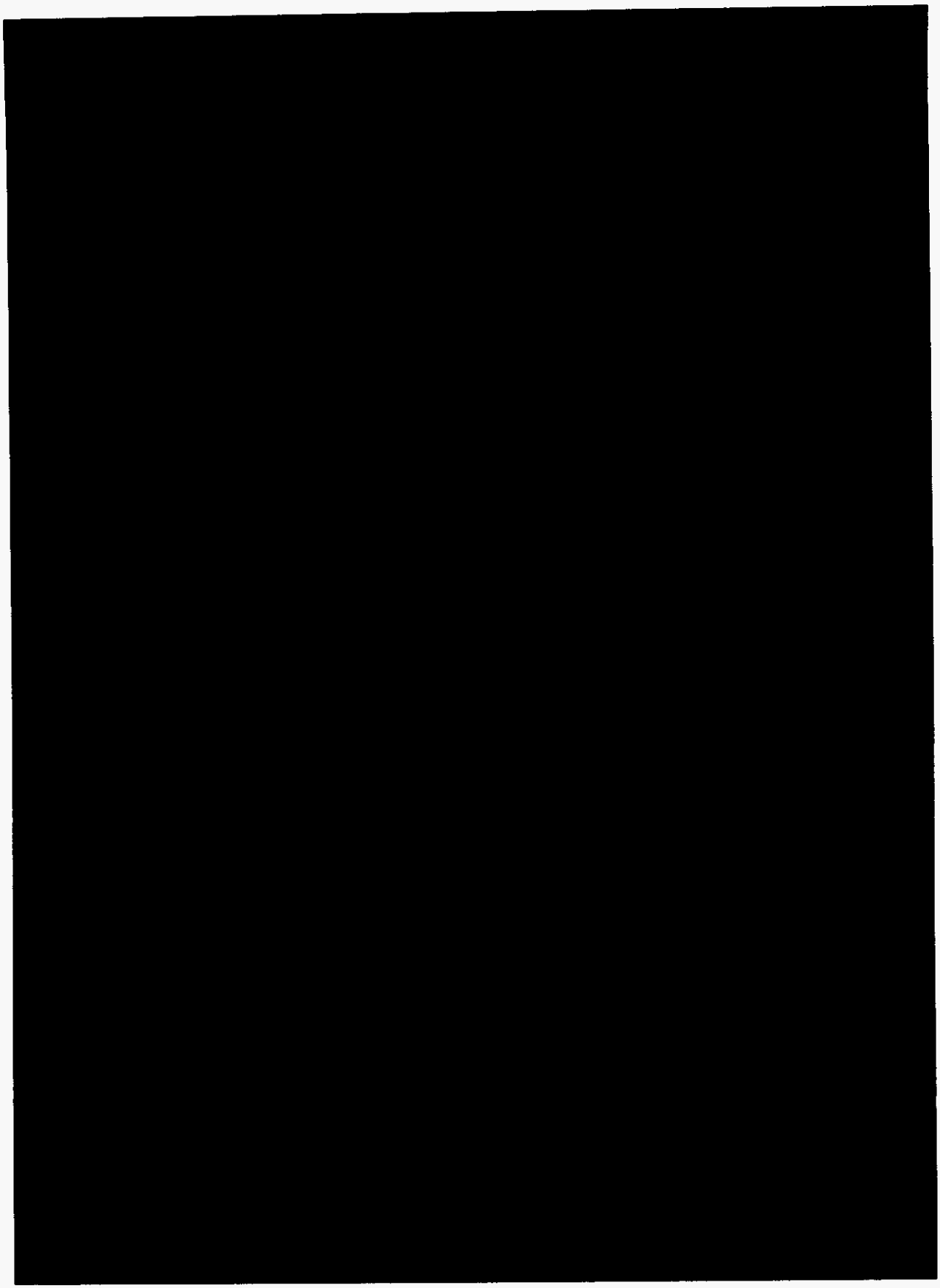
19.2 Assignment Conditions. The non-assigning Party's obligation to recognize or perform for any person claiming rights in this Agreement by outright assignment or through collateral assignment (an "Assignee") shall be subject to such Assignee: (i) establishing that it satisfies the qualifications of an Eligible Assignee; (ii) having cured all existing Events of Default under this Agreement; and (iii) having executed and delivered to the non-assigning Party an assignment and assumption agreement whereby the Assignee assumes and agrees to satisfy all conditions and pay and perform all obligations in favor of the non-assigning Party then existing and/or thereafter arising under this Agreement (the "Assignment Conditions"). Any attempted assignment, directly or indirectly, by way of merger or otherwise, which is not in compliance with the terms hereof shall be void and ineffective.

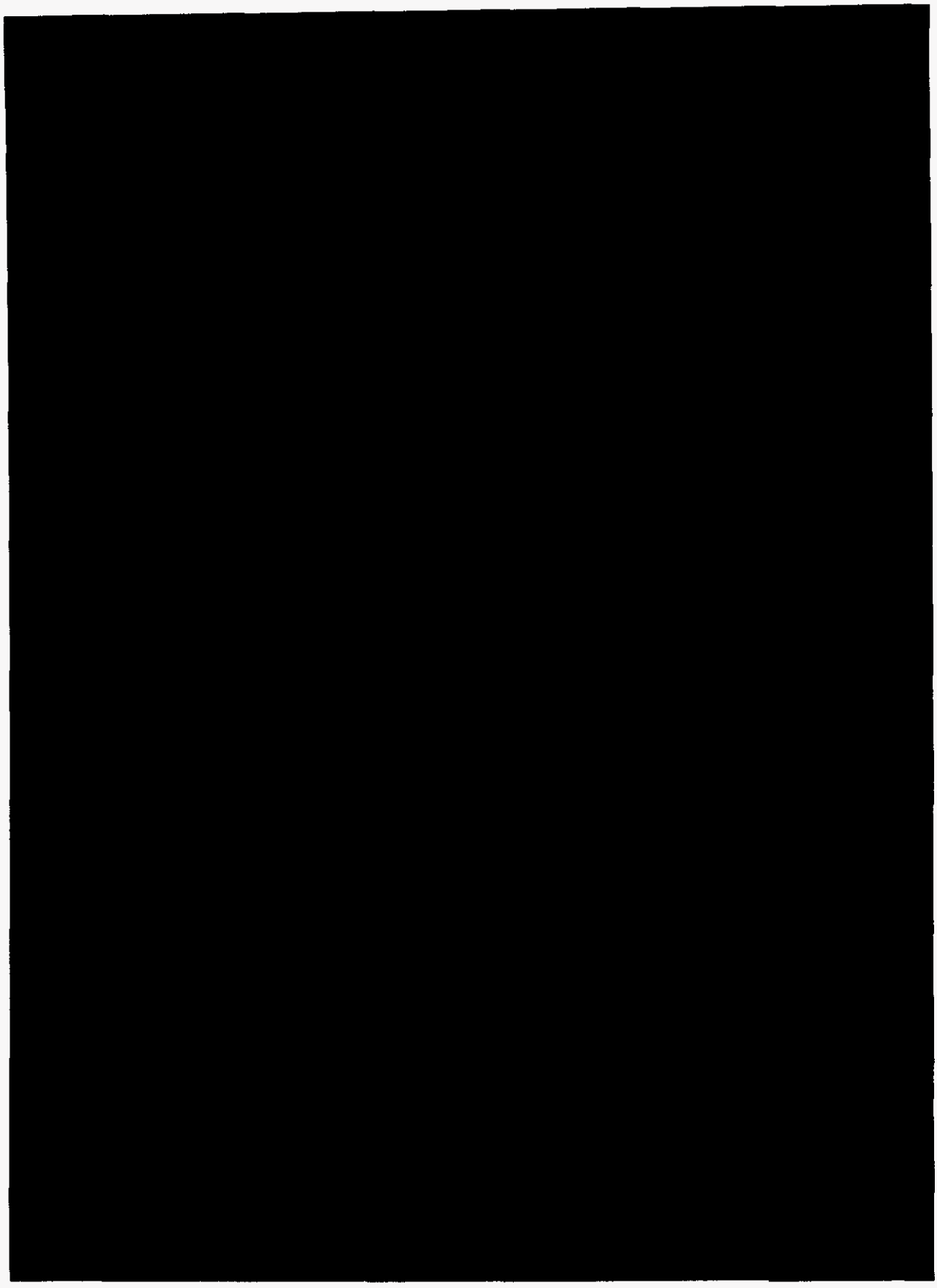
ARTICLE 20

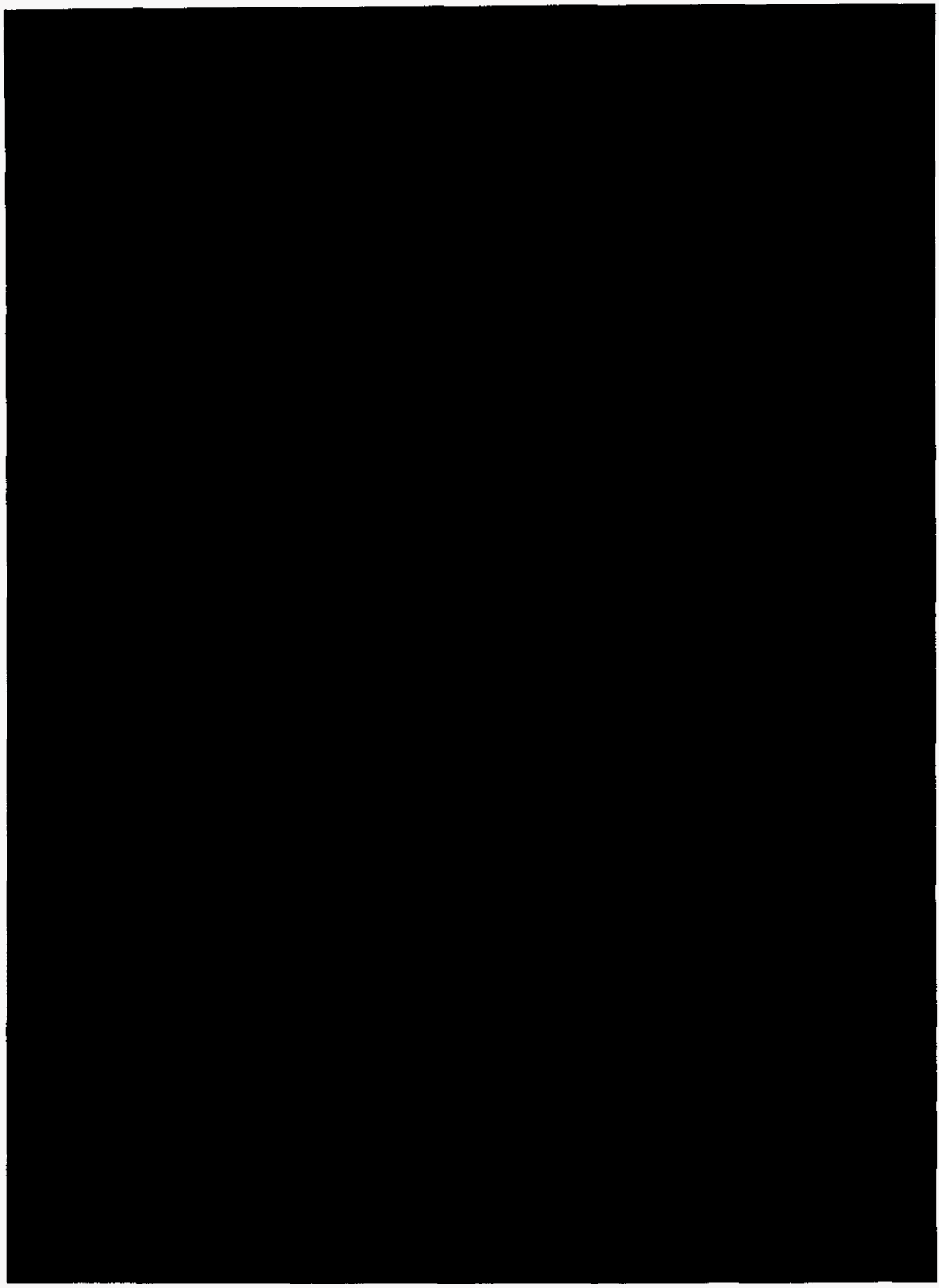
CREDITWORTHINESS AND SECURITY

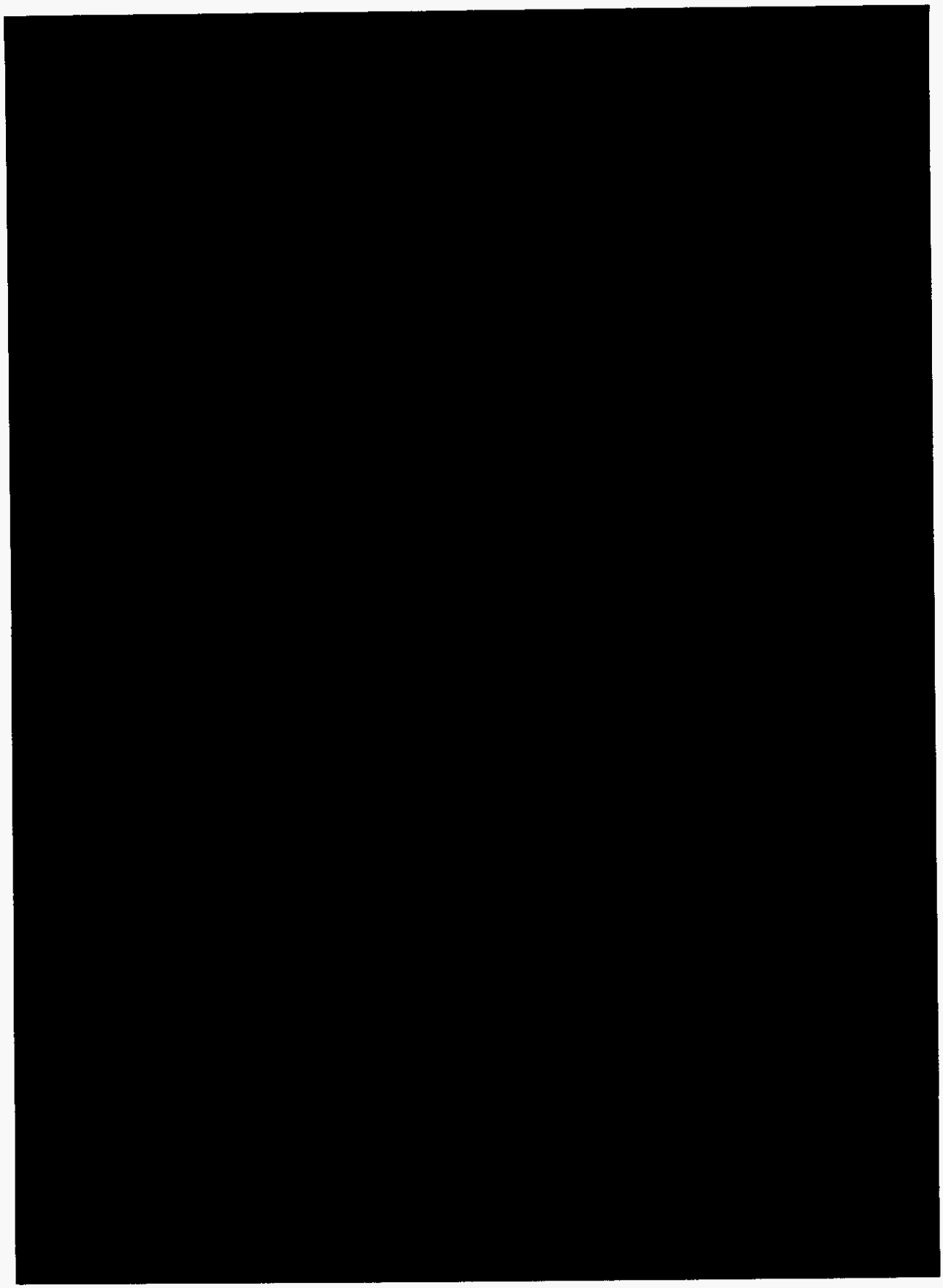
20.1 [redacted]

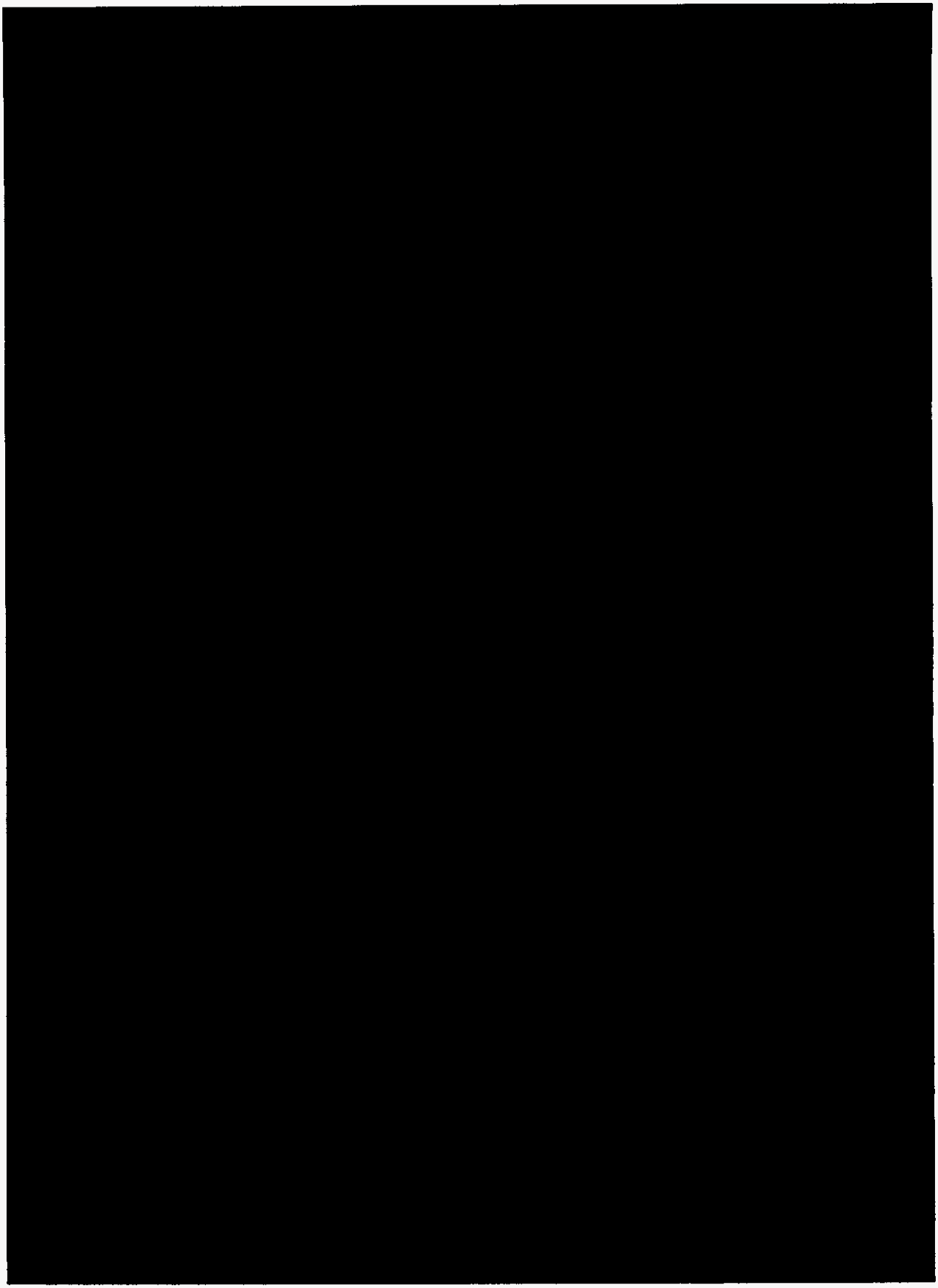


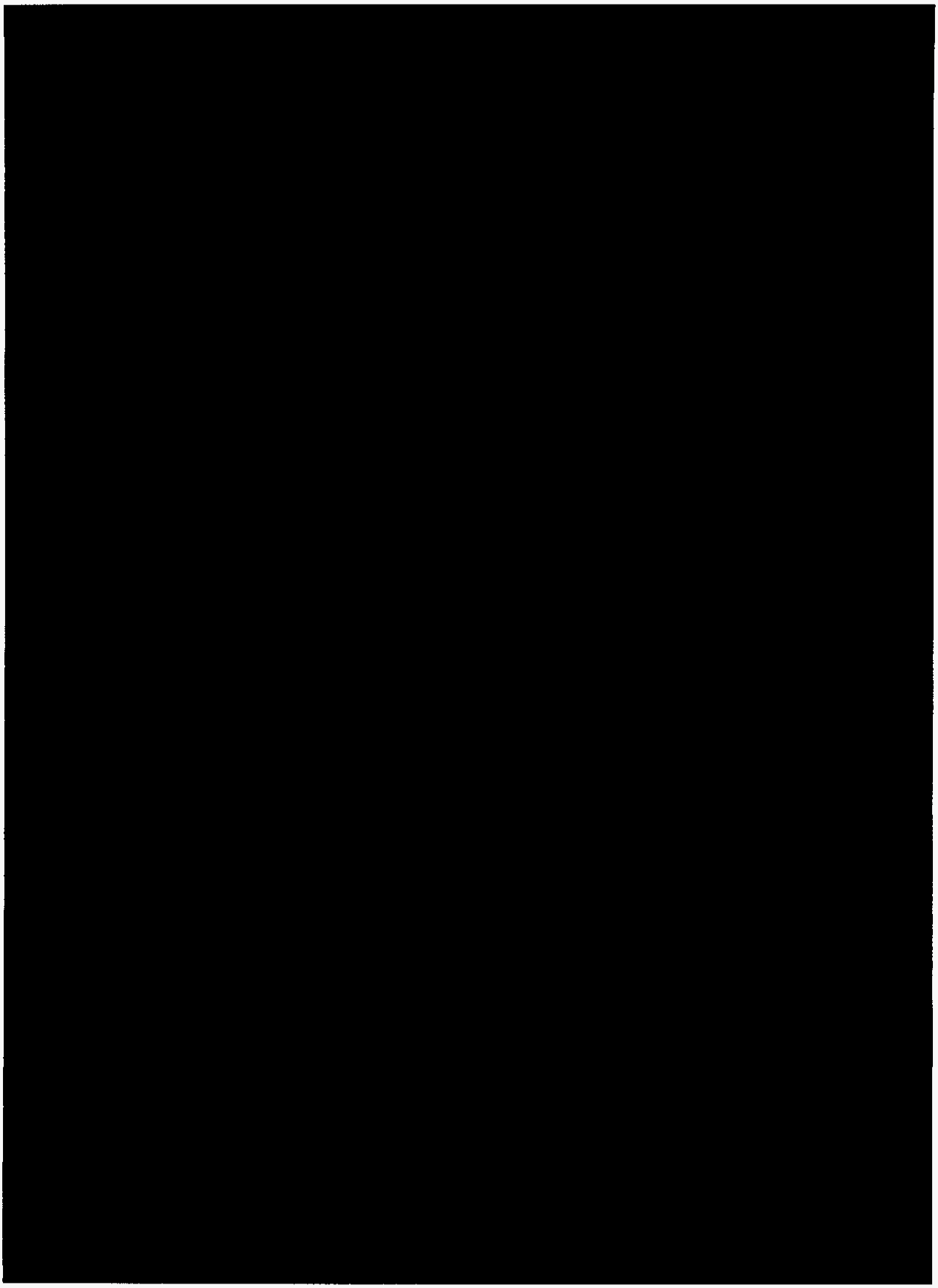












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ARTICLE 21

MISCELLANEOUS

21.1 Governing Law; Waiver of Jury Trial.

THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAW OF THE STATE OF FLORIDA, EXCLUSIVE OF ITS CONFLICTS OF LAW PROVISIONS, AND, TO THE EXTENT APPLICABLE, BY THE FEDERAL LAW OF THE UNITED STATES OF AMERICA. BY CHOOSING TO HAVE THIS AGREEMENT GOVERNED BY AND CONSTRUED UNDER THE LAW OF THE STATE OF FLORIDA, THE PARTIES ARE IN NO WAY SUBMITTING TO OR INCORPORATING INTO THIS AGREEMENT ANY FLORIDA STATUTE,

REGULATION, OR ORDER, OR ANY OF THE SAME INVOLVING THE GENERATION, SALE, PURCHASE OR TRANSMISSION OF ELECTRIC CAPACITY OR ELECTRIC ENERGY IN, OR FOR CONSUMPTION IN, THE STATE OF FLORIDA. EACH PARTY HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT.

21.2 Confidentiality.

21.2.1 Scope of Protection.

(i) For purposes of this Section 21.2: (a) "Seller Confidential Information" means the terms of this Agreement and all drafts of the same, together with any documents, data or drafts labeled or otherwise expressly identified as "Confidential" by Seller when provided to Buyer; (b) "Buyer Confidential Information" means the terms of this Agreement and all drafts of the same, together with any documents, data or drafts labeled or otherwise expressly identified as "Confidential" by Buyer when provided to Seller; and (c) "Confidential Information" means collectively the Seller Confidential Information and the Buyer Confidential Information.

(ii) Seller shall not disclose to third parties any Buyer Confidential Information; provided that nothing contained herein shall prohibit Seller from providing any such Buyer Confidential Information to its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other

Persons in connection with the acquisition of all or a significant portion of the assets or stock of Southern Power or any of its Affiliates or in connection with the analysis, issuance or rating of any debt or equity securities or other financing activities by Southern Power or any of its Affiliates who in the reasonable judgment of Seller should have access to such Buyer Confidential Information and are bound by an obligation to maintain such confidentiality provided that Seller shall be responsible for any use or disclosure of such Buyer Confidential Information by any of its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons inconsistent with this Section 21.2; provided further that nothing contained herein shall prohibit Seller from providing Buyer Confidential Information to the NERC or SEARUC solely to the extent that (i) Seller determines in its reasonable discretion that the provision of such information is required to enhance and/or maintain reliability; (ii) such entity is obligated to maintain such confidentiality; and (iii) Seller has notified Buyer of its intention to release such information no less than 5 Business Days prior to the release subject to the requirements of applicable law and regulation.

(iii) Buyer shall not disclose to third parties any Seller Confidential Information; provided that nothing contained herein shall prohibit Buyer from providing any such Seller Confidential Information to its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons in connection with the acquisition of all or a significant portion of the assets or stock of Buyer or any of its Affiliates or in connection with the analysis, issuance or rating of any debt or equity securities or other financing activities by Buyer or any of its Affiliates who in the

otherwise intends to disclose Seller Confidential Information to FERC or its staff (other than at the request or requirement of FERC or its staff) or pursuant to the request or requirement of any appropriate state regulatory commission or body, Buyer may make disclosure of such Seller Confidential Information; provided, however, that all reasonable steps are taken by Buyer to assure continued confidential treatment by the relevant administrative, regulatory or judicial agencies or other recipient and provided further that as soon as Buyer learns of the disclosure request or requirement or otherwise intends to disclose any Seller Confidential Information pursuant hereto and prior to making disclosure, Buyer shall, to the extent permitted by law, notify Seller of the requirement, request or intention and the terms thereof and any Party may challenge the disclosure requirement, request or intention or seek a protective order or other appropriate remedy. Buyer, at Seller's expense, shall cooperate with Seller to the maximum extent practicable to minimize the disclosure of the Seller Confidential Information consistent with applicable law. Buyer shall cooperate with Seller to obtain proprietary or confidential treatment of such Seller Confidential Information by the Person to whom such Seller Confidential Information will be disclosed (and if practicable, reasonably prior to any such disclosure). If, in the absence of a protective order or other appropriate remedy or the receipt of a waiver by Seller, Buyer is nonetheless, in the written opinion of counsel, legally compelled to disclose Seller Confidential Information or otherwise may become subject to contempt or other censure or penalty, Buyer may, in such instance but not otherwise, without liability hereunder, disclose that portion of the Seller Confidential Information which and to whom such counsel advises Buyer is legally required to be disclosed (but none other), provided that Buyer exercises Commercially Reasonable Efforts to preserve the confidentiality of the Seller Confidential Information, including by cooperating with Seller to obtain an appropriate protective order or

other reliable assurance that the Seller Confidential Information shall be accorded confidential treatment. Seller shall be liable for all reasonable legal costs incurred by Buyer in cooperating with Seller to obtain such an appropriate protective order or confidential treatment.

(ii) Notwithstanding anything in this Section to the contrary, if Seller is required by applicable law or regulation, or in the course of administrative or judicial proceedings or investigations, to disclose to third parties, Buyer Confidential Information or otherwise intends to disclose Buyer Confidential Information to FERC or its staff (other than at the request or requirement of FERC or its staff) or pursuant to the request or requirement of any appropriate state regulatory commission or body, Seller may make disclosure of such Buyer Confidential Information; provided, however, that all reasonable steps are taken by Seller to assure continued confidential treatment by the relevant administrative, regulatory or judicial agencies or other recipient and provided further that as soon as Seller learns of the disclosure request or requirement or otherwise intends to disclose any Buyer Confidential Information pursuant hereto and prior to making disclosure, Seller shall, to the extent permitted by law, notify Buyer of the requirement, request or intention and the terms thereof and any Party may challenge the disclosure requirement, request or intention or seek a protective order or other appropriate remedy. Seller, at Buyer's expense, shall cooperate with Buyer to the maximum extent practicable to minimize the disclosure of the Buyer Confidential Information consistent with applicable law. Seller shall cooperate with Buyer to obtain proprietary or confidential treatment of such Buyer Confidential Information by the Person to whom such Buyer Confidential Information will be disclosed (and if practicable, reasonably prior to any such disclosure). If, in the absence of a protective order or other appropriate protective remedy or the receipt of a waiver by Buyer, Seller is nonetheless, in the written opinion of counsel, legally

compelled to disclose Buyer Confidential Information or otherwise may become subject to contempt or other censure or penalty, Seller may, in such instance but not otherwise, without liability hereunder, disclose that portion of the Buyer Confidential Information which and to whom such counsel advises Seller is legally required to be disclosed (but none other), provided that Seller exercises Commercially Reasonable Efforts to preserve the confidentiality of the Buyer Confidential Information, including, without limitation, by cooperating with Buyer to obtain an appropriate protective order or other reliable assurance that the Buyer Confidential Information shall be accorded confidential treatment. Buyer shall be liable for all reasonable legal costs incurred by Seller in cooperating with such Buyer to obtain an appropriate protective order or confidential treatment.

(iii) Nothing in this Section 21.2 shall prohibit or otherwise limit the use or disclosure of Confidential Information if such Confidential Information: (i) was previously known to the disclosing or using Party unrelated to this Agreement without an obligation of confidentiality; (ii) was developed by or for the disclosing or using Party unrelated to this Agreement using nonconfidential information; (iii) was acquired by the disclosing or using Party from a third party which is not, to the disclosing or using Party's knowledge, under an obligation of confidence with respect to such information; (iv) is or becomes publicly available other than through a manner inconsistent with this Section 21.2; or (v) is provided or made available for inspection by Seller or Buyer under public records or public disclosure laws but only to the extent required to be so provided or made available.

(iv) The provisions of this subsection shall supercede any contrary provisions of this Section 21.2 regarding the disclosure of information to FERC or its staff pursuant to the request or requirement of FERC or its staff. In providing Buyer Confidential

Information to FERC or its staff pursuant to the request or requirement of FERC or its staff, Seller shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. To the extent permitted by law, Seller shall promptly notify Buyer when it is required or requested by FERC or its staff to disclose Buyer Confidential Information. Seller shall not be prohibited to make or liable for the disclosure to FERC or its staff of any Buyer Confidential Information pursuant to the request or requirement of FERC or its staff consistent with this subsection. In providing Seller Confidential Information to FERC or its staff pursuant to the request or requirement of FERC or its staff, Buyer shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. To the extent permitted by law, Buyer shall promptly notify Seller when it is required or requested by FERC or its staff to disclose Seller Confidential Information. Buyer shall not be prohibited to make or liable for the disclosure to FERC or its staff of any Seller Confidential Information pursuant to the request or requirement of FERC or its staff consistent with this subsection. Notwithstanding the foregoing, the Parties acknowledge that any request of FERC for confidential treatment of information may be denied by FERC in whole or in part.

(v) The Parties agree to seek confidential treatment of the Confidential Information from the FPSC to the maximum extent possible pursuant to Chapter 366.093, Florida Statutes, and Rule 25-22.006 of the Florida Administrative Code; however, notwithstanding the foregoing, the Parties acknowledge that a request for confidential treatment of Confidential Information may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the FPSC to such information. In the event any

Confidential Information will need to be disclosed in connection with the application for the FPSC Approval, Buyer shall consult and cooperate with Seller prior to such disclosure, including, without limitation, in determining the extent to which confidential treatment will be sought for such terms, conditions and provisions.

(vi) Seller may file this Agreement with the Securities and Exchange Commission ("Commission") as may be necessary under the Public Utility Holding Company Act and the rules and regulations thereunder in connection with Seller's application to the Commission for such orders and approvals as may be required for financing and/or the issuance and sale of interests in or debt issued or to be issued by Seller and/or its Affiliates. Seller shall request confidential treatment of the Buyer Confidential Information in this Agreement in connection with such filing; however, the Parties acknowledge that such request may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the Commission to such information. In addition, Seller may disclose such Buyer Confidential Information as required by the Commission pursuant to the Securities and Exchange Act of 1934, as amended, and any rule or regulation promulgated thereunder.

(vii) Except for filings with the Commission or other regulatory authorities, any public statement and/or press release by a Party hereto concerning this Agreement (except statements or releases by the Non-Defaulting Party after an Event of Default) shall be reviewed and agreed upon by the Parties before release, which agreement shall not be unreasonably withheld or delayed.

[redacted]

21.3 Survivorship of Obligations. Termination of this Agreement shall not discharge any Party from any obligation it owes the other Party under this Agreement by reason of any transaction, loss, cost, damage, expense or liability occurring, accruing or arising prior to such termination. It is the intent of the Parties that any such obligation owed (whether the same shall be known or unknown as of the termination or cancellation of this Agreement) will survive the termination or cancellation of this Agreement in favor of the Party to which such obligation is owed. The Parties also intend that the indemnification and limitation of liability provisions contained in Sections 14.2 and 14.3 shall remain operative and in full force and effect and that any specific survivability provisions in any other sections be given full effect.

21.4 No Third Party Beneficiaries. This Agreement is not intended to, and shall not, create rights, remedies or benefits of any character whatsoever in favor of any Persons, corporations, associations, or entities other than the Parties and their permitted successors and assigns, and the rights and obligations of each of the Parties under this Agreement are solely for the use and benefit of, and may be enforced solely by the Parties, their permitted successors and assigns.

21.5 Section Headings Not to Affect Meaning. The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and shall in no way modify or restrict any of the terms and provisions thereof. References to "Articles", "Sections" and "Appendices" in this Agreement shall mean the Articles, Sections and Appendices of this Agreement unless otherwise expressly noted.

21.6 Computation of Time. In computing any period of time prescribed or allowed by this Agreement, the designated period of time shall begin to run on the Day immediately following the Day of the act, event or default that precipitated the running of the designated

period of time. The designated period shall expire on the last Day of the period so computed unless that Day is not a Business Day, in which event the period shall run until the end of the next Business Day.

21.7 Interest. Whenever the provisions of this Agreement require the calculation of an interest rate, such rate shall be computed at an annual rate equal to the Prime Rate as of the date on which the calculation begins, but not to exceed the maximum rate which may be lawfully charged. Interest on obligations arising under this Agreement shall be compounded daily and be calculated based on a 360 day year.

21.8 Entire Agreement. [redacted] this Agreement constitutes the entire agreement between the Parties relating to the subject matter hereof and supersedes any other agreements, written or oral, between the Parties concerning such subject matter. The Parties have entered into this Agreement in reliance upon the representations and mutual understandings contained herein and not in reliance upon any oral or written representation or information provided by one Party to another Party not contained or incorporated herein.

21.9 Counterparts. This Agreement may be executed simultaneously in multiple counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

21.10 Amendments. This Agreement may only be amended by written agreement signed by duly authorized representatives of the Parties.

21.11 Waivers. Waivers of the provisions of this Agreement or excuses of any violations of this Agreement shall be valid only if in writing and signed by an authorized officer

of the Party issuing the waiver or excuse. A waiver or excuse issued under one set of circumstances shall not extend to other occurrences under similar circumstances.

21.12 No Partnership Created. Any provision of this Agreement to the contrary notwithstanding, the Parties do not intend to create hereby any joint venture, partnership, association taxable as a corporation, or other entity for the conduct of any business for profit. If it should appear that one or more changes to this Agreement would be required in order not to create an entity referenced in the preceding sentence, the Parties agree to negotiate promptly and in good faith with respect to such changes.

21.13 Character of Sale. The sale of capacity and energy hereunder shall not constitute a sale, lease, transfer or conveyance to Buyer or any other party of any contractual rights or ownership interests in any generating unit or other equipment comprising the Facility, nor does the sale of capacity and energy hereunder constitute a dedication of ownership of any generating unit or other equipment comprising the Facility.

21.14 Notices. Any notice, demand, request, statement, or correspondence provided for in this Agreement, or any notice which a Party may desire to give to the other, shall be in writing (unless otherwise expressly provided by this Agreement) and shall be considered duly delivered when received by hand delivery, first-class mail, facsimile, or by overnight delivery, at the address(es) and to the attention of the person(s) listed below; provided, however, if actual delivery occurs at a time other than between the hours of 0800 and 1700 CPT on a Business Day (each a "Business Hour"), delivery shall be deemed to have occurred in the next Business Hour after actual delivery.

(i) **To Seller:**

Vice President, Business Development
Southern Company Generation and Energy Marketing
Bin 935
270 Peachtree Street, NW
Atlanta, Georgia 30303

Telephone: 404-506-0346
Facsimile: 404-506-0399

With a copy to:

Senior Vice President, General Counsel and Assistant Secretary
Southern Power Company
600 North 18th Street
Birmingham, Alabama 35203

Telephone: 205-257-0472
Facsimile: 205-257-2027

And

Vice President, Fleet Operations and Trading
Southern Company Services, Inc.
600 North 18th Street, GS-8259
Birmingham, Alabama 35203

Telephone: 205-257-6139
Facsimile: 205-257-4441

(ii) **To Buyer:**

Vice President, Energy Marketing and Trading
Florida Power & Light Company
700 Universe Boulevard
EMT/JB
Juno Beach, Florida 33408

Telephone: 561-691-7878
Facsimile: 561-691-7759

With a copy to:

Director, Resource Assessment and Planning
Florida Power & Light Company
9250 West Flagler Street
Miami, Florida 33174

Telephone: 305-552-3622
Facsimile: 305-552-2905

Either Party may change the information set forth in this Section 21.14 by giving written notice to the other Party in the manner prescribed by this Section.

21.15 Survival. Any provision(s) of this Agreement that expressly comes into or remains in force following the termination or expiration of this Agreement shall, subject to the express terms of the relevant provision, survive the termination or expiration of this Agreement.

21.16 Construction. The language used in this Agreement is the product of both Parties' efforts. Accordingly, each Party irrevocably waives the benefit of any rule of contract construction that disfavors the drafter of a contract or the drafter of specific language in a contract.

21.17 Imaged Agreement. Any original executed Agreement, schedule confirmation or other related document may be photocopied and stored on computer tapes and disks (the "Imaged Agreement"). The Imaged Agreement, if introduced as evidence on paper, the schedule confirmation, if introduced as evidence in automated facsimile form, the transaction tape, if introduced as evidence in its original form and as transcribed onto paper, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings, will be admissible as between the Parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the

transaction tape, the schedule confirmation or the Imaged Agreement (or photocopies of the transcription of the transaction tape, the schedule confirmation or the Imaged Agreement) on the basis that such were not originated or maintained in documentary form under either the hearsay rule, the best evidence rule or other rule of evidence.

21.18 Severability. If any provision or provisions of this Agreement or the application thereof to any Person or circumstance or in any jurisdiction is found by a court of competent jurisdiction to be illegal, invalid, unlawful, void or unenforceable as written for any reason, then it is the intent of each of the Parties that any such provision or provisions shall be given force and effect to the fullest possible extent that they are legal, valid and enforceable, that the remainder of this Agreement and the application of such provision or provisions to other Persons or circumstances or in other jurisdictions shall be deemed valid and enforceable to the fullest extent possible and continue in force and effect. If the determination that any provision or provisions hereof are illegal, invalid, unlawful, void or unenforceable (even after such provision or provisions are given force and effect to the fullest extent possible) results in a significant material deviation from the Parties' original intent or economic expectations regarding this Agreement, the Parties shall negotiate to (and/or the applicable court, in its discretion, may) replace any such illegal, invalid, unlawful, void or unenforceable provision or provisions with valid provision(s) which result in the least deviation from the Parties' intent and economic expectations.

21.19 Agency of Southern Company Services, Inc. Seller hereby designates Southern Company Services, Inc. to serve as its agent for purposes of the implementation and administration of this Agreement. Seller may designate a new agent from time to time under this Agreement by giving Buyer 60 Days written notice in which event Southern Company

Services, Inc.'s role, as agent, shall cease and the newly-designated agent shall be substituted for the sole purpose of serving and acting as agent for Seller hereunder.

21.20 Include. As used herein, the words "include" or "including" shall be deemed to be followed by the words "without limitation."

21.21 Examples. Examples of calculations pursuant to the provisions of this Agreement are set forth in Appendix H. Such calculations are for example purposes only and are not intended to, and shall not, modify any of the terms of this Agreement. To the extent there is a conflict between any of these examples and the other terms of this Agreement, such other terms shall govern. Moreover, such examples shall be given no weight in interpreting or construing the provisions of this Agreement.

[The Next Page is the Signature Page.]

IN WITNESS WHEREOF, Seller and Buyer have caused this Agreement to be executed in duplicate by their respective duly authorized officers as of the Effective Date.

SOUTHERN COMPANY SERVICES, INC.
As Agent for
Southern Power Company

BY: _____

NAME: William N. McKenzie

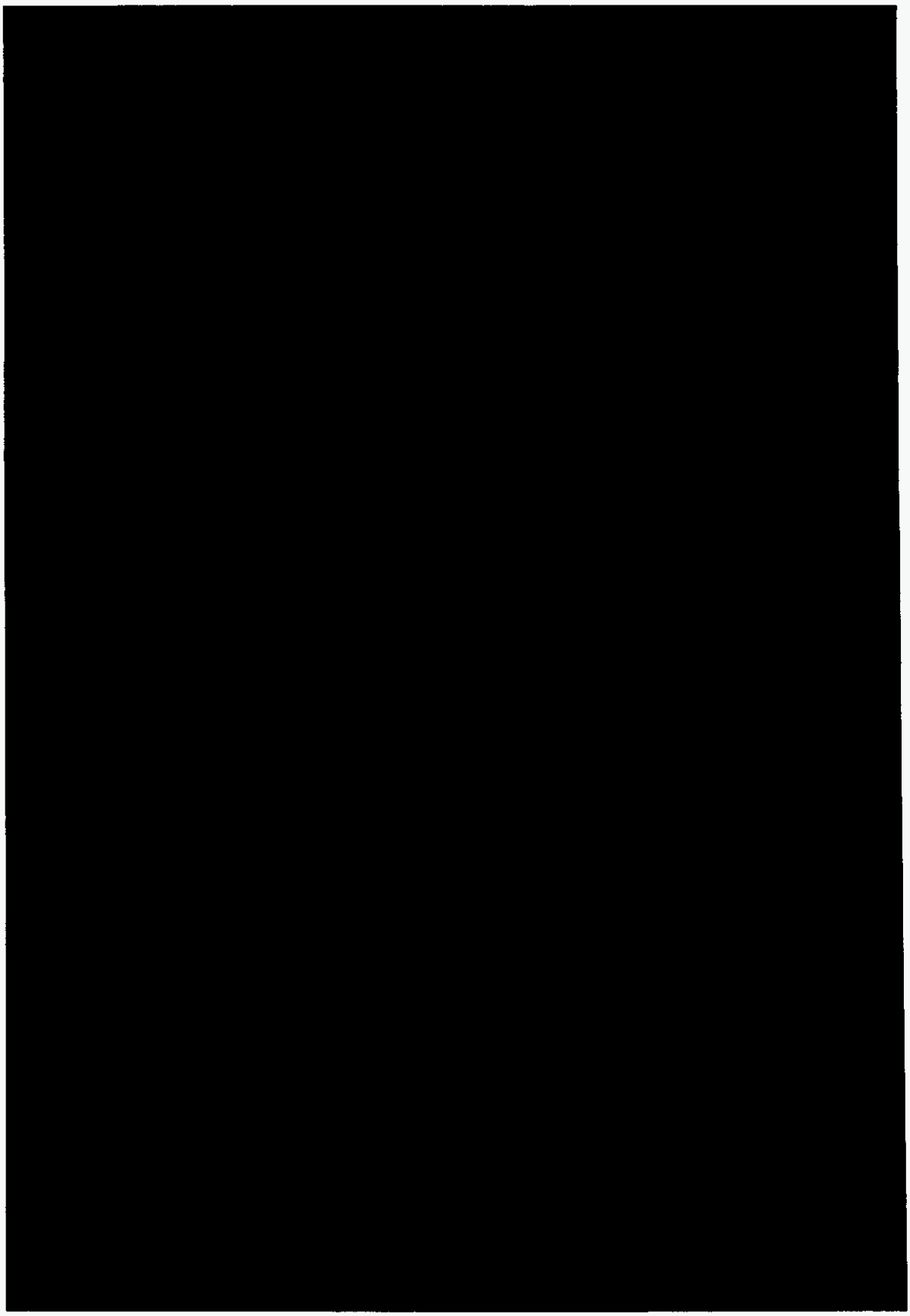
TITLE: Vice President

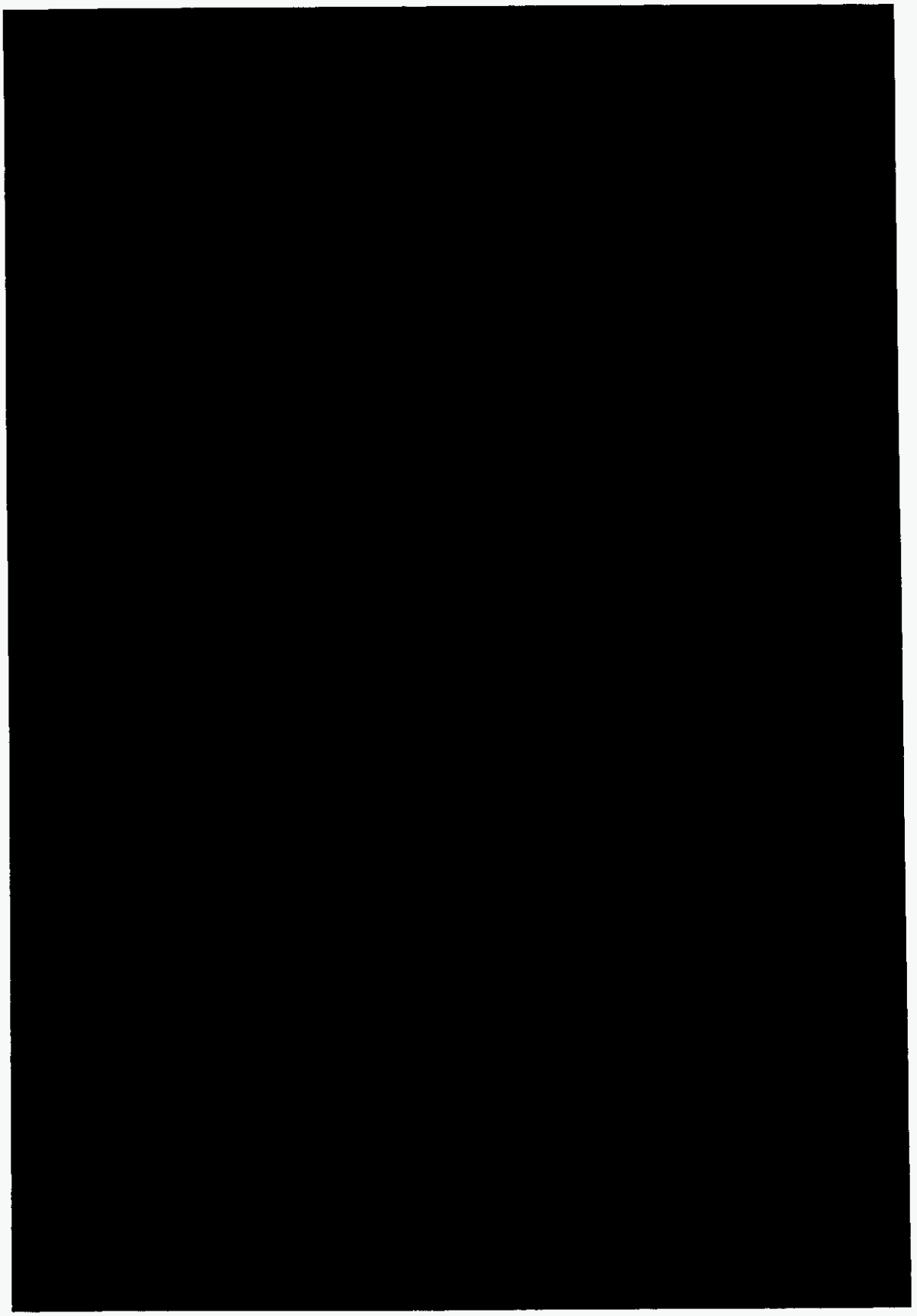
FLORIDA POWER & LIGHT COMPANY

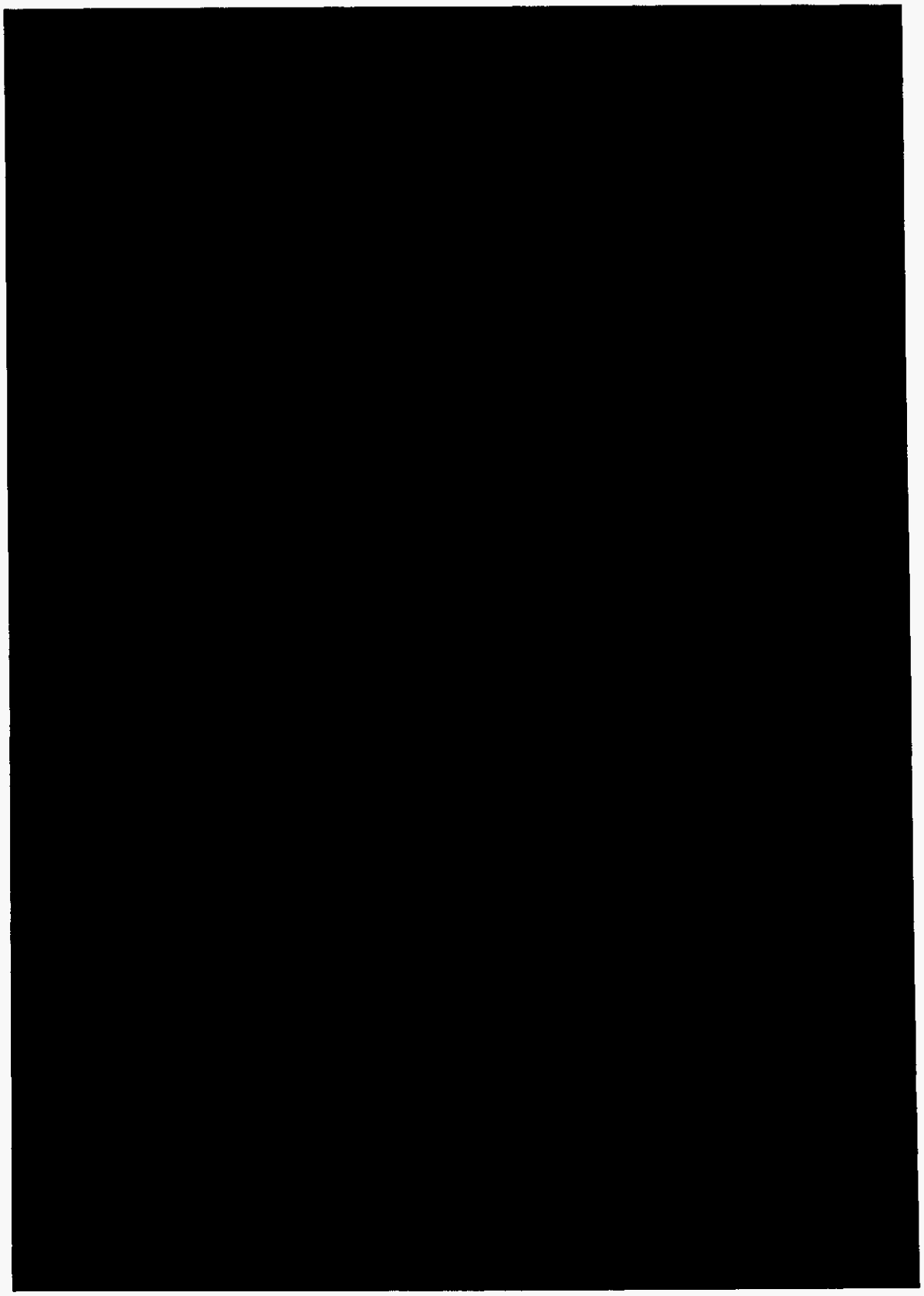
BY: _____

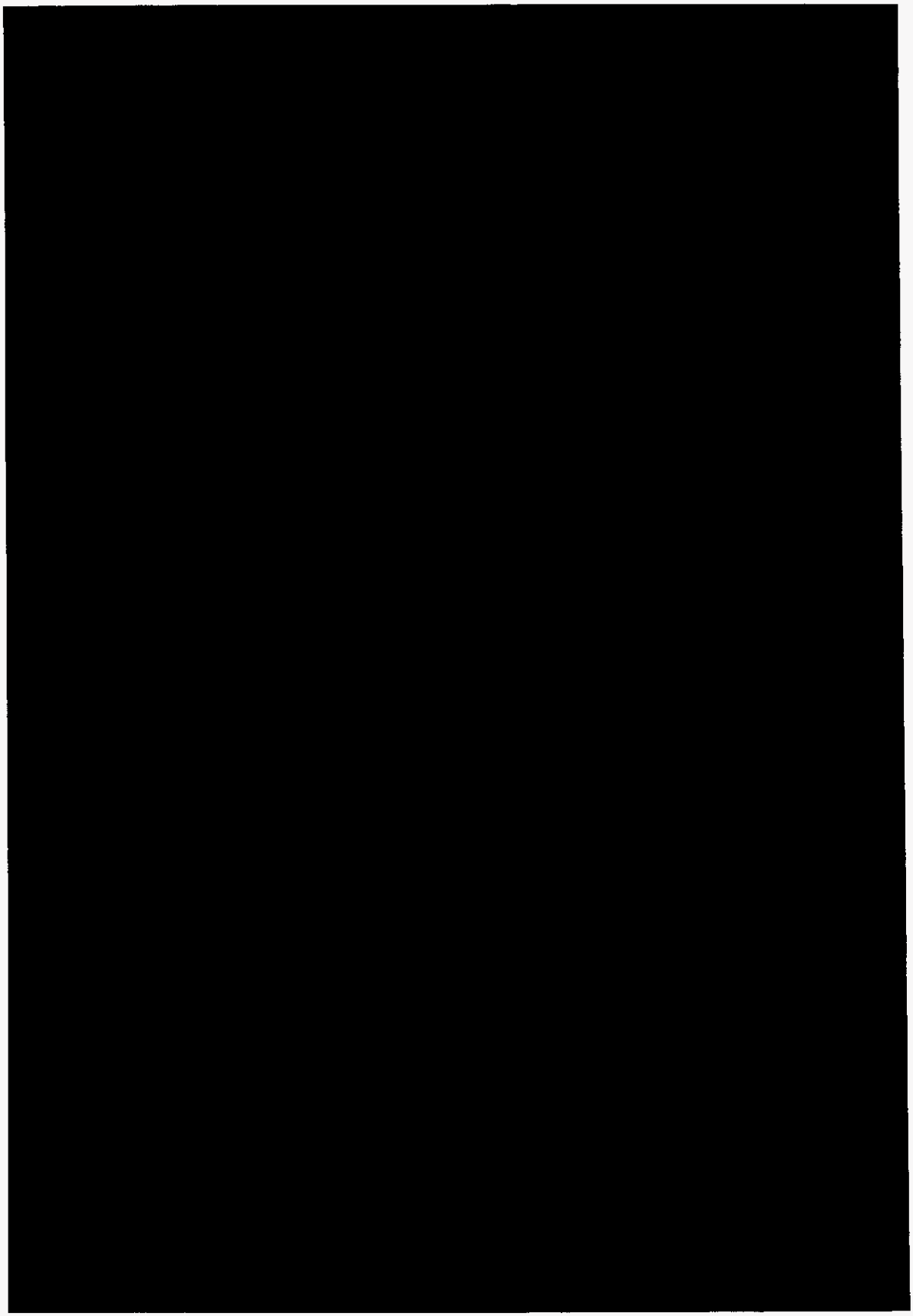
NAME: Terry L. Morrison

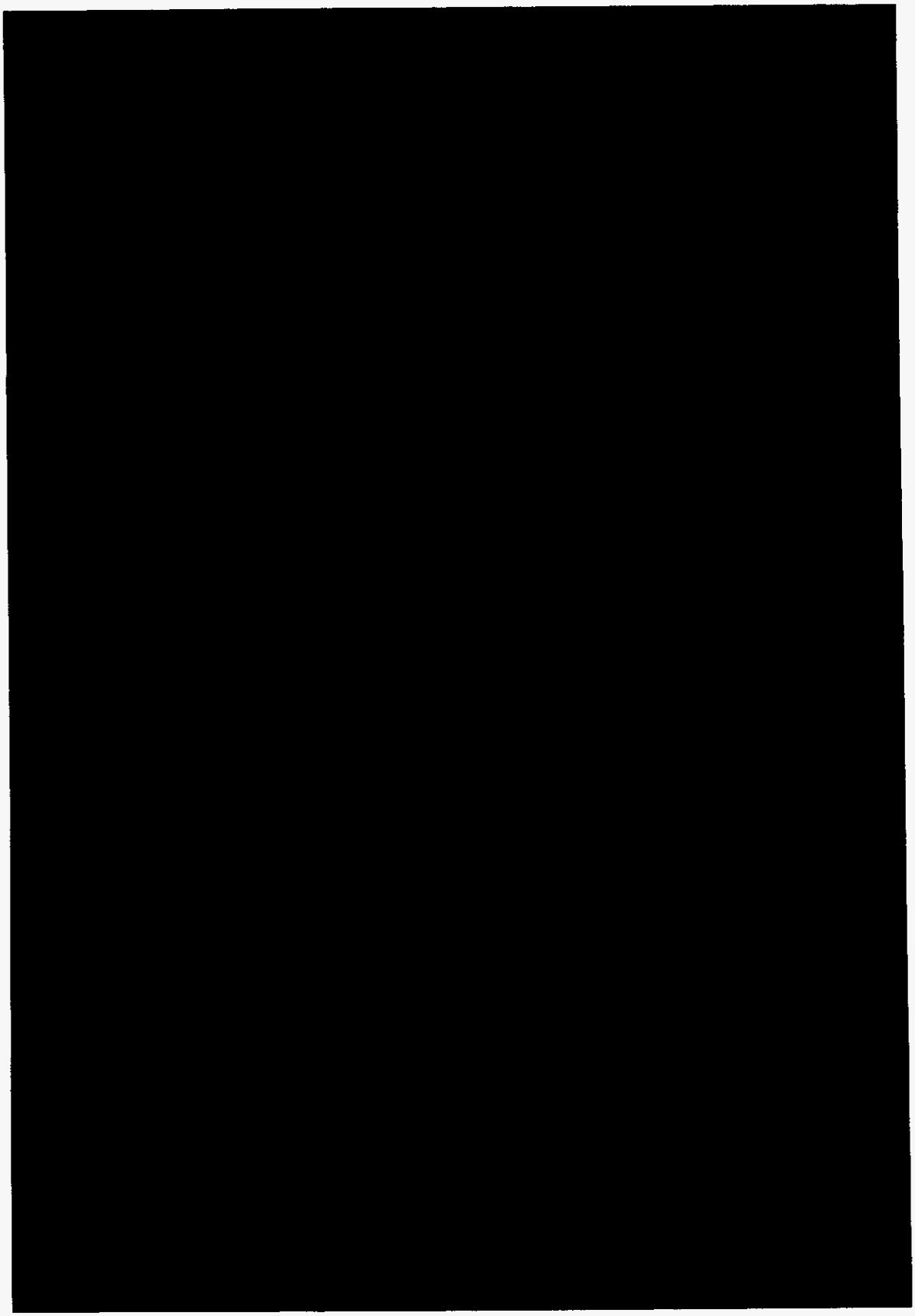
TITLE: Vice President

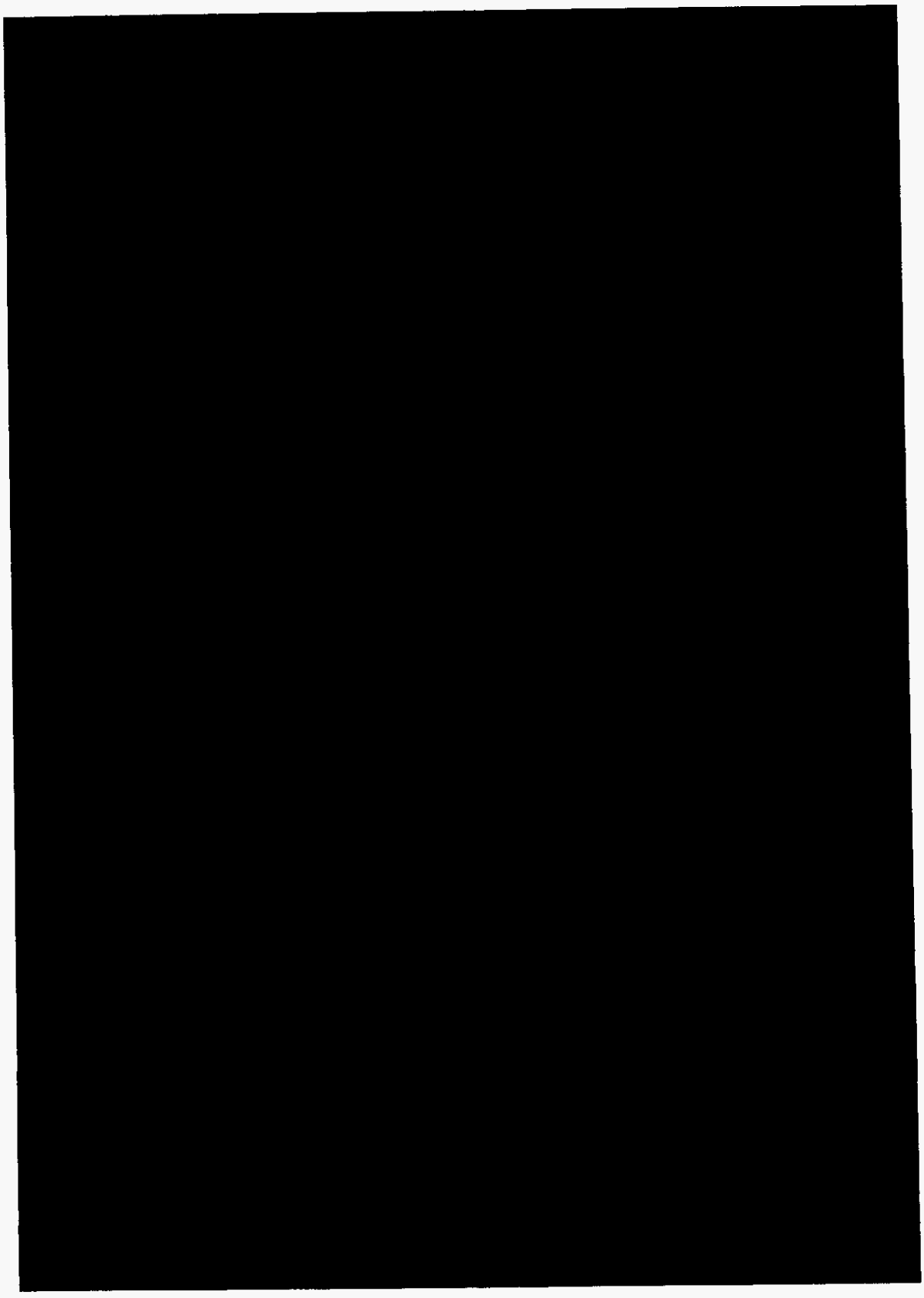


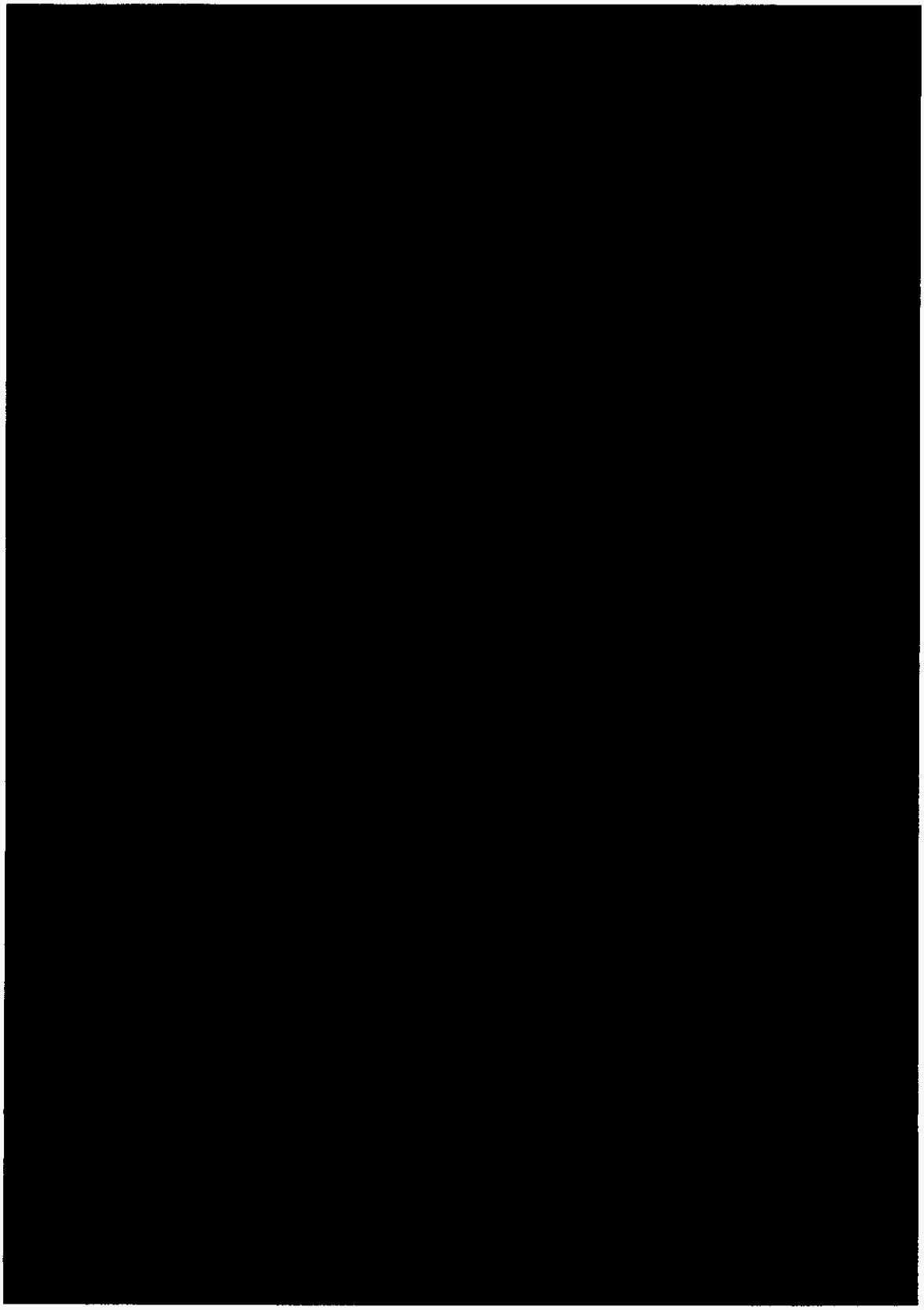


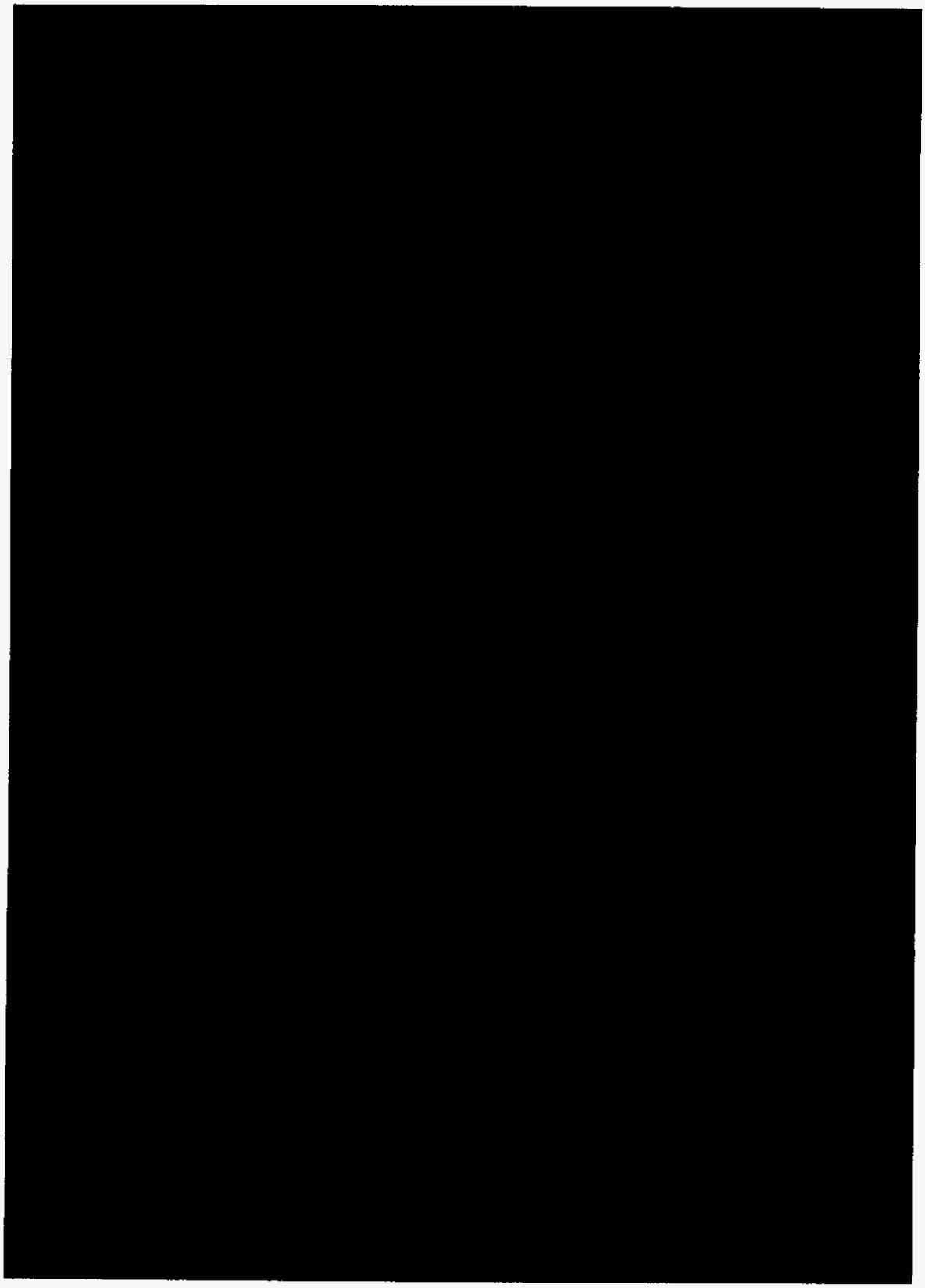


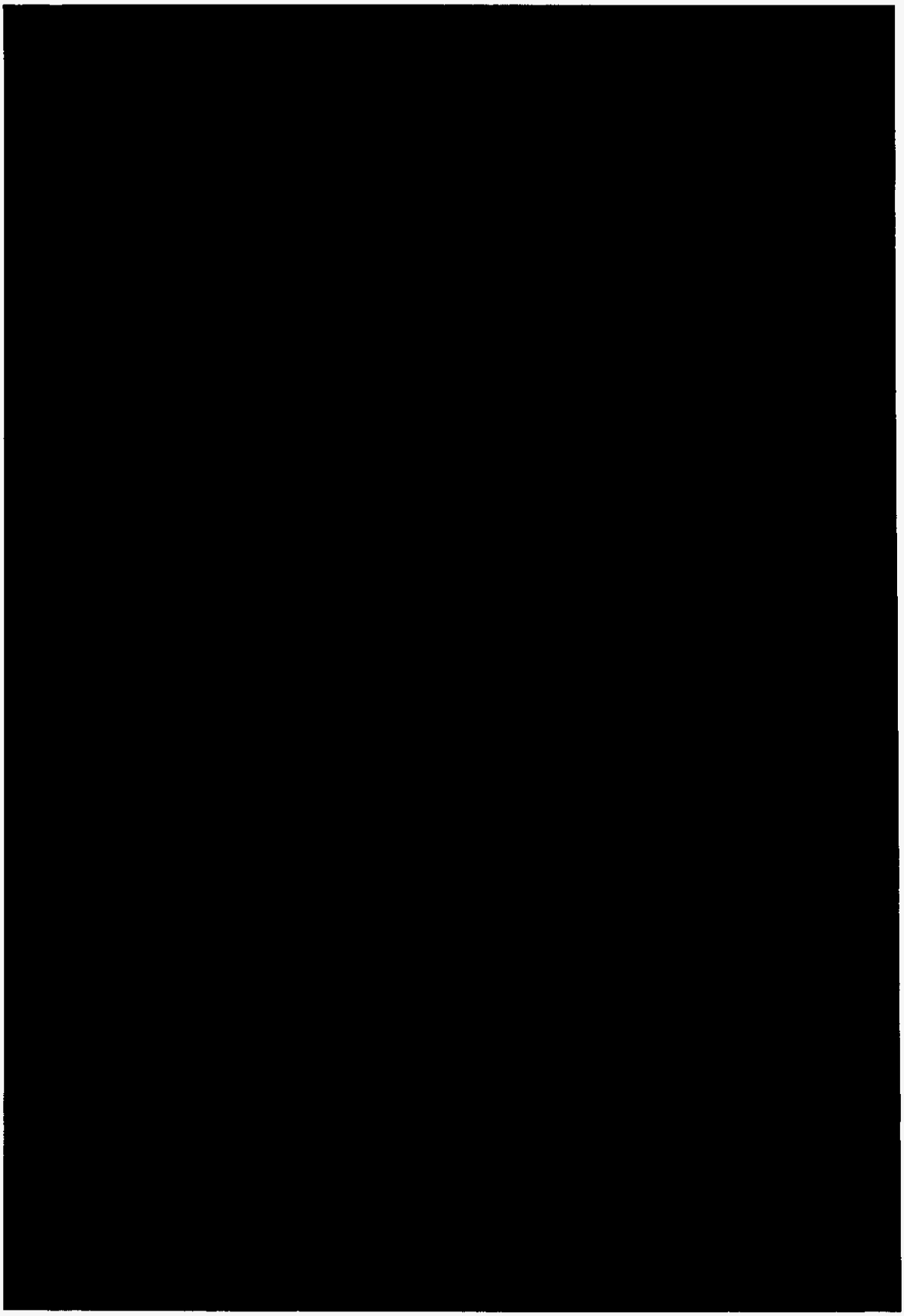


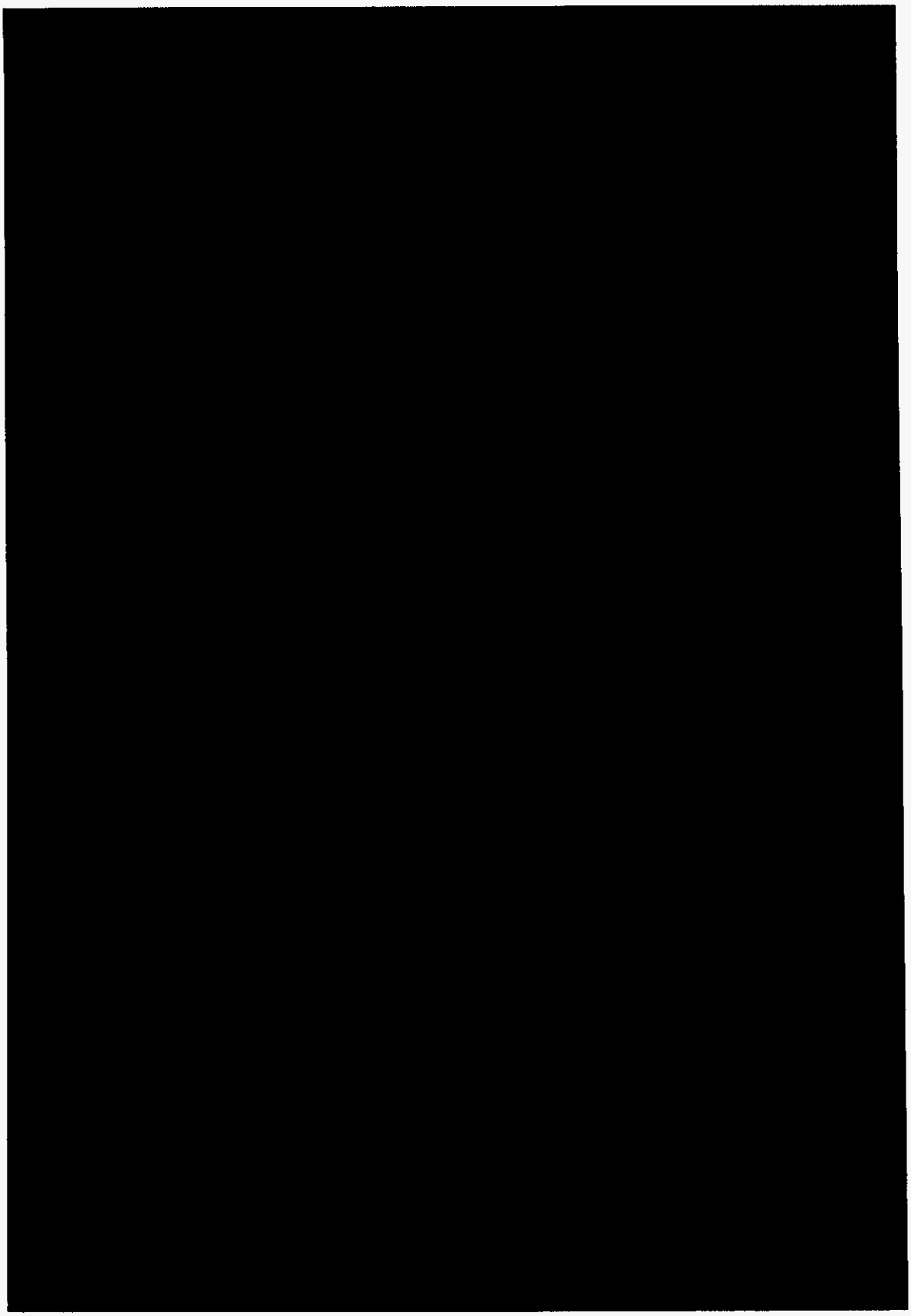


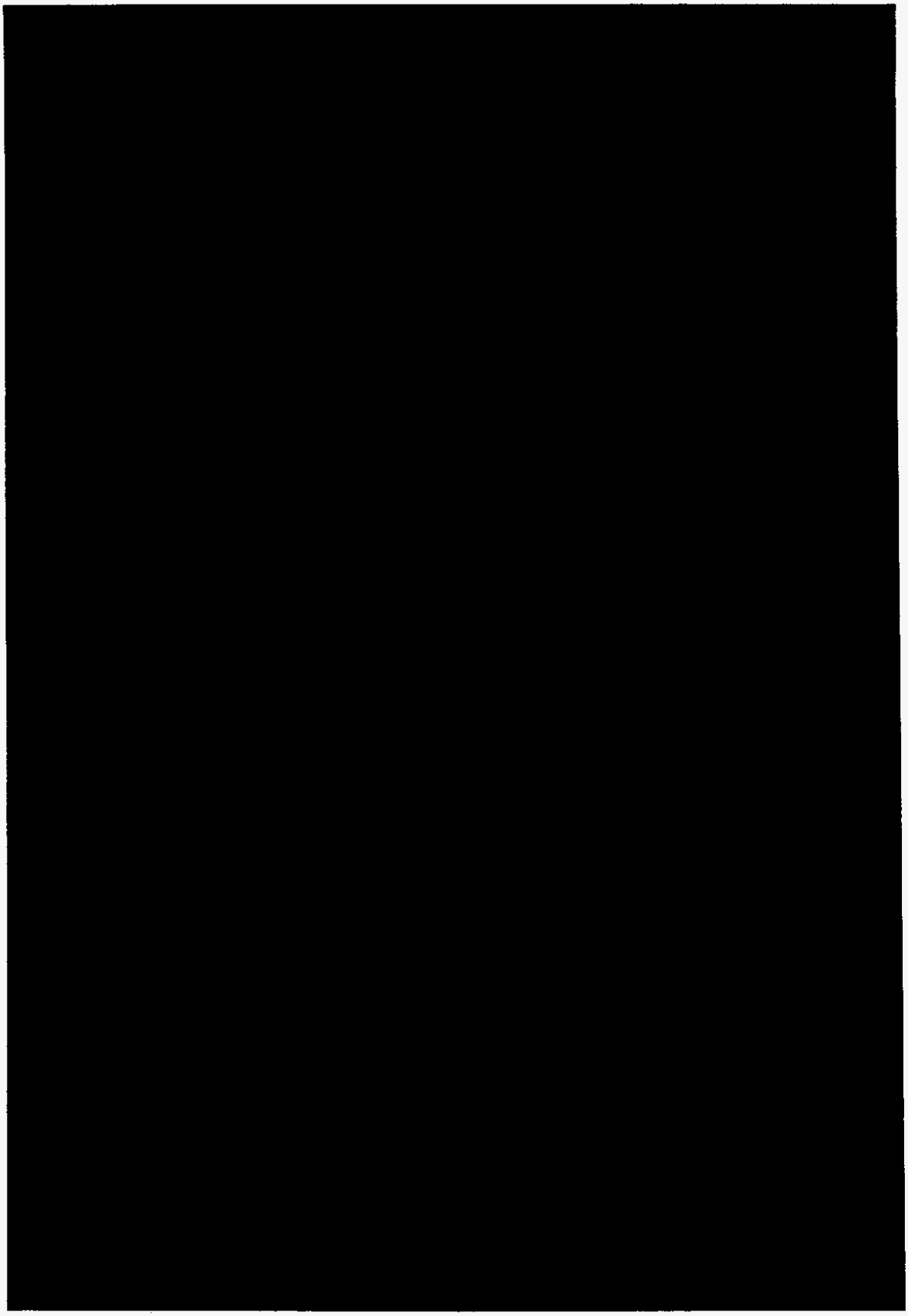


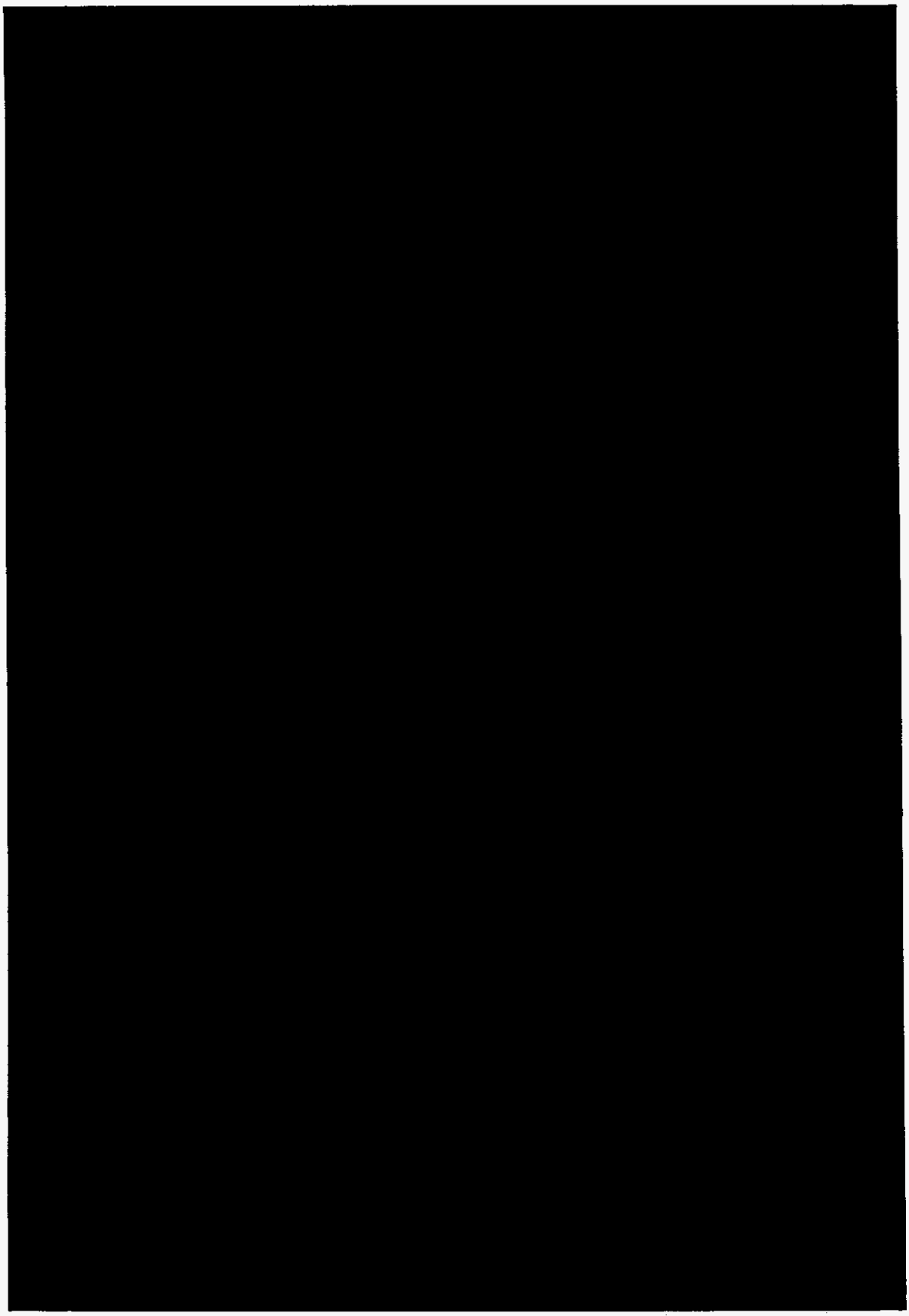


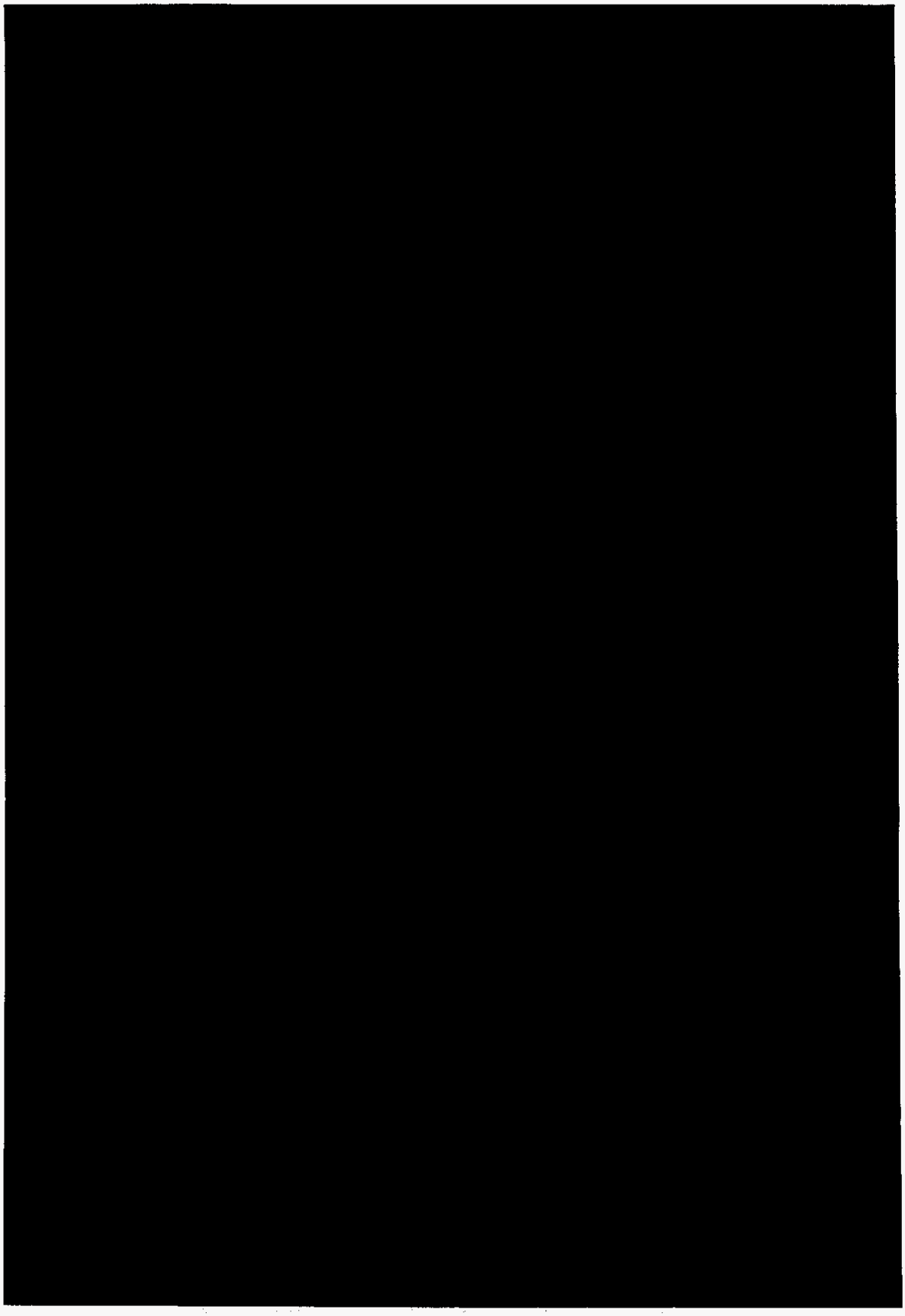


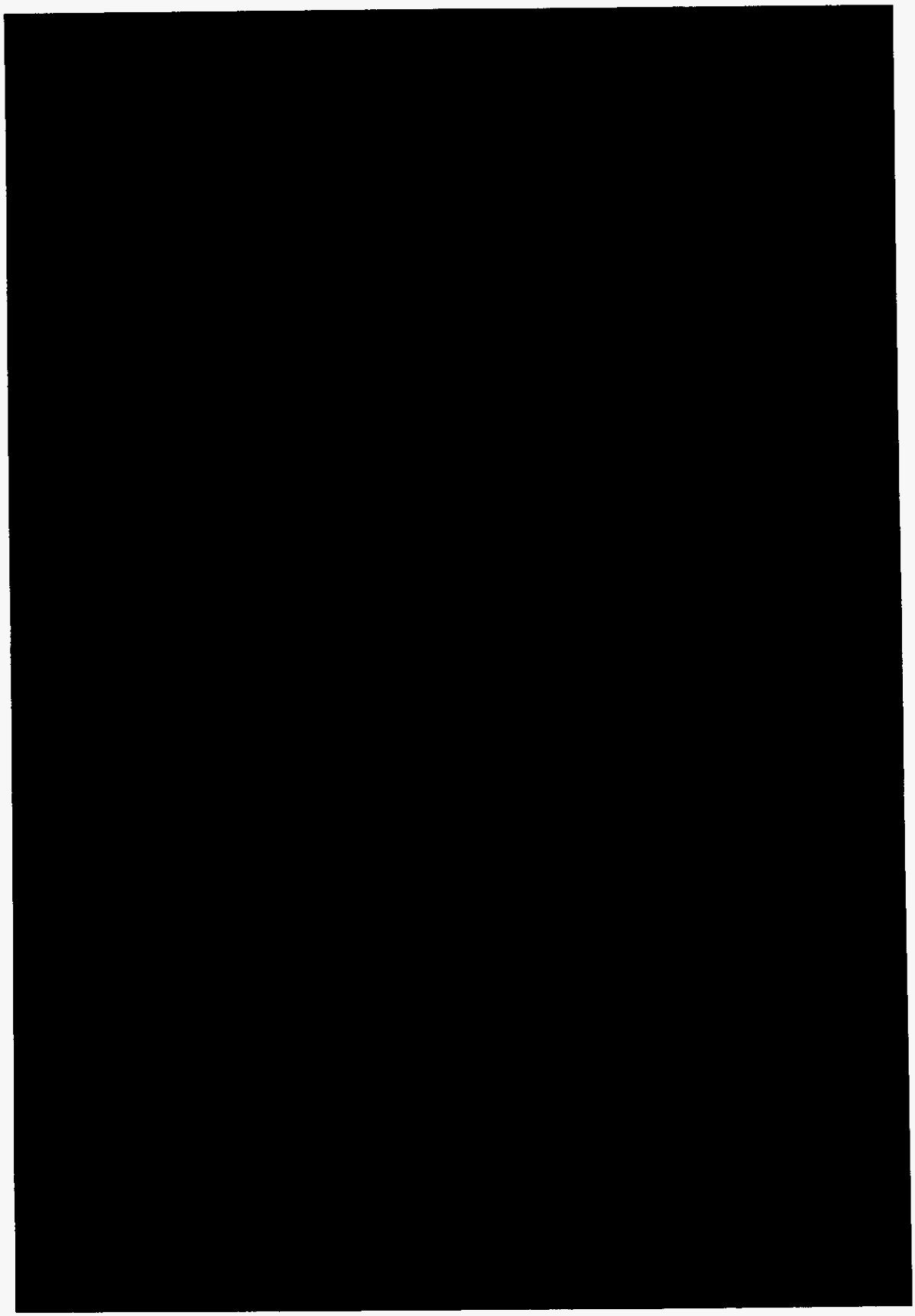


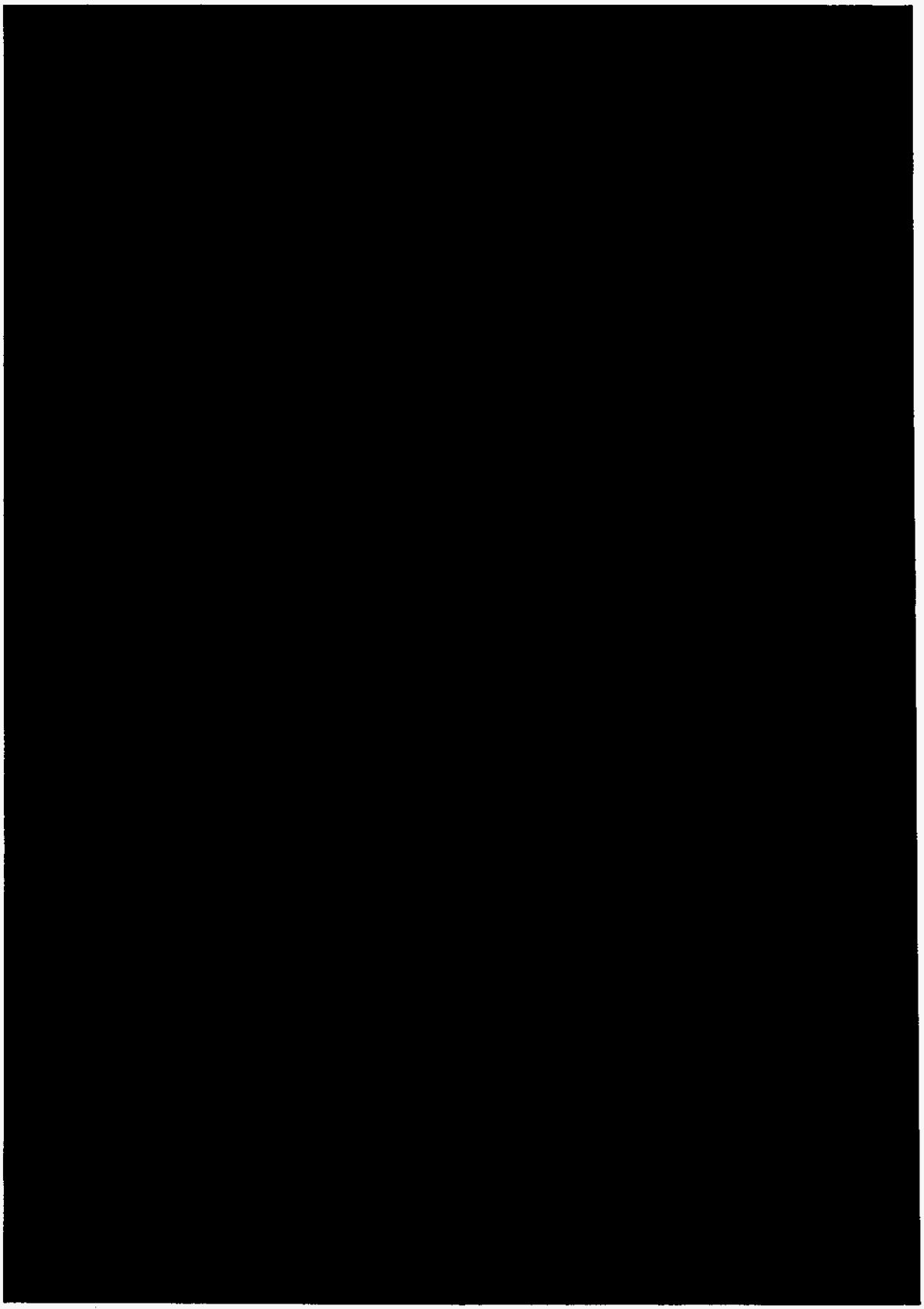


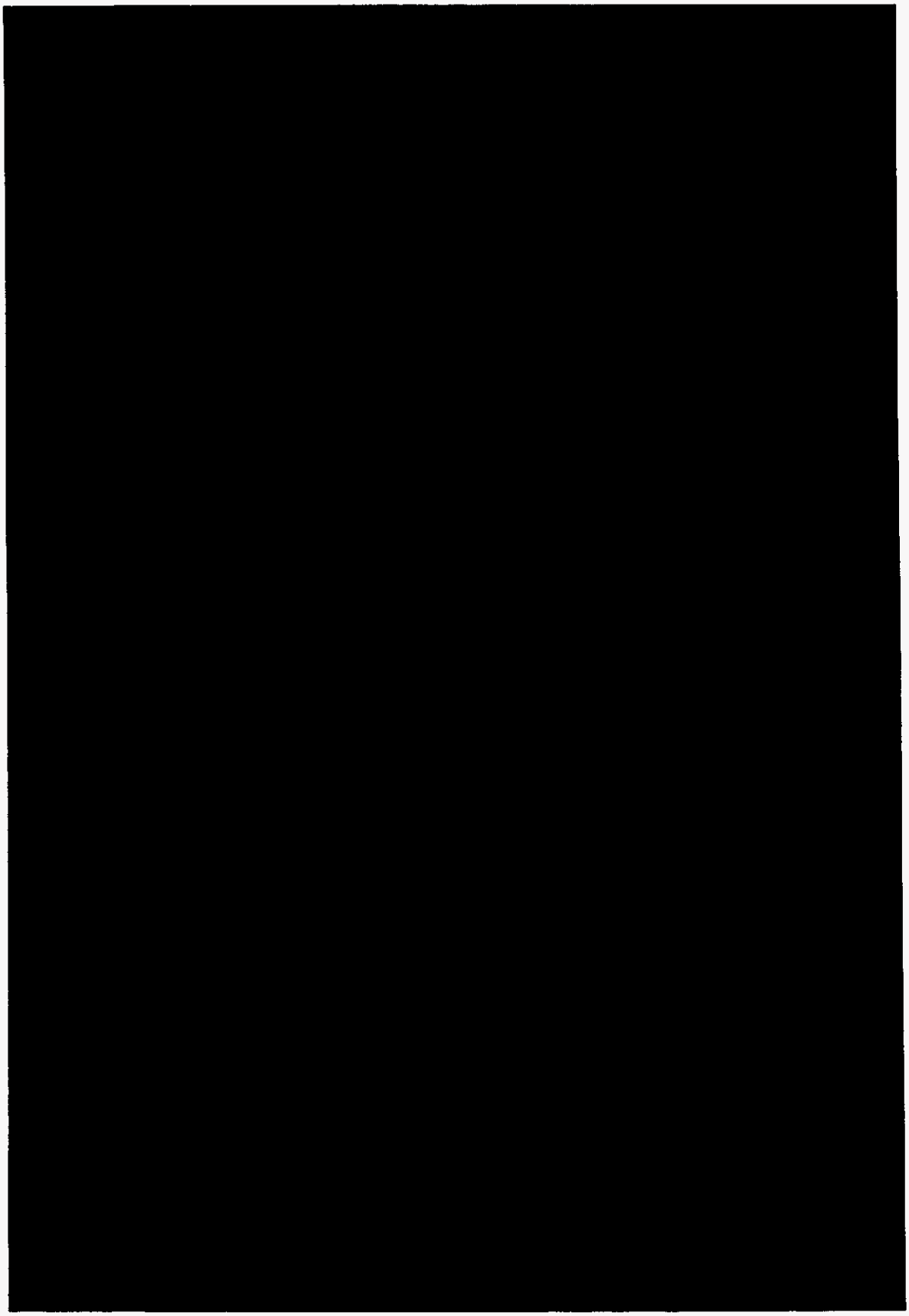


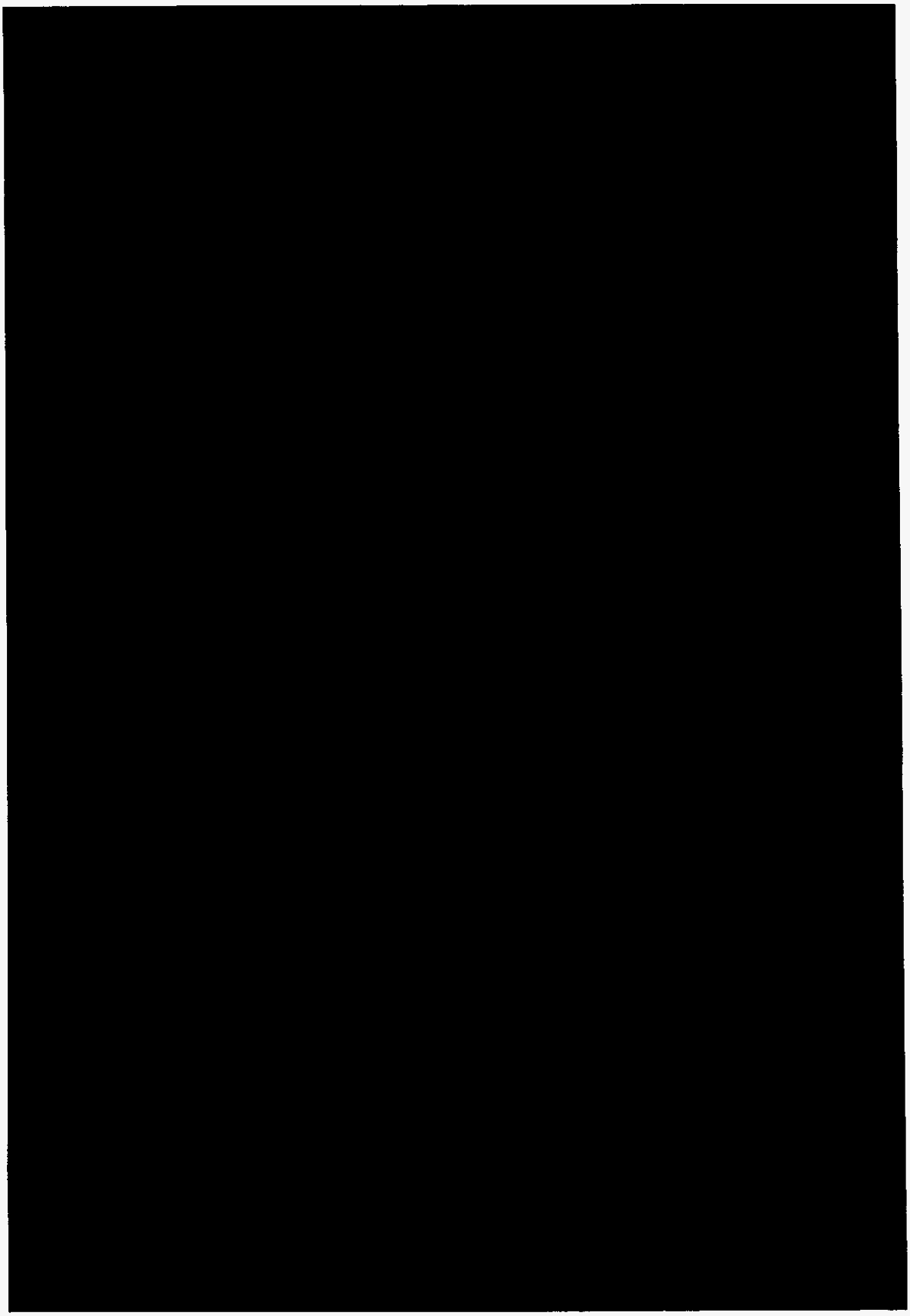


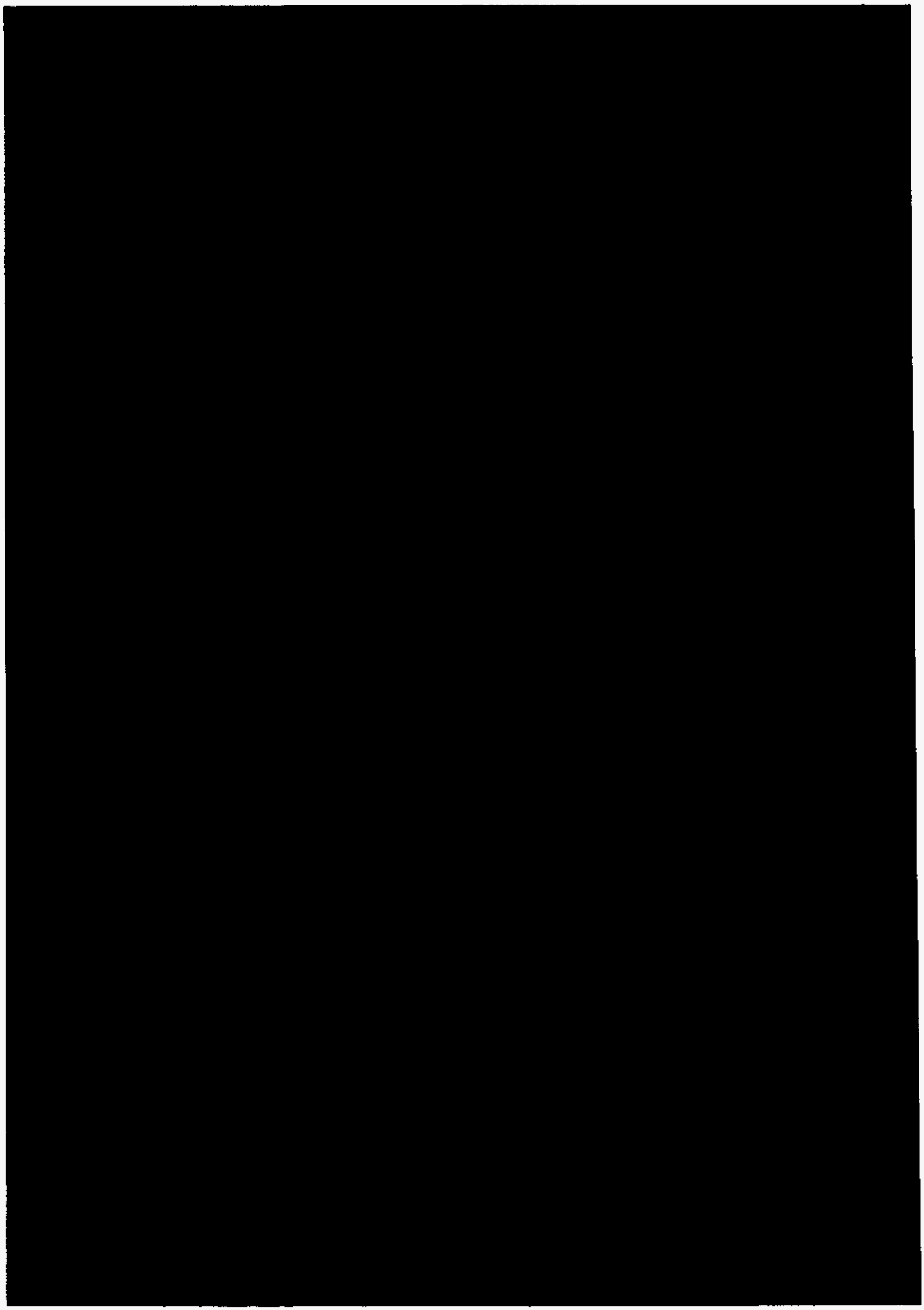


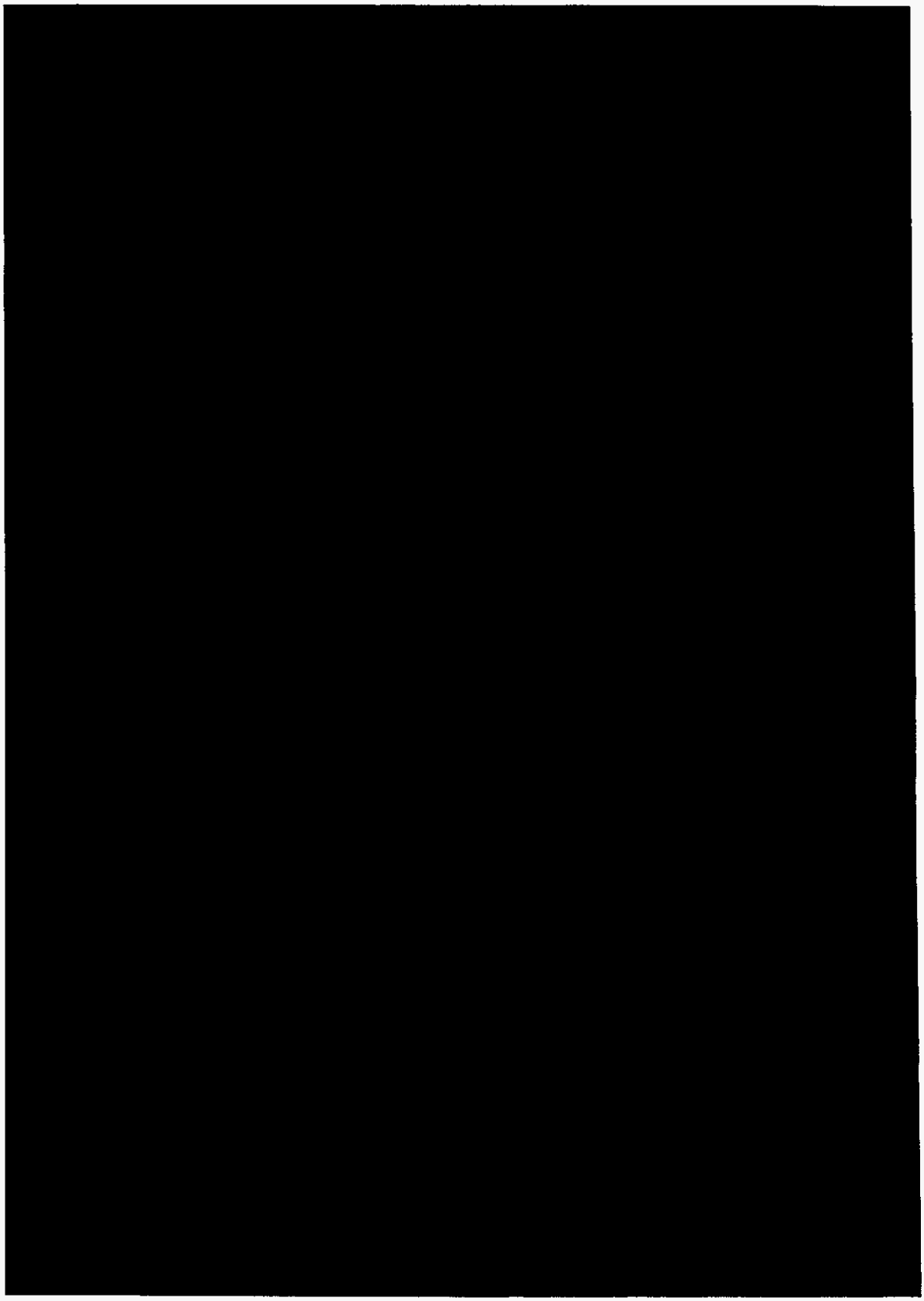


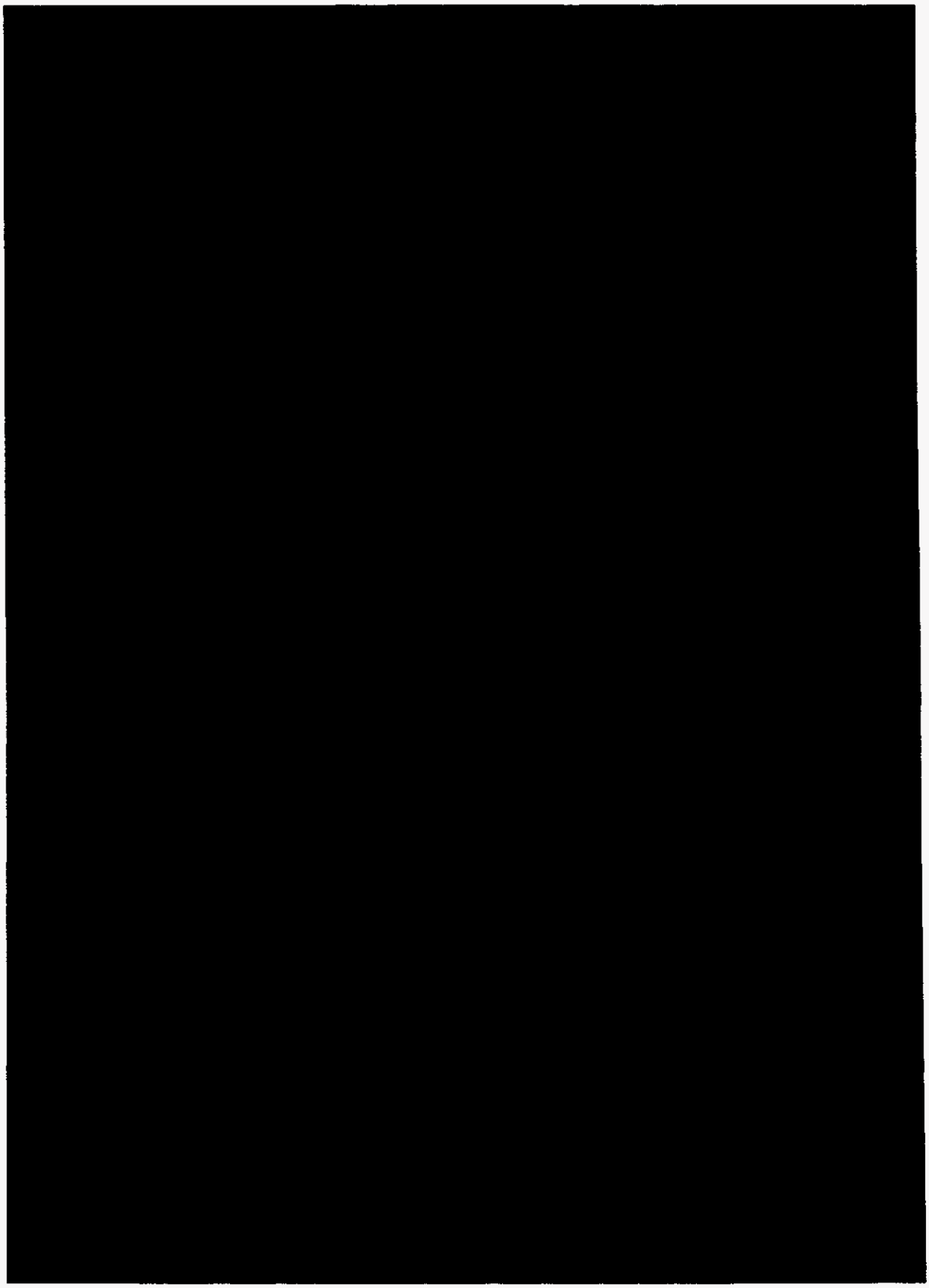


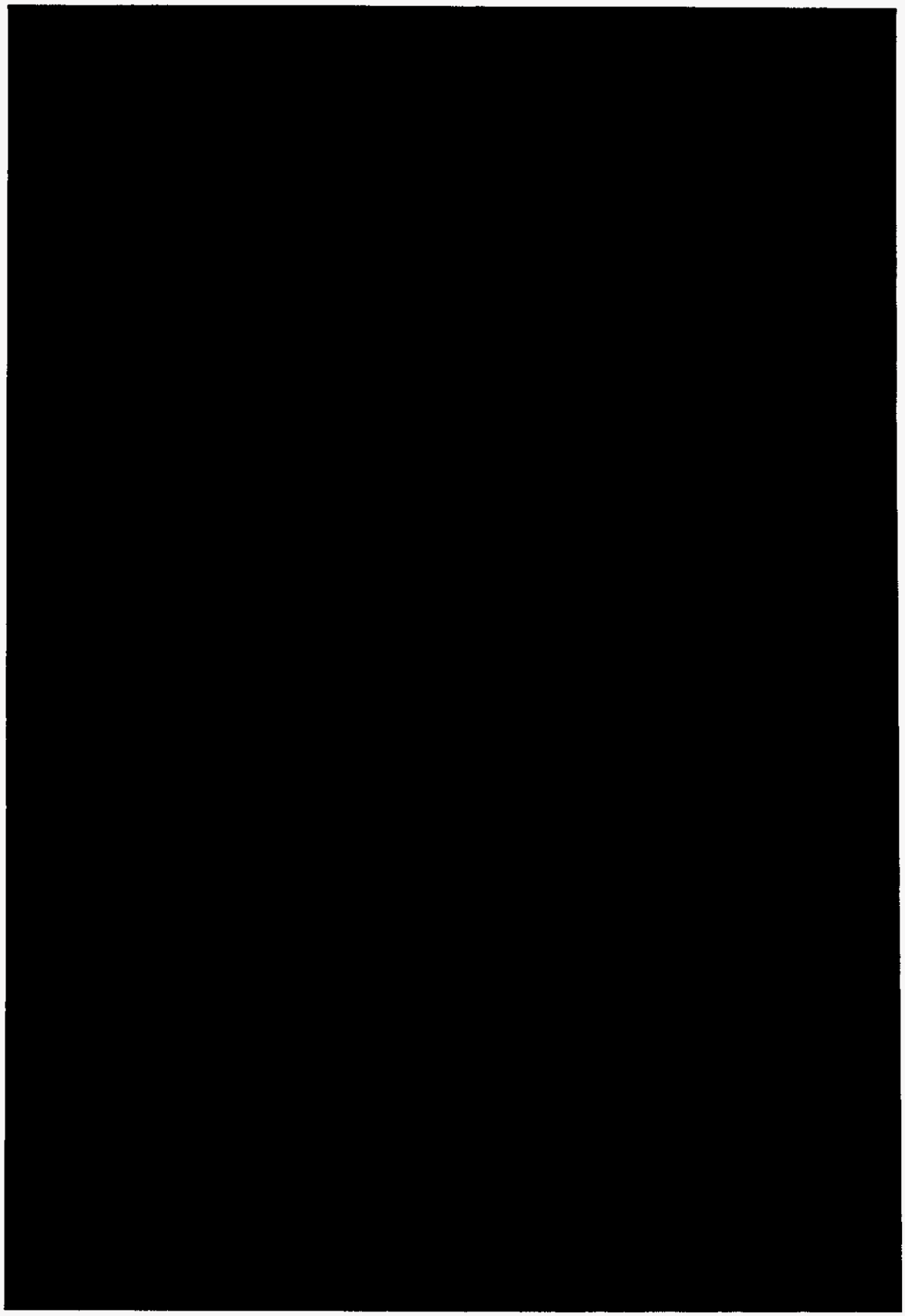


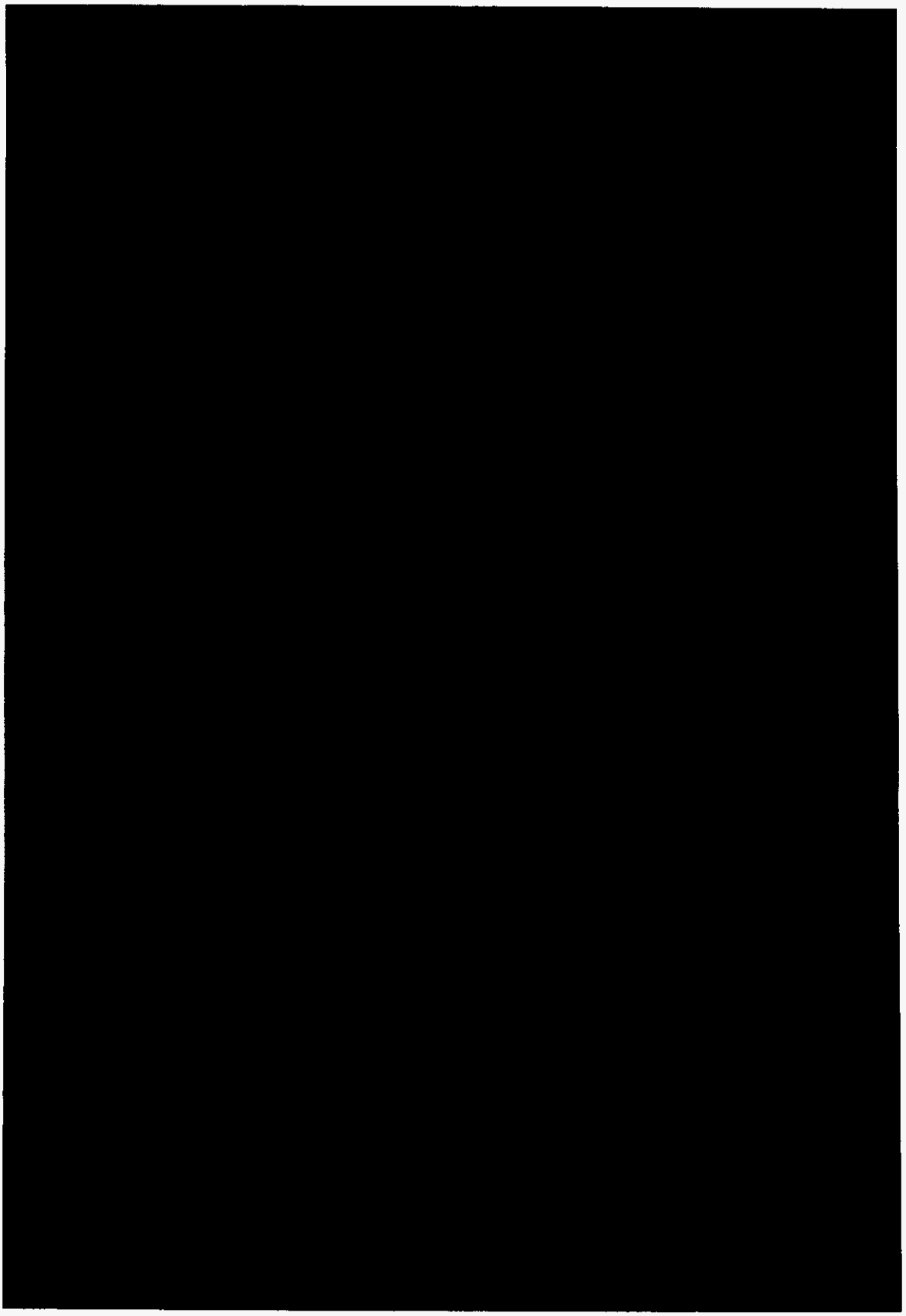


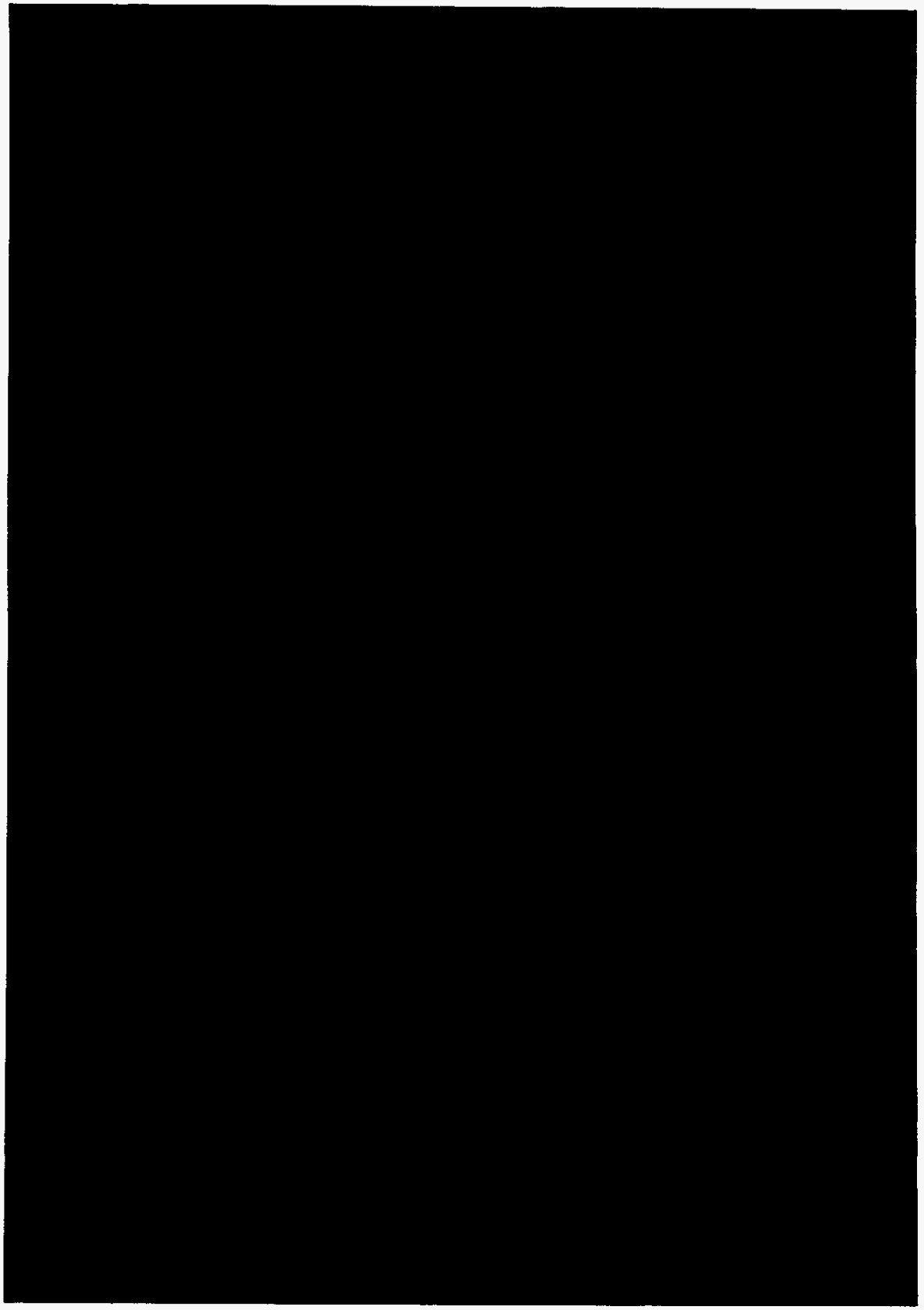


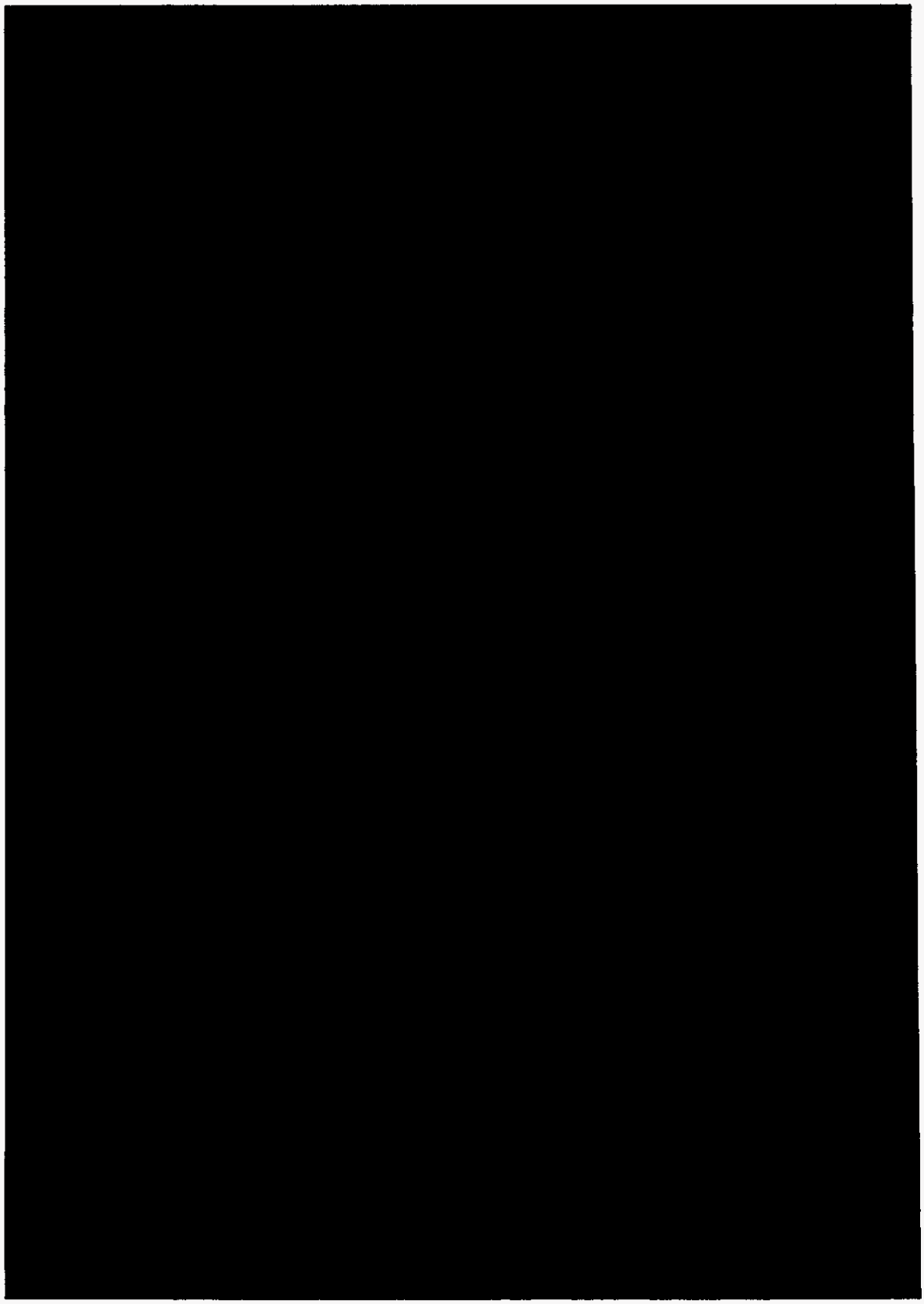


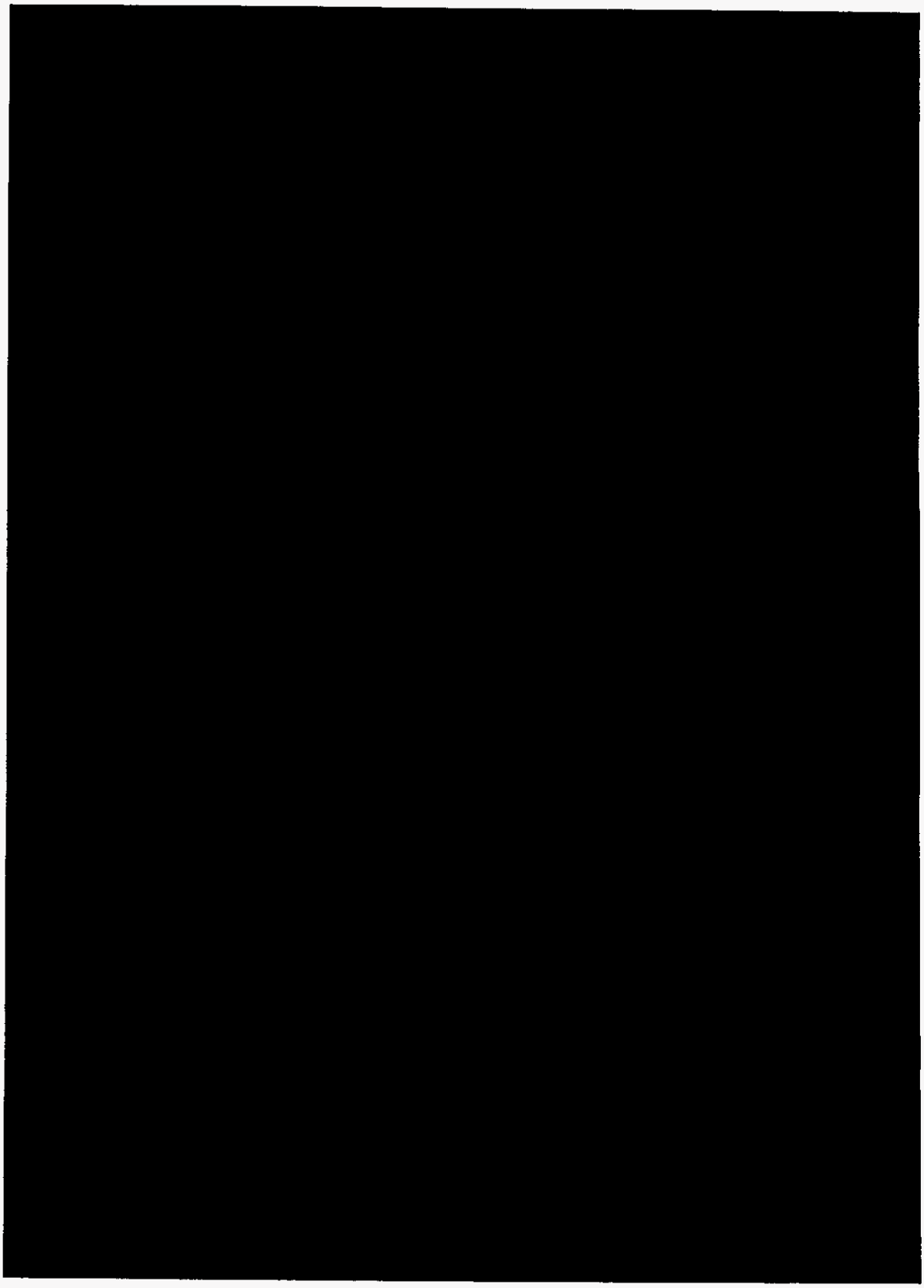


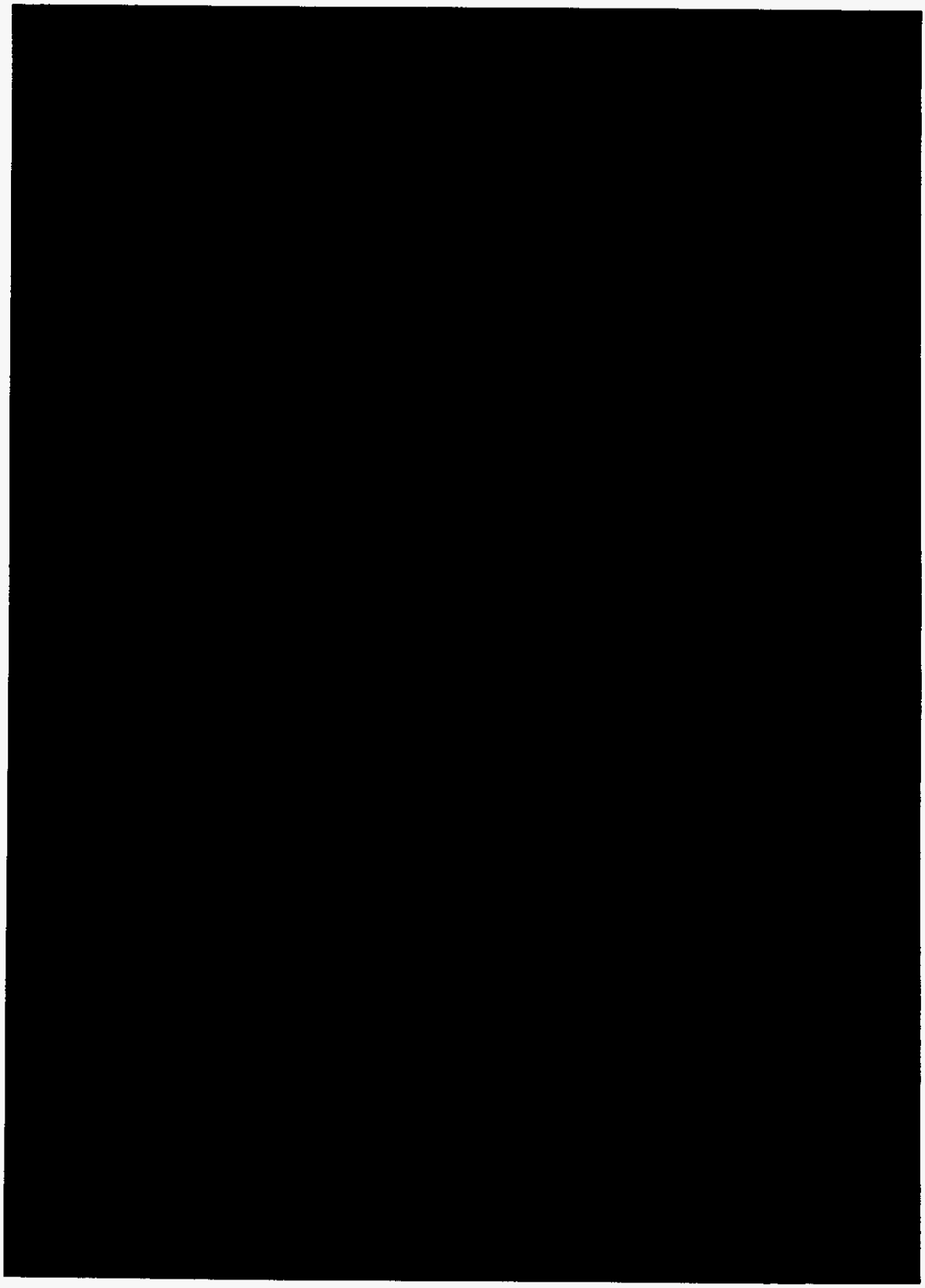


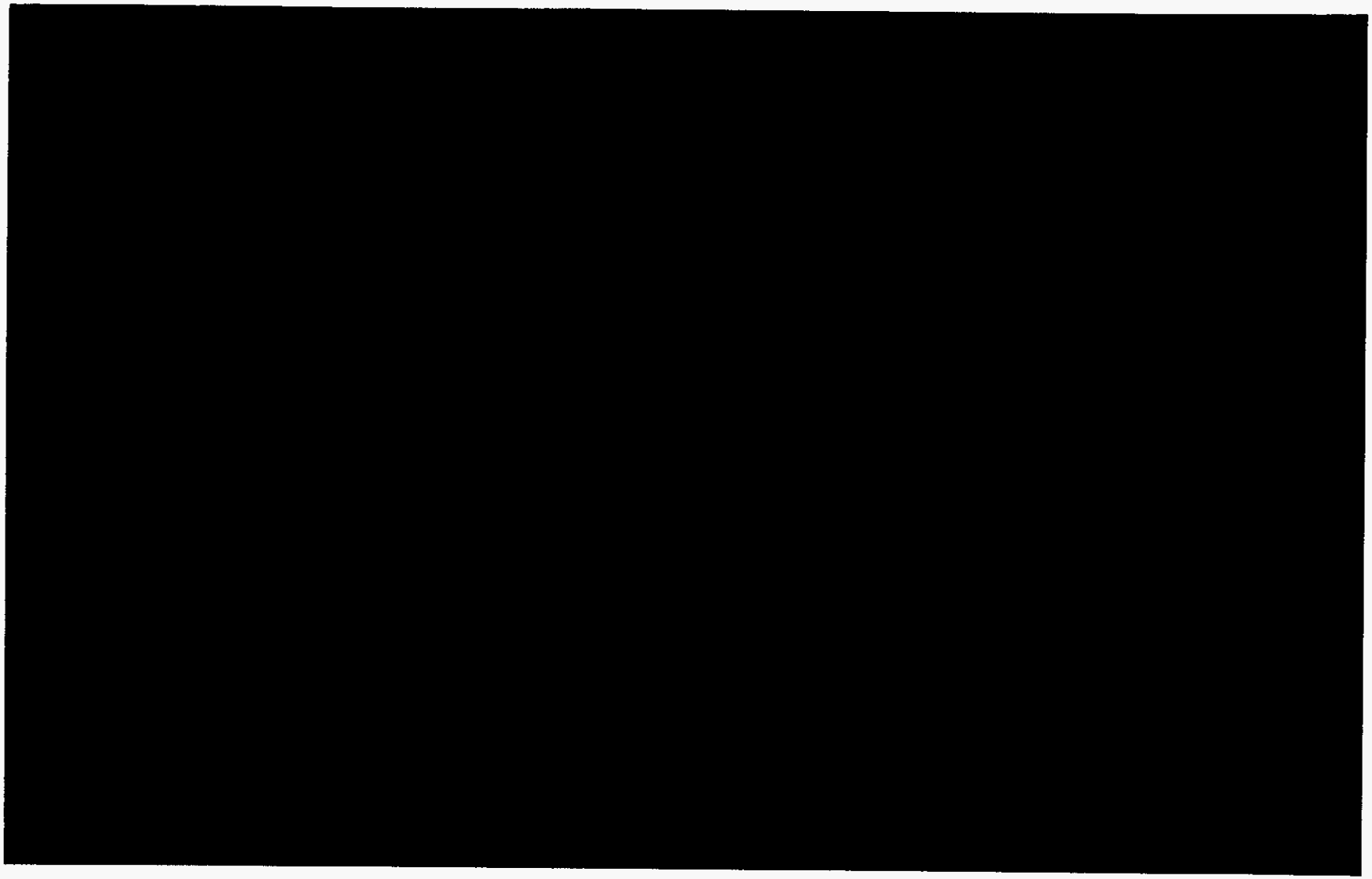


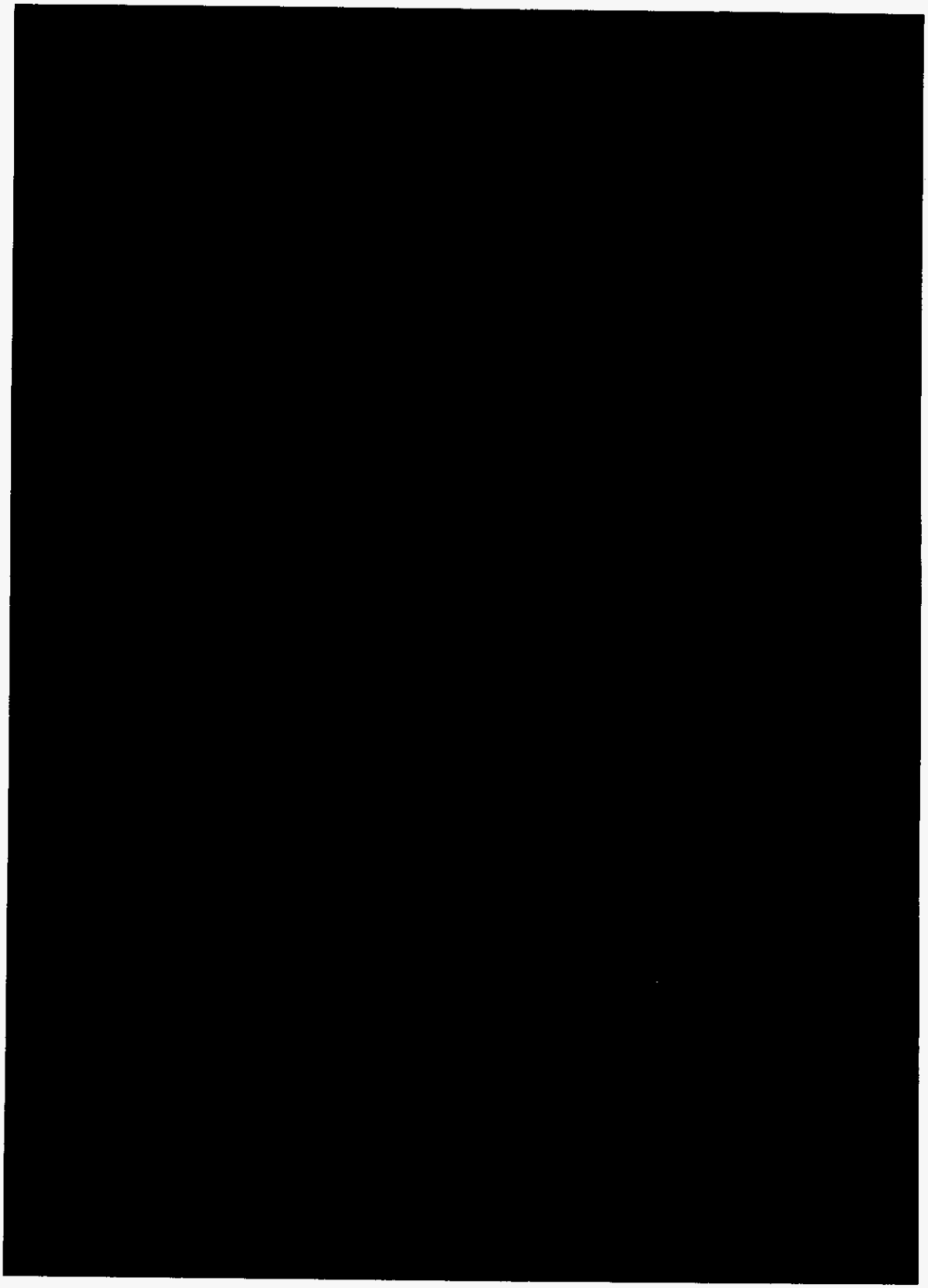












EXECUTION COPY

CONTRACT FOR THE

PURCHASE OF CAPACITY AND ENERGY

BETWEEN

SOUTHERN COMPANY SERVICES, INC.

AND

FLORIDA POWER & LIGHT COMPANY

FROM

PLANT FRANKLIN UNIT NO. 1

DATED AS OF AUGUST 11, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO 15
COMPANY/ F.P.+L.
WITNESS. T.L. Hartman (TLH-3)
DATE 11-08-04

TLH-3
DOCKET NO. 040001-EI
FPL WITNESS: T. HARTMAN
EXHIBIT ____
SEPTEMBER 9, 2004

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EXECUTION COPY

CONTRACT FOR THE PURCHASE OF CAPACITY AND ENERGY BETWEEN SOUTHERN COMPANY SERVICES, INC. AND FLORIDA POWER & LIGHT COMPANY

This CONTRACT FOR THE PURCHASE OF CAPACITY AND ENERGY is made and entered into as of this 11th day of August, 2004 ("Effective Date"), between **SOUTHERN COMPANY SERVICES, INC.**, an Alabama corporation having its principal office and place of business at 600 North 18th Street, Birmingham, Alabama 35203, acting as agent (in such capacity hereinafter referred to as "SCS") for Southern Power Company, a Delaware corporation having its principal office and place of business at 600 North 18th Street, Birmingham, Alabama 35203 (hereinafter referred to as "Southern Power" or "Seller") and **FLORIDA POWER & LIGHT COMPANY** (hereinafter referred to as "FPL" or "Buyer"), a Florida corporation having its principal office and place of business at 700 Universe Boulevard, Juno Beach, Florida 33408. Seller and Buyer are hereafter referred to individually and collectively as a "Party" or the "Parties," respectively.

RECITALS:

Buyer desires to purchase and Seller desires to sell, capacity and energy in accordance with this Agreement.

Subject to the terms and conditions of this Agreement, Seller will provide and sell to Buyer, and Buyer will accept and purchase from Seller, capacity and energy from the Facility or from other resources as provided in this Agreement.

NOW THEREFORE, in consideration of the foregoing recitals and the mutual covenants and agreements hereinafter set forth, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE 1

DEFINITIONS

The following terms shall have the respective meanings set forth below.

"**Affiliate**" means, with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly (through one or more intermediaries) controls, is controlled by, or is under common control with, such corporation, partnership, or other entity.

"After-Tax Basis" means, with respect to any payment under Section 14.2 to any Person, the amount of such payment ("Base Payment") supplemented by a further payment ("Additional Payment") to that Person so that the sum of the Base Payment plus the Additional Payment shall, after deduction of the amount of all Federal, state and local income taxes required to be paid by such Person in respect of the receipt or accrual of the Base Payment and the Additional Payment (taking into account the net present value of any reduction in such income taxes resulting from tax benefits realized by the recipient as a result of the payment or the event giving rise to the payment), be equal to the amount required to be received. Such calculations shall be made on the basis of the highest generally applicable Federal, state and local income tax rates applicable to the Person for whom the calculation is being made for all relevant periods, and shall take into account the deductibility of state and local income taxes for Federal income tax purposes.

"**Agreement**" means this Contract for the Purchase of Capacity and Energy, including, to the extent applicable, any appendices hereto and any amendments that the Parties may execute now or at any time in the future.

"**Alternate Delivery Point(s)**" means, when Seller designates an Alternate Resource(s) pursuant to Section 5.5 or Section 5.6 (including a Replacement Resource), the applicable point(s) of delivery designated by Seller.

"**Alternate Resource(s)**" means any resource or resources other than the Facility (whether such other resources are owned, purchased or otherwise controlled by Seller, or that are otherwise available to Seller) that Seller designates pursuant to Section 5.5 or Section 5.6.

"**Available Capacity**" means, at any given time, the Contract Capacity less the sum of: (i) the Force Majeure Capacity at such time; and (ii) the Outage Capacity at such time.

"**Billing Month**" means each Month during the Term beginning with the second Month of the first Contract Year and includes the Month immediately following the expiration or early termination of this Agreement.

"Block 1 Mode" means any time a Schedule requests energy for any hour in an amount equal to [redacted] MW or, in hours for which Seller has informed Buyer that the amount of capacity Seller will make available to Buyer is less than [redacted] MW, any time a Schedule requests energy in an amount equal to the maximum amount of capacity Seller will make available.

"Block 2 Mode" means any time a Schedule requests energy for any hour in an amount equal to [redacted] MW or, in hours for which Seller has informed Buyer that the amount of capacity Seller will make available to Buyer is less than [redacted] MW but greater than [redacted] MW, any time a Schedule requests energy in an amount equal to the maximum amount of capacity Seller will make available.

"Block 3 Mode" means any time a Schedule requests energy for any hour in an amount equal to [redacted] MW or, in hours for which Seller has informed Buyer that the amount of capacity Seller will make available to Buyer is less than [redacted] MW but greater than [redacted] MW, any time a Schedule requests energy in an amount equal to the maximum amount of capacity Seller will make available.

"Block 4 Mode" means any time a Schedule requests energy for any hour in an amount equal to the full amount of Contract Capacity and such capacity is greater than [redacted] MW or, in hours for which Seller has informed Buyer that the amount of capacity Seller will make available to Buyer is less than the Contract Capacity but greater than [redacted] MW, any time a Schedule requests energy in an amount equal to the maximum amount of capacity Seller will make available.

"Block Mode" means either Block 1 Mode, Block 2 Mode, Block 3 Mode, or Block 4 Mode.

"Btu" means British Thermal Units.

"**Business Day**" means any Day on which Federal Reserve Member Banks in New York, New York are open for business. A Business Day shall begin at 0800 CPT and end at 1700 CPT.

"**Buyer**" has the meaning set forth in the introductory paragraph hereof.

"Buyer Delivery Point(s)" means, for any hour of any Delivery Day, the point(s) on the Southern Company Transmission System to which Buyer intends to transmit energy delivered by Seller under this Agreement.

"Buyer Percentage" means 35.2 percent.

"**Central Prevailing Time**" or "**CPT**" means the local time at any point in Birmingham, Alabama.

"**Change in Law**" means the adoption, enactment, promulgation or issuance of, a change in, or a new or changed interpretation by a Government Agency of, any Law after February 6, 2004.

"**Commercially Reasonable**" or "**Commercially Reasonable Efforts**" means, with respect to any purchase, sale, decision, or other action made, attempted or taken by a Party, such efforts as a reasonably prudent business would undertake for the protection of its own interest under the conditions affecting such purchase, sale, decision, or other action, including without limitation, electric system reliability and stability, the amount of notice of the need to take such action, the duration and type of the purchase or sale or other action, and the commercial environment in which such purchase, sale, decision, or other action occurs.

"**Contemporaneous Agreements**" means: (i) this Agreement; (ii) the Contract for the Purchase of Capacity and Energy from Plant Harris Unit No. 1 dated as of August 11, 2004 between Southern Company Services, Inc. (as agent for Seller) and Buyer; and (iii) the Contract for the Purchase of Capacity and Energy from Plant Scherer Unit No. 3 dated as of August 11, 2004 between Southern Company Services, Inc. (as agent for Georgia Power Company and Gulf Power Company) and Buyer.

"**Contest**" means with respect to any Person, a contest of any Governmental Approval or Law, acts or omissions by any Government Agency, a requirement of any Government Agency, or any related matters, so long as the contesting Party could not reasonably be expected to be prevented from performing its material obligations under this Agreement pending the outcome of such contest.

"**Contract Capacity**" means the lesser of: (i) 190 MW; or (ii) the Total Facility Capacity multiplied by the Buyer Percentage, or such other amount as expressly provided in this Agreement.

"**Contract Year**" means: (i) for the first Contract Year, the Service Commencement Date through the next date that is May 31; and (ii) for each Contract Year thereafter, each 12 Month period beginning June 1 and ending May 31; provided, however, the last Contract Year shall end on the date that this Agreement terminates or expires.

"**Day**" means the period of time beginning at hour ending 0100 CPT and ending at hour ending 2400 CPT.

"**Delivery Day**" means any Day for which Buyer Schedules energy to be delivered in accordance with this Agreement.

"**Delivered Energy**" means, for any hour, the amount of energy (expressed in MWh) delivered by Seller in accordance with this Agreement and shall equal the sum of: (i) energy delivered by Seller to the Delivery Point pursuant to Buyer's Schedule; and (ii) any energy provided and/or procured by Seller to resolve energy imbalances at the Delivery Point. Delivered Energy shall not exceed Scheduled Energy for any hour.

"**Delivered Energy Credit**" means, for any hour, to the extent such difference is positive, the difference of: (i) Delivered Energy for such hour; less (ii) Available Capacity plus the portion of Delivered Energy provided from an Alternate Resource(s) designated for such hour pursuant to Section 5.5.1 in response to a Force Majeure Event.

"**Delivery Excuse**" means: (i) an Event of Default by Buyer; (ii) the interruption of transmission service procured by Buyer or the unavailability of transmission service to Buyer beyond the Delivery Point(s); (iii) any directive from the applicable transmission provider

and/or control area operator to cease deliveries of energy from the Facility; (iv) SNG's failure to schedule or to deliver scheduled quantities of Gas to the Facility (but only if, for the period of such failure, Seller has complied with Section 9.1 and has utilized Commercially Reasonable Efforts to utilize available transportation capacity as required by Section 9.2.1 to satisfy Buyer's Schedule); or (v) a circumstance described in Section 9.2.7 and/or Section 9.3.2.

"**Delivery Point**" means the Facility Delivery Point when Seller designates the Facility as the source of Delivered Energy and/or the Alternate Delivery Point(s) (as applicable) to which Seller shall deliver energy to Buyer hereunder.

"**Effective Date**" has the meaning set forth in the introductory paragraph hereof.

"Electric Metering Equipment" means electric meters and associated equipment, including metering transformers and back-up meters.

"**EFMH**" or "**Equivalent Force Majeure Hour**" shall occur in any hour (or portion of an hour) in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point is occurring or is continuing. During such an hour, EFMH shall equal the ratio of: (A)(i) Force Majeure Capacity for such hour; less (ii) the amount of electric capacity associated with an Alternate Resource(s), whether available or unavailable, that has been designated for such hour pursuant to Section 5.5.1 in response to the Force Majeure Event causing the Force Majeure Capacity to exist; to (B) the Contract Capacity.

"**EUH**" or "**Equivalent Unavailable Hour**" shall occur in any hour (or portion of an hour) in which there is Unavailable Capacity. For such an hour, EUH shall equal the ratio of: (i) Unavailable Capacity for such hour; to (ii) the Contract Capacity for such hour.

"**Event of Default**" has the meaning set forth in Section 16.1.

"**Facility**" means Seller's Gas fired combined cycle electric generating unit known as Plant Franklin Unit No. 1 (as may be modified) and all appurtenant facilities, located near Smiths, Alabama which directly interconnects to the Georgia Integrated Transmission System, or such other resource designated as the Facility pursuant to Section 3.3.

"Facility Delivery Point" means the substation where the Facility interconnects to the Georgia Integrated Transmission System (or other applicable transmission system) at the transmission system voltage.

"**FERC**" means the Federal Energy Regulatory Commission, or any successor to its functions.

"Florida Interface" means the transmission interface between the Southeastern Electric Reliability Council (or its successor) region and the Florida Reliability Coordinating Council (or its successor) region as such regions exist on the Effective Date.

"Force Majeure Capacity" means, for any hour in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, the portion of the Contract Capacity that is not available from the Facility as a result of such Force Majeure Event. Force Majeure Capacity shall be calculated as follows:

Force Majeure Capacity = Contract Capacity – Unaffected Contract Capacity

Where:

Unaffected Contract Capacity = Buyer Percentage * Adjusted Total Unaffected Capacity

Adjusted Total Unaffected Capacity = the lesser of TCUFM or 540 MW

TCUFM = Total Capacity Unaffected by Force Majeure = Total Facility Capacity – TAC

TAC = Total Affected Capacity = the total amount of capacity that is not available from the Facility as a result of the Force Majeure Event.

"**Force Majeure Event**" has the meaning set forth in Section 15.1.

"**Gas**" means natural gas.

"**Georgia Integrated Transmission System**" means the electric transmission systems owned individually by Georgia Power Company, Georgia Transmission Corporation, the Municipal Electric Authority of Georgia and the City of Dalton, Georgia, and operated as an integrated transmission system, as well as any successor transmission system.

"**Government Agency**" means any federal, state, local, territorial or municipal government and any department, commission, board, court, bureau, agency, instrumentality, judicial or administrative body thereof.

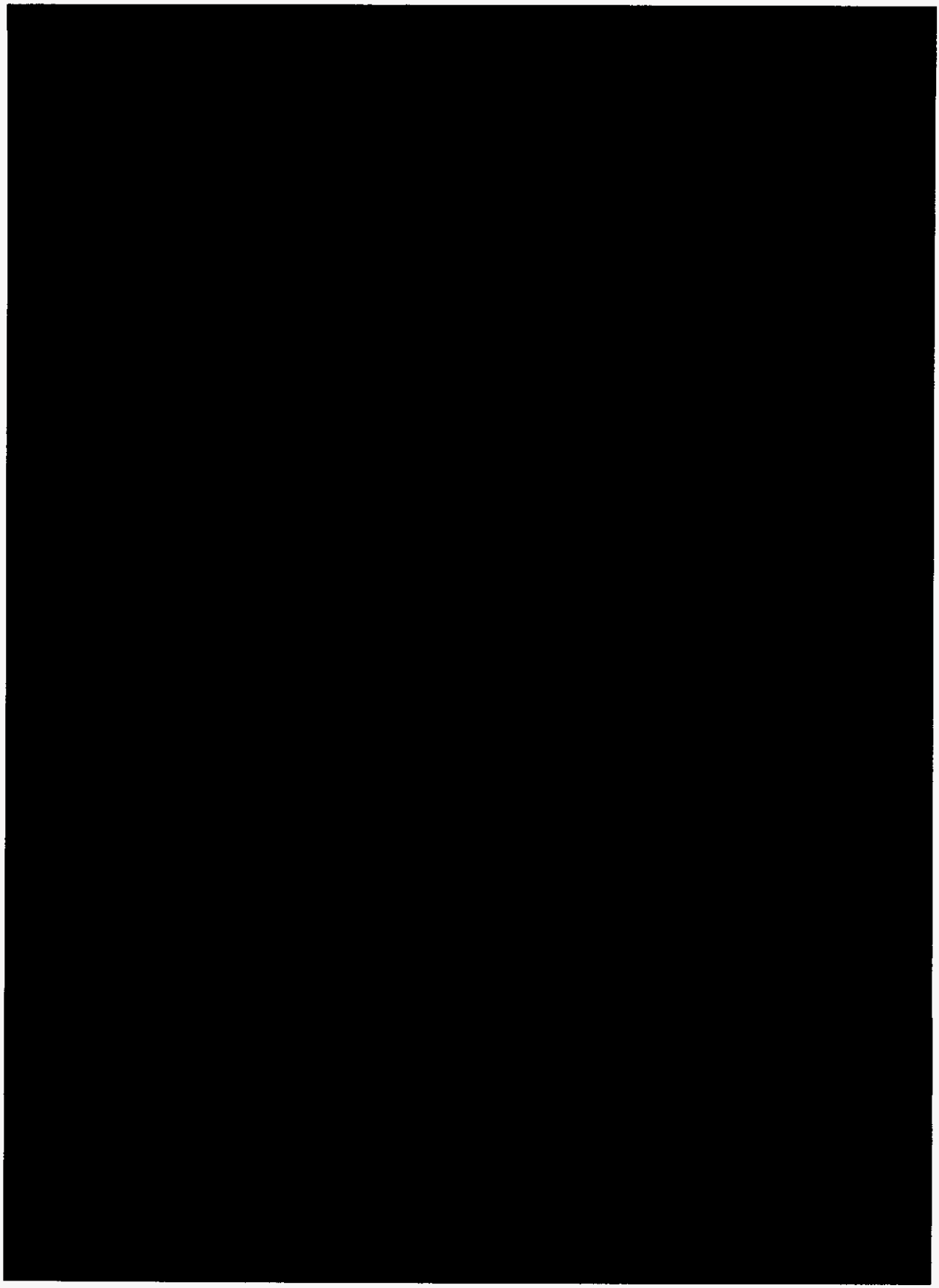
"**Governmental Approval**" means any authorization, consent, approval, license, ruling, permit, exemption, variance, order, judgment, decree, declarations of or regulation of any Government Agency relating to the Facility or to the execution, delivery or performance of this Agreement.

"**Guarantor**" has the meaning set forth in Section 16.1.

"**Guaranty**" means a guaranty or other instrument guaranteeing a Party's obligations under this Agreement as contemplated under Article 20.

"**Imaged Agreement**" has the meaning set forth in Section 21.17.

"**Increased Generation Costs**" [redacted]



"**kW**" means kilowatt(s).

"**kWh**" means kilowatt hour(s).

"**Law**" means any act; statute; law; requirement; ordinance; order; ruling or rule; regulation; standards and/or criteria contained in any permit, license or other approval; legislative or administrative action; or a decree, judgment or order of any Government Agency imposed, whether in effect now or at any time in the future.

"Long Term Firm Transmission Service" means firm point-to-point (or other equivalent) transmission service for a term of one year or more.

"**Maintenance Outage**" has the meaning set forth in Section 4.2.

"Major Maintenance" means the performance of a hot gas path inspection for the combustion turbines at the Facility.

"**Major Maintenance Off-Peak Performance Period**" means any Off-Peak Performance Period in which Major Maintenance occurs.

"**MMBtu**" means one million Btu.

"**Month**" means a calendar month.

"**Monthly Capacity Payment**" means the payment for Contract Capacity to be made by Buyer to Seller pursuant to Section 6.1.

"**Monthly Energy Payment**" means the payment for Delivered Energy to be made by Buyer to Seller pursuant to Section 6.2.

"**Monthly Fuel Transportation Payment**" means the payment for fuel transportation to be made by Buyer to Seller pursuant to Section 6.4.

"**Monthly Start Payment**" means the payment for Successful Starts to be made by Buyer to Seller pursuant to Section 6.3.

"**Moody's**" has the meaning set forth in Section 19.1.

"**MW**" means megawatt(s).

"**MWh**" means megawatt hour(s).

"**NERC**" means the North American Electric Reliability Council, or any successor to its functions.

"**Normal Off-Peak Performance Period**" means any Off-Peak Performance Period in which Major Maintenance does not occur.

"**OATT**" means the Open Access Transmission Tariff of Southern Companies or a successor tariff governing transmission on the Southern Company Transmission System, as the same may be changed or amended from time to time.

"Off-Peak Performance Period" means the period of time consisting of all hours during the Months of October, November, December, January, February, March and April in succession. If this Agreement terminates or expires during such period on a Day other than the last Day of such period, such Off-Peak Performance Period shall be deemed to end on the Day of such termination or expiration. If the Service Commencement Date occurs during such period on a Day other than the first Day of such period, such Off-Peak Performance Period shall be deemed to begin on the Service Commencement Date.

"**Operating Committee**" has the meaning set forth in Section 4.5.

"**Operating Procedures**" has the meaning set forth in Section 4.4.

"**Outage**" means any condition or circumstance in which the generating capability of the Facility is eliminated or reduced (in whole or in part) for any reason, including an actual or threatened component failure and during Scheduled Outages and Maintenance Outages. An Outage does not include those times that the Facility's capability is reduced (in whole or in part)

due to a Force Majeure Event or a Delivery Excuse. In addition, an Outage shall not occur solely because of Seller's ability to sell capacity and/or energy from the Facility to a third party or an Affiliate(s).

"Outage Capacity" means, for any hour in which an Outage occurs or is continuing, the portion of the Contract Capacity that is not available from the Facility as a result of such Outage. Outage Capacity shall be calculated as follows:

Outage Capacity = Contract Capacity – Unaffected Contract Capacity

Where:

Unaffected Contract Capacity = Buyer Percentage * Adjusted Total Unaffected Capacity

Adjusted Total Unaffected Capacity = the lesser of TCUO or 540 MW

TCUO = Total Capacity Unaffected by Outage = [the sum of: (A) the lesser of: (i) Total Facility Capacity; or (ii) 540 MW; and (B) Unused Excess Capacity] – TAC

Unused Excess Capacity = to the extent it is positive, the difference of TCUFM as determined under the definition of "Force Majeure Capacity" hereunder, less 540 MW

TAC = Total Affected Capacity = the total amount of capacity that is not available from the Facility as a result of the Outage.

"Peak Performance Period" means the period of time consisting of all hours during the Months of May, June, July, August and September in succession. If this Agreement terminates or expires during such period on a Day other than the last Day of such period, such Peak Performance Period shall be deemed to end on the Day of such termination or expiration. If the Service Commencement Date occurs during such period on a Day other than the first Day of such period, such Peak Performance Period shall be deemed to begin on the Service Commencement Date.

"Performance Period" shall mean either a Peak Performance Period or an Off-Peak Performance Period.

"Person" means any individual, corporation, limited liability corporation, partnership, joint venture, trust, unincorporated organization, Government Agency or other entity.

"Plant" means Seller's Plant Franklin located near Smiths, Alabama, which currently consists of the Facility and a combined cycle electric generating unit known as Plant Franklin Unit No. 2 and all appurtenant facilities, as such plant and facilities may be modified and/or expanded from time to time (including the addition of generating units).

"Prior Business Day" means the Business Day immediately prior to a Delivery Day.

"Prime Rate" means, for any Day on which the calculation of an interest amount begins under this Agreement, the "Prime Rate" specified for such Day (or, if such Day is not a Business Day, on the first Business Day following such Day) under the "Money Rate" table of the *Wall Street Journal.* In the event that the *Wall Street Journal* ceases to report a Prime Rate, the Prime Rate shall be the prime rate (or its functional equivalent) charged by the Federal Reserve Bank of Atlanta, Georgia.

"Prudent Industry Practices" means any of the practices, methods, standards and acts (including the practices, methods and acts engaged in or approved by a significant portion of the electric power industry in the United States) that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, could have been expected to accomplish the desired result consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts generally conform to operation and maintenance

standards recommended by equipment suppliers and manufacturers, applicable design limits and applicable Governmental Approvals and Laws.

"Redirect Deadline" means the deadline established by the applicable transmission provider for requesting the redirect of transmission service under the applicable transmission tariff.

"**S&P**" has the meaning set forth in Section 19.1.

"**SNG**" means Southern Natural Gas Company.

"**Schedule**" means the right of Buyer to request the delivery of Scheduled Energy in accordance with this Agreement. Any form of the term Schedule (e.g., "Scheduled," "Schedules" or "Scheduling") shall refer to the exercise of such right by Buyer.

"Schedule Shut-Down" means any time Buyer goes from having some energy Scheduled to having no energy Scheduled.

"**Schedule Start**" means each time that Buyer goes from not having any energy Scheduled to having some amount of energy Scheduled (in any Block Mode).

"**Scheduled Energy**" means the amounts of energy, expressed in whole MWh, Scheduled by Buyer to be delivered by Seller in accordance with this Agreement.

"**Scheduled Outage**" means maintenance and/or outages conducted and/or taken by Seller pursuant to Section 4.1.

"**Scheduling Parameters**" has the meaning set forth in Appendix D.

"SEARUC" means the Southeastern Association of Regulatory Utility Commissioners.

"**Seller**" has the meaning set forth in the introductory paragraph hereof.

"**Service Commencement Date**" means June 1, 2010; provided, however, that such date may be extended by Seller due to a Force Majeure Event for a period equal to the period of delay caused by said Force Majeure Event.

"**Southern Company**" means the Southern Company, a publicly held corporation, organized and existing under the laws of the State of Delaware and having its principal place of business in Atlanta, Georgia.

"Southern Company Transmission" means the functional transmission division of Southern Company and its affiliates, as well as any successor transmission service provider.

"Southern Company Transmission System" means the integrated transmission systems of the electric operating companies of Southern Company, as such systems may be modified or expanded from time-to-time, as well as any successor transmission system(s).

"Southern Power" has the meaning set forth in the introductory paragraph.

"**Taxes**" means any or all ad valorem, property, occupational, severance, emissions, generation, first use, conservation, energy, transmission, utility, gross receipts, privilege, sales, use, excise and other taxes, governmental charges, licenses, fees, permits and assessments; provided, however, the term Taxes shall not include taxes based on net income or net worth.

"**Term**" has the meaning set forth in Section 2.1.

"Total Facility Capacity" means, for each Contract Year, the generating capability of the Facility as declared by Seller under Article 8.

"Unavailable Capacity" means, for any hour: (i) Outage Capacity for such hour; less (ii) the Delivered Energy Credit; less (iii) if positive, the difference of the available portion of capacity associated with an Alternate Resource(s) that has been designated for such hour pursuant to Section 5.5.1 in response to the Outage causing Outage Capacity to exist, less the

Delivered Energy Credit; plus (iv) the unavailable portion of capacity associated with an Alternate Resource(s) designated for such hour pursuant to Section 5.5.1 in response to a Force Majeure Event.

ARTICLE 2

TERM OF AGREEMENT

2.1 Term. Subject to the survival provisions herein, this Agreement shall continue in full force and effect from the Effective Date until the end of the Service Term, or on such earlier date on which this Agreement is terminated in accordance with its terms ("Term").

2.2 Service Term. Subject to early termination of this Agreement as provided hereunder, Seller's obligation to provide and sell and Buyer's obligation to accept and purchase Contract Capacity and Scheduled Energy shall extend from the Service Commencement Date through December 31, 2015 ("Service Term"). Provided, however, the Service Term shall be extended through December 31, 2017 if: (i) Buyer provides Seller with written notice of its desire to extend the Service Term in this manner on or before January 31, 2010 ("Extension Notice"); and (ii) [redacted] If Buyer timely provides Seller the Extension Notice but the Parties are unable to agree on such [redacted] and/or a related amendment by December 31, 2010, the Service Term shall be extended through May 31, 2017.

2.3 Survival. All provisions of this Agreement that expressly or by implication come into or continue in force and effect following the expiration or termination of this Agreement shall remain in effect and be enforceable following such expiration or termination.

2.4 **Effect of Termination.** Subject to the exercise of a non-defaulting Party's rights under Section 14.2, in the event that this Agreement is terminated, the rights and obligations of the Parties hereunder shall continue unaffected until the termination is effective in accordance with the terms and conditions thereof. Any termination of this Agreement shall not relieve Buyer of its obligation to pay any unpaid invoices for any Contract Capacity made available and Delivered Energy prior to the effective date of such termination, relieve Seller of its obligation to provide Contract Capacity and to deliver Scheduled Energy prior to the effective date of such termination, or relieve either Party of any of its other liabilities or obligations accruing prior to termination.

ARTICLE 3

SALE AND PURCHASE OF CAPACITY AND ENERGY

3.1 **Sale and Purchase of Capacity.** Subject to the terms and conditions of this Agreement, beginning on the Service Commencement Date and until the end of the Service Term, Seller shall make available and sell to Buyer, and Buyer shall accept and purchase, the Contract Capacity.

3.2 **Sale and Purchase of Energy.** Subject to the terms and conditions of this Agreement, beginning on the Service Commencement Date and until the end of the Service Term, Seller shall deliver and sell to Buyer, and Buyer shall accept and purchase from Seller, energy up to the Contract Capacity as and when Scheduled by Buyer.

3.3 **Change of the Facility.** At any time during the Term, Seller may provide notice to Buyer that it desires to change the generating resource that constitutes the Facility under this Agreement; provided, however, such resource shall be a Gas-fired resource. Provided further, the Facility shall not be changed under this Section 3.3 more often than once every [redacted]

With any such notice, Seller shall identify the generating resource that will be the proposed new Facility, the date that Seller desires for such change to be effective ("Desired Date of Facility Change"), and the anticipated time during which such resource shall provide Contract Capacity and associated energy under this Agreement ("Facility Term"). Seller shall provide Buyer such notice no later than [redacted] prior to the Desired Date of Facility Change. Within 15 Days after receipt of Seller's notice, Buyer and Seller shall confer to discuss the proposed Facility change and any amendment(s) to this Agreement that may be necessary to effect such change. Seller and Buyer agree that any such Facility change(s) shall be subject to the mutual consent of the Parties; provided, however, Buyer shall not unreasonably withhold its consent to a proposed Facility change(s) or reasonable amendment(s) necessary to effect such change. For purposes hereof, it shall be unreasonable for Buyer to withhold its consent to a proposed Facility change by Seller (or associated amendment) if such change and/or amendment would not be expected to result in: (i) an increase in Buyer's costs during the Facility Term as compared to the then current Facility; or (ii) a decrease in Facility reliability during the Facility Term as compared to the then current Facility. Any such change in the Facility shall be expressly conditioned upon Buyer's ability to obtain transmission service during the Facility Term that has a firmness that is the same or greater than, and has a cost that is equal to or less than, the service Buyer has procured from the then current Facility; provided that Buyer shall afford Seller reasonable opportunity to offset any higher cost such that Buyer would be able to obtain such service at a cost equal to the cost of service already procured by Buyer.

ARTICLE 4

FACILITY MAINTENANCE

4.1 Scheduled Outages. Commencing in 2010 and each year thereafter, Seller shall submit to Buyer, before February 1, a schedule of Facility outages during which maintenance and/or the installation of equipment required by Law or Prudent Industry Practices will be performed for the next Contract Year ("Scheduled Outages"); [redacted] Within 30 Days after receiving Seller's proposed schedule for Scheduled Outages, Buyer may request, in writing, that Seller reschedule any such Scheduled Outages. Following receipt of such request, Seller shall attempt to coordinate among Buyer and other parties purchasing capacity and energy from the Facility in order to reschedule such Scheduled Outages; provided, however, Seller shall have sole discretion to decline to accommodate any request to reschedule Scheduled Outages. Following receipt of Buyer's request, Seller shall inform Buyer as to whether it will accommodate Buyer's request and, if so, shall further advise Buyer of the good faith estimated costs that will be incurred by Seller in connection with accommodating the request of Buyer to reschedule the Scheduled Outages. Buyer shall then within 14 Days of the receipt of the estimated costs provided by Seller determine whether Seller should reschedule the Scheduled Outages. Without regard to any prior estimate, Buyer shall reimburse Seller for all Commercially Reasonable costs related to such change in schedule if Seller makes such change. Prior to or during any Contract Year, Seller may reschedule any Scheduled Outages in accordance with Prudent Industry Practices.

4.2 [redacted]

4.3 Permits and Compliance with Laws.

4.3.1 Subject to the right of Contest, each Party shall acquire and maintain in effect all Governmental Approvals necessary for it to perform its obligations under this Agreement.

4.3.2 Subject to the right of Contest, each Party shall at all times comply with all Laws and Governmental Approvals applicable to such Party that are necessary for such Party to perform its obligations under this Agreement.

4.4 Operating Procedures. Buyer and Seller shall begin to develop written Operating Procedures no later than 6 months before the Service Commencement Date. Such Operating Procedures shall be completed no later than 30 Days before the Service Commencement Date. The Operating Procedures shall establish the protocol under which the Parties shall perform their respective responsibilities under this Agreement, including method of Day-to-Day communications, key personnel lists, and logging and tracking of hours of EUH and EFMH, Scheduled Outages, Maintenance Outages, and hours of Delivery Excuse.

4.5 Operating Committee. The Parties shall form a committee to act in matters relating to the performance of their respective obligations under this Agreement ("Operating

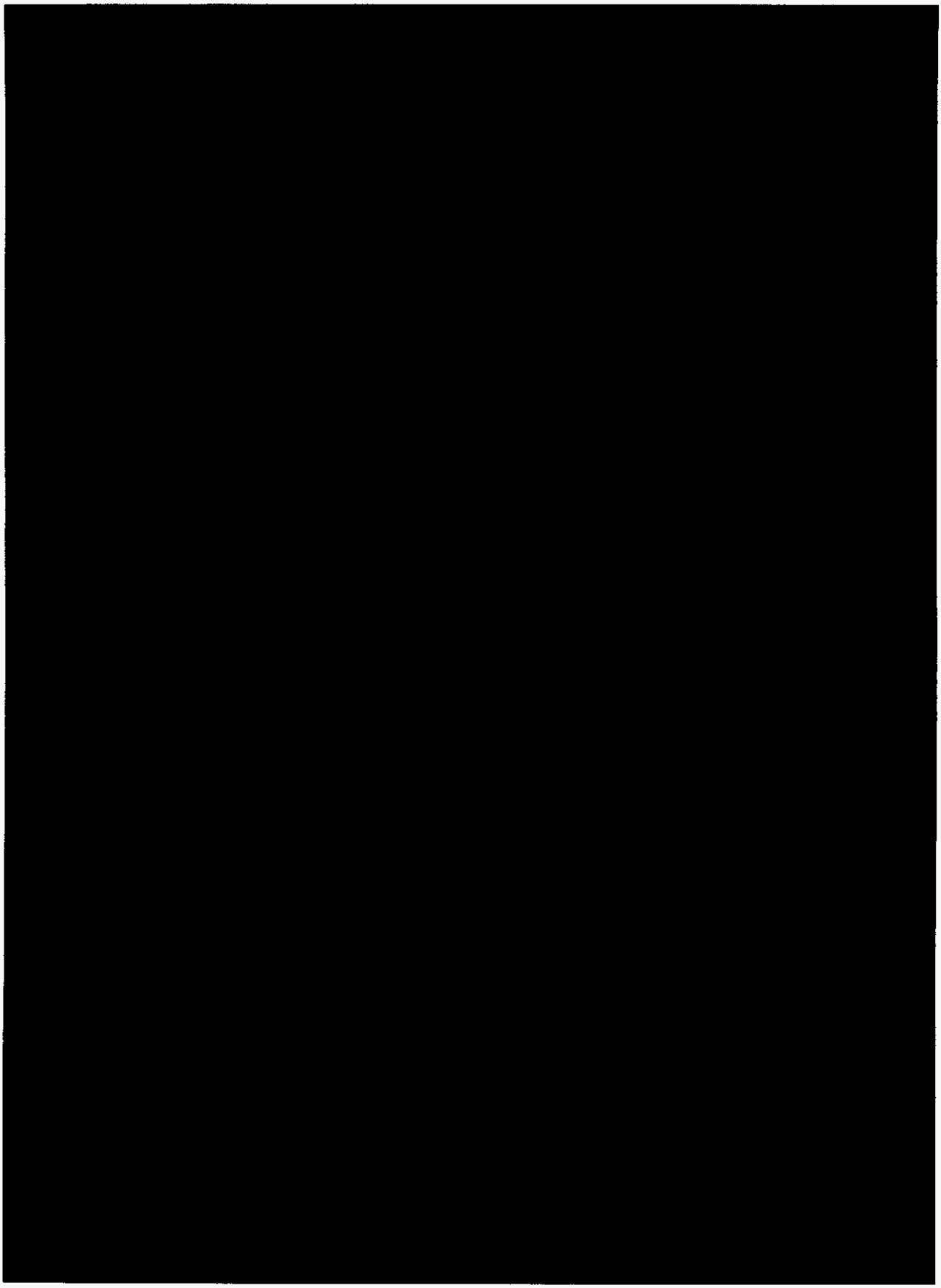
Committee"). Each Party shall appoint one representative and one alternate representative to serve on the Operating Committee. The Parties shall notify each other in writing of such appointments and any changes thereto. The Operating Committee shall have no authority to modify the terms or conditions of this Agreement. Beginning in 2009, the Operating Committee shall meet no less than two times per calendar year (which meetings may be by telephone) and all of its decisions must be the unanimous decision of the representatives. Within a reasonable time after the conclusion of each meeting of the Operating Committee, the representatives of each Party shall exchange written summaries of such meeting, including a description of issues discussed and decisions made.

ARTICLE 5

SCHEDULING AND THE PROVISION OF CAPACITY AND ENERGY

5.1 Scheduling.

[redacted]

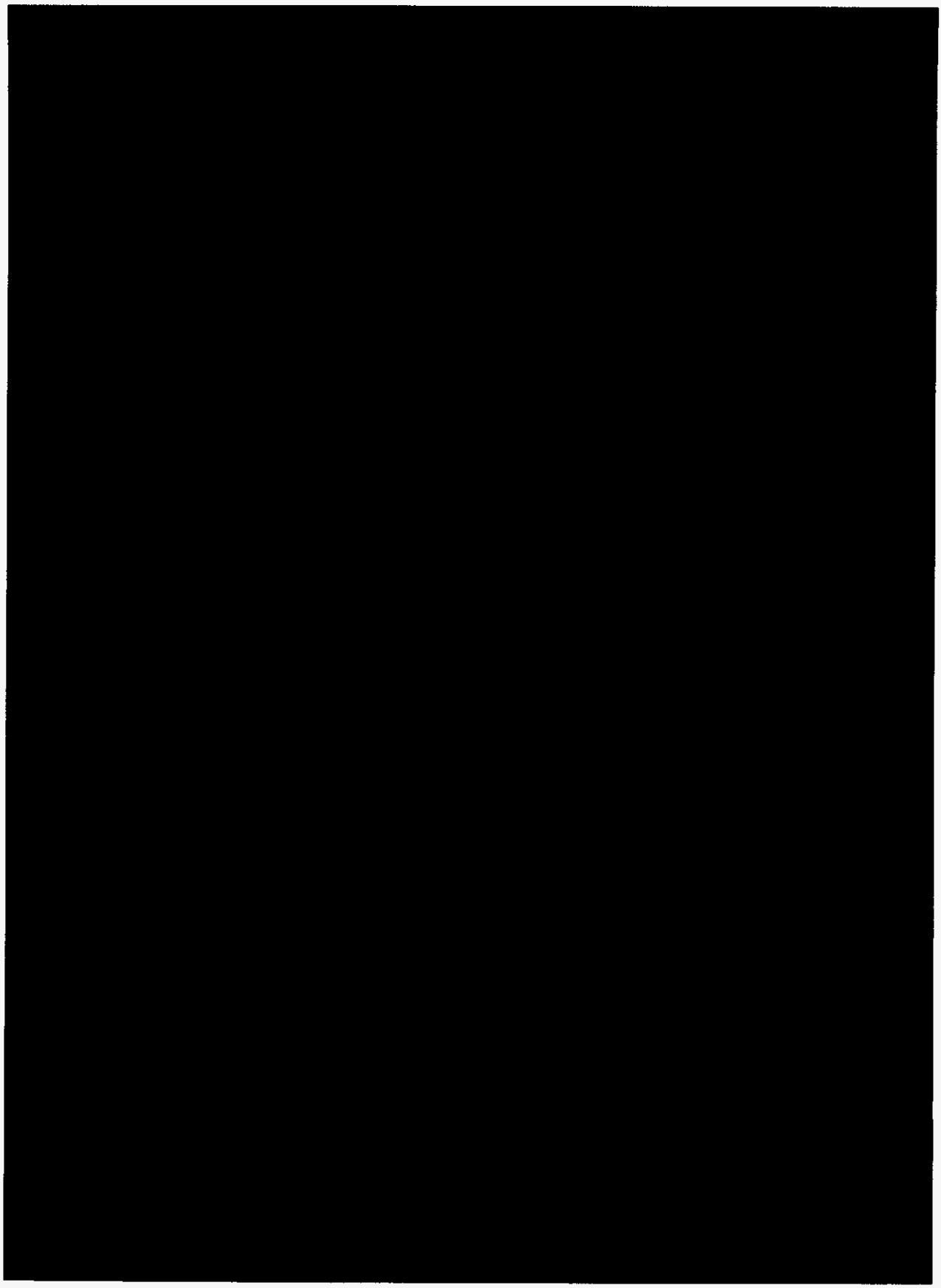


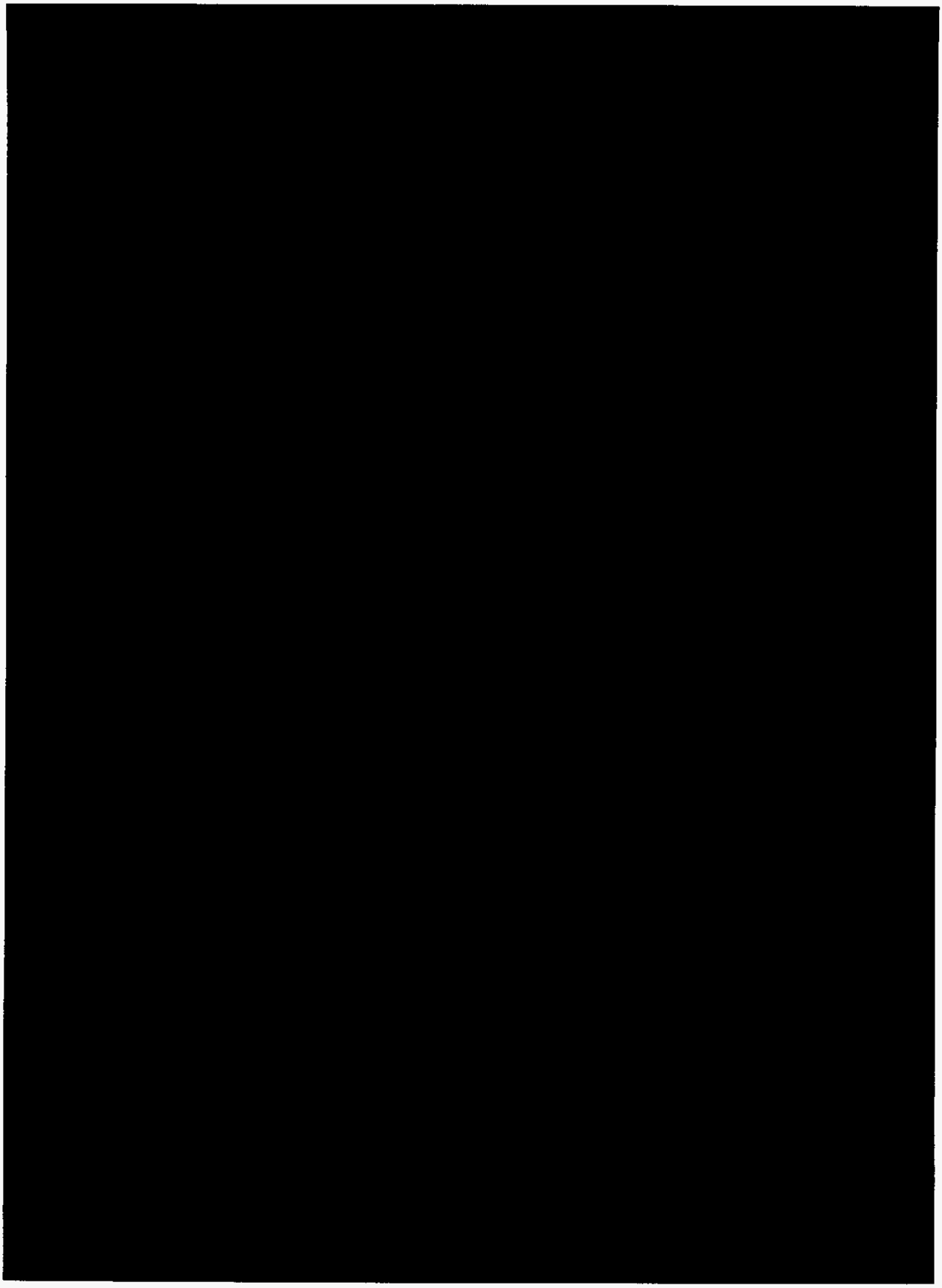
5.2 Transmission and Scheduling Requirements. Buyer shall be responsible for complying with all transmission reservation, scheduling and tagging requirements associated with energy provided hereunder at and after the Delivery Point.

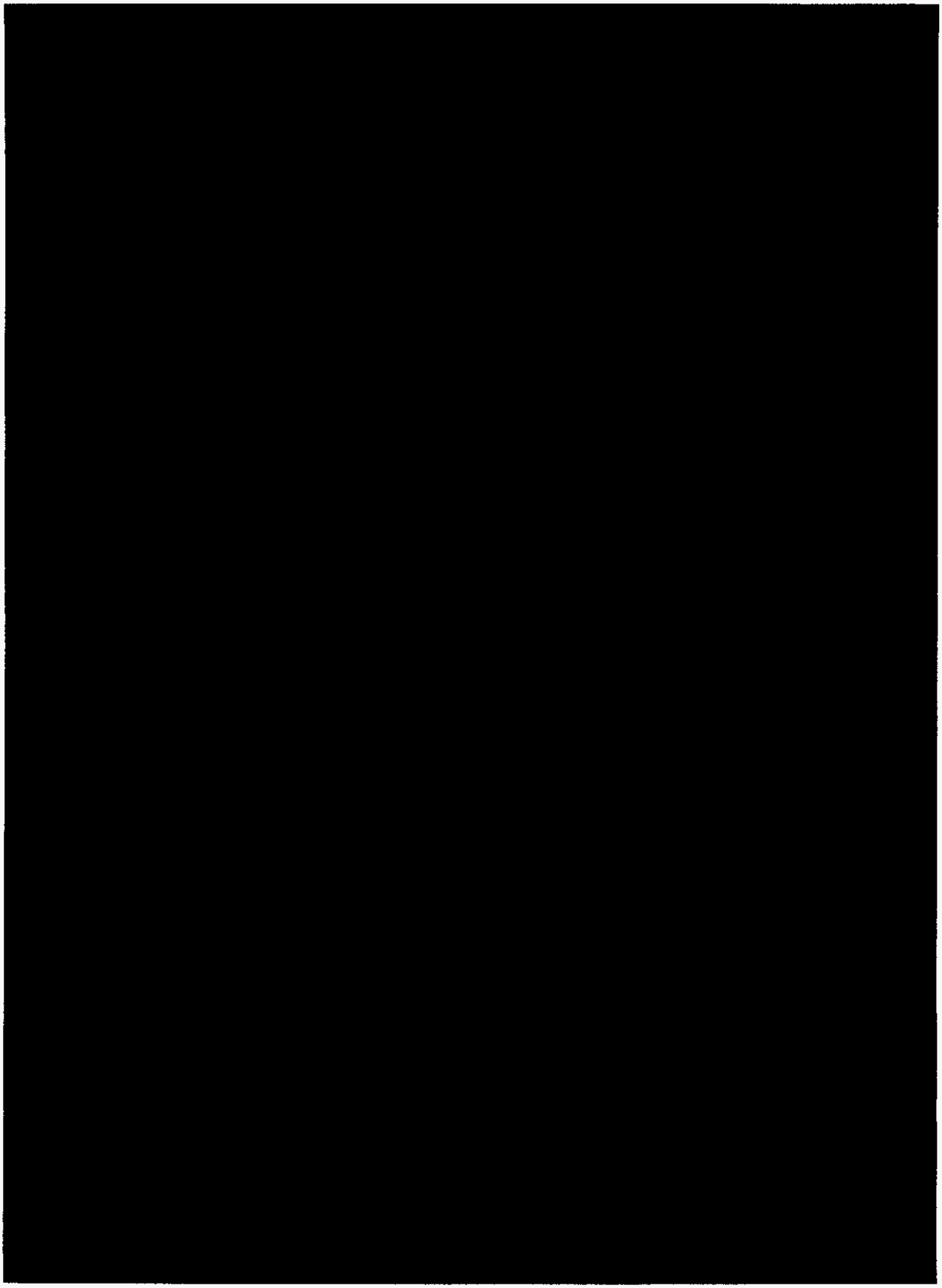
5.3 Costs and Expenses. Except as specifically provided hereunder, all costs and expenses associated with Delivered Energy at and after the Delivery Point shall be the sole responsibility of Buyer. Except as specifically provided hereunder, all costs and expenses associated with Delivered Energy prior to the Delivery Point shall be the responsibility of Seller. Any penalties associated with Delivered Energy shall be the responsibility of the Party whose action or inaction caused the penalty to be assessed.

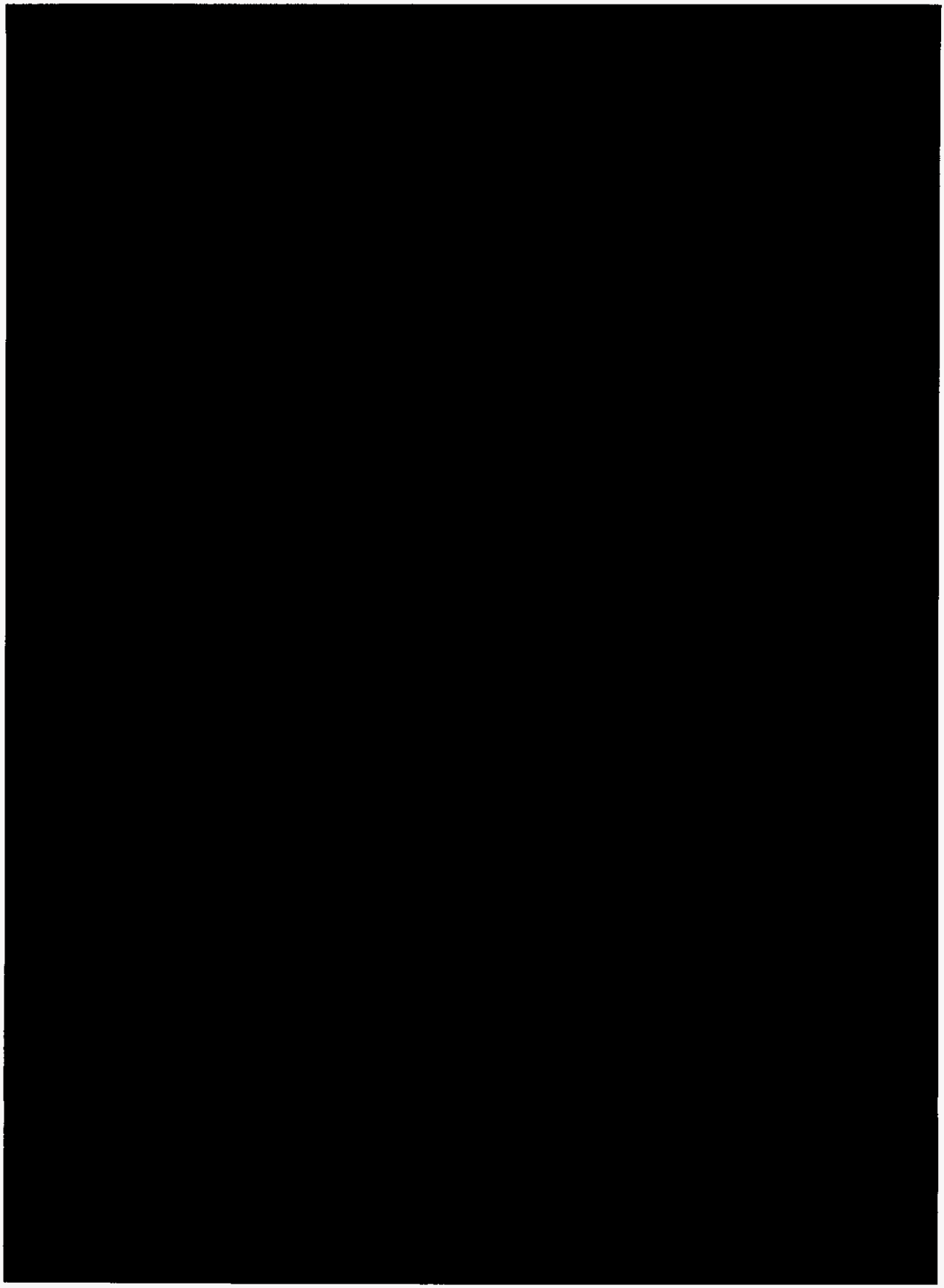
5.4 Delivery of Energy. Subject to the terms of this Agreement and the Scheduling Parameters, energy provided by Seller pursuant to Buyer's Schedule shall be deemed to be delivered at the Delivery Point.

5.5 [redacted]









[redacted]

5.7 Seller's Rights to the Facility. To the extent Buyer has not submitted a Schedule requesting energy associated with the full Contract Capacity, and/or to the extent Scheduled Energy is being provided from Alternate Resources, Seller shall have the right to dispatch the Facility to utilize for its own purposes energy from the Facility not Scheduled and/or replaced with Alternate Energy.

5.8 Title and Risk of Loss. Seller shall be deemed to be in exclusive control of the Delivered Energy prior to the Delivery Point. Buyer shall be deemed to be in exclusive control of the Delivered Energy at and after the Delivery Point. Custody, title and risk of loss of Contract Capacity and Delivered Energy shall transfer from Seller to Buyer at the Delivery Point.

5.9 Force Majeure Event.

5.9.1 For any hour in which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, Seller shall only be obligated to deliver to Buyer the lesser of: (i) Scheduled Energy; or (ii) energy associated with the difference of the Contract Capacity less Force Majeure Capacity. In addition, to the extent of such Force Majeure Event, Seller may elect in its sole discretion pursuant to the procedures under Section 5.5 (but shall not be required) to deliver Scheduled Energy from Alternate Resources.

5.9.2 For any hour during which a Force Majeure Event affecting the Facility or the electric facilities prior to the Facility Delivery Point occurs or is continuing, Seller shall be required to accumulate EFMH (as applicable) for such hour. [redacted]

5.10 Outages and Unavailable Capacity.

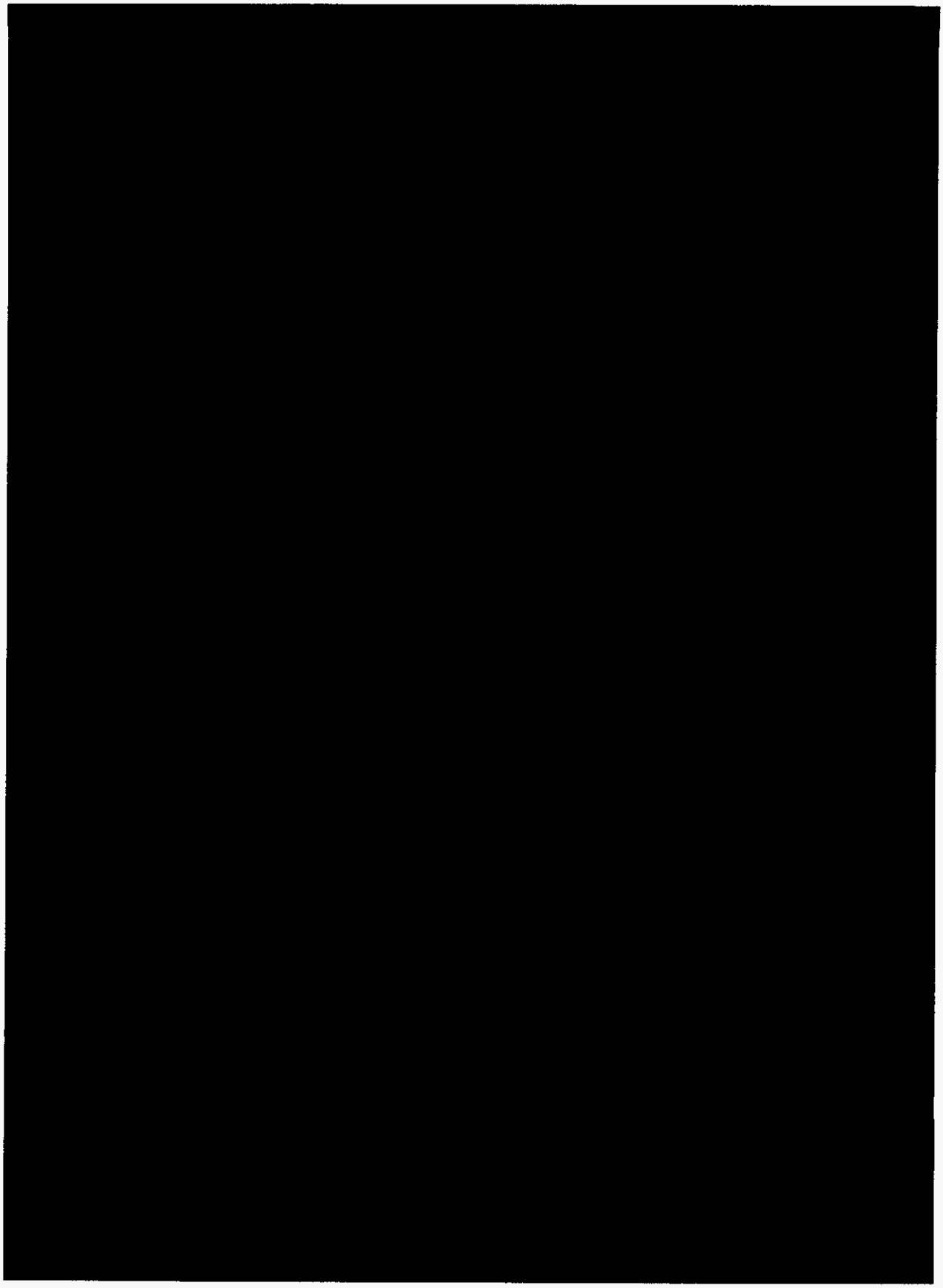
5.10.1 Seller shall notify Buyer as soon as reasonably practicable of: (i) the occurrence of any Outage that is expected to result in Outage Capacity and the estimated duration of such Outage; (ii) the cessation of such Outage; and (iii) if requested by Buyer within 30 Days after the Outage and if known to Seller, the cause of such Outage.

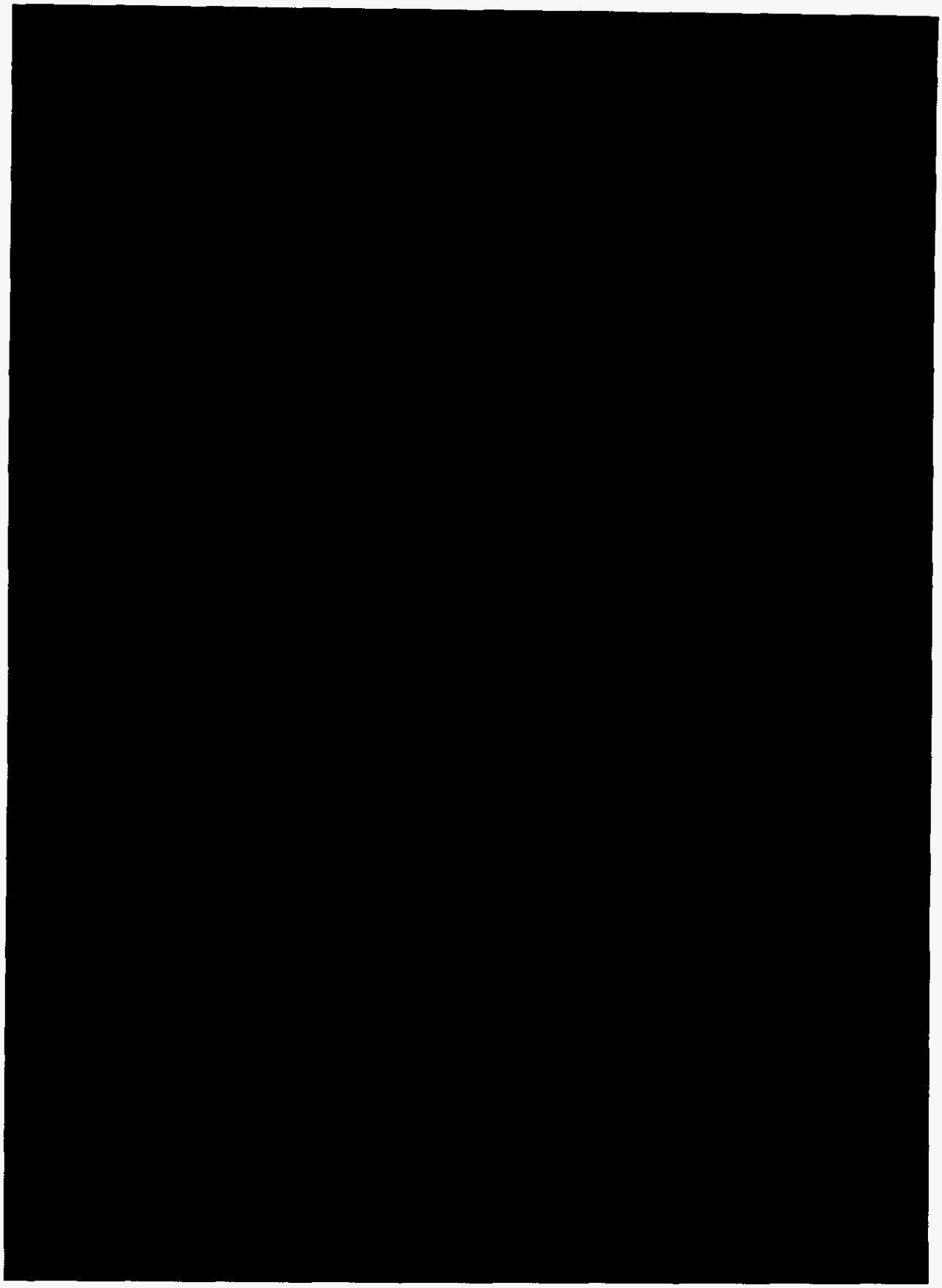
5.10.2 For any hour during which there is Unavailable Capacity, Seller shall be required to accumulate EUH (as applicable) for such hour. [redacted] Seller's sole and exclusive liability and Buyer's sole and exclusive remedy for Seller's failure to provide capacity and/or energy from any resource under this Agreement shall be [redacted]

5.11 Delivery Excuse. For any hour in which a Delivery Excuse is occurring or is continuing, Seller shall not be obligated to deliver, and Buyer shall not be entitled to receive, or submit a Schedule for, Scheduled Energy. In such event, Seller shall not be required to accumulate EFMH or EUH. Buyer shall not be relieved of its performance obligations during a Delivery Excuse, including its obligation to pay Seller the Monthly Capacity Payment.

5.12 Scheduled and Maintenance Outages. Buyer shall not have the right to submit a Schedule for any period of time during which maintenance is being performed and/or outages are taken consistent with Sections 4.1 and 4.2.

5.13 [redacted]





[redacted]

ARTICLE 6

PAYMENTS

6.1 Capacity Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Capacity Payment for the Contract Capacity. The calculation of the Monthly Capacity Payment is set forth in Appendix A.

6.2 Energy Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Energy Payment. The calculation of the Monthly Energy Payment is set forth in Appendix B.

6.3 Start Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Start Payment. The calculation of the Monthly Start Payment is set forth in Appendix C.

6.4 Fuel Transportation Payment. Commencing on the Service Commencement Date and for each Month of the Service Term, Buyer shall pay to Seller a Monthly Fuel Transportation Payment. The calculation of the Monthly Fuel Transportation Payment is set forth in Section 9.2.2.

6.5 Additional Payments. In addition to the payments specified in this Article 6, the Parties shall pay all amounts due pursuant to the other provisions of this Agreement.

ARTICLE 7

TRANSMISSION SERVICE

7.1 Buyer Obligations. Buyer, or its designee, shall have the sole and exclusive responsibility at all times to arrange, obtain, contract and pay for any and all transmission service and ancillary services required (including service under any applicable transmission tariff) to deliver any energy hereunder from and beyond the Delivery Point. Buyer assumes all risk associated with the availability, adequacy and cost of such transmission service and ancillary services.

7.2 Seller Obligations. Seller, or its designee, shall have the sole and exclusive responsibility at all times to arrange, obtain, contract, and pay for any and all transmission service required to deliver energy hereunder to the Delivery Point.

7.3 Imbalances and Penalties. Upon receiving notice of any interruption of the delivery of energy under this Agreement for any reason (e.g., an Outage or a Force Majeure Event), Buyer shall promptly notify the applicable transmission provider and/or system operator in order to avoid any energy imbalances. Any penalties or imbalances (including associated costs) resulting from actions or inactions of Buyer (including the failure to provide required notice to the applicable transmission provider and/or system operator), its designee or any third

party to which Buyer may be supplying the capacity and energy provided hereunder will be the responsibility of Buyer as between the Parties. Any penalties or imbalances (including associated costs) resulting from actions or inactions of Seller or its designee will be the responsibility of Seller as between the Parties. If either Party incurs any costs associated with penalties or imbalances that are the responsibility of the other Party under this Section, such other Party shall provide prompt reimbursement of such costs.

7.4 Buyer's Request for Transmission Service.

7.4.1 Within [redacted] Days after the Effective Date, Buyer shall request from Southern Company Transmission (including by submitting such request on Southern Company Transmission's OASIS and completing any required application(s)) 190 MW of Long Term Firm Transmission Service from the Facility Delivery Point to the Florida Interface, such service to commence on June 1, 2010 ("Requested Service"). As entered into Southern Company Transmission's OASIS, such request shall designate the point of delivery as "FPL." In addition, from the Effective Date, Buyer shall make and/or continue Commercially Reasonable Efforts to have Southern Company Transmission provide Buyer with an offer to provide the Requested Service no later than [redacted] ("Transmission Deadline"); provided, however, the Transmission Deadline shall automatically be extended on a Month to Month basis until either Party provides timely notice to the other that it does not desire for the Transmission Deadline to be extended under this Agreement and in Section 7.4.1 of both of the other Contemporaneous Agreements. Such notice must be provided no later than 5 Days prior to the then existing Transmission Deadline (as may be extended). Notwithstanding the foregoing, the Transmission Deadline in this Agreement shall be extended only to the same

extent as such deadline is also extended under Section 7.4.1 of both of the other Contemporaneous Agreements.

7.4.2 No later than 2 Business Days after the earlier of: (i) the Transmission Deadline; (ii) Southern Company Transmission's notice to Buyer that it will not be able to provide any of the Requested Service to Buyer; or (iii) Southern Company Transmission's notice to Buyer that it will be able to provide some or all of the Requested Service to Buyer, Buyer shall notify Seller ("Transmission Notice") of the total amount of the Requested Service that Southern Company Transmission is able to provide to Buyer at any price and cost ("SCT Service"). In the event that the total cost ("Total Cost") of any portion of the SCT Service is higher than the embedded rate for Long Term Firm Transmission Service under the OATT ("Tariff Rate"), the Transmission Notice shall specify the amount of SCT Service offered at a Total Cost higher than the Tariff Rate, and include any and all documentation of such Total Cost provided to Buyer by Southern Company Transmission. For purposes of this Section 7.4, "Total Cost" shall mean those costs that would be imposed on Buyer directly by the applicable transmission provider for the Requested Service.

7.4.3 Within 2 Business Days after its receipt of the Transmission Notice, Seller may offer to sell to Buyer (including by reassignment) up to 190 MW of Long Term Firm Transmission Service from the Facility Delivery Point to the Florida Interface on any applicable transmission system, such service to commence on June 1, 2010 ("Seller Service"). Such offer shall set forth the amount of Seller Service and the price for such service. For purposes of this Agreement the sum of the Seller Service and the SCT Service shall be referred to as the "Available Service."

7.4.4 [redacted]

7.4.5 Once the procedures in Sections 7.4.1 through 7.4.4 have been completed (as applicable), Buyer may elect to reduce the Contract Capacity for the Service Term by an amount up to the sum of: [redacted] Buyer shall notify Seller of such election within 3 Business Days after the later of the date of (if applicable) the Reduction Notice, receipt of Seller's offer under Section 7.4.3 or the Transmission Notice ("Election Deadline"). In addition, after the procedures in Sections 7.4.1 through 7.4.4 have been completed (as applicable), if Available Service of at least [redacted] MW is not available to Buyer so that Buyer is in effect able to procure Long Term Firm Transmission Service from the Facility at a Total Cost equal to or less than the Tariff Rate (taking into account any offset of Excess Cost by Seller), Buyer may provide notice to Seller that it will terminate this Agreement. Such notice must be provided no later than the Election Deadline.

7.4.6 If Buyer elects, pursuant to Section 7.4.5, to reduce the Contract Capacity by an amount greater than [redacted] MW, Seller shall be entitled to either: [redacted]

[redacted] Seller shall provide Buyer with notice of its election of either (i) or (ii) no later than 2 Business Days after its receipt of Buyer's notice to reduce the Contract Capacity. If Seller accepts the reduction in Contract Capacity, the Parties shall mutually agree on modifications to this Agreement in order to reflect such reduction.

7.4.7 In the event that either Party provides notice to the other Party under this section 7.4 that it has elected to terminate this Agreement, this Agreement and the other Contemporaneous Agreements shall immediately terminate. Upon such termination, no Party shall have any further obligation under any of the Contemporaneous Agreements except for any liabilities and/or obligations accruing prior to such termination. The Parties acknowledge that the other Contemporaneous Agreements contain a provision similar to this Section 7.4.7 and that this Agreement is subject to termination as provided in such similar provisions.

7.4.8 Nothing in this Section 7.4 shall be construed as requiring Buyer to actually purchase any transmission service.

7.4.9 The MW amounts set forth in this Section 7.4 refer to MW amounts at the Facility Delivery Point. As appropriate and/or required, such amounts shall be adjusted consistent with the OATT (or other applicable transmission tariff) to reflect transmission losses to the Florida Interface (e.g., including for purposes of submitting the required transmission service request through Southern Company's OASIS and/or other required application(s) for such service).

7.5 Regional Transmission Organizations.

7.5.1 In the event that a Regional Transmission Organization(s) or similar organization ("RTO") is formed and such formation materially changes the scheduling requirements and/or costs associated with the delivery of energy to and/or from the Delivery

Point, Seller shall be solely responsible for complying with all scheduling requirements and paying all such costs to the Delivery Point (including but not limited to all congestion and/or basis costs). In addition, Buyer shall be solely responsible for complying with all scheduling requirements and paying all such costs at and beyond the Delivery Point to any other point(s) of delivery (including but not limited to all congestion and/or basis costs). Seller agrees to indemnify and hold harmless Buyer for any costs and expenses incurred by Buyer that are Seller's responsibility under this Section 7.5.1. Buyer agrees to indemnify and hold harmless Seller for any costs and expenses incurred by Seller that are Buyer's responsibility under this Section 7.5.1.

7.5.2 [redacted]

1 [redacted]

2 [redacted]

ARTICLE 8

TOTAL FACILITY CAPACITY AND COMMENCEMENT OF SERVICE

8.1 Declaration of the Total Facility Capacity. Through notice to Buyer, Seller shall declare the Total Facility Capacity for each Contract Year pursuant to the procedures set forth in Section 8.2.

8.2 Declaration Prior to Each Contract Year.

8.2.1 Except as provided in Section 8.3.1.1 and 8.3.1.2, within 90 Days prior to the beginning of each Contract Year, Seller shall declare the Total Facility Capacity for such Contract Year. Such declaration shall be based on the demonstrated generating capability of the Facility as determined in accordance with Appendix E.

8.2.2 After Seller's declaration under Section 8.2.1, Buyer shall have the right to require a test to re-demonstrate the capability of the Facility as follows:

8.2.2.1 After Seller's declaration of the Total Facility Capacity for the first Contract Year, Buyer may by notice to Seller ("Test Notice") require Seller to conduct a test to re-demonstrate the capability of the Facility. Buyer shall provide any such Test Notice no later than 30 Days after the Service Commencement Date ("Initial Testing Deadline"). If Buyer timely provides the Test Notice, Seller shall conduct a test of the Facility in accordance with Appendix E within 30 Days after the Test Notice on a Day selected by Seller and provide Buyer with prior notice of such test. Buyer shall pay Seller all costs of testing (including Gas and operation and maintenance costs), and Buyer shall be entitled to utilize all energy produced during testing for its own purposes.

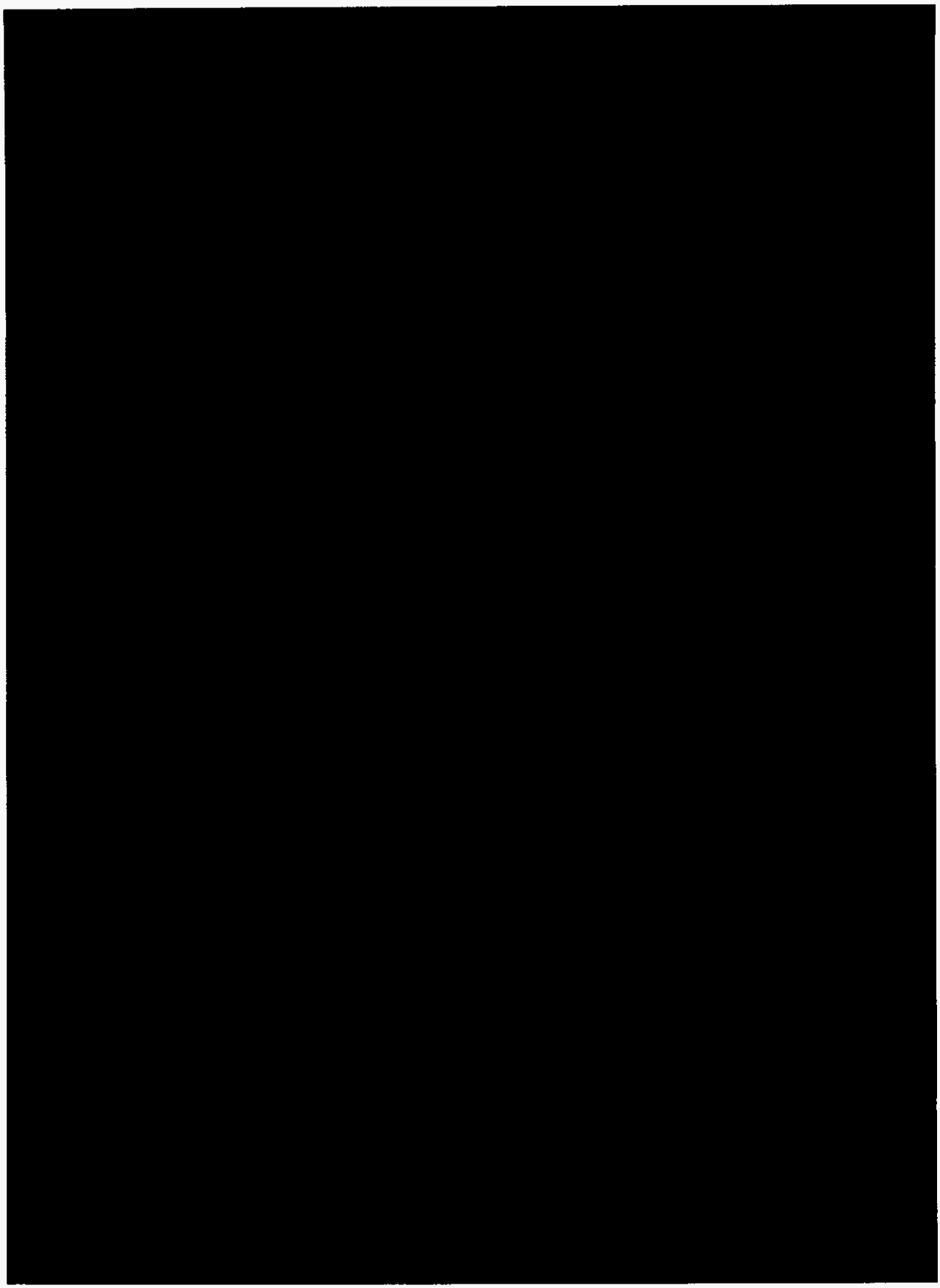
8.2.2.2 After the Initial Testing Deadline, if at any time Buyer has reasonable grounds for disputing Seller's declared amount of Total Facility Capacity (e.g., the delivery of energy by Seller in amounts less than Scheduled Energy), Buyer may provide to Seller a Test Notice to require Seller to conduct a test to re-demonstrate the capability of the Facility. Upon receipt of such notice, Seller shall conduct a test of the Facility in accordance with Appendix E within 30 Days after the Test Notice on a Day selected by Seller and provide Buyer with prior notice of such test. Buyer shall pay Seller all costs of testing (including Gas and operation and maintenance costs), and Buyer shall be entitled to utilize all energy produced during testing for its own purposes.

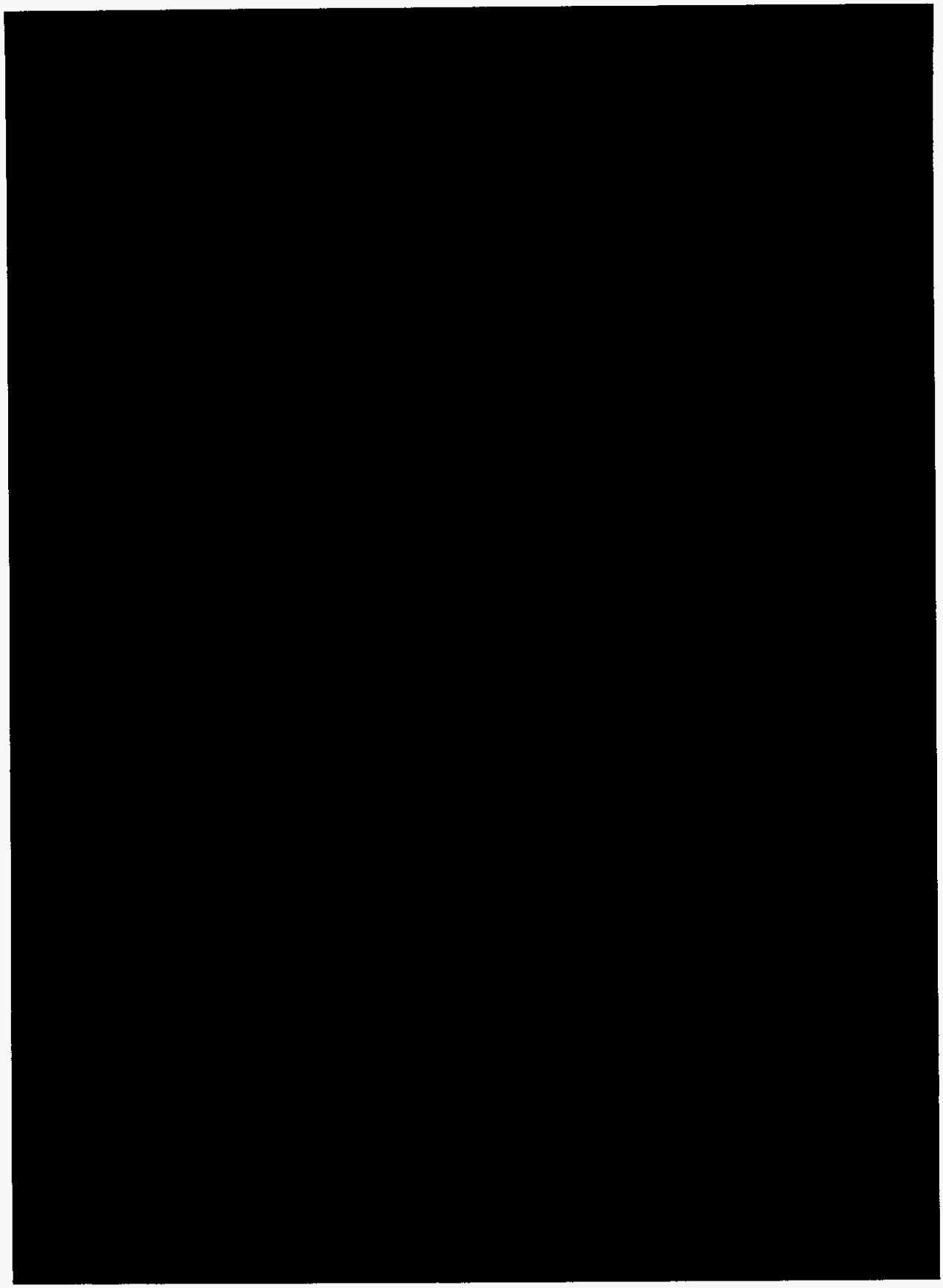
8.2.3 In the event that a test required by Buyer pursuant to Section 8.2.2 indicates that the generating capability of the Facility is different than the Total Facility Capacity declared pursuant to Section 8.2.1, Seller may (at its sole option) conduct additional test(s) of the Facility in accordance with Appendix E, such test(s) to be completed no later than 30 Days after the test conducted pursuant to Section 8.2.2. If Seller does not elect to conduct such additional test(s), the Total Facility Capacity shall be re-set pursuant to Section 8.2.4 to an amount equal to the generating capability demonstrated by the test conducted pursuant to Section 8.2.2. If Seller does elect to conduct additional testing, Seller shall provide Buyer prior notice of the Day(s) of such test(s) and the Total Facility Capacity shall be re-set pursuant to Section 8.2.4 to an amount equal to the generating capability demonstrated through such additional test(s). If such test(s) is performed coincident with Buyer's Schedule for any Day(s), Buyer shall pay Seller the costs of testing (including Gas and operation and maintenance costs) that are the responsibility of Buyer through the application of the Monthly Energy Payment for all Delivered Energy provided to Buyer. To the extent such test(s) is performed during a time

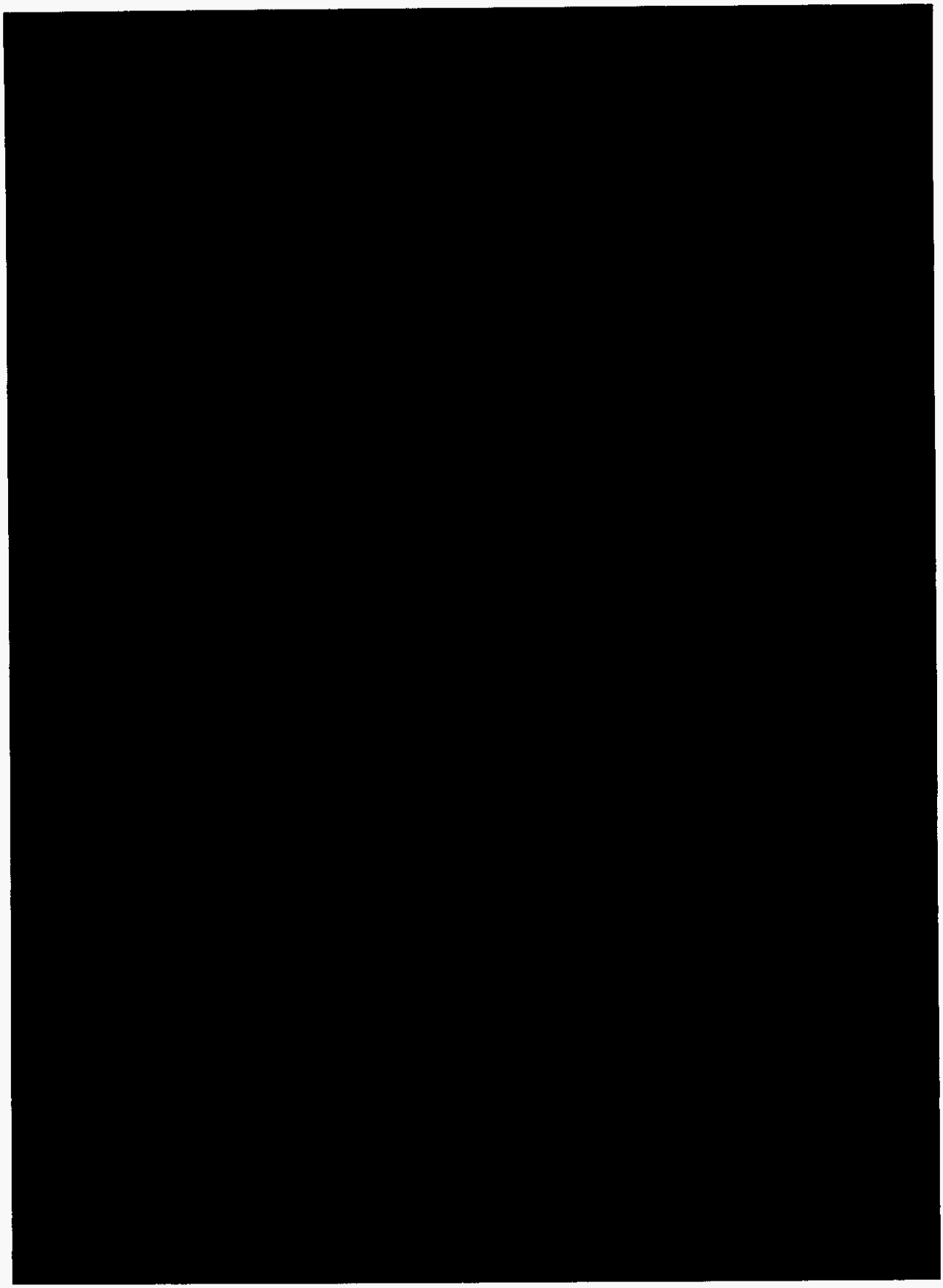
period in which energy will not be delivered to Buyer pursuant to a Schedule, Seller shall be responsible for all costs of testing (including Gas and operation and maintenance costs) and shall be entitled to utilize all energy produced during testing for its own purposes.

8.2.4 If the Total Facility Capacity is set pursuant to a test conducted under Section 8.2.2 or Section 8.2.3 as a result of a Test Notice provided by Buyer on or before the Initial Testing Deadline, the Total Facility Capacity shall be adjusted retroactively to the Service Commencement Date. In all other cases when the Total Facility Capacity is set pursuant to a test conducted under Section 8.2.2 or Section 8.2.3, the Total Facility Capacity shall be adjusted retroactively to the date of the applicable Test Notice. All capacity billing under Section 6.1 shall (if necessary and as soon as practicable) be retroactively adjusted as appropriate (with interest at the Interest Rate) to reflect such adjustment of the Total Facility Capacity.

8.3 [redacted]







ARTICLE 9

FUEL ARRANGEMENTS

9.1 Seller's Commitment. Subject to the provisions of this Agreement, Seller will use Commercially Reasonable Efforts to provide to the Facility the volume of Gas needed to provide Scheduled Energy.

9.2 Gas Transportation Arrangement and Charges.

9.2.1 Subject to the provisions of this Agreement, Seller will utilize up to [redacted] MMBtu per day of firm transportation capacity on the pipeline system of SNG from SNG's Zone 0 to Zone 2 under SNG's Contract Number FSNG284 constructed under South System 1, Phase 1 expansion that was placed in service on June 15, 2002 for deliveries to Point Code 807000, Plant Franklin, as amended ("SNG Contract") as necessary to provide Scheduled Energy under this Agreement. To the extent energy is supplied to Buyer from the Facility, Seller shall afford Buyer's Schedule priority with regard to the use of such transportation capacity that is available; provided, however, if a portion of the total amount of transportation capacity procured by Seller to the Plant is unavailable for any hour(s), Seller shall be permitted to reduce on a pro rata basis the amount of transportation capacity that it will utilize in order to satisfy Buyer's Schedule.

9.2.2 Buyer shall pay to Seller a Monthly Fuel Transportation Payment which shall be an amount equal to the product resulting from multiplying [redacted] MMBtu by the sum of: [redacted]

9.2.3 Buyer acknowledges that charges under the SNG Contract are currently discounted below SNG's maximum tariff rates and that such rates are subject to periodic increases as provided in the SNG Contract and to increases pursuant to actions by FERC. Buyer agrees to pay the then current rates each Month under the SNG Contract during the term of this Agreement.

9.2.4 Buyer acknowledges that Seller may have the right pursuant to Exhibit E of the SNG Contract to terminate that contract; however, Seller shall exercise that right with respect to the transportation capacity necessary to provide Scheduled Energy under this Agreement only if Buyer and Seller agree on mutually acceptable replacement transportation arrangements.

9.2.5 Buyer acknowledges that SNG may impose imbalance, cash-out and other types of charges, including penalty charges, pursuant to its FERC approved tariff under certain conditions ("Penalty Charges"). Buyer agrees to be responsible for and pay or reimburse Seller for any Penalty Charges billed to Seller by SNG that result from any action or failure to act of Buyer under this Agreement. The Parties agree to cooperate in order to attempt to minimize Penalty Charges.

9.2.6 [redacted]

[redacted]

9.2.7 In the event that accommodating Buyer's Schedule would require Gas transportation capacity in addition to that set forth in Section 9.2.1, Seller shall make Commercially Reasonable Efforts to obtain (if available) additional capacity at Buyer's expense and Buyer shall reimburse Seller based on SNG's interruptible transportation rate from Zone 0 to Zone 2 in effect at the time. To the extent Seller is unable to obtain such additional capacity at or below such interruptible transportation rate and such capacity is available, Seller shall make Commercially Reasonable Efforts to provide Buyer the option of having Seller purchase such additional capacity at the higher rate. If Buyer desires to have Seller purchase such additional capacity at the higher rate, Seller shall make Commercially Reasonable Efforts to obtain such capacity to accommodate Buyer's Schedule and Buyer shall reimburse Seller for all associated costs. To the extent that Buyer does not desire to have Seller purchase such additional capacity at the higher rate or Seller is unable to obtain such capacity, Seller shall have a Delivery Excuse to that extent.

9.3 Interruption of Gas Supplies

9.3.1 In the event that Gas supplies are interrupted due to any circumstance affecting Seller's Gas suppliers that qualifies as an event of force majeure as defined in the North American Energy Standards Board's Base Contract for Sale and Purchase of Natural Gas:

A. Seller shall use Commercially Reasonable Efforts to arrange for alternate Gas supplies to overcome such an interruption. If alternate Gas supplies are available, Seller shall offer to Buyer, and Buyer shall have the option to immediately accept, such alternate Gas supplies at the price quoted by Seller.

B. If Seller is unable to arrange for alternate Gas supplies or if Buyer does not accept such alternate Gas supplies pursuant to subparagraph A above, Buyer may arrange to sell alternate gas supplies to Seller at the Gas Price (as defined in Appendix B) by delivering such Gas to SNG at a point on its pipeline at which Seller can schedule receipts of such Gas under the SNG Contract. Buyer shall cooperate with Seller and SNG in order to ensure that such supplies are nominated, scheduled and delivered to SNG for transportation under the SNG Contract and under the terms of SNG's FERC approved tariff. Buyer shall be responsible for any Penalty Charges resulting from any difference between the volume scheduled for delivery by Buyer to and receipt by SNG and the actual volume delivered by Buyer to and received by SNG.

9.3.2 In the event that there is no arrangement for alternate Gas supplies under Section 9.3.1, the interruption of Gas supplies described in Section 9.3.1 shall constitute a Delivery Excuse as defined in this Agreement.

9.3.3 Notwithstanding any other provision of this Agreement, Seller shall not be obligated to obtain or use any Gas storage services in order to provide Gas under this Agreement.

9.4 Scheduling Changes. In the event that Buyer requests a Schedule change pursuant to Section 5.1.2 after the Scheduling Deadline, Seller shall quote a price for supplying incremental Gas needed to accommodate an increase in Scheduled Energy (subject to Gas availability and the ability to schedule delivery of Gas) or for selling excess Gas resulting from a decrease in Scheduled Energy, as appropriate. Upon receipt of Seller's quote, Buyer shall immediately exercise one of the following options: (i) not changing the existing Schedule: (ii) proceeding with the requested Scheduling Change and the increase or decrease in Gas supplies based on the quoted price (to buy the incremental Gas supply, or to sell the excess Gas supply, as applicable), or (iii) proceeding with the increase (if applicable) in Scheduled Energy and notifying Seller that Buyer will supply the required incremental Gas supply utilizing the procedures set forth in Section 9.3.1B.

ARTICLE 10

ELECTRIC METERING

10.1 Metering. At no cost to Buyer, Seller shall be responsible for performing, or causing to be performed, the installation, maintenance, testing and calibration of the Electric Metering Equipment owned by Seller and/or its Affiliates at the Delivery Point(s).

10.2 Industry Standards. All Electric Metering Equipment owned by Seller and/or its Affiliates at the Delivery Point(s), shall be operated, maintained and tested by and/or on behalf of Seller in accordance with Prudent Industry Practices.

10.3 Records. The Parties shall maintain accurate and detailed records relating to the metering of energy at the Delivery Point(s) for one year or for such longer period as may be required by an applicable Government Agency or Law. All records shall be available for inspection by either Party upon reasonable notice.

10.4 Meter Errors. If the Electric Metering Equipment at the Delivery Point(s) fails to register, or if the measurement made by a metering device is found upon testing to vary by more than 0.5% from the measurement made by the standard meter used in a test, an adjustment shall be made correcting all measurements of energy made by the Electric Metering Equipment during: (i) the actual period when inaccurate measurements were made, if that period can be determined to the mutual satisfaction of the Parties; or (ii) if such actual period cannot be determined to the mutual satisfaction of the Parties, the latter half of the period from the date of the last test of the Electric Metering Equipment to the date such failure is discovered or such test is made (each being an "Adjustment Period"). If the Parties are unable to agree on the amount of the adjustment to be applied to the Adjustment Period, the amount of the adjustment shall be determined: (i) by correcting the error if the percentage of error is ascertainable by calibration, tests or mathematical calculation; or (ii) if not so ascertainable, by estimating on the basis of deliveries under similar conditions during the period since the last test.

ARTICLE 11

BILLING AND PAYMENT

11.1 Timing and Method of Payment. Seller will submit to Buyer, as promptly as practicable after the first of each Billing Month, an invoice (by mail, facsimile or electronic means) for the amounts due under the terms of this Agreement for the preceding Month. Amounts due pursuant to such invoice shall be due and payable [redacted]

[redacted]("Payment Due Date"). If the Payment Due Date falls on a Day that is not a Business Day, the Payment Due Date shall be the next Business Day. Payment shall be made, on or before the due date, to Seller in accordance with the invoice in immediately available funds through wire transfer, or other mutually agreeable method.

11.2 **Late Payment.** Amounts that are owed Seller shall, if not remitted within the time period specified under Section 11.1, be subject to a late payment charge equal to the interest calculated pursuant to Section 21.7, accrued and payable on a Monthly basis with respect to the unpaid amount. Such late payment charge shall accrue from the due date of such amount until the date on which it is paid.

11.3 **Disputed Billings.** In the event that either Party has a bona fide dispute with any invoice submitted hereunder, such Party shall inform the other Party in writing of its grounds for disputing such invoice. Notwithstanding such dispute, [redacted]

11.4 **Adjustments.** If any overcharge or undercharge in any form whatsoever shall at any time be found and the invoice therefor has been paid, the Party that has been paid the

overcharge shall refund the amount of the overcharge to the other Party, and the Party that has been undercharged shall pay the amount of the undercharge to the other Party, within 30 Days after final determination thereof; provided, however, that no retroactive adjustment shall be made for any overcharge or undercharge unless written notice of the same is provided to the other Party within a period of 12 Months from the date of the invoice in which such overcharge or undercharge was first included. Any such adjustments shall be made with interest calculated in accordance with Section 21.7 from the date that the undercharge or overcharge actually occurred.

11.5 Audit Rights. Subject to Section 10.3, the Parties shall keep complete and accurate records of their operations under this Agreement and shall maintain such data for a period of at least [redacted] years after the completion of the relevant Billing Month hereunder; provided, however, records relating to a disputed matter shall be retained until the dispute is resolved. Such records shall be available for inspection and audit by the other Party upon reasonable request during any regular Business Day.

ARTICLE 12

REGULATORY

12.1 Initial Approval of the Florida Public Service Commission.

12.1.1 No later than [redacted] Days after the Effective Date, Buyer shall make a filing with the Florida Public Service Commission ("FPSC") seeking approval for Buyer to recover from its customers all payments required to be made to Seller under the Contemporaneous Agreements without material modification or condition with respect to such agreements ("FPSC Approval"). After making such filing, Buyer shall utilize diligent efforts to obtain the FPSC Approval for the Contemporaneous Agreements by no later than [redacted] Days

after the Effective Date ("Approval Deadline"). Seller agrees to reasonably assist and support Buyer's efforts to obtain the FPSC Approval. Buyer shall promptly notify Seller when it receives the FPSC Approval.

12.1.2 If FPSC Approval for the Contemporaneous Agreements is not received by the Approval Deadline, but the date of the Transmission Notice under Section 7.4.2 has not yet occurred and the FPSC has not yet issued an order denying the Buyer's request for FPSC Approval ("FPSC Denial"), the Approval Deadline shall automatically be extended until the date of the Transmission Notice. During this extended period, Buyer shall keep Seller closely informed as to the progress of its efforts to obtain FPSC Approval and Buyer shall continue diligent efforts to obtain FPSC Approval.

12.1.3 If FPSC Approval is not received by the Approval Deadline (as extended under Section 12.1.2) or if an FPSC Denial is issued prior to the Approval Deadline, Buyer shall provide notice to Seller within 30 Days after the Approval Deadline or the FPSC Denial (whichever occurs first) that it desires to either: (i) terminate all (but not less than all) of the Contemporaneous Agreements, in which case all of the Contemporaneous Agreements shall immediately terminate; or (ii) continue all (but not less than all) of the Contemporaneous Agreements regardless of FPSC Approval. If Buyer elects option (ii) under the foregoing sentence, all of the Contemporaneous Agreements shall continue in full force and effect for the Term notwithstanding any subsequent action or inaction of the FPSC (including the subsequent issuance of a FPSC Denial or failure to issue an FPSC Approval).

12.1.4 The Parties acknowledge that the other Contemporaneous Agreements contain provisions that are substantially similar to Sections 12.1.1 through 12.1.3 above and that this Agreement may be subject to termination as provided in such similar provisions.

12.1.5 After the procedures in Sections 12.1.1, 12.1.2, and 12.1.3 (as applicable) have been completed, except as provided under Section 12.3, at no time shall this Agreement be subject to termination or modification due to any action or inaction of any Government Agency or Buyer's inability to recover from its customers amounts to be paid to Seller pursuant this Agreement whether such inability is due to action of any Government Agency or otherwise.

12.2 Changes in Agreement. Except for any changes pursuant to Section 12.3, absent the agreement of all Parties to the proposed change, the standard of review for changes to this contract proposed by a Party, a non-Party or the FERC acting sua sponte shall be the "public interest" standard of review set forth in United Gas Pipeline Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. (1956) (the "Mobile-Sierra" doctrine).

12.3 Federal Energy Regulatory Commission.

12.3.1 The Parties anticipate that this Agreement is not required to be filed and accepted by FERC because it is a market-based contract. Therefore, this Agreement shall not be contingent on FERC acceptance. Having freely negotiated and agreed upon the economic bargain among them as set forth hereunder, Seller and Buyer waive all rights under Sections 205 and 206 of the Federal Power Act to effect a change in the Agreement. Moreover, it is the Parties' mutual intent that FERC be precluded, to the fullest extent permitted by law, from altering this Agreement in any way. Notwithstanding the foregoing, if at any time FERC takes some action that reduces the economic benefit of this Agreement to either Party ("Impacted Party") as contemplated on the Effective Date ("Original Economic Benefit"), Impacted Party

shall be deemed to have retained rights under Section 205 to file for changes in the Agreement, but only to the extent required to restore the Original Economic Benefit.

12.3.2 Impacted Party may exercise its Section 205 rights provided under Section 12.3.1 if at any time it reasonably determines in its sole discretion that it may be able to have some or all of the Original Economic Benefit restored. Before exercising such rights, Impacted Party shall negotiate with the other Party in an effort to reach mutual agreement regarding amendments to this Agreement (including amendments regarding those provisions addressing the determination of payments between the Parties and adjustments to capacity payments due to unavailability) that would restore some or all of the Original Economic Benefit. Impacted Party shall file any resulting amendments for acceptance by FERC, and the other Party shall actively support such filing(s). If the Parties are unable to agree upon such amendment(s), Impacted Party shall be entitled to make unilateral filing(s) at FERC to modify the Agreement in order to restore some or all of the Original Economic Benefit. In this latter event, the other Party shall actively support Impacted Party's right to recover the Original Economic Benefit, including by making filings at FERC (provided that the non-impacted Party shall retain the right to challenge the amount of and/or the methodology for calculating the Original Economic Benefit).

12.3.3 Any amendment(s) or unilateral filing(s) contemplated hereunder shall restore the Original Economic Benefit (or any allowed portion thereof) for the remainder of the Term, including any portion of the Original Economic Benefit associated with prior periods (with interest). Such amendment(s) or filing(s) by the Impacted Party shall not require the other Party to bear more of an economic burden than originally contemplated in this Agreement on the Effective Date. Nothing in this Agreement is intended to or shall restrict the number of

times that a Party may exercise the above-described Section 205 rights during the Term or within any specific time frame.

ARTICLE 13

CHANGE IN LAW

13.1 Increased Generation Costs. The Parties acknowledge that during the Term of this Agreement, Changes in Law that increase Seller's cost of providing capacity and/or energy hereunder could occur. Any Increased Generation Costs will be paid by Buyer through an additional payment or surcharge each Month ("Change in Law Surcharge"). Once Seller has incurred Increased Generation Costs, Buyer shall pay for all Increased Generation Costs through the Change in Law Surcharge, as provided below.

13.2 Determination. If Seller determines that a Change in Law will or has resulted in Increased Generation Costs and that Buyer is responsible for such costs under this Agreement, Seller shall, within 6 Months after identifying such costs, notify Buyer of: (a) the applicable Change in Law giving rise to the Increased Generation Costs; and (b) the resulting Increased Generation Costs. Provided, however, the failure by Seller to provide such notice within such time period shall not under any circumstance result in an Event of Default, nor shall such failure prejudice or affect in any way Seller's right to receive reimbursement from Buyer for any Increased Generation Costs under this Agreement. Provided further, such notice by Seller shall include reasonable documentation of the applicable Change in Law and resulting Increased Generation Costs. Within 60 Days after receipt of such notice, Buyer will: (i) make a good faith determination of whether the Increased Generation Costs result from a Change in Law as specified in this Agreement; (ii) make a good faith determination of whether the Increased Generation Costs are determined in accordance with this Agreement; and (iii) provide Seller

written notice of its determination. In the event that Buyer does not provide written notice of its determination within such time period, Buyer shall be deemed to have concurred that the specified Increased Generation Costs result from a Change in Law. If Buyer does not concur, the Parties shall commence discussions in an effort to address and resolve the basis for Buyer's disagreement. If the Parties are unable to resolve their disagreement within 30 Days after commencing such discussions, the Parties shall submit the issue to arbitration under the procedures set forth in Section 18.2. The arbitrators shall determine whether a Change in Law has occurred and, if so, the amount of the resulting Increased Generation Costs.

13.3 Initiation of Surcharge. In the event that Increased Generation Costs result from a Change in Law, Seller shall provide Buyer with written notice of a Change in Law Surcharge or an increase in an existing Change in Law Surcharge to recover Increased Generation Costs. No earlier than 30 Days thereafter, Seller may initiate a Change in Law Surcharge (or, if applicable, an increase in an existing Change in Law Surcharge) consistent with such notice. Provided, however, Seller shall reduce any Change in Law Surcharge to the extent that any costs included in such surcharge are not incurred. After the end of the Term, Seller shall not be entitled to initiate a Change in Law Surcharge, an increase in an existing Change in Law Surcharge, or any other additional charge intended to recover costs resulting from a Change in Law unless: (i) Seller has provided Buyer with notice of the applicable Change in Law, surcharge or increase prior to the expiration of the Term; and (ii) the costs Seller seeks to recover were incurred during the Service Term as a result of such Change in Law.

13.4 Timing. Any Change in Law Surcharge (or increase in an existing Change in Law Surcharge) hereunder due to Increased Generation Costs shall recognize the timing of the

Increased Generation Costs (including the recovery through such payments of amounts associated with the Increased Generation Costs in prior periods, with interest) for which Buyer is responsible under this Agreement.

ARTICLE 14

LIABILITY ALLOCATION; LIMITATIONS ON LIABILITY

14.1 Costs, Taxes and Charges. Except as otherwise provided in this Agreement, in addition to all other amounts due and payable under this Agreement: (i) except for any Taxes included in the Gas Charges, Seller shall be responsible for all costs, Taxes, and charges of any kind prior to the Delivery Point relating to the delivery of energy and the provision of capacity under this Agreement, transmission, and/or related services (by way of clarification of the foregoing, Taxes prior to the Delivery Point include: ad valorem taxes); and (ii) Buyer shall be responsible for all costs, Taxes, and charges of any kind at and after the Delivery Point relating to the delivery of energy and the provision of capacity under this Agreement, transmission, and/or related services (by way of clarification of the foregoing, Taxes at and after the Delivery Point include: any Taxes incurred in connection with sales of the Delivered Energy). Each Party shall provide the other Party upon written request a certificate of exemption or other reasonably satisfactory evidence of exemption if any exemption from or reduction of any Tax is applicable. Each Party shall exercise Commercially Reasonable Efforts to obtain and to cooperate in obtaining any exemption from or reduction of any Tax. In addition, each Party shall be responsible for paying its own income taxes and net worth taxes on it or its property.

14.2 Indemnification. Unless otherwise agreed in writing by the Parties, Seller and Buyer shall each defend, indemnify and save harmless, on an After-Tax Basis, the other and their respective officers, directors, servants, agents, employees and representatives from and

against any and all claims, demands, costs or expenses (including reasonable attorneys' fees) for loss, damage or injury to any person, property or interest arising out of or in any way related to this Agreement to the extent such loss, damage or injury occurs on its own side of the Delivery Point, irrespective of negligence, whether actual or claimed, of the other. Nothing in this Agreement shall create a contractual relationship between one Party and the customers of the other Party, nor shall it create a duty of any kind to such customers.

14.3 Limitation of Liability.

14.3.1 THERE ARE NO WARRANTIES UNDER THIS AGREEMENT EXCEPT TO THE EXTENT SPECIFICALLY SET FORTH HEREIN. THE PARTIES HEREBY SPECIFICALLY DISCLAIM AND EXCLUDE ALL IMPLIED WARRANTIES, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR A PARTICULAR PURPOSE.

14.3.2 SUBJECT TO SECTION 16.2, NEITHER PARTY SHALL BE LIABLE TO THE OTHER FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES SUFFERED BY THAT PARTY OR BY ANY CUSTOMER OF THAT PARTY, FOR LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, WHETHER BY VIRTUE OF ANY STATUTE, IN TORT OR CONTRACT, UNDER ANY PROVISION OF INDEMNITY OR OTHERWISE. THE PARTIES INTEND THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING, WITHOUT LIMITATION, THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY

DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, THAT OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT, AND THAT THE LIQUIDATED DAMAGES CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS.

14.3.3 In the event that any provision of this Section 14.3 is held to be invalid or unenforceable, this Section shall be void and of no effect solely to the extent of such invalidity or unenforceability, and no claim arising out of such invalidity or lack of enforceability shall be made by one Party against the other or its officers, agents, or employees. Notwithstanding the foregoing, this Section 14.3 shall not limit or negate the right of either Party to be fully indemnified as provided in Section 14.2 or limit the remedies set forth in this Agreement for an Event of Default.

14.3.4 Without prejudice to the obligations and liabilities of an entity pursuant to an Eligible Guaranty, neither any Affiliate of a Party nor any stockholder, officer, director or employee of a Party or of any Affiliate of a Party (collectively, the "Nonrecourse Persons") shall have any liability to the other Party for the payment of any sums now or hereafter owing by such Party or for the performance of any of the obligations of such Party contained herein, and each of the Parties hereto agrees that all of the obligations of the other Party under this Agreement shall be obligations solely of such other Party and recourse in enforcing said obligations shall only be had against the assets of such other Party; provided that the foregoing provision shall not constitute a waiver, release or discharge of any of the terms, covenants or conditions of this Agreement or any Eligible Guaranty and the same shall continue until fully paid, discharged, observed or performed.

ARTICLE 15

FORCE MAJEURE EVENT

15.1 Force Majeure Event Defined.

15.1.1 As used herein, an Event of Force Majeure with respect to a Party means an occurrence, non-occurrence, or set of circumstances that is beyond the reasonable control of such Party and is not caused by the fault or negligence of such Party, including but not limited to acts of God, strike, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, sabotage, or terrorism, which, by the exercise of due diligence, it is unable to overcome.

15.1.2 Notwithstanding anything contained in Section 15.1.1, the term Force Majeure shall not include any of the following:

(i) the inability of Buyer, for any reason, to obtain or maintain adequate transmission service from and after the Delivery Point;

(ii) a change or circumstance in market conditions that affect the cost, price, or demand for capacity and/or energy from the Facility;

(iii) a change or circumstance in market conditions or otherwise that affects the economic value of this Agreement to any Party;

(iv) an increase in costs or expenses to any Party as a result (either directly or indirectly) of such Party's performance under this Agreement;

(v) a change in Law, action or inaction by any Governmental Agency or the inability to comply with any Law; or

(vi) any event or circumstance that qualifies as a Delivery Excuse.

15.2 Applicability of Force Majeure Event. Neither Party shall be in breach or liable for any delay or failure in its performance under this Agreement (except for such Party's performance of its payment obligations hereunder, which shall not be excused by any Force Majeure Event) to the extent such performance is prevented or delayed due to a Force Majeure Event, provided that:

15.2.1 The non-performing Party shall give the other Party written notice within 3 Business Days of the commencement of the Force Majeure Event, with available details to be supplied within 15 Days after the commencement of the Force Majeure Event further describing the particulars of the occurrence of the Force Majeure Event;

15.2.2 The delay in performance shall be of no greater scope and of no longer duration than is directly caused by the Force Majeure Event;

15.2.3 The Party whose performance is delayed or prevented shall proceed with Commercially Reasonable Efforts to overcome the events or circumstances preventing or delaying performance and shall, as requested (but not more often than weekly), provide written progress reports to the other Party during the period that performance is delayed or prevented describing actions taken and to be taken to remedy the consequences of the Force Majeure Event, the schedule for such actions and the expected date by which performance shall no longer be affected by the Force Majeure Event; and

15.2.4 When the performance of the Party claiming the Force Majeure Event is no longer being delayed or prevented, that Party shall give the other Party written notice to that effect.

15.3 Effect of Force Majeure Event.

15.3.1 Except for the obligation of either Party to make any required payments under this Agreement, the Parties shall be excused from performing their respective obligations under this Agreement and shall not be liable in damages or otherwise if and to the extent that they are unable to so perform or are prevented from performing by a Force Majeure Event.

15.3.2 To the extent Seller is unable to provide Contract Capacity or Scheduled Energy from the Facility due to a Force Majeure Event, Seller shall be excused from performance hereunder and shall not be required to provide capacity and/or energy from other resources (including Alternate Resources) in order to satisfy Buyer's Schedule; provided, however, to the extent Seller does provide capacity and/or energy at its sole option to satisfy Buyer's Schedule consistent with this Agreement, [redacted]

15.4 [redacted]

ARTICLE 16

EVENT OF DEFAULT

16.1 Event of Default. The occurrence of any one or more of the following events with respect to a Party shall constitute an "Event of Default" attributable to such Party under this Agreement:

16.1.1 The failure by a Party to make payment to the other Party for amounts due under this Agreement after said amounts have become due and payable and such failure is not cured within 15 Days after receiving written notice of such failure from the Party to which such payments are due;

16.1.2 A Party or any Person guaranteeing such Party's obligations hereunder (a "Guarantor") shall: (i) admit in writing its inability to pay its debts as such debts become due; (ii) make a general assignment or an arrangement or composition with or for the benefit of its creditors; (iii) take any action for the purpose of effectuating any of the foregoing; or (iv) fail to comply with the terms and conditions of its Guaranty;

16.1.3 A proceeding or case shall be commenced by a Party or against a Party with the consent of such Party or by its Guarantor or against its Guarantor with the consent of such Guarantor, in any court of competent jurisdiction, seeking: (i) its liquidation, reorganization of its debts, dissolution or winding-up, or the composition or readjustment of its debts; (ii) the appointment of a receiver, custodian, liquidator or the like of the Party or its Guarantor or of all or any substantial part of its assets or the assets of its Guarantor; or (iii) similar relief in respect of such Party or its Guarantor under any law relating to bankruptcy, insolvency, reorganization of its debts, winding-up, composition or adjustment of debt;

16.1.4 A proceeding or case shall be commenced without the consent of a Party against such Party or without the consent of its Guarantor against such Guarantor, in any court of competent jurisdiction, seeking: (i) its liquidation, reorganization of its debts, dissolution or winding-up, or the composition or readjustment of its debts; (ii) the appointment of a receiver, custodian, liquidator or the like of the Party or its Guarantor or of all or any substantial part of its assets or the assets of its Guarantor; or (iii) similar relief in respect of such

Party or its Guarantor under any law relating to bankruptcy, insolvency, reorganization of its debts, winding-up, composition or adjustment of debt, unless such proceeding or case is dismissed within 60 days of the filing thereof;

16.1.5 The failure of any Party to comply with the requirements of Article 20 regarding creditworthiness and/or security;

16.1.6 The failure of a Party to comply with the requirements of Article 19 regarding assignment;

16.1.7 Any representation or warranty made by a Party under Article 17 proves to have been false or misleading in any material respect when made and such representation or warranty is not made true within 30 Days after such Party has obtained actual knowledge thereof or has been provided notice thereof by the other Party; provided, however, that the cure must also remove any adverse effect on the Non-Defaulting Party;

16.1.8 A Party or its Guarantor shall fail to pay when due (subject to any applicable cure or grace period), whether by acceleration or otherwise, any principal or interest on indebtedness aggregating in excess of [redacted] in principal amount; or any indebtedness aggregating in excess of [redacted] shall be declared due and payable or be required to be prepaid (other than by a regularly scheduled payment) prior to the stated maturity of such indebtedness; or

16.1.9 [redacted]

16.1.10 The material failure by a Party to comply with any material provision of this Agreement if such failure is not the result of a Force Majeure Event or is not otherwise excused in accordance with this Agreement, and such failure continues uncured for 30 Days

after written notice thereof from the other Party; provided, however, if such failure is not capable of being cured within such period of 30 Days with the exercise of reasonable diligence, then such cure period shall be extended for an additional reasonable period of time (not to exceed 90 Days), so long as the Party is exercising reasonable diligence to cure such failure. Provided, however, this Section 16.1.10 shall not apply to: (i) any event described in Sections 16.1.1 through 16.1.9; (ii) any event described in Sections 5.9, 5.10, and 8.3 for which a remedy is expressly provided in those Sections; or (iii) Seller's failure to provide capacity and/or energy pursuant to any provision of this Agreement.

The Party in default or the Party to whom an Event of Default is attributable as provided in this Section 16.1 shall be referred to as the "Defaulting Party" and the other Party shall be referred to as the "Non-Defaulting Party".

16.2 Exclusive Remedies.

16.2.1 Upon and after the occurrence of an Event of Default, the Non-Defaulting Party's sole and exclusive remedy (whether arising in contract, tort or otherwise) shall be to suspend its performance under this Agreement and declare an Early Termination Date with the relevant remedies as provided below.

16.2.2 If an Event of Default has occurred, the Non-Defaulting Party shall have the right, in its sole discretion, by no more than 20 Days notice to the Defaulting Party, to designate a Day no earlier than the Day such notice is effective as the date on which the Agreement shall terminate ("Early Termination Date"). Subject to Sections 21.3 and 21.15, this Agreement shall terminate on the Early Termination Date and neither Party shall have any further liability or obligation to the other hereunder, except (i) the Defaulting Party shall pay to the Non-Defaulting Party on demand [redacted] in liquidated damages and (ii) as provided in

Sections 16.2.3 or 16.2.4 below. The exercise by a Party of its rights under this Section 16.2 shall be the sole and exclusive remedy of such Party for an Event of Default by or attributable to the other Party. The Parties acknowledge and agree that in the event of termination of this Agreement due to an Event of Default, all or a portion of the amount of damages arising therefrom are not susceptible to an accurate determination. The Parties further acknowledge and agree that the liquidated damages set forth above are not intended as a penalty and represent a fair and reasonable approximation of all or a portion of the damages a Non-Defaulting Party may incur in each particular case.

16.2.3 With respect to an Event of Default by or attributable to Buyer, within 15 Days after Seller's notice under Section 16.2.2, the Parties shall each select an independent party to determine the Seller's Damages. Within 30 Days after such notice, the two independent parties shall select a third independent party to determine the Seller's Damages. Within 60 Days after such notice, the three (3) independent parties shall provide the Parties with their respective estimates of the Seller's Damages. The actual Seller's Damages shall equal the arithmetic average of the three estimates. If one Party disputes the actual Seller's Damages, within 5 Business Days of notice of the Seller's Damages determined by the independent parties, such Party may submit the dispute for resolution pursuant to the arbitration procedures of Article 18 and the arbitration order or finding regarding the Seller's Damages shall be conclusive, provided, however, in no event shall the Seller's Damages be less [redacted] at any time whether or not arbitrated. Subject to such qualification, the Seller's Damages will be paid by Buyer to Seller within 3 Business Days after being determined by the independent parties unless disputed and arbitrated pursuant to the terms of this Agreement in which event it shall be paid within 3 Business Days of the relevant arbitration

finding or order. As used herein, "Seller's Damages" means [redacted]

16.2.4 With respect to an Event of Default by or attributable to Seller, within 15 Days after Buyer's notice under Section 16.2.2, the Parties shall each select an independent party to determine the Buyer's Damages. Within 30 Days after such notice, the two independent parties shall select a third independent party to determine the Buyer's Damages. Within 60 Days after such notice, the 3 independent parties shall provide the Parties with their respective estimates of the Buyer's Damages. The actual Buyer's Damages shall equal the arithmetic average of the three estimates. If one Party disputes the actual Buyer's Damages, within 5 Business Days of notice of the Buyer's Damages determined by the independent parties, such Party may submit the dispute for resolution pursuant to the arbitration procedures of Article 18 and the arbitration order or finding regarding the Buyer's Damages shall be conclusive, provided, however, in no event shall the Buyer's Damages be less than [redacted] at any time whether or not arbitrated. Subject to such qualification, the Buyer's Damages will be paid by Seller to Buyer within 3 Business Days after being determined by the independent parties unless disputed and arbitrated pursuant to the terms of this Agreement in which event it shall be paid within 3 Business Days of the relevant arbitration

finding or order. As used herein, "Buyer's Damages" [redacted]

ARTICLE 17

REPRESENTATIONS AND WARRANTIES

17.1 Execution. Each Party represents and warrants to the other Party as of the Effective Date that: (i) it has all the necessary corporate and legal power and authority and has been duly authorized by all necessary corporate action to enable it to lawfully execute, deliver and perform under this Agreement; and (ii) it is a valid legal entity duly organized and validly existing in good standing under the laws of the state of its formation and is, to the extent required, qualified to do business in the state where it is organized;

17.2 Permits. Each Party represents and warrants to the other Party that as of the Effective Date it has all permits, licenses or approvals necessary to lawfully perform its obligations contained herein in the manner prescribed by this Agreement.

17.3 Binding Obligations. Each Party represents and warrants to the other Party that as of the Effective Date this Agreement is the valid and binding obligation of such Party, enforceable against such Party in accordance with its terms, except as such enforceability may be limited by bankruptcy, insolvency, reorganization, fraudulent conveyance, moratorium or

other similar laws affecting enforcement generally, and by equitable principles regardless of whether such principals are considered in a proceeding at law or in equity.

17.4 Execution and Consummation. Each Party represents and warrants to the other Party that as of the Effective Date the execution and delivery of this Agreement, the consummation of the transactions contemplated hereby and the fulfillment of and compliance with the provisions of this Agreement do not and will not conflict with any of the terms, conditions or provisions of its organizational documents or any law applicable to it or result in a breach or default under any evidence of its indebtedness or any other agreement or instrument to which it is a party or by which it or any of its property is bound which has a reasonable likelihood of materially and adversely affecting the consummation of the transactions contemplated hereby or the performance by the Party of any of its obligations under this Agreement.

17.5 Actions and Proceedings. Each Party represents and warrants to the other that as of the Effective Date there is no pending or, to the knowledge of such Party, threatened action or proceeding affecting such Party before any Government Agency that has a reasonable likelihood of materially adversely affecting or reasonably threatening the ability of such Party to perform its obligations under this Agreement or the validity or enforceability of this Agreement against it and that there are no bankruptcy proceedings pending or being contemplated by it or, to its knowledge, threatened against it.

17.6 Absence of Certain Events. Each Party represents and warrants to the other Party that as of the Effective Date no Event of Default attributable to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement.

ARTICLE 18

DISPUTE RESOLUTION

18.1 Senior Officers.

18.1.1 Each of the Parties will designate in writing to the other Parties a representative who will be authorized to resolve any dispute arising under this Agreement and, unless otherwise expressly provided herein, to exercise the authority of such Party to make decisions by mutual agreement.

18.1.2 If such designated representatives are unable to resolve a dispute under this Agreement, such dispute will be referred by each Party's representative, respectively, to a designated senior officer.

18.1.3 The Parties hereto agree: (i) to attempt to resolve all disputes arising hereunder promptly; and (ii) to provide each other with reasonable access during normal business hours to any and all non-privileged and non-confidential records, information and data pertaining to any such dispute. Non-privileged and non-confidential information shall be made available to a Party pursuant to a confidentiality agreement consistent with the confidentiality provisions of this Agreement.

18.2 Arbitration.

18.2.1 All disputes arising under, out of, or in relation to any provision of this Agreement that are not resolved pursuant to Section 18.1 within 30 Days after either Party's receipt of notice referring the dispute to the senior officers of the Parties (and in any event within the time which legal or equitable proceedings based on such claim, dispute, or controversy would not be barred by the applicable statute of limitations) will be submitted upon written request of any Party to binding arbitration. Each Party will have the right to designate

an arbitrator of its choice, who need not be from the American Arbitration Association ("AAA") panel of arbitrators but who (a) will be an expert in the independent power electric generation field and (b) will not be and will not have been previously an employee or agent of or consultant or counsel to either Party or any of its Affiliates and will not have a direct or indirect interest in either Party or any of its Affiliates or the subject matter of the arbitration. Such designation will be made by notice to the other Party and to the AAA within 10 Days or, in the case of payment disputes, 5 Days after the date of the giving of notice of the demand for arbitration. The arbitrators designated by the Parties will designate a third arbitrator, who will have a background in legal and judicial matters (and who will act as chairman), within 10 Days or, in the case of payment disputes, 5 Days after the date of the designation of the last of the arbitrators to be designated by the Parties, and the arbitration will be decided by the three arbitrators. If the two arbitrators cannot or do not select a third independent arbitrator within such period, either Party may apply to the AAA for the purpose of appointing any person listed with the AAA as the third independent arbitrator under the expedited rules of the AAA. Such arbitration will be held in alternating locations of the home offices of the Parties, commencing with Buyer's home office, or in any other mutually agreed upon location. The rules of the AAA will apply to the extent not inconsistent with the rules herein specified. Each Party will bear its own expenses (including attorneys' fees) with respect to the arbitration. The arbitrators will designate the Party to bear the expenses of the arbitrators or the respective amounts of such expense to be borne by each Party.

18.2.2 Subject to Section 16.2, the arbitrators conducting an arbitration proceeding under this Section shall have no authority to award to any Party consequential, incidental, punitive, exemplary or indirect damages or any lost profits or business interruption

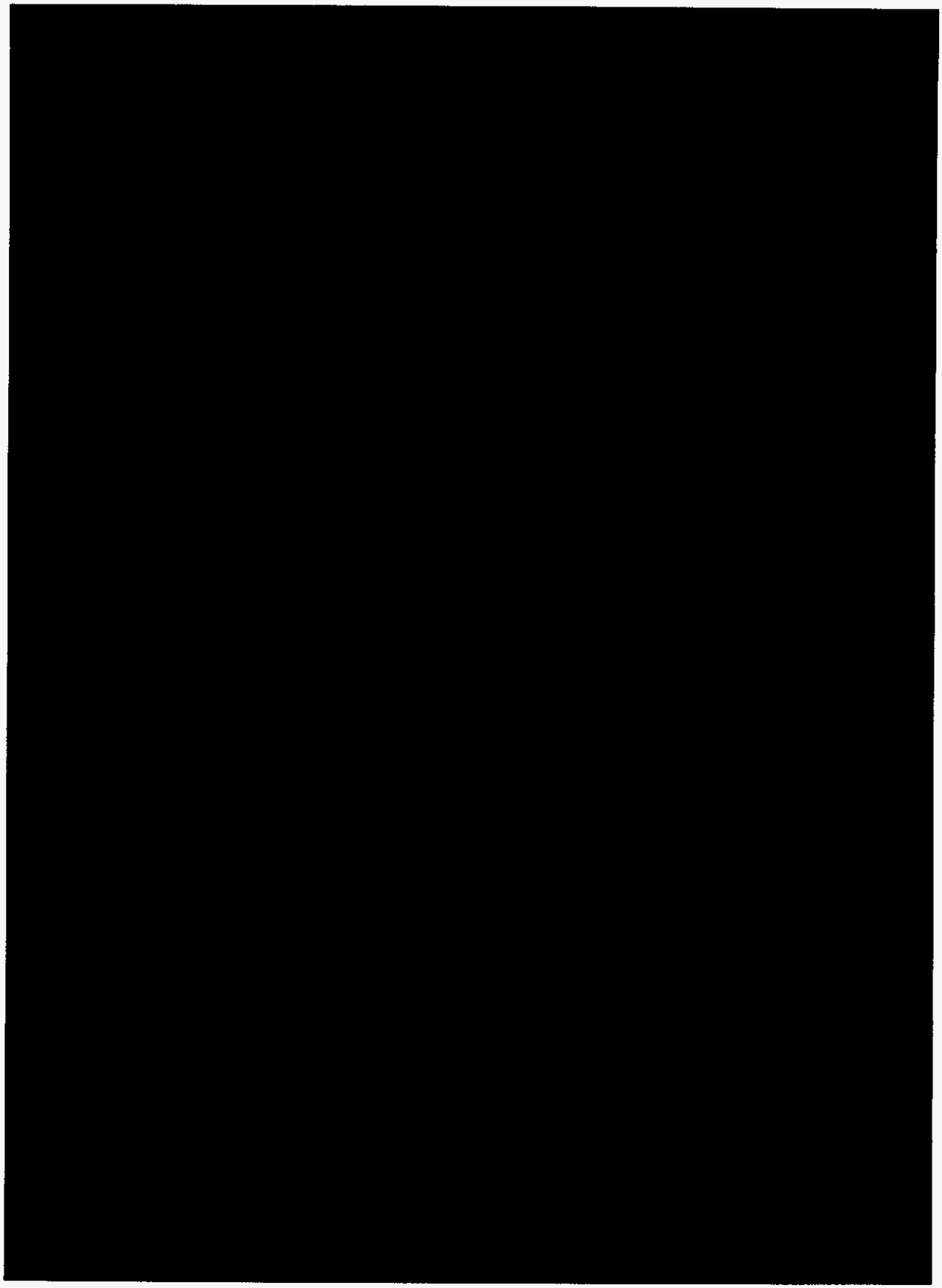
damages, whether by virtue of any Law or otherwise. Provided further, the fact that any arbitration proceeding is conducted hereunder and the decision of the arbitrators shall be deemed Confidential Information under Section 21.2; provided further, notwithstanding any provision in Article 21, Confidential Information, to the extent relevant, may be disclosed by any Party to the arbitrators conducting the arbitration and any court of competent jurisdiction enforcing the arbitrators' award.

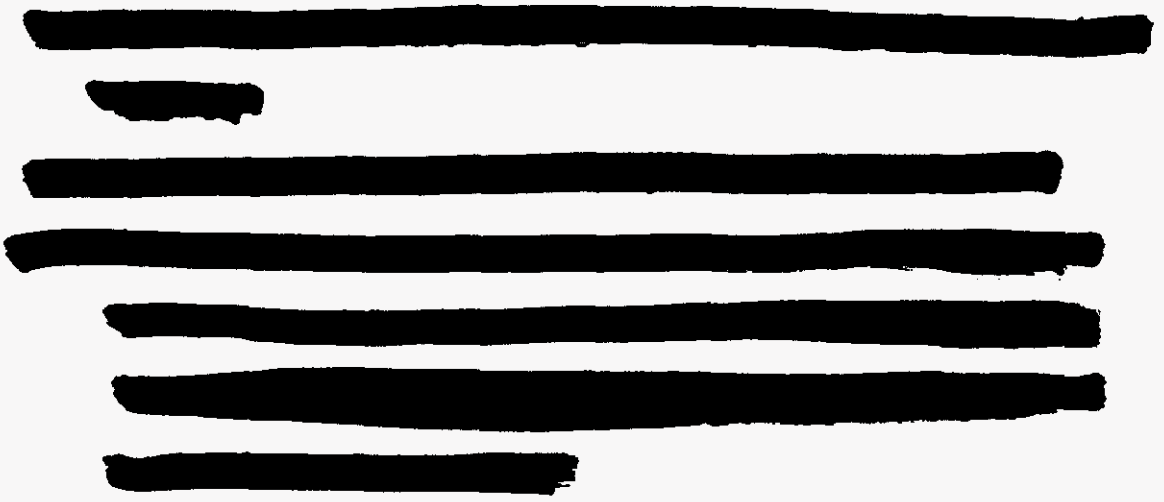
18.3 Binding Nature of Proceedings. Each Party understands that this Agreement contains an agreement to arbitrate with respect to specified disputes. After signing this Agreement, each Party understands that it will not be able to bring a lawsuit concerning any dispute that may arise that is covered by this arbitration provision. Instead, each Party agrees to submit any such dispute to arbitration pursuant to Section 18.2. Any award of the arbitrator may be enforced by the Party in whose favor such award is made in any court of competent jurisdiction.

ARTICLE 19

ASSIGNMENT

19.1 Assignment. Either Party may assign outright or collaterally this Agreement and its rights and obligations hereunder subject to the written consent of the other Party (which consent shall not be unreasonably withheld); provided that either Party may assign outright this Agreement and its rights and obligations hereunder without the consent of the other Party to any person with [redacted]





who has the legal power and authority, licenses and technical ability to perform and satisfy the obligations of the assigning Party under this Agreement (an "Eligible Assignee"). The assigning Party will notify the other Party in writing prior to any assignment with respect to which consent is not required hereunder. No assignment by a Party of this Agreement or its rights or obligations hereunder shall relieve the assigning Party of liability for its obligations under this Agreement without the written release of the other Party. Such release shall not be withheld if the Assignment Conditions (defined below) are satisfied.

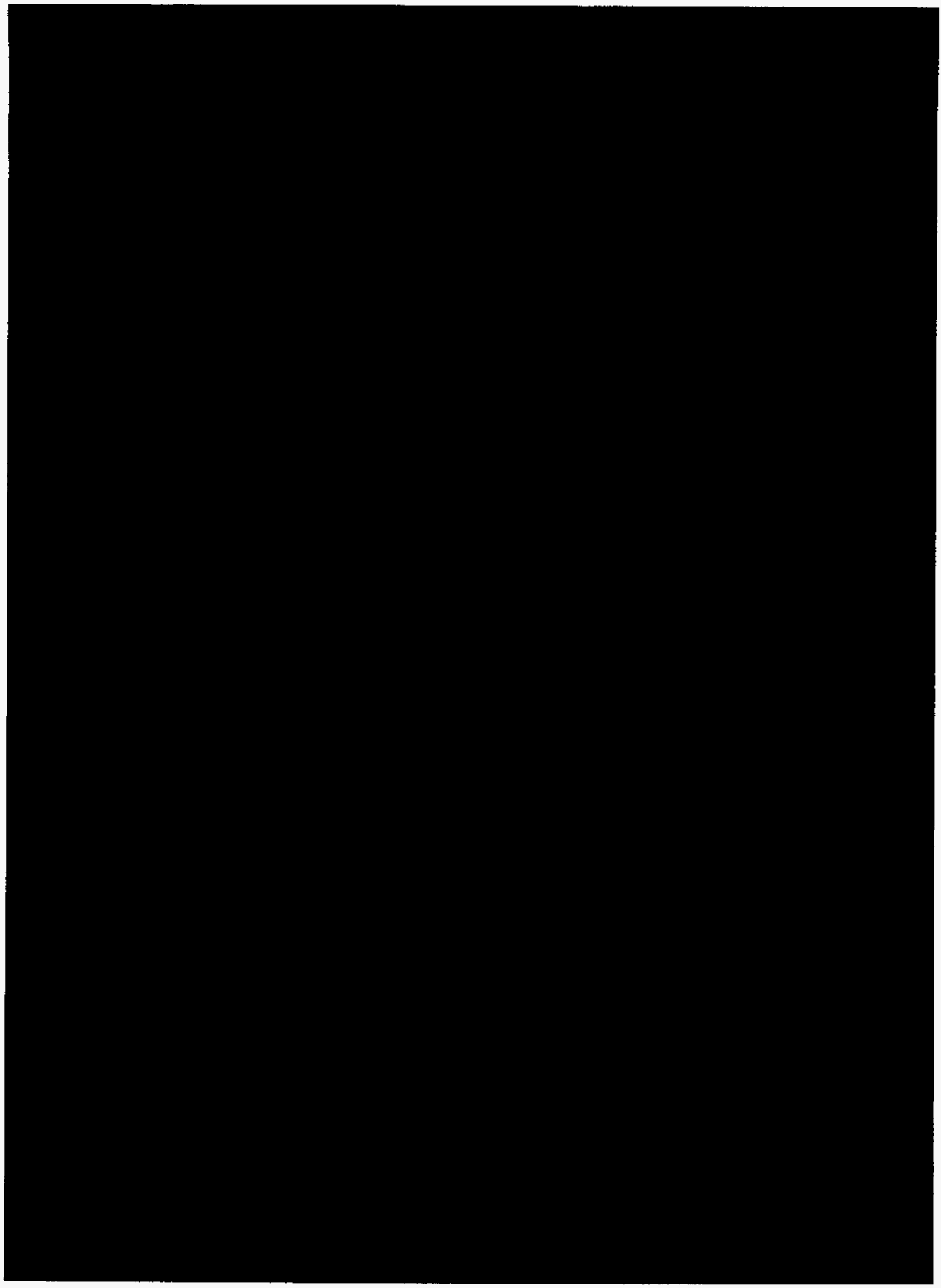
19.2 Assignment Conditions. The non-assigning Party's obligation to recognize or perform for any person claiming rights in this Agreement by outright assignment or through collateral assignment (an "Assignee") shall be subject to such Assignee: (i) establishing that it satisfies the qualifications of an Eligible Assignee; (ii) having cured all existing Events of Default under this Agreement; and (iii) having executed and delivered to the non-assigning Party an assignment and assumption agreement whereby the Assignee assumes and agrees to satisfy all conditions and pay and perform all obligations in favor of the non-assigning Party then existing and/or thereafter arising under this Agreement (the "Assignment Conditions").

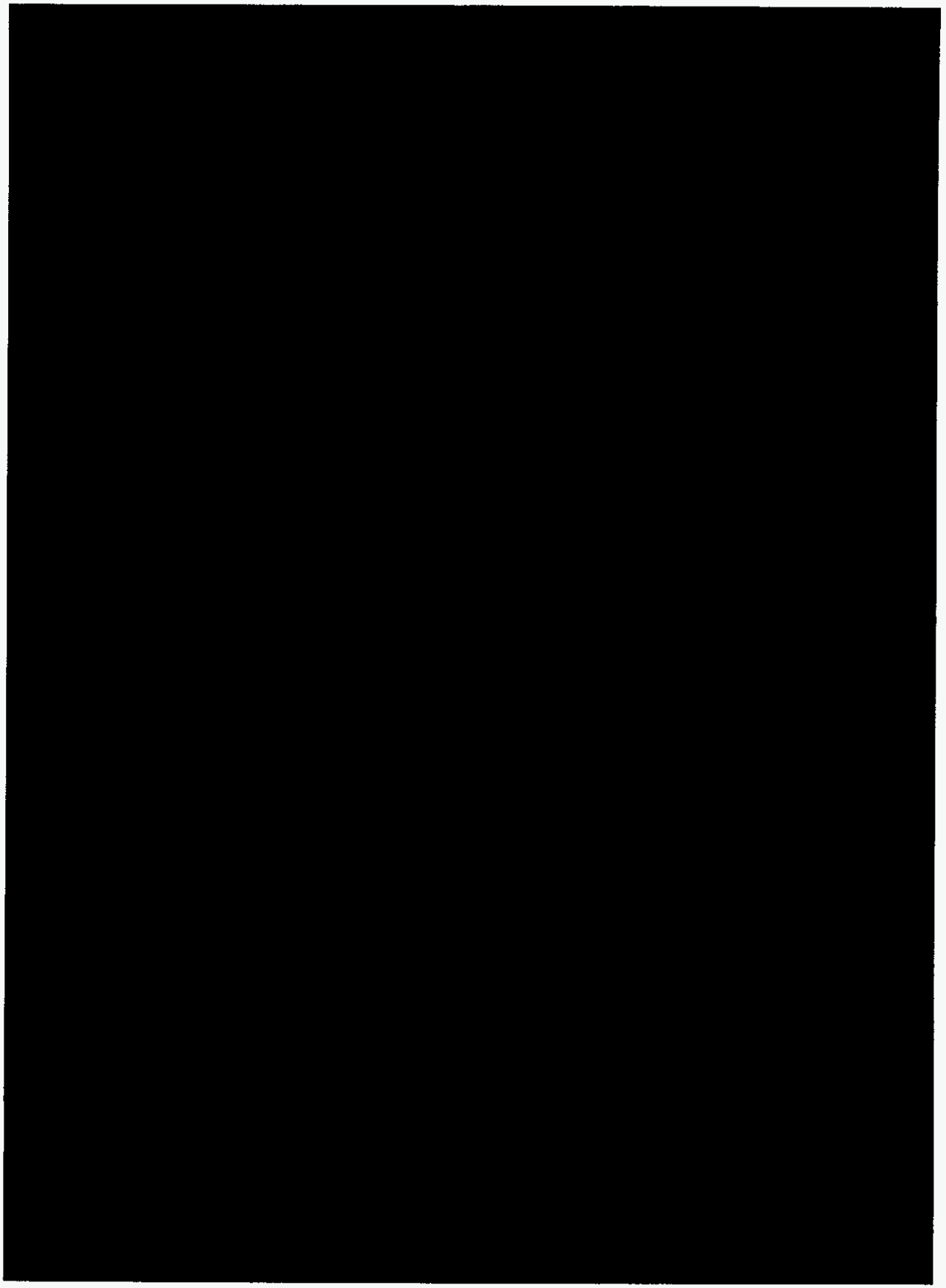
Any attempted assignment, directly or indirectly, by way of merger or otherwise, which is not in compliance with the terms hereof shall be void and ineffective.

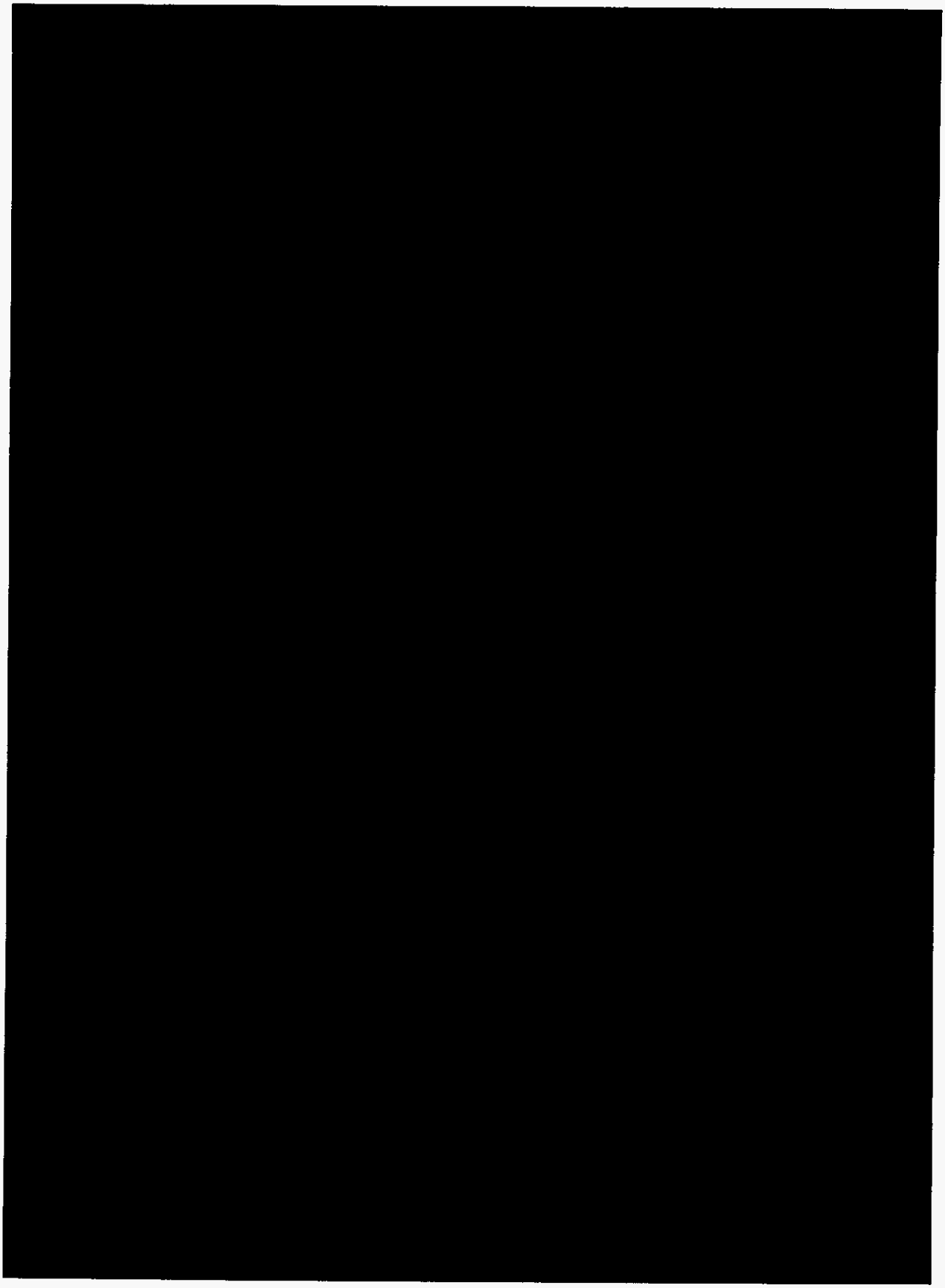
ARTICLE 20

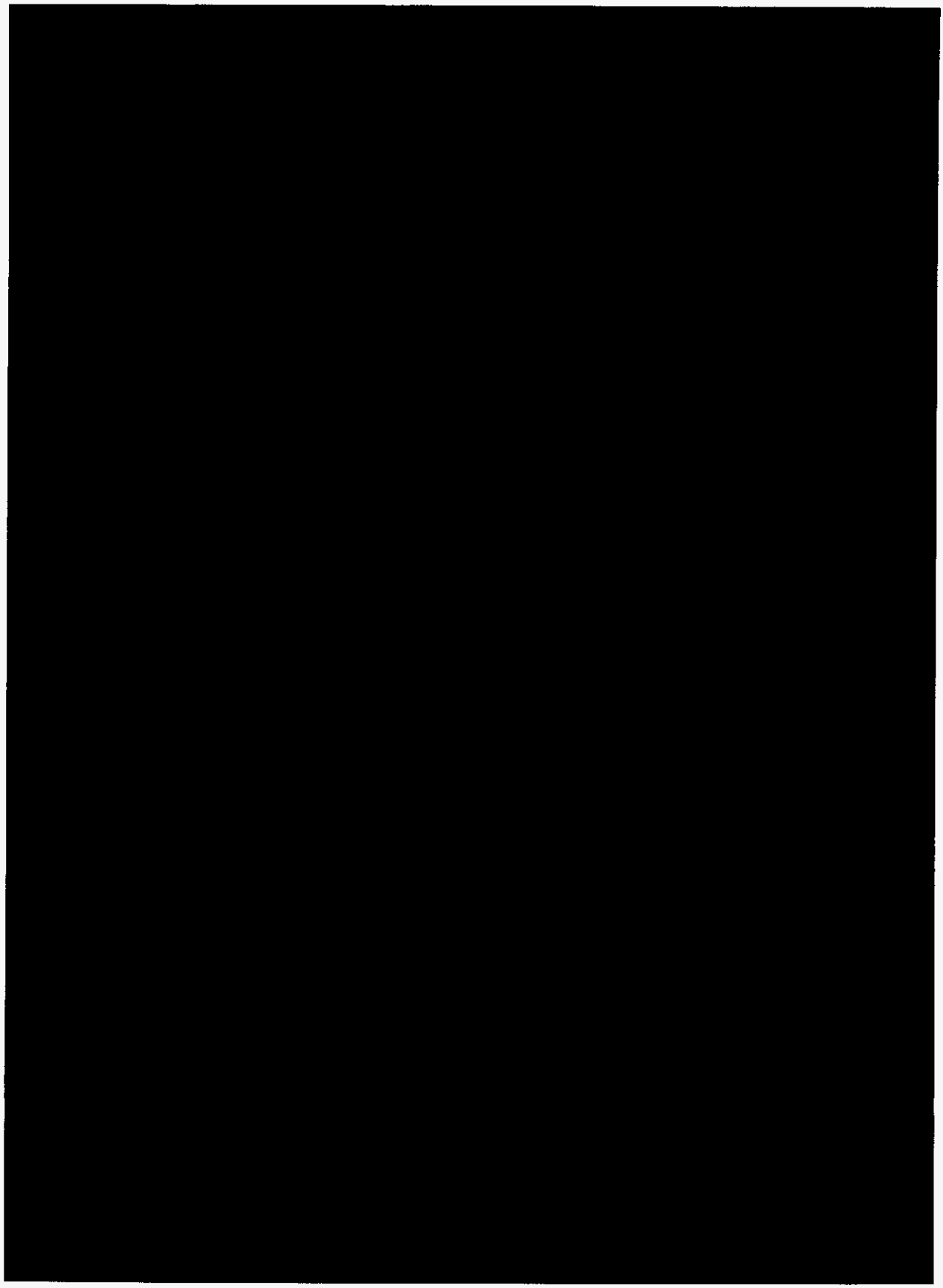
CREDITWORTHINESS AND SECURITY

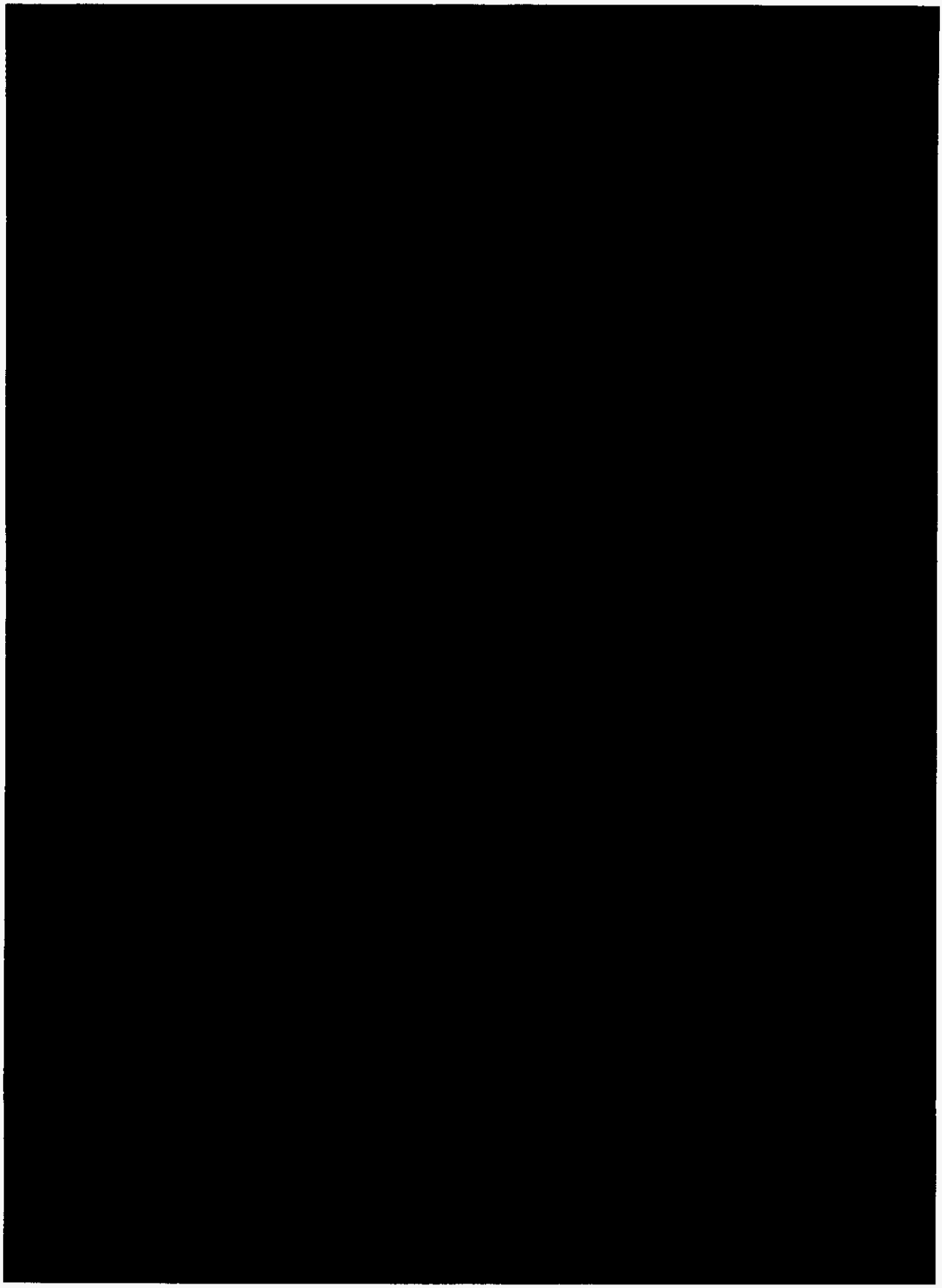
20.1 [redacted]

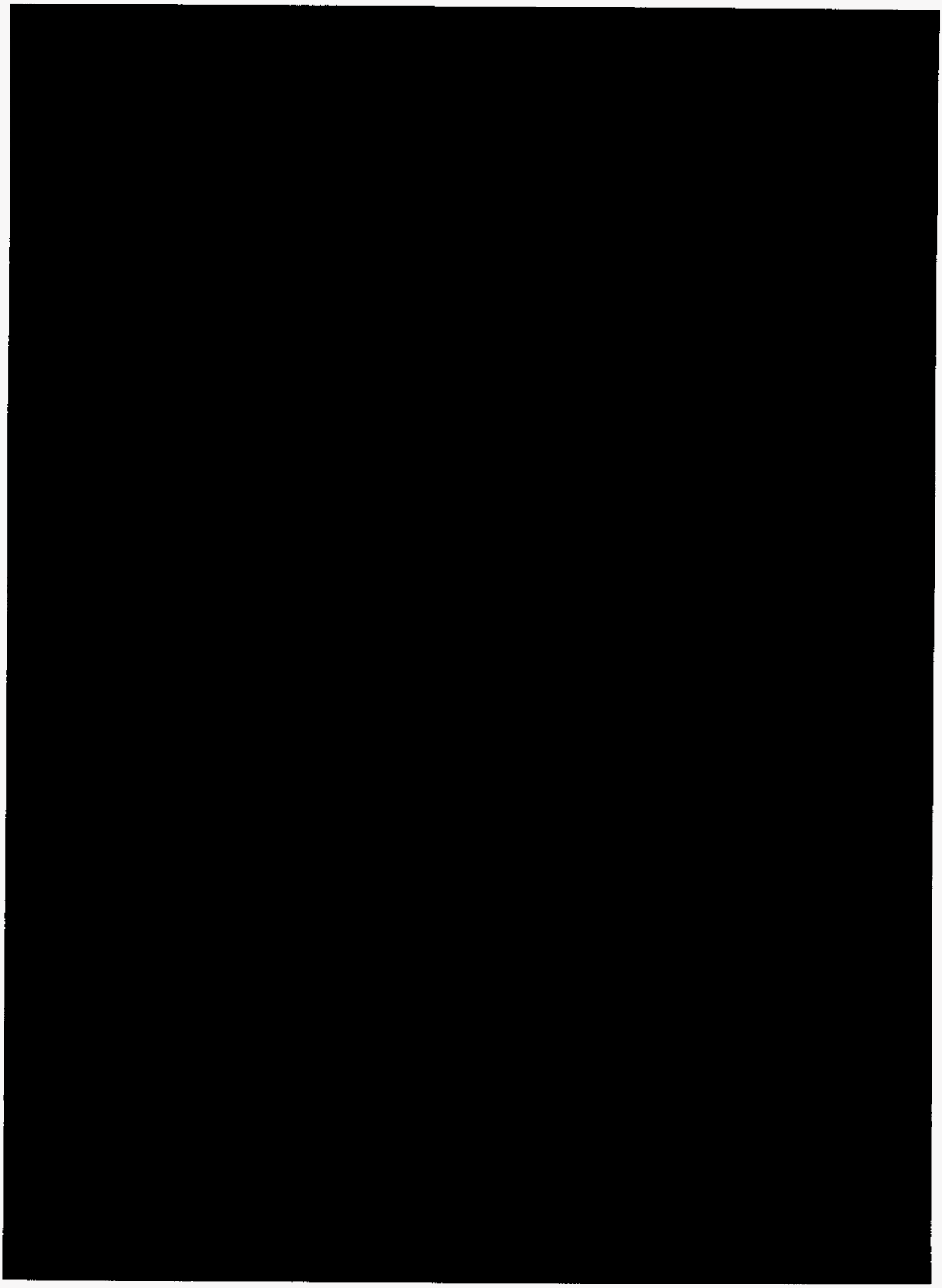


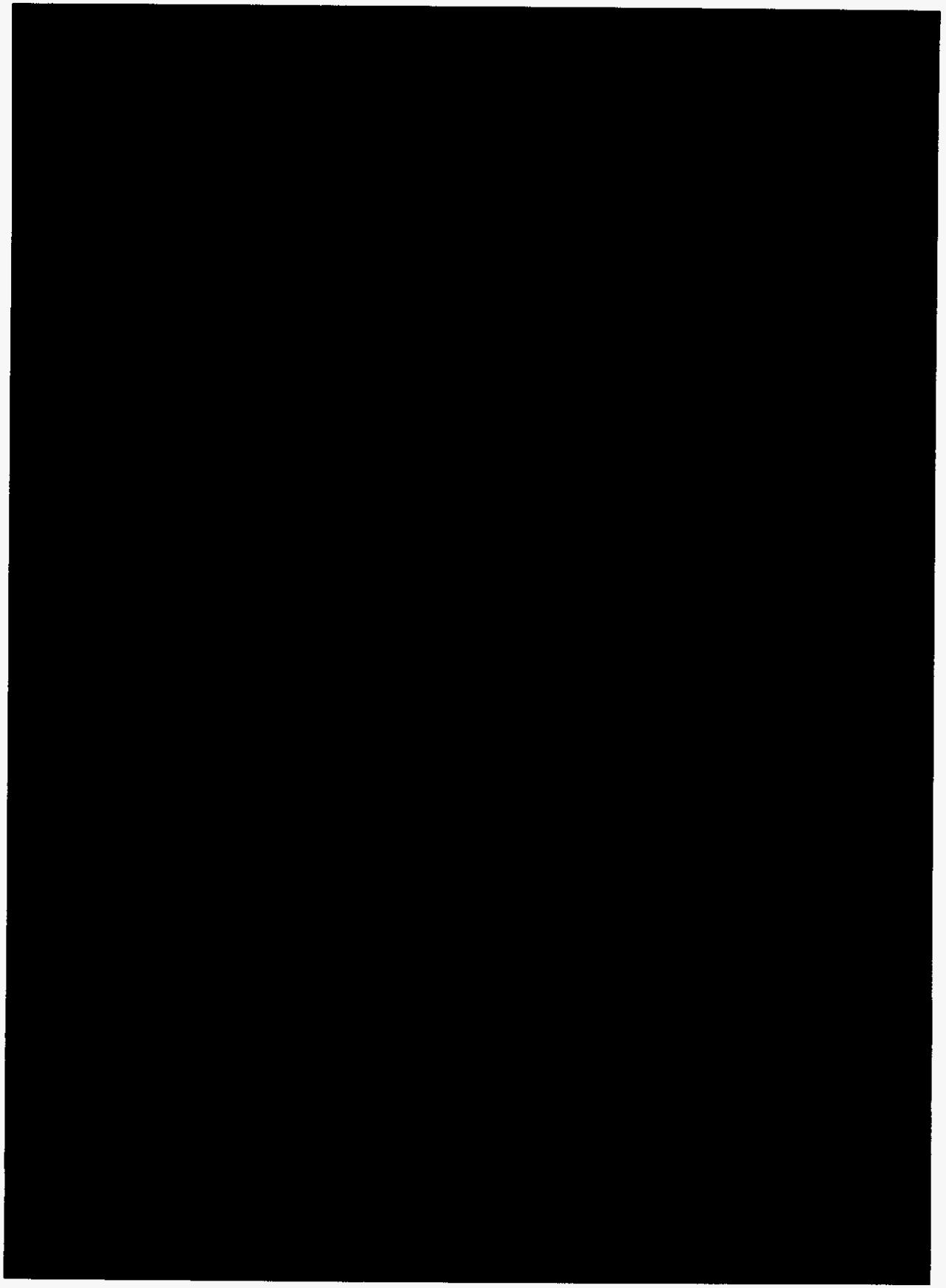












ARTICLE 21

MISCELLANEOUS

21.1 Governing Law; Waiver of Jury Trial.

THIS AGREEMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAW OF THE STATE OF FLORIDA, EXCLUSIVE OF ITS CONFLICTS OF LAW PROVISIONS, AND, TO THE EXTENT APPLICABLE, BY THE FEDERAL LAW OF THE UNITED STATES OF AMERICA. BY CHOOSING TO HAVE THIS AGREEMENT GOVERNED BY AND CONSTRUED UNDER THE LAW OF THE STATE OF FLORIDA, THE PARTIES ARE IN NO WAY SUBMITTING TO OR INCORPORATING INTO THIS AGREEMENT ANY FLORIDA STATUTE, REGULATION, OR ORDER, OR ANY OF THE SAME INVOLVING THE GENERATION, SALE, PURCHASE OR TRANSMISSION OF ELECTRIC CAPACITY OR ELECTRIC ENERGY IN, OR FOR CONSUMPTION IN, THE STATE OF FLORIDA. EACH PARTY HEREBY IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT.

21.2 Confidentiality.

21.2.1 Scope of Protection.

(i) For purposes of this Section 21.2: (a) "Seller Confidential Information" means the terms of this Agreement and all drafts of the same, together with any documents, data or drafts labeled or otherwise expressly identified as "Confidential" by Seller

when provided to Buyer; (b) "Buyer Confidential Information" means the terms of this Agreement and all drafts of the same, together with any documents, data or drafts labeled or otherwise expressly identified as "Confidential" by Buyer when provided to Seller; and (c) "Confidential Information" means collectively the Seller Confidential Information and the Buyer Confidential Information.

(ii) Seller shall not disclose to third parties any Buyer Confidential Information; provided that nothing contained herein shall prohibit Seller from providing any such Buyer Confidential Information to its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons in connection with the acquisition of all or a significant portion of the assets or stock of Southern Power or any of its Affiliates or in connection with the analysis, issuance or rating of any debt or equity securities or other financing activities by Southern Power or any of its Affiliates who in the reasonable judgment of Seller should have access to such Buyer Confidential Information and are bound by an obligation to maintain such confidentiality provided that Seller shall be responsible for any use or disclosure of such Buyer Confidential Information by any of its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons inconsistent with this Section 21.2; provided further that nothing contained herein shall prohibit Seller from providing Buyer Confidential Information to the NERC or SERUC solely to the extent that (i) Seller determines in its reasonable discretion that the provision of such information is required to enhance and/or maintain reliability; (ii) such entity is obligated to maintain such confidentiality;

and (iii) Seller has notified Buyer of its intention to release such information no less than 5 Business Days prior to the release subject to the requirements of applicable law and regulation.

(iii) Buyer shall not disclose to third parties any Seller Confidential Information; provided that nothing contained herein shall prohibit Buyer from providing any such Seller Confidential Information to its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons in connection with the acquisition of all or a significant portion of the assets or stock of Buyer or any of its Affiliates or in connection with the analysis, issuance or rating of any debt or equity securities or other financing activities by Buyer or any of its Affiliates who in the reasonable judgment of Buyer should have access to such Seller Confidential Information and are bound by an obligation to maintain such confidentiality provided that Buyer shall be responsible for any use or disclosure of such Seller Confidential Information by any of its or its Affiliates' agents, employees, officers, directors, representatives, contractors, advisors, accountants, rating agencies, underwriters, investors, counsel, prospective or actual purchasers, prospective or actual lenders or such other Persons inconsistent with this Section 21.2; provided further that nothing contained herein shall prohibit Buyer from providing Seller Confidential Information to the NERC or SEARUC solely to the extent that (i) Buyer determines in its reasonable discretion that the provision of such information is required to enhance and/or maintain reliability, (ii) such entity is obligated to maintain such confidentiality, and (iii) Buyer has notified Seller of its intention to release such information no less than 5 Business Days prior to the release subject to the requirements of applicable law and regulation.

(iv) Notwithstanding the foregoing, either Party may disclose Confidential Information (i) to the extent relevant, to the independent parties determining Seller's Damages or Buyer's Damages (as appropriate), and (ii) to its and its Affiliates' employees, officers, directors, accountants, counsel and other advisors who need to know such information in connection with the performance of their duties or services for the disclosing Party or its Affiliates; provided, however, that such Persons shall be required to maintain the confidentiality of such information consistent with the requirements of this Agreement.

21.2.2 Required and Other Disclosure.

(i) Notwithstanding anything in this Section to the contrary, if Buyer is required by applicable law or regulation, or in the course of administrative or judicial proceedings or investigations, to disclose to third parties, Seller Confidential Information or otherwise intends to disclose Seller Confidential Information to FERC or its staff (other than at the request or requirement of FERC or its staff) or pursuant to the request or requirement of any appropriate state regulatory commission or body, Buyer may make disclosure of such Seller Confidential Information; provided, however, that all reasonable steps are taken by Buyer to assure continued confidential treatment by the relevant administrative, regulatory or judicial agencies or other recipient and provided further that as soon as Buyer learns of the disclosure request or requirement or otherwise intends to disclose any Seller Confidential Information pursuant hereto and prior to making disclosure, Buyer shall, to the extent permitted by law, notify Seller of the requirement, request or intention and the terms thereof and any Party may challenge the disclosure requirement, request or intention or seek a protective order or other appropriate remedy. Buyer, at Seller's expense, shall cooperate with Seller to the maximum extent practicable to minimize the disclosure of the Seller Confidential Information consistent

with applicable law. Buyer shall cooperate with Seller to obtain proprietary or confidential treatment of such Seller Confidential Information by the Person to whom such Seller Confidential Information will be disclosed (and if practicable, reasonably prior to any such disclosure). If, in the absence of a protective order or other appropriate remedy or the receipt of a waiver by Seller, Buyer is nonetheless, in the written opinion of counsel, legally compelled to disclose Seller Confidential Information or otherwise may become subject to contempt or other censure or penalty, Buyer may, in such instance but not otherwise, without liability hereunder, disclose that portion of the Seller Confidential Information which and to whom such counsel advises Buyer is legally required to be disclosed (but none other), provided that Buyer exercises Commercially Reasonable Efforts to preserve the confidentiality of the Seller Confidential Information, including by cooperating with Seller to obtain an appropriate protective order or other reliable assurance that the Seller Confidential Information shall be accorded confidential treatment. Seller shall be liable for all reasonable legal costs incurred by Buyer in cooperating with Seller to obtain such an appropriate protective order or confidential treatment.

(ii) Notwithstanding anything in this Section to the contrary, if Seller is required by applicable law or regulation, or in the course of administrative or judicial proceedings or investigations, to disclose to third parties, Buyer Confidential Information or otherwise intends to disclose Buyer Confidential Information to FERC or its staff (other than at the request or requirement of FERC or its staff) or pursuant to the request or requirement of any appropriate state regulatory commission or body, Seller may make disclosure of such Buyer Confidential Information; provided, however, that all reasonable steps are taken by Seller to assure continued confidential treatment by the relevant administrative, regulatory or judicial agencies or other recipient and provided further that as soon as Seller learns of the disclosure

request or requirement or otherwise intends to disclose any Buyer Confidential Information pursuant hereto and prior to making disclosure, Seller shall, to the extent permitted by law, notify Buyer of the requirement, request or intention and the terms thereof and any Party may challenge the disclosure requirement, request or intention or seek a protective order or other appropriate remedy. Seller, at Buyer's expense, shall cooperate with Buyer to the maximum extent practicable to minimize the disclosure of the Buyer Confidential Information consistent with applicable law. Seller shall cooperate with Buyer to obtain proprietary or confidential treatment of such Buyer Confidential Information by the Person to whom such Buyer Confidential Information will be disclosed (and if practicable, reasonably prior to any such disclosure). If, in the absence of a protective order or other appropriate protective remedy or the receipt of a waiver by Buyer, Seller is nonetheless, in the written opinion of counsel, legally compelled to disclose Buyer Confidential Information or otherwise may become subject to contempt or other censure or penalty, Seller may, in such instance but not otherwise, without liability hereunder, disclose that portion of the Buyer Confidential Information which and to whom such counsel advises Seller is legally required to be disclosed (but none other), provided that Seller exercises Commercially Reasonable Efforts to preserve the confidentiality of the Buyer Confidential Information, including, without limitation, by cooperating with Buyer to obtain an appropriate protective order or other reliable assurance that the Buyer Confidential Information shall be accorded confidential treatment. Buyer shall be liable for all reasonable legal costs incurred by Seller in cooperating with such Buyer to obtain an appropriate protective order or confidential treatment.

(iii) Nothing in this Section 21.2 shall prohibit or otherwise limit the use or disclosure of Confidential Information if such Confidential Information: (i) was

previously known to the disclosing or using Party unrelated to this Agreement without an obligation of confidentiality; (ii) was developed by or for the disclosing or using Party unrelated to this Agreement using nonconfidential information; (iii) was acquired by the disclosing or using Party from a third party which is not, to the disclosing or using Party's knowledge, under an obligation of confidence with respect to such information; (iv) is or becomes publicly available other than through a manner inconsistent with this Section 21.2; or (v) is provided or made available for inspection by Seller or Buyer under public records or public disclosure laws but only to the extent required to be so provided or made available.

(iv) The provisions of this subsection shall supercede any contrary provisions of this Section 21.2 regarding the disclosure of information to FERC or its staff pursuant to the request or requirement of FERC or its staff. In providing Buyer Confidential Information to FERC or its staff pursuant to the request or requirement of FERC or its staff, Seller shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. To the extent permitted by law, Seller shall promptly notify Buyer when it is required or requested by FERC or its staff to disclose Buyer Confidential Information. Seller shall not be prohibited to make or liable for the disclosure to FERC or its staff of any Buyer Confidential Information pursuant to the request or requirement of FERC or its staff consistent with this subsection. In providing Seller Confidential Information to FERC or its staff pursuant to the request or requirement of FERC or its staff, Buyer shall, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by FERC and its staff and that the information be withheld from public disclosure. To the extent permitted by law, Buyer shall promptly notify Seller when it is required or requested by FERC or its staff to

disclose Seller Confidential Information. Buyer shall not be prohibited to make or liable for the disclosure to FERC or its staff of any Seller Confidential Information pursuant to the request or requirement of FERC or its staff consistent with this subsection. Notwithstanding the foregoing, the Parties acknowledge that any request of FERC for confidential treatment of information may be denied by FERC in whole or in part.

(v) The Parties agree to seek confidential treatment of the Confidential Information from the FPSC to the maximum extent possible pursuant to Chapter 366.093, Florida Statutes, and Rule 25-22.006 of the Florida Administrative Code; however, notwithstanding the foregoing, the Parties acknowledge that a request for confidential treatment of Confidential Information may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the FPSC to such information. In the event any Confidential Information will need to be disclosed in connection with the application for the FPSC Approval, Buyer shall consult and cooperate with Seller prior to such disclosure, including, without limitation, in determining the extent to which confidential treatment will be sought for such terms, conditions and provisions.

(vi) Seller may file this Agreement with the Securities and Exchange Commission ("Commission") as may be necessary under the Public Utility Holding Company Act and the rules and regulations thereunder in connection with Seller's application to the Commission for such orders and approvals as may be required for financing and/or the issuance and sale of interests in or debt issued or to be issued by Seller and/or its Affiliates. Seller shall request confidential treatment of the Buyer Confidential Information in this Agreement in connection with such filing; however, the Parties acknowledge that such request may be denied in whole or in part, and accordingly, that confidential treatment may not be afforded by the

Commission to such information. In addition, Seller may disclose such Buyer Confidential Information as required by the Commission pursuant to the Securities and Exchange Act of 1934, as amended, and any rule or regulation promulgated thereunder.

(vii) Except for filings with the Commission or other regulatory authorities, any public statement and/or press release by a Party hereto concerning this Agreement (except statements or releases by the Non-Defaulting Party after an Event of Default) shall be reviewed and agreed upon by the Parties before release, which agreement shall not be unreasonably withheld or delayed.

The obligations under this Section 21.2 with respect to any Party shall survive until the earlier of [redacted]

21.3 Survivorship of Obligations. Termination of this Agreement shall not discharge any Party from any obligation it owes the other Party under this Agreement by reason of any transaction, loss, cost, damage, expense or liability occurring, accruing or arising prior to such termination. It is the intent of the Parties that any such obligation owed (whether the same shall be known or unknown as of the termination or cancellation of this Agreement) will survive the termination or cancellation of this Agreement in favor of the Party to which such obligation is owed. The Parties also intend that the indemnification and limitation of liability provisions contained in Sections 14.2 and 14.3 shall remain operative and in full force and effect and that any specific survivability provisions in any other sections be given full effect.

21.4 No Third Party Beneficiaries. This Agreement is not intended to, and shall not, create rights, remedies or benefits of any character whatsoever in favor of any Persons, corporations, associations, or entities other than the Parties and their permitted successors and assigns, and the rights and obligations of each of the Parties under this Agreement are solely for

the use and benefit of, and may be enforced solely by the Parties, their permitted successors and assigns.

21.5 Section Headings Not to Affect Meaning. The descriptive headings of the various Articles and Sections of this Agreement have been inserted for convenience of reference only and shall in no way modify or restrict any of the terms and provisions thereof. References to "Articles", "Sections" and "Appendices" in this Agreement shall mean the Articles, Sections and Appendices of this Agreement unless otherwise expressly noted.

21.6 Computation of Time. In computing any period of time prescribed or allowed by this Agreement, the designated period of time shall begin to run on the Day immediately following the Day of the act, event or default that precipitated the running of the designated period of time. The designated period shall expire on the last Day of the period so computed unless that Day is not a Business Day, in which event the period shall run until the end of the next Business Day.

21.7 Interest. Whenever the provisions of this Agreement require the calculation of an interest rate, such rate shall be computed at an annual rate equal to the Prime Rate as of the date on which the calculation begins, but not to exceed the maximum rate which may be lawfully charged. Interest on obligations arising under this Agreement shall be compounded daily and be calculated based on a 360 day year.

21.8 Entire Agreement. [redacted] this Agreement constitutes the entire agreement between the Parties relating to the subject matter hereof and supersedes any other agreements, written or oral, between the Parties concerning such subject matter. The Parties have entered into this Agreement in reliance upon the representations and mutual

understandings contained herein and not in reliance upon any oral or written representation or information provided by one Party to another Party not contained or incorporated herein.

21.9 Counterparts. This Agreement may be executed simultaneously in multiple counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

21.10 Amendments. This Agreement may only be amended by written agreement signed by duly authorized representatives of the Parties.

21.11 Waivers. Waivers of the provisions of this Agreement or excuses of any violations of this Agreement shall be valid only if in writing and signed by an authorized officer of the Party issuing the waiver or excuse. A waiver or excuse issued under one set of circumstances shall not extend to other occurrences under similar circumstances.

21.12 No Partnership Created. Any provision of this Agreement to the contrary notwithstanding, the Parties do not intend to create hereby any joint venture, partnership, association taxable as a corporation, or other entity for the conduct of any business for profit. If it should appear that one or more changes to this Agreement would be required in order not to create an entity referenced in the preceding sentence, the Parties agree to negotiate promptly and in good faith with respect to such changes.

21.13 Character of Sale. The sale of capacity and energy hereunder shall not constitute a sale, lease, transfer or conveyance to Buyer or any other party of any contractual rights or ownership interests in any generating unit or other equipment comprising the Facility, nor does the sale of capacity and energy hereunder constitute a dedication of ownership of any generating unit or other equipment comprising the Facility.

21.14 Notices. Any notice, demand, request, statement, or correspondence provided for in this Agreement, or any notice which a Party may desire to give to the other, shall be in writing (unless otherwise expressly provided by this Agreement) and shall be considered duly delivered when received by hand delivery, first-class mail, facsimile, or by overnight delivery, at the address(es) and to the attention of the person(s) listed below; provided, however, if actual delivery occurs at a time other than between the hours of 0800 and 1700 CPT on a Business Day (each a "Business Hour"), delivery shall be deemed to have occurred in the next Business Hour after actual delivery.

(i) **To Seller:**

Vice President, Business Development
Southern Company Generation and Energy Marketing
Bin 935
270 Peachtree Street, NW
Atlanta, Georgia 30303

Telephone: 404-506-0346
Facsimile: 404-506-0399

With a copy to:

Senior Vice President, General Counsel and Assistant Secretary
Southern Power Company
600 North 18th Street
Birmingham, Alabama 35203

Telephone: 205-257-0472
Facsimile: 205-257-2027

And

Vice President, Fleet Operations and Trading
Southern Company Services, Inc.
600 North 18th Street, GS-8259
Birmingham, Alabama 35203

Telephone: 205-257-6139
Facsimile: 205-257-4441

(ii) **To Buyer:**

Vice President, Energy Marketing and Trading
Florida Power & Light Company
700 Universe Boulevard
EMT/JB
Juno Beach, Florida 33408

Telephone: 561-691-7878
Facsimile: 561-691-7759

With a copy to:

Director, Resource Assessment and Planning
Florida Power & Light Company
9250 West Flagler Street
Miami, Florida 33174

Telephone: 305-552-3622
Facsimile: 305 552-2905

Either Party may change the information set forth in this Section 21.14 by giving written notice to the other Party in the manner prescribed by this Section.

21.15 Survival. Any provision(s) of this Agreement that expressly comes into or remains in force following the termination or expiration of this Agreement shall, subject to the express terms of the relevant provision, survive the termination or expiration of this Agreement.

21.16 Construction. The language used in this Agreement is the product of both Parties' efforts. Accordingly, each Party irrevocably waives the benefit of any rule of contract construction that disfavors the drafter of a contract or the drafter of specific language in a contract.

21.17 Imaged Agreement. Any original executed Agreement, schedule confirmation or other related document may be photocopied and stored on computer tapes and disks (the "Imaged Agreement"). The Imaged Agreement, if introduced as evidence on paper, the

schedule confirmation, if introduced as evidence in automated facsimile form, the transaction tape, if introduced as evidence in its original form and as transcribed onto paper, and all computer records of the foregoing, if introduced as evidence in printed format, in any judicial, arbitration, mediation or administrative proceedings, will be admissible as between the Parties to the same extent and under the same conditions as other business records originated and maintained in documentary form. Neither Party shall object to the admissibility of the transaction tape, the schedule confirmation or the Imaged Agreement (or photocopies of the transcription of the transaction tape, the schedule confirmation or the Imaged Agreement) on the basis that such were not originated or maintained in documentary form under either the hearsay rule, the best evidence rule or other rule of evidence.

21.18 Severability. If any provision or provisions of this Agreement or the application thereof to any Person or circumstance or in any jurisdiction is found by a court of competent jurisdiction to be illegal, invalid, unlawful, void or unenforceable as written for any reason, then it is the intent of each of the Parties that any such provision or provisions shall be given force and effect to the fullest possible extent that they are legal, valid and enforceable, that the remainder of this Agreement and the application of such provision or provisions to other Persons or circumstances or in other jurisdictions shall be deemed valid and enforceable to the fullest extent possible and continue in force and effect. If the determination that any provision or provisions hereof are illegal, invalid, unlawful, void or unenforceable (even after such provision or provisions are given force and effect to the fullest extent possible) results in a significant material deviation from the Parties' original intent or economic expectations regarding this Agreement, the Parties shall negotiate to (and/or the applicable court, in its discretion, may) replace any such illegal, invalid, unlawful, void or unenforceable provision or

provisions with valid provision(s) which result in the least deviation from the Parties' intent and economic expectations.

21.19 Agency of Southern Company Services, Inc. Seller hereby designates Southern Company Services, Inc. to serve as its agent for purposes of the implementation and administration of this Agreement. Seller may designate a new agent from time to time under this Agreement by giving Buyer 60 Days written notice in which event Southern Company Services, Inc.'s role, as agent, shall cease and the newly-designated agent shall be substituted for the sole purpose of serving and acting as agent for Seller hereunder.

21.20 Include. As used herein, the words "include" or "including" shall be deemed to be followed by the words "without limitation."

21.21 Examples. Examples of calculations pursuant to the provisions of this Agreement are set forth in Appendix H. Such calculations are for example purposes only and are not intended to, and shall not, modify any of the terms of this Agreement. To the extent there is a conflict between any of these examples and the other terms of this Agreement, such other terms shall govern. Moreover, such examples shall be given no weight in interpreting or construing the provisions of this Agreement.

[The Next Page is the Signature Page.]

IN WITNESS WHEREOF, Seller and Buyer have caused this Agreement to be executed in duplicate by their respective duly authorized officers as of the Effective Date.

SOUTHERN COMPANY SERVICES, INC.
As Agent for
Southern Power Company

BY: _____

NAME: William N. McKenzie

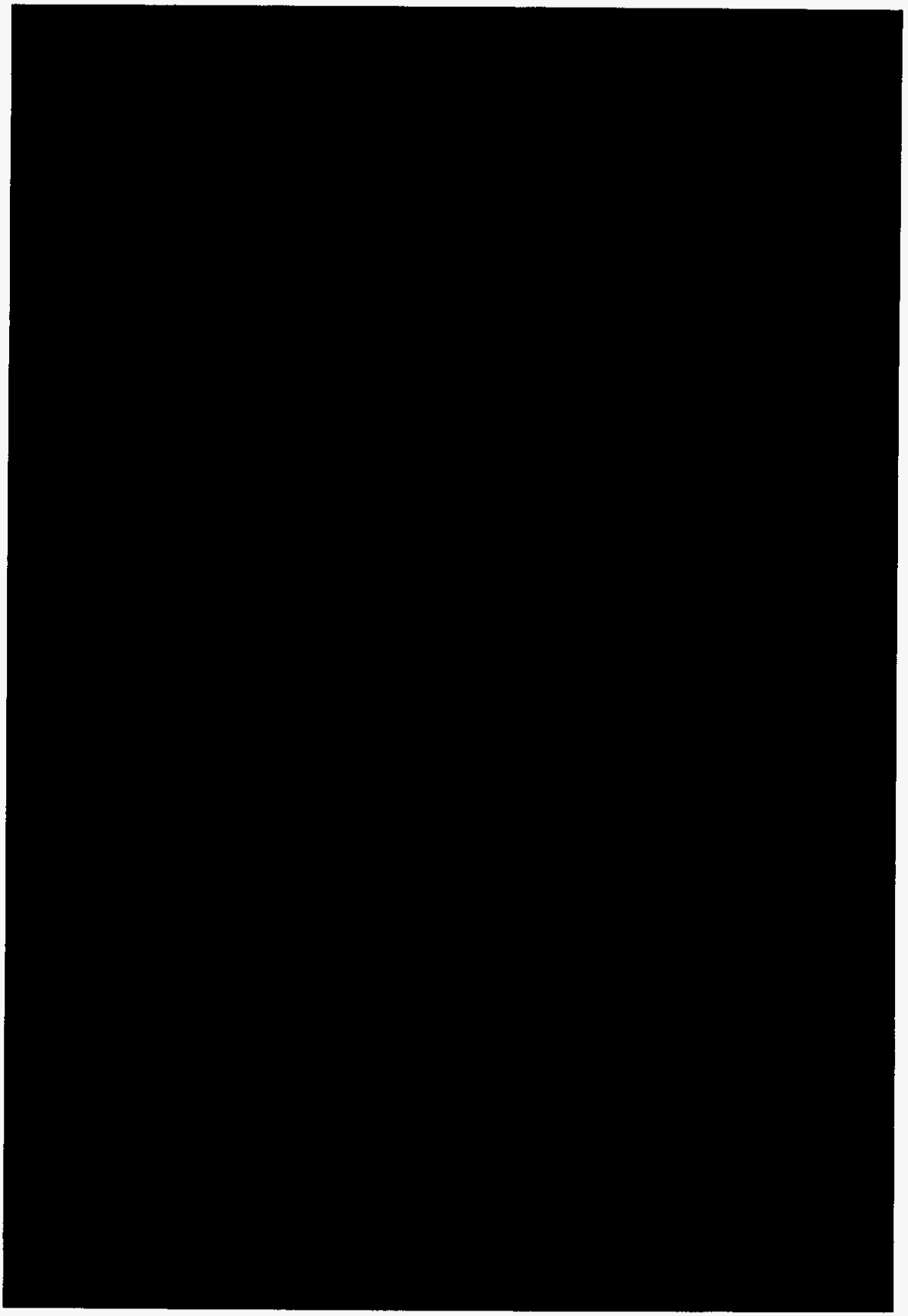
TITLE: Vice President

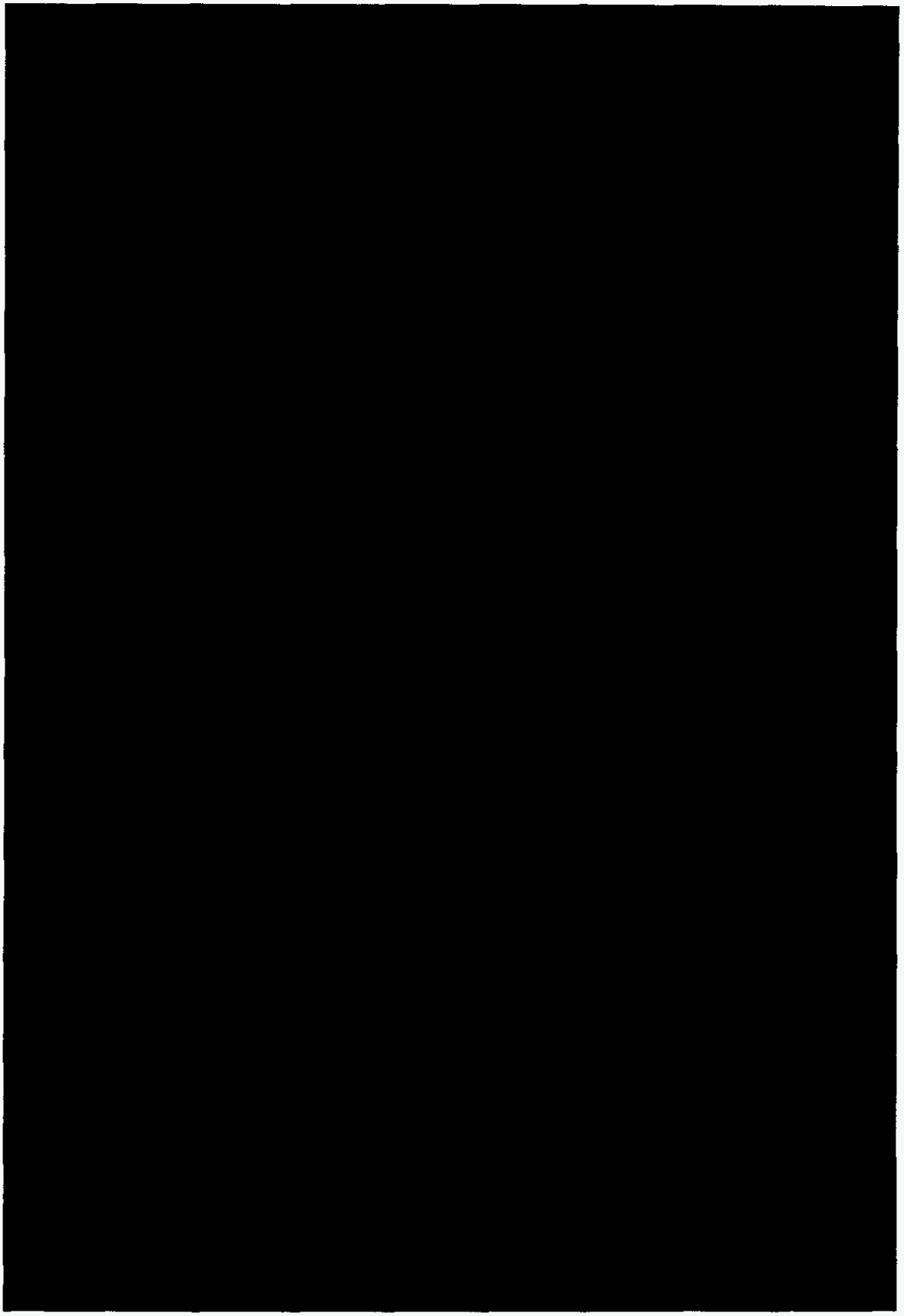
FLORIDA POWER & LIGHT COMPANY

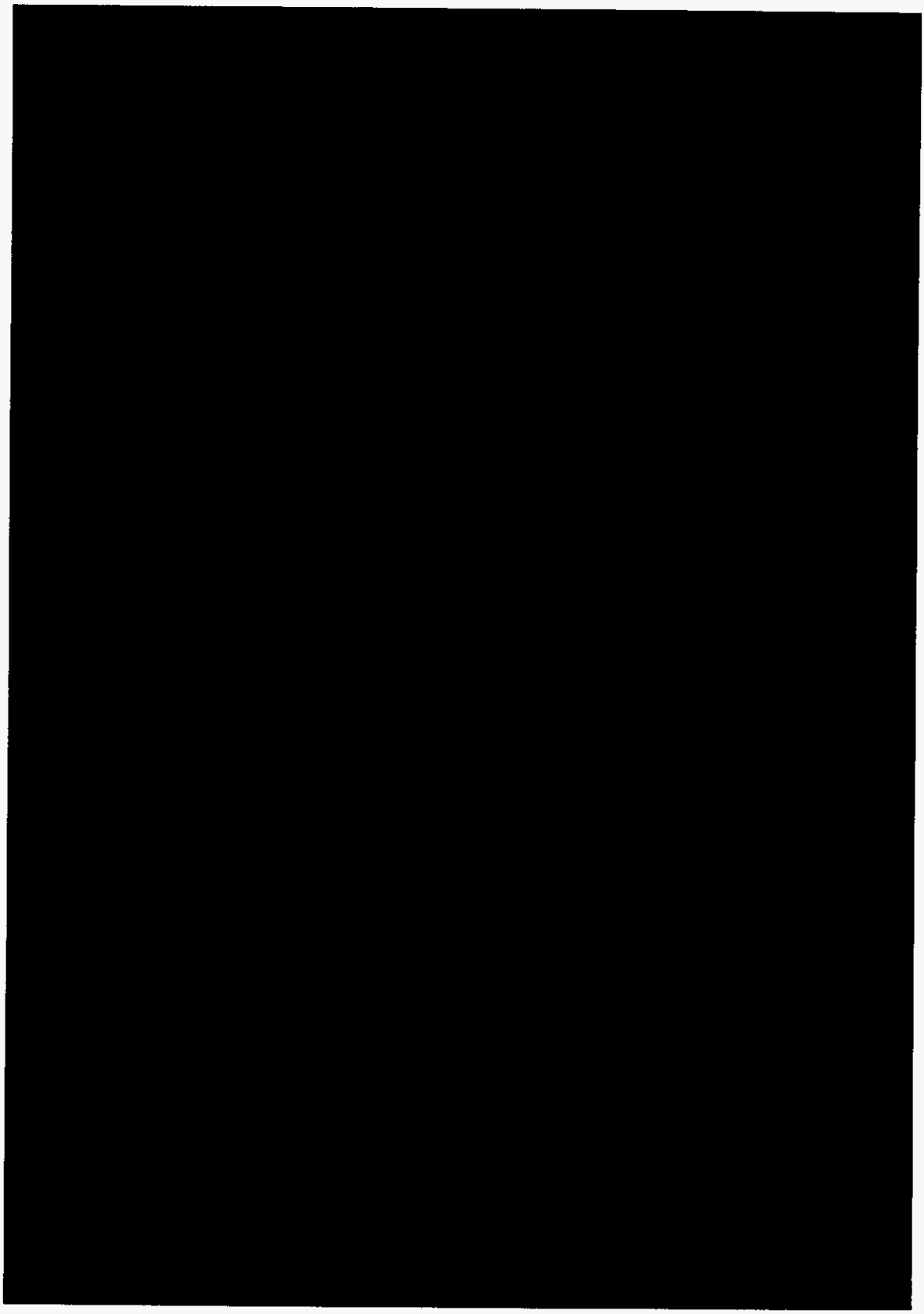
BY: _____

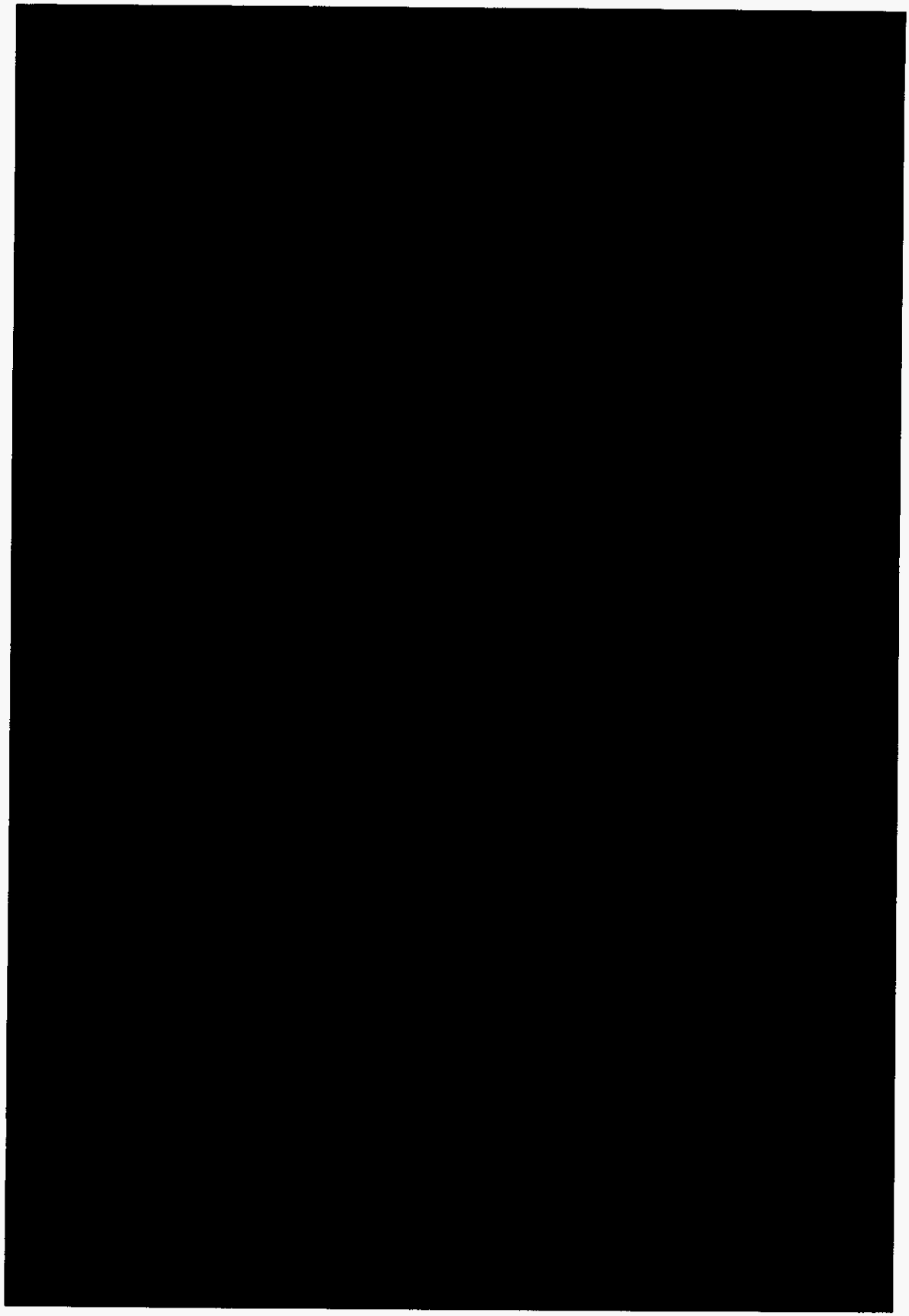
NAME: Terry L. Morrison

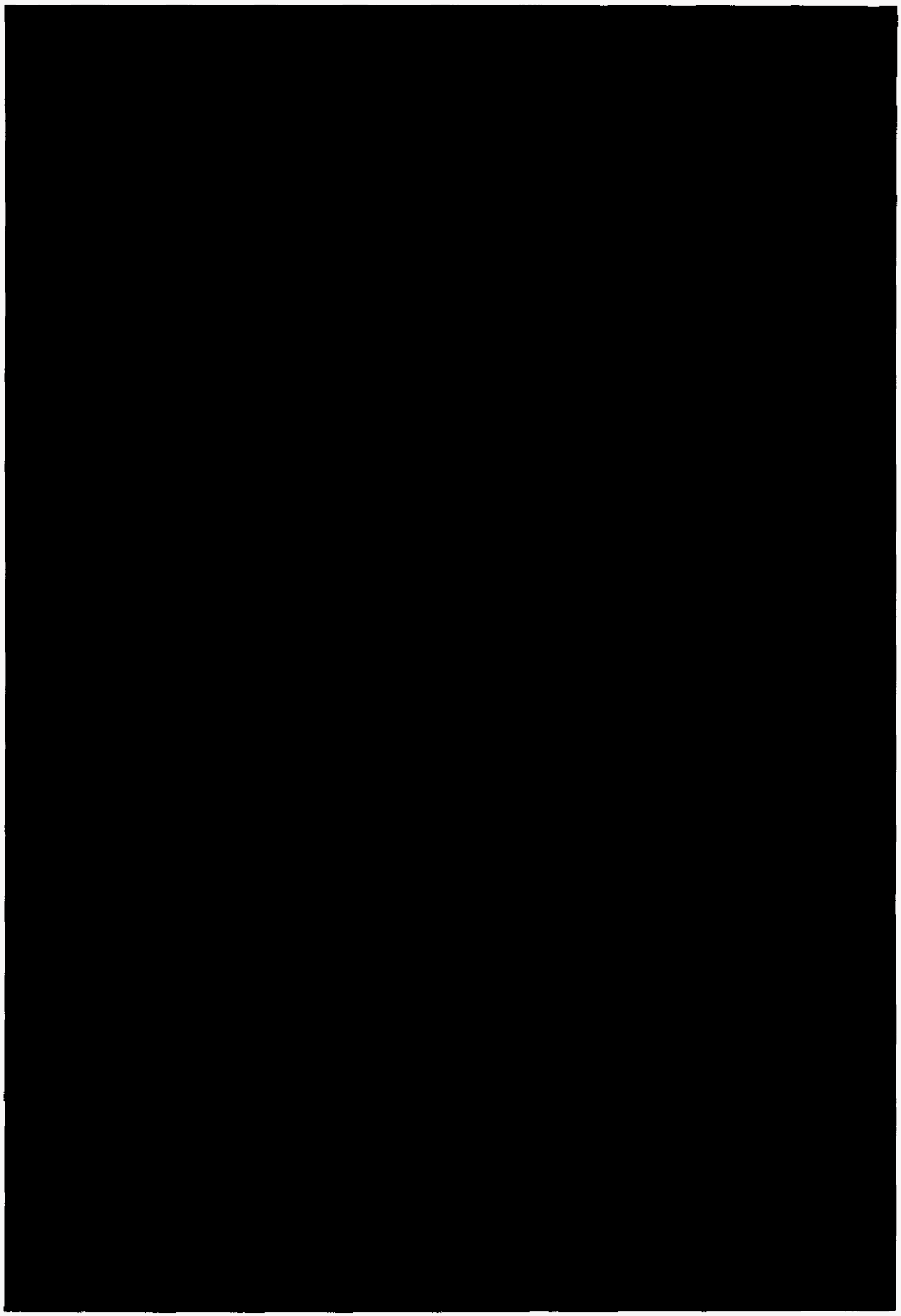
TITLE: Vice President

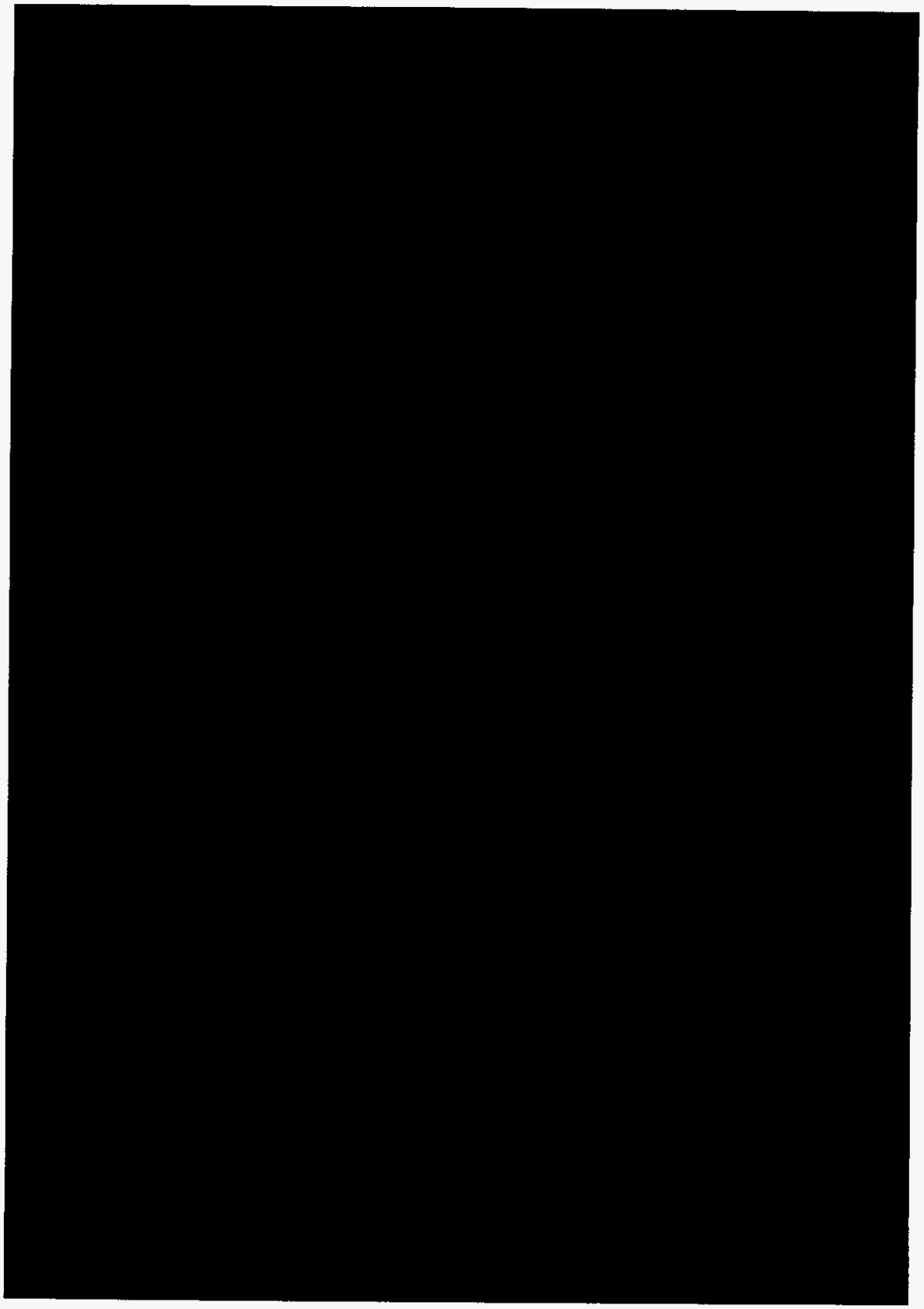


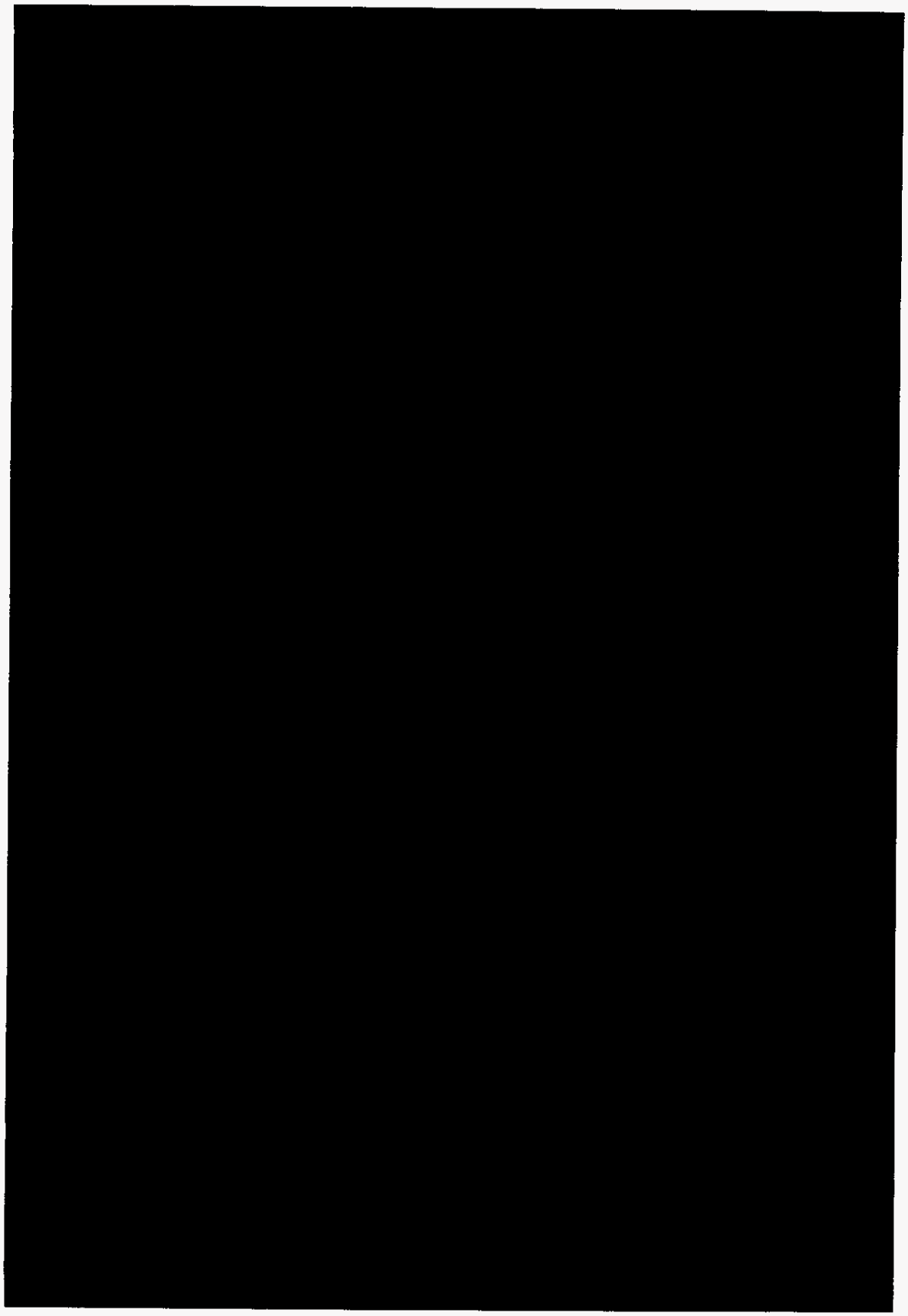


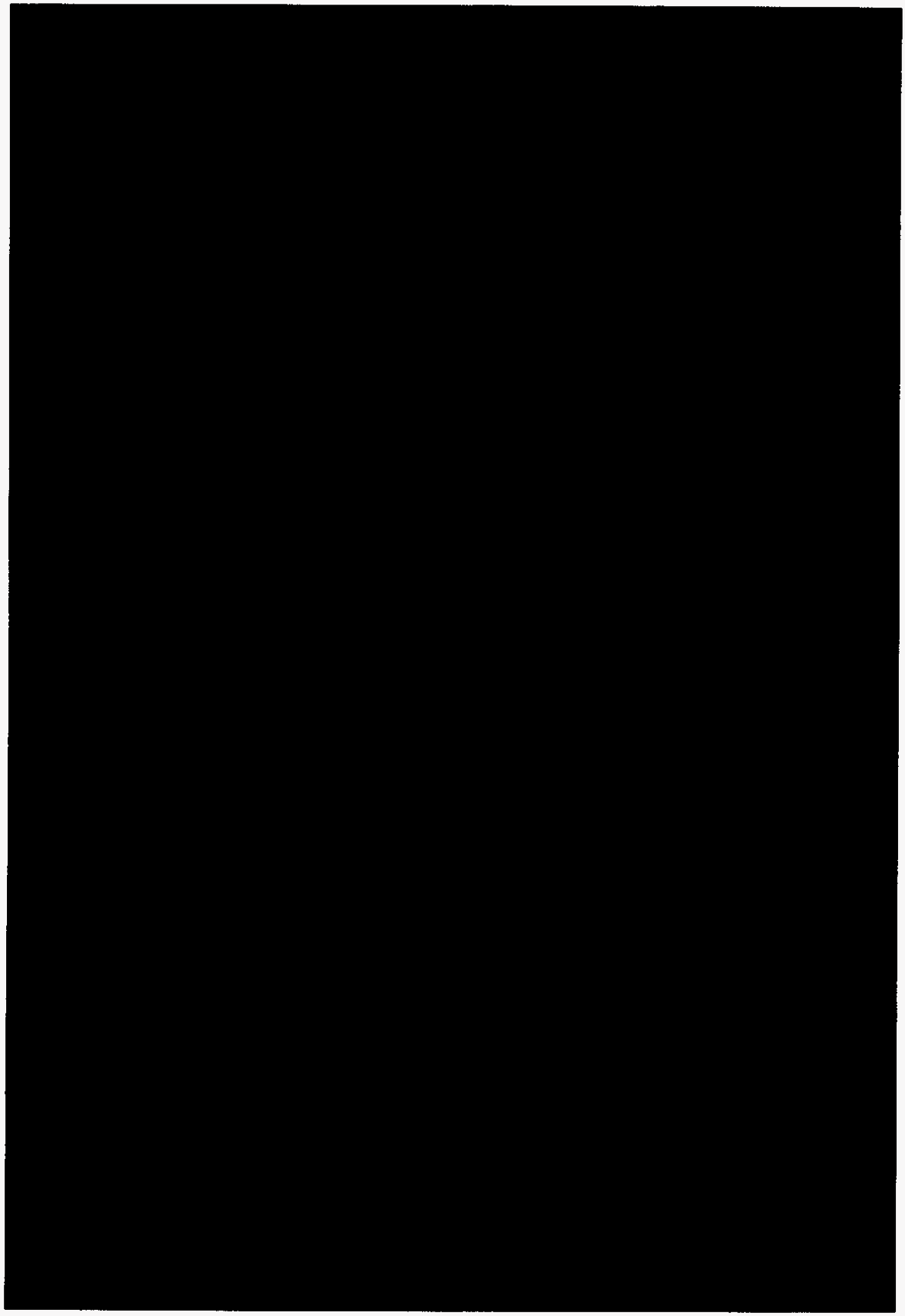


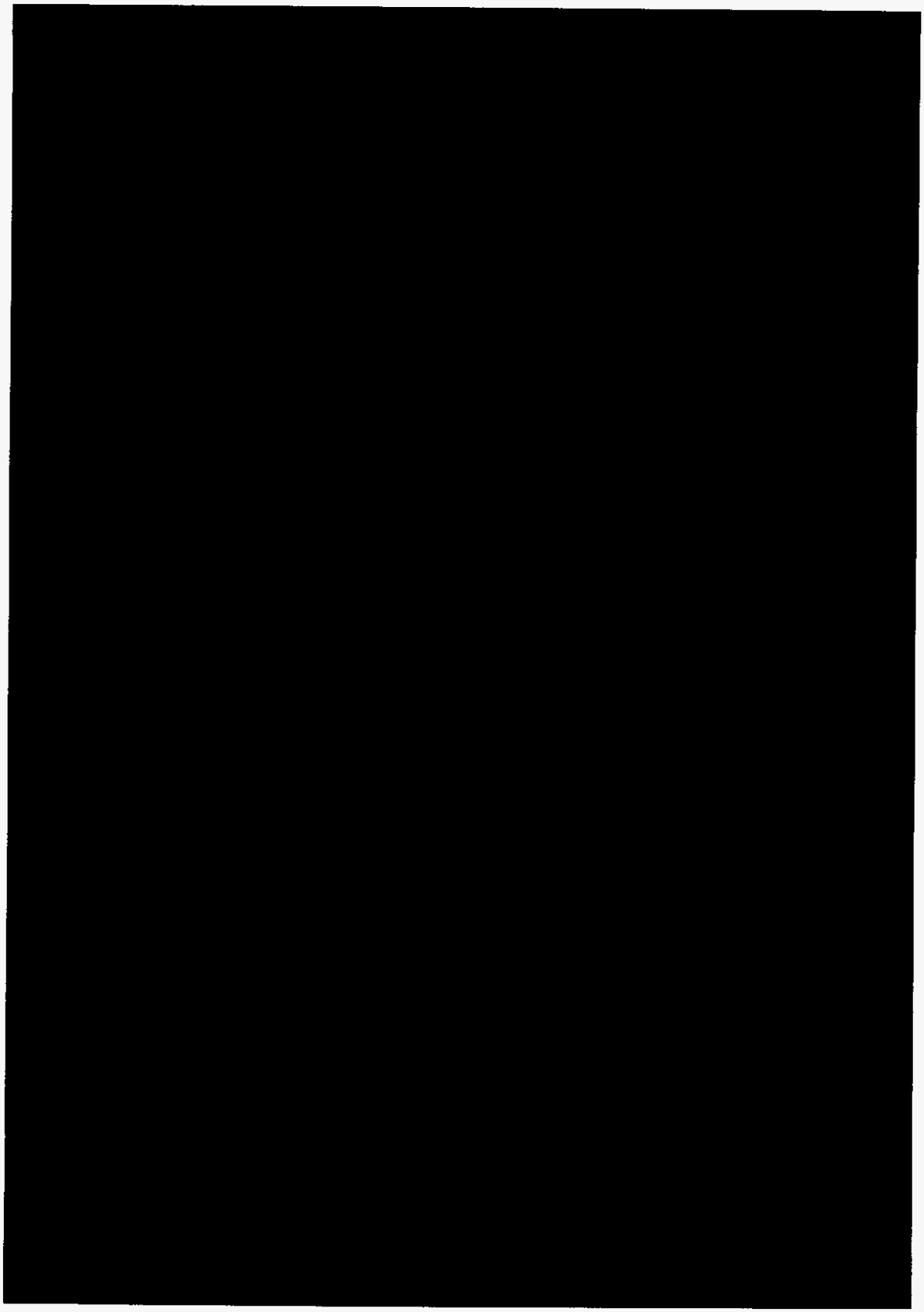


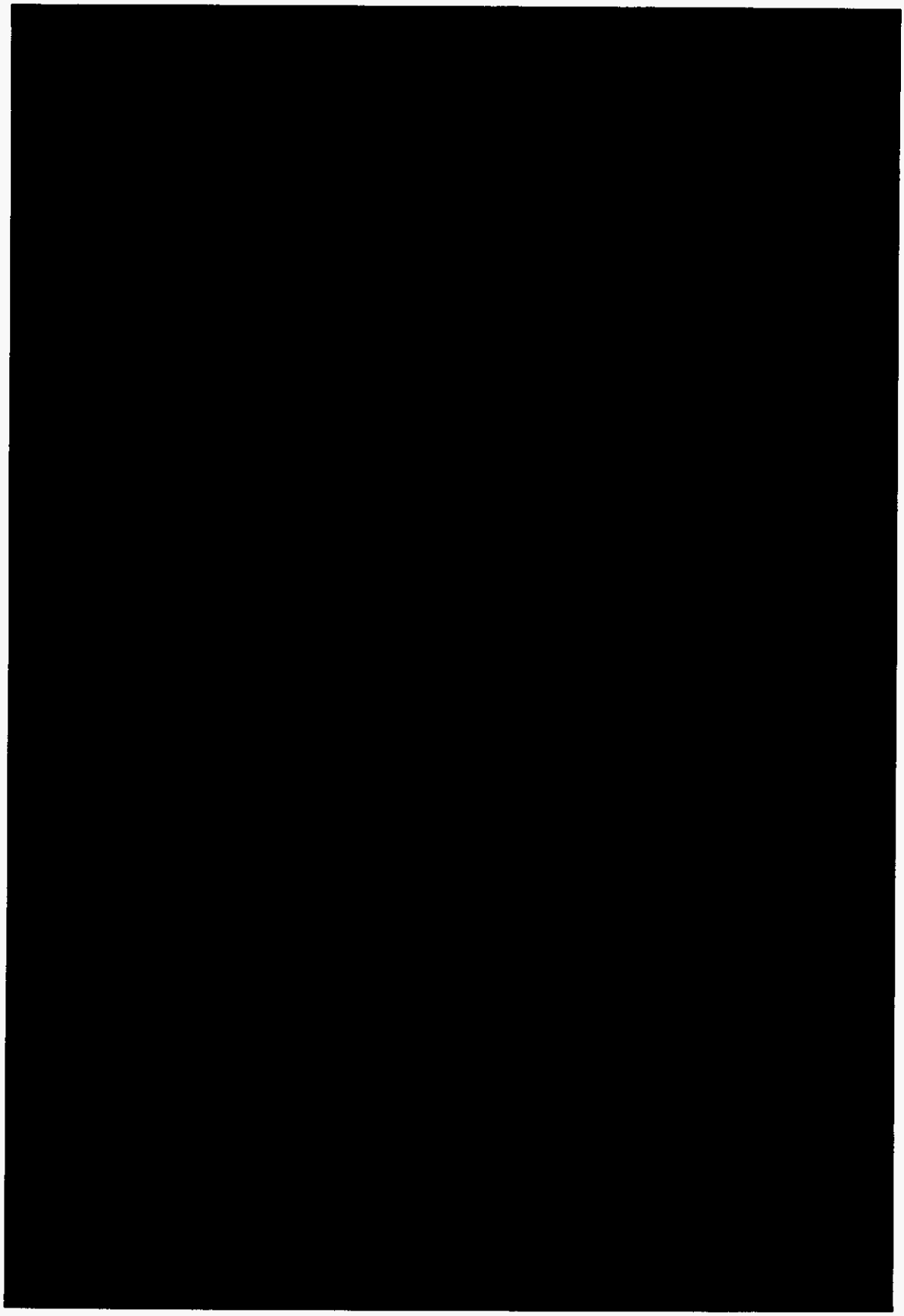


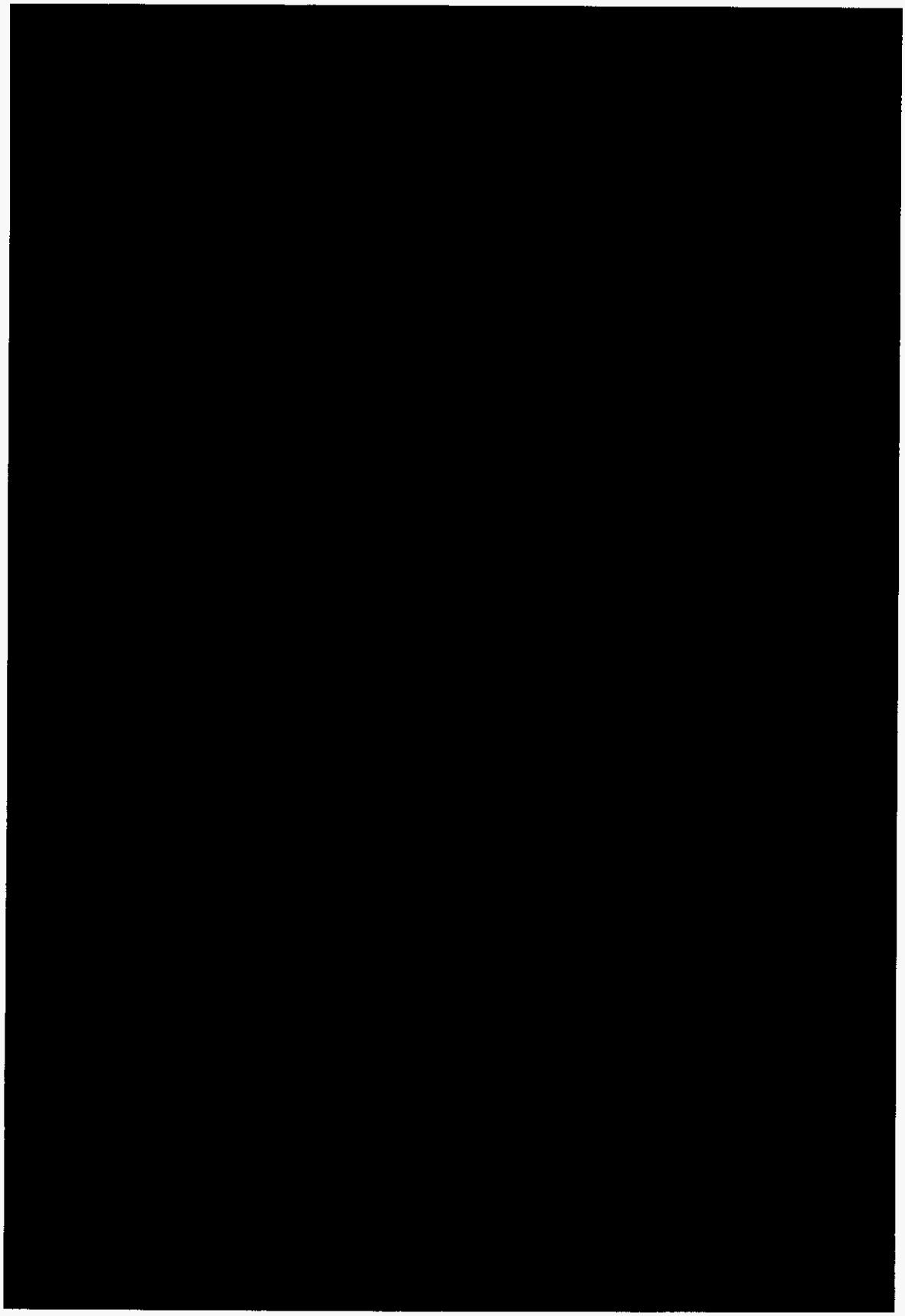


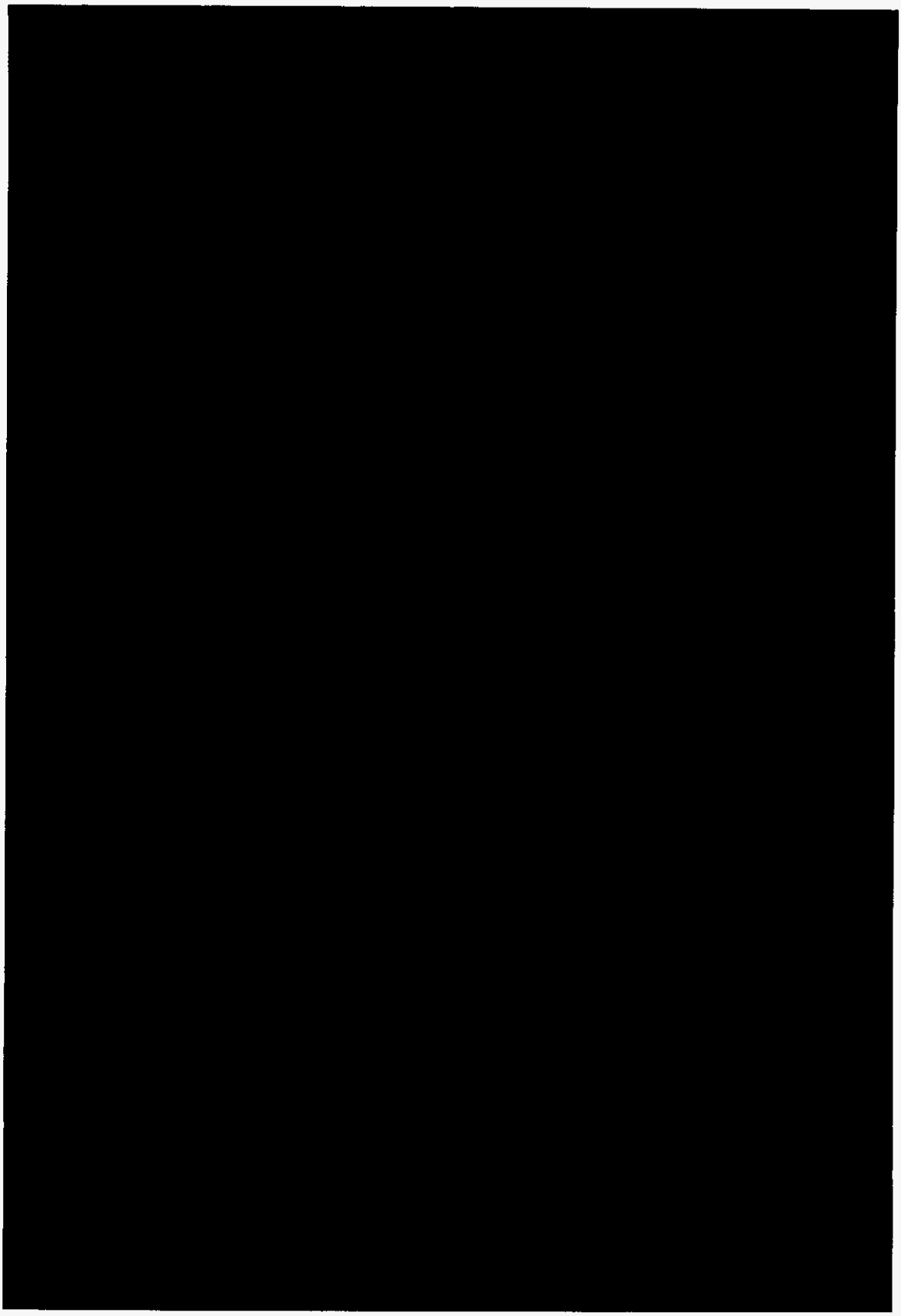


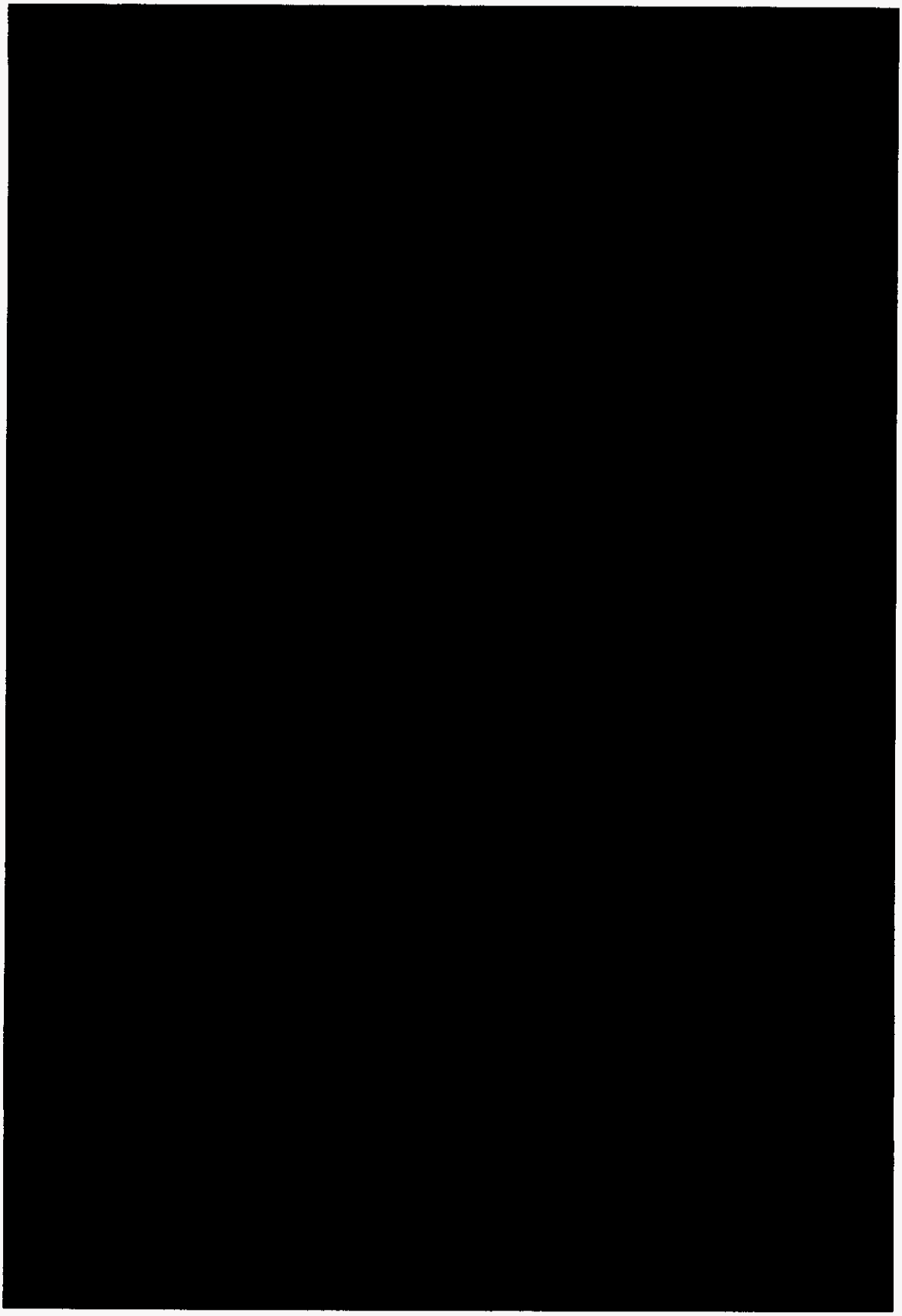


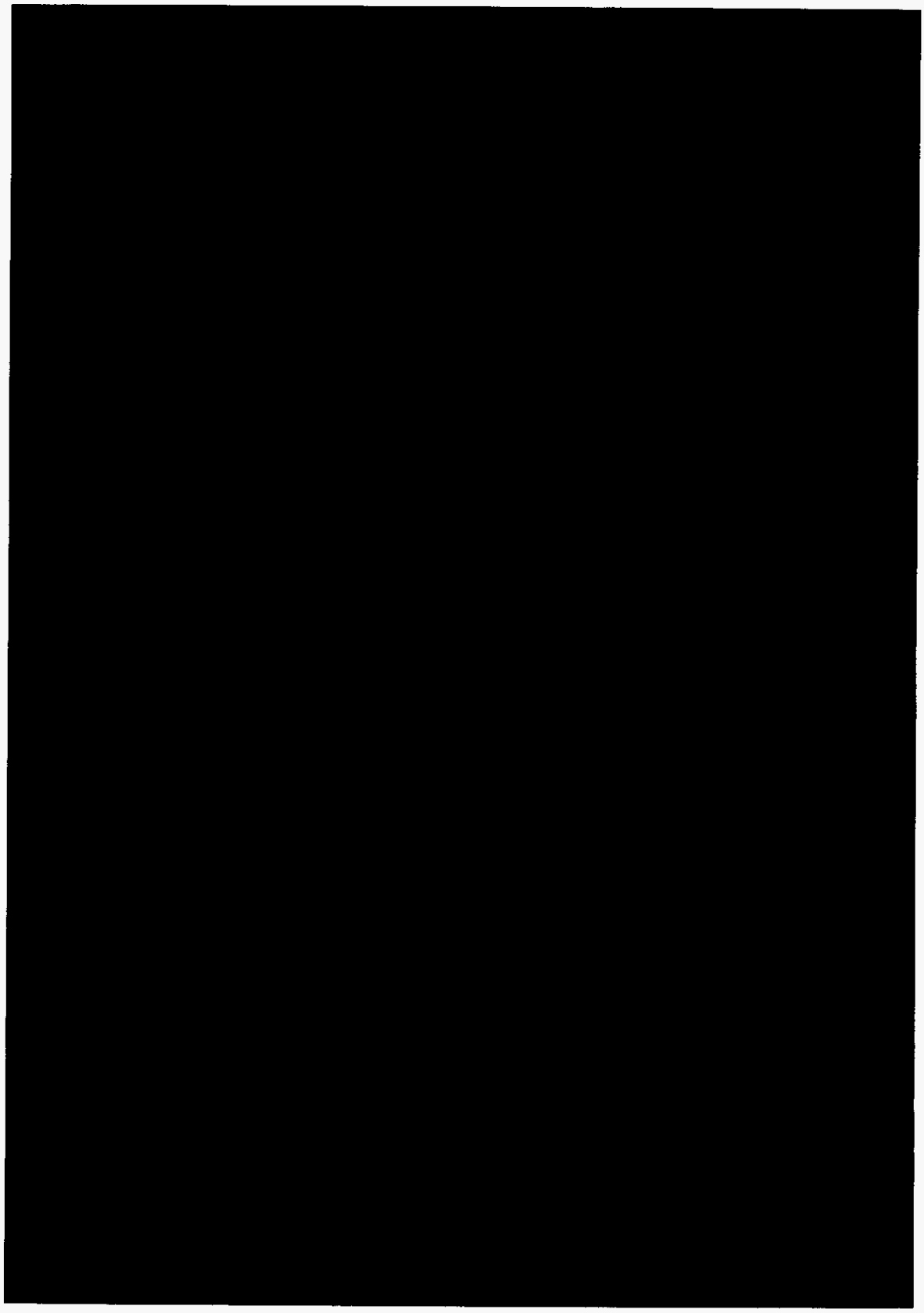


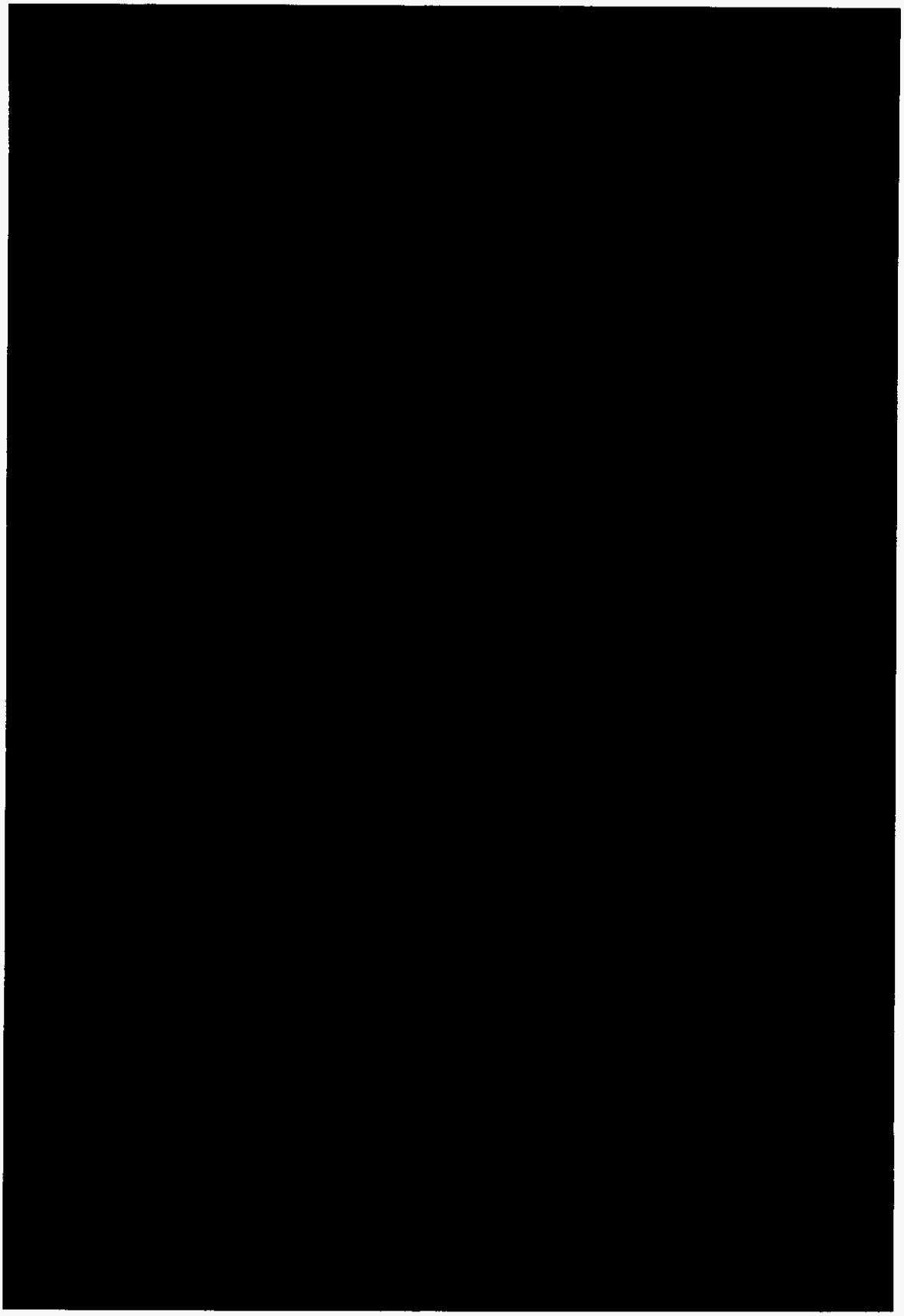


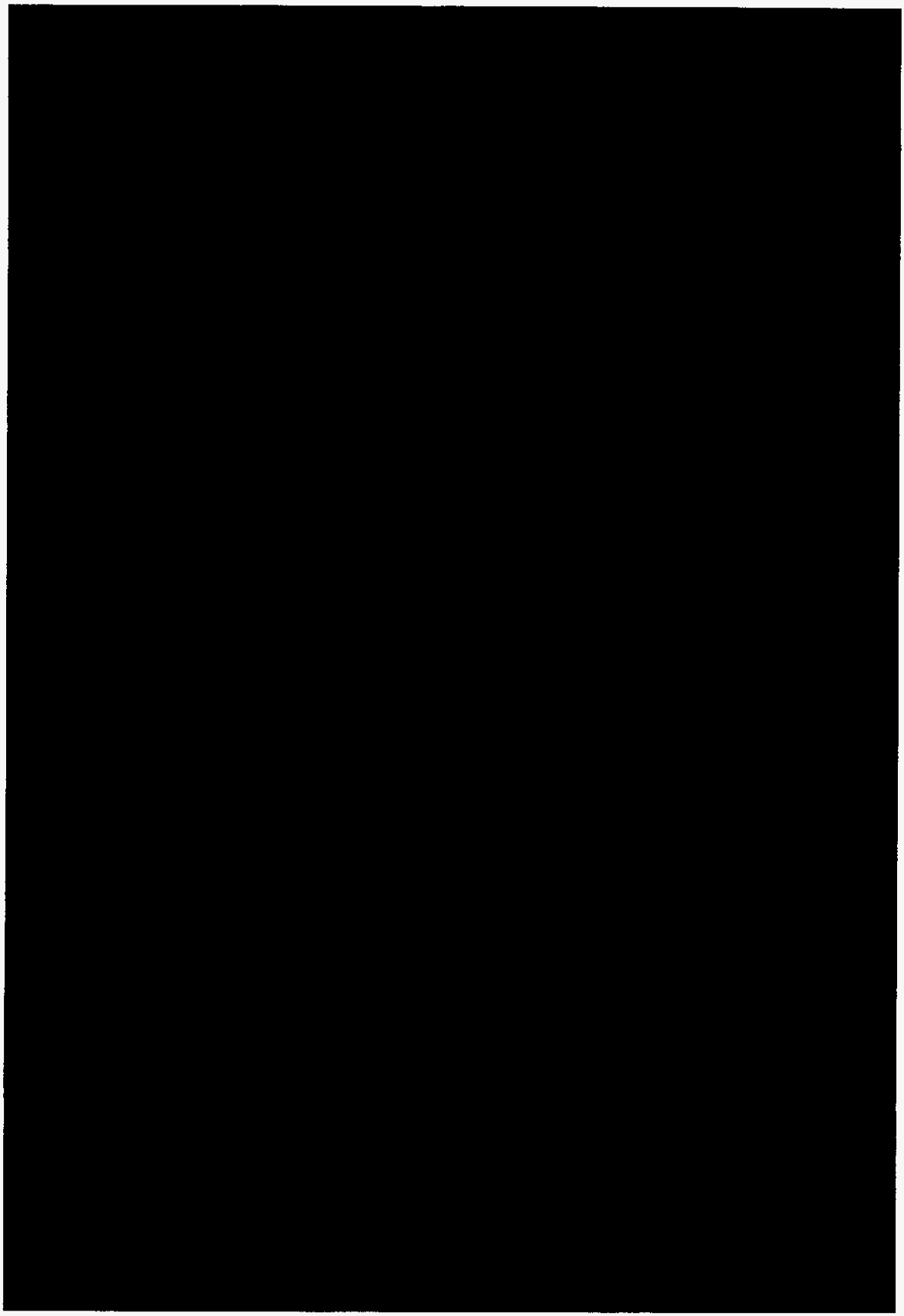


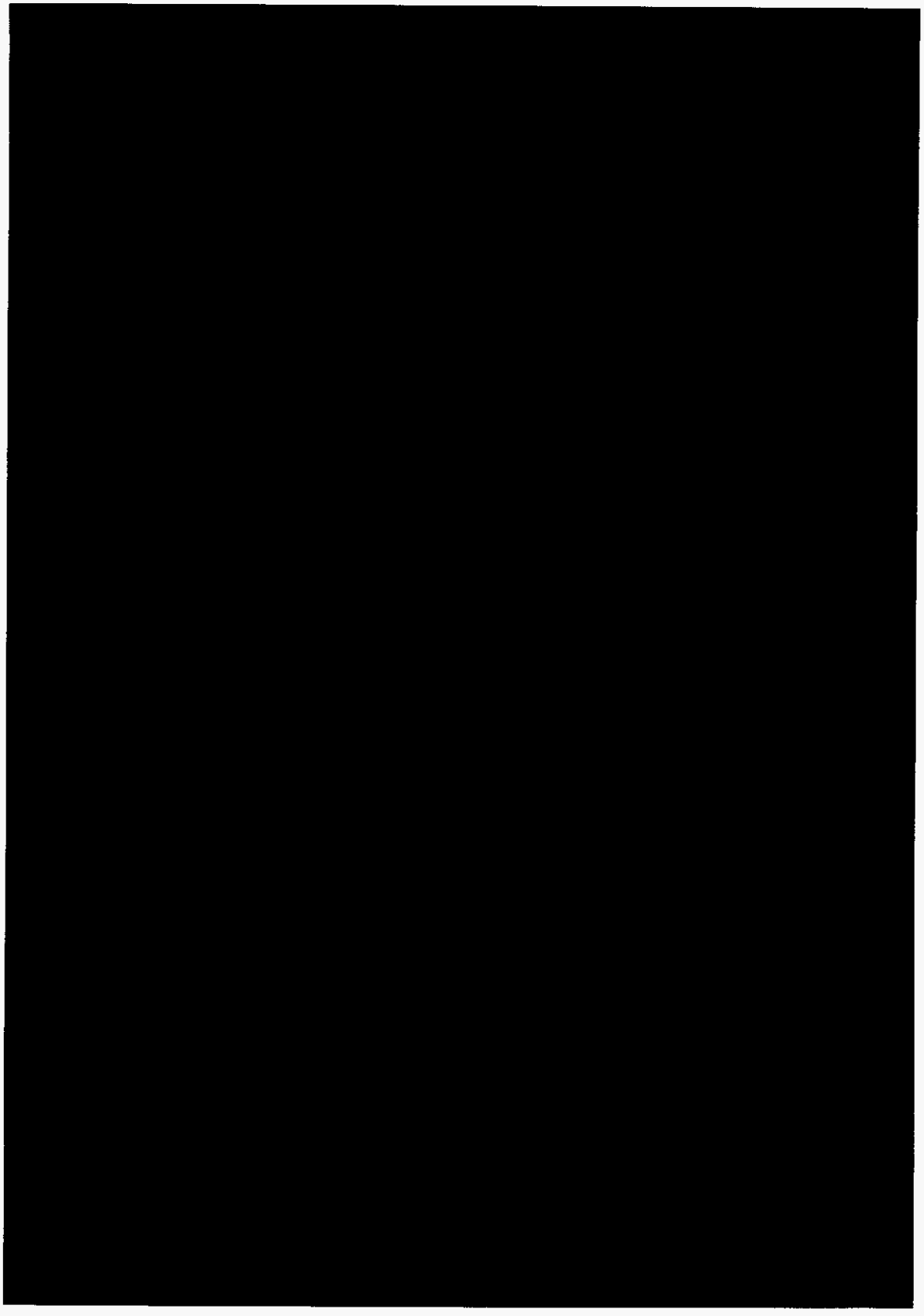


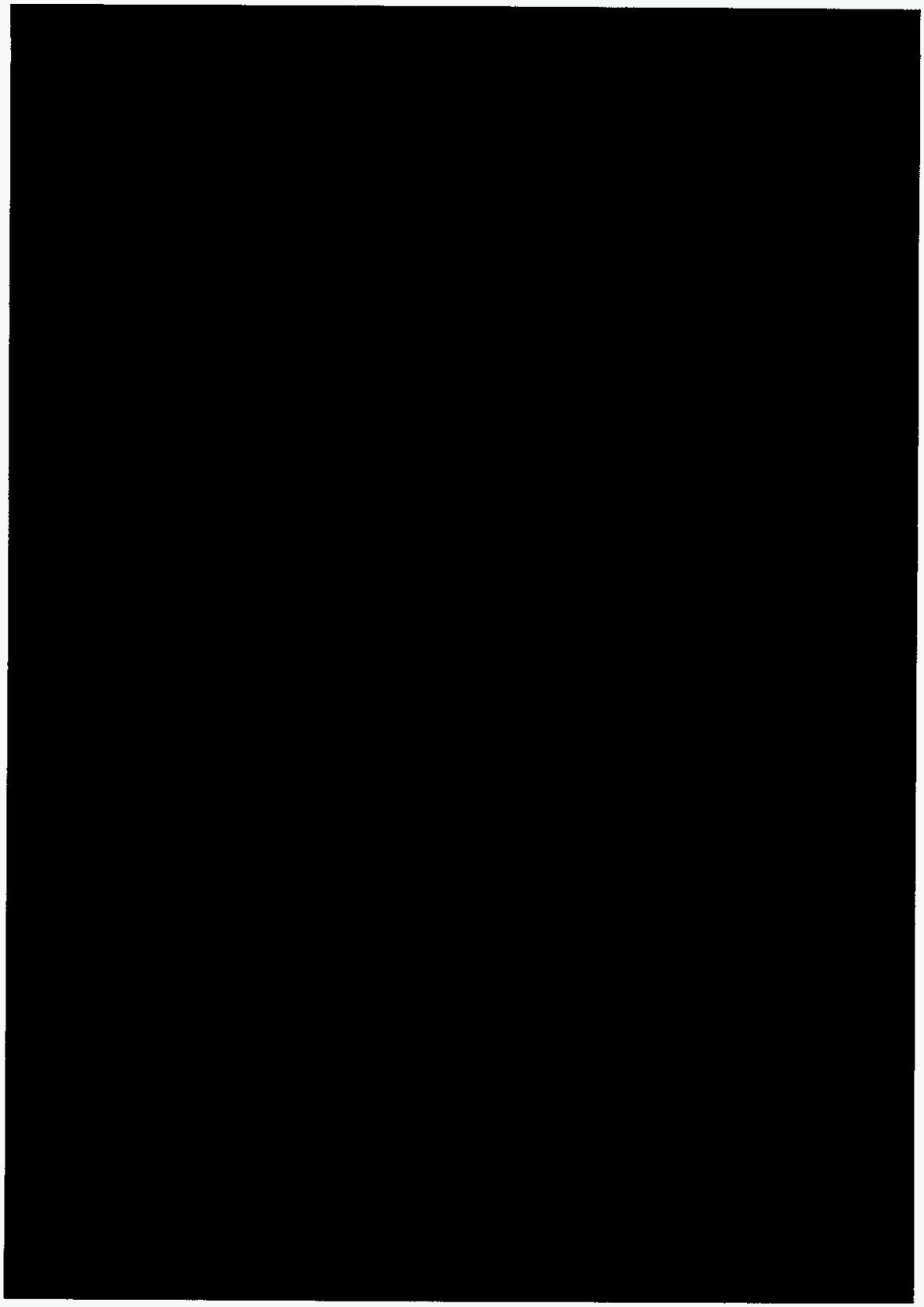


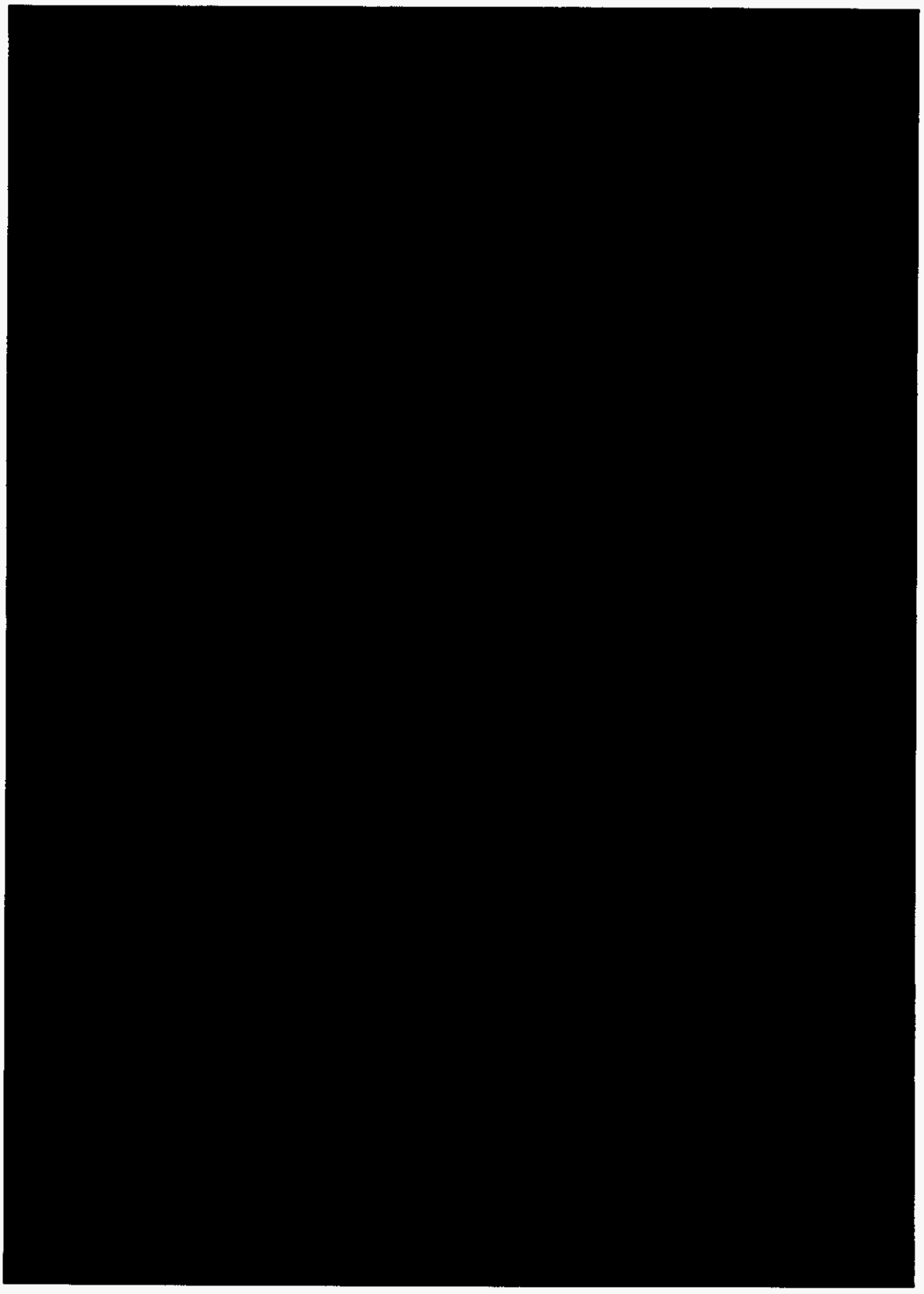


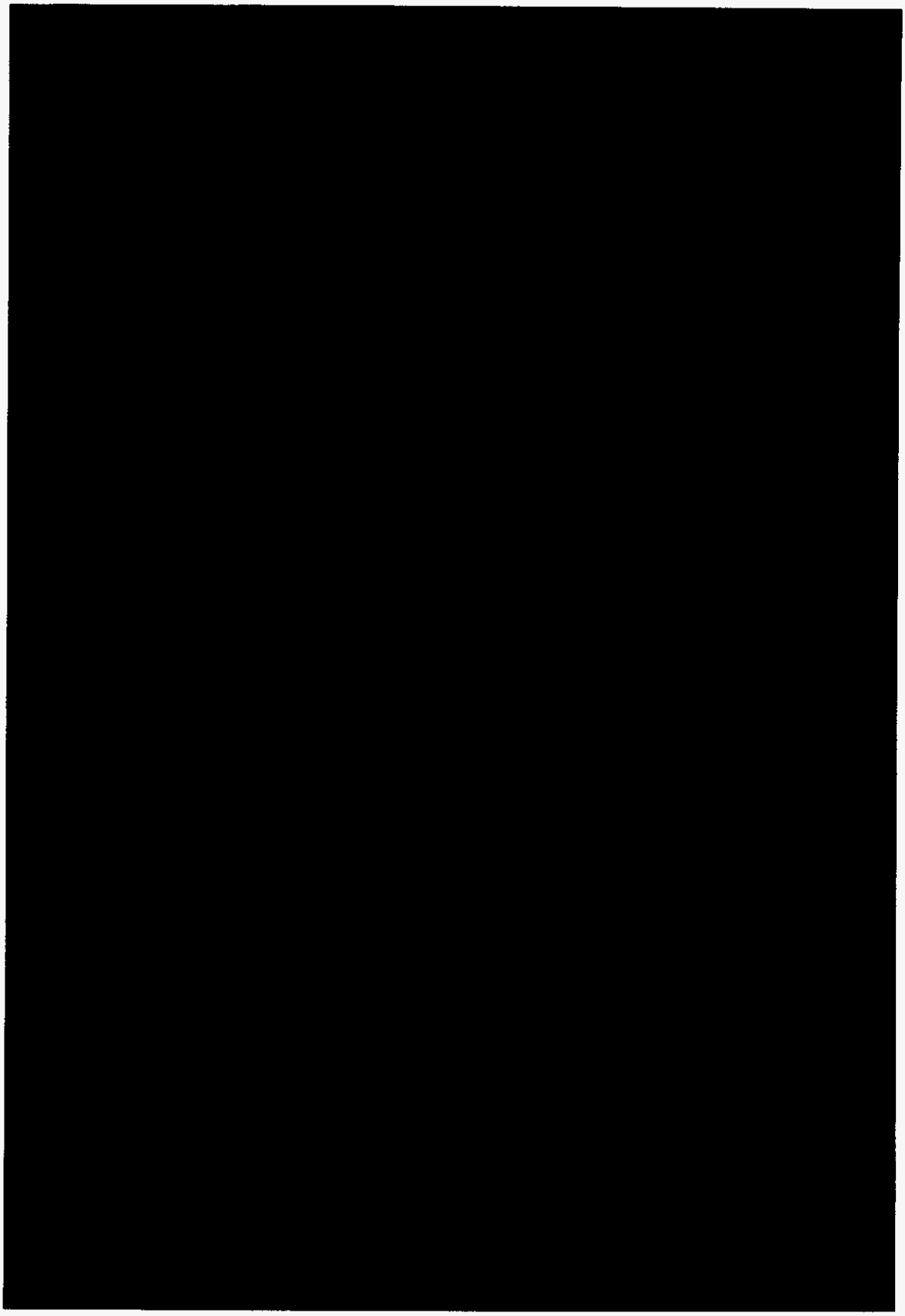


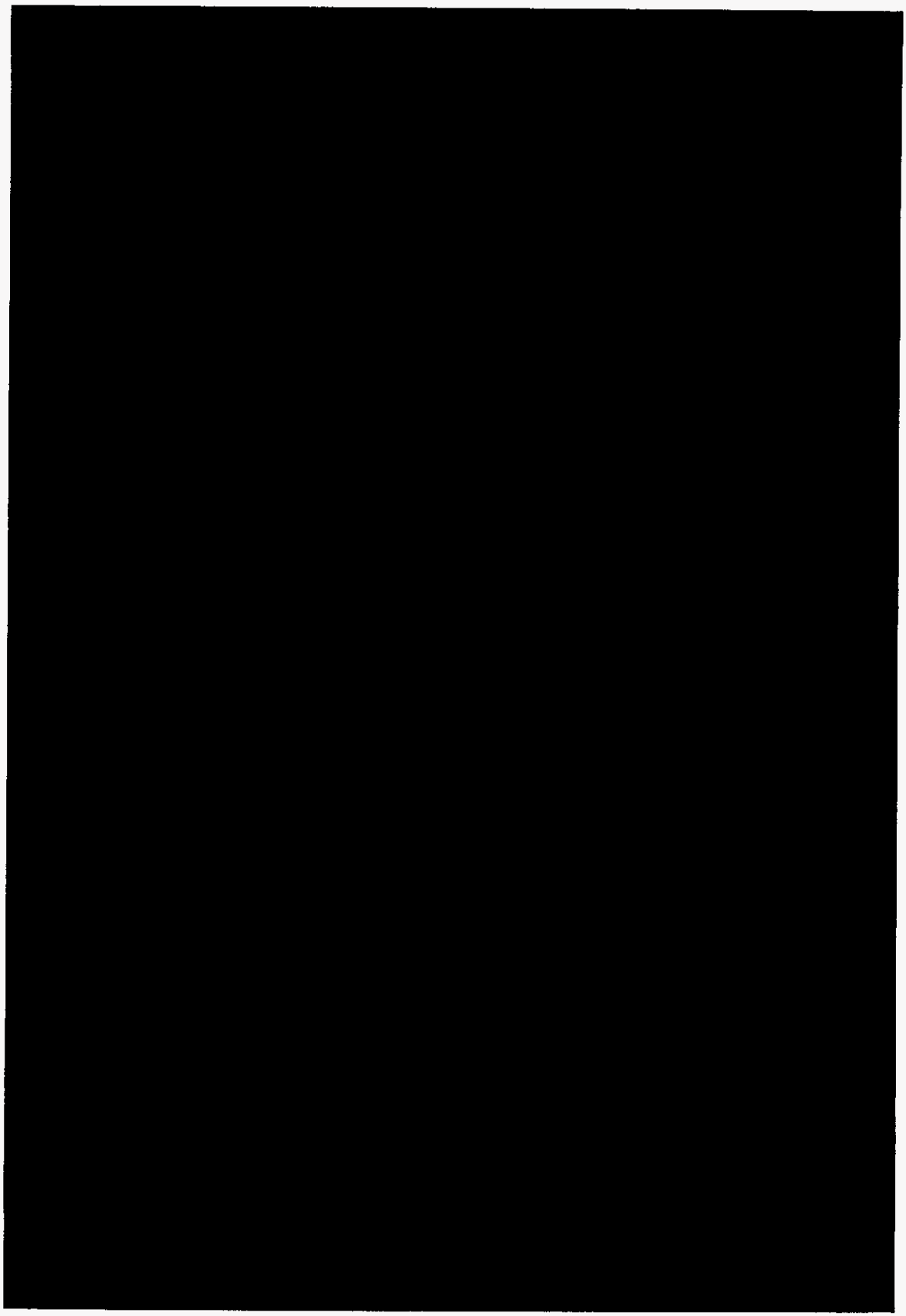


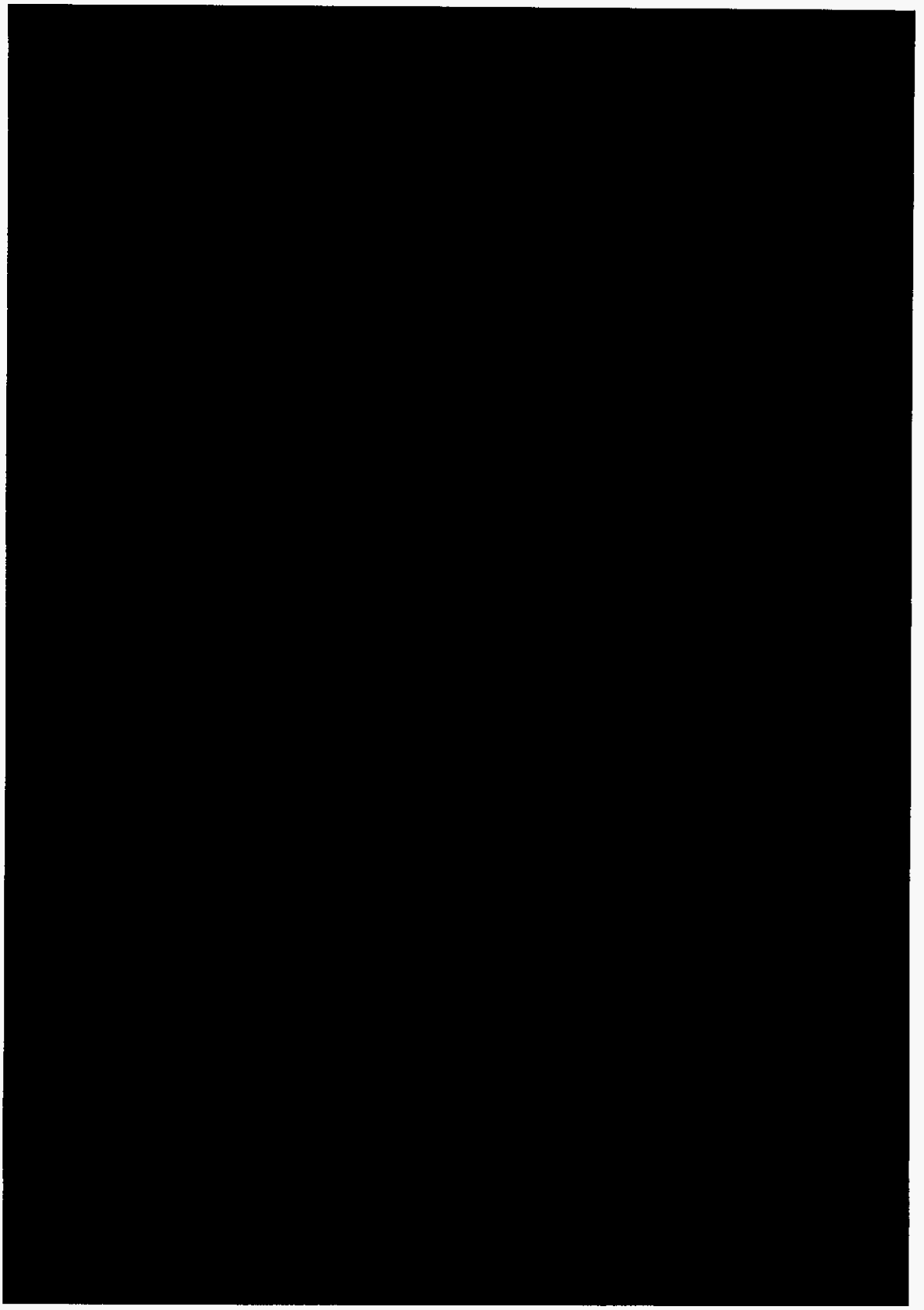


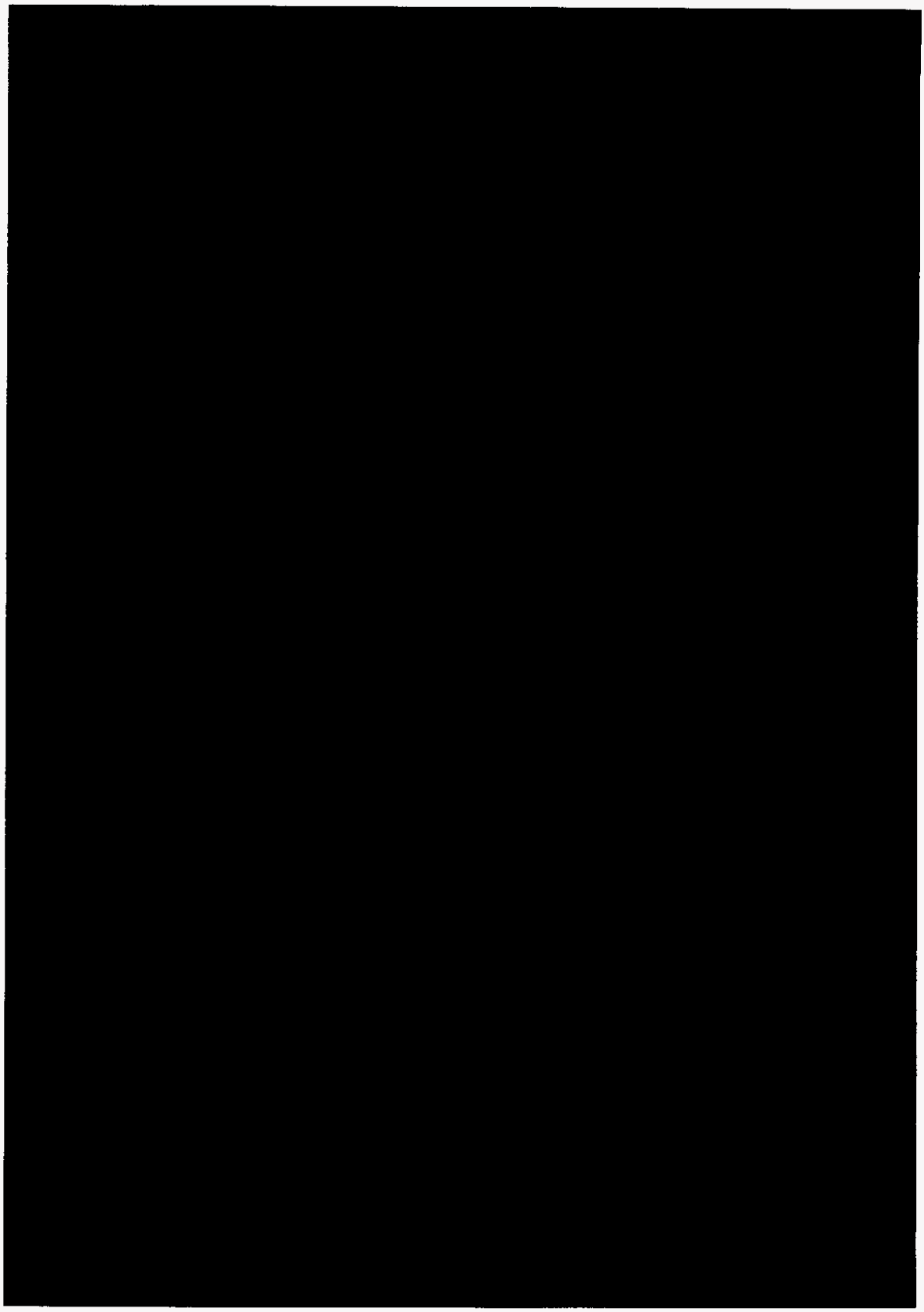


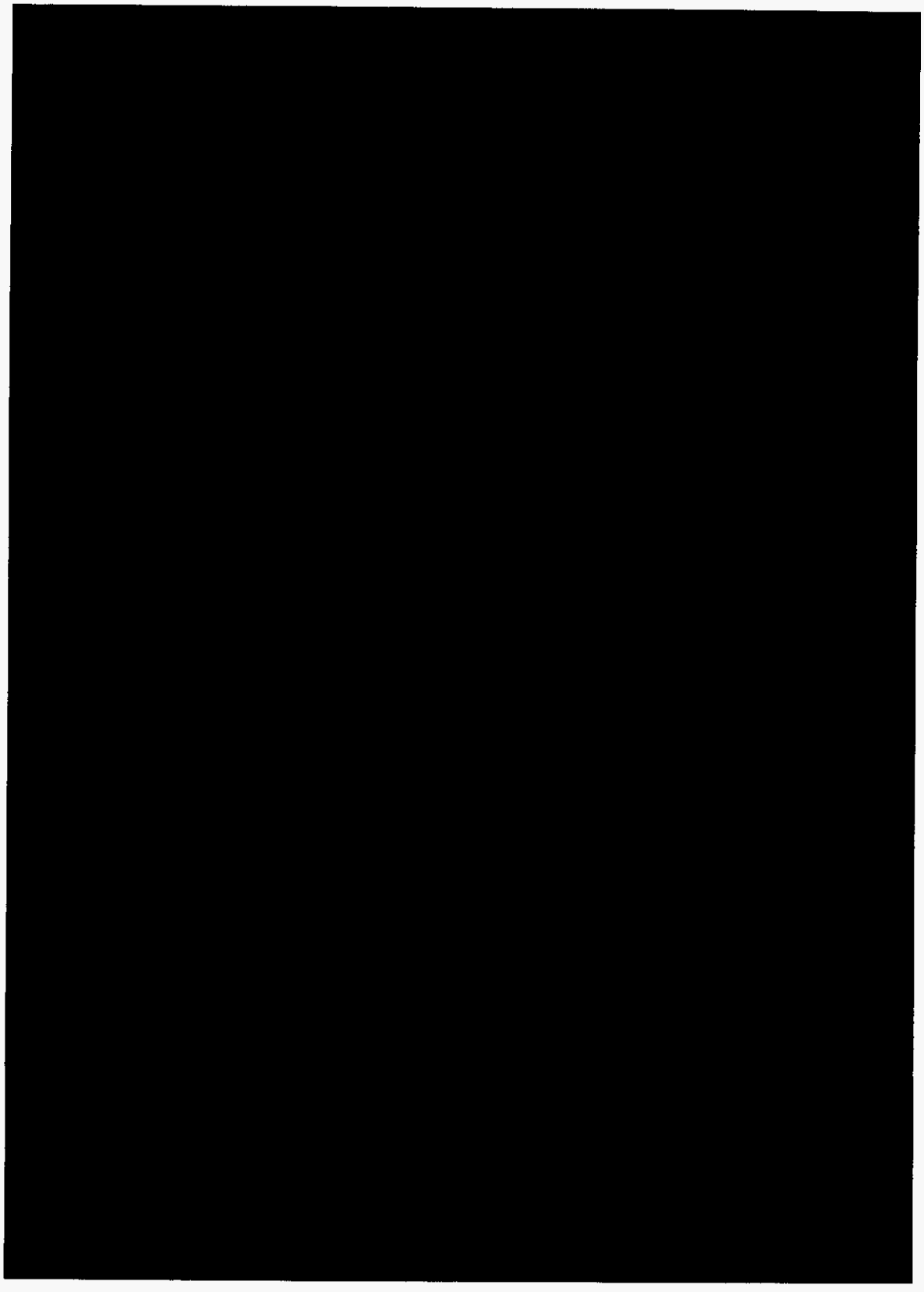


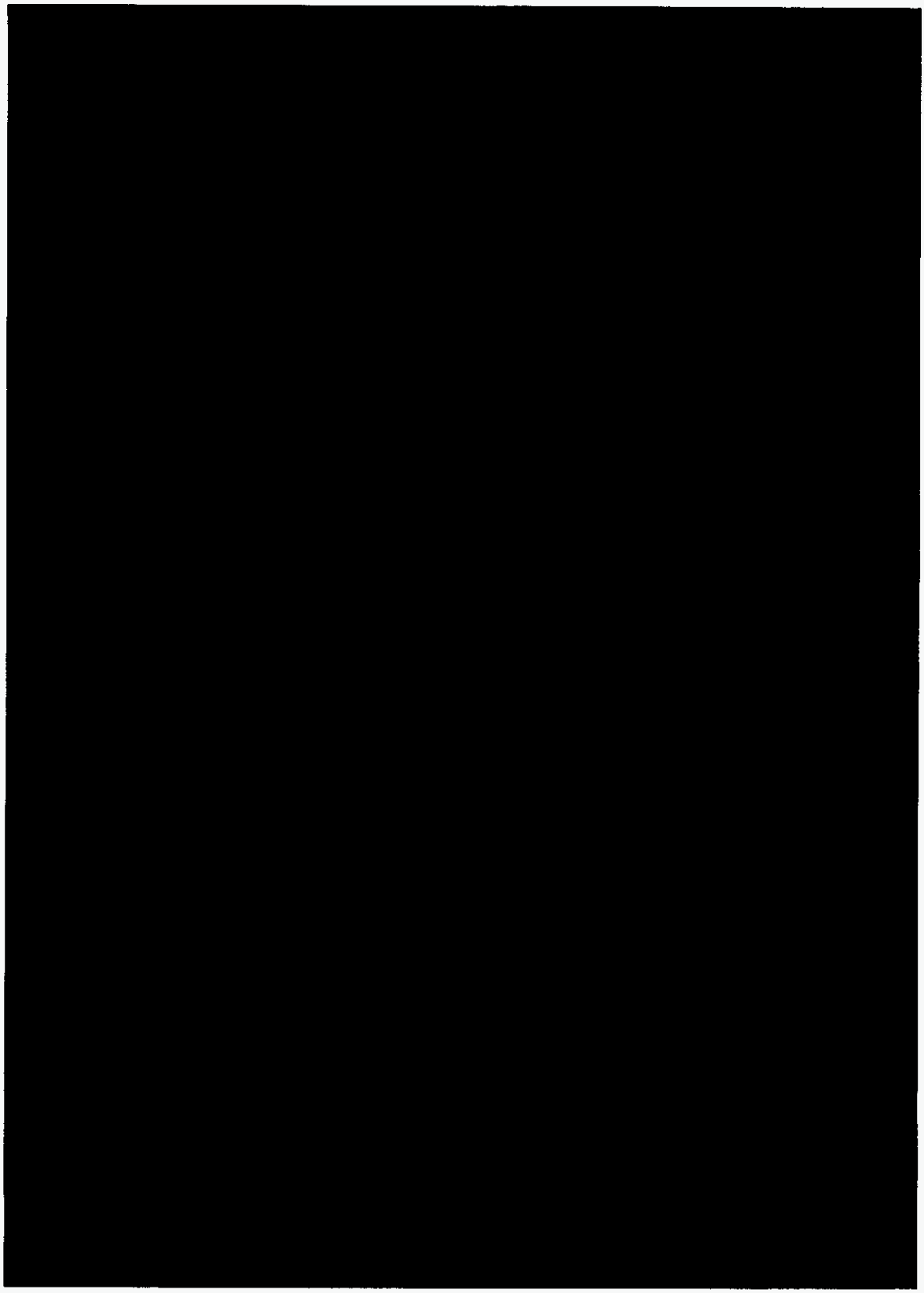


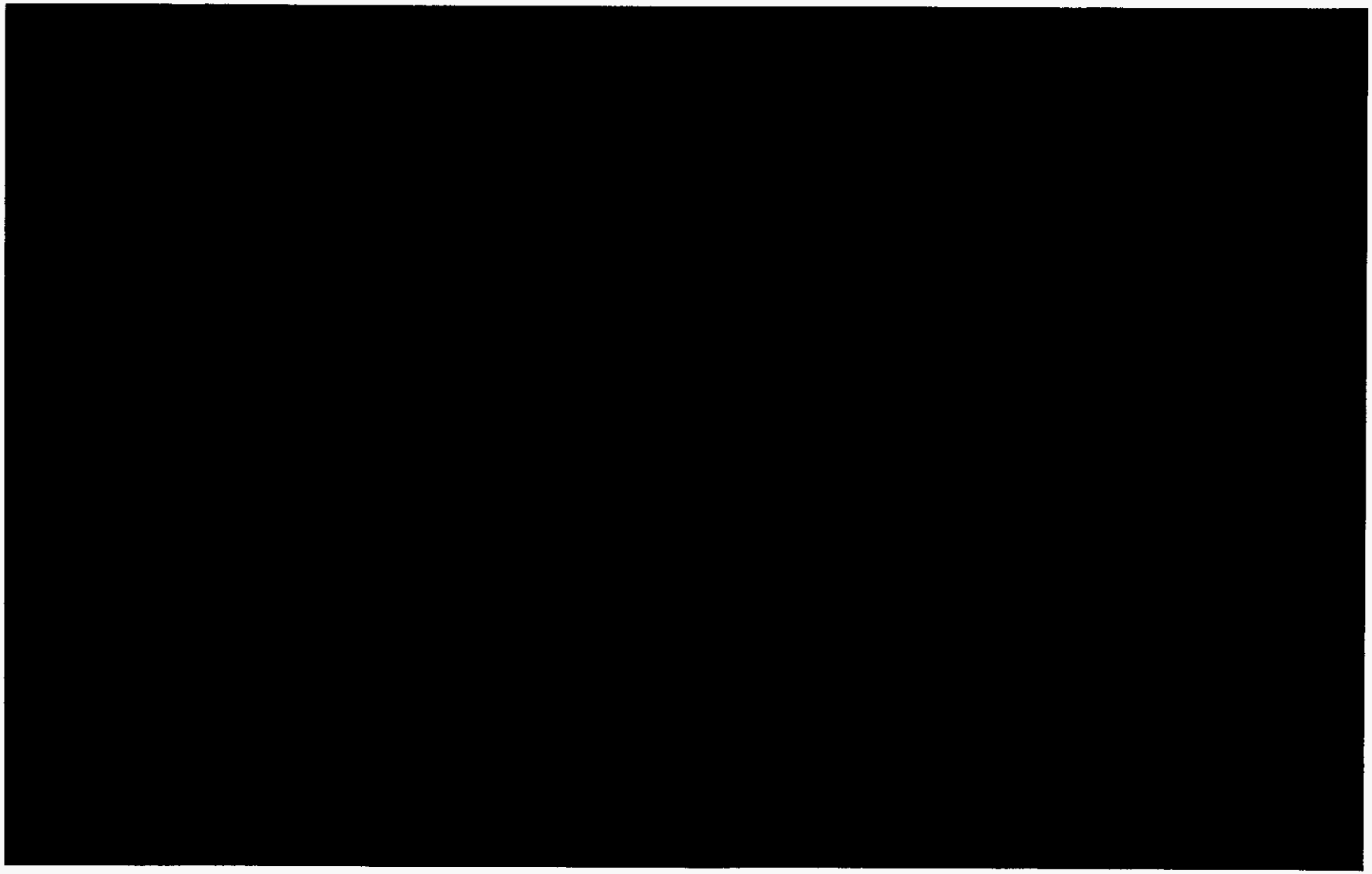


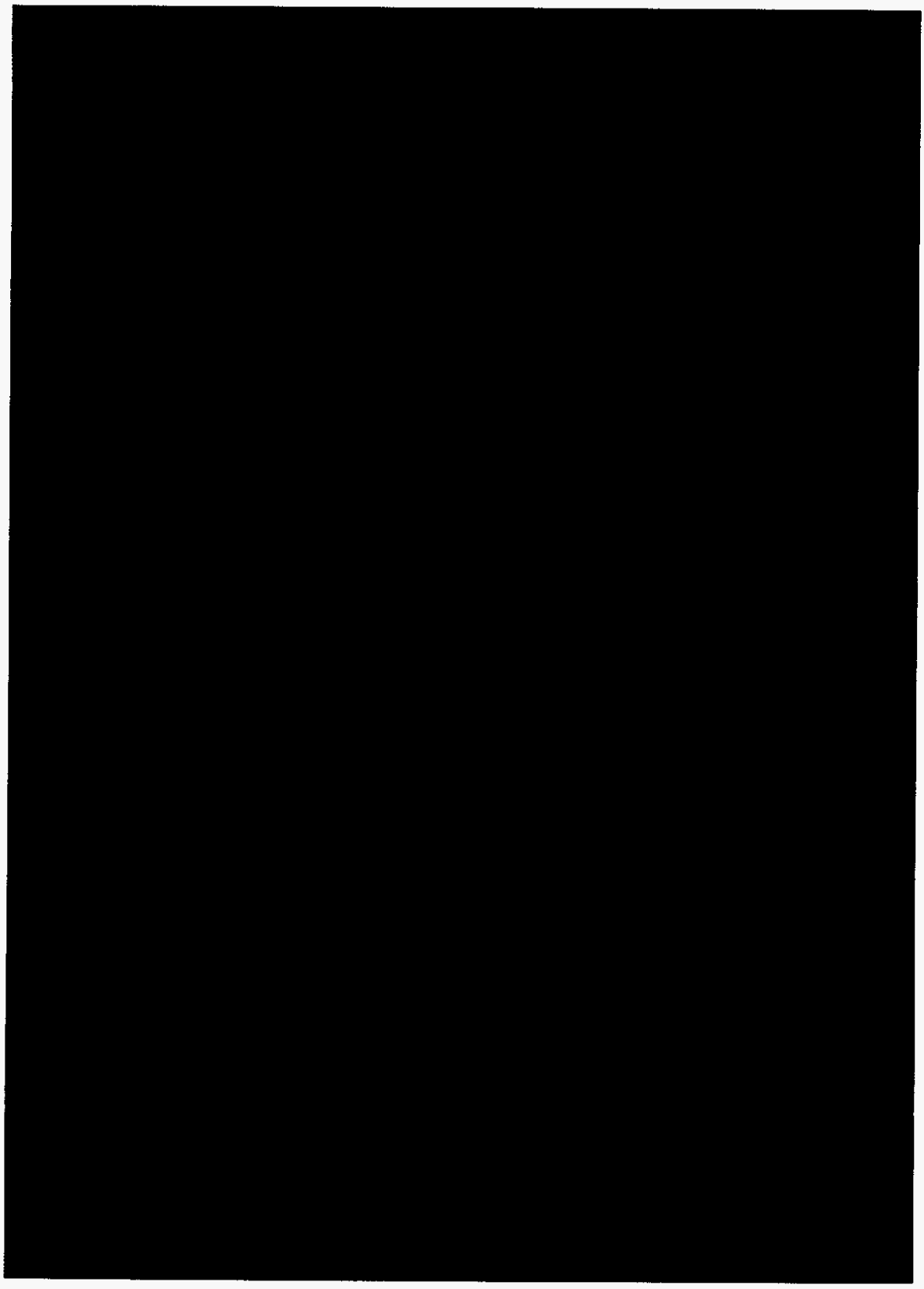












EXECUTION COPY

CONTRACT FOR THE

PURCHASE OF CAPACITY AND ENERGY

BETWEEN

SOUTHERN COMPANY SERVICES, INC.

AND

FLORIDA POWER & LIGHT COMPANY

FROM

PLANT FRANKLIN UNIT NO. 1

DATED AS OF AUGUST 11, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. _____ EXHIBIT NO. _____
COMPANY/
WITNESS: _____
DATE: _____

CONFIDENTIALITY
DESIGNATION REVISED
11/2/2004

TLH-3
DOCKET NO. 040001-EI
FPL WITNESS: T. HARTMAN
EXHIBIT _____
SEPTEMBER 9, 2004

overcharge shall refund the amount of the overcharge to the other Party, and the Party that has been undercharged shall pay the amount of the undercharge to the other Party, within 30 Days after final determination thereof; provided, however, that no retroactive adjustment shall be made for any overcharge or undercharge unless written notice of the same is provided to the other Party within a period of 12 Months from the date of the invoice in which such overcharge or undercharge was first included. Any such adjustments shall be made with interest calculated in accordance with Section 21.7 from the date that the undercharge or overcharge actually occurred.

11.5 Audit Rights. Subject to Section 10.3, the Parties shall keep complete and accurate records of their operations under this Agreement and shall maintain such data for a period of at least [redacted] years after the completion of the relevant Billing Month hereunder; provided, however, records relating to a disputed matter shall be retained until the dispute is resolved. Such records shall be available for inspection and audit by the other Party upon reasonable request during any regular Business Day.

ARTICLE 12

REGULATORY

12.1 Initial Approval of the Florida Public Service Commission.

12.1.1 No later than 90 Days after the Effective Date, Buyer shall make a filing with the Florida Public Service Commission ("FPSC") seeking approval for Buyer to recover from its customers all payments required to be made to Seller under the Contemporaneous Agreements without material modification or condition with respect to such agreements ("FPSC Approval"). After making such filing, Buyer shall utilize diligent efforts to obtain the FPSC Approval for the Contemporaneous Agreements by no later than 180 Days

after the Effective Date ("Approval Deadline"). Seller agrees to reasonably assist and support Buyer's efforts to obtain the FPSC Approval. Buyer shall promptly notify Seller when it receives the FPSC Approval.

12.1.2 If FPSC Approval for the Contemporaneous Agreements is not received by the Approval Deadline, but the date of the Transmission Notice under Section 7.4.2 has not yet occurred and the FPSC has not yet issued an order denying the Buyer's request for FPSC Approval ("FPSC Denial"), the Approval Deadline shall automatically be extended until the date of the Transmission Notice. During this extended period, Buyer shall keep Seller closely informed as to the progress of its efforts to obtain FPSC Approval and Buyer shall continue diligent efforts to obtain FPSC Approval.

12.1.3 If FPSC Approval is not received by the Approval Deadline (as extended under Section 12.1.2) or if an FPSC Denial is issued prior to the Approval Deadline, Buyer shall provide notice to Seller within 30 Days after the Approval Deadline or the FPSC Denial (whichever occurs first) that it desires to either: (i) terminate all (but not less than all) of the Contemporaneous Agreements, in which case all of the Contemporaneous Agreements shall immediately terminate; or (ii) continue all (but not less than all) of the Contemporaneous Agreements regardless of FPSC Approval. If Buyer elects option (ii) under the foregoing sentence, all of the Contemporaneous Agreements shall continue in full force and effect for the Term notwithstanding any subsequent action or inaction of the FPSC (including the subsequent issuance of a FPSC Denial or failure to issue an FPSC Approval).

12.1.4 The Parties acknowledge that the other Contemporaneous Agreements contain provisions that are substantially similar to Sections 12.1.1 through 12.1.3 above and that this Agreement may be subject to termination as provided in such similar provisions.

12.1.5 After the procedures in Sections 12.1.1, 12.1.2, and 12.1.3 (as applicable) have been completed, except as provided under Section 12.3, at no time shall this Agreement be subject to termination or modification due to any action or inaction of any Government Agency or Buyer's inability to recover from its customers amounts to be paid to Seller pursuant this Agreement whether such inability is due to action of any Government Agency or otherwise.

12.2 Changes in Agreement. Except for any changes pursuant to Section 12.3, absent the agreement of all Parties to the proposed change, the standard of review for changes to this contract proposed by a Party, a non-Party or the FERC acting sua sponte shall be the "public interest" standard of review set forth in United Gas Pipeline Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. (1956) (the "Mobile-Sierra" doctrine).

12.3 Federal Energy Regulatory Commission.

12.3.1 The Parties anticipate that this Agreement is not required to be filed and accepted by FERC because it is a market-based contract. Therefore, this Agreement shall not be contingent on FERC acceptance. Having freely negotiated and agreed upon the economic bargain among them as set forth hereunder, Seller and Buyer waive all rights under Sections 205 and 206 of the Federal Power Act to effect a change in the Agreement. Moreover, it is the Parties' mutual intent that FERC be precluded, to the fullest extent permitted by law, from altering this Agreement in any way. Notwithstanding the foregoing, if at any time FERC takes some action that reduces the economic benefit of this Agreement to either Party ("Impacted Party") as contemplated on the Effective Date ("Original Economic Benefit"), Impacted Party

shall be deemed to have retained rights under Section 205 to file for changes in the Agreement, but only to the extent required to restore the Original Economic Benefit.

12.3.2 Impacted Party may exercise its Section 205 rights provided under Section 12.3.1 if at any time it reasonably determines in its sole discretion that it may be able to have some or all of the Original Economic Benefit restored. Before exercising such rights, Impacted Party shall negotiate with the other Party in an effort to reach mutual agreement regarding amendments to this Agreement (including amendments regarding those provisions addressing the determination of payments between the Parties and adjustments to capacity payments due to unavailability) that would restore some or all of the Original Economic Benefit. Impacted Party shall file any resulting amendments for acceptance by FERC, and the other Party shall actively support such filing(s). If the Parties are unable to agree upon such amendment(s), Impacted Party shall be entitled to make unilateral filing(s) at FERC to modify the Agreement in order to restore some or all of the Original Economic Benefit. In this latter event, the other Party shall actively support Impacted Party's right to recover the Original Economic Benefit, including by making filings at FERC (provided that the non-impacted Party shall retain the right to challenge the amount of and/or the methodology for calculating the Original Economic Benefit).

12.3.3 Any amendment(s) or unilateral filing(s) contemplated hereunder shall restore the Original Economic Benefit (or any allowed portion thereof) for the remainder of the Term, including any portion of the Original Economic Benefit associated with prior periods (with interest). Such amendment(s) or filing(s) by the Impacted Party shall not require the other Party to bear more of an economic burden than originally contemplated in this Agreement on the Effective Date. Nothing in this Agreement is intended to or shall restrict the number of

times that a Party may exercise the above-described Section 205 rights during the Term or within any specific time frame.

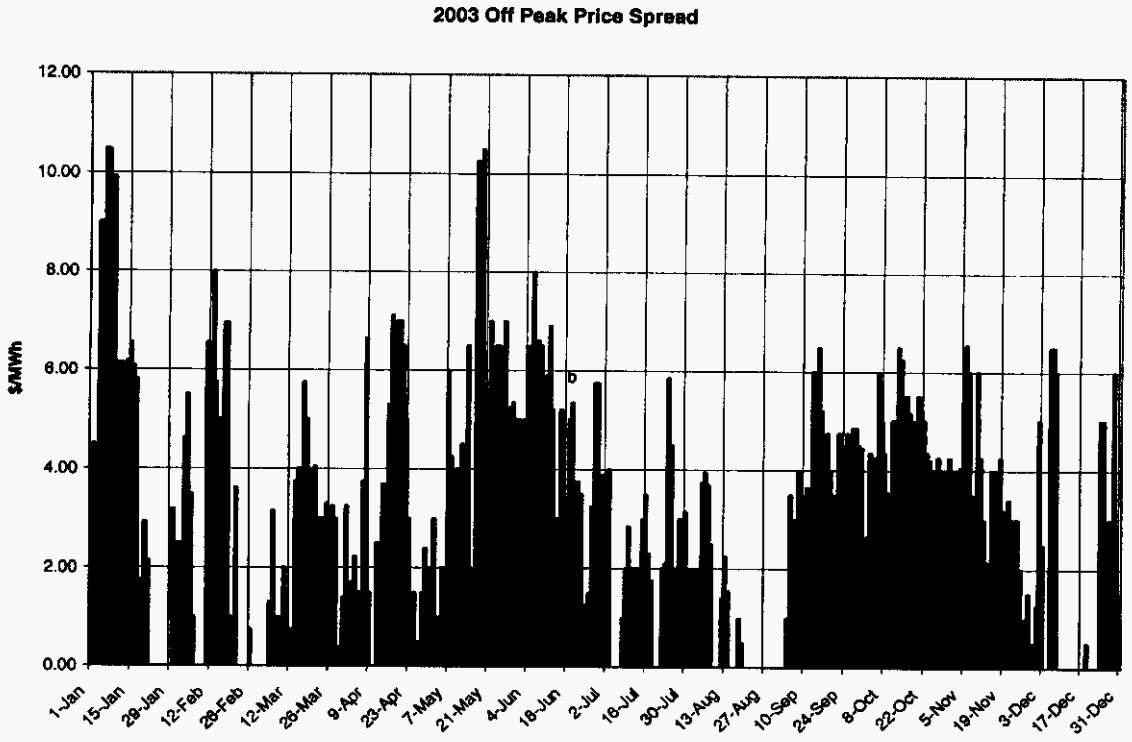
ARTICLE 13

CHANGE IN LAW

13.1 Increased Generation Costs. The Parties acknowledge that during the Term of this Agreement, Changes in Law that increase Seller's cost of providing capacity and/or energy hereunder could occur. Any Increased Generation Costs will be paid by Buyer through an additional payment or surcharge each Month ("Change in Law Surcharge"). Once Seller has incurred Increased Generation Costs, Buyer shall pay for all Increased Generation Costs through the Change in Law Surcharge, as provided below.

13.2 Determination. If Seller determines that a Change in Law will or has resulted in Increased Generation Costs and that Buyer is responsible for such costs under this Agreement, Seller shall, within 6 Months after identifying such costs, notify Buyer of: (a) the applicable Change in Law giving rise to the Increased Generation Costs; and (b) the resulting Increased Generation Costs. Provided, however, the failure by Seller to provide such notice within such time period shall not under any circumstance result in an Event of Default, nor shall such failure prejudice or affect in any way Seller's right to receive reimbursement from Buyer for any Increased Generation Costs under this Agreement. Provided further, such notice by Seller shall include reasonable documentation of the applicable Change in Law and resulting Increased Generation Costs. Within 60 Days after receipt of such notice, Buyer will: (i) make a good faith determination of whether the Increased Generation Costs result from a Change in Law as specified in this Agreement; (ii) make a good faith determination of whether the Increased Generation Costs are determined in accordance with this Agreement; and (iii) provide Seller

2003 off peak price spread between Florida and Southeastern SERC



TLH-4
DOCKET NO. 040001-EI
FPL WITNESS: T. Hartman
EXHIBIT _____
SEPTEMBER 9, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 16
COMPANY/ F.P.+L.
WITNESS. T. L. Hartman (TLH-4)
DATE: 11-08-04

Merchant Plants

Owner	Plant	Capacity	State		Notes
Simple Cycle Plants					
FPL Energy	Calhoun	668	AL		
Southern Co.	Greene County	740	AL		
Duke Energy	Sandersville	640	GA		
NRG Energy	Sterling	202	LA	]	
NRG Energy	Bayou Cove	320	LA	|	
Duke Energy	New Albany	350	MS	|	Must wheel through transmission constrained areas
Duke Energy	Southhaven	640	MS	|	
Duke Energy	Enterprise	640	MS	]	
Combined Cycle Plants					
In transmission constrained areas:					
Calpine	Pine Bluff	213	AR	]	
Cleco	Perryville	718	AR	|	
Duke Energy	Hot Springs	620	AR	|	Must wheel through transmission constrained areas
Mirant/Kinder	Wrightsville	550	AR	|	
Teco Energy	Union	2,200	AR	]	
Calpine	Hog Bayou	246	LA	]	
Calpine	Carville	501	LA	|	
Calpine	Arcadia	1,160	LA	|	
Cleco	Evangeline	919	LA	|	
Cogentrix	Ouachita	816	LA	|	
Cogentrix	Caldonia	810	MS	|	
Cogentrix	Southhaven	810	MS	|	Must wheel through transmission constrained areas
Duke Energy	Hinds	520	MS	|	
Intergen	Magnolia	900	MS	|	
NEGT	Attala	526	MS	|	
NRG Energy	Batesville	837	MS	]	
Reliant	Choctaw County	804	MS	]	
Southern Co.	Daniel	1,064	MS	]	
Extra Wheel					
Calpine	Decatur	792	AL	—	Connect to TVA
Calpine	Morgan	807	AL	—	Connect to TVA
Duke Energy	Murray	1,240	GA	—	Half under contract to Ga Power, remainder transmission constrained, need to wheel through Dalton, TVA, and Southern
Viable Alternatives					
Southern Co.	Barry	1,064	AL		
Southern Co.	Franklin	1,185	AL	—	Current offer
Southern Co.	Harris	1,254	AL	—	Current offer
Tenaska	Lindsey Hill	845	AL	—	Under contract until 2020 to Coral
Tenaska	Central Alabama	885	AL	—	Under contract until 2020 to Williams
Total		26,486			

TLH-5
DOCKET NO. 040001-EI
FPL WITNESS: T. Hartman
EXHIBIT _____
SEPTEMBER 9, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO 17
COMPANY/ FPL
WITNESS: T. L. Hartman (TLH-5)
DATE: 11-08-04

Economic Analysis Against 2003 RFP Plant

SoCo Offer Economic Comparison to 2003 RFP Plant
(millions, NPV, 2004$, 2004 - 2032)

Description of Options	MW	Effective FPL Border Costs	Trans. Related Costs	Net Equity Adj.	Total	Difference from 2003 RFP Plant
Southern Company Offer						
Average Arbitrage	955	64,301	127	17	64,445	(28)
Minimum Arbitrage	955	64,325	127	17	64,468	(4)
Maximum Arbitrage	955	64,278	127	17	64,421	(51)
Comparison:						
2003 RFP Plant	1,220	64,342	73	58	64,473	

TLH-6
DOCKET NO. 040001-EI
FPL WITNESS: T. Hartman
EXHIBIT _____
SEPTEMBER 9, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 18
COMPANY/ F.P.+L.
WITNESS: T. L. Hartman (TLH-6)
DATE: 11-08-04

Timeline for Firm Transmission Service

Milestone Schedule for Obtaining Transmission

	Milestone	Maximum Duration	Maximum Cumulative Days	Tariff Reference
FPL	Request for service	0	0	
Southern	System Impact Study Agreement	30	30	19.1
FPL	Response	15	45	19.1
Southern	System Impact Study	60	105	19.3
FPL	Response	15	120	19.3
Southern	Facilities Study Agreement	30	135	19.4
FPL	Response	15	150	19.4
Southern	Facilities Study	60	210	19.4
FPL	Service Agreement	30	240	19.4

TLH-7
Docket No. 040001-EI
FPL Witness T. Hartman
Exhibit _____
October 18, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 19
COMPANY/ FP+L
WITNESS. T. L. Hartman (TLH-7)
DATE 11-09-04

SOUTHERN COMPANY TRANSMISSION QUEUE

TLH-8
Docket No. 040001-EI
FPL Witness T. Hartman
Exhibit_____
Pages 1-5
October 18, 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 20
COMPANY/ FP+L
WITNESS: T. L. Hartman (TLH-8)
DATE 11-03-04

SOCO OASIS 1.4 - Status Query Results

Menus | Transmission | Offerings | Advanced Offerings | New Reservation | Status | Monitor | Query

Query Criteria
TS Class = Firm
Points Of Receipt = SOCO
Points Of Delivery = FPC, FPL, JEA, TAL
Path Name = SS/SOCO/SOCO-FL//
Service Period...
from 15-Oct-04 17:00 CD
to 15-Oct-21 18:00 CD

Status Info
Time of Query
15-Oct-04 16:03:24 CDT
44 Result Rows

Transmission Reservations where Customer and Seller are as selected

New Status	Status	ARef	Source / Sink	Begin Time	End Time	Requested Max Cap Sum:Avg	Granted Max Cap Sum:Avg	Offer Price	Bid Price	Price Units
	CONFIRMED	128534	UPS FPL	01-Jan-00 01:00 CD	01-Jan-11 01:00 CD	19 202:18	19 202:18	16440.00	16440.00	$/MWyr
	SOCO-FPL		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller
			Time Queued 31-Aug-99 11:50 CD							SOCO/SOCO
										Deal Ref PRIOR
			Customer Comments Prior Service UPS to FPL incremental increase for annual adjustment							
			Check Ancillaries							
	CONFIRMED	128535	UPS FPC	01-Jan-00 01:00 CD	01-Jan-11 01:00 CD	7 74:6	7 74:6	16440.00	16440.00	$/MWyr
IMPACTED	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller
			Time Queued 31-Aug-99 11:52 CD							SOCO/SOCO
										Deal Ref PRIOR
			Customer Comments Prior Service UPS to FPC incremental increase for annual adjustment							
			Check Ancillaries							
	CONFIRMED	128536	UPS JEA	01-Jan-00 01:00 CD	01-Jan-11 01:00 CD	5 54:4	5 54:4	16440.00	16440.00	$/MWyr
IMPACTED	SOCO-JEA		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller
			Time Queued 31-Aug-99 11:53 CD							SOCO/SOCO
										Deal Ref PRIOR
			Customer Comments Prior Service UPS to JEA incremental increase for annual adjustment							
			Check Ancillaries							
	CONFIRMED	128545	SCHERER4 FPL	01-Jan-00 01:00 CD	01-Jan-20 01:00 CD	38 760:38	38 760:38	16440.00	16440.00	$/MWyr
IMPACTED	SOCO-FPL		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller
			Time Queued 31-Aug-99 12:09 CD							SOCO/SOCO
										Deal Ref PRIOR
			Customer Comments Prior Service Scherer4 to FPL incremental increase for annual adjustment							
			Check Ancillaries							
	CONFIRMED	128546	SCHERER4 JEA	01-Jan-00 01:00 CD	01-Jan-20 01:00 CD	12 240:12	12 240:12	16440.00	16440.00	$/MWyr
	SOCO-JEA		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller
			Time Queued 31-Aug-99 12:10 CD							SOCO/SOCO
										Deal Ref PRIOR
			Customer Comments Prior Service Scherer4 to JEA incremental increase for annual adjustment							
			Check Ancillaries							
	CONFIRMED	322721	BRANCH TAL	01-Jun-03 00:00 CD	01-Jun-23 00:00 CD	50 1000:50	19 19:0	21685.56	21685.56	$/MWyr
IMPACTED	SOCO-TAL		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller
			Time Queued 12-Feb-02 17:21 CD							SWE/SOCO
			Expires 14-Mar-03 17:00 CD							Request Ref
			Status Comments Pursuant to terms of Service Agreement.							
			Seller Comments Yearly ATC based on monthly ATC, 6/1/03 to 6/1/04 - 1st year only							
			Check Ancillaries							
	STUDY	324518	WANSLEY FPL	01-Jun-10 00:00 CD	01-Jun-30 00:00 CD	1125 22500:1125	0 0:0	16440.00	16440.00	$/MWyr
	SOCO-FPL		Yearly/Firm/Point_To_Point/Full_Period/Sliding							Customer/Seller

			Time Queued Seller Comments		25-Feb-02 10:19 CD System Impact Study initiated					SWE/SOCO
	STUDY	324519	GOATROCK FPC	01-Jun-10 00:00 CD	01-Jun-30 00:00 CD	425 8500:425	0 0:0	16440.00	16440.00	$/MWyr
	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		25-Feb-02 10:19 CD System Impact Study initiated					Customer/Seller SWE/SOCO
	STUDY	324520	GOATROCK JEA	01-Jun-10 00:00 CD	01-Jun-30 00:00 CD	200 4000:200	0 0:0	16440.00	16440.00	$/MWyr
	SOCO-JEA		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		25-Feb-02 10:20 CD System Impact Study initiated					Customer/Seller SWE/SOCO
	STUDY	359209	BOWEN FPL	01-Jan-06 01:00 CD	01-Jan-16 01:00 CD	150 1500:150	0 0:0	16440.00	16440.00	$/MWyr
	SOCO-FPL		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		16-Jul-02 14:30 CD System Impact Study initiated					Customer/Seller SWE/SOCO
	STUDY	359210	BRANCH FPL	01-Jan-06 01:00 CD	01-Jan-16 01:00 CD	150 1500:150	0 0:0	16440.00	16440.00	$/MWyr
	SOCO-FPL		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		16-Jul-02 14:30 CD System Impact Study initiated					Customer/Seller SWE/SOCO
	STUDY	359211	SCHERER FPL	01-Jan-06 01:00 CD	01-Jan-16 01:00 CD	150 1500:150	0 0:0	16440.00	16440.00	$/MWyr
	SOCO-FPL		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		16-Jul-02 14:31 CD System Impact Study initiated					Customer/Seller SWE/SOCO
	STUDY	403740	LLEA LLC TAL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-TAL		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403741	LLEA LLC TAL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-TAL		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403742	LLEA LLC FPC	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403743	LLEA LLC FPC	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403744	LLEA LLC FPC	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403745	LLEA LLC FPC	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403746	LLEA LLC FPC	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
	SOCO-FPC		Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued Seller Comments		23-Jan-03 15:55 CD System Impact Study initiated					Customer/Seller TZEA/SOCO
	STUDY	403747	LLEA LLC FPC	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	50 50:50	0 0:0	21685.56	21685.56	$/MWyr

		SOCO-FPC	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:55 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	STUDY	403748	LLEA LLC FPL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:56 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	STUDY	403749	LLEA LLC FPL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:56 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	STUDY	403750	LLEA LLC FPL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:56 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	STUDY	403751	LLEA LLC FPL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:56 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	STUDY	403752	LLEA LLC FPL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	100 100:100	0 0:0	21685.56	21685.56	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:56 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	STUDY	403753	LLEA LLC FPL	01-Jun-09 00:00 CD	01-Jun-10 00:00 CD	50 50:50	0 0:0	21685.56	21685.56	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 23-Jan-03 15:56 CD Seller Comments System Impact Study initiated							Customer/Seller TZEA/SOCO
	CONFIRMED	478082	BRANCH TAL	01-Jun-04 00:00 CD	01-Jun-05 00:00 CD	19 19:19	19 19:19	21042.21	21042.21	$/MWyr
RENEWAL - Related Ref 322721 IMPACTED		SOCO-TAL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 29-Mar-04 09:14 CD Status Comments Pursuant to terms of Service Agreement. Seller Comments Yearly ATC based on monthly ATC, 6/1/04 to 6/1/05 Customer Comments Rollover Request of 322721 Check Ancillaries							Customer/Seller SWE/SOCO
	CONFIRMED	488588	YATES FPL	01-Jun-04 00:00 CD	01-Jun-05 00:00 CD	1 12:1	1 12:1	1753.52	1753.52	$/MWmo
IMPACTED		SOCO-FPL	Monthly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 28-May-04 10:55 CD Seller Comments Not a real transaction. Customer Comments To permit correction of ATC due to contract adjustments Check Ancillaries							Customer/Seller SOCO/SOCO Deal Ref PSEUDO
	RECEIVED	505440	MILLER FPL	01-Jun-10 00:00 CD	01-Jun-15 00:00 CD	720 3600:720	0 0:0	21042.21	21042.21	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 25-Aug-04 13:47 CD Customer Comments ROLLOVER OF PRE-TARIFF UPS SERVICE							Customer/Seller FPLM/SOCO
	RECEIVED	505441	SCHERER FPL	01-Jun-10 00:00 CD	01-Jun-15 00:00 CD	210 1050:210	0 0:0	21042.21	21042.21	$/MWyr
		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 25-Aug-04 13:48 CD Customer Comments ROLLOVER OF PRE-TARIFF UPS SERVICE							Customer/Seller FPLM/SOCO
	RECEIVED	505443	HILLABEE FPL	01-Jun-10 00:00 CD	01-Jun-12 00:00 CD	700 1400:700	0 0:0			$/MWyr
REDIRECT - Related Ref 465863 Related POR/POD SOCO-GTC Related Sink OPCLOAD		SOCO-FPL	Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 25-Aug-04 14:14 CD Check Ancillaries							Customer/Seller CALP/SOCO

	STUDY	505590	MILLER TAL	01-Jul-05 00:00 CD	01-Sep-05 00:00 CD	50 100:50	0 0:0	1712.61	1712.61	$/MWmo
SOCO-TAL			Monthly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 26-Aug-04 12:55 CD							Customer/Seller MSCG/SOCO	
	CONFIRMED	507786	HEARDCOTNSK FPL	01-Oct-04 00:00 CD	01-May-05 00:00 CD	66 462:66	66 198:28			$/MWmo	
SOCO-FPL REDIRECT - Related Ref 422069 Related POR/POD SOCO-EES Related Sink EES			Monthly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 09-Sep-04 06:03 CD Expires 08-Oct-04 12:35 CD Seller Comments Please confirm or withdraw ASAP Check Ancillaries							Customer/Seller EXGN/SOCO Request Ref	
	RECEIVED	512147	MILLER FPL	01-Jan-05 01:00 CD	01-Jan-08 01:00 CD	100 300:100	0 0:0	20451.52	20451.52	$/MWyr	
SOCO-FPL			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 06-Oct-04 07:22 CD							Customer/Seller MSCG/SOCO	
	RECEIVED	512148	MILLER FPL	01-Jan-05 01:00 CD	01-Jan-08 01:00 CD	100 300:100	0 0:0	20451.52	20451.52	$/MWyr	
SOCO-FPL			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 06-Oct-04 07:22 CD							Customer/Seller MSCG/SOCO	
	CONFIRMED	513236	BRANCH TAL	15-Oct-04 00:00 CD	16-Oct-04 00:00 CD	19 19:19	19 19:19			$/MWdy	
SOCO-TAL REDIRECT - Related Ref 510447 Related POR/POD TVA-TAL Related Source TVA			Daily/Firm/Point_To_Point/Full_Period/Fixed Time Queued 14-Oct-04 10:22 CD Check Ancillaries							Customer/Seller SWE/SOCO	
	CONFIRMED	513297	BRANCH TAL	18-Oct-04 00:00 CD	19-Oct-04 00:00 CD	19 19:19	19 19:19			$/MWdy	
SOCO-TAL REDIRECT - Related Ref 510447 Related POR/POD TVA-TAL Related Source TVA			Daily/Firm/Point_To_Point/Full_Period/Fixed Time Queued 15-Oct-04 12:22 CD Check Ancillaries							Customer/Seller SWE/SOCO	
	CONFIRMED	513306	BRANCH TAL	16-Oct-04 00:00 CD	18-Oct-04 00:00 CD	19 38:19	19 38:19			$/MWdy	
SOCO-TAL REDIRECT - Related Ref 510447 Related POR/POD TVA-TAL Related Source TVA			Daily/Firm/Point_To_Point/Full_Period/Fixed Time Queued 15-Oct-04 14:27 CD Check Ancillaries							Customer/Seller SWE/SOCO	
	CONFIRMED	90100	SOCO FPC	01-Mar-97 01:00 CD	01-Mar-13 01:00 CD	10 160:10	10 160:10	16440.00	16440.00	$/MWyr	
SOCO-FPC IMPACTED			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 01-Jan-97 01:00 CD Customer Comments Prior Service SOCO to Bay County							Customer/Seller SOCO/SOCO Deal Ref PRIOR	
	CONFIRMED	90110	UPS FPL	01-Jun-98 00:00 CD	01-Jun-10 00:00 CD	921 11052:921	921 11052:921	16440.00	16440.00	$/MWyr	
SOCO-FPL IMPACTED			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 01-Jan-99 01:00 CD Customer Comments Prior Service UPS to FPL							Customer/Seller SOCO/SOCO Deal Ref PRIOR	
	CONFIRMED	90120	UPS FPC	01-Jun-98 00:00 CD	01-Jun-10 00:00 CD	409 4908:409	409 4908:409	16440.00	16440.00	$/MWyr	
SOCO-FPC IMPACTED			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 01-Jan-99 01:00 CD Customer Comments Prior Service UPS to FPC							Customer/Seller SOCO/SOCO Deal Ref PRIOR	
	CONFIRMED	90130	UPS JEA	01-Jun-98 00:00 CD	01-Jun-10 00:00 CD	205 2460:205	205 2460:205	16440.00	16440.00	$/MWyr	
SOCO-JEA IMPACTED			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 01-Jan-99 01:00 CD Customer Comments Prior Service UPS to JEA							Customer/Seller SOCO/SOCO Deal Ref PRIOR	
	CONFIRMED	90150	SCHERER4 FPL	01-Jan-99 01:00 CD	01-Jan-20 01:00 CD	649 13629:649	649 13629:649	16440.00	16440.00	$/MWyr	
SOCO-FPL IMPACTED			Yearly/Firm/Point_To_Point/Full_Period/Sliding Time Queued 01-Jan-99 01:00 CD							Customer/Seller SOCO/SOCO	

			Customer Comments		Prior Service Scherer4 to FPL						Deal Ref PRIOR
	CONFIRMED	90160	SCHERER4 JEA	01-Jan-99 01:00 CD	01-Jan-20 01:00 CD	201 4221:201	201 4221:201	16440.00	16440.00	$/MWyr	
IMPACTED		SOCO-JEA	Yearly/Firm/Point_To_Point/Full_Period/Sliding								Customer/Seller SOCO/SOCO
			Time Queued		01-Jan-99 01:00 CD						Deal Ref PRIOR
			Customer Comments		Prior Service Scherer4 to JEA						

SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2004 - DECEMBER 2004
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

Marianna Division

Under-recovery of purchased power costs for the period January 2004 - December 2004. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2003)(Estimated)	$	(854,985)

Exhibit No._____
DOCKET NO. 040001-EI
Florida Public Utilities Company
(GMB-1)
Page 1 of 6

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 21
COMPANY/ FPUC
WITNESS: George M. Bachman (GMB-1)
DATE: 11-05-04

DOCUMENT NUMBER-DATE
08709 AUG 10 04
FPSC-COMMISSION CLERK

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION
ESTIMATED FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

Schedule E1-B

MARIANNA DIVISION			ACTUAL JANUARY 2004	ACTUAL FEBRUARY 2004	ACTUAL MARCH 2004	ACTUAL APRIL 2004	ACTUAL MAY 2004	ACTUAL JUNE 2004	Estimated JULY 2004	Estimated AUGUST 2004	Estimated SEPTEMBER 2004	Estimated OCTOBER 2004	Estimated NOVEMBER 2004	Estimated DECEMBER 2004	Total
Total System Sales - KWH			28,916,312	25,785,248	23,223,450	21,415,624	21,896,946	28,005,951	25,222,653	25,207,331	25,233,533	25,238,941	25,224,964	25,252,262	300,623,235
Total System Purchases - KWH			29,069,532	26,131,216	22,273,650	22,185,213	27,989,514	30,623,247	30,965,000	30,766,000	26,814,000	23,260,000	21,931,000	26,562,000	318,600,372
System Billing Demand - KW			61,724	57,422	51,596	43,946	50,754	64,184	63,000	63,000	55,000	49,000	46,000	58,000	664,628
Purchased Power Rates:															
Base Fuel Costs - $/KWH			0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	0.02180	
Demand and Non-Fuel:															
Demand Charge - $/KW			6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	6.80	
Customer Charge - $			550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	550.00	
Transformation Charge			31,979	31,980	31,980	31,979	31,979	31,979	31,980	31,980	31,980	31,980	31,980	31,980	
Purchased Power Costs:															
Base Fuel Costs			633,716	569,661	485,566	483,638	610,171	667,587	675,070	670,738	584,570	507,085	478,083	579,756	6,945,641
Subtotal Fuel Costs			633,716	569,661	485,566	483,638	610,171	667,587	675,070	670,738	584,570	507,085	478,083	579,756	6,945,641
Demand and Non-Fuel Costs:															
Demand Charge			419,724	390,489	350,852	298,847	345,128	436,452	428,404	428,404	380,794	333,194	312,804	394,394	4,519,456
Customer Charge			550	550	550	550	550	550	550	550	550	550	550	550	6,600
Transformation Charge			31,979	31,980	31,980	31,979	31,979	31,979	31,980	31,980	31,980	31,980	31,980	31,980	383,756
Subtotal Demand & Non-Fuel Costs			452,253	422,999	383,382	331,376	377,657	468,981	460,934	460,934	413,324	365,724	345,334	426,924	4,909,822
Total System Purchased Power Costs			1,085,969	992,660	868,948	815,014	987,828	1,136,568	1,136,004	1,131,672	997,894	872,809	823,417	1,006,680	11,855,463
Sales Revenues															
Fuel Adjustment Revenues:		Rates													
Residential	RS	0.04053	610,329	537,156	448,887	373,857	378,106	515,784	474,965	475,255	475,545	475,787	476,077	476,318	5,717,865
Commercial	GS	0.04002	98,051	94,828	88,721	85,568	85,809	107,279	94,025	94,025	94,025	94,025	94,025	94,025	1,124,006
Commercial	GSD	0.03735	256,884	246,498	240,028	238,087	247,797	305,590	287,131	287,131	287,131	287,131	287,131	287,131	3,257,670
Industrial	GSLD	0.03533	145,277	112,052	109,904	116,361	119,848	141,784	109,561	109,561	109,561	109,561	109,561	109,561	1,402,570
Residential	OL,OL-2	0.02910	5,511	5,863	5,873	6,718	8,826	8,871	8,294	7,635	8,189	8,170	8,120	8,184	92,254
Other	SL-1,SL-2,SL-3	0.02901	5,647	5,663	5,608	2,656	2,850	2,896	2,342	2,346	2,345	2,350	1,756	2,342	38,832
Total Fuel Revenues			1,121,899	1,001,859	899,021	825,047	843,034	1,062,184	976,318	975,953	976,797	977,024	976,700	977,561	11,633,197
Non-Fuel Revenues			615,552	570,324	528,974	520,469	571,446	664,133	629,032	626,437	629,153	629,106	626,480	629,579	7,240,705
Total Sales Revenue			1,737,251	1,572,183	1,427,995	1,345,536	1,414,480	1,746,317	1,605,350	1,602,390	1,605,950	1,606,130	1,603,180	1,607,140	18,873,902
KWH Sales:															
Residential	RS		15,058,887	13,253,812	11,075,172	9,219,086	9,330,391	12,727,271	11,718,839	11,725,997	11,733,155	11,739,120	11,746,278	11,752,243	141,080,251
Commercial	GS		2,449,978	2,364,449	2,216,834	2,138,020	2,139,062	2,680,553	2,349,450	2,349,450	2,349,450	2,349,450	2,349,450	2,349,450	28,086,596
Commercial	GSD		6,881,983	6,599,136	6,425,905	6,373,964	6,533,909	8,181,110	7,687,564	7,687,564	7,687,564	7,687,564	7,687,564	7,687,564	87,221,390
Industrial	GSLD		4,142,568	3,171,164	3,110,384	3,293,135	3,391,744	4,012,052	3,101,065	3,101,065	3,101,065	3,101,065	3,101,065	3,101,065	39,727,438
Residential	OL,OL-2		188,765	201,512	201,849	299,848	303,598	305,136	285,005	262,386	281,418	280,747	279,031	281,222	3,170,519
Other	SL-1,SL-2,SL-3		194,675	195,175	193,306	91,570	98,243	99,829	80,730	80,867	80,881	80,995	81,576	80,738	1,338,585
Total KWH Sales			28,916,856	25,785,248	23,223,450	21,415,624	21,896,946	28,005,951	25,222,653	25,207,331	25,233,533	25,238,941	25,224,964	25,252,262	300,623,779
True-up Calculation:															Period to Date
Fuel Revenues			1,121,899	1,001,859	899,021	825,047	843,034	1,062,184	976,318	975,953	976,797	977,024	976,700	977,561	11,633,197
True-up Provision		DIVIDED BY 12	52,022	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	624,352
Gross Receipts Tax Refund			0	0				0	0	0	0	0	0	0	0
Fuel Revenue			1,069,877	949,829	846,991	773,017	791,004	1,030,154	924,288	923,923	924,767	924,994	924,670	925,531	11,008,845
Total Purchased Power Costs			1,085,969	992,660	868,948	815,014	987,828	1,136,568	1,136,004	1,131,672	997,894	872,809	823,417	1,006,680	11,855,463
True-up Provision for the Period			(16,292)	(42,831)	(21,957)	(41,997)	(196,824)	(106,414)	(211,716)	(207,749)	(73,127)	52,185	101,253	(81,149)	(846,618)
Interest Provision for the Period			(528)	(490)	(462)	(457)	(530)	(705)	(757)	(903)	(985)	(947)	(830)	(773)	(8,357)
True-up and Interest Provision Beginning of Period			(624,352)	(589,150)	(580,441)	(550,830)	(541,254)	(686,578)	(741,667)	(902,110)	(1,058,732)	(1,080,814)	(977,546)	(825,093)	(624,352)
True-up Collected or (Refunded)			52,022	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	52,030	624,352
End of Period, Net True-up			(589,150)	(580,441)	(550,830)	(541,254)	(686,578)	(741,667)	(902,110)	(1,056,732)	(1,080,814)	(977,546)	(825,093)	(854,985)	(854,985)
10% Rule															
Interest Provision:															-7.21%
Beginning True-up Amount			(624,352)	(588,150)	(580,441)	(550,830)	(541,254)	(686,578)	(741,667)	(902,110)	(1,058,732)	(1,080,814)	(977,546)	(825,093)	
Ending True-up Amount Before Interest			(588,622)	(579,951)	(550,368)	(540,797)	(686,048)	(740,962)	(901,353)	(1,057,829)	(1,079,829)	(976,599)	(824,263)	(854,212)	
Total Beginning and Ending True-up			(1,212,974)	(1,169,101)	(1,130,809)	(1,091,627)	(1,227,302)	(1,427,540)	(1,643,020)	(1,959,939)	(2,138,561)	(2,057,413)	(1,801,809)	(1,679,305)	
Average True-up Amount			(606,487)	(584,551)	(565,405)	(545,814)	(613,651)	(713,770)	(821,510)	(979,970)	(1,069,281)	(1,028,707)	(900,905)	(839,653)	
Average Annual Interest Rate			1.0450%	1.0050%	0.9800%	1.0050%	1.0350%	1.1850%	1.1050%	1.1050%	1.1050%	1.1050%	1.1050%	1.1050%	
Monthly Average Interest Rate			0.0871%	0.0838%	0.0817%	0.0838%	0.0863%	0.0988%	0.0921%	0.0921%	0.0921%	0.0921%	0.0921%	0.0921%	
Interest Provision			(528)	(490)	(462)	(457)	(530)	(705)	(757)	(903)	(985)	(947)	(830)	(773)	

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FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

SCHEDULE E1-B1

		DOLLARS				MWH				CENTS/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2	Nuclear Fuel Disposal Cost												
3	Coal Car Investment												
4	Adjustments to Fuel Cost (A2, Page 1)												
5	TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	6,945,641	6,758,252	187,389	2.8%	318,600	310,000	8,600	2.8%	2.18005	2.18008	(0.00003)	0.0%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	4,909,822	4,755,958	153,864	3.2%	318,600	310,000	8,600	2.8%	1.54108	1.53418	0.00688	0.5%
11	Energy Payments to Qualifying Facilities (A8a)												
12	TOTAL COST OF PURCHASED POWER	11,855,463	11,514,210	341,253	3.0%	318,600	310,000	8,600	2.8%	3.72111	3.71426	0.00685	0.2%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					318,600	310,000	8,600	2.8%				
14	Fuel Cost of Economy Sales (A6)												
15	Gain on Economy Sales (A6)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A6)												
17	Fuel Cost of Other Power Sales (A6)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19	NET INADVERTENT INTERCHANGE												
20	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	11,855,463	11,514,210	341,253	3.0%	318,600	310,000	8,600	2.8%	3.72111	3.71426	0.00685	0.2%
21	Net Unbilled Sales	184,307 *	(469,854) *	654,161	-139.2%	4,953	(12,650)	17,603	-139.2%	0.06131	(0.15157)	0.21288	-140.5%
22	Company Use	10,419 *	9,286 *	1,133	12.2%	280	250	30	12.0%	0.00347	0.00300	0.00047	15.7%
23	T & D Losses	474,218 *	460,568 *	13,650	3.0%	12,744	12,400	344	2.8%	0.15775	0.14857	0.00918	6.2%
24	SYSTEM KWH SALES	11,855,463	11,514,210	341,253	3.0%	300,623	310,000	(9,377)	-3.0%	3.94364	3.71426	0.22938	6.2%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	11,855,463	11,514,210	341,253	3.0%	300,623	310,000	(9,377)	-3.0%	3.94364	3.71426	0.22938	6.2%
26a	Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	11,855,463	11,514,210	341,253	3.0%	300,623	310,000	(9,377)	-3.0%	3.94364	3.71426	0.22938	6.2%
28	GPIF**												
29	TRUE-UP**	624,352	343,777	280,575	81.6%	300,623	310,000	(9,377)	-3.0%	0.20769	0.11090	0.09679	87.3%
30	TOTAL JURISDICTIONAL FUEL COST	12,479,815	11,857,987	621,828	5.2%	300,623	310,000	(9,377)	-3.0%	4.15132	3.82516	0.32616	8.5%
31	Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
32	Fuel Factor Adjusted for Taxes									4.15431	3.82791	0.32640	8.5%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									4.154	3.828	0.326	8.5%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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Schedule E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2004 - DECEMBER 2004
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Fernandina Beach Division

Over-recovery of purchased power costs for the period January 2004 - December 2004. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2003.)(Estimated)	$	(69,844)

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FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD
ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED
(EXCLUDES LINE LOSS , EXCLUDES TAXES)

Schedule E1-B

FERNANDINA BEACH		ACTUAL JANUARY 2004	ACTUAL FEBRUARY 2004	ACTUAL MARCH 2004	ACTUAL APRIL 2004	ACTUAL MAY 2004	ACTUAL JUNE 2004	Estimated JULY 2004	Estimated AUGUST 2004	Estimated SEPTEMBER 2004	Estimated OCTOBER 2004	Estimated NOVEMBER 2004	Estimated DECEMBER 2004	Total Estimated
Total System Sales - KWH		37,283,836	35,256,592	36,663,661	31,559,370	31,625,808	43,185,305	37,426,921	38,221,164	38,696,444	38,738,044	38,779,644	39,342,084	446,808,851
JSC Purchases - KWH		534,500	607,800	271,200	308,900	306,700	165,700	400,000	400,000	400,000	400,000	400,000	400,000	4,595,800
JEA Purchases - KWH		38,227,951	34,757,822	37,145,830	31,767,791	35,767,009	48,313,294	37,026,921	37,821,164	38,296,444	38,338,044	38,379,644	38,942,084	454,783,978
System Billing Demand - KW		83,373	88,032	89,261	58,509	71,501	85,210	93,373	93,117	92,000	78,108	67,850	83,387	963,719
Purchased Power Rates:														
CCA Fuel Costs - $/KWH		0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	0.018700	
Base Fuel Costs - $/KWH		0.01786	0.01786	0.01786	0.01788	0.01786	0.01786	0.01845	0.01845	0.01845	0.01845	0.01845	0.01845	
Fuel Adjustment - $/KWH		0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	
Demand and Non-Fuel:														
Demand Charge - $/KW		6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	
Customer Charge - $		225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	225.00	
Energy Charge (Excl. Fuel) $/KWH		0.00164	0.00164	0.00164	0.00164	0.00164	0.00164	0.00105	0.00105	0.00105	0.00105	0.00105	0.00105	
Purchased Power Costs:														
CCA Fuel Costs		9,995	11,366	5,071	5,795	5,736	3,098	7,480	7,480	7,480	7,480	7,480	7,480	85,941
JEA Base Fuel Costs		682,751	620,775	663,425	567,373	638,799	862,875	683,147	697,800	706,589	707,337	708,104	718,481	8,257,436
JEA Fuel Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Fuel Costs		582,746	632,141	668,496	573,168	644,534	865,974	690,627	705,280	714,049	714,817	715,584	725,961	8,343,377
Demand and Non-Fuel Costs:														
Demand Charge		500,236	528,191	415,586	351,054	429,006	511,260	560,237	558,701					
Customer Charge		225	225	225	225	225	225	225	225	225	225	225	225	
Energy Charge		62,694	57,003	60,919	52,099	58,658	79,234	38,878	39,712	40,211	40,255	40,299	40,889	610,851
Subtotal Demand & Non-Fuel Costs		563,157	585,419	476,710	403,378	487,889	590,719	599,339	598,638	592,435	509,115	447,623	641,436	8,395,857
Total System Purchased Power Costs		1,255,903	1,217,560	1,145,206	976,546	1,132,423	1,456,693	1,289,966	1,303,918	1,306,484	1,223,932	1,163,207	1,367,396	14,739,234
Less Direct Billing To GSLD Class:														
Demand		32,386	100,131	38,072	66,256	31,397	0	132,870	132,870	132,870	132,870	132,870	132,870	1,065,462
Commodity		169,273	168,076	219,070	155,408	163,672	220,338	212,079	212,079	212,079	212,079	212,079	212,079	2,368,311
Net Purchased Power Costs		1,054,244	949,353	888,064	754,882	937,354	1,236,355	945,017	958,969	961,535	878,983	818,258	922,447	11,305,481
Sales Revenues														
Fuel Adjustment Revenues:	Rate													
RS	0.02942	503,570	481,474	454,013	367,255	367,254	552,193	485,372	488,295	489,510	490,725	491,940	508,369	5,579,970
GS	0.02915	82,422	68,936	58,493	68,789	61,743	83,633	79,935	80,481	93,036	93,036	93,036	93,036	956,576
GSD	0.02739	235,097	213,094	221,263	243,855	238,670	285,531	198,334	215,172	215,172	215,172	215,172	215,172	2,711,704
OL	0.01931	1,072	1,182	1,252	2,987	3,093	1,975	1,697	1,913	1,913	1,913	1,913	1,913	22,823
SL,CSL	0.01931	2,044	1,620	1,951	159	0	1,426	1,319	2,002	2,002	2,002	2,002	2,002	18,829
Total Fuel Revenues (Excl. GSLD1)		824,205	766,606	736,972	683,045	670,760	924,758	766,657	787,863	801,633	802,848	804,063	820,492	9,389,902
GSLD1 Fuel Revenues		201,659	268,207	257,142	221,664	195,069	220,338	344,949	344,949	344,949	344,949	344,949	344,949	3,433,773
Non-Fuel Revenues		628,719	615,792	602,002	573,304	614,252	738,533	622,094	642,888	656,918	658,203	659,786	675,159	7,887,852
Total Sales Revenue		1,654,583	1,650,605	1,596,116	1,478,013	1,480,081	1,883,629	1,733,700	1,775,700	1,803,500	1,806,000	1,808,800	1,840,600	20,511,327
KWH Sales:														
RS		17,247,852	16,493,031	15,540,957	12,437,090	12,483,677	18,770,046	16,616,650	15,716,700	16,758,300	16,799,900	16,841,500	17,403,920	194,109,623
GS		2,854,104	2,381,385	2,020,654	2,348,407	2,118,178	2,899,144	2,815,997	2,834,874	3,268,554	3,268,554	3,268,554	3,268,554	33,318,959
GSD		8,623,382	7,851,281	8,108,654	8,671,367	8,713,680	10,424,519	8,787,568	9,406,190	9,406,190	9,406,190	9,406,190	9,406,190	108,411,381
GSLD1		8,430,000	8,370,000	10,910,000	7,740,000	8,150,000	10,970,000	9,050,000	9,060,000	9,060,000	9,060,000	9,060,000	9,060,000	106,920,000
OL		56,808	61,158	64,995	154,401	160,271	102,331	88,164	99,400	99,400	99,400	99,400	99,400	1,184,128
SL,CSL		106,195	99,737	101,357	6,105	0	49,265	68,542	104,000	104,000	104,000	104,000	104,000	953,181
Total KWH Sales		37,317,311	35,256,592	36,746,617	31,558,370	31,625,806	43,185,305	37,426,921	38,221,164	38,696,444	38,738,044	38,779,644	39,342,064	446,895,282
True-up Calculation (Excl. GSLD):														
Fuel Revenues		824,205	766,606	736,972	683,045	670,760	924,758	766,657	787,863	801,633	802,848	804,063	820,492	9,389,902
True-up Provision		(153,169)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(1,837,973)
Gross Receipts Tax Refund		0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue		977,374	919,770	890,136	836,209	823,924	1,077,922	919,821	941,027	954,797	956,012	957,227	973,656	11,227,875
Net Purchased Power Costs		1,054,244	949,353	888,064	754,882	937,354	1,236,355	945,017	958,969	961,535	878,983	818,258	922,447	11,305,481
True-up Provision for the Period		(76,870)	(29,583)	2,072	81,327	(113,430)	(158,433)	(25,196)	(17,942)	(6,738)	77,029	138,969	51,209	(77,586)
Interest Provision for the Period		1,501	1,272	1,105	1,041	927	776	499	338	186	78	38	(17)	7,742
True-up and Interest Provision														
Beginning of Period		1,837,973	1,609,435	1,427,960	1,277,973	1,207,177	941,510	630,689	452,828	282,060	122,344	46,287	32,128	1,837,973
True-up Collected or (Refunded)		(153,169)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(153,164)	(1,837,973)
End of Period, Net True-up		1,609,435	1,427,960	1,277,973	1,207,177	941,510	630,689	452,828	282,060	122,344	46,287	32,128	(69,844)	(69,844)
10% Rule Interest Provision:														-0.474
Beginning True-up Amount		1,837,973	1,609,435	1,427,960	1,277,973	1,207,177	941,510	630,689	452,828	282,060	122,344	46,287	32,128	
Ending True-up Amount Before Interest		1,607,934	1,426,688	1,276,868	1,206,136	940,583	629,913	452,329	281,722	122,158	46,209	32,092	(69,827)	
Total Beginning and Ending True-up		3,445,907	3,036,123	2,704,828	2,484,109	2,147,760	1,571,423	1,083,018	734,550	404,218	168,553	78,379	(37,699)	
Average True-up Amount		1,722,954	1,518,062	1,352,414	1,242,055	1,073,880	785,712	541,509	367,275	202,109	84,277	39,190	(18,850)	
Average Interest Rate		1.0450%	1.0050%	0.9800%	1.0050%	1.0350%	1.1850%	1.1050%	1.1050%	1.1050%	1.1050%	1.1050%	1.1050%	
Monthly Average Interest Rate		0.0871%	0.0838%	0.0817%	0.0838%	0.0863%	0.0988%	0.0921%	0.0921%	0.0921%	0.0921%	0.0921%	0.0921%	
Interest Provision		1,501	1,272	1,105	1,041	927	776	499	338	186	78	36	(17)	

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Florida Public Utilities Company
(GMB-1)
Page 5 of 6

SCHEDULE E1-B1

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
JANUARY 2004 - DECEMBER 2004

	DOLLARS				MWH				CENTS/KWH			
	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1 Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2 Nuclear Fuel Disposal Cost (A13)												
3 Coal Car Investment												
4 Adjustments to Fuel Cost (A2, Page 1)												
5 TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6 Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	8,257,436	8,514,672	(257,236)	-3.0%	454,784	461,500	(6,716)	-1.5%	1.81568	1.84500	(0.02932)	-1.6%
7 Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8 Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9 Energy Cost of Sched E Economy Purch (A9)												
10 Demand and Non Fuel Cost of Purchased Power (A9)	6,395,857	6,533,715	(137,858)	-2.1%	454,784	461,500	(6,716)	-1.5%	1.40635	1.41576	(0.00941)	-0.7%
11 Energy Payments to Qualifying Facilities (A8a)	85,941	89,760	(3,819)	-4.3%	4,596	4,800	(204)	-4.3%	1.86991	1.87000	(0.00009)	0.0%
12 TOTAL COST OF PURCHASED POWER	14,739,234	15,138,147	(398,913)	-2.6%	459,380	466,300	(6,920)	-1.5%	3.20851	3.24644	(0.03793)	-1.2%
13 TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					459,380	466,300	(6,920)	-1.5%				
14 Fuel Cost of Economy Sales (A7)												
15 Gain on Economy Sales (A7a)												
16 Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17 Fuel Cost of Other Power Sales (A7)												
18 TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19 NET INADVERTENT INTERCHANGE (A10)												
20 TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	14,739,234	15,138,147	(398,913)	-2.6%	459,380	466,300	(6,920)	-1.5%	3.20851	3.24644	(0.03793)	-1.2%
21 Net Unbilled Sales (A4)	(497,127) *	(922,443) *	425,316	-46.1%	(15,494)	(28,414)	12,920	-45.5%	(0.11126)	(0.19782)	0.08656	-43.8%
22 Company Use (A4)	16,107 *	14,154 *	1,953	13.8%	502	436	66	15.1%	0.00360	0.00304	0.00056	18.4%
23 T & D Losses (A4)	884,362 *	908,289 *	(23,927)	-2.6%	27,563	27,978	(415)	-1.5%	0.19793	0.19479	0.00314	1.6%
24 SYSTEM KWH SALES	14,739,234	15,138,147	(398,913)	-2.6%	446,809	466,300	(19,491)	-4.2%	3.29878	3.24645	0.05233	1.6%
25 Wholesale KWH Sales												
26 Jurisdictional KWH Sales	14,739,234	15,138,147	(398,913)	-2.6%	446,809	466,300	(19,491)	-4.2%	3.29878	3.24645	0.05233	1.6%
26a Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27 Jurisdictional KWH Sales Adjusted for Line Losses	14,739,234	15,138,147	(398,913)	-2.6%	446,809	466,300	(19,491)	-4.2%	3.29878	3.24645	0.05233	1.6%
28 GPIF**												
29 TRUE-UP**	(1,837,973)	(1,302,700)	(535,273)	41.1%	446,809	466,300	(19,491)	-4.2%	(0.41136)	(0.27937)	(0.13199)	47.3%
30 TOTAL JURISDICTIONAL FUEL COST	12,901,261	13,835,447	(934,186)	-6.8%	446,809	466,300	(19,491)	-4.2%	2.88742	2.96707	(0.07965)	-2.7%
31 Revenue Tax Factor									1.01597	1.01597	0.00000	0.0%
32 Fuel Factor Adjusted for Taxes									2.93353	3.01445	(0.08092)	-2.7%
33 FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)												

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

ORIGINAL

LAW OFFICES
Messer, Caparello & Self
A Professional Association

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Tallahassee, Florida 32302-1876
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November 2, 2004

BY HAND DELIVERY
Ms. Blanca Bayo, Director
Division of Records and Reporting
Room 110, Easley Building
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Florida Public Utilities Company; Docket No. 040001-EI

Dear Ms. Bayo:

Enclosed for filing on behalf of Florida Public Utilities Company in this docket is an original and 10 copies of Revised Composite Exhibit GMB-2. This exhibit will replace the Composite Exhibit GMB-2 filed on September 17, 2004

Please acknowledge receipt of these documents by stamping the enclosed extra copy of this letter.

CMP ____
COM 5
CTR mg
ECR ____
GCL ____
OPC ____
MMS ____
RCA ____
SCR ____
SEC 1
OTH ____

Thank you for your assistance.

Sincerely,

Norman H. Horton, Jr.

NHH/amb
Enclosures
cc: Mr. George Bachman

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 22
COMPANY/ FPUC
WITNESS. George M. Bachman (GMB-2)
DATE 11-08-04

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DOCUMENT NUMBER-DA
11806 NOV-2
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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

SCHEDULE E1
PAGE 1 OF 2

MARIANNA DIVISION

		(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			0	
2	Nuclear Fuel Disposal Costs (E2)				
3	Coal Car Investment				
4	Adjustments to Fuel Cost				
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0		0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	7,536,301		336,442	2.24000
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)				
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)				
9	Energy Cost of Sched E Economy Purch (E9)				
10	Demand & Transformation Cost of Purch Power (E2)	5,219,208		336,442	1.55130
10a	Demand Costs of Purchased Power	4,828,860	*		
10b	Transformation Energy & Customer Costs of Purchased Power	390,348	*		
11	Energy Payments to Qualifying Facilities (E8a)				
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	12,755,509		336,442	3.79130
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	12,755,509		336,442	3.79130
14	Fuel Cost of Economy Sales (E6)				
15	Gain on Economy Sales (E6)				
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)				
17	Fuel Cost of Other Power Sales				
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0		0	0.00000
19	Net Inadvertent Interchange				
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	12,755,509		336,442	3.79130
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	9,478	*	250	0.00301
23	T & D Losses	805,234	*	21,239	0.25567
24	SYSTEM MWH SALES	12,755,509		314,953	4.04997
25	Less Total Demand Cost Recovery	4,828,860	***		
26	Jurisdictional MWH Sales	7,926,649		314,953	2.51677
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	7,926,649		314,953	2.51677
28	GPIF **				
29	TRUE-UP **	511,209		314,953	0.16231
30	TOTAL JURISDICTIONAL FUEL COST	8,437,858		314,953	2.67908
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes				2.68101
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH				2.681

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

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DOCKET NO. 040001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 1 OF 14
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DOCUMENT NUMBER-DATE
11806 NOV-2 8
FPSC-COMMISSION CLERK

FLORIDA PUBLIC UTLITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER
ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

MARIANNA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*4,380)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
34	RS	149,152,998	61.971%	54,950.2	1.089	1.000	59,840.8	149,152,998	52.06%	47.35%
35	GS	29,469,134	64.200%	10,479.9	1.089	1.000	11,412.6	29,469,134	9.93%	9.36%
36	GSD	105,180,585	73.168%	32,820.1	1.083	1.000	35,544.2	105,180,585	30.93%	33.40%
37	GSLD	26,117,895	84.178%	7,083.8	1.038	1.000	7,353.0	26,117,895	6.40%	8.29%
38	OL, OL1	3,805,245	160.732%	540.5	1.089	1.000	588.6	3,805,245	0.51%	1.21%
39	SL1, SL2 & SL3	1,228,307	160.732%	174.5	1.089	1.000	190.0	1,228,307	0.17%	0.39%
40	TOTAL	314,954,164		106,049.0			114,929.2	314,954,164	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) ot. Col. 13 * (12	(14) (13)/(1)	(15) (14) * 1.00072	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	emand Allocation Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
41	RS	48.05%	3.64%	51.69%	$2,496,038	0.01673	0.01674	0.02681	$0.04355
42	GS	9.17%	0.72%	9.89%	477,574	0.01621	0.01622	0.02681	$0.04303
43	GSD	28.55%	2.57%	31.12%	1,502,741	0.01429	0.01430	0.02681	$0.04111
44	GSLD	5.91%	0.64%	6.55%	316,290	0.01211	0.01212	0.02681	$0.03893
45	OL, OL1	0.47%	0.09%	0.56%	27,042	0.00711	0.00712	0.02681	$0.03393
46	SL1, SL2 & SL3	0.16%	0.03%	0.19%	9,175	0.00747	0.00748	0.02681	$0.03429
47	TOTAL	92.31%	7.69%	100.00%	$4,828,860				

(2) From Gulf Power Co. 2003 Load Research results.
(4) From Fernandina Rate Case.

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DOCKET NO. 040001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 2 OF 14

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SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2003 - DECEMBER 2003
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

Marianna Division

Under-recovery of purchased power costs for the period January 2004 - December 2004. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2004)(Estimated)	$	(511,209)
Estimated kilowatt hour sales for the months of January 2005 - December 2005 as per estimate filed with the Commission.		314,954,164
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2005 - December 2005.		(0.16231)

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Florida Public Utilities Company
(GMB-2)
Page 3 of 14
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SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

LINE NO.			(a) 2005 JANUARY	(b) 2005 FEBRUARY	(c) ESTIMATED 2005 MARCH	(d) 2005 APRIL	(e) 2005 MAY	2005 JUNE	2005 JULY	2005 AUGUST	2005 SEPTEMBER	2005 OCTOBER	2005 NOVEMBER	(f) 2005 DECEMBER	(g) TOTAL PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		676,614	521,942	535,360	534,621	640,954	682,349	741,910	749,347	668,954	581,930	543,581	658,739	7,536,301	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER		516,249	427,289	372,384	359,874	432,154	464,124	494,704	473,854	446,749	396,709	377,249	457,869	5,219,208	3a
3b	QUALIFYING FACILITIES														0	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		1,192,863	949,231	907,744	894,495	1,073,108	1,146,473	1,236,614	1,223,201	1,115,703	978,639	920,830	1,116,608	12,755,509	5
6	LESS: TOTAL DEMAND COST RECOVERY		483,720	394,760	339,855	327,345	399,625	431,595	462,175	441,325	414,220	364,180	344,720	425,340	4,828,860	6
7	TOTAL OTHER COST TO BE RECOVERED		709,143	554,471	567,889	567,150	673,483	714,878	774,439	781,876	701,483	614,459	576,110	691,268	7,926,649	7
7a	SYSTEM KWH SOLD (MWH)		29,693	25,478	21,442	20,730	24,500	27,886	28,978	29,325	31,065	25,501	22,559	27,796	314,953	7a
7b	COST PER KWH SOLD (CENTS/KWH)		2.38825	2.17627	2.64849	2.73589	2.74891	2.56357	2.67251	2.66624	2.25811	2.40955	2.55379	2.48693	2.51677	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		2.38825	2.17627	2.64849	2.73589	2.74891	2.56357	2.67251	2.66624	2.25811	2.40955	2.55379	2.48693	2.51677	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)		0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	0.16231	11
12	TOTAL		2.55056	2.33858	2.81080	2.89820	2.91122	2.72588	2.83482	2.82855	2.42042	2.57186	2.71610	2.64924	2.67908	12
13	REVENUE TAX FACTOR	0.00072	0.00184	0.00168	0.00202	0.00209	0.00210	0.00196	0.00204	0.00204	0.00174	0.00185	0.00196	0.00191	0.00193	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		2.55240	2.34026	2.81282	2.90029	2.91332	2.72784	2.83686	2.83059	2.42216	2.57371	2.71806	2.65115	2.68101	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		2.552	2.340	2.813	2.900	2.913	2.728	2.837	2.831	2.422	2.574	2.718	2.651	2.681	15

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FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 4 OF 14

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SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY	2005	GULF POWER COMPANY	RE	30,206,000			30,206,000	2.239999	3.949093	676,614
FEBRUARY	2005	GULF POWER COMPANY	RE	23,301,000			23,301,000	2.239998	4.073778	521,942
MARCH	2005	GULF POWER COMPANY	RE	23,900,000			23,900,000	2.240001	3.798092	535,360
APRIL	2005	GULF POWER COMPANY	RE	23,867,000			23,867,000	2.240001	3.747832	534,621
MAY	2005	GULF POWER COMPANY	RE	28,614,000			28,614,000	2.240000	3.750290	640,954
JUNE	2005	GULF POWER COMPANY	RE	30,462,000			30,462,000	2.240000	3.763617	682,349
JULY	2005	GULF POWER COMPANY	RE	33,121,000			33,121,000	2.240000	3.733625	741,910
AUGUST	2005	GULF POWER COMPANY	RE	33,453,000			33,453,000	2.240000	3.656476	749,347
SEPTEMBER	2005	GULF POWER COMPANY	RE	29,864,000			29,864,000	2.240001	3.735946	668,954
OCTOBER	2005	GULF POWER COMPANY	RE	25,979,000			25,979,000	2.240000	3.767039	581,930
NOVEMBER	2005	GULF POWER COMPANY	RE	24,267,000			24,267,000	2.239999	3.794577	543,581
DECEMBER	2005	GULF POWER COMPANY	RE	29,408,000			29,408,000	2.239997	3.796953	658,739
TOTAL				336,442,000	0	0	336,442,000	2.240000	3.791295	7,536,301

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SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY

MARIANNA DIVISION

RESIDENTIAL BILL COMPARISON

FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

	JANUARY 2005	FEBRUARY 2005	MARCH 2005	APRIL 2005	MAY 2005	JUNE 2005	JULY 2005
BASE RATE REVENUES ** $	24.26	24.26	24.26	24.26	24.26	24.26	24.26
FUEL RECOVERY FACTOR CENTS/KWH	4.36	4.36	4.36	4.36	4.36	4.36	4.36
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	43.55	43.55	43.55	43.55	43.55	43.55	43.55
GROSS RECEIPTS TAX	1.74	1.74	1.74	1.74	1.74	1.74	1.74
TOTAL REVENUES *** $	69.55	69.55	69.55	69.55	69.55	69.55	69.55

	AUGUST 2005	SEPTEMBER 2005	OCTOBER 2005	NOVEMBER 2005	DECEMBER 2005	PERIOD TOTAL
BASE RATE REVENUES ** $	24.26	24.26	24.26	24.26	24.26	291.12
FUEL RECOVERY FACTOR CENTS/KWH	4.36	4.36	4.36	4.36	4.36	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	43.55	43.55	43.55	43.55	43.55	522.60
GROSS RECEIPTS TAX	1.74	1.74	1.74	1.74	1.74	20.88
TOTAL REVENUES *** $	69.55	69.55	69.55	69.55	69.55	834.60

* MONTHLY AND CUMULATIVE SIX MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	10.00
CENTS/KWH	13.73
CONSERVATION FACTOR	0.530
	24.26

*** EXCLUDES FRANCHISE TAXES

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

FERNANDINA BEACH DIVISON

		(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)				
2	Nuclear Fuel Disposal Costs (E2)				
3	Coal Car Investment				
4	Adjustments to Fuel Cost				
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0		0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	8,687,929		470,890	1.84500
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)				
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)				
9	Energy Cost of Sched E Economy Purch (E9)				
10	Demand & Non Fuel Cost of Purch Power (E2)	6,396,947		470,890	1.35848
10a	Demand Costs of Purchased Power	5,899,812	*		
10b	Non-fuel Energy & Customer Costs of Purchased Power	497,135	*		
11	Energy Payments to Qualifying Facilities (E8a)	56,056		2,998	1.86978
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	15,140,932		473,888	3.19504
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	15,140,932		473,888	3.19504
14	Fuel Cost of Economy Sales (E6)				
15	Gain on Economy Sales (E6)				
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)				
17	Fuel Cost of Other Power Sales				
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0		0	0.00000
19	Net Inadvertent Interchange				
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	15,140,932		473,888	3.19504
21	Net Unbilled Sales	0	*	(0)	0.00000
22	Company Use	13,930	*	436	0.00294
23	T & D Losses	(13,930)	*	(436)	-0.00294
24	SYSTEM MWH SALES	15,140,932		473,888	3.19504
25	Wholesale MWH Sales				
26	Jurisdictional MWH Sales	15,140,932		473,888	3.19504
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	15,140,932		473,888	3.19504
27a	GSLD1 MWH Sales			126,705	
27b	Other Classes MWH Sales			347,183	
27c	GSLD1 CP KW			258,000	*
28	GPIF **				
29	TRUE-UP (OVER) UNDER RECOVERY **	1,372,544		473,888	0.28963
30	TOTAL JURISDICTIONAL FUEL COST	16,513,476		473,888	3.48468
30a	Demand Purchased Power Costs (Line 10a)	5,899,812	*		
30b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	9,241,120	*		
30c	True up Over/Under Recovery (Line 29)	1,372,544	*		

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

	FERNANDINA BEACH DIVISON	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	5,899,812		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $6.18)	1,594,440	258,000 (KW)	$6.18 /KW
33	Balance to Other Classes	4,305,372	347,183	1.24009
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	9,241,120		
35	Total KWH Purchased (Line 12)		473,888	
36	Average Cost per KWH Purchased			1.95006
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			2.00856
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	2,544,945	126,705	2.00856
39	Balance to Other Classes	6,696,175	347,183	1.92871
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	1,594,440	258,000 (KW)	$6.18 /KW
40b	Revenue Tax Factor			1.00072
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$6.18 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	2,544,945	126,705	2.00856
40e	Total Non-demand Costs Including True-up	2,544,945	126,705	2.00856
40f	Revenue Tax Factor			1.00072
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			2.01001
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	11,001,547	347,183	3.16880
41b	Less: Total Demand Cost Recovery	4,305,372 ***		
41c	Total Other Costs to be Recovered	6,696,175	347,183	1.92871
41d	Other Classes' Portion of True-up (Line 30c)	1,372,544	347,183	0.39534
41e	Total Demand & Non-demand Costs Including True-up	8,068,719	347,183	2.32405
42	Revenue Tax Factor			1.00072
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded			2.326

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

FERNANDINA BEACH DIVISON

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*4,380)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
44	RS	204,266,826	63.060%	73,955.4	1.089	1.000	80,537.4	204,266,826	62.67%	57.70%
45	GS	32,015,259	69.973%	10,446.1	1.089	1.000	11,375.8	32,015,259	8.85%	9.04%
46	GSD	104,244,617	77.702%	30,630.0	1.083	1.000	33,172.3	104,244,617	25.81%	29.45%
47	GSLD	11,350,703	83.923%	3,087.9	1.083	1.000	3,344.2	11,350,703	2.60%	3.21%
48	OL	1,281,755	565.360%	51.8	1.089	1.000	56.4	1,281,755	0.04%	0.36%
49	SL	834,724	565.360%	33.7	1.089	1.000	36.7	834,724	0.03%	0.24%
	TOTAL	353,993,884		118,204.9			128,522.8	353,993,884	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (12)	(14) (13)/(1)	(15) (14) * 1.00072	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocation Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
50	RS	57.83%	4.44%	62.27%	$2,680,955	0.01312	0.01313	0.02326	0.03639
51	GS	8.17%	0.70%	8.87%	381,886	0.01193	0.01194	0.02326	0.03520
52	GSD	23.82%	2.27%	26.09%	1,123,272	0.01078	0.01079	0.02326	0.03405
53	GSLD	2.40%	0.25%	2.65%	114,092	0.01005	0.01006	0.02326	0.03332
54	OL	0.04%	0.03%	0.07%	3,014	0.00235	0.00235	0.02326	0.02561
55	SL	0.03%	0.02%	0.05%	2,153	0.00258	0.00258	0.02326	0.02584
	TOTAL	92.29%	7.71%	100.00%	$4,305,372				

(2) From Florida Power & Light Co. 2003 Load Research results.
(4) From Fernandina Beach Rate Case 881056-EI.

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FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2005 - DECEMBER 2005
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Fernandina Beach Division

Over-recovery of purchased power costs for the period January 2004 - December 2004. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2004.)(Estimated)	$	(1,372,544)
Estimated kilowatt hour sales for the months of January 2005 - December 2005 as per estimate filed with the Commission. (Excludes GSLD1 customers)		353,993,884
Cents per kilowatt hour necessary to refund over-recovered purchased power costs over the period January 2005 - December 2005.		-0.38773

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SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

LINE NO.			(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(h) JULY	(i) AUGUST	(j) SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) TOTAL PERIOD	LINE NO.
			ESTIMATED													
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	NUCLEAR FUEL DISPOSAL														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		713,006	678,712	641,283	582,428	659,708	891,980	877,384	912,469	809,151	638,140	514,118	769,550	8,687,929	3
3a	DEMAND & NON FUEL COST OF PUR POWER		552,872	559,620	555,858	405,958	466,774	562,391	706,874	715,555	532,843	440,593	406,187	491,422	6,396,947	3a
3b	QUALIFYING FACILITIES		3,099	4,392	2,917	6,468	2,508	5,732	6,865	4,393	5,071	4,600	3,545	6,466	56,056	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		1,268,977	1,242,724	1,200,058	994,854	1,128,990	1,460,103	1,591,123	1,632,417	1,347,065	1,083,333	923,850	1,267,438	15,140,932	5
5a	LESS: TOTAL DEMAND COST RECOVERY		376,964	375,680	332,888	289,754	342,788	410,840	415,148	413,612	406,910	323,546	262,010	355,232	4,305,372	5a
5b	TOTAL OTHER COST TO BE RECOVERED		892,013	867,044	867,170	705,100	786,202	1,049,263	1,175,975	1,218,805	940,155	759,787	661,840	912,206	10,835,560	5b
6	APPORTIONMENT TO GSLD CLASS		344,946	344,949	344,949	344,949	344,949	344,949	344,949	344,949	344,949	344,949	344,949	344,949	4,139,385	6
6a	BALANCE TO OTHER CLASSES		547,067	522,095	522,221	360,151	441,253	704,314	831,026	873,856	595,206	414,838	316,891	567,257	6,696,175	6a
6b	SYSTEM KWH SOLD (MWH)		38,811	37,021	34,914	31,914	35,891	48,652	47,922	49,691	44,128	34,834	28,055	42,056	473,888	6b
7	GSLD MWH SOLD		10,559	10,559	10,560	10,559	10,559	10,560	10,551	10,559	10,559	10,562	10,559	10,559	126,705	7
7a	BALANCE MWH SOLD OTHER CLASSES		28,252	26,462	24,354	21,355	25,332	38,092	37,371	39,132	33,569	24,272	17,496	31,497	347,183	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		1.93638	1.97297	2.1443	1.68651	1.7419	1.84897	2.22373	2.23308	1.7731	1.70915	1.81121	1.80099	1.92871	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		1.93638	1.97297	2.14430	1.68651	1.74190	1.84897	2.22373	2.23308	1.77310	1.70915	1.81121	1.80099	1.92871	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)	1,372,544	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	0.39534	11
12	TOTAL		2.33172	2.36831	2.53964	2.08185	2.13724	2.24431	2.61907	2.62842	2.16844	2.10449	2.20655	2.19633	2.32405	12
13	REVENUE TAX FACTOR	0.00072	0.00168	0.00171	0.00183	0.00150	0.00154	0.00162	0.00189	0.00189	0.00156	0.00152	0.00159	0.00158	0.00167	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		2.33340	2.37002	2.54147	2.08335	2.13878	2.24593	2.62096	2.63031	2.17000	2.10601	2.20814	2.19791	2.32572	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		2.333	2.37	2.541	2.083	2.139	2.246	2.621	2.63	2.17	2.106	2.208	2.198	2.326	15

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FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL KWH PURCHASED	(5) KWH FOR OTHER UTILITIES	(6) KWH FOR INTERRUPTIBLE	(7) KWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,645,324			38,645,324	1.844999	3.275630	713,006
FEBRUARY 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	36,786,543			36,786,543	1.845001	3.366264	678,712
MARCH 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	34,757,897			34,757,897	1.844999	3.444227	641,283
APRIL 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	31,567,895			31,567,895	1.845001	3.130985	582,428
MAY 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	35,756,543			35,756,543	1.844999	3.150422	659,708
JUNE 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	48,345,789			48,345,789	1.845000	3.008268	891,980
JULY 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	47,554,698			47,554,698	1.845000	3.331444	877,384
AUGUST 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	49,456,290			49,456,290	1.845001	3.291844	912,469
SEPTEMBER 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	43,856,398			43,856,398	1.845001	3.059973	809,151
OCTOBER 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	34,587,543			34,587,543	1.845000	3.118848	638,140
NOVEMBER 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	27,865,498			27,865,498	1.844998	3.302668	514,118
DECEMBER 2005	JACKSONVILLE ELECTRIC AUTHORITY	MS	41,710,045			41,710,045	1.844999	3.023185	769,550
TOTAL			470,890,463	0	0	470,890,463	1.845000	3.203479	8,687,929

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FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2005	JEFFERSON SMURFIT CORPORATION		165,700			165,700	1.870247	1.870247	3,099
FEBRUARY 2005	JEFFERSON SMURFIT CORPORATION		234,888			234,888	1.869827	1.869827	4,392
MARCH 2005	JEFFERSON SMURFIT CORPORATION		156,000			156,000	1.869872	1.869872	2,917
APRIL 2005	JEFFERSON SMURFIT CORPORATION		345,876			345,876	1.870034	1.870034	6,468
MAY 2005	JEFFERSON SMURFIT CORPORATION		134,098			134,098	1.870274	1.870274	2,508
JUNE 2005	JEFFERSON SMURFIT CORPORATION		306,500			306,500	1.870147	1.870147	5,732
JULY 2005	JEFFERSON SMURFIT CORPORATION		367,098			367,098	1.870073	1.870073	6,865
AUGUST 2005	JEFFERSON SMURFIT CORPORATION		234,945			234,945	1.869799	1.869799	4,393
SEPTEMBER 2005	JEFFERSON SMURFIT CORPORATION		271,200			271,200	1.869838	1.869838	5,071
OCTOBER 2005	JEFFERSON SMURFIT CORPORATION		245,987			245,987	1.870018	1.870018	4,600
NOVEMBER 2005	JEFFERSON SMURFIT CORPORATION		189,564			189,564	1.870081	1.870081	3,545
DECEMBER 2005	JEFFERSON SMURFIT CORPORATION		345,765			345,765	1.870056	1.870056	6,466
TOTAL			2,997,621	0	0	2,997,621	1.870016	1.870016	56,056

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FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

	JANUARY 2005	FEBRUARY 2005	MARCH 2005	APRIL 2005	MAY 2005	JUNE 2005	JULY 2005
BASE RATE REVENUES ** $	24.26	24.26	24.26	24.26	24.26	24.26	24.26
FUEL RECOVERY FACTOR CENTS/KWH	3.64	3.64	3.64	3.64	3.64	3.64	3.64
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	36.39	36.39	36.39	36.39	36.39	36.39	36.39
GROSS RECEIPTS TAX	0.62	0.62	0.62	0.62	0.62	0.62	0.62
TOTAL REVENUES *** $	61.27	61.27	61.27	61.27	61.27	61.27	61.27

	AUGUST 2005	SEPTEMBER 2005	OCTOBER 2005	NOVEMBER 2005	DECEMBER 2005	PERIOD TOTAL
BASE RATE REVENUES ** $	24.26	24.26	24.26	24.26	24.26	291.12
FUEL RECOVERY FACTOR CENTS/KWH	3.64	3.64	3.64	3.64	3.64	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	36.39	36.39	36.39	36.39	36.39	436.68
GROSS RECEIPTS TAX	0.62	0.62	0.62	0.62	0.62	7.44
TOTAL REVENUES *** $	61.27	61.27	61.27	61.27	61.27	735.24

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	10.00
CENTS/KWH	13.73
CONSERVATION FACTOR	0.530
	24.26

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
DOCKET NO. 040001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 14 OF 14

REVISED

GULF POWER COMPANY
COAL SUPPLIERS
January 1, 2003 – December 31, 2003

Contract Coal Suppliers	Tons Purchased (1)	
Peabody Coal Sales	1,876,045	
Black Mountain Resources	185,351	
Arch Coal Sales - West Elk	951,312	
Twenty Mile Coal Company	301,535	
TOTAL Contract Coal		3,314,243

Spot Coal Suppliers	Tons Purchased (1)	
Peabody Coaltrade	589,204	
Mississippi Power Co.	23,906	
Interocean Coal Sales	1,091,739	
TOTAL Spot Coal		1,704,849
GRAND TOTAL COAL PURCHASES		5,019,092

(1) Excludes Plant Scherer: Coal purchases at Plant Scherer are reported on a MMBTU basis. Coal purchases by owner expressed in tons is not maintained.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 23
COMPANY/ Gulf
WITNESS: H. R. Ball (HRB-1)
DATE: 11-08-04

Florida Public Service Commission
Docket No. 040001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB-1)
Schedule 2
Page 1 of 1

This information has been provided pursuant to the Request for Confidential Classification filed on April 1, 2004.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 040001-EI

Before me the undersigned authority, personally appeared H. R. Ball, who being first duly sworn, deposes, and says that he is the Fuel Manager at Gulf Power Company, a Maine corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

H. R. Ball
Fuel Manager

Sworn to and subscribed before me this 29th day of March, 2004

Acknowledged before me this date who is personally known to me and who did not take an oath.

Notary Public, State of Florida at Large

CANDACE KLINGLESMITH
MY COMMISSION # DD 194327
EXPIRES: May 18, 2007
Bonded Thru Notary Public Underwriters

Commission Number: DD194327

Commission Expires: 5-18-07

GULF POWER COMPANY
PROJECTED VS. ACTUAL FUEL COST OF SYSTEM NET GENERATION

Cents / KWH Fuel Cost [1]

Period Ending	Projected	Actual	% Difference
March 1995	1.8874	2.0388	8.02
September 1995	2.0456	2.0344	(0.55)
March 1996	1.9795	2.0743	4.79
September 1996	2.0405	1.9639	(3.75)
March 1997	1.9282	2.0332	5.45
September 1997	1.9434	1.9431	(0.02)
March 1998	1.8734	1.8647	(0.46)
September 1998	1.5916	1.6361	2.80
December 1999	1.5291	1.5696	2.65
December 2000	1.6048	1.6460	2.57
December 2001	1.5782	1.7218	9.10
December 2002	2.0241	2.0505	1.30
December 2003	1.9639	2.1133	7.61
December 2004	2.0934		
December 2005	2.5014		

[1] Line No. 1 from FPSC Schedule A-1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO 24
COMPANY/ Gulf
WITNESS. H.R. Ball (HRB-2)
DATE 11-08-04

Florida Public Service Commission
Docket No. 040001-EI
GULF POWER COMPANY
Witness: T. A. Davis
Exhibit No. _____ (TAD-1)
Schedule 1

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
January 2003 - December 2003

1.	Estimated over/(under) - recovery for the period January 2003 - December 2003 (Schedule E1-A approved in Order No. PSC-03-1461-FOF-EI dated December 22, 2003)	$ (23,923,505)
2.	Actual over/(under)-recovery for the period January 2003 - December 2003 (DECEMBER 2003 Schedule A-2, Pg. 2 of 3, "Period-to-Date", Lines 7and 8)	(21,388,487)
3.	Amount to be refunded/(recovered) in the JANUARY 2005 - DECEMBER 2005 projection period (Line 2 - Line 1)	$ 2,535,018

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO 25
COMPANY/ GULF
WITNESS. T.A. Davis (TAD-1)
DATE: 11-08-04

Florida Public Service Commission
Docket No. 040001-EI
GULF POWER COMPANY
Witness: T. A. Davis
Exhibit No. ____ (TAD -1)
SCHEDULE CCA-1
Revised 4/1/04

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
JANUARY 2003 - DECEMBER 2003

1. Estimated over/(under)-recovery for the period JANUARY 2003 - DECEMBER 2003 (Schedule CCE-1a approved in Order No. PSC-03-1461-FOF-EI dated December 22, 2003)	$ 1,058,876
2. Actual over/(under)-recovery for the period JANUARY 2003 - DECEMBER 2003 (Schedule CCA-2 Line 10+11 in the Total column)	2,112,655
3. Amount to be refunded/(recovered) in the JANUARY 2005 - DECEMBER 2005 projection period (Line 2 - Line 1)	$ 1,053,779

SCHEDULE CCA-2
Revised 4/1/04

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD JANUARY 2003 - DECEMBER 2003

	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	ACTUAL TOTAL
1. IIC Payments / (Receipts) ($)	576,317	4,193	192,099	(9,415)	(102,417)	374,563	1,404,921	2,183,978	1,936,562	34,769	(48,418)	32,057	6,579,209
2. Transmission Revenue ($)	(51,592)	(78,086)	(31,701)	(44,371)	(39,430)	(22,413)	(31,968)	(36,890)	(16,169)	(17,100)	(8,525)	(28,942)	(407,187)
3. Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
4. Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	586,927	(11,691)	222,600	8,416	(79,645)	414,352	1,435,155	2,209,290	1,982,595	79,871	5,259	65,317	6,918,446
5. Jurisdictional %	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187
6. Jurisdictional Capacity Payments / (Receipts) (Line 4 x 5) ($)	566,395	(11,282)	214,813	8,122	(76,858)	399,857	1,384,952	2,132,006	1,913,241	77,077	5,075	63,033	6,676,429
7. Jurisdictional Capacity Cost Recovery Revenue Net of Taxes ($)	832,086	588,475	600,711	633,690	804,474	850,248	896,302	909,151	797,922	656,741	618,482	1,052,895	9,241,177
8. True-Up Provision ($)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(466,176)
9. Jurisdictional Capacity Cost Recovery Revenue (Line 7 + 8) ($)	793,238	549,627	561,863	594,842	765,626	811,400	857,454	870,303	759,074	617,893	579,634	1,014,047	8,775,001
10. Over/(Under) Recovery (Line 9 - 6) ($)	226,843	560,909	347,050	586,720	842,485	411,543	(527,497)	(1,261,703)	(1,154,167)	540,816	574,559	951,015	2,098,574
11. Interest Provision ($)	(149)	308	796	1,277	2,047	2,500	2,305	1,622	599	361	861	1,554	14,081
12. Beginning Balance True-Up & Interest Provision ($)	(272,479)	(6,937)	593,129	979,823	1,606,668	2,490,048	2,942,939	2,456,595	1,235,362	120,642	700,667	1,314,935	(272,479)
13. True-Up Collected/(Refunded) ($)	38,848	38,848	38,848	38,848	38,848	38,848	38,848	38,848	38,848	38,848	38,848	38,848	466,176
14. End Of Period Total Net True-Up (Lines 10 + 11 + 12 + 13) ($)	(6,937)	593,129	979,823	1,606,668	2,490,048	2,942,939	2,456,595	1,235,362	120,642	700,667	1,314,935	2,306,352	

SCHEDULE CCA-3
Revised 4/1/04

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2003 - DECEMBER 2003

	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	TOTAL
1. Beginning True-Up Amount ($)	(272,479)	(6,906)	593,188	979,882	1,606,727	2,490,107	2,942,998	2,456,654	1,235,421	120,701	700,726	1,314,994	
3. Ending True-Up Amount Before Interest ($)	(6,757)	592,880	979,086	1,605,450	2,488,059	2,940,496	2,454,349	1,233,799	120,103	700,365	1,314,135	2,304,857	
4. Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	(279,236)	585,974	1,572,274	2,585,332	4,094,786	5,430,603	5,397,347	3,690,453	1,355,524	821,066	2,014,861	3,619,851	
5. Average True-Up Amount ($)	(139,618)	292,987	786,137	1,292,666	2,047,393	2,715,302	2,698,674	1,845,227	677,762	410,533	1,007,431	1,809,926	
6. Interest Rate - First Day of Reporting Business Month	0.012900	0.012700	0.012500	0.011800	0.011900	0.012100	0.010000	0.010500	0.010600	0.010600	0.010500	0.010000	
7. Interest Rate - First Day of Subsequent Business Month	0.012700	0.012500	0.011800	0.011900	0.012100	0.010000	0.010500	0.010600	0.010600	0.010500	0.010000	0.010600	
8. Total Interest Rate (Lines 5 + 6)	0.025600	0.025200	0.024300	0.023700	0.024000	0.022100	0.020500	0.021100	0.021200	0.021100	0.020500	0.020600	
9. Average Interest Rate	0.012800	0.012600	0.012150	0.011850	0.012000	0.011050	0.010250	0.010550	0.010600	0.010550	0.010250	0.010300	
10. Monthly Average Interest Rate (1/12 Of Line 8)	0.001067	0.001050	0.001013	0.000988	0.001000	0.000921	0.000854	0.000879	0.000883	0.000879	0.000854	0.000858	
11. Interest Provision For the Month (Lines 4 X 9) ($)	(149)	308	796	1,277	2,048	2,502	2,305	1,622	598	361	859	1,554	14,081

SCHEDULE E-1A

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 2004 (Sch. E-1B, page 2, line 9)	($29,107,969)
2.	Final over/(under)-recovery JANUARY - DECEMBER 2003 (EXHIBIT No.____(TAD-1), filed April 1, 2004	2,535,018
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in JANUARY 2005 - DECEMBER 2005 (Schedule E1, Line 28)	($26,572,951)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005	11,032,273,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.2409

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 26
COMPANY/ Gulf
WITNESS: T. A. Davis (TAD-2)
DATE: 11-08-04

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	28,588,955.96	26,528,981.43	22,286,468.42	26,664,669.64	32,124,877.67	33,132,736.65	$169,326,689.77
	1a	Fuel Cost of Hedging Settlement	(997,750.00)	(164,350.00)	541,100.00	(693,600.00)	(744,900.00)	(1,491,210.00)	(3,550,710.00)
	1b	Fuel Cost of Hedging Support	2,537.49	1,879.56	1,541.14	1,656.50	2,251.24	1,265.75	11,131.68
	2	Fuel Cost of Power Sold	(8,291,799.04)	(9,575,999.98)	(9,263,064.53)	(8,992,603.34)	(11,091,183.10)	(8,244,548.81)	(55,459,198.80)
	3	Fuel Cost of Purchased Power	2,390,298.72	2,420,900.76	4,004,189.98	4,928,139.04	5,591,431.22	4,436,332.60	23,771,292.32
	3a	Demand & Non-Fuel Cost Of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3b	Energy Payments to Qualified Facilities	36,721.00	23,625.00	54,159.00	22,333.00	25,724.00	56,281.00	218,843.00
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	Other Generation	131,338.97	137,774.76	151,479.14	150,528.35	149,955.63	154,795.10	875,871.95
	6	Adjustment to Fuel Cost	(99,721.17)	111,683.30	(2,332.30)	7,899.11	19,335.24	26,227.54	63,091.72
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	$21,760,581.93	$19,484,494.83	$17,773,540.85	$22,089,022.30	$26,077,491.90	$28,071,879.83	$135,257,011.64
B	1	Jurisdictional KWH Sales	900,413,364	829,782,367	774,360,621	769,393,414	980,459,512	1,069,388,710	5,323,797,988
	2	Non-Jurisdictional KWH Sales	32,378,859	29,080,350	25,031,604	24,974,940	31,550,354	34,499,450	177,515,557
	3	TOTAL SALES (Lines B1 + B2)	932,792,223	858,862,717	799,392,225	794,368,354	1,012,009,866	1,103,888,160	5,501,313,545
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.5288%	96.6141%	96.8687%	96.8560%	96.8824%	96.8747%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	$22,142,468.41	$20,235,607.77	$18,971,959.87	$18,883,164.05	$24,058,701.90	$26,282,204.72	$130,574,106.72
	2	True-Up Provision	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(11,433,291.96)
	2a	Incentive Provision	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(215,804.58)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$20,200,952.32	$18,294,091.68	$17,030,443.78	$16,941,647.96	$22,117,185.81	$24,340,688.63	$118,925,010.18
	4	Fuel & Net Power Transactions (Line A7)	$21,760,581.93	$19,484,494.83	$17,773,540.85	$22,089,022.30	$26,077,491.90	$28,071,879.83	$135,257,011.64
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7x Line B4 x 1.0007)	21,019,932.27	18,837,946.66	17,229,049.86	21,409,519.62	25,282,185.16	27,213,585.55	$130,992,219.12
	6	Over/(Under) Recovery (Line C3-C5)	(818,979.95)	(543,854.98)	(198,606.08)	(4,467,871.66)	(3,164,999.35)	(2,872,896.92)	($12,067,208.94)
	7	Interest Provision	(17,235.59)	(15,571.20)	(13,363.08)	(14,076.17)	(16,157.34)	(19,613.63)	($96,017.02)
	8	Prior Period Adjustment	0.00	0.00	706,360.01	0.00	0.00	0.00	$706,360.01
	9	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2004 - JUNE 2004							($11,456,865.95)

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

			JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	39,370,000.00	39,635,000.00	36,094,000.00	32,383,000.00	27,021,000.00	29,016,000.00	$372,845,689.77
	1a	Fuel Cost of Hedging Settlement	0.00	0.00	0.00	0.00	0.00	0.00	($3,550,710.00)
	1b	Fuel Cost of Hedging Support	2,757.00	2,757.00	2,757.00	2,757.00	2,757.00	2,759.00	$27,675.68
	2	Fuel Cost of Power Sold	(14,209,000.00)	(14,260,000.00)	(13,520,000.00)	(9,400,000.00)	(10,667,000.00)	(10,356,000.00)	($127,871,198.80)
	3	Fuel Cost of Purchased Power	3,401,000.00	3,812,000.00	845,000.00	1,581,000.00	1,538,000.00	2,563,000.00	$37,511,292.32
	3a	Demand & Non-Fuel Cost Of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities	0.00	0.00	0.00	0.00	0.00	0.00	$218,843.00
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation	257,000.00	257,000.00	249,000.00	257,000.00	249,000.00	257,000.00	$2,401,871.95
	6	Adjustment to Fuel Cost	0.00	0.00	0.00	0.00	0.00	0.00	$63,091.72
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	$28,821,757.00	$29,446,757.00	$23,670,757.00	$24,823,757.00	$18,143,757.00	$21,482,759.00	$281,646,555.64
B	1	Jurisdictional KWH Sales	1,121,280,000	1,121,219,000	928,542,000	820,717,000	711,070,000	814,258,000	10,840,883,988
	2	Non-Jurisdictional KWH Sales	38,218,000	38,147,000	33,249,000	29,300,000	27,425,000	30,672,000	374,526,557
	3	TOTAL SALES (Lines B1 + B2)	1,159,498,000	1,159,366,000	961,791,000	850,017,000	738,495,000	844,930,000	11,215,410,545
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.7039%	96.7097%	96.5430%	96.5530%	96.2864%	96.3699%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes) (1)	$27,552,437.45	$27,550,938.53	$22,816,419.96	$20,166,910.85	$17,472,631.01	$20,008,198.32	$266,141,642.84
	2	True-Up Provision	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.74)	($22,866,584.00)
	2a	Incentive Provision	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.51)	($431,609.24)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$25,610,921.36	$25,609,422.44	$20,874,903.87	$18,225,394.76	$15,531,114.92	$18,066,682.07	$242,843,449.60
	4	Fuel & Net Power Transactions (Line A7)	$28,821,757.00	$29,446,757.00	$23,670,757.00	$24,823,757.00	$18,143,757.00	$21,482,759.00	$281,646,555.64
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0007)	27,891,273.30	28,497,804.86	22,868,455.65	23,984,859.75	17,482,199.42	20,717,405.40	$272,434,217.50
	6	Over/(Under) Recovery (Line C3-C5)	(2,280,351.94)	(2,888,382.42)	(1,993,551.78)	(5,759,464.99)	(1,951,084.50)	(2,650,723.33)	($29,590,767.90)
	7	Interest Provision (2)	(10,240.59)	(20,976.82)	(21,526.54)	(23,495.12)	(25,444.66)	(25,860.41)	($223,561.00)
	8	Prior Period Adjustment	0.00	0.00	0.00	0.00	0.00	0.00	$706,360.01
	9	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2004 - DECEMBER 2004							($29,107,968.89)

Note 1: Estimated Revenues based on the 2004 Fuel Factor excluding revenue taxes of 2.4572 ¢/KWH
Note 2: Interest Calculated for July through December at June's rate of 0.0988

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

	DOLLARS				KWH				¢/KWH			
	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMT.	%
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1 Fuel Cost of System Net Generation (A3)	372,845,690	340,226,335	32,619,355	9.59	15,605,983,000	16,251,250,000	(645,267,000)	(3.97)	2.3891	2.0935	0.2956	14.12
1a Fuel Cost of Hedging Settlement	(3,550,710)	0										
2 Hedging Support Costs	27,676	33,086	(5,410)	(16.35)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3 Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4 Other Generation	2,401,872	19,205	2,382,667	12,406.49	78,019,000	790,000	77,229,000	9,775.82	3.0786	2.431	0.6476	26.64
5 Adjustment to Fuel Cost	63,092											
5 TOTAL COST OF GENERATED POWER	371,787,619	340,278,626	31,508,993	9.26	15,684,002,000	16,252,040,000	(568,038,000)	(3.50)	2.3705	2.0938	0.2767	13.22
6 Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
7 Energy Cost of Schedule C&X Econ. Purchases (Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8 Energy Cost of Other Economy Purchases (Nonbroker) (A9)	37,511,292	12,776,000	24,735,292	193.61	1,032,349,249	477,038,000	555,311,249	116.41	3.6336	2.6782	0.9554	35.67
9 Energy Cost of Schedule E Economy Purchases (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
10 Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11 Energy Payments to Qualifying Facilities (A9a)	218,843	0	218,843	#N/A	6,578,895	0	6,578,895	#N/A	3.3264	#N/A	#N/A	#N/A
12 TOTAL COST OF PURCHASED POWER	37,730,135	12,776,000	24,954,135	195.32	1,038,928,144	477,038,000	561,890,144	117.79	3.6316	2.6782	0.9534	35.60
13 Total Available KWH (Lines 5 + Line 12)	409,517,754	353,054,626	56,463,128	15.99	16,722,930,144	16,729,078,000	(6,147,856)	(0.04)				
14 Fuel Cost of Economy Sales (A6)	(61,778,195)	(2,289,000)	(59,489,195)	(2,598.92)	(160,861,993)	(74,677,000)	(86,184,993)	(115.41)	(38.4045)	(3.0652)	(35.3393)	(1,152.92)
15 Gain on Economy Sales (A6)	(15,752,402)	(363,000)	(15,369,402)	(4,012.90)			0	#N/A	#N/A	#N/A	#N/A	#N/A
16 Fuel Cost of Unit Power Sales (A6)	(16,568,637)	(26,458,000)	9,889,363	37.38	(1,431,724,048)	(1,561,911,000)	130,186,952	8.34	(1.1573)	(1.6940)	0.5367	31.68
17 Fuel Cost of Other Power Sales (A6)	(33,771,965)	(79,395,000)	45,623,035	57.46	(3,202,473,809)	(3,440,414,000)	237,940,191	6.92	(1.0546)	(2.3077)	1.2531	54.30
18 TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 14+15+16+17)	(127,871,199)	(108,525,000)	(19,346,199)	(17.83)	(4,795,059,850)	(5,077,002,000)	281,942,150	5.55	(2.8667)	(2.1376)	(0.5291)	(24.75)
19 Net Inadvertent Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
20 TOTAL FUEL & NET POWER TRANSACTIONS (LINES 5+12+18+19)	281,646,556	244,529,626	37,116,930	15.18	11,927,870,294	11,652,076,000	275,794,294	2.37	2.3612	2.0986	0.2626	12.51
21 Net Unbilled Sales	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
22 Company Use *	560,171	545,195	14,976	2.75	23,723,999	25,979,000	(2,255,001)	(8.68)	2.3612	2.0986	0.2626	12.51
23 T & D Losses *	16,262,429	14,395,200	1,867,229	12.97	688,735,750	685,943,000	2,792,750	0.41	2.3612	2.0986	0.2626	12.51
24 TERRITORIAL (SYSTEM) SALES	281,646,556	244,529,626	37,116,930	15.18	11,215,410,545	10,940,154,000	275,256,545	2.52	2.5112	2.2352	0.2760	12.35
25 Wholesale Sales	9,402,909	8,348,785	1,054,124	12.63	374,526,557	373,514,000	1,012,557	0.27	2.5106	2.2352	0.2754	12.32
26 Jurisdictional Sales	272,243,647	236,180,841	36,062,806	15.27	10,840,883,988	10,566,640,000	274,243,988	2.60	2.5113	2.2352	0.2761	12.35
26a Jurisdictional Loss Multiplier***	1.0007	1.0007										
27 Jurisdictional Sales Adj. for Line Losses (Line 26 x 1.0007)	272,434,218	236,346,168	36,088,050	15.27	10,840,883,988	10,566,640,000	274,243,988	2.60	2.5130	2.2367	0.2763	12.35
28 TRUE-UP **	22,866,584	22,866,584	0	0.00	10,840,883,988	10,566,640,000	274,243,988	2.60	0.2109	0.2164	(0.0055)	(2.54)
29 TOTAL JURISDICTIONAL FUEL COST	295,300,802	259,212,752	36,088,050	13.92	10,840,883,988	10,566,640,000	274,243,988	2.60	2.7239	2.4531	0.2708	11.04
30 Revenue Tax Factor									1.00072	1.00072		
31 Fuel Factor Adjusted for Revenue Taxes									2.7259	2.4549	0.2710	11.04
32 GPIF Reward / (Penalty) **	431,920	431,920	0	0.00	10,840,883,988	10,566,640,000	274,243,988	2.60	0.0040	0.0041	(0.0001)	(2.44)
33 Fuel Factor Adjusted for GPIF Reward / (Penalty)									2.7299	2.459	0.2709	11.02
34 FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)									2.730	2.459	0.271	11.02

* Included for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
Note: Amounts Included in the Estimated/Actual Column represent 8 months actual and 4 months estimate.

Purchased Power Capacity Cost Recovery Clause
Calculation of True-up
Gulf Power Company
January 2005 - December 2005

1	Estimated over/(under)-recovery, January 2004 - December 2004 (Schedule CCE-1b-1, Line 15)	$817,151
2	Final True-Up, January 2003 - December 2003 (Exhibit No.____(TAD-1), filed April 1, 2004	1,053,779
3	Total Over/(Under)-Recovery (Line 1 & 2) (To be included in January 2005 - December 2005)	$1,870,930
4	Jurisdictional KWH sales, January 2005 - December 2005	11,032,273,000
5	True-up Factor (Line 3 / Line 4) x 100 (Cents/KWH)	(0.0170)

Schedule CCE-1b

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2004 - December 2004

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	1,265,929	353,640	464,415	7,329	41,220	1,632,176	6,286,325	5,666,244	2,360,242	199,560	67,649	144,635	18,731,384
2	Projected Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3	Transmission Revenue ($)	(56,915)	(37,118)	(31,779)	(15,372)	(28,687)	(20,062)	(13,000)	(7,000)	(11,000)	(7,000)	(9,000)	(7,000)	(243,933)
4	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	1,271,216	378,724	514,838	54,159	74,735	1,674,316	6,335,527	5,743,446	2,411,444	254,762	120,851	199,837	19,233,875
5	Jurisdictional %	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	
6	Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	1,226,747	365,476	496,828	52,264	72,122	1,808,750	6,113,902	5,542,533	2,327,069	245,869	116,623	192,846	18,561,047
7	Retail KWH Sales							1,121,280,000	1,121,219,000	928,542,000	820,717,000	711,070,000	814,256,000	
8	Purchased Power Capacity Cost Recovery Factor (¢/KWH)							0.167	0.167	0.167	0.167	0.167	0.167	
9	Capacity Cost Recovery Revenues (Line 7 x Line 8/100) ($)	1,606,955	1,364,327	1,256,441	1,242,257	1,612,485	1,794,023	1,872,536	1,872,436	1,550,665	1,370,597	1,187,467	1,359,811	18,108,022
10	Revenue Taxes (Line 9 x .00072) ($)*	1,156	997	904	894	1,161	1,292	1,348	1,348	1,116	987	855	979	13,037
11	True-Up Provision ($)	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	1,252,572
12	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 9 - Line 10 + Line 11) ($)	1,709,180	1,467,711	1,358,918	1,345,744	1,715,705	1,897,112	1,975,571	1,975,469	1,653,930	1,473,991	1,291,013	1,463,213	19,347,557
13	Over/(Under) Recovery (Line 12 - Line 6) ($)	462,433	1,122,235	862,090	1,293,480	1,643,583	88,362	(4,138,331)	(3,567,064)	(673,159)	1,228,122	1,174,390	1,270,367	786,510
14	Interest Provision ($)	2,173	2,676	3,337	4,240	5,547	7,108	5,015	1,110	(1,066)	(916)	166	1,271	30,641
15	Total Estimated True-Up for the Period January 2003 - December 2003 (Lines 13 + 14) ($)													817,151

NOTE 1: Interest is Calculated for July - December at June's rate of 0.0966 %
NOTE 2: Actual IIC Payments for January through June include Market Capacity Payments

SCHEDULE E-1

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

Line				(a) $	(b) KWH	(c) ¢ / KWH
1	Fuel Cost of System Net Generation		E-3	393,442,768	15,728,660,000	2.5014
2	Nuclear Fuel Disposal Costs		E-2			#N/A
3	Coal Car Investment					#N/A
4	Other Generation		E-3	2,795,957	101,010,000	2.7680
5	Hedging Administration Costs		E-2	33,086		#N/A
6	**Total Cost of Generated Power**	(Line 1 - 5)		396,271,811	15,829,670,000	2.5033
7	Fuel Cost of Purchased Power (Exclusive of Economy)		E-7			#N/A
8	Energy Cost of Schedule C & X Econ. Purch.		E-9			#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker)		E-9	18,804,000	536,336,000	3.5060
10	Energy Cost of Schedule E Economy Purch.		E-9			#N/A
11	Capacity Cost of Schedule E Economy Purchases		E-2			#N/A
12	Energy Payments to Qualifying Facilities		E-8			#N/A
13	**Total Cost of Purchased Power**	(Line 6 - 12)		18,804,000	536,336,000	3.5060
14	**Total Available KWH**	(Line 5 + 13)			16,366,006,000	
15	Fuel Cost of Economy Sales		E-6	(2,993,000)	(73,662,000)	4.0632
16	Gain on Economy Sales		E-6	(2,627,000)		#N/A
17	Fuel Cost of Unit Power Sales		E-6	(26,327,000)	(1,404,369,000)	1.8746
18	Fuel Cost of Other Power Sales			(89,596,000)	(2,743,151,000)	3.2662
19	**Total Fuel Cost & Gains on Power Sales**	(Line 15 -18)		(121,543,000)	(4,221,182,000)	2.8794
20	Net Inadvertant Interchange			0	0	#N/A
21	**Total Fuel & Net Power Trans.**	(Line 6+13+19+20)		293,532,811	12,144,824,000	2.4169
22	Net Unbilled Sales *			0	0	#N/A
23	Company Use *			591,923	24,491,000	2.4169
24	T & D Losses *			17,104,401	707,700,000	2.4169
25	**System KWH Sales**			293,532,811	11,412,633,000	2.5720
26	Wholesale KWH Sales			9,782,859	380,360,000	2.5720
27	Jurisdictional KWH Sales			283,749,952	11,032,273,000	2.5720
27a	Jurisdictional Line Loss Multiplier			1.0007		1.0007
28	Jurisdictional KWH Sales Adjusted for Line Losses			283,948,577	11,032,273,000	2.5738
29	**True-Up ****			26,572,951	11,032,273,000	0.2409
30	**Total Jurisdictional Fuel Cost**			310,521,528	11,032,273,000	2.8147
31	Revenue Tax Factor					1.00072
32	Fuel Factor Adjusted For Revenue Taxes					2.8167
33	GPIF Reward/(Penalty) **			625,280	11,032,273,000	0.0057
34	Fuel Factor Adjusted for GPIF					2.8224
35	**Fuel Factor Rounded to Nearest .001(¢ / KWH)**					**2.822**

*For informational purposes only
** Calculation Based on Jurisdictional KWH Sales

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 27
COMPANY/ Gulf
WITNESS: T.A. Davis (TAD-3)
DATE: 11-08-04

SCHEDULE E-1A

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 2004 (Sch. E-1B, page 2, line 9)	($29,107,969)
2.	Final over/(under)-recovery JANUARY - DECEMBER 2003 (EXHIBIT No.____(TAD-1), filed April 1, 2004	2,535,018
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in JANUARY 2005 - DECEMBER 2005 (Schedule E1, Line 28)	($26,572,951)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005	11,032,273,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.2409

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	28,588,955.96	26,528,981.43	22,286,468.42	26,664,669.64	32,124,877.67	33,132,736.65	$169,326,689.77
	1a	Fuel Cost of Hedging Settlement	(997,750.00)	(164,350.00)	541,100.00	(693,600.00)	(744,900.00)	(1,491,210.00)	(3,550,710.00)
	1b	Fuel Cost of Hedging Support	2,537.49	1,879.56	1,541.14	1,656.50	2,251.24	1,265.75	11,131.68
	2	Fuel Cost of Power Sold	(8,291,799.04)	(9,575,999.98)	(9,263,064.53)	(8,992,603.34)	(11,091,183.10)	(8,244,548.81)	(55,459,198.80)
	3	Fuel Cost of Purchased Power	2,390,298.72	2,420,900.76	4,004,189.98	4,928,139.04	5,591,431.22	4,436,332.60	23,771,292.32
	3a	Demand & Non-Fuel Cost Of Purchased Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3b	Energy Payments to Qualified Facilities	36,721.00	23,625.00	54,159.00	22,333.00	25,724.00	56,281.00	218,843.00
	4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	Other Generation	131,338.97	137,774.76	151,479.14	150,528.35	149,955.63	154,795.10	875,871.95
	6	Adjustment to Fuel Cost	(99,721.17)	111,683.30	(2,332.30)	7,899.11	19,335.24	26,227.54	63,091.72
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	$21,760,581.93	$19,484,494.83	$17,773,540.85	$22,089,022.30	$26,077,491.90	$28,071,879.83	$135,257,011.64
B	1	Jurisdictional KWH Sales	900,413,364	829,782,367	774,360,621	769,393,414	980,459,512	1,069,388,710	5,323,797,988
	2	Non-Jurisdictional KWH Sales	32,378,859	29,080,350	25,031,604	24,974,940	31,550,354	34,499,450	177,515,557
	3	TOTAL SALES (Lines B1 + B2)	932,792,223	858,862,717	799,392,225	794,368,354	1,012,009,866	1,103,888,160	5,501,313,545
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.5288%	96.6141%	96.8687%	96.8560%	96.8824%	96.8747%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	$22,142,468.41	$20,235,607.77	$18,971,959.87	$18,883,164.05	$24,058,701.90	$26,282,204.72	$130,574,106.72
	2	True-Up Provision	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(11,433,291.96)
	2a	Incentive Provision	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(215,804.58)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$20,200,952.32	$18,294,091.68	$17,030,443.78	$16,941,647.96	$22,117,185.81	$24,340,688.63	$118,925,010.18
	4	Fuel & Net Power Transactions (Line A7)	$21,760,581.93	$19,484,494.83	$17,773,540.85	$22,089,022.30	$26,077,491.90	$28,071,879.83	$135,257,011.64
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7x Line B4 x 1.0007)	21,019,932.27	18,837,946.66	17,229,049.86	21,409,519.62	25,282,185.16	27,213,585.55	$130,992,219.12
	6	Over/(Under) Recovery (Line C3-C5)	(818,979.95)	(543,854.98)	(198,606.08)	(4,467,871.66)	(3,164,999.35)	(2,872,896.92)	($12,067,208.94)
	7	Interest Provision	(17,235.59)	(15,571.20)	(13,363.08)	(14,076.17)	(16,157.34)	(19,613.63)	($96,017.02)
	8	Prior Period Adjustment	0.00	0.00	706,360.01	0.00	0.00	0.00	$706,360.01
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2004 - JUNE 2004**							($11,456,865.95)

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

				JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
				(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation		39,370,000.00	39,635,000.00	36,094,000.00	32,383,000.00	27,021,000.00	29,016,000.00	$372,845,689.77
	1a	Fuel Cost of Hedging Settlement		0.00	0.00	0.00	0.00	0.00	0.00	($3,550,710.00)
	1b	Fuel Cost of Hedging Support		2,757.00	2,757.00	2,757.00	2,757.00	2,757.00	2,759.00	$27,675.68
	2	Fuel Cost of Power Sold		(14,209,000.00)	(14,260,000.00)	(13,520,000.00)	(9,400,000.00)	(10,667,000.00)	(10,356,000.00)	($127,871,198.80)
	3	Fuel Cost of Purchased Power		3,401,000.00	3,812,000.00	845,000.00	1,581,000.00	1,538,000.00	2,563,000.00	$37,511,292.32
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities		0.00	0.00	0.00	0.00	0.00	0.00	$218,843.00
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		257,000.00	257,000.00	249,000.00	257,000.00	249,000.00	257,000.00	$2,401,871.95
	6	Adjustment to Fuel Cost		0.00	0.00	0.00	0.00	0.00	0.00	$63,091.72
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)		$28,821,757.00	$29,446,757.00	$23,670,757.00	$24,823,757.00	$18,143,757.00	$21,482,759.00	$281,646,555.64
B	1	Jurisdictional KWH Sales		1,121,280,000	1,121,219,000	928,542,000	820,717,000	711,070,000	814,258,000	10,840,883,988
	2	Non-Jurisdictional KWH Sales		38,218,000	38,147,000	33,249,000	29,300,000	27,425,000	30,672,000	374,526,557
	3	TOTAL SALES (Lines B1 + B2)		1,159,498,000	1,159,366,000	961,791,000	850,017,000	738,495,000	844,930,000	11,215,410,545
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.7039%	96.7097%	96.5430%	96.5530%	96.2864%	96.3699%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$27,552,437.45	$27,550,938.53	$22,816,419.96	$20,166,910.85	$17,472,631.01	$20,008,198.32	$266,141,642.84
	2	True-Up Provision		(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.66)	(1,905,548.74)	($22,866,584.00)
	2a	Incentive Provision		(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.43)	(35,967.51)	($431,609.24)
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$25,610,921.36	$25,609,422.44	$20,874,903.87	$18,225,394.76	$15,531,114.92	$18,066,682.07	$242,843,449.60
	4	Fuel & Net Power Transactions (Line A7)		$28,821,757.00	$29,446,757.00	$23,670,757.00	$24,823,757.00	$18,143,757.00	$21,482,759.00	$281,646,555.64
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0007)		27,891,273.30	28,497,804.86	22,868,455.65	23,984,859.75	17,482,199.42	20,717,405.40	$272,434,217.50
	6	Over/(Under) Recovery (Line C3-C5)		(2,280,351.94)	(2,888,382.42)	(1,993,551.78)	(5,759,464.99)	(1,951,084.50)	(2,650,723.33)	($29,590,767.90)
	7	Interest Provision	(2)	(10,240.59)	(20,976.82)	(21,526.54)	(23,495.12)	(25,444.66)	(25,860.41)	($223,561.00)
	8	Prior Period Adjustment		0.00	0.00	0.00	0.00	0.00	0.00	$706,360.01
	9	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2004 - DECEMBER 2004**								($29,107,968.89)

Note 1: Estimated Revenues based on the 2004 Fuel Factor excluding revenue taxes of 2.4572 ¢/KWH
Note 2: Interest Calculated for July through December at June's rate of 0.0988

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

		DOLLARS				KWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMT.	DIFFERENCE %
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	372,845,690	340,226,335	32,619,355	9.59	15,605,983,000	16,251,250,000	(645,267,000)	(3.97)	2.3891	2.0935	0.2956	14.12
1a	Fuel Cost of Heding Settlement	(3,550,710)	0										
2	Hedging Support Costs	27,676	33,086	(5,410)	(16.35)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Other Generation	2,401,872	19,205	2,382,667	12,406.49	78,019,000	790,000	77,229,000	9,775.82	3.0786	2.431	0.6476	26.64
5	Adjustment to Fuel Cost	63,092											
5	TOTAL COST OF GENERATED POWER	371,787,619	340,278,626	31,508,993	9.26	15,684,002,000	16,252,040,000	(568,038,000)	(3.50)	2.3705	2.0938	0.2767	13.22
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
7	Energy Cost of Schedule C&X Econ. Purchases (Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Other Economy Purchases (Nonbroker) (A9)	37,511,292	12,776,000	24,735,292	193.61	1,032,349,249	477,038,000	555,311,249	116.41	3.6336	2.6782	0.9554	35.67
9	Energy Cost of Schedule E Economy Purchases (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Energy Payments to Qualifying Facilities (A9a)	218,843	0	218,843	#N/A	6,578,895	0	6,578,895	#N/A	3.3264	#N/A	#N/A	#N/A
12	TOTAL COST OF PURCHASED POWER	37,730,135	12,776,000	24,954,135	195.32	1,038,928,144	477,038,000	561,890,144	117.79	3.6316	2.6782	0.9534	35.60
13	Total Available KWH (Lines 5 + Line 12)	409,517,754	353,054,626	56,463,128	15.99	16,722,930,144	16,729,078,000	(6,147,856)	(0.04)				
14	Fuel Cost of Economy Sales (A6)	(61,778,195)	(2,289,000)	(59,489,195)	(2,598.92)	(160,861,993)	(74,677,000)	(86,184,993)	(115.41)	(38.4045)	(3.0652)	(35.3393)	(1,152.92)
15	Gain on Economy Sales (A6)	(15,752,402)	(383,000)	(15,369,402)	(4,012.90)			0	#N/A	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Unit Power Sales (A6)	(16,568,637)	(26,458,000)	9,889,363	37.38	(1,431,724,048)	(1,561,911,000)	130,186,952	8.34	(1.1573)	(1.6940)	0.5367	31.68
17	Fuel Cost of Other Power Sales (A6)	(33,771,965)	(79,395,000)	45,623,035	57.46	(3,202,473,809)	(3,440,414,000)	237,940,191	6.92	(1.0546)	(2.3077)	1.2531	54.30
18	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 14+15+16+17)	(127,871,199)	(108,525,000)	(19,346,199)	(17.83)	(4,795,059,850)	(5,077,002,000)	281,942,150	5.55	(2.6667)	(2.1376)	(0.5291)	(24.75)
19	Net Inadvertent Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
20	**TOTAL FUEL & NET POWER TRANSACTIONS** (LINES 5+12+18+19)	281,646,556	244,529,626	37,116,930	15.18	11,927,870,294	11,652,076,000	275,794,294	2.37	2.3612	2.0986	0.2626	12.51
21	Net Unbilled Sales	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
22	Company Use *	560,171	545,195	14,976	2.75	23,723,999	25,979,000	(2,255,001)	(8.68)	2.3612	2.0986	0.2626	12.51
23	T & D Losses *	16,262,429	14,395,200	1,867,229	12.97	688,735,750	685,943,000	2,792,750	0.41	2.3612	2.0986	0.2626	12.51
24	TERRITORIAL (SYSTEM) SALES	281,646,556	244,529,626	37,116,930	15.18	11,215,410,545	10,940,154,000	275,256,545	2.52	2.5112	2.2352	0.2760	12.35
25	Wholesale Sales	9,402,909	8,348,785	1,054,124	12.63	374,526,557	373,514,000	1,012,557	0.27	2.5106	2.2352	0.2754	12.32
26	Jurisdictional Sales	272,243,647	236,180,841	36,062,806	15.27	10,840,883,988	10,566,640,000	274,243,988	2.60	2.5113	2.2352	0.2761	12.35
26a	Jurisdictional Loss Multiplier***	1.0007	1.0007										
27	Jurisdictional Sales Adj. for Line Losses (Line 26 x 1.0007)	272,434,218	236,346,168	36,088,050	15.27	10,840,883,988	10,566,640,000	274,243,988	2.60	2.5130	2.2367	0.2763	12.35
28	TRUE-UP **	22,866,584	22,866,584	0	0.00	10,840,883,988	10,566,640,000	274,243,988	2.60	0.2109	0.2164	(0.0055)	(2.54)
29	TOTAL JURISDICTIONAL FUEL COST	295,300,802	259,212,752	36,088,050	13.92	10,840,883,988	10,566,640,000	274,243,988	2.60	2.7239	2.4531	0.2708	11.04
30	Revenue Tax Factor									1.00072	1.00072		
31	Fuel Factor Adjusted for Revenue Taxes									2.7259	2.4549	0.2710	11.04
32	GPIF Reward / (Penalty) **	431,920	431,920	0	0.00	10,840,883,988	10,566,640,000	274,243,988	2.60	0.0040	0.0041	(0.0001)	(2.44)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									2.7299	2.459	0.2709	11.02
34	**FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)**									2.730	2.459	0.271	11.02

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

Note: Amounts included in the Estimated/Actual Column represent 8 months actual and 4 months estimate.

SCHEDULE E-1C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE-UP FACTOR GULF POWER COMPANY FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward/(Penalty)	$	625,280
	B. True-Up (Over)/Under Recovered	$	26,572,951
2.	TOTAL SALES (KWH)		11,032,273,000
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor		0.0057
	B. True-Up Factor		0.2409

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

		NET ENERGY FOR LOAD %
	On-Peak	29.83
	Off-Peak	70.17
		100.00

	AVERAGE	ON-PEAK	OFF-PEAK
Cost per KWH Sold	2.5720	3.0536	2.3671
Jurisdictional Loss Factor	1.0007	1.0007	1.0007
Jurisdictional Fuel Factor	2.5738	3.0557	2.3688
GPIF	0.0057	0.0057	0.0057
True-Up	0.2409	0.2409	0.2409
TOTAL	2.8204	3.3023	2.6154
Revenue Tax Factor	1.00072	1.00072	1.00072
Recovery Factor	2.8223	3.3047	2.6173
Recovery Factor Rounded to the Nearest .001 ¢/KWH	2.822	3.305	2.617

HOURS:	ON-PEAK	25.59%
	OFF-PEAK	74.41%
		100.00%

SCHEDULE E-1E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

Group	Rate Schedules	Average Factor	Fuel Recovery Loss Multipliers	Standard Fuel Recovery Factor
A	RS, GS, GSD, OSIII, SBS (1)	2.822	1.00526	2.837
B	LP/LPT, SBS (2)	2.822	0.98890	2.791
C	PX, RTP, CSA	2.822	0.98063	2.767
D	OS-I/II	2.822	1.00529	2.808 *

		TOU
A	On-Peak	3.322
	Off-Peak	2.631
B	On-Peak	3.268
	Off-Peak	2.588
C	On-Peak	3.241
	Off-Peak	2.567
D	On-Peak	N/A
	Off-Peak	N/A

Group D Calculation

* D	On-Peak	3.305 ¢ / KWH	x	0.2559	=	0.846	¢ / KWH
	Off-Peak	2.617 ¢ / KWH	x	0.7441	=	1.947	¢ / KWH
						2.793	¢ / KWH
			Line Loss Multiplier		x	1.00529	
						2.808	¢ / KWH

(1) Includes SBS customers with a Contract Demand in the range of 100 to 499 KW
(2) Includes SBS customers with a Contract Demand in the range of 500 to 7,499 KW

SCHEDULE E-2

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

LINE	LINE DESCRIPTION	(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) JULY	(h) AUGUST	(i) SEPTEMBER	(j) OCTOBER	(k) NOVEMBER	(l) DECEMBER	(m) TOTAL
	$													
1	Fuel Cost of System Generation	32,946,451	24,264,379	25,545,736	28,691,817	35,623,850	38,297,282	43,971,039	44,949,349	35,985,305	31,955,668	24,998,301	26,213,591	393,442,768
1a	Other Generation	237,494	214,520	237,494	229,744	237,494	229,744	237,494	237,494	229,744	237,494	229,744	237,497	2,795,957
2	Fuel Cost of Power Sold	(14,111,000)	(8,057,000)	(6,311,000)	(10,415,000)	(11,464,000)	(9,469,000)	(12,630,000)	(13,918,000)	(10,248,000)	(7,460,000)	(8,189,000)	(9,271,000)	(121,543,000)
3	Fuel Cost of Purchased Power	604,000	1,205,000	4,290,000	986,000	1,065,000	1,559,000	1,607,000	953,000	1,696,000	1,969,000	2,179,000	691,000	18,804,000
3a	Demand & Non-Fuel Cost of Pur Power													0
3b	Qualifying Facilities	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Energy Cost of Economy Purchases													0
5	Hedging Administrative Cost	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,759	33,086
6	**Total Fuel & Net Power Trans.** (Sum of Lines 1 -4)	19,679,702	17,629,656	23,764,987	19,495,318	25,465,101	30,619,783	33,188,290	32,224,600	27,665,806	26,704,919	19,220,802	17,873,847	293,532,811
6	System KWH Sold	890,307,000	788,402,000	813,345,000	820,632,000	1,034,272,000	1,144,402,000	1,207,547,000	1,190,308,000	994,251,000	880,832,000	777,777,000	870,558,000	11,412,633,000
6a	Jurisdictional % of Total Sales	96.3881	96.6811	96.5483	96.7326	96.8985	96.9623	96.7891	96.7485	96.6018	96.6105	96.4049	96.4130	96.6672
7	Cost per KWH Sold (¢/KWH)	2.2104	2.2361	2.9219	2.3756	2.4621	2.6756	2.7484	2.7072	2.7826	3.0318	2.4712	2.0531	2.5720
7a	Jurisdictional Loss Multiplier	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007
7b	Jurisdictional Cost (¢/KWH)	2.2119	2.2377	2.9239	2.3773	2.4638	2.6775	2.7503	2.7091	2.7845	3.0339	2.4729	2.0545	2.5738
8	GPIF (¢ / KWH) *	0.0061	0.0068	0.0066	0.0066	0.0052	0.0047	0.0045	0.0045	0.0054	0.0061	0.0069	0.0062	0.0057
9	True-Up (¢/KWH) *	0.2580	0.2905	0.2820	0.2790	0.2210	0.1996	0.1895	0.1923	0.2306	0.2602	0.2953	0.2638	0.2409
10	TOTAL	2.4760	2.5350	3.2125	2.6629	2.6900	2.8818	2.9443	2.9059	3.0205	3.3002	2.7751	2.3245	2.8204
11	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
12	Recovery Factor Adjusted for Taxes	2.4778	2.5368	3.2148	2.6648	2.6919	2.8839	2.9464	2.9080	3.0227	3.3026	2.7771	2.3262	2.8223
13	**Recovery Factor Rounded to the Nearest .001 ¢/KWH**	2.478	2.537	3.215	2.665	2.692	2.884	2.946	2.908	3.023	3.303	2.777	2.326	2.822

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	FUEL COST - NET GEN. ($)													
2	LIGHTER OIL (B.L.)	49,536	43,639	37,416	44,095	50,979	51,248	51,487	51,699	51,889	45,042	52,155	51,401	580,586
3	COAL excluding Scherer	20,669,919	13,309,357	10,668,262	14,836,507	20,956,684	21,837,162	24,450,749	24,923,577	19,917,001	14,718,364	14,515,885	21,201,344	222,004,811
3a	COAL at Scherer	2,587,366	2,346,801	2,608,068	2,526,529	2,631,446	2,562,132	2,648,283	2,648,510	2,561,843	2,616,667	2,531,067	2,616,960	30,885,672
4	GAS - Generation	9,598,119	8,534,881	12,204,542	11,249,458	11,946,049	13,808,048	16,780,243	17,263,083	13,417,818	14,557,234	7,862,381	2,303,258	139,525,114
4a	GAS (B.L.)	41,511	29,701	27,448	35,228	38,692	38,692	40,277	40,335	36,754	18,361	36,813	40,628	424,440
6	OTHER - C.T.	0	0	0	0	0	0	0	22,145	0	0	0	0	22,145
6a	OTHER GENERATION	237,494	214,520	237,494	229,744	237,494	229,744	237,494	237,494	229,744	237,494	229,744	237,497	2,795,957
7	TOTAL ($)	33,183,945	24,478,899	25,783,230	28,921,561	35,861,344	38,527,026	44,208,533	45,186,843	36,215,049	32,193,162	25,228,045	26,451,088	396,238,725
	SYSTEM NET GEN. (MWH)													
10	COAL	1,259,070	884,630	723,270	962,210	1,261,340	1,262,440	1,359,550	1,365,160	1,114,410	860,760	848,340	1,217,890	13,119,070
11	GAS	147,270	199,290	241,320	232,950	208,120	246,310	301,250	303,570	250,740	263,220	189,940	25,390	2,609,370
13	OTHER - C.T.	0	0	0	0	0	0	0	220	0	0	0	0	220
13a	OTHER GENERATION	8,580	7,750	8,580	8,300	8,580	8,300	8,580	8,580	8,300	8,580	8,300	8,580	101,010
14	TOTAL (MWH)	1,414,920	1,091,670	973,170	1,203,460	1,478,040	1,517,050	1,669,380	1,677,530	1,373,450	1,132,560	1,046,580	1,251,860	15,829,670
	UNITS OF FUEL BURNED													
16	LIGHTER OIL (BBL)	1,192	1,044	897	1,045	1,192	1,192	1,192	1,192	1,192	1,020	1,192	1,172	13,523
17	COAL excl. Scherer (TON)	497,555	333,691	260,179	368,320	500,178	502,355	544,192	545,338	437,325	319,420	317,421	483,439	5,109,413
18	GAS-all (MCF)	1,202,853	1,066,934	1,698,797	1,468,005	1,437,812	1,709,249	2,059,273	2,127,068	1,738,263	1,910,114	1,087,930	213,316	17,719,614
20	OTHER - C.T. (BBL)	0	0	0	0	0	0	0	534	0	0	0	0	534
	BTU'S BURNED (MMBTU)													
23	COAL + GAS B.L. + OIL B.L.	12,901,722	8,929,778	7,474,597	9,846,650	13,004,076	12,984,311	13,998,002	14,010,241	11,456,996	8,863,489	8,724,848	12,492,959	134,687,669
24	GAS-Generation	1,233,067	1,094,692	1,745,511	1,506,173	1,475,075	1,754,654	2,115,179	2,185,008	1,784,539	1,964,484	1,114,696	213,843	18,186,921
26	OTHER - C.T.	0	0	0	0	0	0	0	3,151	0	0	0	0	3,151
27	TOTAL (MMBTU)	14,134,789	10,024,470	9,220,108	11,352,823	14,479,151	14,738,965	16,113,181	16,198,400	13,241,535	10,827,973	9,839,544	12,706,802	152,877,741

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	GENERATION MIX (% MWH)													
30	COAL	88.99	81.03	74.32	79.95	85.34	83.22	81.44	81.38	81.14	76.00	81.06	97.28	82.88
31	GAS-Generation	10.41	18.26	24.80	19.36	14.08	16.23	18.05	18.10	18.26	23.24	18.15	2.03	16.48
33	OTHER - C.T.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00
33a	OTHER GENERATION	0.60	0.71	0.88	0.69	0.58	0.55	0.51	0.51	0.60	0.76	0.79	0.69	0.64
34	TOTAL (% MWH)	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST $ / UNIT													
36	LIGHTER OIL ($/BBL)	41.55	41.80	41.72	42.20	42.77	42.99	43.19	43.37	43.53	44.15	43.75	43.86	42.93
37	COAL ($/TON)*	41.54	39.89	41.00	40.28	41.90	43.47	44.93	45.70	45.54	46.08	45.73	43.86	43.45
38	GAS + B.L. ($/MCF)	8.01	8.03	7.20	7.69	8.34	8.10	8.17	8.13	7.74	7.63	7.26	10.99	7.90
40	OTHER - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	41.51	#N/A	#N/A	#N/A	#N/A	41.47
	FUEL COST $ / MMBTU													
43	COAL + GAS B.L. + OIL B.L.	1.81	1.76	1.78	1.77	1.82	1.88	1.94	1.97	1.97	1.96	1.96	1.91	1.88
44	GAS-Generation	7.78	7.80	6.99	7.47	8.10	7.87	7.93	7.90	7.52	7.41	7.05	10.77	7.67
46	OTHER - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	7.03	#N/A	#N/A	#N/A	#N/A	7.03
47	TOTAL ($/MMBTU)	2.35	2.44	2.80	2.55	2.48	2.61	2.74	2.79	2.73	2.97	2.56	2.08	2.59
	BTU BURNED BTU / KWH													
50	COAL + GAS B.L. + OIL B.L.	10,247	10,094	10,334	10,233	10,310	10,285	10,296	10,263	10,281	10,297	10,285	10,258	10,267
51	GAS-Generation	8,373	5,493	7,233	6,466	7,088	7,124	7,021	7,198	7,117	7,463	5,869	8,422	6,970
53	OTHER - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	14,323	#N/A	#N/A	#N/A	#N/A	14,323
	TOTAL (BTU/KWH)	10,051	9,248	9,559	9,499	9,853	9,769	9,702	9,706	9,700	9,634	9,477	10,220	9,720
	FUEL COST CENTS / KWH													
57	COAL + GAS B.L. + OIL B.L.	1.85	1.78	1.84	1.81	1.88	1.94	2.00	2.03	2.03	2.02	2.02	1.96	1.94
58	GAS-Generation	6.52	4.28	5.06	4.83	5.74	5.61	5.57	5.69	5.35	5.53	4.14	9.07	5.35
60	OTHER - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	10.07	#N/A	#N/A	#N/A	#N/A	10.07
61	TOTAL (¢/KWH)	2.35	2.24	2.65	2.40	2.43	2.54	2.65	2.69	2.64	2.84	2.41	2.11	2.50

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JANUARY 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	2													
3	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
4	3													
5	Crist 4	78.0	47,560	82.0	99.5	82.4	10,854	Coal	21,808	11,835	516,219	993,670	2.09	45.56
6	4							Gas - G						
7	Crist 5	80.0	42,080	70.7	89.0	79.4	10,772	Coal	19,149	11,835	453,266	872,491	2.07	45.56
8	5							Gas - G						
9	Crist 6	302.0	179,720	80.0	97.4	82.1	10,790	Coal	81,925	11,835	1,939,225	3,732,811	2.08	45.56
10	6							Gas - G						
11	Crist 7	477.0	266,600	75.1	85.9	87.5	10,181	Coal	114,665	11,835	2,714,207	5,224,572	1.96	45.56
12	7							Gas - G						
13	Scherer 3 (2)	210.8	148,790	94.9	94.5	100.4	10,246	Coal	87,007	8,761	1,524,461	2,587,366	1.74	29.74
14	Scholz 1	46.0	10,770	31.5	89.5	35.2	13,552	Coal	5,708	12,786	145,958	302,803	2.81	53.05
15	Scholz 2	46.0	12,090	35.3	87.0	40.6	12,505	Coal	5,912	12,786	151,189	313,655	2.59	53.05
16	Smith 1	162.0	99,730	82.7	98.4	84.1	10,183	Coal	42,324	11,998	1,015,574	1,670,989	1.68	39.48
17	Smith 2	189.0	80,780	57.4	67.1	85.6	9,908	Coal	33,357	11,998	800,407	1,316,962	1.63	39.48
18	Smith 3	531.0	147,270	37.3	88.4	42.2	8,373	Gas - G	1,197,152	1,030	1,233,067	9,598,119	6.52	8.02
19	Smith A (CT)	40.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
20	Other Generation		8,580									237,494	2.77	#N/A
21	Daniel 1 (1)	257.0	185,320	96.9	96.9	100.0	10,092	Coal	89,021	10,504	1,870,199	3,217,402	1.74	36.14
22	Daniel 2 (1)	257.0	185,630	97.1	97.3	99.8	9,471	Coal	83,686	10,504	1,758,106	3,024,564	1.63	36.14
23	Gas,BL							Gas	5,701	1,030	5,871	41,511	#N/A	7.28
	Ltr. Oil							Oil	1,192	140,606	7,040	49,536	#N/A	41.55
		2,734.8	1,414,920	69.5	90.9	76.5	10,051				14,134,789	33,183,945	2.35	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : FEBRUARY 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	46,350	88.4	99.3	89.1	10,478	Coal	20,431	11,885	485,654	885,766	1.91	43.35
4	4							Gas - G						
5	Crist 5	80.0	41,320	76.9	87.9	87.4	10,543	Coal	18,327	11,885	435,642	794,551	1.92	43.35
6	5							Gas - G						
7	Crist 6	302.0	174,930	86.2	97.5	88.4	10,211	Coal	75,145	11,885	1,786,231	3,257,838	1.86	43.35
8	6							Gas - G						
9	Crist 7	477.0	0	0.0	0.0	#N/A	#N/A	Coal	0	0	0	0	#N/A	#N/A
10	7							Gas - G						
11	Scherer 3 (2)	210.8	134,420	94.9	94.5	100.4	10,244	Coal	78,551	8,765	1,377,012	2,346,801	1.75	29.88
12	Scholz 1	46.0	15,710	50.8	85.0	59.8	10,256	Coal	6,443	12,505	161,128	388,962	2.48	60.37
13	Scholz 2	46.0	15,690	50.8	84.5	60.1	10,389	Coal	6,518	12,505	163,004	393,490	2.51	60.37
14	Smith 1	162.0	96,050	88.2	98.5	89.6	10,260	Coal	41,062	12,000	985,494	1,619,470	1.69	39.44
15	Smith 2	189.0	68,020	53.6	60.4	88.7	10,053	Coal	28,491	12,000	683,786	1,123,672	1.65	39.44
16	Smith 3	531.0	199,290	55.8	88.4	63.2	5,493	Gas - G	1,062,808	1,030	1,094,692	8,534,881	4.28	8.03
17	Smith A (CT	40.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		7,750				0					214,520	2.77	#N/A
19	Daniel 1 (1)	257.0	136,750	79.2	79.5	99.6	9,932	Coal	65,617	10,349	1,358,196	2,316,202	1.69	35.30
20	Daniel 2 (1)	257.0	155,390	90.0	90.3	99.6	9,545	Coal	71,657	10,349	1,483,217	2,529,406	1.63	35.30
21	Gas,BL							Gas	4,126	1,030	4,249	29,701	#N/A	7.20
22	Ltr. Oil							Oil	1,044	140,603	6,165	43,639	#N/A	41.80
23		2,734.8	1,091,670	59.4	73.1	81.3	9,248				10,024,470	24,478,899	2.24	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MARCH 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	50,740	87.4	99.3	88.1	10,642	Coal	22,657	11,917	539,999	950,331	1.87	41.94
4	4							Gas - G						
5	Crist 5	80.0	50,720	85.2	98.3	86.7	10,566	Coal	22,486	11,917	535,928	943,166	1.86	41.94
6	5							Gas - G						
7	Crist 6	302.0	123,530	55.0	62.6	87.8	10,224	Coal	52,992	11,917	1,263,002	2,222,727	1.80	41.94
8	6							Gas - G						
9	Crist 7	477.0	0	0.0	0.0	#N/A	#N/A	Coal	0	0	0	0	#N/A	#N/A
10	7							Gas - G						
11	Scherer 3 (2)	210.8	148,790	94.9	94.5	100.4	10,246	Coal	86,909	8,770	1,524,461	2,608,068	1.75	30.01
12	Scholz 1	46.0	17,900	52.3	85.6	61.1	12,784	Coal	9,301	12,301	228,825	610,640	3.41	65.65
13	Scholz 2	46.0	18,550	54.2	84.5	64.1	12,772	Coal	9,630	12,301	236,918	632,237	3.41	65.65
14	Smith 1	162.0	103,880	86.2	98.7	87.3	10,266	Coal	44,431	12,001	1,066,465	1,751,491	1.69	39.42
15	Smith 2	189.0	0	0.0	0.0	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
16	Smith 3	531.0	241,320	61.1	88.4	69.1	7,233	Gas - G	1,694,671	1,030	1,745,511	12,204,542	5.06	7.20
17	Smith A (CT	40.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,580									237,494	2.77	#N/A
19	Daniel 1 (1)	257.0	185,390	97.0	96.9	100.1	9,928	Coal	87,767	10,486	1,840,573	3,164,193	1.71	36.05
20	Daniel 2 (1)	257.0	23,770	12.4	12.5	99.5	9,629	Coal	10,915	10,486	228,882	393,477	1.66	36.05
21	Gas,BL							Gas	4,126	1,030	4,249	27,448	#N/A	6.65
22	Ltr. Oil							Oil	897	140,593	5,295	37,416	#N/A	41.73
23		2,734.8	973,170	47.8	59.7	80.1	9,559				9,220,108	25,783,230	2.65	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : APRIL 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	47,230	84.1	99.4	84.6	10,686	Coal	21,119	11,949	504,695	856,871	1.81	40.57
4	4							Gas - G						
5	Crist 5	80.0	47,170	81.9	98.6	83.1	10,660	Coal	21,041	11,949	502,833	853,709	1.81	40.57
6	5							Gas - G						
7	Crist 6	302.0	141,430	65.0	78.0	83.4	10,280	Coal	60,839	11,949	1,453,915	2,468,454	1.75	40.57
8	6							Gas - G						
9	Crist 7	477.0	116,680	34.0	41.3	82.3	10,356	Coal	50,563	11,949	1,208,323	2,051,488	1.76	40.57
10	7							Gas - G						
11	Scherer 3 (2)	210.8	143,930	94.9	94.6	100.3	10,246	Coal	84,053	8,772	1,474,651	2,526,529	1.76	30.06
12	Scholz 1	46.0	16,350	49.4	84.8	58.2	10,631	Coal	7,126	12,195	173,816	487,590	2.98	68.42
13	Scholz 2	46.0	16,580	50.1	85.1	58.8	11,435	Coal	7,773	12,195	189,597	531,859	3.21	68.42
14	Smith 1	162.0	95,370	81.8	98.7	82.8	10,282	Coal	40,851	12,002	980,601	1,610,891	1.69	39.43
15	Smith 2	189.0	0	0.0	0.0	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
16	Smith 3	481.0	232,950	67.3	88.5	76.0	6,466	Gas - G	1,462,304	1,030	1,506,173	11,249,458	4.83	7.69
17	Smith A (CT)	32.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,300									229,744	2.77	#N/A
19	Daniel 1 (1)	257.0	177,450	95.9	97.1	98.8	9,935	Coal	83,773	10,522	1,762,920	3,148,244	1.77	37.58
20	Daniel 2 (1)	257.0	160,020	86.5	87.5	98.8	9,894	Coal	75,235	10,522	1,583,258	2,827,401	1.77	37.58
21	Gas,BL							Gas	5,701	1,030	5,871	35,228	#N/A	6.18
22	Ltr. Oil							Oil	1,045	140,598	6,170	44,095	#N/A	42.20
23		2,676.8	1,203,460	62.4	75.4	82.8	9,499				11,352,823	28,921,561	2.40	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MAY 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	46,870	80.8	99.5	81.2	10,639	Coal	20,948	11,902	498,647	909,406	1.94	43.41
4	4							Gas - G						
5	Crist 5	80.0	46,470	78.1	98.5	79.3	10,779	Coal	21,042	11,902	500,895	913,506	1.97	43.41
6	5							Gas - G						
7	Crist 6	302.0	170,130	75.7	97.4	77.7	10,376	Coal	74,157	11,902	1,765,236	3,219,346	1.89	43.41
8	6							Gas - G						
9	Crist 7	477.0	272,660	76.8	95.2	80.7	10,373	Coal	118,815	11,902	2,828,301	5,158,110	1.89	43.41
10	7							Gas - G						
11	Scherer 3 (2)	210.8	149,870	95.6	95.7	99.9	10,239	Coal	87,452	8,773	1,534,486	2,631,446	1.76	30.09
12	Scholz 1	46.0	15,690	45.8	88.2	52.0	12,508	Coal	8,091	12,129	196,253	567,714	3.62	70.17
13	Scholz 2	46.0	16,140	47.2	87.8	53.7	12,733	Coal	8,472	12,128	205,510	594,492	3.68	70.17
14	Smith 1	162.0	93,220	77.3	98.7	78.4	10,304	Coal	40,012	12,003	960,544	1,578,448	1.69	39.45
15	Smith 2	189.0	98,970	70.4	91.4	77.0	10,361	Coal	42,716	12,003	1,025,476	1,685,150	1.70	39.45
16	Smith 3	481.0	208,120	58.2	93.8	62.0	7,088	Gas - G	1,432,111	1,030	1,475,075	11,946,049	5.74	8.34
17	Smith A (CT)	32.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,580									237,494	2.77	#N/A
19	Daniel 1 (1)	257.0	174,410	91.2	97.2	93.8	9,975	Coal	83,051	10,474	1,739,763	3,168,634	1.82	38.15
20	Daniel 2 (1)	257.0	176,910	92.5	97.3	95.1	9,813	Coal	82,874	10,474	1,736,054	3,161,878	1.79	38.15
21	Gas,BL							Gas	5,701	1,030	5,871	38,692	#N/A	6.79
22	Ltr. Oil							Oil	1,192	140,606	7,040	50,979	#N/A	42.76
23		2,676.8	1,478,040	74.2	95.7	77.5	9,853				14,479,151	35,861,344	2.43	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JUNE 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	46,290	82.4	99.4	82.9	10,595	Coal	20,648	11,876	490,455	944,315	2.04	45.73
4	4							Gas - G						
5	Crist 5	80.0	46,270	80.3	98.6	81.5	10,710	Coal	20,863	11,876	495,552	954,128	2.06	45.73
6	5							Gas - G						
7	Crist 6	302.0	169,170	77.8	97.5	79.8	10,339	Coal	73,634	11,876	1,749,003	3,367,505	1.99	45.73
8	6							Gas - G						
9	Crist 7	477.0	269,200	78.4	95.1	82.4	10,356	Coal	117,369	11,876	2,787,844	5,367,673	1.99	45.73
10	7							Gas - G						
11	Scherer 3 (2)	210.8	145,830	96.1	95.7	100.4	10,243	Coal	85,128	8,773	1,493,725	2,562,132	1.76	30.10
12	Scholz 1	46.0	19,160	57.9	87.5	66.1	12,126	Coal	9,612	12,085	232,332	685,312	3.58	71.30
13	Scholz 2	46.0	18,010	54.4	88.2	61.7	12,329	Coal	9,186	12,085	222,040	654,954	3.64	71.30
14	Smith 1	162.0	91,830	78.7	98.8	79.7	10,297	Coal	39,387	12,004	945,597	1,554,189	1.69	39.46
15	Smith 2	189.0	101,630	74.7	94.4	79.1	10,374	Coal	43,914	12,004	1,054,296	1,732,847	1.71	39.46
16	Smith 3	481.0	246,310	71.1	93.9	75.7	7,124	Gas - G	1,703,548	1,030	1,754,654	13,808,048	5.61	8.11
17	Smith A (CT)	32.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,300									229,744	2.77	#N/A
19	Daniel 1 (1)	257.0	176,860	95.6	97.1	98.4	9,938	Coal	84,225	10,434	1,757,667	3,302,000	1.87	39.20
20	Daniel 2 (1)	257.0	178,190	96.3	97.2	99.1	9,781	Coal	83,517	10,434	1,742,889	3,274,239	1.84	39.20
21	Gas,BL							Gas	5,701	1,030	5,871	38,692	#N/A	6.79
22	*Ltr. Oil*							Oil	1,192	140,606	7,040	51,248	#N/A	42.99
23		2,676.8	1,517,050	78.7	95.9	82.1	9,769				14,738,965	38,527,026	2.54	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JULY 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	99.3	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	49,890	86.0	99.5	86.4	10,522	Coal	22,154	11,847	524,933	1,066,671	2.14	48.15
4	4							Gas - G						
5	Crist 5	80.0	49,970	84.0	98.5	85.2	10,388	Coal	21,909	11,847	519,111	1,054,842	2.11	48.15
6	5							Gas - G						
7	Crist 6	302.0	186,290	82.9	97.4	85.1	10,509	Coal	82,624	11,847	1,957,706	3,978,088	2.14	48.15
8	6							Gas - G						
9	Crist 7	477.0	295,160	83.2	95.2	87.4	10,410	Coal	129,679	11,847	3,072,650	6,243,671	2.12	48.15
10	7							Gas - G						
11	Scherer 3 (2)	210.8	150,690	96.1	95.7	100.4	10,245	Coal	87,980	8,773	1,543,767	2,648,283	1.76	30.10
12	Scholz 1	46.0	21,650	63.3	87.6	72.2	12,063	Coal	10,833	12,055	261,171	781,310	3.61	72.12
13	Scholz 2	46.0	20,820	60.8	87.8	69.3	12,454	Coal	10,755	12,054	259,290	775,682	3.73	72.12
14	Smith 1	162.0	101,250	84.0	98.7	85.1	10,273	Coal	43,323	12,004	1,040,142	1,712,140	1.69	39.52
15	Smith 2	189.0	112,800	80.2	94.5	84.9	10,204	Coal	47,940	12,004	1,150,979	1,894,583	1.68	39.52
16	Smith 3	481.0	301,250	84.2	93.8	89.7	7,021	Gas - G	2,053,572	1,030	2,115,179	16,780,243	5.57	8.17
17	Smith A (CT)	32.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,580									237,494	2.77	#N/A
19	Daniel 1 (1)	257.0	185,360	96.9	97.2	99.7	9,928	Coal	88,088	10,446	1,840,208	3,495,697	1.89	39.68
20	Daniel 2 (1)	257.0	185,670	97.1	97.3	99.8	9,776	Coal	86,887	10,446	1,815,134	3,448,065	1.86	39.68
21	Gas,BL							Gas	5,701	1,030	5,871	40,277	#N/A	7.06
22	Ltr. Oil							Oil	1,192	140,606	7,040	51,487	#N/A	43.19
23		2,676.8	1,669,380	83.8	95.9	87.4	9,702				16,113,181	44,208,533	2.65	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : AUGUST 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	400	2.2	98.9	2.3	16,488	Gas - G	6,403	1,030	6,595	45,306	11.33	7.08
2	Crist 3	35.0	780	3.0	100.0	3.0	14,505	Gas - G	10,984	1,030	11,314	77,726	9.96	7.08
3	Crist 4	78.0	50,220	86.5	99.5	87.0	10,509	Coal	22,307	11,830	527,779	1,104,701	2.20	49.52
4	4							Gas - G						
5	Crist 5	80.0	50,240	84.4	98.5	85.7	10,329	Coal	21,933	11,830	518,932	1,086,184	2.16	49.52
6	5							Gas - G						
7	Crist 6	302.0	187,830	83.6	97.4	85.8	10,521	Coal	83,525	11,830	1,976,192	4,136,394	2.20	49.52
8	6							Gas - G						
9	Crist 7	477.0	297,220	83.8	95.2	88.0	10,304	Coal	129,441	11,830	3,062,576	6,410,318	2.16	49.52
10	7							Gas - G						
11	Scherer 3 (2)	210.8	150,690	96.1	95.7	100.4	10,245	Coal	87,980	8,773	1,543,767	2,648,510	1.76	30.10
12	Scholz 1	46.0	21,210	62.0	87.6	70.7	11,482	Coal	10,118	12,035	243,526	735,123	3.47	72.65
13	Scholz 2	46.0	20,580	60.1	88.0	68.3	12,489	Coal	10,679	12,035	257,025	775,873	3.77	72.65
14	Smith 1	162.0	102,380	84.9	98.7	86.1	10,269	Coal	43,789	12,005	1,051,331	1,732,076	1.69	39.56
15	Smith 2	189.0	113,980	81.1	94.5	85.8	10,200	Coal	48,425	12,005	1,162,641	1,915,460	1.68	39.56
16	Smith 3	481.0	302,390	84.5	93.8	90.1	7,167	Gas - G	2,103,980	1,030	2,167,099	17,140,051	5.67	8.15
17	Smith A (CT)	32.0	220	0.9	100.0	0.9	14,323	Oil - G	534	140,621	3,151	22,145	10.07	41.51
18	Other Generation		8,580									237,494	2.77	#N/A
19	Daniel 1 (1)	257.0	185,230	96.9	97.2	99.7	9,929	Coal	88,154	10,432	1,839,169	3,537,553	1.91	40.13
20	Daniel 2 (1)	257.0	185,580	97.1	97.3	99.7	9,777	Coal	86,967	10,432	1,814,392	3,489,895	1.88	40.13
21	Gas,BL							Gas	5,701	1,030	5,871	40,335	#N/A	7.08
22	Ltr. Oil							Oil	1,192	140,606	7,040	51,699	#N/A	43.37
23		2,676.8	1,677,530	84.2	95.9	87.8	9,706				16,198,400	45,186,843	2.69	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : SEPTEMBER 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	290	1.7	98.9	1.7	17,940	Gas - G	5,051	1,030	5,203	32,569	11.23	6.45
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	47,150	84.0	99.4	84.5	10,559	Coal	21,080	11,809	497,877	1,052,168	2.23	49.91
4	4							Gas - G						
5	Crist 5	80.0	47,340	82.2	98.6	83.4	10,443	Coal	20,932	11,809	494,386	1,044,790	2.21	49.91
6	5							Gas - G						
7	Crist 6	302.0	51,700	23.8	29.3	81.1	10,318	Coal	22,585	11,809	533,431	1,127,305	2.18	49.91
8	6							Gas - G						
9	Crist 7	477.0	272,950	79.5	95.1	83.6	10,473	Coal	121,031	11,809	2,858,596	6,041,098	2.21	49.91
10	7							Gas - G						
11	Scherer 3 (2)	210.8	145,830	96.1	95.7	100.4	10,237	Coal	85,076	8,774	1,492,887	2,561,843	1.76	30.11
12	Scholz 1	46.0	17,430	52.6	88.6	59.4	11,817	Coal	8,565	12,023	205,963	624,997	3.59	72.97
13	Scholz 2	46.0	17,530	52.9	88.8	59.6	12,286	Coal	8,957	12,023	215,376	653,560	3.73	72.97
14	Smith 1	162.0	93,930	80.5	98.8	81.5	10,288	Coal	40,248	12,005	966,345	1,592,833	1.70	39.58
15	Smith 2	189.0	104,700	76.9	94.4	81.5	10,220	Coal	44,567	12,005	1,070,030	1,763,738	1.68	39.57
16	Smith 3	481.0	250,450	72.3	93.9	77.0	7,105	Gas - G	1,727,511	1,030	1,779,336	13,385,249	5.34	7.75
17	Smith A (CT	32.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,300									229,744	2.77	#N/A
19	Daniel 1 (1)	257.0	136,680	73.9	74.4	99.3	9,932	Coal	65,211	10,408	1,357,483	2,626,827	1.92	40.28
20	Daniel 2 (1)	257.0	179,170	96.8	97.2	99.6	9,777	Coal	84,149	10,408	1,751,711	3,389,685	1.89	40.28
21	Gas,BL							Gas	5,701	1,030	5,871	36,754	#N/A	6.45
22	Ltr. Oil							Oil	1,192	140,606	7,040	51,889	#N/A	43.53
23		2,676.8	1,373,450	71.3	86.1	82.8	9,700				13,241,535	36,215,049	2.64	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : OCTOBER 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	49,280	84.9	99.2	85.6	10,544	Coal	22,071	11,771	519,592	1,098,670	2.23	49.78
4	4							Gas - G						
5	Crist 5	80.0	49,350	82.9	98.4	84.3	10,360	Coal	21,718	11,771	511,265	1,081,064	2.19	49.78
6	5							Gas - G						
7	Crist 6	302.0	0	0.0	0.0	#N/A	#N/A	Coal	0	0	0	0	#N/A	#N/A
8	6							Gas - G						
9	Crist 7	477.0	239,040	67.4	79.5	84.7	10,224	Coal	103,816	11,771	2,443,978	5,167,762	2.16	49.78
10	7							Gas - G						
11	Scherer 3 (2)	210.8	148,790	94.9	94.5	100.4	10,246	Coal	86,870	8,774	1,524,461	2,616,667	1.76	30.12
12	Scholz 1	46.0	15,960	46.6	86.8	53.7	13,590	Coal	9,027	12,014	216,894	661,006	4.14	73.23
13	Scholz 2	46.0	16,170	47.2	86.2	54.8	13,221	Coal	8,897	12,014	213,784	651,527	4.03	73.23
14	Smith 1	162.0	66,610	55.3	66.7	82.9	10,283	Coal	28,527	12,005	684,928	1,130,709	1.70	39.64
15	Smith 2	189.0	102,560	72.9	88.3	82.6	10,215	Coal	43,636	12,005	1,047,696	1,729,582	1.69	39.64
16	Smith 3	481.0	263,220	73.6	88.5	83.1	7,463	Gas - G	1,907,266	1,030	1,964,484	14,557,234	5.53	7.63
17	Smith A (CT	32.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,580									237,494	2.77	#N/A
19	Daniel 1 (1)	257.0	0	0.0	0.0	#N/A	#N/A	Coal	0	0	0	0	#N/A	#N/A
20	Daniel 2 (1)	257.0	173,000	90.5	91.0	99.4	9,780	Coal	81,728	10,351	1,691,933	3,198,044	1.85	39.13
21	Gas,BL							Gas	2,848	1,030	2,933	18,361	#N/A	6.45
22	Ltr. Oil							Oil	1,020	140,613	6,025	45,042	#N/A	44.15
23		2,676.8	1,132,560	56.9	68.7	82.8	9,634				10,827,973	32,193,162	2.84	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : NOVEMBER, 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	#N/A	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	46,960	83.6	99.3	84.2	10,567	Coal	21,123	11,746	496,226	1,049,270	2.23	49.67
4	4							Gas - G						
5	Crist 5	80.0	46,770	81.2	98.6	82.4	10,137	Coal	20,181	11,746	474,094	1,002,472	2.14	49.67
6	5							Gas - G						
7	Crist 6	302.0	54,180	24.9	32.2	77.4	10,396	Coal	23,976	11,746	563,248	1,190,987	2.20	49.67
8	6							Gas - G						
9	Crist 7	477.0	192,620	56.1	66.3	84.6	10,337	Coal	84,756	11,746	1,991,085	4,210,147	2.19	49.67
10	7							Gas - G						
11	Scherer 3 (2)	210.8	143,870	94.8	94.6	100.2	10,250	Coal	84,033	8,774	1,474,651	2,531,067	1.76	30.12
12	Scholz 1	46.0	15,640	47.2	86.3	54.7	12,614	Coal	8,213	12,009	197,276	602,580	3.85	73.37
13	Scholz 2	46.0	10,110	30.5	73.6	41.5	14,218	Coal	5,985	12,009	143,740	439,055	4.34	73.36
14	Smith 1	162.0	25,610	22.0	26.4	83.2	10,281	Coal	10,967	12,005	263,304	435,033	1.70	39.67
15	Smith 2	189.0	105,250	77.3	94.2	82.1	10,218	Coal	44,793	12,005	1,075,474	1,776,907	1.69	39.67
16	Smith 3	531.0	189,940	49.7	82.5	60.2	5,869	Gas - G	1,082,229	1,030	1,114,696	7,862,381	4.14	7.26
17	Smith A (CT)	40.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,300									229,744	2.77	#N/A
19	Daniel 1 (1)	257.0	28,760	15.5	16.3	95.4	9,959	Coal	13,727	10,433	286,422	536,740	1.87	39.10
20	Daniel 2 (1)	257.0	178,570	96.5	96.9	99.6	9,780	Coal	83,700	10,433	1,746,417	3,272,694	1.83	39.10
21	Gas,BL							Gas	5,701	1,030	5,871	36,813	#N/A	6.46
22	Ltr. Oil							Oil	1,192	140,606	7,040	52,155	#N/A	43.75
23		2,734.8	1,046,580	53.2	69.2	76.8	9,477				9,839,544	25,228,045	2.41	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : DECEMBER 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned MMBTU	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	100.0	0.0	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
2	Crist 3	35.0	0	0.0	100.0	0.0	#N/A	Gas - G	0	0	0	0	#N/A	#N/A
3	Crist 4	78.0	41,750	71.9	93.0	77.4	10,751	Coal	19,066	11,771	448,845	914,179	2.19	47.95
4	4							Gas - G						
5	Crist 5	80.0	42,990	72.2	98.5	73.3	10,986	Coal	20,062	11,771	472,296	961,944	2.24	47.95
6	5							Gas - G						
7	Crist 6	302.0	149,510	66.5	88.0	75.6	10,416	Coal	66,149	11,771	1,557,265	3,171,743	2.12	47.95
8	6							Gas - G						
9	Crist 7	477.0	271,530	76.5	95.2	80.4	10,377	Coal	119,686	11,771	2,817,620	5,738,757	2.11	47.95
10	7							Gas - G						
11	Scherer 3 (2)	210.8	148,790	94.9	94.5	100.4	10,246	Coal	86,868	8,775	1,524,461	2,616,960	1.76	30.13
12	Scholz 1	46.0	8,760	25.6	89.7	28.5	13,365	Coal	4,875	12,008	117,081	357,863	4.09	73.41
13	Scholz 2	46.0	0	0.0	19.4	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
14	Smith 1	162.0	91,470	75.9	98.7	76.9	10,313	Coal	39,289	12,005	943,332	1,559,709	1.71	39.70
15	Smith 2	189.0	92,510	65.8	85.3	77.1	10,245	Coal	39,476	12,005	947,804	1,567,102	1.69	39.70
16	Smith 3	531.0	25,390	6.4	37.1	17.3	8,422	Gas - G	207,615	1,030	213,843	2,303,258	9.07	11.09
17	Smith A (CT	40.0	0	0.0	100.0	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		8,580									237,497	2.77	#N/A
19	Daniel 1 (1)	257.0	185,010	96.8	97.2	99.5	9,930	Coal	87,966	10,442	1,837,170	3,486,732	1.88	39.64
20	Daniel 2 (1)	257.0	185,570	97.1	97.0	100.1	9,777	Coal	86,870	10,442	1,814,293	3,443,315	1.86	39.64
21	Gas,BL							Gas	5,701	1,030	5,871	40,628	#N/A	7.13
22	Ltr. Oil							Oil	1,172	140,605	6,921	51,401	#N/A	43.86
23		2,734.8	1,251,860	61.5	81.8	75.2	10,220				12,706,802	26,451,088	2.11	

Notes:
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(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD : JANUARY 2005 - DECEMBER 2005

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	690	0.3	99.8	0.3	17,099	Gas - G	11,454	1,030	11,798	77,874	11.29	6.80
2	Crist 3	35.0	780	0.3	99.9	0.3	14,505	Gas - G	10,984	1,030	11,314	77,726	9.96	7.08
3	Crist 4	78.0	570,290	83.5	98.9	84.4	10,610	Coal	255,412	11,845	6,050,921	11,826,018	2.07	46.30
4	4							Gas - G						
5	Crist 5	80.0	560,690	80.0	96.9	82.6	10,548	Coal	249,643	11,845	5,914,200	11,562,847	2.06	46.32
6	5							Gas - G						
7	Crist 6	302.0	1,588,420	60.0	72.9	82.4	10,416	Coal	697,551	11,859	16,544,454	31,873,198	2.01	45.69
8	6							Gas - G						
9	Crist 7	477.0	2,493,660	59.7	70.8	84.3	10,340	Coal	1,089,821	11,830	25,785,180	51,613,596	2.07	47.36
10	7							Gas - G						
11	Scherer 3 (2)	210.8	1,760,290	95.3	95.0	100.4	10,244	Coal	1,027,907	8,772	18,032,790	30,885,672	1.75	30.05
12	Scholz 1	46.0	196,230	48.7	87.3	55.8	12,130	Coal	97,912	12,155	2,380,223	6,805,900	3.47	69.51
13	Scholz 2	46.0	182,270	45.2	80.0	56.5	12,385	Coal	92,764	12,168	2,257,473	6,416,384	3.52	69.17
14	Smith 1	162.0	1,061,330	74.8	90.0	83.1	10,274	Coal	454,210	12,003	10,903,657	17,947,978	1.69	39.51
15	Smith 2	189.0	981,200	59.3	72.2	82.1	10,211	Coal	417,315	12,004	10,018,589	16,506,003	1.68	39.55
16	Smith 3	502.0	2,607,900	59.3	85.9	69.0	6,965	Gas - G	17,634,767	1,030	18,163,809	139,369,513	5.34	7.90
17	Smith A (CT)	35.0	220	0.1	100.0	0.1	14,323	Oil - G	534	140,621	3,151	22,145	10.07	41.51
18	Other Generation		101,010									2,795,957	2.77	#N/A
19	Daniel 1 (1)	257.0	1,757,220	78.1	79.0	98.8	9,953	Coal	836,600	10,453	17,489,770	32,000,224	1.82	38.25
20	Daniel 2 (1)	257.0	1,967,470	87.4	88.2	99.1	9,742	Coal	918,185	10,437	19,166,286	35,452,663	1.80	38.61
21	Gas,BL							Gas	62,409	1,030	64,270	424,440	#N/A	6.80
22	Ltr. Oil							Oil	13,523	140,605	79,856	580,586	#N/A	42.93
23		2,700.8	15,829,670	66.9	82.5	81.1	9,720				152,877,741	396,238,725	2.50	

Notes:
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(2) Represents Gulf's 25% Ownership

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	LIGHT OIL													
1	*PURCHASES :*													
2	UNITS (BBL)	1,192	1,044	897	1,045	1,192	1,192	1,192	1,192	1,192	1,020	1,192	1,172	13,523
3	UNIT COST ($/BBL)	44.78	44.85	44.89	44.81	44.78	44.78	44.78	44.78	44.78	44.87	44.78	44.79	44.80
4	AMOUNT ($)	53,382	46,819	40,252	46,815	53,382	53,382	53,382	53,382	53,382	45,774	53,382	52,487	605,821
5	*BURNED :*													
6	UNITS (BBL)	1,192	1,044	897	1,045	1,192	1,192	1,192	1,192	1,192	1,020	1,192	1,172	13,523
7	UNIT COST ($/BBL)	41.55	41.80	41.73	42.20	42.76	42.99	43.19	43.37	43.53	44.15	43.75	43.86	42.93
8	AMOUNT ($)	49,536	43,639	37,416	44,095	50,979	51,248	51,487	51,699	51,889	45,042	52,155	51,401	580,586
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	8,368	8,368	8,368	8,368	8,368	8,368	8,368	8,368	8,368	8,368	8,368	8,368	
11	UNIT COST ($/BBL)	40.71	41.09	41.43	41.76	42.04	42.30	42.53	42.73	42.90	42.99	43.14	43.27	
12	AMOUNT ($)	340,689	343,869	346,705	349,425	351,828	353,962	355,857	357,540	359,033	359,765	360,992	362,078	
13	DAYS SUPPLY:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
	COAL EXCLUDING PLANT SCHERER													
14	*PURCHASES :*													
15	UNITS (TONS)	511,247	353,296	268,186	382,424	515,144	502,652	542,524	543,984	436,325	320,795	318,124	482,137	5,176,838
16	UNIT COST ($/TON)	40.81	38.63	40.52	40.62	43.96	45.37	46.34	46.57	45.79	45.15	45.26	43.25	43.76
17	AMOUNT ($)	20,865,697	13,647,161	10,866,576	15,535,546	22,647,855	22,804,019	25,140,258	25,334,687	19,979,038	14,484,179	14,398,540	20,851,253	226,554,809
18	*BURNED :*													
19	UNITS (TONS)	497,555	333,691	260,179	368,320	500,178	502,355	544,192	545,338	437,325	319,420	317,421	483,439	5,109,413
20	UNIT COST ($/TON)	41.54	39.89	41.00	40.28	41.90	43.47	44.93	45.70	45.54	46.08	45.73	43.86	43.45
21	AMOUNT ($)	20,669,919	13,309,357	10,668,262	14,836,507	20,956,684	21,837,162	24,450,749	24,923,577	19,917,001	14,718,364	14,515,885	21,201,344	222,004,811
22	*ENDING INVENTORY :*													
23	UNITS (TONS)	543,703	563,308	571,315	585,419	600,385	600,682	599,014	597,660	596,660	598,035	598,738	597,436	
24	UNIT COST ($/TON)	43.22	42.32	42.07	42.25	44.02	45.60	46.88	47.68	47.86	47.36	47.11	46.62	
25	AMOUNT ($)	23,500,205	23,838,009	24,036,323	24,735,362	26,426,533	27,393,390	28,082,899	28,494,009	28,556,046	28,321,861	28,204,516	27,854,425	
26	DAYS SUPPLY:	28	29	29	30	31	31	31	31	31	31	31	31	

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	COAL AT PLANT SCHERER													
27	*PURCHASES :*													
28	UNITS (MMBTU)	1,253,653	1,330,734	1,624,279	1,490,235	1,522,138	1,439,003	1,433,745	1,437,425	1,489,863	1,521,235	1,471,514	1,521,234	17,535,059
29	UNIT COST ($/MMBTU	1.71	1.71	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.72
30	AMOUNT ($)	2,147,208	2,281,069	2,790,854	2,558,067	2,613,470	2,469,095	2,459,964	2,466,354	2,557,421	2,611,902	2,525,555	2,611,902	30,092,862
31	*BURNED :*													
32	UNITS (MMBTU)	1,524,461	1,377,012	1,524,461	1,474,651	1,534,486	1,493,725	1,543,767	1,543,767	1,492,887	1,524,461	1,474,651	1,524,461	18,032,790
33	UNIT COST ($/MMBTU	1.70	1.70	1.71	1.71	1.71	1.72	1.72	1.72	1.72	1.72	1.72	1.72	1.71
34	AMOUNT ($)	2,587,366	2,346,801	2,608,068	2,526,529	2,631,446	2,562,132	2,648,283	2,648,510	2,561,843	2,616,667	2,531,067	2,616,960	30,885,672
35	*ENDING INVENTORY :*													
36	UNITS (MMBTU)	2,063,323	2,017,045	2,116,863	2,132,447	2,120,099	2,065,377	1,955,355	1,849,013	1,845,990	1,842,763	1,839,627	1,836,400	
37	UNIT COST ($/MMBTU	1.70	1.71	1.71	1.71	1.71	1.72	1.72	1.72	1.72	1.72	1.72	1.72	
38	AMOUNT ($)	3,505,099	3,439,368	3,622,155	3,653,693	3,635,717	3,542,680	3,354,361	3,172,205	3,167,783	3,163,019	3,157,507	3,152,449	
39	DAYS SUPPLY:	40	39	41	41	41	40	38	36	36	35	35	35	
	GAS													
44	*BURNED :*													
45	UNITS (MCF)	1,202,853	1,066,934	1,698,797	1,468,005	1,437,812	1,709,249	2,059,273	2,127,068	1,738,263	1,910,114	1,087,930	213,316	17,719,614
46	UNIT COST ($/MCF)	8.01	8.03	7.20	7.69	8.34	8.10	8.17	8.13	7.74	7.63	7.26	10.99	7.90
47	AMOUNT ($)	9,639,630	8,564,582	12,231,990	11,284,686	11,984,741	13,846,740	16,820,520	17,303,418	13,454,572	14,575,595	7,899,194	2,343,886	139,949,554
	OTHER - C.T. OIL													
53	*PURCHASES :*													
54	UNITS (BBL)	0	0	0	0	0	0	0	534	0	0	0	0	534
55	UNIT COST ($/BBL)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	44.55	#N/A	#N/A	#N/A	#N/A	44.55
56	AMOUNT ($)	0	0	0	0	0	0	0	23,789	0	0	0	0	23,789
57	*BURNED :*													
58	UNITS (BBL)	0	0	0	0	0	0	0	534	0	0	0	0	534
59	UNIT COST ($/BBL)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	41.47	#N/A	#N/A	#N/A	#N/A	41.47
60	AMOUNT ($)	0	0	0	0	0	0	0	22,145	0	0	0	0	22,145
61	*ENDING INVENTORY :*													
62	UNITS (BBL)	12,857	12,857	12,857	12,857	12,857	12,857	12,857	12,857	12,857	12,857	12,857	12,857	
63	UNIT COST ($/BBL)	41.38	41.38	41.38	41.38	41.38	41.38	41.38	41.51	41.51	41.51	41.51	41.51	
64	AMOUNT ($)	532,049	532,049	532,049	532,049	532,049	532,049	532,049	533,693	533,693	533,693	533,693	533,693	
65	DAYS SUPPLY:	7	7	7	7	7	7	7	7	7	7	7	7	

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
					(A)	(B)	(6) x (7)(A)	(6) x (7)(B)
			KWH		¢ / KWH		TOTAL $	
	MONTH	TOTAL	WHEELED	KWH	FUEL	TOTAL	FOR FUEL	TOTAL COST
LINE	TYPE & SCHEDULE	KWH SOLD	FROM OTHER SYSTEMS	FROM OWN GENERATION	COST	COST	ADJUSTMENT	$
	JANUARY							
1	Southern Co. Interchange	375,877,000	0	375,877,000	3.07	3.31	11,546,000	12,440,000
2	Unit Power Sales	108,739,000	0	108,739,000	1.84	1.98	2,003,000	2,151,000
3	Economy Sales	7,638,000	0	7,638,000	3.71	3.77	283,000	288,000
4	Gain on Economy Sales						279,000	279,000
5	TOTAL ESTIMATED SALES	492,254,000	0	492,254,000	2.87	3.08	14,111,000	15,158,000
	FEBRUARY							
1	Southern Co. Interchange	160,664,000	0	160,664,000	3.09	3.35	4,972,000	5,376,000
2	Unit Power Sales	133,090,000	0	133,090,000	2.01	2.13	2,678,000	2,841,000
3	Economy Sales	4,068,000	0	4,068,000	4.25	4.13	173,000	168,000
4	Gain on Economy Sales						234,000	234,000
5	TOTAL ESTIMATED SALES	297,822,000	0	297,822,000	2.71	2.89	8,057,000	8,619,000
	MARCH							
1	Southern Co. Interchange	77,571,000	0	77,571,000	3.36	3.60	2,606,000	2,791,000
2	Unit Power Sales	157,535,000	0	157,535,000	2.00	2.13	3,155,000	3,348,000
3	Economy Sales	8,542,000	0	8,542,000	4.13	4.13	353,000	353,000
4	Gain on Economy Sales						197,000	197,000
5	TOTAL ESTIMATED SALES	243,648,000	0	243,648,000	2.59	2.75	6,311,000	6,689,000
	APRIL							
1	Southern Co. Interchange	256,070,000	0	256,070,000	3.15	3.39	8,058,000	8,676,000
2	Unit Power Sales	108,451,000	0	108,451,000	1.85	1.99	2,011,000	2,162,000
3	Economy Sales	4,691,000	0	4,691,000	3.88	3.94	182,000	185,000
4	Gain on Economy Sales						164,000	164,000
5	TOTAL ESTIMATED SALES	369,212,000	0	369,212,000	2.82	3.03	10,415,000	11,187,000
	MAY							
1	Southern Co. Interchange	296,843,000	0	296,843,000	3.07	3.30	9,103,000	9,808,000
2	Unit Power Sales	107,463,000	0	107,463,000	1.82	1.96	1,958,000	2,106,000
3	Economy Sales	4,909,000	0	4,909,000	3.63	3.71	178,000	182,000
4	Gain on Economy Sales						225,000	225,000
5	TOTAL ESTIMATED SALES	409,215,000	0	409,215,000	2.80	3.01	11,464,000	12,321,000
	JUNE							
1	Southern Co. Interchange	192,906,000	0	192,906,000	3.39	3.62	6,535,000	6,988,000
2	Unit Power Sales	126,356,000	0	126,356,000	1.82	1.96	2,302,000	2,478,000
3	Economy Sales	8,828,000	0	8,828,000	3.89	3.94	343,000	348,000
4	Gain on Economy Sales						289,000	289,000
5	TOTAL ESTIMATED SALES	328,090,000	0	328,090,000	2.89	3.08	9,469,000	10,103,000

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
					(A)	(B)	(6) x (7)(A)	(6) x (7)(B)
			KWH		¢ / KWH		TOTAL $	
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH SOLD	WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	FUEL COST	TOTAL COST	FOR FUEL ADJUSTMENT	TOTAL COST $
	JULY							
1	Southern Co. Interchange	260,376,000	0	260,376,000	3.67	3.91	9,554,000	10,181,000
2	Unit Power Sales	127,569,000	0	127,569,000	1.85	1.98	2,356,000	2,532,000
3	Economy Sales	8,463,000	0	8,463,000	4.82	4.84	408,000	410,000
4	Gain on Economy Sales						312,000	312,000
5	TOTAL ESTIMATED SALES	396,408,000	0	396,408,000	3.19	3.39	12,630,000	13,435,000
	AUGUST							
1	Southern Co. Interchange	282,011,000	0	282,011,000	3.91	4.15	11,033,000	11,695,000
2	Unit Power Sales	127,879,000	0	127,879,000	1.85	1.99	2,371,000	2,546,000
3	Economy Sales	4,590,000	0	4,590,000	5.29	5.34	243,000	245,000
4	Gain on Economy Sales						271,000	271,000
5	TOTAL ESTIMATED SALES	414,480,000	0	414,480,000	3.36	3.56	13,918,000	14,757,000
	SEPTEMBER							
1	Southern Co. Interchange	242,762,000	0	242,762,000	3.27	3.51	7,948,000	8,523,000
2	Unit Power Sales	105,510,000	0	105,510,000	1.83	1.97	1,930,000	2,076,000
3	Economy Sales	7,125,000	0	7,125,000	4.08	4.14	291,000	295,000
4	Gain on Economy Sales						79,000	79,000
5	TOTAL ESTIMATED SALES	355,397,000	0	355,397,000	2.88	3.09	10,248,000	10,973,000
	OCTOBER							
1	Southern Co. Interchange	167,937,000	0	167,937,000	3.28	3.54	5,501,000	5,942,000
2	Unit Power Sales	91,028,000	0	91,028,000	1.87	2.00	1,699,000	1,825,000
3	Economy Sales	4,359,000	0	4,359,000	3.83	3.88	167,000	169,000
4	Gain on Economy Sales						93,000	93,000
5	TOTAL ESTIMATED SALES	263,324,000	0	263,324,000	2.83	3.05	7,460,000	8,029,000
	NOVEMBER							
1	Southern Co. Interchange	190,487,000	0	190,487,000	3.10	3.36	5,896,000	6,399,000
2	Unit Power Sales	98,578,000	0	98,578,000	1.85	1.99	1,827,000	1,964,000
3	Economy Sales	5,749,000	0	5,749,000	3.79	3.83	218,000	220,000
4	Gain on Economy Sales						248,000	248,000
5	TOTAL ESTIMATED SALES	294,814,000	0	294,814,000	2.78	3.00	8,189,000	8,831,000
	DECEMBER							
1	Southern Co. Interchange	239,647,000	0	239,647,000	2.86	3.08	6,844,000	7,380,000
2	Unit Power Sales	112,171,000	0	112,171,000	1.82	1.96	2,037,000	2,193,000
3	Economy Sales	4,700,000	0	4,700,000	3.28	3.38	154,000	159,000
4	Gain on Economy Sales						236,000	236,000
5	TOTAL ESTIMATED SALES	356,518,000	0	356,518,000	2.60	2.80	9,271,000	9,968,000
	TOTAL							
1	Southern Co. Interchange	2,743,151,000	0	2,743,151,000	3.27	3.51	89,596,000	96,199,000
2	Unit Power Sales	1,404,369,000	0	1,404,369,000	1.87	2.01	26,327,000	28,222,000
3	Economy Sales	73,662,000	0	73,662,000	4.06	4.10	2,993,000	3,022,000
4	Gain on Economy Sales						2,627,000	2,627,000
5	TOTAL ESTIMATED SALES	4,221,182,000	0	4,221,182,000	2.88	3.08	121,543,000	130,070,000

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							¢ / KWH		
MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL KWH PURCH.	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7)x(8)(a)
January	NONE								
February	NONE								
March	NONE								
April	NONE								
May	NONE								
June	NONE								
July	NONE								
August	NONE								
September	NONE								
October	NONE								
November	NONE								
December	NONE								
Total	NONE								

SCHEDULE E-8

ENERGY PAYMENT TO QUALIFYING FACILITIES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				KWH			¢/KWH		
MONTH	PURCHASED FROM:	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
JANUARY	Solutia	COG-1				None			
FEBRUARY	Solutia	COG-1				None			
MARCH	Solutia	COG-1				None			
APRIL	Solutia	COG-1				None			
MAY	Solutia	COG-1				None			
JUNE	Solutia	COG-1				None			
JULY	Solutia	COG-1				None			
AUGUST	Solutia	COG-1				None			
SEPTEMBER	Solutia	COG-1				None			
OCTOBER	Solutia	COG-1				None			
NOVEMBER	Solutia	COG-1				None			
DECEMBER	Solutia	COG-1				None			
TOTAL			0			-			0

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JANUARY			
1	Southern Co. Interchange	11,206,000	2.97	333,000
2	Unit Power Sales	1,078,000	3.71	40,000
3	Economy Energy	3,045,000	3.71	113,000
4	Other Purchases	4,220,000	2.80	118,000
5	TOTAL ESTIMATED PURCHASES	19,549,000	3.09	604,000
	FEBRUARY			
1	Southern Co. Interchange	20,008,000	3.53	707,000
2	Unit Power Sales	4,138,000	3.79	157,000
3	Economy Energy	2,100,000	4.00	84,000
4	Other Purchases	8,620,000	2.98	257,000
5	TOTAL ESTIMATED PURCHASES	34,866,000	3.46	1,205,000
	MARCH			
1	Southern Co. Interchange	103,471,000	3.35	3,467,000
2	Unit Power Sales	4,212,000	3.70	156,000
3	Economy Energy	3,348,000	4.06	136,000
4	Other Purchases	15,900,000	3.34	531,000
5	TOTAL ESTIMATED PURCHASES	126,931,000	3.38	4,290,000
	APRIL			
1	Southern Co. Interchange	8,421,000	3.50	295,000
2	Unit Power Sales	1,550,000	3.55	55,000
3	Economy Energy	1,995,000	3.76	75,000
4	Other Purchases	17,960,000	3.76	561,000
5	TOTAL ESTIMATED PURCHASES	29,926,000	3.29	986,000
	MAY			
1	Southern Co. Interchange	12,146,000	2.96	360,000
2	Unit Power Sales	1,517,000	3.36	51,000
3	Economy Energy	2,445,000	3.56	87,000
4	Other Purchases	19,690,000	2.88	567,000
5	TOTAL ESTIMATED PURCHASES	35,798,000	2.98	1,065,000
	JUNE			
1	Southern Co. Interchange	20,267,000	3.90	790,000
2	Unit Power Sales	2,051,000	3.71	76,000
3	Economy Energy	4,622,000	3.72	172,000
4	Other Purchases	15,350,000	3.39	521,000
5	TOTAL ESTIMATED PURCHASES	42,290,000	3.69	1,559,000

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2004 - DECEMBER 2004

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JULY			
1	Southern Co. Interchange	16,755,000	5.63	944,000
2	Unit Power Sales	2,334,000	4.97	116,000
3	Economy Energy	4,960,000	4.90	243,000
4	Other Purchases	8,050,000	3.78	304,000
5	TOTAL ESTIMATED PURCHASES	32,099,000	5.01	1,607,000
	AUGUST			
1	Southern Co. Interchange	8,424,000	4.25	358,000
2	Unit Power Sales	2,292,000	5.19	119,000
3	Economy Energy	3,049,000	5.41	165,000
4	Other Purchases	7,990,000	3.89	311,000
5	TOTAL ESTIMATED PURCHASES	21,755,000	4.38	953,000
	SEPTEMBER			
1	Southern Co. Interchange	26,217,000	4.49	1,178,000
2	Unit Power Sales	1,598,000	3.63	58,000
3	Economy Energy	4,602,000	4.06	187,000
4	Other Purchases	8,440,000	3.23	273,000
5	TOTAL ESTIMATED PURCHASES	40,857,000	4.15	1,696,000
	OCTOBER			
1	Southern Co. Interchange	47,636,000	3.23	1,540,000
2	Unit Power Sales	1,314,000	3.73	49,000
3	Economy Energy	2,530,000	3.75	95,000
4	Other Purchases	10,320,000	2.76	285,000
5	TOTAL ESTIMATED PURCHASES	61,800,000	3.19	1,969,000
	NOVEMBER			
1	Southern Co. Interchange	52,081,000	3.40	1,771,000
2	Unit Power Sales	1,541,000	3.83	59,000
3	Economy Energy	2,096,000	3.67	77,000
4	Other Purchases	9,720,000	2.80	272,000
5	TOTAL ESTIMATED PURCHASES	65,438,000	3.33	2,179,000
	DECEMBER			
1	Southern Co. Interchange	11,480,000	2.79	320,000
2	Unit Power Sales	1,078,000	3.25	35,000
3	Economy Energy	2,089,000	3.30	69,000
4	Other Purchases	10,380,000	2.57	267,000
5	TOTAL ESTIMATED PURCHASES	25,027,000	2.76	691,000
	TOTAL FOR PERIOD			
1	Southern Co. Interchange	338,112,000	3.57	12,063,000
2	Unit Power Sales	24,703,000	3.93	971,000
3	Economy Energy	36,881,000	4.08	1,503,000
4	Other Purchases	136,640,000	3.12	4,267,000
5	TOTAL ESTIMATED PURCHASES	536,336,000	3.51	18,804,000

Schedule E-10

RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2005 - DECEMBER 2005

	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	AVERAGE
Customer Charge	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00
Energy Charge	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30
Conservation Cost Recovery	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76
Environmental Cost Recovery	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40	2.40
Capacity Cost Recovery	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10	2.10
Subtotal Base	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56
Fuel Cost (Schedule E2)	24.78	25.37	32.15	26.65	26.92	28.84	29.46	29.08	30.23	33.03	27.77	23.26	28.22
Group Line Loss Multiplier	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526	1.00526
Fuel Cost Recovery	24.91	25.50	32.32	26.79	27.06	28.99	29.61	29.23	30.39	33.20	27.92	23.38	28.36
Gross Receipts	2.04	2.05	2.23	2.09	2.09	2.14	2.16	2.15	2.18	2.25	2.12	2.00	2.13
Total	81.51	82.11	89.11	83.44	83.71	85.69	86.33	85.93	87.13	90.01	84.59	79.94	85.06

Note: ECCR is current 2004 factor because the projected 2005 factor has not been filed. Fuel, PPCC & ECRC are projected 2005 factors.
*Monthly and cumulative twelve month estimated data

SCHEDULE E-11

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST
GULF POWER COMPANY

		TOTAL ¢ / KWH
2005	JANUARY	1.978
	FEBRUARY	1.978
	MARCH	1.978
	APRIL	2.180
	MAY	2.180
	JUNE	2.180
	JULY	2.180
	AUGUST	2.180
	SEPTEMBER	2.180
	OCTOBER	2.180
	NOVEMBER	1.965
	DECEMBER	1.965
2006	JANUARY	1.965
	FEBRUARY	1.965
	MARCH	1.965
	APRIL	2.210
	MAY	2.210
	JUNE	2.210
	JULY	2.210
	AUGUST	2.210
	SEPTEMBER	2.210
	OCTOBER	2.210
	NOVEMBER	2.027
	DECEMBER	2.027

SCHEDULE H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2005 - DECEMBER 2005

LINE	LINE DESCRIPTION	2002	2003	2004	2005	DIFFERENCE (%) FROM PRIOR PERIOD 2002 to 2003	2003 to 2004	2004 to 2005
	FUEL COST OF SYSTEM NET GENERATION ($)							
2	LIGHTER OIL (B.L.)	595,280	387,045	423,760	580,586	(34.98)	9.49	37.01
3	COAL	200,532,553	184,938,103	209,531,242	222,004,811	(7.78)	13.30	5.95
3a	COAL at Scherer	24,868,993	27,665,239	25,476,894	30,885,672	11.24	(7.91)	21.23
4	GAS	76,046,394	99,393,351	104,550,093	139,525,114	30.70	5.19	33.45
4a	GAS (B.L.)	393,420	279,368	241,670	424,440	(28.99)	(13.49)	75.63
6	OTHER - C.T.	1,093,946	82,237	2,676	22,145	(92.48)	(96.75)	727.54
6a	OTHER GENERATION	217,158	19,253	19,205	2,795,957	(91.13)	(0.25)	14,458.48
7	TOTAL ($)	303,747,744	312,764,596	340,245,540	396,238,725	2.97	8.79	16.46
	SYSTEM NET GENERATION (MWH)							
8	COAL	13,141,770	13,087,710	14,070,680	13,119,070	(0.41)	7.51	(6.76)
9	GAS	1,838,690	2,836,540	2,180,540	2,609,370	54.27	(23.13)	19.67
10	OTHER - C.T.	15,210	1,020	30	220	(93.29)	(97.06)	633.33
10a	OTHER GENERATION	10,200	820	790	101,010	(91.96)	(3.66)	12,686.08
11	TOTAL (MWH)	15,005,870	15,926,090	16,252,040	15,829,670	6.13	2.05	(2.60)
	UNITS OF FUEL BURNED							
12	LIGHTER OIL (BBL)	19,560	13,859	13,904	13,523	(29.15)	0.32	(2.74)
13	COAL excl. Scherer (TON)	5,044,600	5,078,332	5,405,166	5,109,413	0.67	6.44	(5.47)
14	GAS (MCF)	14,594,108	20,528,086	15,288,394	17,719,614	40.66	(25.52)	15.90
15	OTHER - C.T. (BBL)	36,207	2,467	77	534	(93.19)	(96.88)	593.51
	BTU'S BURNED (MMBTU)							
16	COAL + GAS B.L. + OIL B.L.	134,479,733	135,130,195	144,133,613	134,687,669	0.48	6.66	(6.55)
17	GAS - Generation	14,936,020	21,067,944	15,701,522	18,186,921	41.05	(25.47)	15.83
18	OTHER - C.T.	213,809	14,404	450	3,151	(93.26)	(96.88)	600.22
19	TOTAL (MMBTU)	149,629,562	156,212,544	159,835,585	152,877,741	4.40	2.32	(4.35)
	GENERATION MIX (% MWH)							
30	COAL + GAS B.L. + OIL B.L.	87.58	82.17	86.57	82.88	(6.18)	5.35	(4.26)
31	GAS - Generation	12.25	17.81	13.42	16.48	45.39	(24.65)	22.80
33	OTHER - C.T.	0.10	0.01	0.00	0.00	(90.00)	(100.00)	#N/A
33a	OTHER GENERATION	0.07	0.01	0.00	0.64	(85.71)	(100.00)	#N/A
34	TOTAL (% MWH)	100.00	100.00	100.00	100.00	0.00	0.00	0.00
	FUEL COST PER UNIT							
36	LIGHTER OIL B.L. ($/BBL)	30.43	27.93	30.48	42.93	(8.22)	9.13	40.85
37	COAL ($/TON)	39.75	36.42	38.76	43.45	(8.38)	6.43	12.10
38	GAS +B.L. ($/MCF)	5.24	4.86	6.85	7.90	(7.25)	40.95	15.33
40	OTHER - C.T.	30.21	33.34	34.79	41.47	10.36	4.35	19.20
	FUEL COST ($) / MMBTU							
43	COAL + GAS B.L. + OIL B.L.	1.68	1.58	1.64	1.89	(5.95)	3.80	15.24
44	GAS - Generation	5.09	4.72	6.66	7.67	(7.27)	41.10	15.17
46	OTHER - C.T.	5.12	5.71	5.95	7.03	11.52	4.20	18.15
47	TOTAL ($/MMBTU)	2.03	2.00	2.13	2.57	(1.48)	6.50	20.66
	BTU BURNED / KWH							
50	COAL + GAS B.L. + OIL B.L.	10,233	10,325	10,244	10,267	0.90	(0.78)	0.22
51	GAS - Generation	8,123	7,427	7,201	6,970	(8.57)	(3.04)	(3.21)
53	OTHER - C.T.	14,057	14,121	15,000	14,323	0.46	6.22	(4.51)
54	TOTAL (BTU/KWH)	9,978	9,809	9,835	9,720	(1.69)	0.27	(1.17)
	FUEL COST (¢ / KWH)							
57	COAL + GAS B.L. + OIL B.L.	1.72	1.63	1.67	1.93	(5.23)	2.45	15.57
58	GAS - Generation	4.14	3.50	4.79	5.35	(15.46)	36.86	11.69
60	OTHER - C.T.	7.19	8.06	8.92	10.07	12.10	10.67	12.89
60a	OTHER GENERATION	2.13	2.35	2.43	2.77	10.33	3.40	13.99
61	TOTAL (¢ / KWH)	2.02	1.96	2.09	2.50	(2.97)	6.63	19.62

Schedule CCE-1

Projected Purchased Power Capacity Payments/(Receipts)
Gulf Power Company
For January 2005 - December 2005

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	Projected IIC Payments/(Receipts) & Market Sales ($)	1,424,368	501,844	678,421	66,376	251,085	2,414,018	8,237,685	6,749,241	2,975,736	273,624	80,287	146,260	23,798,945
2	Projected Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	0	0	0	0	0	0	0	311,010
2a	Subtotal	1,486,570	564,046	740,623	128,578	313,287	2,414,018	8,237,685	6,749,241	2,975,736	273,624	80,287	146,260	24,109,955
3	Projected Transmission Revenue	(10,000)	(6,000)	(12,000)	(6,000)	(7,000)	(12,000)	(11,000)	(6,000)	(10,000)	(6,000)	(8,000)	(6,000)	(100,000)
4	Total Projected Capacity Payments/(Receipts) (Line 2a + 3) ($)	1,476,570	558,046	728,623	122,578	306,287	2,402,018	8,226,685	6,743,241	2,965,736	267,624	72,287	140,260	24,009,955
5	Jurisdictional %	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872	0.9664872
6	Projected Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	1,427,086	539,344	704,205	118,470	296,022	2,321,520	7,950,986	6,517,256	2,866,346	258,655	69,864	135,559	23,205,313
7	True-Up ($)													(2,851,475)
8	Total Jurisdictional Amount to be Recovered (Line 6 + Line 7) ($)													20,353,838
9	Revenue Tax Multiplier													1.00072
10	Total Recoverable Capacity Payments/(Receipts) (Line 8 x Line 9) ($)													20,368,493

Calculation of Jurisdictional % *

	12 CP KW	%
FPSC	1,757,001.79	96.64872%
FERC	60,923.80	3.35128%
Total	1,817,925.59	100.00000%

* Based on 2003 Actual Data

Schedule CCE-1a
REVISED 9/9/2004

Purchased Power Capacity Cost Recovery Clause
Calculation of True-up
Gulf Power Company
January 2005 - December 2005

1	Estimated over/(under)-recovery, January 2004 - December 2004 (Revised Schedule CCE-1b-1, Line 15)	$1,797,696
2	Final True-Up, January 2003 - December 2003 (Exhibit No.____(TAD-1), filed April 1, 2004	1,053,779
3	Total Over/(Under)-Recovery (Line 1 & 2) (To be included in January 2005 - December 2005)	$2,851,475
4	Jurisdictional KWH sales, January 2005 - December 2005	11,032,273,000
5	True-up Factor (Line 3 / Line 4) x 100 (Cents/KWH)	(0.0258)

Schedule CCE-1b
REVISED 9/9/2004

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2004 - December 2004

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	1,265,929	353,640	484,415	7,329	41,220	1,832,176	5,405,203	5,688,244	2,360,242	199,580	67,649	144,635	17,850,262
2	Projected Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3	Transmission Revenue ($)	(56,915)	(37,119)	(31,779)	(15,372)	(28,687)	(20,062)	(14,323)	(7,000)	(11,000)	(7,000)	(9,000)	(7,000)	(245,256)
4	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	1,271,216	378,724	514,838	54,159	74,735	1,874,316	5,453,082	5,743,446	2,411,444	254,782	120,851	199,837	18,351,430
5	Jurisdictional %	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	
6	Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	1,226,747	365,476	496,828	52,264	72,122	1,808,750	5,262,326	5,542,533	2,327,089	245,869	116,623	192,846	17,709,471
7	Retail KWH Sales								1,121,219,000	928,542,000	820,717,000	711,070,000	814,258,000	
8	Purchased Power Capacity Cost Recovery Factor (¢/KWH)								0.167	0.167	0.167	0.167	0.167	
9	Capacity Cost Recovery Revenues (Line 7 x Line 8/100) ($)	1,605,955	1,384,327	1,255,441	1,242,257	1,612,485	1,794,023	1,994,320	1,872,436	1,550,665	1,370,597	1,187,487	1,359,811	18,229,804
10	Revenue Taxes (Line 9 x .00072) ($)*	1,156	997	904	894	1,161	1,292	1,436	1,348	1,116	987	855	979	13,125
11	True-Up Provision ($)	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	104,381	1,252,572
12	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 9 - Line 10 + Line 11) ($)	1,709,180	1,487,711	1,358,918	1,345,744	1,715,705	1,897,112	2,097,265	1,975,469	1,653,930	1,473,991	1,291,013	1,463,213	19,469,251
13	Over/(Under) Recovery (Line 12 - Line 6) ($)	482,433	1,122,235	862,090	1,293,480	1,643,583	88,362	(3,165,061)	(3,567,064)	(673,159)	1,228,122	1,174,390	1,270,367	1,759,780
14	Interest Provision ($)	2,173	2,676	3,337	4,240	5,547	7,108	6,490	2,449	(144)	58	1,338	2,644	37,916
15	Total Estimated True-Up for the Period January 2004 - December 2004 (Lines 13 + 14) ($)													1,797,696

NOTE 1: Interest is Calculated for August - December at July's rate of 0.1167 %
NOTE 2: Actual IIC Payments for January through June include Market Capacity Payments

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
For January 2005 - December 2005

Rate Class	A Average 12 CP Load Factor at Meter	B Jan - Dec 05 Projected KWH Sales at Meter	C Projected Avg 12 CP KW at Meter Col B / (8,760 hours x Col A)	D Demand Loss Expansion Factor	E Energy Loss Expansion Factor	F Jan - Dec 05 Projected KWH Sales at Generation Col B x Col E	G Projected Avg 12 CP KW at Generation Col C x Col D	H Percentage of KWH Sales at Generation Col F / Total Col F	I Percentage of 12 CP KW Demand at Generation Col G / Total Col G
RS, RSVP	61.971315%	5,115,450,000	942,299.64	1.0053010	1.00530097	5,142,566,847	947,294.77	46.61346%	53.35737%
GS	64.200053%	210,439,000	37,418.53	1.0052978	1.00529775	211,553,853	37,616.77	1.91757%	2.11880%
GSD, GSDT, GSTOU	73.167949%	2,554,407,000	398,533.75	1.0051660	1.00516604	2,567,603,169	400,592.58	23.27337%	22.56380%
LP, LPT	84.177808%	1,946,335,000	263,946.48	0.9891199	0.98911989	1,925,158,661	261,074.72	17.45010%	14.70531%
PX, PXT, RTP, SBS	101.650370%	1,073,614,000	120,568.84	0.9805725	0.98057253	1,052,756,396	118,226.49	9.54244%	6.65923%
OS - I / II	160.732077%	105,411,000	7,486.51	1.0052949	1.00529485	105,969,135	7,526.15	0.96053%	0.42392%
OS-III	100.278526%	26,617,000	3,030.03	1.0052683	1.00526827	26,757,226	3,045.99	0.24253%	0.17157%
TOTAL		11,032,273,000	1,773,283.78			11,032,365,287	1,775,377.47	100.00000%	100.00000%

Notes:
Col A - Average 12 CP load factor based on actual 2003 load research data.
Col C - 8,760 is the number of hours in 12 months.

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
For January 2005 - December 2005

Rate Class	A Jan - Dec 05 Percentage of KWH Sales at Generation Page 1, Col H	B Percentage of 12 CP KW Demand at Generation Page 1, Col I	C Energy-Related Costs ($)	D Demand-Related Costs ($)	E Total Capacity Costs ($) Col C + Col D	F Jan - Dec 05 Projected KWH Sales at Meter Page 1, Col B	G Capacity Cost Recovery Factors (¢ / KWH) Col E / Col F x 100
RS, RSVP	46.61346%	53.35737%	730,342	10,032,085	10,762,427	5,115,450,000	0.210
GS	1.91757%	2.11880%	30,045	398,370	428,415	210,439,000	0.204
GSD, GSDT, GSTOU	23.27337%	22.56380%	364,649	4,242,375	4,607,024	2,554,407,000	0.180
LP, LPT	17.45010%	14.70531%	273,409	2,764,846	3,038,255	1,946,335,000	0.156
PX, PXT, RTP, SBS	9.54244%	6.65923%	149,512	1,252,048	1,401,560	1,073,614,000	0.131
OS - I / II	0.96053%	0.42392%	15,050	79,704	94,754	105,411,000	0.090
OS-III	0.24253%	0.17157%	3,800	32,258	36,058	26,617,000	0.135
TOTAL	100.00000%	100.00000%	$1,566,807	$18,801,686	$20,368,493	11,032,273,000	0.185

Notes:
Col C - (Recoverable Amount from Schedule CCE-1, line 12) / 13 x Col A
Col D - (Recoverable Amount from Schedule CCE-1, line 12) x 12 / 13 x Col B

Florida Public Service Commission
Docket No. 040001-EI
Gulf Power Company
Witness: L. S. Noack
Exhibit No. ___ (LSN-1)

EXHIBIT TO THE TESTIMONY OF

L. S. NOACK

IN FPSC DOCKET 040001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 28
COMPANY/ Gulf
WITNESS. L.S. Noack (LSN-1)
DATE: 11-08-04

I. CORRECTIONS TO REPORTED DATA FOR THE JANUARY 2003 - DECEMBER 2003 PERIOD

Additions and Corrections to Outages Previously Reported
for the January 2003 - December 2003 Period

Date	Unit	Change	Outage Type	Hours	MW	Description
03/30/03	Crist 7	Event Type	NC	4.8	477.0	Change to FFO
03/27/03	Daniel 1	Event Type	FMO	10.1	507.0	Change to PO
03/28/03	Daniel 1	Event Type	FMO	12.4	507.0	Change to PO
05/19/03	Daniel 2	MW Affected	PFO	150.3	61.0	Change 61.0 to 63.8 (Overlapping Event)
05/19/03	Daniel 2	MW Affected	PMO	5.4	374.0	Change 374.0 to 310.0 (Overlapping Event)
05/20/03	Daniel 2	MW Affected	PFO	0.2	374.0	Change 374.0 to 310.0 (Overlapping Event)
05/20/03	Daniel 2	MW Affected	PFO	0.3	254.0	Change 254.0 to 190.0 (Overlapping Event)
05/20/03	Daniel 2	MW Affected	PFO	0.3	204.0	Change 204.0 to 140.0 (Overlapping Event)
05/20/03	Daniel 2	MW Affected	PFO	1.1	184.0	Change 184.0 to 120.0 (Overlapping Event)
07/10/03	Crist 6	Event Hours	PMO	15.5	302.0	Change 15.5 to 16.4
07/10/03	Crist 6	Event Hours	FMO	20.2	302.0	Change 20.2 to 19.3

II. CALCULATIONS OF EQUIVALENT AVAILABILITY POINTS

Comparison of Forecast and Actual Planned Outages
for January 2003 - December 2003

Unit	Note	Forecast Planned Outage Schedule	Forecast Hours*	Actual Planned Outage Schedule	Actual Hours*
Crist 4	1	09/20/03 - 10/12/03	552.0	10/24/03 - 11/15/03	525.7
Crist 5	2	10/25/03 - 11/16/03	553.0	10/31/03 - 11/21/03	501.4
Crist 6	3	03/01/03 - 03/30/03	720.0	04/05/03 - 04/26/03	516.1
Crist 7	4	04/05/03 - 05/04/03	719.0	02/28/03 - 03/30/03	699.9
Smith 1	5	04/11/03 - 05/11/03	744.0	04/18/03 - 05/17/03	684.8
Smith 1	6	11/29/03 - 12/07/03	216.0	11/29/03 - 12/24/03	607.2
Smith 2	7	01/04/03 - 04/06/03	2231.0	01/01/03 - 04/13/03	2449.1
Smith 2	8	10/25/03 - 11/02/03	217.0	-	-
Daniel 1	9	01/06/03 - 03/30/03	2016.0	01/05/03 - 03/28/03	1970.9
Daniel 1	10	-	-	11/20/03 - 12/06/03	372.2
Daniel 2	11	-	-	02/14/03 - 02/27/03	307.4
Daniel 2	12	10/11/03 - 11/09/03	721.0	11/08/03 - 12/19/03	1002.0

* Planned outage hours in the January 2003 - December 2003 period only.

Notes:
1. The outage date was changed subsequent to the target filing, and it proceeded as scheduled.
2. The outage date was changed subsequent to the target filing, and it proceeded as scheduled with all work completed ahead of schedule.
3. The outage date was changed subsequent to the target filing, and it proceeded as scheduled with all work completed ahead of schedule.
4. The outage date was changed subsequent to the target filing, and it proceeded as scheduled.
5. The outage date was changed subsequent to the target filing.
6. The outage date was changed subsequent to the target filing, and it proceeded as scheduled with all work completed ahead of schedule.
7. The outage date was changed subsequent to the target filing, and it proceeded as scheduled.
8. The outage date was changed subsequent to the target filing.
9. This outage proceeded as scheduled and was completed ahead of schedule.
10. The outage date was added subsequent to the target filing, and it proceeded as scheduled.
11. The outage date was added subsequent to the target filing, and it proceeded as scheduled.
12. The outage date was changed subsequent to the target filing.

Calculation of Actual Equivalent Availability
for January 2003 - December 2003
Based on Target Planned Outage Hours
Crist 4

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	73.4	0.0	0.0	54.1	127.5
EFOH	0.0	0.0	0.0	0.0	0.0	0.6	
	0.0	0.0	0.0	0.0	0.0	0.0	0.6
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	171.1	354.6	0.0	525.7
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(127.5 + 0.6 + 0.0 + 0.0)}{(8760.0 - 525.7 - 0.0)}$$

$$EUOR = 0.0156$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 552.0

Target RSH* = 392.0

$$EA = \left[1 - \frac{(552.0 + 0.0156\ (8760.0 - 552.0 - 392.0))}{8760.0} \right] \times 100 = 92.3\ \%$$

Note: Please refer to page 12 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2003 - December 2003
Based on Target Planned Outage Hours
Crist 5

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	31.3	0.0	
	0.0	0.0	2.6	0.0	24.8	36.7	95.4
EFOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	31.7	0.0	46.5	36.3	114.5
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	3.7	497.7	0.0	501.4
RSH	0.0	0.0	0.0	0.0	71.3	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	71.3

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(95.4 + 0.0 + 114.5 + 0.0)}{(8760.0 - 501.4 - 71.3)}$$

$$EUOR = 0.0256$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 553.0

Target RSH* = 236.0

$$EA = \left[1 - \frac{(553.0 + 0.0256\ (8760.0 - 553.0 - 236.0))}{8760.0} \right] \times 100 = 91.4\ \%$$

Note: Please refer to page 12 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2003 - December 2003
Based on Target Planned Outage Hours
Crist 6

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	19.1	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	19.1
EFOH	1.2	0.0	0.0	0.0	0.0	0.0	
	0.0	1.1	0.0	21.7	0.0	0.0	24.0
MOH	47.7	0.0	28.1	0.0	0.0	0.0	
	87.1	0.0	0.0	0.0	0.0	0.0	162.9
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	5.3	0.0	0.0	0.0	0.0	0.0	5.3
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	0.0	516.1	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	516.1
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	11.5	11.5

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(19.1 + 24.0 + 162.9 + 5.3)}{(8760.0 - 516.1 - 11.5)}$$

$$EUOR = 0.0257$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

$$Target\ POH^* = 720.0$$

$$Target\ RSH^* = 0.0$$

$$EA = \left[1 - \frac{(720.0 + 0.0257\ (8760.0 - 720.0 - 0.0))}{8760.0} \right] \times 100 = 89.4\ \%$$

Note: Please refer to page 12 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2003 - December 2003
Based on Target Planned Outage Hours
Crist 7

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	4.8	0.0	0.0	0.0	
	0.0	0.0	0.0	26.5	0.0	0.0	31.3
EFOH	0.9	0.2	10.9	18.4	0.0	0.0	
	1.2	0.0	8.1	0.3	0.6	1.1	41.7
MOH	0.0	0.0	0.0	30.2	0.0	0.0	
	0.0	0.0	55.8	0.0	0.0	0.0	86.0
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.4	43.6	0.0	0.0	44.0
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.4	699.5	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	699.9
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(31.3 + 41.7 + 86.0 + 44.0)}{(8760.0 - 699.9 - 0.0)}$$

EUOR = 0.0252

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 719.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(719.0 + 0.0252\ (8760.0 - 719.0 - 0.0))}{8760.0} \right] \times 100 = 89.5\ \%$$

Note: Please refer to page 12 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2003 - December 2003
Based on Target Planned Outage Hours
Smith 1

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.3	41.0	0.0	0.0	0.0	0.0	
	0.0	325.2	0.0	0.0	0.0	14.0	380.5
EFOH	0.0	0.5	1.1	0.3	0.3	0.2	
	0.0	0.0	0.8	0.2	0.2	0.0	3.6
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	22.6	0.0	0.0	0.0	83.8	106.4
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	0.0	289.9	394.9	0.0	
	0.0	0.0	0.0	0.0	43.7	563.5	1292.0
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	11.6	11.6

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(380.5 + 3.6 + 106.4 + 0.0)}{(8760.0 - 1292.0 - 11.6)}$$

$$EUOR = 0.0658$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 960.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(960.0 + 0.0658\ (8760.0 - 960.0 - 0.0))}{8760.0} \right] \times 100 = 83.2\ \%$$

Note: Please refer to page 12 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2003 - December 2003
Based on Target Planned Outage Hours
Smith 2

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	7.3	
	0.0	0.0	0.0	0.0	0.0	0.0	7.3
EFOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	1.9	0.0	1.8	0.5	0.0	4.2
MOH	0.0	0.0	0.0	0.0	54.5	0.0	
	0.0	0.0	0.0	118.4	0.0	0.0	172.9
EMOH	0.0	0.0	0.0	61.2	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	61.2
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	742.4	672.0	744.0	290.7	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	2449.1
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(7.3 + 4.2 + 172.9 + 61.2)}{(8760.0 - 2449.1 - 0.0)}$$

$$EUOR = 0.0389$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

$$\text{Target } POH^* = 2448.0$$

$$\text{Target } RSH^* = 0.0$$

$$EA = \left[1 - \frac{(2448.0 + 0.0389\ (8760.0 - 2448.0 - 0.0))}{8760.0} \right] \times 100 = 69.3\ \%$$

Note: Please refer to page 12 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2003 - December 2003
Based on Target Planned Outage Hours
Daniel 1

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	49.8	0.0	4.7	54.5
EFOH	1.8	0.0	0.0	6.3	3.0	5.7	
	1.3	0.3	5.3	7.9	1.1	0.6	33.3
MOH	0.0	0.0	0.0	0.0	43.7	42.4	
	0.0	0.0	0.0	0.0	0.0	18.0	104.1
EMOH	0.0	0.0	0.0	0.0	5.5	1.1	
	0.0	0.0	0.0	103.4	0.0	0.0	110.0
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	645.1	672.0	653.8	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	252.2	120.0	2343.1
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(54.5 + 33.3 + 104.1 + 110.0)}{(8760.0 - 2343.1 - 0.0)}$$

EUOR = 0.0470

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 2016.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(2016.0 + 0.0470\ (8760.0 - 2016.0 - 0.0))}{8760.0} \right] \times 100 = 73.4\ \%$$

Note: Please refer to page 12 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2003 - December 2003
Based on Target Planned Outage Hours
Daniel 2

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	22.5	0.0	13.8	6.5	14.6	
	0.0	0.0	11.3	0.0	0.0	1.2	69.9
EFOH	2.8	4.7	4.6	7.8	21.3	11.3	
	1.4	1.5	6.4	2.4	0.0	1.8	66.0
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	41.8	0.0	0.0	0.0	41.8
EMOH	0.0	0.0	0.0	0.2	10.0	5.9	
	2.0	10.5	0.0	0.0	0.0	0.0	28.6
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	307.4	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	551.1	450.9	1309.4
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(69.9 + 66.0 + 41.8 + 28.6)}{(8760.0 - 1309.4 - 0.0)}$$

$$EUOR = 0.0277$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

$$\text{Target } POH^* = 721.0$$

$$\text{Target } RSH^* = 0.0$$

$$EA = \left[1 - \frac{(721.0 + 0.0277\ (8760.0 - 721.0 - 0.0))}{8760.0} \right] \times 100 = 89.2\ \%$$

Note: Please refer to page 12 of this schedule for an explanation of symbols.

Calculation of Equivalent Availability Points
for January 2003 - December 2003

(1) Unit	(2) Equivalent Availability Target*	(3) Actual Equivalent Availability Adjusted to Target Planned Outage Basis**	(4) Minimum or Maximum Attainable Equivalent Availability*	(5) Availability Points***
Crist 4	91.2	92.3	91.9	10.00
Crist 5	89.8	91.4	91.0	10.00
Crist 6	84.3	89.4	86.6	10.00
Crist 7	79.5	89.5	83.2	10.00
Smith 1	86.8	83.2	85.7	-10.00
Smith 2	67.8	69.3	69.1	10.00
Daniel 1	70.1	73.4	72.2	10.00
Daniel 2	83.0	89.2	85.7	10.00

* As appropriate from page 5, Schedule 3 of Exhibit to L. S. Noack's September 20, 2002 GPIF testimony in Docket 020001-EI.

** Refer to pages 3 through 10 of this schedule for calculations.

*** If (3) > (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times 10$$

If (3) < (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times -10$$

Summary of Equivalent Availability Symbols

EA - Equivalent Availability
POH - Planned Outage Hours
EUOR - Equivalent Unplanned Outage Rate
PH - Period Hours
FOH - Forced Outage Hours
EFOH - Equivalent Forced Outage Hours
MOH - Maintenance Outage Hours
EMOH - Equivalent Maintenance Outage Hours
RSH - Reserve Shutdown Hours

III. CALCULATION OF GPIF UNIT HEAT RATE POINTS

Calculation of Average Net Operating Heat Rate Points
for January 2003 - December 2003

Crist 4

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	43232.9	37063.7	49280.3	46632.8	42313.8	41543.9	
	43522.4	43875.3	37129.2	34468.9	23354.6	40505.0	482922.8
BTU/Lb*	11744.2	11652.9	11561.9	11559.1	11717.5	11540.7	
	11590.9	11633.0	11685.9	11843.7	11836.0	11756.1	11665.0
Coal, MMBTU	507735.8	431899.6	569773.9	539033.2	495812.0	479445.7	
	504463.8	510401.4	433888.1	408239.3	276425.0	476180.8	5633298.6
Oil, MMBTU	122.1	77.0	139.8	274.9	650.4	288.9	
	531.4	203.2	511.1	482.8	260.2	943.3	4485.1
Gas, MMBTU	0.0	1386.0	0.0	0.0	0.0	0.0	
	0.0	0.0	1302.0	0.0	1493.0	392.0	4573.0
Startup, MMBTU **	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	-800.0	0.0	-400.0	-400.0	-1600.0
Total Fuel Consumption, MMBTU	507857.9	433362.6	569913.7	539308.1	496462.4	479734.6	
	504995.2	510604.6	434901.2	408722.1	277778.2	477116.1	5640756.7
Net MWH Generation***	46829	39730	52600	50323	47356	45496	
	48228	49697	40776	39064	25854	45338	531291
Average Net Operating Heat Rate	10845	10908	10835	10717	10484	10545	
	10471	10274	10666	10463	10744	10524	10617

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2003 - December 2003

Crist 5

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	42309.1	36997.2	48169.7	46310.7	35417.0	40008.1	
	42977.6	42169.9	38021.4	42469.8	8241.9	38161.0	461253.4
BTU/Lb*	11758.2	11711.6	11548.2	11542.6	11741.3	11646.7	
	11584.4	11601.9	11689.3	11877.1	11720.8	11744.6	11672.9
Coal, MMBTU	497478.9	433296.4	556273.3	534545.9	415841.6	465962.3	
	497869.7	489251.0	444443.6	504418.1	96601.7	448185.7	5384168.2
Oil, MMBTU	234.5	146.4	423.1	852.9	2072.0	1769.6	
	2655.3	1030.2	1033.2	728.5	632.8	642.6	12221.1
Gas, MMBTU	182.0	0.0	0.0	0.0	1299.0	254.0	
	0.0	0.0	627.0	0.0	1195.0	912.0	4469.0
Startup, MMBTU **	0.0	0.0	0.0	0.0	-800.0	0.0	
	0.0	0.0	-400.0	0.0	-1200.0	-800.0	-3200.0
Total Fuel Consumption, MMBTU	497895.4	433442.8	556696.4	535398.8	418412.6	467985.9	
	500525.0	490281.2	445703.8	505146.6	97229.5	448940.3	5397658.3
Net MWH Generation***	45490	38811	51287	49153	39532	44434	
	47950	48664	42536	48749	9096	42518	508220
Average Net Operating Heat Rate	10945	11168	10855	10892	10584	10532	
	10438	10075	10478	10362	10689	10559	10621

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2003 - December 2003

Crist 6

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	163264.1	160619.4	168866.1	32642.2	154349.0	152250.7	
	147383.4	172222.8	160155.9	165299.0	168580.9	162798.3	1808431.8
BTU/Lb*	11719.2	11728.0	11527.0	11678.7	11702.0	11605.3	
	11598.3	11648.8	11704.8	11798.9	11761.1	11750.3	11686.4
Coal, MMBTU	1913324.6	1883744.3	1946519.5	381218.5	1806192.0	1766915.0	
	1709396.9	2006189.0	1874592.8	1950346.4	1982696.8	1912928.9	21134064.7
Oil, MMBTU	185.4	65.0	513.4	191.5	356.5	66.0	
	188.7	36.7	73.3	224.9	330.1	123.9	2355.4
Gas, MMBTU	1570.0	7568.0	11619.0	28621.0	0.0	1051.0	
	3287.0	0.0	0.0	18802.0	3252.0	3127.0	78897.0
Startup, MMBTU **	-4040.0	0.0	-4040.0	-4040.0	0.0	0.0	
	-4040.0	0.0	0.0	0.0	0.0	0.0	-16160.0
Total Fuel Consumption, MMBTU	1911040.0	1891377.3	1954611.9	405991.0	1806548.5	1768032.0	
	1708832.6	2006225.7	1874666.1	1969373.3	1986278.9	1916179.8	21199157.1
Net MWH Generation***	187100	182725	188407	40770	173989	170770	
	162635	195035	181517	185905	189713	188145	2046711
Average Net Operating Heat Rate	10214	10351	10374	9958	10383	10353	
	10507	10286	10328	10593	10470	10185	10358

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2003 - December 2003

Crist 7

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	271547.0	247262.3	9767.1	248495.0	264591.0	271663.6	
	279763.3	290689.0	249569.2	247119.5	280286.1	281011.3	2941764.4
BTU/Lb*	11771.7	11732.9	11448.0	11546.5	11759.4	11418.3	
	11594.6	11550.7	11667.9	11787.9	11739.9	11780.4	11666.3
Coal, MMBTU	3196569.8	2901103.8	111813.8	2869247.5	3111431.4	3101936.5	
	3243743.6	3357661.4	2911948.5	2913020.0	3290530.8	3310425.5	34319432.6
Oil, MMBTU	1389.0	543.7	270.8	998.3	1957.3	593.5	
	279.7	207.8	720.0	861.5	876.8	667.5	9365.9
Gas, MMBTU	0.0	0.0	5406.0	1608.0	0.0	0.0	
	0.0	0.0	1961.0	1948.0	0.0	0.0	10923.0
Startup, MMBTU **	0.0	0.0	-2256.0	-2256.0	0.0	0.0	
	0.0	0.0	-2256.0	-2256.0	0.0	0.0	-9024.0
Total Fuel Consumption, MMBTU	3197958.8	2901647.5	115234.6	2869597.8	3113388.7	3102530.0	
	3244023.3	3357869.2	2912373.5	2913573.5	3291407.6	3311093.0	34330697.5
Net MWH Generation***	316380	283056	9525	280898	300365	295793	
	315840	330470	278984	283263	319768	322915	3337257
Average Net Operating Heat Rate	10108	10251	12098	10216	10365	10489	
	10271	10161	10439	10286	10293	10254	10287

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2003 - December 2003

Smith 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	86737.9	67655.2	94306.5	52723.3	37819.1	81313.5	
	87976.1	45177.8	81964.9	89960.0	79146.4	7288.8	812069.5
BTU/Lb*	11816.0	11829.8	11697.8	12126.4	11777.9	11890.0	
	11879.5	11864.5	11948.2	11669.1	11869.2	11913.3	11841.9
Coal, MMBTU	1024895.0	800347.5	1103178.6	639343.8	445429.6	966817.5	
	1045112.1	536012.0	979333.0	1049752.2	939404.5	86833.7	9616459.5
Oil, MMBTU	402.3	1197.2	851.3	621.9	1973.9	940.9	
	302.3	2810.8	264.5	624.2	515.4	5406.6	15911.3
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	-964.0	0.0	0.0	-964.0	0.0	
	0.0	-964.0	0.0	0.0	0.0	-2892.0	-5784.0
Total Fuel Consumption, MMBTU	1025297.3	800580.7	1104029.9	639965.7	446439.5	967758.4	
	1045414.4	537858.8	979597.5	1050376.4	939919.9	89348.3	9626586.8
Net MWH Generation***	100234	78642	104529	60579	42319	92538	
	100256	51355	94238	101677	92806	7869	927042
Average Net Operating Heat Rate	10229	10180	10562	10564	10549	10458	
	10427	10473	10395	10331	10128	11354	10384

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2003 - December 2003

Smith 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	71.7	0.0	0.0	49278.7	84374.9	87942.5	
	96644.3	97254.7	92996.4	86348.7	97419.0	104869.7	797200.6
BTU/Lb*	11768.0	0.0	0.0	11864.8	11827.3	11880.2	
	11868.2	11799.4	11943.6	11658.6	11878.2	11937.1	11853.0
Coal, MMBTU	843.8	0.0	0.0	584681.9	997927.3	1044774.5	
	1146993.9	1147547.1	1110711.8	1006705.0	1157162.4	1251840.1	9449187.8
Oil, MMBTU	84.3	0.0	0.0	2511.3	1304.1	1428.4	
	377.0	517.0	231.2	1942.1	539.9	281.0	9216.3
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	0.0	-1190.0	-1190.0	0.0	
	0.0	0.0	0.0	-1190.0	0.0	0.0	-3570.0
Total Fuel Consumption, MMBTU	928.1	0.0	0.0	586003.2	998041.4	1046202.9	
	1147370.9	1148064.1	1110943.0	1007457.1	1157702.3	1252121.1	9454834.1
Net MWH Generation***	63	0	0	57403	97276	102368	
	112185	112788	109404	98475	114506	123325	927793
Average Net Operating Heat Rate	14732	---	---	10209	10260	10220	
	10227	10179	10155	10231	10110	10153	10191

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2003 - December 2003

Daniel 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	29428.0	0.0	31532.0	278274.0	239356.0	245280.0	
	300726.0	280850.0	259756.0	222672.0	192392.0	249166.0	2329432.0
BTU/Lb*	11613.6	0.0	11691.6	11645.7	11585.9	11638.5	
	11525.6	11596.1	11726.4	11928.7	11682.6	11630.2	11655.0
Coal, MMBTU	341765.0	0.0	368659.5	3240695.5	2773154.7	2854691.3	
	3466047.6	3256764.7	3046002.8	2656187.5	2247638.8	2897850.4	27149457.8
Oil, MMBTU	231.3	0.0	10740.2	0.0	3647.7	3411.5	
	0.0	0.0	621.3	3070.5	3294.3	5965.2	30982.0
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	0.0	-4777.4	0.0	-2388.7	-2388.7	
	0.0	0.0	0.0	-2388.7	0.0	-2388.7	-14332.2
Total Fuel Consumption, MMBTU	341996.3	0.0	374622.3	3240695.5	2774413.7	2855714.1	
	3466047.6	3256764.7	3046624.1	2656869.3	2250933.1	2901426.9	27166107.6
Net MWH Generation***	39730	0	34421	331929	288606	288730	
	342500	337744	311837	270673	224466	290554	2761190
Average Net Operating Heat Rate	8608	---	10884	9763	9613	9891	
	10120	9643	9770	9816	10028	9986	9839

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2003 - December 2003

Daniel 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	281950.0	116980.0	298362.0	273230.0	252228.0	263524.0	
	292828.0	273300.0	230392.0	293021.8	64890.0	100868.0	2741573.8
BTU/Lb*	11899.4	11765.8	11761.9	11648.2	11614.9	11588.7	
	11526.1	11593.2	11726.5	11942.5	11721.9	11589.3	11701.7
Coal, MMBTU	3355035.8	1376363.3	3509304.0	3182637.7	2929603.0	3053900.6	
	3375164.8	3168421.6	2701691.8	3499412.8	760634.1	1168989.5	32081159.0
Oil, MMBTU	0.0	8176.1	258.0	3407.8	983.5	2102.2	
	157.8	0.0	6181.9	3.1	394.5	11226.8	32891.7
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	-2388.7	0.0	0.0	0.0	0.0	
	0.0	0.0	-2388.7	0.0	0.0	-2388.7	-7166.1
Total Fuel Consumption, MMBTU	3355035.8	1382150.7	3509562.0	3186045.5	2930586.5	3056002.8	
	3375322.6	3168421.6	2705485.0	3499415.9	761028.6	1177827.6	32106884.6
Net MWH Generation***	346887	139746	368994	323558	300615	308174	
	336252	330019	281941	354938	77720	113626	3282470
Average Net Operating Heat Rate	9672	9890	9511	9847	9749	9916	
	10038	9601	9596	9859	9792	10366	9781

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate
for January 2003 - December 2003
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2002

Crist 4

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10538	10475	10611	10427	10607	10483	
		10464	10733	10422	10790	10735	10953	
2.	Target Heat Rate	10495	10520	10423	10306	10435	10472	
	at Actual Conditions**	10424	10662	10456	10342	10216	10364	
3.	Adjustment to Actual	43	-45	188	121	172	11	
	Heat Rate (1-2)	40	71	-34	448	519	589	
4.	Actual Heat Rate	10845	10908	10835	10717	10484	10545	
	(Page 2 of Sched. 3)	10471	10274	10666	10463	10744	10524	
5.	Adjusted Actual	10888	10863	11023	10838	10656	10556	
	Heat Rate (4+3)	10511	10345	10632	10911	11263	11113	
6.	Net MWH Generation	46829	39730	52600	50323	47356	45496	
		48228	49697	40776	39064	25854	45338	
7.	Adjusted Actual Heat Rate for January 2003 - December 2003 $=(\Sigma(5*6)/\Sigma 6)$							10780

* From pages 20 & 21, Schedule 3 of Exhibit to L. S. Noack's September 20, 2002 GPIF testimony in Docket 020001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2003 - December 2003
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2002

Crist 5

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10392	10333	10345	10319	10494	10608	
		10305	10488	10333	10142	10757	10675	
2.	Target Heat Rate	10570	10695	10322	10336	10552	10807	
	at Actual Conditions**	10458	10617	10538	10150	10603	10491	
3.	Adjustment to Actual	-178	-362	23	-17	-58	-199	
	Heat Rate (1-2)	-153	-129	-205	-8	154	184	
4.	Actual Heat Rate	10945	11168	10855	10892	10584	10532	
	(Page 3 of Sched. 3)	10438	10075	10478	10362	10689	10559	
5.	Adjusted Actual	10767	10806	10878	10875	10526	10333	
	Heat Rate (4+3)	10285	9946	10273	10354	10843	10743	
6.	Net MWH Generation	45490	38811	51287	49153	39532	44434	
		47950	48664	42536	48749	9096	42518	
7.	Adjusted Actual Heat Rate for January 2003 - December 2003 =(Σ(5*6) / Σ6)							10529

* From pages 22 & 23, Schedule 3 of Exhibit to L. S. Noack's September 20, 2002 GPIF testimony in Docket 020001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2003 - December 2003
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2002

Crist 6

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10447	10424	10419	10421	10501	10602	
		10592	10599	10417	10442	10486	10553	
2.	Target Heat Rate	10384	10334	10328	10565	10512	10685	
	at Actual Conditions**	10594	10554	10391	10452	10385	10377	
3.	Adjustment to Actual	63	90	91	-144	-11	-83	
	Heat Rate (1-2)	-2	45	26	-10	101	176	
4.	Actual Heat Rate	10214	10351	10374	9958	10383	10353	
	(Page 4 of Sched. 3)	10507	10286	10328	10593	10470	10185	
5.	Adjusted Actual	10277	10441	10465	9814	10372	10270	
	Heat Rate (4+3)	10505	10331	10354	10583	10571	10361	
6.	Net MWH Generation	187100	182725	188407	40770	173989	170770	
		162635	195035	181517	185905	189713	188145	
7.	Adjusted Actual Heat Rate for January 2003 - December 2003 =($\Sigma(5*6) / \Sigma 6$)							10400

* From pages 24 & 25, Schedule 3 of Exhibit to L. S. Noack's September 20, 2002 GPIF testimony in Docket 020001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2003 - December 2003
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2002

Crist 7

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10124 10396	10119 10289	9679 10290	10141 10220	10089 10135	10152 10134	
2.	Target Heat Rate at Actual Conditions**	10207 10496	10214 10341	9997 10380	10243 10390	10113 10170	10237 10189	
3.	Adjustment to Actual Heat Rate (1-2)	-83 -100	-95 -52	-318 -90	-102 -170	-24 -35	-85 -55	
4.	Actual Heat Rate (Page 5 of Sched. 3)	10108 10271	10251 10161	12098 10439	10216 10286	10365 10293	10489 10254	
5.	Adjusted Actual Heat Rate (4+3)	10025 10171	10156 10109	11780 10349	10114 10116	10341 10258	10404 10199	
6.	Net MWH Generation	316380 315840	283056 330470	9525 278984	280898 283263	300365 319768	295793 322915	

7. Adjusted Actual Heat Rate for January 2003 - December 2003 $=(\Sigma(5*6)/\Sigma 6)$ 10207

* From pages 26 & 27, Schedule 3 of Exhibit to L. S. Noack's September 20, 2002 GPIF testimony in Docket 020001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2003 - December 2003
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2002

Smith 1

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	9969	9955	10048	10046	10094	10121	
		10052	10049	9982	10046	9965	10052	
2.	Target Heat Rate	10051	10070	10119	10118	10175	10222	
	at Actual Conditions**	10131	10148	10068	10128	10022	10203	
3.	Adjustment to Actual	-82	-115	-71	-72	-81	-101	
	Heat Rate (1-2)	-79	-99	-86	-82	-57	-151	
4.	Actual Heat Rate	10229	10180	10562	10564	10549	10458	
	(Page 6 of Sched. 3)	10427	10473	10395	10331	10128	11354	
5.	Adjusted Actual	10147	10065	10491	10492	10468	10357	
	Heat Rate (4+3)	10348	10374	10309	10249	10071	11203	
6.	Net MWH Generation	100234	78642	104529	60579	42319	92538	
		100256	51355	94238	101677	92806	7869	
7.	Adjusted Actual Heat Rate for January 2003 - December 2003 =($\Sigma(5*6) / \Sigma 6$)							10300

* From pages 28 & 29 , Schedule 3 of Exhibit to L. S. Noack's September 20, 2002 GPIF testimony in Docket 020001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2003 - December 2003
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2002

Smith 2

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	9933 10205	0 10116	0 10109	10000 10113	10060 10128	10132 10127	
2.	Target Heat Rate at Actual Conditions**	12799 10326	0 10196	0 10208	10161 10185	10166 10172	10275 10137	
3.	Adjustment to Actual Heat Rate (1-2)	-2866 -121	0 -80	0 -99	-161 -72	-106 -44	-143 -10	
4.	Actual Heat Rate (Page 7 of Sched. 3)	14732 10227	0 10179	0 10155	10209 10231	10260 10110	10220 10153	
5.	Adjusted Actual Heat Rate (4+3)	11866 10106	0 10099	0 10056	10048 10159	10154 10066	10077 10143	
6.	Net MWH Generation	63 112185	0 112788	0 109404	57403 98475	97276 114506	102368 123325	
7.	Adjusted Actual Heat Rate for January 2003 - December 2003 =(Σ (5*6) / Σ 6)							10103

* From pages 30 & 31, Schedule 3 of Exhibit to L. S. Noack's September 20, 2002 GPIF testimony in Docket 020001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2003 - December 2003
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2002

Daniel 1

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	9945	0	10086	9866	10089	9952	
		10263	10123	10084	9864	10079	10053	
2.	Target Heat Rate	10123	0	9804	9938	10006	9996	
	at Actual Conditions**	10302	10223	10243	10019	10010	9767	
3.	Adjustment to Actual	-178	0	282	-72	83	-44	
	Heat Rate (1-2)	-39	-100	-159	-155	69	286	
4.	Actual Heat Rate***	8608	0	10884	9763	9613	9891	
	(Page 8 of Sched. 3)	10120	9643	9770	9816	10028	9986	
5.	Adjusted Actual	8430	0	11166	9691	9696	9847	
	Heat Rate (4+3)	10081	9543	9611	9661	10097	10272	
6.	Net MWH Generation	39730	0	34421	331929	288606	288730	
		342500	337744	311837	270673	224466	290554	
7.	Adjusted Actual Heat Rate for January 2003 - December 2003 $=(\Sigma(5*6)/\Sigma 6)$							9821

* From pages 32 & 33, Schedule 3 of Exhibit to L. S. Noack's September 20, 2002 GPIF testimony in Docket 020001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2003 - December 2003
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2002

Daniel 2

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	9587	9614	9813	9804	10071	9901	
		9838	9819	9659	9829	9702	9844	
2.	Target Heat Rate	9672	9945	9841	9963	10174	10045	
	at Actual Conditions**	9982	10031	9909	9923	9799	10193	
3.	Adjustment to Actual	-85	-331	-28	-159	-103	-144	
	Heat Rate (1-2)	-144	-212	-250	-94	-97	-349	
4.	Actual Heat Rate***	9672	9890	9511	9847	9749	9916	
	(Page 9 of Sched. 3)	10038	9601	9596	9859	9792	10366	
5.	Adjusted Actual	9587	9559	9483	9688	9646	9772	
	Heat Rate (4+3)	9894	9389	9346	9765	9695	10017	
6.	Net MWH Generation	346887	139746	368994	323558	300615	308174	
		336252	330019	281941	354938	77720	113626	
7.	Adjusted Actual Heat Rate for January 2003 - December 2003 $=(\Sigma(5*6)/\Sigma 6)$							9634

* From pages 34 & 35, Schedule 3 of Exhibit to L. S. Noack's September 20, 2002 GPIF testimony in Docket 020001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 20 of this Schedule.

Actual Values of
Target Heat Rate Equation Parameters
for January 2003 - December 2003

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec
Crist 4						
+3						
AKW * 10	62.9	59.1	70.7	70.0	63.7	63.2
	64.8	66.8	63.1	68.1	70.8	65.7
+6						
LSRF * 10	4156.6	3659.3	5114.1	5030.6	4242.7	4188.8
	4384.8	4634.4	4170.1	4792.9	5102.3	4483.2
Crist 5						
+3						
AKW * 10	61.1	57.8	68.9	68.4	61.6	61.7
	64.4	65.4	62.0	65.8	60.2	63.4
+6						
LSRF * 10	3940.8	3496.9	4881.2	4812.1	3997.8	4018.4
	4333.7	4460.3	4046.2	4500.4	3803.2	4184.3
Crist 6						
+3						
AKW * 10	268.7	271.9	270.4	200.9	233.9	237.2
	247.6	262.1	252.1	249.5	263.5	256.9
+6						
LSRF * 10	75482.3	76232.6	75407.9	44423.2	60209.0	61993.6
	65650.7	72090.3	67449.3	67080.8	72947.8	69597.0
Crist 7						
+3						
AKW * 10	425.2	421.5	239.9	407.8	403.7	410.8
	424.5	444.2	420.0	394.2	444.1	434.0
+6						
LSRF * 10	188184.3	184665.0	58835.5	174998.5	174481.5	178695.5
	187767.4	201940.6	184122.4	168237.9	203004.6	195097.4
Smith 1						
+3						
AKW * 10	134.8	124.6	140.5	141.2	121.2	128.5
	134.8	129.6	130.9	136.5	137.2	110.7
+6						
LSRF * 10	19293.5	16775.4	20851.9	20963.8	16564.3	18290.2
	19650.5	18445.2	18659.5	19972.8	20194.1	14456.5
Smith 2						
+3						
AKW * 10	39.4	0.0	0.0	134.0	141.1	143.6
	150.8	151.6	152.0	157.2	159.0	165.8
+6						
LSRF * 10	1174.5	0.0	0.0	20581.3	22479.7	23263.5
	24928.2	24811.0	25108.2	26486.0	26887.3	28551.1

Actual Values of
Target Heat Rate Equation Parameters
for January 2003 - December 2003

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec
Daniel 1						
AKW * 10^{+3}	401.7	0.0	381.6	461.7	412.1	426.1
	460.3	454.0	433.1	389.3	479.8	483.2
LSRF * 10^{+6}	179383.0	0.0	175913.5	222630.1	189345.1	198394.2
	222942.7	217298.9	203042.3	174715.1	238034.0	242257.9
Daniel 2						
AKW * 10^{+3}	466.2	408.5	496.0	458.8	407.6	436.9
	452.0	443.6	422.8	476.4	460.2	389.3
LSRF * 10^{+6}	227871.2	185071.9	247890.0	221641.5	184848.3	206033.4
	217234.4	209843.5	197596.1	232255.7	221608.1	176777.6

Target Heat Rate Equations

Crist 4 ANOHR = 10^6 / AKW * [790.16 + 9.96 * MAR + 18.89 * AUG]

-14470 + 0.18768 * LSRF / AKW

Crist 5 ANOHR = 10^6 / AKW * [134.06 + 15.92 * JUN + 12.53 * AUG - 17.36 * OCT]

+ 8,376

Crist 6 ANOHR = 10^6 / AKW * [942.11 + 38.69 * JUN + 43.57 * JUL + 47.19 * AUG]

+ 2,167 + 0.01677 * LSRF / AKW

Crist 7 ANOHR = 10^6 / AKW * [364.26 - 208.93 * MAR - 56.05 * MAY + 122.15 * JUL + 75.82 * AUG + 68.14 * SEP + 45.83 * OCT]

+ 9,350

Smith 1 ANOHR = 10^6 / AKW * [-6.55 - 12.65 * JAN - 14.68 * FEB + 9.56 * JUN - 10.32 * SEP - 14.06 * NOV]

+ 10,971 - 0.00543 * LSRF / AKW

Smith 2 ANOHR = 10^6 / AKW * [261.83 - 36.53 * JAN - 44.18 * FEB - 58.60 * MAR - 21.11 * APR - 15.99 * MAY + 15.64 * JUL]

+ 6,772 + 0.01037 * LSRF / AKW

Daniel 1 ANOHR = 10^6 / AKW * [-931.04 + 183.89 * JUL + 122.54 * AUG + 110.76 * SEP + 89.14 * NOV]

+ 18,532 - 0.01364 * LSRF / AKW

Daniel 2 ANOHR = 10^6 / AKW * [187.07 - 118.14 * JAN - 94.43 * FEB - 73.36 * SEP - 78.52 * NOV]

+ 12,178 - 0.00543 * LSRF / AKW

Where:		
	ANOHR	Average Net Operating Heat Rate, BTU/KWH
	AKW	Average Kilowatt Load, KW
	LSRF	Load Square Range Factor, KW^2
	JAN	January, 0 if not January, 1 if January
	FEB	February, 0 if not February, 1 if February
	MAR	March, 0 if not March, 1 if March
	APR	April, 0 if not April, 1 if April
	MAY	May, 0 if not May, 1 if May
	JUN	June, 0 if not June, 1 if June
	JUL	July, 0 if not July, 1 if July
	AUG	August, 0 if not August, 1 if August
	SEP	September, 0 if not September, 1 if September
	OCT	October, 0 if not October, 1 if October
	NOV	November, 0 if not November, 1 if November

Calculation of Heat Rate Points
for January 2003 - December 2003

(1)	(2)	(3)	(4)	(5)
Unit	Actual Average Average Net Operating Heat Rate Target*	Net Operating Heat Rate Adjusted to Target Basis**	Minimum Attainable Heat Rate*	Heat Rate Points***
Crist 4	10591	10780	10273	-4.69
Crist 5	10418	10529	10105	-1.51
Crist 6	10501	10400	10186	1.08
Crist 7	10150	10207	9846	0.00
Smith 1	10029	10300	9728	-8.67
Smith 2	10113	10103	9810	0.00
Daniel 1	10042	9821	9741	6.46
Daniel 2	9789	9634	9495	3.65

* From page 5, Schedule 3 of Exhibit to L. S. Noack's September 20, 2002 GPIF testimony in Docket 020001-EI.

** Refer to pages 10 through 17 of this Schedule for calculation.

*** If [(2) - 75] <= (3) <= [(2) + 75] then points = 0

If [(2) - (3) - 75] > 0 then points = $\frac{(2) - (3) - 75}{(2) - (4) - 75} * 10$

If [(2) - (3) + 75] < 0 then points = $\frac{(2) - (3) + 75}{(2) - (4) - 75} * 10$

IV. CALCULATION OF COMPANY GPIF POINTS AND REWARD/PENALTY

Calculation of Heat Rate Points

GPIF Points and Reward or Penalty

for January 2003 - December 2003

Unit	Availability Points	Availability* Weighting Factor	Heat Rate Points	Heat Rate* Weighting Factor
Crist 4	10.00	0.001	-4.69	0.030
Crist 5	10.00	0.002	-1.51	0.031
Crist 6	10.00	0.013	1.08	0.099
Crist 7	10.00	0.084	0.00	0.205
Smith 1	-10.00	0.005	-8.67	0.087
Smith 2	10.00	0.018	0.00	0.068
Daniel 1	10.00	0.076	6.46	0.097
Daniel 2	10.00	0.076	3.65	0.109

Company GPIF Points = + 10.00 * 0.001 - 4.69 * 0.030
+ 10.00 * 0.002 - 1.51 * 0.031
+ 10.00 * 0.013 + 1.08 * 0.099
+ 10.00 * 0.084 + 0.00 * 0.205
- 10.00 * 0.005 - 8.67 * 0.087
+ 10.00 * 0.018 + 0.00 * 0.068
+ 10.00 * 0.076 + 6.46 * 0.097
+ 10.00 * 0.076 + 3.65 * 0.109

= 2.82

Company reward/penalty = 2.82 points * $219396 per point

= $625,280

* From page 5, Schedule 3 of Exhibit to L. S. Noack's September 20, 2002 GPIF testimony in Docket 020001-EI.

V. GPIF MINIMUM FILING REQUIREMENTS FOR THE JANUARY 2003 - DECEMBER 2003 PERIOD

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Generating Performance Incentive Factor

Actual Reward/Penalty Table

Gulf Power Company

Period of: January 2003 - December 2003

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	5880	2194
+ 9	5292	1975
+ 8	4704	1755
+ 7	4116	1536
+ 6	3528	1316
+ 5	2940	1097
+ 4	2352	878
+ 3	1764	658
+ 2	1176	439
+ 1	588	219
0	0	0
- 1	-666	-219
- 2	-1331	-439
- 3	-1997	-658
- 4	-2662	-878
- 5	-3328	-1097
- 6	-3993	-1316
- 7	-4659	-1536
- 8	-5324	-1755
- 9	-5990	-1975
- 10	-6655	-2194
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Actual

Gulf Power Company

Period of: January 2003 - December 2003

Line 1	Beginning of Period Balance of Common Equity	$549,298,482
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '03	$566,863,375
Line 3	Month of Feb '03	$553,052,338
Line 4	Month of Mar '03	$557,090,196
Line 5	Month of Apr '03	$541,406,285
Line 6	Month of May '03	$546,014,363
Line 7	Month of Jun '03	$556,502,903
Line 8	Month of Jul '03	$550,256,663
Line 9	Month of Aug '03	$561,918,826
Line 10	Month of Sep '03	$572,066,291
Line 11	Month of Oct '03	$559,363,891
Line 12	Month of Nov '03	$561,726,825
Line 13	Month of Dec '03	$561,358,079
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$556,686,040
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	61.3808%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$2,267,347
Line 18	Jurisdictional Sales (KWH)	10,884,788,538
Line 19	Total Territorial Sales (KWH)	11,248,857,000
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	96.7635%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$2,193,964

Issued by: S. N. Story

Filed: April 01, 2004
Suspended:
Effective: April 01, 2004
Docket No.: 040001-EI
Order No.:

Calculation of System Actual GPIF Points

Gulf Power Company

Period of: January 2003 - December 2003

Plant & Unit	Performance Indicator (EAF or ANOHR)	Weighting Factor	Unit Points	Weighted Unit Points
Crist 4	EAF1	0.1%	10.00	0.010
Crist 4	ANOHR1	3.0%	-4.69	-0.143
Crist 5	EAF2	0.2%	10.00	0.020
Crist 5	ANOHR2	3.1%	-1.51	-0.046
Crist 6	EAF3	1.3%	10.00	0.129
Crist 6	ANOHR3	9.9%	1.08	0.107
Crist 7	EAF4	8.4%	10.00	0.835
Crist 7	ANOHR4	20.5%	0.00	0.000
Smith 1	EAF5	0.5%	-10.00	-0.054
Smith 1	ANOHR5	8.7%	-8.67	-0.752
Smith 2	EAF6	1.8%	10.00	0.179
Smith 2	ANOHR6	6.8%	0.00	0.000
Daniel 1	EAF7	7.6%	10.00	0.757
Daniel 1	ANOHR7	9.7%	6.46	0.626
Daniel 2	EAF8	7.6%	10.00	0.757
Daniel 2	ANOHR8	10.9%	3.65	0.397
Gulf Power GPIF Total		100.0%		2.82

Issued by: S. N. Story

Filed: April 01, 2004
Suspended:
Effective: April 01, 2004
Docket No.: 040001-EI
Order No.:

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2003 - December 2003

Crist 4

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	6	91.90	+ 10	179	10,273
+ 9	5	91.83	+ 9	161	10,297
+ 8	5	91.76	+ 8	143	10,322
+ 7	4	91.69	+ 7	125	10,346
+ 6	4	91.62	+ 6	107	10,370
+ 5	3	91.55	+ 5	90	10,395
+ 4	2	91.48	+ 4	72	10,419
+ 3	2	91.41	+ 3	54	10,443
+ 2	1	91.34	+ 2	36	10,467
+ 1	1	91.27	+ 1	18	10,492
				0	10,516
0	0	91.20	0	0	10,591
				0	10,666
- 1	(1)	91.08	- 1	(18)	10,690
- 2	(2)	90.96	- 2	(36)	10,715
- 3	(3)	90.84	- 3	(54)	10,739
- 4	(4)	90.72	- 4	(72)	10,763
- 5	(5)	90.60	- 5	(90)	10,788
- 6	(5)	90.48	- 6	(107)	10,812
- 7	(6)	90.36	- 7	(125)	10,836
- 8	(7)	90.24	- 8	(143)	10,860
- 9	(8)	90.12	- 9	(161)	10,885
- 10	(9)	90.00	- 10	(179)	10,909
Weighting Factor:		0.001	Weighting Factor:		0.030

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2003 - December 2003

Crist 5

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	12	91.00	+ 10	181	10,105
+ 9	11	90.88	+ 9	163	10,129
+ 8	10	90.76	+ 8	145	10,153
+ 7	8	90.64	+ 7	127	10,176
+ 6	7	90.52	+ 6	109	10,200
+ 5	6	90.40	+ 5	91	10,224
+ 4	5	90.28	+ 4	72	10,248
+ 3	4	90.16	+ 3	54	10,272
+ 2	2	90.04	+ 2	36	10,295
+ 1	1	89.92	+ 1	18	10,319
				0	10,343
0	0	89.80	0	0	10,418
				0	10,493
- 1	(2)	89.63	- 1	(18)	10,517
- 2	(5)	89.46	- 2	(36)	10,541
- 3	(7)	89.29	- 3	(54)	10,564
- 4	(9)	89.12	- 4	(72)	10,588
- 5	(12)	88.95	- 5	(91)	10,612
- 6	(14)	88.78	- 6	(109)	10,636
- 7	(16)	88.61	- 7	(127)	10,660
- 8	(18)	88.44	- 8	(145)	10,683
- 9	(21)	88.27	- 9	(163)	10,707
- 10	(23)	88.10	- 10	(181)	10,731
Weighting Factor:		0.002	Weighting Factor:		0.031

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2003 - December 2003

Crist 6

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	76	86.60	+ 10	583	10,186
+ 9	68	86.37	+ 9	525	10,210
+ 8	61	86.14	+ 8	466	10,234
+ 7	53	85.91	+ 7	408	10,258
+ 6	46	85.68	+ 6	350	10,282
+ 5	38	85.45	+ 5	292	10,306
+ 4	30	85.22	+ 4	233	10,330
+ 3	23	84.99	+ 3	175	10,354
+ 2	15	84.76	+ 2	117	10,378
+ 1	8	84.53	+ 1	58	10,402
				0	10,426
0	0	84.30	0	0	10,501
				0	10,576
- 1	(12)	83.97	- 1	(58)	10,600
- 2	(23)	83.64	- 2	(117)	10,624
- 3	(35)	83.31	- 3	(175)	10,648
- 4	(47)	82.98	- 4	(233)	10,672
- 5	(59)	82.65	- 5	(292)	10,696
- 6	(70)	82.32	- 6	(350)	10,720
- 7	(82)	81.99	- 7	(408)	10,744
- 8	(94)	81.66	- 8	(466)	10,768
- 9	(105)	81.33	- 9	(525)	10,792
- 10	(117)	81.00	- 10	(583)	10,816
Weighting Factor:		0.013	Weighting Factor:		0.099

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2003 - December 2003

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	491	83.20	+ 10	1,204	9,846
+ 9	442	82.83	+ 9	1,084	9,869
+ 8	393	82.46	+ 8	963	9,892
+ 7	344	82.09	+ 7	843	9,915
+ 6	295	81.72	+ 6	722	9,938
+ 5	246	81.35	+ 5	602	9,961
+ 4	196	80.98	+ 4	482	9,983
+ 3	147	80.61	+ 3	361	10,006
+ 2	98	80.24	+ 2	241	10,029
+ 1	49	79.87	+ 1	120	10,052
				0	10,075
0	0	79.50	0	0	10,150
				0	10,225
- 1	(76)	78.94	- 1	(120)	10,248
- 2	(153)	78.38	- 2	(241)	10,271
- 3	(229)	77.82	- 3	(361)	10,294
- 4	(306)	77.26	- 4	(482)	10,317
- 5	(382)	76.70	- 5	(602)	10,340
- 6	(458)	76.14	- 6	(722)	10,363
- 7	(535)	75.58	- 7	(843)	10,386
- 8	(611)	75.02	- 8	(963)	10,409
- 9	(688)	74.46	- 9	(1,084)	10,432
- 10	(764)	73.90	- 10	(1,204)	10,455
Weighting Factor:		0.084	Weighting Factor:		0.205

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2003 - December 2003

Smith 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	32	87.40	+ 10	510	9,728
+ 9	29	87.34	+ 9	459	9,751
+ 8	26	87.28	+ 8	408	9,773
+ 7	22	87.22	+ 7	357	9,796
+ 6	19	87.16	+ 6	306	9,818
+ 5	16	87.10	+ 5	255	9,841
+ 4	13	87.04	+ 4	204	9,864
+ 3	10	86.98	+ 3	153	9,886
+ 2	6	86.92	+ 2	102	9,909
+ 1	3	86.86	+ 1	51	9,931
				0	9,954
0	0	86.80	0	0	10,029
				0	10,104
- 1	(6)	86.69	- 1	(51)	10,127
- 2	(12)	86.58	- 2	(102)	10,149
- 3	(19)	86.47	- 3	(153)	10,172
- 4	(25)	86.36	- 4	(204)	10,194
- 5	(31)	86.25	- 5	(255)	10,217
- 6	(37)	86.14	- 6	(306)	10,240
- 7	(43)	86.03	- 7	(357)	10,262
- 8	(50)	85.92	- 8	(408)	10,285
- 9	(56)	85.81	- 9	(459)	10,307
- 10	(62)	85.70	- 10	(510)	10,330
Weighting Factor:		0.005	Weighting Factor:		0.087

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2003 - December 2003

Smith 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	105	69.10	+ 10	401	9,810
+ 9	95	68.97	+ 9	361	9,833
+ 8	84	68.84	+ 8	321	9,856
+ 7	74	68.71	+ 7	281	9,878
+ 6	63	68.58	+ 6	241	9,901
+ 5	53	68.45	+ 5	201	9,924
+ 4	42	68.32	+ 4	160	9,947
+ 3	32	68.19	+ 3	120	9,970
+ 2	21	68.06	+ 2	80	9,992
+ 1	11	67.93	+ 1	40	10,015
				0	10,038
0	0	67.80	0	0	10,113
				0	10,188
- 1	(15)	67.61	- 1	(40)	10,211
- 2	(29)	67.42	- 2	(80)	10,234
- 3	(44)	67.23	- 3	(120)	10,256
- 4	(58)	67.04	- 4	(160)	10,279
- 5	(73)	66.85	- 5	(201)	10,302
- 6	(87)	66.66	- 6	(241)	10,325
- 7	(102)	66.47	- 7	(281)	10,348
- 8	(116)	66.28	- 8	(321)	10,370
- 9	(131)	66.09	- 9	(361)	10,393
- 10	(145)	65.90	- 10	(401)	10,416
Weighting Factor:		0.018	Weighting Factor:		0.068

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2003 - December 2003

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	445	72.20	+ 10	570	9,741
+ 9	401	71.99	+ 9	513	9,764
+ 8	356	71.78	+ 8	456	9,786
+ 7	312	71.57	+ 7	399	9,809
+ 6	267	71.36	+ 6	342	9,831
+ 5	223	71.15	+ 5	285	9,854
+ 4	178	70.94	+ 4	228	9,877
+ 3	134	70.73	+ 3	171	9,899
+ 2	89	70.52	+ 2	114	9,922
+ 1	45	70.31	+ 1	57	9,944
				0	9,967
0	0	70.10	0	0	10,042
				0	10,117
- 1	(64)	69.79	- 1	(57)	10,140
- 2	(129)	69.48	- 2	(114)	10,162
- 3	(193)	69.17	- 3	(171)	10,185
- 4	(258)	68.86	- 4	(228)	10,207
- 5	(322)	68.55	- 5	(285)	10,230
- 6	(386)	68.24	- 6	(342)	10,253
- 7	(451)	67.93	- 7	(399)	10,275
- 8	(515)	67.62	- 8	(456)	10,298
- 9	(580)	67.31	- 9	(513)	10,320
- 10	(644)	67.00	- 10	(570)	10,343
Weighting Factor:		0.076	Weighting Factor:		0.097

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2003 - December 2003

Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	445	85.70	+ 10	640	9,495
+ 9	401	85.43	+ 9	576	9,517
+ 8	356	85.16	+ 8	512	9,539
+ 7	312	84.89	+ 7	448	9,561
+ 6	267	84.62	+ 6	384	9,583
+ 5	223	84.35	+ 5	320	9,605
+ 4	178	84.08	+ 4	256	9,626
+ 3	134	83.81	+ 3	192	9,648
+ 2	89	83.54	+ 2	128	9,670
+ 1	45	83.27	+ 1	64	9,692
				0	9,714
0	0	83.00	0	0	9,789
				0	9,864
- 1	(62)	82.61	- 1	(64)	9,886
- 2	(125)	82.22	- 2	(128)	9,908
- 3	(187)	81.83	- 3	(192)	9,930
- 4	(249)	81.44	- 4	(256)	9,952
- 5	(312)	81.05	- 5	(320)	9,974
- 6	(374)	80.66	- 6	(384)	9,995
- 7	(436)	80.27	- 7	(448)	10,017
- 8	(498)	79.88	- 8	(512)	10,039
- 9	(561)	79.49	- 9	(576)	10,061
- 10	(623)	79.10	- 10	(640)	10,083
Weighting Factor:		0.076	Weighting Factor:		0.109

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GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2003 - December 2003

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)	EAF Adjusted Actual %	Actual Fuel Savings/ Loss ($000)
Crist 4	0.1	91.2	91.9	90.0	6.0	-9.0	92.3	$6
Crist 5	0.2	89.8	91.0	88.1	12.0	-23.0	91.4	$12
Crist 6	1.3	84.3	86.6	81.0	76.0	-117.0	89.4	$76
Crist 7	8.4	79.5	83.2	73.9	491.0	-764.0	89.5	$491
Smith 1	0.5	86.8	87.4	85.7	32.0	-62.0	83.2	($62)
Smith 2	1.8	67.8	69.1	65.9	105.0	-145.0	69.3	$105
Daniel 1	7.6	70.1	72.2	67.0	445.0	-644.0	73.4	$445
Daniel 2	7.6	83.0	85.7	79.1	445.0	-623.0	89.2	$445
Total:	27.4							

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Max BTU/KWH	ANOHR Range Min BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)	ANOHR Adjusted Actual BTU/KWH	Actual Fuel Savings/ Loss ($000)
Crist 4	3.0	10,591	81.6	10,909	10,273	$179	($179)	10,780	($84)
Crist 5	3.1	10,418	83.0	10,731	10,105	$181	($181)	10,529	($27)
Crist 6	9.9	10,501	83.0	10,816	10,186	$583	($583)	10,400	$63
Crist 7	20.5	10,150	97.0	10,455	9,846	$1,204	($1,204)	10,207	$0
Smith 1	8.7	10,029	98.7	10,330	9,728	$510	($510)	10,300	($442)
Smith 2	6.8	10,113	95.0	10,416	9,810	$401	($401)	10,103	$0
Daniel 1	9.7	10,042	95.2	10,343	9,741	$570	($570)	9,821	$368
Daniel 2	10.9	9,789	96.4	10,083	9,495	$640	($640)	9,634	$234
Total:	72.6								

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Actual Unit Performance Data

Gulf Power Company

Period of: January 2003 - December 2003

Plant & Unit	Actual EAF %	Adjustments* to EAF %	Adjusted Actual %
Crist 4	92.5	-0.2	92.3
Crist 5	91.9	-0.5	91.4
Crist 6	91.7	-2.3	89.4
Crist 7	89.7	-0.2	89.5
Smith 1	79.7	3.5	83.2
Smith 2	69.2	0.1	69.3
Daniel 1	69.8	3.6	73.4
Daniel 2	82.7	6.5	89.2

Plant & Unit	Actual ANOHR BTU/KWH	Adjustments** to ANOHR BTU/KWH	ANOHR Adjusted Actual BTU/KWH
Crist 4	10,617	163	10,780
Crist 5	10,621	-92	10,529
Crist 6	10,358	42	10,400
Crist 7	10,287	-80	10,207
Smith 1	10,384	-84	10,300
Smith 2	10,191	-88	10,103
Daniel 1	9,839	-18	9,821
Daniel 2	9,781	-147	9,634

* Refer to pages 3 through 10, Schedule 2.

** Refer to pages 10 through 17, Schedule 3.

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	CRIST 4	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	
1.	EAF (%)	100.0	100.0	100.0	100.0	100.0	99.9	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	672.0	744.0	719.0	744.0	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	0.0	0.0	0.0	0.0	0.0	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	2.8	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	18.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	
14.	Oper MBtu	507858	433363	569914	539308	496462	479735	
15.	Net Gen (MWH)	46829	39730	52600	50323	47356	45496	
16.	ANOHR (Btu/KWH)	10845	10908	10835	10717	10484	10545	
17.	NOF %	80.7	75.8	90.6	89.7	81.6	81.0	
18.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	

19.	ANOHR Equation	10^6 / AKW * [790.16 + 9.96 * MAR + 18.89 * AUG] -14470 + 0.18768 * LSRF / AKW

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	CRIST 4	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	Total
1.	EAF (%)	100.0	100.0	89.8	77.0	50.8	92.7	92.5
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	744.0	646.6	573.9	365.4	689.9	8106.8
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	0.0	0.0	73.4	171.1	354.6	54.1	653.2
6.	POH	0.0	0.0	0.0	171.1	354.6	0.0	525.7
7.	FOH	0.0	0.0	73.4	0.0	0.0	54.1	127.5
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	2.8
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	18.0
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	78.0
14.	Oper MBtu	504995	510605	434901	408722	277778	477116	5640757
15.	Net Gen (MWH)	48228	49697	40776	39064	25854	45338	531291
16.	ANOHR (Btu/KWH)	10471	10274	10666	10463	10744	10524	10617
17.	NOF %	83.1	85.6	80.8	87.3	90.7	84.3	84.0
18.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	78.0
19.	ANOHR Equation	10^6 / AKW * [790.16 + 9.96 * MAR + 18.89 * AUG] -14470 + 0.18768 * LSRF / AKW						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	CRIST 5	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	
1.	EAF (%)	100.0	100.0	100.0	100.0	95.8	100.0	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	672.0	744.0	719.0	641.4	720.0	
4.	RSH	0.0	0.0	0.0	0.0	71.3	0.0	
5.	UH	0.0	0.0	0.0	0.0	31.3	0.0	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	31.3	0.0	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	80.0	80.0	80.0	80.0	80.0	80.0	
14.	Oper MBtu	497895	433443	556696	535399	418413	467986	
15.	Net Gen (MWH)	45490	38811	51287	49153	39532	44434	
16.	ANOHR (Btu/KWH)	10945	11168	10855	10892	10584	10532	
17.	NOF %	76.4	72.2	86.2	85.5	77.0	77.1	
18.	NPC (MW)	80.0	80.0	80.0	80.0	80.0	80.0	
19.	ANOHR Equation	10^6 / AKW * [134.06 + 15.92 * JUN + 12.53 * AUG - 17.36 * OCT] + 8,376						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	CRIST 5	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	Total
1.	EAF (%)	100.0	100.0	95.2	99.5	21.0	90.2	91.9
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	744.0	685.7	741.3	151.0	671.0	7977.4
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	71.3
5.	UH	0.0	0.0	34.3	3.7	569.0	73.0	711.3
6.	POH	0.0	0.0	0.0	3.7	497.7	0.0	501.4
7.	FOH	0.0	0.0	2.6	0.0	24.8	36.7	95.4
8.	MOH	0.0	0.0	31.7	0.0	46.5	36.3	114.5
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	80.0	80.0	80.0	80.0	80.0	80.0	80.0
14.	Oper MBtu	500525	490281	445704	505147	97229	448940	5397658
15.	Net Gen (MWH)	47950	48664	42536	48749	9096	42518	508220
16.	ANOHR (Btu/KWH)	10438	10075	10478	10362	10689	10559	10621
17.	NOF %	80.6	81.8	77.5	82.2	75.3	79.2	79.6
18.	NPC (MW)	80.0	80.0	80.0	80.0	80.0	80.0	80.0
19.	ANOHR Equation	10^6 / AKW * [134.06 + 15.92 * JUN + 12.53 * AUG - 17.36 * OCT] + 8,376						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	CRIST 6	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	
1.	EAF (%)	93.4	100.0	93.7	28.2	100.0	100.0	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	696.3	672.0	696.8	202.9	744.0	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	47.7	0.0	47.2	516.1	0.0	0.0	
6.	POH	0.0	0.0	0.0	516.1	0.0	0.0	
7.	FOH	0.0	0.0	19.1	0.0	0.0	0.0	
8.	MOH	47.7	0.0	28.1	0.0	0.0	0.0	
9.	PFOH	1.2	0.0	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	292.0	0.0	0.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	
14.	Oper MBtu	1911040	1891377	1954612	405991	1806548	1768032	
15.	Net Gen (MWH)	187100	182725	188407	40770	173989	170770	
16.	ANOHR (Btu/KWH)	10214	10351	10374	9958	10383	10353	
17.	NOF %	89.0	90.0	89.5	66.5	77.4	78.5	
18.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	

19.	ANOHR Equation	10^6 / AKW * [942.11 + 38.69 * JUN + 43.57 * JUL + 47.19 * AUG] + 2,167 + 0.01677 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	CRIST 6	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	Total
1.	EAF (%)	87.6	99.9	100.0	97.1	100.0	100.0	91.7
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	656.9	744.0	720.0	745.0	720.0	732.5	8050.4
4.	RSH	0.0	0.0	0.0	0.0	0.0	11.5	11.5
5.	UH	87.1	0.0	0.0	0.0	0.0	0.0	698.1
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	516.1
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	19.1
8.	MOH	87.1	0.0	0.0	0.0	0.0	0.0	162.9
9.	PFOH	0.0	2.5	0.0	42.7	0.0	0.0	46.4
10.	LR pf (MW)	0.0	127.0	0.0	153.6	0.0	0.0	155.7
11.	PMOH	16.4	0.0	0.0	0.0	0.0	0.0	16.4
12.	LR pm (MW)	97.0	0.0	0.0	0.0	0.0	0.0	97.0
13.	NSC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	302.0
14.	Oper MBtu	1708833	2006226	1874666	1969373	1986279	1916180	21199157
15.	Net Gen (MWH)	162635	195035	181517	185905	189713	188145	2046711
16.	ANOHR (Btu/KWH)	10507	10286	10328	10593	10470	10185	10358
17.	NOF %	82.0	86.8	83.5	82.6	87.2	85.1	84.2
18.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	302.0
19.	ANOHR Equation	10^6 / AKW * [942.11 + 38.69 * JUN + 43.57 * JUL + 47.19 * AUG] + 2,167 + 0.01677 * LSRF / AKW						

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GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	CRIST 7	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	
1.	EAF (%)	99.9	99.9	3.9	93.2	100.0	100.0	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	671.6	39.7	688.8	744.0	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	0.4	704.3	30.2	0.0	0.0	
6.	POH	0.0	0.4	699.5	0.0	0.0	0.0	
7.	FOH	0.0	0.0	4.8	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	30.2	0.0	0.0	
9.	PFOH	4.7	5.9	24.0	58.0	0.0	0.0	
10.	LR pf (MW)	89.7	15.9	217.0	151.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	
14.	Oper MBtu	3197959	2901648	115235	2869598	3113389	3102530	
15.	Net Gen (MWH)	316380	283056	9525	280898	300365	295793	
16.	ANOHR (Btu/KWH)	10108	10251	12098	10216	10365	10489	
17.	NOF %	89.1	88.4	50.3	85.5	84.6	86.1	
18.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	
19.	ANOHR Equation	10^6 / AKW * [364.26 - 208.93 * MAR - 56.05 * MAY + 122.15 * JUL + 75.82 * AUG + 68.14 * SEP + 45.83 * OCT] + 9,350						

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GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	CRIST 7	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	Total
1.	EAF (%)	99.8	100.0	91.1	90.6	99.9	99.9	89.7
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	744.0	664.2	718.5	720.0	744.0	7942.8
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	0.0	0.0	55.8	26.5	0.0	0.0	817.2
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	699.9
7.	FOH	0.0	0.0	0.0	26.5	0.0	0.0	31.3
8.	MOH	0.0	0.0	55.8	0.0	0.0	0.0	86.0
9.	PFOH	8.2	0.0	29.8	2.1	1.7	17.8	152.2
10.	LR pf (MW)	72.7	0.0	129.0	60.1	176.1	29.9	130.6
11.	PMOH	0.0	0.0	4.0	74.8	0.0	0.0	78.8
12.	LR pm (MW)	0.0	0.0	51.0	278.0	0.0	0.0	266.5
13.	NSC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	477.0
14.	Oper MBtu	3244023	3357869	2912374	2913573	3291408	3311093	34330699
15.	Net Gen (MWH)	315840	330470	278984	283263	319768	322915	3337257
16.	ANOHR (Btu/KWH)	10271	10161	10439	10286	10293	10254	10287
17.	NOF %	89.0	93.1	88.1	82.7	93.1	91.0	88.1
18.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	477.0
19.	ANOHR Equation	10^6 / AKW * [364.26 - 208.93 * MAR - 56.05 * MAY + 122.15 * JUL + 75.82 * AUG + 68.14 * SEP + 45.83 * OCT] + 9,350						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	SMITH 1	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	
1.	EAF (%)	100.0	93.8	99.8	59.6	46.9	100.0	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	743.7	631.0	744.0	429.1	349.1	720.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.3	41.0	0.0	289.9	394.9	0.0	
6.	POH	0.0	0.0	0.0	289.9	394.9	0.0	
7.	FOH	0.3	41.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	0.0	0.5	3.0	1.6	0.3	0.8	
10.	LR pf (MW)	0.0	156.0	60.7	32.0	155.0	42.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	
14.	Oper MBtu	1025297	800581	1104030	639966	446439	967758	
15.	Net Gen (MWH)	100234	78642	104529	60579	42319	92538	
16.	ANOHR (Btu/KWH)	10229	10180	10562	10564	10549	10458	
17.	NOF %	83.2	76.9	86.7	87.1	74.8	79.3	
18.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	

19.	ANOHR Equation	10^6 / AKW * [-6.55 - 12.65 * JAN - 14.68 * FEB + 9.56 * JUN - 10.32 * SEP - 14.06 * NOV] + 10,971 - 0.00543 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	SMITH 1	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	Total
1.	EAF (%)	100.0	53.3	99.9	100.0	93.9	11.1	79.7
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	396.2	720.0	745.0	676.3	71.1	6969.5
4.	RSH	0.0	0.0	0.0	0.0	0.0	11.6	11.6
5.	UH	0.0	347.8	0.0	0.0	43.7	661.3	1778.9
6.	POH	0.0	0.0	0.0	0.0	43.7	563.5	1292.0
7.	FOH	0.0	325.2	0.0	0.0	0.0	14.0	380.5
8.	MOH	0.0	22.6	0.0	0.0	0.0	83.8	106.4
9.	PFOH	0.0	0.0	0.8	1.4	1.7	0.0	10.1
10.	LR pf (MW)	0.0	0.0	157.1	22.0	22.0	0.0	57.9
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0
14.	Oper MBtu	1045414	537859	979598	1050376	939920	89348	9626586
15.	Net Gen (MWH)	100256	51355	94238	101677	92806	7869	927042
16.	ANOHR (Btu/KWH)	10427	10473	10395	10331	10128	11354	10384
17.	NOF %	83.2	80.0	80.8	84.2	84.7	68.3	82.1
18.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0
19.	ANOHR Equation	10^6 / AKW * [-6.55 - 12.65 * JAN - 14.68 * FEB + 9.56 * JUN - 10.32 * SEP - 14.06 * NOV] + 10,971 - 0.00543 * LSRF / AKW						

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GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	SMITH 2	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	
1.	EAF (%)	0.2	0.0	0.0	51.1	92.7	99.0	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	1.6	0.0	0.0	428.3	689.5	712.7	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	742.4	672.0	744.0	290.7	54.5	7.3	
6.	POH	742.4	672.0	744.0	290.7	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	7.3	
8.	MOH	0.0	0.0	0.0	0.0	54.5	0.0	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	118.1	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	98.0	0.0	0.0	
13.	NSC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	
14.	Oper MBtu	928	0	0	586003	998041	1046203	
15.	Net Gen (MWH)	63	0	0	57403	97276	102368	
16.	ANOHR (Btu/KWH)	14730	0	0	10209	10260	10220	
17.	NOF %	20.8	0.0	0.0	70.9	74.6	76.0	
18.	NPC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	
19.	ANOHR Equation	10^6 / AKW * [261.83 - 36.53 * JAN - 44.18 * FEB - 58.60 * MAR - 21.11 * APR - 15.99 * MAY + 15.64 * JUL] + 6,772 + 0.01037 * LSRF / AKW						

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GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	SMITH 2	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	Total
1.	EAF (%)	100.0	99.7	100.0	83.9	99.9	100.0	69.2
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	744.0	720.0	626.6	720.0	744.0	6130.7
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	0.0	0.0	0.0	118.4	0.0	0.0	2629.3
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	2449.1
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	7.3
8.	MOH	0.0	0.0	0.0	118.4	0.0	0.0	172.9
9.	PFOH	0.0	2.5	0.0	6.4	2.4	0.0	11.3
10.	LR pf (MW)	0.0	142.0	0.0	52.0	37.0	0.0	68.7
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	118.1
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	98.0
13.	NSC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	189.0
14.	Oper MBtu	1147371	1148064	1110943	1007457	1157702	1252121	9454833
15.	Net Gen (MWH)	112185	112788	109404	98475	114506	123325	927793
16.	ANOHR (Btu/KWH)	10227	10179	10155	10231	10110	10153	10191
17.	NOF %	79.8	80.2	80.4	83.2	84.1	87.7	80.1
18.	NPC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	189.0
19.	ANOHR Equation	10^6 / AKW * [261.83 - 36.53 * JAN - 44.18 * FEB - 58.60 * MAR - 21.11 * APR - 15.99 * MAY + 15.64 * JUL] + 6,772 + 0.01037 * LSRF / AKW						

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GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	DANIEL 1	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	
1.	EAF (%)	13.1	0.0	12.1	99.1	93.0	93.2	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	98.9	0.0	90.2	719.0	700.3	677.6	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	645.1	672.0	653.8	0.0	43.7	42.4	
6.	POH	645.1	672.0	653.8	0.0	0.0	0.0	
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	43.7	42.4	
9.	PFOH	98.9	0.0	0.8	54.2	39.9	81.3	
10.	LR pf (MW)	9.0	0.0	27.0	58.6	38.3	35.6	
11.	PMOH	0.0	0.0	0.0	0.0	8.0	2.3	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	350.1	239.0	
13.	NSC (MW)	507.0	507.0	507.0	507.0	507.0	507.0	
14.	Oper MBtu	341996	0	374622	3240696	2774414	2855714	
15.	Net Gen (MWH)	39730	0	34421	331929	288606	288730	
16.	ANOHR (Btu/KWH)	8608	0	10884	9763	9613	9891	
17.	NOF %	79.2	0.0	75.3	91.1	81.3	84.0	
18.	NPC (MW)	507.0	507.0	507.0	507.0	507.0	507.0	

19.	ANOHR Equation	10^6 / AKW * [-931.04 + 183.89 * JUL + 122.54 * AUG + 110.76 * SEP + 89.14 * NOV] + 18,532 - 0.01364 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	DANIEL 1	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	Total
1.	EAF (%)	99.8	100.0	99.3	78.4	64.8	80.7	69.8
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	744.0	720.0	695.2	467.8	601.3	6258.3
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	0.0	0.0	0.0	49.8	252.2	142.7	2501.7
6.	POH	0.0	0.0	0.0	0.0	252.2	120.0	2343.1
7.	FOH	0.0	0.0	0.0	49.8	0.0	4.7	54.5
8.	MOH	0.0	0.0	0.0	0.0	0.0	18.0	104.1
9.	PFOH	3.1	6.6	47.9	97.0	3.9	0.6	434.2
10.	LR pf (MW)	208.5	20.6	55.6	41.5	144.8	505.0	38.8
11.	PMOH	0.0	0.0	0.0	150.1	0.0	0.0	160.4
12.	LR pm (MW)	0.0	0.0	0.0	349.3	0.0	0.0	347.8
13.	NSC (MW)	507.0	507.0	507.0	507.0	507.0	507.0	507.0
14.	Oper MBtu	3466048	3256765	3046624	2656869	2250933	2901427	27166109
15.	Net Gen (MWH)	342500	337744	311837	270673	224466	290554	2761190
16.	ANOHR (Btu/KWH)	10120	9643	9770	9816	10028	9986	9839
17.	NOF %	90.8	89.5	85.4	76.8	94.6	95.3	87.0
18.	NPC (MW)	507.0	507.0	507.0	507.0	507.0	507.0	507.0
19.	ANOHR Equation	10^6 / AKW * [-931.04 + 183.89 * JUL + 122.54 * AUG + 110.76 * SEP + 89.14 * NOV] + 18,532 - 0.01364 * LSRF / AKW						

Issued by: S. N. Story

Filed: April 01, 2004
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Effective: April 01, 2004
Docket No.: 040001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	DANIEL 2	Jan '03	Feb '03	Mar '03	Apr '03	May '03	Jun '03	
1.	EAF (%)	99.6	50.2	99.4	97.0	94.9	95.6	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	342.1	744.0	705.2	737.5	705.4	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	329.9	0.0	13.8	6.5	14.6	
6.	POH	0.0	307.4	0.0	0.0	0.0	0.0	
7.	FOH	0.0	22.5	0.0	13.8	6.5	14.6	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	13.9	14.0	18.4	18.9	162.4	38.8	
10.	LR pf (MW)	104.5	173.7	127.7	212.4	67.5	149.6	
11.	PMOH	0.0	0.0	0.0	0.4	17.8	16.3	
12.	LR pm (MW)	0.0	0.0	0.0	234.0	287.8	186.0	
13.	NSC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	
14.	Oper MBtu	3355036	1382151	3509562	3186046	2930586	3056003	
15.	Net Gen (MWH)	346887	139746	368994	323558	300615	308174	
16.	ANOHR (Btu/KWH)	9672	9890	9511	9847	9749	9916	
17.	NOF %	90.7	79.5	96.5	89.3	79.3	85.0	
18.	NPC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	

19.	ANOHR Equation	10^6 / AKW * [187.07 - 118.14 * JAN - 94.43 * FEB - 73.36 * SEP - 78.52 * NOV] + 12,178 - 0.00543 * LSRF / AKW

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2003 - December 2003

	DANIEL 2	Jul '03	Aug '03	Sep '03	Oct '03	Nov '03	Dec '03	Total
1.	EAF (%)	99.5	98.4	91.7	99.7	23.5	39.0	82.7
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	744.0	666.9	745.0	168.9	291.9	7338.9
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	0.0	0.0	53.1	0.0	551.1	452.1	1421.1
6.	POH	0.0	0.0	0.0	0.0	551.1	450.9	1309.4
7.	FOH	0.0	0.0	11.3	0.0	0.0	1.2	69.9
8.	MOH	0.0	0.0	41.8	0.0	0.0	0.0	41.8
9.	PFOH	10.0	5.7	7.7	30.3	0.7	1.9	322.7
10.	LR pf (MW)	70.0	134.5	428.8	41.3	19.0	483.3	105.3
11.	PMOH	12.7	20.5	0.0	0.0	0.0	0.0	67.7
12.	LR pm (MW)	81.4	262.2	0.0	0.0	0.0	0.0	216.5
13.	NSC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	514.0
14.	Oper MBtu	3375323	3168422	2705485	3499416	761029	1177828	32106887
15.	Net Gen (MWH)	336252	330019	281941	354938	77720	113626	3282470
16.	ANOHR (Btu/KWH)	10038	9601	9596	9859	9792	10366	9781
17.	NOF %	87.9	86.3	82.2	92.7	89.5	75.7	87.0
18.	NPC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	514.0
19.	ANOHR Equation	10^6 / AKW * [187.07 - 118.14 * JAN - 94.43 * FEB - 73.36 * SEP - 78.52 * NOV] + 12,178 - 0.00543 * LSRF / AKW						

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Planned Outage Schedules (Actual)

Period of: January 2003 - December 2003

Critical path bar charts of actual work activity performed during major planned outages are not shown here since corresponding bar charts of forecast work activity were not provided earlier in conformance with agreement with Staff to avoid the premature production of charts prior to their normal course of development. Forecast and actual critical path bar charts are developed for each planned outage and, per agreement with Staff, these charts will be provided on request.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 040001-EI

Before me, the undersigned authority, personally appeared Lonzelle S. Noack, who being first duly sworn, deposes, and says that she is the Power Generation Specialist, Senior for Gulf Power Company, a Maine corporation, and that the foregoing is true and correct to the best of her knowledge, information, and belief. She is personally known to me.

Lonzelle S. Noack
Power Generation Specialist, Senior

Sworn to and subscribed before me this 29th day of March, 2004.

Acknowledged before me this date, who is personally known to me [illegible] did not take an oath.

Notary Public, State of Florida at Large

Commission Number: DD 194327

Commission Expires: 5-18-07

CANDACE KLINGLESMITH
MY COMMISSION # DD 194327
EXPIRES: May 18, 2007
Bonded Thru Notary Public Underwriters

Florida Public Service Commission
Docket No. 040001-EI
Gulf Power Company
Witness: L. S. Noack
Exhibit No.___(LSN-2)

EXHIBIT TO THE TESTIMONY OF

L. S. NOACK

IN FPSC DOCKET 040001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-ET EXHIBIT NO. 29
COMPANY/ Gulf
WITNESS. L.S. Noack (LSN-2)
DATE 11-08-04

I. DETERMINATION OF HEAT RATE TARGETS

Target Heat Rate Equations

Crist 4 ANOHR = 10^6 / AKW * [604.51 + 16.03 * JAN + 10.26 * MAR + 8.72 * APR]

- 7798 + 0.13404 * LSRF / AKW

Crist 5 ANOHR = 10^6 / AKW * [160.95 - 14.39 * JUL - 17.85 * AUG - 13.91 * SEP - 18.50 * OCT - 35.97 * NOV]

+ 8,240

Crist 6 ANOHR = 10^6 / AKW * [1533.78 + 120.92 * JAN + 64.73 * JUL + 71.04 * AUG + 66.84 * OCT]

- 3884 + 0.02998 * LSRF / AKW

Crist 7 ANOHR = 10^6 / AKW * [1414.12 - 52.99 * JAN - 235.50 * MAR + 42.16 * JUL + 51.30 * SEP - 45.57 * OCT]

+ 2,568 + 0.00993 * LSRF / AKW

Smith 1 ANOHR = 10^6 / AKW * [334.98 - 12.87 * JAN]

+ 4,856 + 0.02059 * LSRF / AKW

Smith 2 ANOHR = 10^6 / AKW * [-318.85 - 47.20 * JAN - 23.05 * FEB - 61.42 * MAR + 62.94 * APR + 16.98 * MAY + 24.15 * JUN]

+ 15,607 - 0.02010 * LSRF / AKW

Daniel 1 ANOHR = 10^6 / AKW * [382.13 + 83.86 * JAN - 72.84 * OCT]

+ 9,183

Daniel 2 ANOHR = 10^6 / AKW * [1305.50 - 156.38 * JAN - 119.09 * FEB - 75.83 * MAR + 57.36 * APR]

+ 3,696 + 0.00694 * LSRF / AKW

Where:

ANOHR = Average Net Operating Heat Rate, BTU/KWH
AKW = Average Kilowatt Load, KW
LSRF = Load Square Range Factor, KW^2
BTU/LB = Coal Burned Average Heat Content, BTU/LB
JAN = January, 0 if not January, 1 if January
FEB = February, 0 if not February, 1 if February
MAR = March, 0 if not March, 1 if March
APR = April, 0 if not April, 1 if April
MAY = May, 0 if not May, 1 if May
JUN = June, 0 if not June, 1 if June
JUL = July, 0 if not July, 1 if July
AUG = August, 0 if not August, 1 if August
SEP = September, 0 if not September, 1 if September
OCT = October, 0 if not October, 1 if October
NOV = November, 0 if not November, 1 if November

WEEKLY UNIT OPERATING

DATA USED TO DEVELOP

TARGET HEAT RATE EQUATIONS

Data Base for CRIST 4 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10471	168	51.2	2751	0	0	0	0	0	0	1	0	0	0	0	0	2001
10392	168	58.3	3603	0	0	0	0	0	0	1	0	0	0	0	0	2001
10585	168	58.8	3681	0	0	0	0	0	0	1	0	0	0	0	0	2001
10579	168	58.1	3591	0	0	0	0	0	0	1	0	0	0	0	0	2001
10251	168	65.7	4503	0	0	0	0	0	0	0	1	0	0	0	0	2001
10724	168	64.6	4351	0	0	0	0	0	0	0	1	0	0	0	0	2001
10625	168	65.3	4461	0	0	0	0	0	0	0	1	0	0	0	0	2001
10838	168	62.0	4093	0	0	0	0	0	0	0	1	0	0	0	0	2001
10965	168	59.2	3738	0	0	0	0	0	0	0	1	0	0	0	0	2001
10865	168	55.2	3274	0	0	0	0	0	0	0	0	1	0	0	0	2001
10726	168	54.6	3205	0	0	0	0	0	0	0	0	1	0	0	0	2001
10715	168	52.9	2984	0	0	0	0	0	0	0	0	1	0	0	0	2001
10812	167	53.2	3041	0	0	0	0	0	0	0	0	1	0	0	0	2001
* 9345	39	66.5	4682	0	0	0	0	0	0	0	0	0	1	0	1	2001
12170	104	53.5	3084	1	0	0	0	0	0	0	0	0	0	0	1	2002
12101	47	63.3	4275	1	0	0	0	0	0	0	0	0	0	0	0	2002
12171	144	43.3	1982	0	1	0	0	0	0	0	0	0	0	0	1	2002
11446	158	45.9	2142	0	1	0	0	0	0	0	0	0	0	0	0	2002
11184	168	46.5	2217	0	1	0	0	0	0	0	0	0	0	0	0	2002
11293	168	52.0	2850	0	0	1	0	0	0	0	0	0	0	0	0	2002
11386	168	50.5	2669	0	0	1	0	0	0	0	0	0	0	0	0	2002
11355	168	48.6	2425	0	0	1	0	0	0	0	0	0	0	0	0	2002
11337	168	53.6	3027	0	0	1	0	0	0	0	0	0	0	0	0	2002
11192	168	52.8	2927	0	0	1	0	0	0	0	0	0	0	0	0	2002
11122	167	52.4	2903	0	0	0	1	0	0	0	0	0	0	0	0	2002
11422	168	49.9	2625	0	0	0	1	0	0	0	0	0	0	0	0	2002
11155	168	59.4	3755	0	0	0	1	0	0	0	0	0	0	0	0	2002
11282	168	55.6	3299	0	0	0	1	0	0	0	0	0	0	0	0	2002
11264	168	58.2	3633	0	0	0	0	1	0	0	0	0	0	0	0	2002
11296	168	60.8	3949	0	0	0	0	1	0	0	0	0	0	0	0	2002
11369	94	55.3	3305	0	0	0	0	1	0	0	0	0	0	0	0	2002
11392	87	56.6	3440	0	0	0	0	1	0	0	0	0	0	0	1	2002
11443	168	49.9	2662	0	0	0	0	1	0	0	0	0	0	0	0	2002
11730	168	48.1	2451	0	0	0	0	0	1	0	0	0	0	0	0	2002
11832	168	49.0	2557	0	0	0	0	0	1	0	0	0	0	0	0	2002
11737	168	49.1	2560	0	0	0	0	0	1	0	0	0	0	0	0	2002
11631	144	52.4	2934	0	0	0	0	0	1	0	0	0	0	0	0	2002
11757	168	49.2	2548	0	0	0	0	0	0	1	0	0	0	0	0	2002
11715	168	50.7	2663	0	0	0	0	0	0	1	0	0	0	0	0	2002
11769	168	53.5	3054	0	0	0	0	0	0	1	0	0	0	0	0	2002
11825	168	48.2	2443	0	0	0	0	0	0	1	0	0	0	0	0	2002
11303	168	55.4	3269	0	0	0	0	0	0	0	1	0	0	0	0	2002
11154	168	48.5	2462	0	0	0	0	0	0	0	1	0	0	0	0	2002
11341	168	51.6	2817	0	0	0	0	0	0	0	1	0	0	0	0	2002
11361	168	54.5	3159	0	0	0	0	0	0	0	1	0	0	0	0	2002
11734	168	48.1	2441	0	0	0	0	0	0	0	1	0	0	0	0	2002
11326	168	53.8	3104	0	0	0	0	0	0	0	0	1	0	0	0	2002

Data Base for CRIST 4 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11052	168	62.1	4095	0	0	0	0	0	0	0	0	1	0	0	0	2002
11159	160	64.3	4379	0	0	0	0	0	0	0	0	1	0	0	0	2002
11082	168	57.2	3439	0	0	0	0	0	0	0	0	1	0	0	0	2002
11045	168	62.4	4098	0	0	0	0	0	0	0	0	0	1	0	0	2002
11075	168	57.3	3436	0	0	0	0	0	0	0	0	0	1	0	0	2002
11218	168	49.0	2451	0	0	0	0	0	0	0	0	0	1	0	0	2002
10914	169	58.2	3554	0	0	0	0	0	0	0	0	0	1	0	0	2002
10974	168	56.5	3368	0	0	0	0	0	0	0	0	0	1	0	0	2002
10699	168	52.2	2854	0	0	0	0	0	0	0	0	0	0	1	0	2002
*10330	168	47.1	2243	0	0	0	0	0	0	0	0	0	0	1	0	2002
10464	119	48.6	2400	0	0	0	0	0	0	0	0	0	0	1	0	2002
12817	44	39.2	1657	0	0	0	0	0	0	0	0	0	0	0	1	2002
11789	168	52.5	2890	0	0	0	0	0	0	0	0	0	0	0	0	2002
11835	160	45.6	2132	0	0	0	0	0	0	0	0	0	0	0	0	2002
11803	24	46.2	2133	0	0	0	0	0	0	0	0	0	0	0	0	2002
11010	168	58.0	3543	1	0	0	0	0	0	0	0	0	0	0	0	2003
10839	168	59.0	3685	1	0	0	0	0	0	0	0	0	0	0	0	2003
10855	168	68.0	4781	1	0	0	0	0	0	0	0	0	0	0	0	2003
10777	168	64.1	4286	1	0	0	0	0	0	0	0	0	0	0	0	2003
10800	168	62.0	4014	0	1	0	0	0	0	0	0	0	0	0	0	2003
10991	168	57.1	3420	0	1	0	0	0	0	0	0	0	0	0	0	2003
11023	168	55.6	3222	0	1	0	0	0	0	0	0	0	0	0	0	2003
10820	168	62.4	4043	0	1	0	0	0	0	0	0	0	0	0	0	2003
10772	168	70.2	5041	0	0	1	0	0	0	0	0	0	0	0	0	2003
10807	168	69.3	4940	0	0	1	0	0	0	0	0	0	0	0	0	2003
10905	168	68.7	4869	0	0	1	0	0	0	0	0	0	0	0	0	2003
10812	168	71.3	5206	0	0	1	0	0	0	0	0	0	0	0	0	2003
10798	168	72.4	5315	0	0	1	0	0	0	0	0	0	0	0	0	2003
10752	167	70.1	5029	0	0	0	1	0	0	0	0	0	0	0	0	2003
10689	168	71.2	5187	0	0	0	1	0	0	0	0	0	0	0	0	2003
10696	168	69.3	4942	0	0	0	1	0	0	0	0	0	0	0	0	2003
10730	168	69.6	4996	0	0	0	1	0	0	0	0	0	0	0	0	2003
10412	168	68.6	4871	0	0	0	0	1	0	0	0	0	0	0	0	2003
10495	168	63.4	4214	0	0	0	0	1	0	0	0	0	0	0	0	2003
10594	168	63.4	4196	0	0	0	0	1	0	0	0	0	0	0	0	2003
10497	168	60.8	3893	0	0	0	0	1	0	0	0	0	0	0	0	2003
10450	168	62.8	4133	0	0	0	0	1	0	0	0	0	0	0	0	2003
10428	168	63.0	4133	0	0	0	0	0	1	0	0	0	0	0	0	2003
10466	168	62.9	4145	0	0	0	0	0	1	0	0	0	0	0	0	2003
10546	168	61.6	4037	0	0	0	0	0	1	0	0	0	0	0	0	2003
10810	144	65.7	4496	0	0	0	0	0	1	0	0	0	0	0	0	2003
10494	168	60.7	3867	0	0	0	0	0	0	1	0	0	0	0	0	2003
10482	168	66.2	4554	0	0	0	0	0	0	1	0	0	0	0	0	2003
10398	168	66.7	4633	0	0	0	0	0	0	1	0	0	0	0	0	2003
10553	168	64.0	4271	0	0	0	0	0	0	1	0	0	0	0	0	2003
10357	168	64.9	4392	0	0	0	0	0	0	0	1	0	0	0	0	2003
10197	168	66.1	4549	0	0	0	0	0	0	0	1	0	0	0	0	2003

Data Base for CRIST 4 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10258	168	68.3	4804	0	0	0	0	0	0	0	1	0	0	0	0	2003
10234	168	68.1	4801	0	0	0	0	0	0	0	1	0	0	0	0	2003
10429	168	67.2	4701	0	0	0	0	0	0	0	1	0	0	0	0	2003
10996	139	60.0	3860	0	0	0	0	0	0	0	0	1	0	0	1	2003
10595	168	63.9	4295	0	0	0	0	0	0	0	0	1	0	0	0	2003
10581	168	62.5	4109	0	0	0	0	0	0	0	0	1	0	0	0	2003
10503	135	65.9	4509	0	0	0	0	0	0	0	0	1	0	0	0	2003
10572	159	63.4	4243	0	0	0	0	0	0	0	0	0	1	0	1	2003
10434	168	68.7	4867	0	0	0	0	0	0	0	0	0	1	0	0	2003
10545	168	69.4	4969	0	0	0	0	0	0	0	0	0	1	0	0	2003
10402	94	69.5	4976	0	0	0	0	0	0	0	0	0	1	0	0	2003
11270	54	66.8	4740	0	0	0	0	0	0	0	0	0	0	1	1	2003
10622	168	73.1	5383	0	0	0	0	0	0	0	0	0	0	1	0	2003
10695	168	70.1	5038	0	0	0	0	0	0	0	0	0	0	1	0	2003
10621	115	70.8	5182	0	0	0	0	0	0	0	0	0	0	0	1	2003
10471	168	69.6	4975	0	0	0	0	0	0	0	0	0	0	0	0	2003
10427	168	68.2	4774	0	0	0	0	0	0	0	0	0	0	0	0	2003
10649	168	54.9	3142	0	0	0	0	0	0	0	0	0	0	0	0	2003
10637	24	61.3	3929	0	0	0	0	0	0	0	0	0	0	0	0	2003
10531	168	58.1	3557	1	0	0	0	0	0	0	0	0	0	0	0	2004
10364	168	72.8	5372	1	0	0	0	0	0	0	0	0	0	0	0	2004
10454	168	67.7	4691	1	0	0	0	0	0	0	0	0	0	0	0	2004
10438	168	68.4	4787	1	0	0	0	0	0	0	0	0	0	0	0	2004
10468	168	68.9	4848	0	1	0	0	0	0	0	0	0	0	0	0	2004
10540	168	68.2	4743	0	1	0	0	0	0	0	0	0	0	0	0	2004
10366	168	73.3	5422	0	1	0	0	0	0	0	0	0	0	0	0	2004
10228	168	73.2	5397	0	1	0	0	0	0	0	0	0	0	0	0	2004
10282	168	72.7	5342	0	1	0	0	0	0	0	0	0	0	0	0	2004
10406	168	71.8	5237	0	0	1	0	0	0	0	0	0	0	0	0	2004
10227	168	76.6	5887	0	0	1	0	0	0	0	0	0	0	0	0	2004
10325	168	76.3	5848	0	0	1	0	0	0	0	0	0	0	0	0	2004
10402	168	72.5	5340	0	0	1	0	0	0	0	0	0	0	0	0	2004
10372	167	75.7	5759	0	0	0	1	0	0	0	0	0	0	0	0	2004
10474	168	70.0	5027	0	0	0	1	0	0	0	0	0	0	0	0	2004
10431	168	71.3	5188	0	0	0	1	0	0	0	0	0	0	0	0	2004
10505	168	71.8	5259	0	0	0	1	0	0	0	0	0	0	0	0	2004
10564	168	61.5	3947	0	0	0	0	1	0	0	0	0	0	0	0	2004
10529	168	65.7	4461	0	0	0	0	1	0	0	0	0	0	0	0	2004
10520	168	68.0	4776	0	0	0	0	1	0	0	0	0	0	0	0	2004
10513	168	66.3	4556	0	0	0	0	1	0	0	0	0	0	0	0	2004
10590	168	64.5	4350	0	0	0	0	1	0	0	0	0	0	0	0	2004
10499	168	65.3	4428	0	0	0	0	0	1	0	0	0	0	0	0	2004
10568	168	68.0	4760	0	0	0	0	0	1	0	0	0	0	0	0	2004
10748	168	65.5	4449	0	0	0	0	0	1	0	0	0	0	0	0	2004
10785	142	63.0	4179	0	0	0	0	0	1	0	0	0	0	0	1	2004

Data Base for CRIST 4 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 5 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10473	168	50.9	2719	0	0	0	0	0	0	1	0	0	0	0	0	2001
10313	168	58.3	3616	0	0	0	0	0	0	1	0	0	0	0	0	2001
10406	168	59.1	3720	0	0	0	0	0	0	1	0	0	0	0	0	2001
10210	168	58.3	3618	0	0	0	0	0	0	1	0	0	0	0	0	2001
10150	168	65.8	4537	0	0	0	0	0	0	0	1	0	0	0	0	2001
10601	168	64.4	4342	0	0	0	0	0	0	0	1	0	0	0	0	2001
10553	168	65.7	4519	0	0	0	0	0	0	0	1	0	0	0	0	2001
10518	168	61.8	4081	0	0	0	0	0	0	0	1	0	0	0	0	2001
10832	168	60.2	3837	0	0	0	0	0	0	0	1	0	0	0	0	2001
10618	168	56.9	3481	0	0	0	0	0	0	0	0	1	0	0	0	2001
10622	166	56.2	3391	0	0	0	0	0	0	0	0	1	0	0	0	2001
10443	168	55.2	3252	0	0	0	0	0	0	0	0	1	0	0	0	2001
10617	168	54.6	3203	0	0	0	0	0	0	0	0	1	0	0	0	2001
10426	168	51.8	2856	0	0	0	0	0	0	0	0	0	1	0	0	2001
10409	168	54.9	3192	0	0	0	0	0	0	0	0	0	1	0	0	2001
10420	46	53.7	3107	0	0	0	0	0	0	0	0	0	1	0	0	2001
10505	38	58.9	3877	0	0	0	0	0	0	0	0	0	1	0	1	2001
13359	24	34.6	1586	0	1	0	0	0	0	0	0	0	0	0	1	2002
11055	168	53.1	3064	0	1	0	0	0	0	0	0	0	0	0	0	2002
11005	23	48.0	2442	0	1	0	0	0	0	0	0	0	0	0	0	2002
11614	118	50.3	2785	0	0	1	0	0	0	0	0	0	0	0	2	2002
11250	168	52.0	2838	0	0	1	0	0	0	0	0	0	0	0	0	2002
11202	168	51.2	2696	0	0	1	0	0	0	0	0	0	0	0	0	2002
11332	166	55.5	3283	0	0	1	0	0	0	0	0	0	0	0	0	2002
11163	168	55.8	3259	0	0	1	0	0	0	0	0	0	0	0	0	2002
10918	167	56.9	3386	0	0	0	1	0	0	0	0	0	0	0	0	2002
10829	168	58.5	3586	0	0	0	1	0	0	0	0	0	0	0	0	2002
10888	168	61.4	3969	0	0	0	1	0	0	0	0	0	0	0	0	2002
10941	168	59.0	3657	0	0	0	1	0	0	0	0	0	0	0	0	2002
11090	168	59.1	3672	0	0	0	0	1	0	0	0	0	0	0	0	2002
11050	168	63.2	4206	0	0	0	0	1	0	0	0	0	0	0	0	2002
11057	96	57.5	3536	0	0	0	0	1	0	0	0	0	0	0	0	2002
11497	85	55.2	3294	0	0	0	0	1	0	0	0	0	0	0	1	2002
11231	168	52.6	2915	0	0	0	0	1	0	0	0	0	0	0	0	2002
11511	168	51.6	2785	0	0	0	0	0	1	0	0	0	0	0	0	2002
11536	168	53.5	3043	0	0	0	0	0	1	0	0	0	0	0	0	2002
11589	168	52.4	2910	0	0	0	0	0	1	0	0	0	0	0	0	2002
11541	144	54.9	3220	0	0	0	0	0	1	0	0	0	0	0	0	2002
11611	168	51.0	2720	0	0	0	0	0	0	1	0	0	0	0	0	2002
11506	168	54.2	3062	0	0	0	0	0	0	1	0	0	0	0	0	2002
11601	168	56.5	3396	0	0	0	0	0	0	1	0	0	0	0	0	2002
11651	168	51.0	2724	0	0	0	0	0	0	1	0	0	0	0	0	2002
11144	168	58.2	3611	0	0	0	0	0	0	0	1	0	0	0	0	2002
11037	168	52.0	2825	0	0	0	0	0	0	0	1	0	0	0	0	2002
11189	168	55.5	3255	0	0	0	0	0	0	0	1	0	0	0	0	2002
11142	168	57.1	3473	0	0	0	0	0	0	0	1	0	0	0	0	2002
11301	168	53.3	3028	0	0	0	0	0	0	0	1	0	0	0	0	2002

Data Base for CRIST 5 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11112	147	58.1	3608	0	0	0	0	0	0	0	0	1	0	0	0	2002
11191	168	57.8	3516	0	0	0	0	0	0	0	0	1	0	0	0	2002
11074	168	66.4	4609	0	0	0	0	0	0	0	0	1	0	0	0	2002
11135	168	57.3	3474	0	0	0	0	0	0	0	0	1	0	0	0	2002
11058	168	63.4	4221	0	0	0	0	0	0	0	0	0	1	0	0	2002
11120	168	58.0	3513	0	0	0	0	0	0	0	0	0	1	0	0	2002
11341	168	48.0	2324	0	0	0	0	0	0	0	0	0	1	0	0	2002
11106	169	58.9	3649	0	0	0	0	0	0	0	0	0	1	0	0	2002
11518	168	52.6	2887	0	0	0	0	0	0	0	0	0	1	0	0	2002
10867	168	52.4	2880	0	0	0	0	0	0	0	0	0	0	1	0	2002
10573	168	47.4	2273	0	0	0	0	0	0	0	0	0	0	1	0	2002
10469	120	49.4	2458	0	0	0	0	0	0	0	0	0	0	1	0	2002
*14672	28	41.5	1829	0	0	0	0	0	0	0	0	0	0	0	1	2002
12320	168	47.0	2252	0	0	0	0	0	0	0	0	0	0	0	0	2002
12309	168	45.1	2092	0	0	0	0	0	0	0	0	0	0	0	0	2002
12325	24	42.6	1816	0	0	0	0	0	0	0	0	0	0	0	0	2002
11110	168	54.4	3097	1	0	0	0	0	0	0	0	0	0	0	0	2003
11039	168	56.9	3457	1	0	0	0	0	0	0	0	0	0	0	0	2003
10852	168	67.1	4663	1	0	0	0	0	0	0	0	0	0	0	0	2003
10906	168	63.0	4167	1	0	0	0	0	0	0	0	0	0	0	0	2003
10985	168	62.4	4070	0	1	0	0	0	0	0	0	0	0	0	0	2003
11243	168	55.8	3282	0	1	0	0	0	0	0	0	0	0	0	0	2003
11209	168	54.3	3055	0	1	0	0	0	0	0	0	0	0	0	0	2003
11148	168	58.2	3530	0	1	0	0	0	0	0	0	0	0	0	0	2003
10947	168	69.8	4983	0	0	1	0	0	0	0	0	0	0	0	0	2003
10858	168	68.2	4785	0	0	1	0	0	0	0	0	0	0	0	0	2003
10926	168	65.9	4485	0	0	1	0	0	0	0	0	0	0	0	0	2003
10799	168	69.5	4974	0	0	1	0	0	0	0	0	0	0	0	0	2003
10800	168	71.8	5247	0	0	1	0	0	0	0	0	0	0	0	0	2003
10877	167	67.6	4706	0	0	0	1	0	0	0	0	0	0	0	0	2003
10850	168	68.7	4832	0	0	0	1	0	0	0	0	0	0	0	0	2003
10877	168	69.1	4921	0	0	0	1	0	0	0	0	0	0	0	0	2003
10956	168	67.7	4740	0	0	0	1	0	0	0	0	0	0	0	0	2003
10350	168	67.4	4713	0	0	0	0	1	0	0	0	0	0	0	0	2003
10446	168	62.8	4129	0	0	0	0	1	0	0	0	0	0	0	0	2003
10372	168	61.3	3978	0	0	0	0	1	0	0	0	0	0	0	0	2003
11754	97	56.9	3453	0	0	0	0	1	0	0	0	0	0	0	1	2003
10754	138	55.8	3322	0	0	0	0	1	0	0	0	0	0	0	1	2003
10657	168	60.3	3825	0	0	0	0	0	1	0	0	0	0	0	0	2003
10472	168	62.6	4104	0	0	0	0	0	1	0	0	0	0	0	0	2003
10567	168	60.7	3939	0	0	0	0	0	1	0	0	0	0	0	0	2003
10401	144	65.0	4431	0	0	0	0	0	1	0	0	0	0	0	0	2003
10498	168	60.0	3760	0	0	0	0	0	0	1	0	0	0	0	0	2003
10487	168	65.6	4482	0	0	0	0	0	0	1	0	0	0	0	0	2003
10401	168	66.0	4540	0	0	0	0	0	0	1	0	0	0	0	0	2003
10444	168	64.8	4377	0	0	0	0	0	0	1	0	0	0	0	0	2003
10137	168	65.0	4404	0	0	0	0	0	0	0	1	0	0	0	0	2003

Data Base for CRIST 5 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
9962	168	65.4	4473	0	0	0	0	0	0	0	1	0	0	0	0	2003
10035	168	65.9	4494	0	0	0	0	0	0	0	1	0	0	0	0	2003
10064	168	65.9	4536	0	0	0	0	0	0	0	1	0	0	0	0	2003
10362	168	65.2	4444	0	0	0	0	0	0	0	1	0	0	0	0	2003
10814	168	62.0	4037	0	0	0	0	0	0	0	0	1	0	0	0	2003
10379	168	62.1	4058	0	0	0	0	0	0	0	0	1	0	0	0	2003
10239	168	61.3	3969	0	0	0	0	0	0	0	0	1	0	0	0	2003
10466	135	63.0	4223	0	0	0	0	0	0	0	0	1	0	0	1	2003
10321	168	63.1	4164	0	0	0	0	0	0	0	0	0	1	0	0	2003
10392	168	66.9	4653	0	0	0	0	0	0	0	0	0	1	0	0	2003
10436	168	69.0	4915	0	0	0	0	0	0	0	0	0	1	0	0	2003
10337	169	68.6	4882	0	0	0	0	0	0	0	0	0	1	0	0	2003
10318	93	55.5	3178	0	0	0	0	0	0	0	0	0	1	0	0	2003
10520	55	53.2	3090	0	0	0	0	0	0	0	0	0	0	1	2	2003
10802	123	63.6	4324	0	0	0	0	0	0	0	0	0	0	1	1	2003
10480	168	70.0	4975	0	0	0	0	0	0	0	0	0	0	0	0	2003
10346	165	67.4	4698	0	0	0	0	0	0	0	0	0	0	0	0	2003
11024	99	63.0	4181	0	0	0	0	0	0	0	0	0	0	0	2	2003
10714	168	52.9	2922	0	0	0	0	0	0	0	0	0	0	0	0	2003
10711	24	58.8	3615	0	0	0	0	0	0	0	0	0	0	0	0	2003
10567	168	57.3	3464	1	0	0	0	0	0	0	0	0	0	0	0	2004
10347	168	71.7	5225	1	0	0	0	0	0	0	0	0	0	0	0	2004
10391	168	66.6	4565	1	0	0	0	0	0	0	0	0	0	0	0	2004
10428	168	68.5	4819	1	0	0	0	0	0	0	0	0	0	0	0	2004
10531	168	64.9	4364	0	1	0	0	0	0	0	0	0	0	0	0	2004
10492	168	66.6	4569	0	1	0	0	0	0	0	0	0	0	0	0	2004
10490	164	70.1	5003	0	1	0	0	0	0	0	0	0	0	0	0	2004
10634	147	69.5	4903	0	1	0	0	0	0	0	0	0	0	0	1	2004
10495	168	70.6	5029	0	1	0	0	0	0	0	0	0	0	0	0	2004
10440	168	71.6	5225	0	0	1	0	0	0	0	0	0	0	0	0	2004
10316	168	77.1	5953	0	0	1	0	0	0	0	0	0	0	0	0	2004
10333	168	77.2	5968	0	0	1	0	0	0	0	0	0	0	0	0	2004
10359	168	72.1	5291	0	0	1	0	0	0	0	0	0	0	0	0	2004
10463	167	75.3	5692	0	0	0	1	0	0	0	0	0	0	0	0	2004
10445	168	69.9	5031	0	0	0	1	0	0	0	0	0	0	0	0	2004
10492	168	71.3	5192	0	0	0	1	0	0	0	0	0	0	0	0	2004
10574	168	72.3	5332	0	0	0	1	0	0	0	0	0	0	0	0	2004
10616	168	60.7	3869	0	0	0	0	1	0	0	0	0	0	0	0	2004
10596	168	66.8	4631	0	0	0	0	1	0	0	0	0	0	0	0	2004
10615	168	67.8	4754	0	0	0	0	1	0	0	0	0	0	0	0	2004
10630	168	66.3	4568	0	0	0	0	1	0	0	0	0	0	0	0	2004
10784	168	64.6	4358	0	0	0	0	1	0	0	0	0	0	0	0	2004
10506	168	65.0	4400	0	0	0	0	0	1	0	0	0	0	0	0	2004
10538	168	68.7	4855	0	0	0	0	0	1	0	0	0	0	0	0	2004
10642	168	67.1	4675	0	0	0	0	0	1	0	0	0	0	0	0	2004
10749	168	66.3	4573	0	0	0	0	0	1	0	0	0	0	0	0	2004

Data Base for CRIST 5 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11034	168	179.7	36387	0	0	0	0	0	0	1	0	0	0	0	0	2001
10941	168	216.2	52184	0	0	0	0	0	0	1	0	0	0	0	0	2001
11082	168	214.7	51899	0	0	0	0	0	0	1	0	0	0	0	0	2001
11046	168	208.1	48669	0	0	0	0	0	0	1	0	0	0	0	0	2001
10780	168	239.4	62416	0	0	0	0	0	0	0	1	0	0	0	0	2001
10382	168	233.6	59282	0	0	0	0	0	0	0	1	0	0	0	0	2001
11369	168	243.9	64531	0	0	0	0	0	0	0	1	0	0	0	0	2001
11347	168	228.1	58131	0	0	0	0	0	0	0	1	0	0	0	0	2001
11260	168	222.3	55007	0	0	0	0	0	0	0	1	0	0	0	0	2001
10900	168	199.6	45497	0	0	0	0	0	0	0	0	1	0	0	0	2001
10434	168	191.9	42096	0	0	0	0	0	0	0	0	1	0	0	0	2001
*12358	168	186.0	39395	0	0	0	0	0	0	0	0	1	0	0	0	2001
11146	146	158.7	28544	0	0	0	0	0	0	0	0	1	0	0	0	2001
11167	168	160.7	28258	0	0	0	0	0	0	0	0	0	1	0	0	2001
11212	168	166.9	31106	0	0	0	0	0	0	0	0	0	1	0	0	2001
11276	168	152.1	25988	0	0	0	0	0	0	0	0	0	1	0	0	2001
10702	168	209.7	50015	0	0	0	0	0	0	0	0	0	1	0	0	2001
11684	169	145.6	22617	0	0	0	0	0	0	0	0	0	1	0	0	2001
*11878	168	130.3	17165	0	0	0	0	0	0	0	0	0	0	1	0	2001
10602	168	166.9	31381	0	0	0	0	0	0	0	0	0	0	1	0	2001
*11680	168	133.9	18904	0	0	0	0	0	0	0	0	0	0	1	0	2001
*11186	168	162.9	30917	0	0	0	0	0	0	0	0	0	0	1	0	2001
*11264	168	135.3	18786	0	0	0	0	0	0	0	0	0	0	0	0	2001
*11077	168	148.6	24595	0	0	0	0	0	0	0	0	0	0	0	0	2001
*11493	168	147.4	24482	0	0	0	0	0	0	0	0	0	0	0	0	2001
*11180	168	142.3	22065	0	0	0	0	0	0	0	0	0	0	0	0	2001
*11230	24	127.9	16364	0	0	0	0	0	0	0	0	0	0	0	0	2001
11108	168	202.5	46070	1	0	0	0	0	0	0	0	0	0	0	0	2002
*11306	168	168.3	32082	1	0	0	0	0	0	0	0	0	0	0	0	2002
*11335	168	159.4	28927	1	0	0	0	0	0	0	0	0	0	0	0	2002
*11937	168	133.1	18333	1	0	0	0	0	0	0	0	0	0	0	0	2002
11419	159	163.3	30770	0	1	0	0	0	0	0	0	0	0	0	0	2002
11044	96	179.4	36812	0	1	0	0	0	0	0	0	0	0	0	0	2002
*23013	16	67.1	6230	0	0	0	1	0	0	0	0	0	0	0	1	2002
11428	145	179.1	40163	0	0	0	1	0	0	0	0	0	0	0	0	2002
*10561	168	236.2	60970	0	0	0	1	0	0	0	0	0	0	0	0	2002
*10540	168	201.9	46346	0	0	0	1	0	0	0	0	0	0	0	0	2002
10491	99	204.5	47661	0	0	0	0	1	0	0	0	0	0	0	0	2002
10896	105	198.8	46019	0	0	0	0	1	0	0	0	0	0	0	1	2002
10622	168	191.1	41090	0	0	0	0	1	0	0	0	0	0	0	0	2002
10731	152	188.8	41134	0	0	0	0	1	0	0	0	0	0	0	0	2002
11072	168	163.6	30277	0	0	0	0	1	0	0	0	0	0	0	0	2002
11149	168	166.2	30550	0	0	0	0	0	1	0	0	0	0	0	0	2002
11228	168	164.5	30075	0	0	0	0	0	1	0	0	0	0	0	0	2002
*10958	168	197.9	43593	0	0	0	0	0	1	0	0	0	0	0	0	2002
11157	89	191.3	43113	0	0	0	0	0	1	0	0	0	0	0	1	2002
10981	168	183.7	39026	0	0	0	0	0	0	1	0	0	0	0	0	2002

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11059	168	193.0	42028	0	0	0	0	0	0	1	0	0	0	0	0	2002
11058	141	196.5	44137	0	0	0	0	0	0	1	0	0	0	0	1	2002
10693	115	211.7	50374	0	0	0	0	0	0	1	0	0	0	0	1	2002
*11345	93	178.0	38388	0	0	0	0	0	0	0	1	0	0	0	2	2002
11081	167	180.3	36714	0	0	0	0	0	0	0	1	0	0	0	0	2002
10790	167	198.9	45056	0	0	0	0	0	0	0	1	0	0	0	0	2002
10589	168	214.5	52158	0	0	0	0	0	0	0	1	0	0	0	0	2002
10845	167	180.8	37617	0	0	0	0	0	0	0	1	0	0	0	0	2002
10828	168	209.9	50386	0	0	0	0	0	0	0	0	1	0	0	0	2002
10871	168	206.5	48946	0	0	0	0	0	0	0	0	1	0	0	0	2002
10550	168	243.5	63877	0	0	0	0	0	0	0	0	1	0	0	0	2002
10553	168	209.0	49696	0	0	0	0	0	0	0	0	1	0	0	0	2002
10749	168	234.5	60594	0	0	0	0	0	0	0	0	0	1	0	0	2002
10554	168	240.8	62956	0	0	0	0	0	0	0	0	0	1	0	0	2002
10763	168	171.4	32738	0	0	0	0	0	0	0	0	0	1	0	0	2002
10624	169	242.2	63916	0	0	0	0	0	0	0	0	0	1	0	0	2002
11021	168	218.5	52972	0	0	0	0	0	0	0	0	0	1	0	0	2002
*11060	168	194.3	42200	0	0	0	0	0	0	0	0	0	0	1	0	2002
11172	108	165.2	30616	0	0	0	0	0	0	0	0	0	0	1	1	2002
11063	168	167.1	30892	0	0	0	0	0	0	0	0	0	0	1	0	2002
11230	168	145.6	23047	0	0	0	0	0	0	0	0	0	0	1	0	2002
10305	140	215.4	52152	0	0	0	0	0	0	0	0	0	0	0	1	2002
10781 *	168	201.7	45536	0	0	0	0	0	0	0	0	0	0	0	0	2002
11064	168	162.5	29734	0	0	0	0	0	0	0	0	0	0	0	0	2002
10698	168	154.9	26662	0	0	0	0	0	0	0	0	0	0	0	0	2002
*11131	24	128.6	16689	0	0	0	0	0	0	0	0	0	0	0	0	2002
*10566	121	209.0	50146	1	0	0	0	0	0	0	0	0	0	0	1	2003
*10210	168	281.3	15091	1	0	0	0	0	0	0	0	0	0	0	0	2003
*10192	168	267.7	9406	1	0	0	0	0	0	0	0	0	0	0	0	2003
*10177	168	291.3	20169	1	0	0	0	0	0	0	0	0	0	0	0	2003
10259	168	284.6	16944	0	1	0	0	0	0	0	0	0	0	0	0	2003
10349	168	264.4	8137	0	1	0	0	0	0	0	0	0	0	0	0	2003
10311	168	265.4	8161	0	1	0	0	0	0	0	0	0	0	0	0	2003
10294	168	285.9	16524	0	1	0	0	0	0	0	0	0	0	0	0	2003
10326	168	274.3	10732	0	0	1	0	0	0	0	0	0	0	0	0	2003
10282	168	267.3	8836	0	0	1	0	0	0	0	0	0	0	0	0	2003
10497	160	270.3	10431	0	0	1	0	0	0	0	0	0	0	0	0	2003
10639	131	257.9	4439	0	0	1	0	0	0	0	0	0	0	0	1	2003
10242	167	264.7	6412	0	0	1	0	0	0	0	0	0	0	0	0	2003
* 9379	75	196.4	39895	0	0	0	1	0	0	0	0	0	0	0	0	2003
11769	81	173.7	37047	0	0	0	1	0	0	0	0	0	0	0	1	2003
* 9075	168	252.3	2118	0	0	0	0	1	0	0	0	0	0	0	0	2003
9757	168	235.0	60567	0	0	0	0	1	0	0	0	0	0	0	0	2003
9993	168	234.8	60513	0	0	0	0	1	0	0	0	0	0	0	0	2003
11358	168	223.6	56523	0	0	0	0	1	0	0	0	0	0	0	0	2003
*11785	168	230.3	58755	0	0	0	0	1	0	0	0	0	0	0	0	2003
10407	168	231.3	59099	0	0	0	0	0	1	0	0	0	0	0	0	2003

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10178	168	243.0	64410	0	0	0	0	0	1	0	0	0	0	0	0	2003
10300	168	227.9	58544	0	0	0	0	0	1	0	0	0	0	0	0	2003
10333	144	249.2	1605	0	0	0	0	0	1	0	0	0	0	0	0	2003
10703	168	228.4	57836	0	0	0	0	0	0	1	0	0	0	0	0	2003
10665	89	234.6	59513	0	0	0	0	0	0	1	0	0	0	0	1	2003
10345	168	264.3	7560	0	0	0	0	0	0	1	0	0	0	0	0	2003
10507	161	246.7	65509	0	0	0	0	0	0	1	0	0	0	0	0	2003
10476	168	254.2	3333	0	0	0	0	0	0	0	1	0	0	0	0	2003
10293	168	255.0	3336	0	0	0	0	0	0	0	1	0	0	0	0	2003
10291	168	264.2	7434	0	0	0	0	0	0	0	1	0	0	0	0	2003
10305	168	262.6	6902	0	0	0	0	0	0	0	1	0	0	0	0	2003
10184	168	276.1	12335	0	0	0	0	0	0	0	1	0	0	0	0	2003
10301	168	257.7	4516	0	0	0	0	0	0	0	0	1	0	0	0	2003
10359	168	254.8	2714	0	0	0	0	0	0	0	0	1	0	0	0	2003
10373	168	246.1	64750	0	0	0	0	0	0	0	0	1	0	0	0	2003
10288	168	251.2	1812	0	0	0	0	0	0	0	0	1	0	0	0	2003
*11512	168	251.2	1856	0	0	0	0	0	0	0	0	0	1	0	0	2003
*11675	168	260.0	5340	0	0	0	0	0	0	0	0	0	1	0	0	2003
11590	168	230.4	59733	0	0	0	0	0	0	0	0	0	1	0	0	2003
* 8778	169	252.9	2755	0	0	0	0	0	0	0	0	0	1	0	0	2003
* 9357	168	239.2	63040	0	0	0	0	0	0	0	0	0	1	0	0	2003
10417	168	277.2	13593	0	0	0	0	0	0	0	0	0	0	1	0	2003
10608	168	276.1	13453	0	0	0	0	0	0	0	0	0	0	1	0	2003
10423	168	258.8	4323	0	0	0	0	0	0	0	0	0	0	1	0	2003
10363	168	263.8	7551	0	0	0	0	0	0	0	0	0	0	1	0	2003
10385	168	276.6	13273	0	0	0	0	0	0	0	0	0	0	0	0	2003
10220	168	272.2	11323	0	0	0	0	0	0	0	0	0	0	0	0	2003
10145	168	266.9	8326	0	0	0	0	0	0	0	0	0	0	0	0	2003
9887	168	208.3	47580	0	0	0	0	0	0	0	0	0	0	0	0	2003
10276	24	245.9	65409	0	0	0	0	0	0	0	0	0	0	0	0	2003
*175492	7	48.0	3497	1	0	0	0	0	0	0	0	0	0	0	1	2004
* 9669	91	271.9	11916	0	1	0	0	0	0	0	0	0	0	0	0	2004
9610	168	264.7	7535	0	1	0	0	0	0	0	0	0	0	0	0	2004
9644	168	288.9	18821	0	1	0	0	0	0	0	0	0	0	0	0	2004
* 9504	145	280.0	15581	0	1	0	0	0	0	0	0	0	0	0	0	2004
9547	168	278.6	14018	0	1	0	0	0	0	0	0	0	0	0	0	2004
9934	152	280.0	14942	0	0	1	0	0	0	0	0	0	0	0	0	2004
9798	167	262.7	6575	0	0	1	0	0	0	0	0	0	0	0	0	2004
9790	167	278.7	13646	0	0	1	0	0	0	0	0	0	0	0	0	2004
9852	168	283.4	16255	0	0	1	0	0	0	0	0	0	0	0	0	2004
* 9057	4	171.3	29362	0	0	0	1	0	0	0	0	0	0	0	0	2004
10406	115	257.0	5430	0	0	0	1	0	0	0	0	0	0	0	1	2004
*10389	168	221.3	53157	0	0	0	0	1	0	0	0	0	0	0	0	2004
10694	168	239.1	62131	0	0	0	0	1	0	0	0	0	0	0	0	2004
10710	138	251.0	2485	0	0	0	0	1	0	0	0	0	0	0	1	2004
10623	168	240.7	63153	0	0	0	0	1	0	0	0	0	0	0	0	2004
10581	140	245.1	271	0	0	0	0	1	0	0	0	0	0	0	1	2004

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10054	163	241.2	63766	0	0	0	0	0	1	0	0	0	0	0	0	2004
10532	132	259.3	5984	0	0	0	0	0	1	0	0	0	0	0	1	2004
10203	168	251.5	2491	0	0	0	0	0	1	0	0	0	0	0	0	2004
10157	168	247.6	1262	0	0	0	0	0	1	0	0	0	0	0	0	2004

Data Base for CRIST 6 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10560	168	378.6	25324	0	0	0	0	0	0	1	0	0	0	0	0	2001
10538	168	426.8	56438	0	0	0	0	0	0	1	0	0	0	0	0	2001
10567	155	424.2	56464	0	0	0	0	0	0	1	0	0	0	0	0	2001
10403	138	427.2	57724	0	0	0	0	0	0	1	0	0	0	0	1	2001
10483	168	424.5	56882	0	0	0	0	0	0	0	1	0	0	0	0	2001
10327	168	428.0	60101	0	0	0	0	0	0	0	1	0	0	0	0	2001
10742	77	376.3	26784	0	0	0	0	0	0	0	1	0	0	0	1	2001
10726	132	335.5	60291	0	0	0	0	0	0	0	0	0	1	0	1	2001
10793	133	276.4	18411	0	0	0	0	0	0	0	0	0	1	0	0	2001
10651	152	291.3	33337	0	0	0	0	0	0	0	0	0	1	0	1	2001
10500	156	290.9	28777	0	0	0	0	0	0	0	0	0	1	0	0	2001
10606	168	292.3	29313	0	0	0	0	0	0	0	0	0	0	1	0	2001
10153	168	351.0	6496	0	0	0	0	0	0	0	0	0	0	1	0	2001
10907	167	253.2	5658	0	0	0	0	0	0	0	0	0	0	1	0	2001
10789	168	297.3	35249	0	0	0	0	0	0	0	0	0	0	1	0	2001
10737	168	245.8	63840	0	0	0	0	0	0	0	0	0	0	0	0	2001
10511	168	269.0	14477	0	0	0	0	0	0	0	0	0	0	0	0	2001
10728	168	245.1	64858	0	0	0	0	0	0	0	0	0	0	0	0	2001
10591	168	275.3	19663	0	0	0	0	0	0	0	0	0	0	0	0	2001
10234	24	381.0	18773	0	0	0	0	0	0	0	0	0	0	0	0	2001
10314	168	378.7	24041	1	0	0	0	0	0	0	0	0	0	0	0	2002
10654	168	295.2	34461	1	0	0	0	0	0	0	0	0	0	0	0	2002
10666	168	267.6	16590	1	0	0	0	0	0	0	0	0	0	0	0	2002
11168	168	207.6	43385	1	0	0	0	0	0	0	0	0	0	0	0	2002
11091	168	219.0	50598	0	1	0	0	0	0	0	0	0	0	0	0	2002
10690	168	301.9	38965	0	1	0	0	0	0	0	0	0	0	0	0	2002
10837	168	256.2	7724	0	1	0	0	0	0	0	0	0	0	0	0	2002
10703	168	272.4	16244	0	1	0	0	0	0	0	0	0	0	0	0	2002
9861	168	361.2	12556	0	0	1	0	0	0	0	0	0	0	0	0	2002
9411	130	393.9	37892	0	0	1	0	0	0	0	0	0	0	0	1	2002
9501	96	369.2	19940	0	0	1	0	0	0	0	0	0	0	0	0	2002
11124	129	274.2	20002	0	0	0	0	1	0	0	0	0	0	0	1	2002
10431	156	271.9	9174	0	0	0	0	1	0	0	0	0	0	0	0	2002
10157	93	295.6	22086	0	0	0	0	1	0	0	0	0	0	0	0	2002
10606	157	334.6	60611	0	0	0	0	1	0	0	0	0	0	0	1	2002
10494	168	350.8	6705	0	0	0	0	0	1	0	0	0	0	0	0	2002
10460	168	344.6	2074	0	0	0	0	0	1	0	0	0	0	0	0	2002
10519	124	372.9	22137	0	0	0	0	0	1	0	0	0	0	0	1	2002
10545	144	368.1	18450	0	0	0	0	0	1	0	0	0	0	0	0	2002
10577	168	367.6	18013	0	0	0	0	0	0	1	0	0	0	0	0	2002
10465	168	388.2	32189	0	0	0	0	0	0	1	0	0	0	0	0	2002
10482	164	411.8	48265	0	0	0	0	0	0	1	0	0	0	0	0	2002
10485	168	379.4	25374	0	0	0	0	0	0	1	0	0	0	0	0	2002
10389	168	396.8	37802	0	0	0	0	0	0	0	1	0	0	0	0	2002
10451	168	393.9	34795	0	0	0	0	0	0	0	1	0	0	0	0	2002
10384	168	402.2	40811	0	0	0	0	0	0	0	1	0	0	0	0	2002
10481	168	399.1	38218	0	0	0	0	0	0	0	1	0	0	0	0	2002

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10446	168	381.4	26812	0	0	0	0	0	0	0	1	0	0	0	0	2002
10416	168	397.4	37232	0	0	0	0	0	0	0	0	1	0	0	0	2002
10343	168	411.2	45910	0	0	0	0	0	0	0	0	1	0	0	0	2002
10405	123	425.2	57890	0	0	0	0	0	0	0	0	1	0	0	1	2002
10507	168	414.3	48171	0	0	0	0	0	0	0	0	1	0	0	0	2002
10094	168	449.2	7663	0	0	0	0	0	0	0	0	0	1	0	0	2002
10088	168	440.3	1090	0	0	0	0	0	0	0	0	0	1	0	0	2002
10040	168	388.4	29897	0	0	0	0	0	0	0	0	0	1	0	0	2002
9955	115	430.0	60394	0	0	0	0	0	0	0	0	0	1	0	0	2002
11162	40	313.3	44711	0	0	0	0	0	0	0	0	0	0	1	1	2002
10579	168	364.5	11672	0	0	0	0	0	0	0	0	0	0	1	0	2002
10476	168	404.8	41263	0	0	0	0	0	0	0	0	0	0	1	0	2002
10403	168	375.9	19933	0	0	0	0	0	0	0	0	0	0	1	0	2002
10094	168	454.3	12461	0	0	0	0	0	0	0	0	0	0	0	0	2002
10143	168	421.0	53094	0	0	0	0	0	0	0	0	0	0	0	0	2002
10354	168	378.2	22136	0	0	0	0	0	0	0	0	0	0	0	0	2002
10334	168	383.7	26281	0	0	0	0	0	0	0	0	0	0	0	0	2002
10373	24	360.2	8220	0	0	0	0	0	0	0	0	0	0	0	0	2002
10195	168	415.9	49969	1	0	0	0	0	0	0	0	0	0	0	0	2003
10092	168	439.9	2003	1	0	0	0	0	0	0	0	0	0	0	0	2003
10027	168	448.9	9080	1	0	0	0	0	0	0	0	0	0	0	0	2003
10125	168	393.4	34461	1	0	0	0	0	0	0	0	0	0	0	0	2003
10260	168	405.0	41190	0	1	0	0	0	0	0	0	0	0	0	0	2003
10365	168	423.0	53736	0	1	0	0	0	0	0	0	0	0	0	0	2003
9942	168	413.5	47996	0	1	0	0	0	0	0	0	0	0	0	0	2003
10315	168	433.0	62817	0	1	0	0	0	0	0	0	0	0	0	0	2003
10368	72	456.4	16069	0	0	1	0	0	0	0	0	0	0	0	0	2003
*11640	64	242.4	60292	0	0	1	0	0	0	0	0	0	0	0	1	2003
10358	167	405.8	41420	0	0	0	1	0	0	0	0	0	0	0	0	2003
10019	168	422.2	54676	0	0	0	1	0	0	0	0	0	0	0	0	2003
10334	138	408.0	44851	0	0	0	1	0	0	0	0	0	0	0	1	2003
10201	168	424.4	55148	0	0	0	1	0	0	0	0	0	0	0	0	2003
10332	168	412.5	50190	0	0	0	0	1	0	0	0	0	0	0	0	2003
10332	168	403.2	43092	0	0	0	0	1	0	0	0	0	0	0	0	2003
10369	168	411.6	47518	0	0	0	0	1	0	0	0	0	0	0	0	2003
10405	168	386.1	32339	0	0	0	0	1	0	0	0	0	0	0	0	2003
10313	168	406.1	43854	0	0	0	0	1	0	0	0	0	0	0	0	2003
10492	168	408.9	45376	0	0	0	0	0	1	0	0	0	0	0	0	2003
10437	168	420.2	53343	0	0	0	0	0	1	0	0	0	0	0	0	2003
10638	168	385.7	32935	0	0	0	0	0	1	0	0	0	0	0	0	2003
10498	144	426.2	58068	0	0	0	0	0	1	0	0	0	0	0	0	2003
10674	168	384.0	28887	0	0	0	0	0	0	1	0	0	0	0	0	2003
10212	168	429.4	60300	0	0	0	0	0	0	1	0	0	0	0	0	2003
10204	168	435.2	64104	0	0	0	0	0	0	1	0	0	0	0	0	2003
10120	168	444.6	5142	0	0	0	0	0	0	1	0	0	0	0	0	2003
10126	168	430.0	59749	0	0	0	0	0	0	0	1	0	0	0	0	2003
10130	168	432.6	62919	0	0	0	0	0	0	0	1	0	0	0	0	2003

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10143	168	443.6	4851	0	0	0	0	0	0	0	1	0	0	0	0	2003
10219	168	446.9	7051	0	0	0	0	0	0	0	1	0	0	0	0	2003
10189	168	454.0	11316	0	0	0	0	0	0	0	1	0	0	0	0	2003
10451	168	428.1	58284	0	0	0	0	0	0	0	0	1	0	0	0	2003
10424	168	432.5	62176	0	0	0	0	0	0	0	0	1	0	0	0	2003
10392	168	419.9	53764	0	0	0	0	0	0	0	0	1	0	0	0	2003
10564	113	402.7	43099	0	0	0	0	0	0	0	0	1	0	0	1	2003
10176	168	427.2	58354	0	0	0	0	0	0	0	0	0	1	0	0	2003
10402	167	437.1	810	0	0	0	0	0	0	0	0	0	1	0	0	2003
10320	143	303.0	42635	0	0	0	0	0	0	0	0	0	1	0	1	2003
10372	169	378.3	27275	0	0	0	0	0	0	0	0	0	1	0	0	2003
10339	168	401.3	41290	0	0	0	0	0	0	0	0	0	1	0	0	2003
10136	168	457.5	15522	0	0	0	0	0	0	0	0	0	0	1	0	2003
10328	168	454.5	13568	0	0	0	0	0	0	0	0	0	0	1	0	2003
10285	168	457.3	15421	0	0	0	0	0	0	0	0	0	0	1	0	2003
10314	168	442.7	5822	0	0	0	0	0	0	0	0	0	0	1	0	2003
10270	168	448.1	8110	0	0	0	0	0	0	0	0	0	0	0	0	2003
10183	168	440.3	2412	0	0	0	0	0	0	0	0	0	0	0	0	2003
10184	168	447.6	8590	0	0	0	0	0	0	0	0	0	0	0	0	2003
10349	168	393.1	34928	0	0	0	0	0	0	0	0	0	0	0	0	2003
10476	24	411.4	50446	0	0	0	0	0	0	0	0	0	0	0	0	2003
10362	168	351.6	5197	1	0	0	0	0	0	0	0	0	0	0	0	2004
10105	168	465.8	21599	1	0	0	0	0	0	0	0	0	0	0	0	2004
10211	168	431.5	61561	1	0	0	0	0	0	0	0	0	0	0	0	2004
10218	168	435.1	64899	1	0	0	0	0	0	0	0	0	0	0	0	2004
10133	94	437.9	2135	0	1	0	0	0	0	0	0	0	0	0	0	2004
11789	25	288.6	34975	0	0	0	1	0	0	0	0	0	0	0	1	2004
10895	37	336.6	4192	0	0	0	1	0	0	0	0	0	0	0	1	2004
10496	166	343.9	1556	0	0	0	0	1	0	0	0	0	0	0	0	2004
10588	168	393.2	36388	0	0	0	0	1	0	0	0	0	0	0	0	2004
10511	121	394.6	37010	0	0	0	0	1	0	0	0	0	0	0	1	2004
10335	168	408.0	46083	0	0	0	0	1	0	0	0	0	0	0	0	2004
10432	168	370.9	20023	0	0	0	0	1	0	0	0	0	0	0	0	2004
10313	168	383.7	29981	0	0	0	0	0	1	0	0	0	0	0	0	2004
10407	130	375.1	23331	0	0	0	0	0	1	0	0	0	0	0	1	2004
10327	168	395.8	37430	0	0	0	0	0	1	0	0	0	0	0	0	2004
10434	124	362.7	16316	0	0	0	0	0	1	0	0	0	0	0	1	2004

Data Base for CRIST 7 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10113	168	142.3	20828	0	0	0	0	0	0	1	0	0	0	0	0	2001
10378	168	151.8	23364	0	0	0	0	0	0	1	0	0	0	0	0	2001
10167	168	148.8	22610	0	0	0	0	0	0	1	0	0	0	0	0	2001
10134	168	161.6	26174	0	0	0	0	0	0	1	0	0	0	0	0	2001
10155	168	159.9	25585	0	0	0	0	0	0	0	1	0	0	0	0	2001
10302	168	157.3	24789	0	0	0	0	0	0	0	1	0	0	0	0	2001
10230	168	152.8	23707	0	0	0	0	0	0	0	1	0	0	0	0	2001
10274	168	148.5	22460	0	0	0	0	0	0	0	1	0	0	0	0	2001
10131	168	149.5	22934	0	0	0	0	0	0	0	1	0	0	0	0	2001
10140	168	144.6	21330	0	0	0	0	0	0	0	0	1	0	0	0	2001
9948	168	143.5	20980	0	0	0	0	0	0	0	0	1	0	0	0	2001
10076	168	138.9	20135	0	0	0	0	0	0	0	0	1	0	0	0	2001
10331	168	145.3	21456	0	0	0	0	0	0	0	0	1	0	0	0	2001
10244	160	143.6	21158	0	0	0	0	0	0	0	0	0	1	0	0	2001
10358	91	151.1	23357	0	0	0	0	0	0	0	0	0	1	0	1	2001
10206	168	140.6	20494	0	0	0	0	0	0	0	0	0	1	0	0	2001
10282	142	129.9	17952	0	0	0	0	0	0	0	0	0	1	0	1	2001
10116	168	124.8	16968	0	0	0	0	0	0	0	0	0	0	1	0	2001
10211	168	120.5	15363	0	0	0	0	0	0	0	0	0	0	1	0	2001
10233	168	118.6	15274	0	0	0	0	0	0	0	0	0	0	1	0	2001
10232	168	113.0	13153	0	0	0	0	0	0	0	0	0	0	1	0	2001
10310	168	104.8	11379	0	0	0	0	0	0	0	0	0	0	0	0	2001
10200	168	107.5	12147	0	0	0	0	0	0	0	0	0	0	0	0	2001
10168	168	113.7	13477	0	0	0	0	0	0	0	0	0	0	0	0	2001
10299	168	107.6	12069	0	0	0	0	0	0	0	0	0	0	0	0	2001
10191	24	102.1	10851	0	0	0	0	0	0	0	0	0	0	0	0	2001
10030	168	136.0	19496	1	0	0	0	0	0	0	0	0	0	0	0	2002
9888	168	126.0	16469	1	0	0	0	0	0	0	0	0	0	0	0	2002
9919	168	118.3	14431	1	0	0	0	0	0	0	0	0	0	0	0	2002
10393	111	111.1	12561	1	0	0	0	0	0	0	0	0	0	0	1	2002
10252	168	116.5	13672	0	1	0	0	0	0	0	0	0	0	0	0	2002
10101	168	126.6	16327	0	1	0	0	0	0	0	0	0	0	0	0	2002
10079	168	123.9	15654	0	1	0	0	0	0	0	0	0	0	0	0	2002
10141	166	129.4	17179	0	1	0	0	0	0	0	0	0	0	0	0	2002
10210	168	141.5	20440	0	0	1	0	0	0	0	0	0	0	0	0	2002
10391	168	147.6	22150	0	0	1	0	0	0	0	0	0	0	0	0	2002
10114	168	140.7	20238	0	0	1	0	0	0	0	0	0	0	0	0	2002
10114	168	137.1	19239	0	0	1	0	0	0	0	0	0	0	0	0	2002
9920	4	99.5	10395	0	0	1	0	0	0	0	0	0	0	0	0	2002
10726	95	108.3	13091	0	0	0	1	0	0	0	0	0	0	0	1	2002
10488	168	93.2	9151	0	0	0	0	1	0	0	0	0	0	0	0	2002
10248	168	126.9	17102	0	0	0	0	1	0	0	0	0	0	0	0	2002
10435	168	117.4	15392	0	0	0	0	1	0	0	0	0	0	0	0	2002
10224	168	121.7	16435	0	0	0	0	1	0	0	0	0	0	0	0	2002
10197	168	117.7	15534	0	0	0	0	1	0	0	0	0	0	0	0	2002
10169	168	133.5	18662	0	0	0	0	0	1	0	0	0	0	0	0	2002
10286	168	132.8	18519	0	0	0	0	0	1	0	0	0	0	0	0	2002

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10234	168	136.9	19484	0	0	0	0	0	1	0	0	0	0	0	0	2002
10320	144	139.1	20030	0	0	0	0	0	1	0	0	0	0	0	0	2002
10485	168	136.5	19362	0	0	0	0	0	0	1	0	0	0	0	0	2002
10378	168	140.6	20422	0	0	0	0	0	0	1	0	0	0	0	0	2002
10183	168	145.7	21765	0	0	0	0	0	0	1	0	0	0	0	0	2002
10215	168	138.2	19782	0	0	0	0	0	0	1	0	0	0	0	0	2002
10321	168	138.0	19683	0	0	0	0	0	0	0	1	0	0	0	0	2002
10272	168	137.1	19720	0	0	0	0	0	0	0	1	0	0	0	0	2002
10225	168	143.5	21171	0	0	0	0	0	0	0	1	0	0	0	0	2002
10146	168	143.8	21239	0	0	0	0	0	0	0	1	0	0	0	0	2002
10073	168	136.4	19178	0	0	0	0	0	0	0	1	0	0	0	0	2002
10251	168	145.6	21886	0	0	0	0	0	0	0	0	1	0	0	0	2002
10249	168	146.6	22022	0	0	0	0	0	0	0	0	1	0	0	0	2002
10068	168	150.4	22943	0	0	0	0	0	0	0	0	1	0	0	0	2002
10210	168	141.2	20822	0	0	0	0	0	0	0	0	1	0	0	0	2002
10151	168	154.3	24070	0	0	0	0	0	0	0	0	0	1	0	0	2002
10277	168	154.3	23998	0	0	0	0	0	0	0	0	0	1	0	0	2002
10281	151	136.6	19816	0	0	0	0	0	0	0	0	0	1	0	0	2002
10281	116	146.6	22107	0	0	0	0	0	0	0	0	0	1	0	0	2002
11783	14	79.2	7743	0	0	0	0	0	0	0	0	0	1	0	1	2002
10473	168	127.7	17780	0	0	0	0	0	0	0	0	0	0	1	0	2002
10496	168	124.1	15935	0	0	0	0	0	0	0	0	0	0	1	0	2002
10452	168	138.5	19777	0	0	0	0	0	0	0	0	0	0	1	0	2002
10205	168	136.7	19277	0	0	0	0	0	0	0	0	0	0	1	0	2002
10181	168	148.6	22429	0	0	0	0	0	0	0	0	0	0	0	0	2002
10236	168	141.1	20565	0	0	0	0	0	0	0	0	0	0	0	0	2002
10124	168	134.6	19144	0	0	0	0	0	0	0	0	0	0	0	0	2002
10717	168	119.9	15616	0	0	0	0	0	0	0	0	0	0	0	0	2002
10640	24	113.8	13946	0	0	0	0	0	0	0	0	0	0	0	0	2002
10717	168	124.4	17108	1	0	0	0	0	0	0	0	0	0	0	0	2003
10193	168	133.6	18777	1	0	0	0	0	0	0	0	0	0	0	0	2003
10121	168	143.1	21448	1	0	0	0	0	0	0	0	0	0	0	0	2003
10044	168	135.6	19412	1	0	0	0	0	0	0	0	0	0	0	0	2003
10101	168	121.3	15992	0	1	0	0	0	0	0	0	0	0	0	0	2003
10271	168	122.2	16108	0	1	0	0	0	0	0	0	0	0	0	0	2003
10044	168	122.1	16169	0	1	0	0	0	0	0	0	0	0	0	0	2003
10178	128	129.3	18120	0	1	0	0	0	0	0	0	0	0	0	1	2003
10361	168	152.1	23496	0	0	1	0	0	0	0	0	0	0	0	0	2003
10440	168	141.5	20982	0	0	1	0	0	0	0	0	0	0	0	0	2003
10573	168	138.4	20415	0	0	1	0	0	0	0	0	0	0	0	0	2003
10843	168	134.7	19386	0	0	1	0	0	0	0	0	0	0	0	0	2003
10414	168	141.9	21395	0	0	1	0	0	0	0	0	0	0	0	0	2003
10511	167	145.7	21928	0	0	0	1	0	0	0	0	0	0	0	0	2003
10807	168	136.5	20039	0	0	0	1	0	0	0	0	0	0	0	0	2003
10360	71	133.9	19622	0	0	0	1	0	0	0	0	0	0	0	0	2003
10860	85	115.8	15111	0	0	0	0	1	0	0	0	0	0	0	1	2003
10512	168	122.1	16885	0	0	0	0	1	0	0	0	0	0	0	0	2003

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10391	168	124.5	17250	0	0	0	0	1	0	0	0	0	0	0	0	2003
10475	168	129.3	18281	0	0	0	0	0	1	0	0	0	0	0	0	2003
10422	168	131.0	18761	0	0	0	0	0	1	0	0	0	0	0	0	2003
10588	168	119.8	16640	0	0	0	0	0	1	0	0	0	0	0	0	2003
10406	144	137.0	20224	0	0	0	0	0	1	0	0	0	0	0	0	2003
10464	168	123.6	17078	0	0	0	0	0	0	1	0	0	0	0	0	2003
10438	168	133.9	19483	0	0	0	0	0	0	1	0	0	0	0	0	2003
10332	168	138.4	20548	0	0	0	0	0	0	1	0	0	0	0	0	2003
10487	168	140.3	20842	0	0	0	0	0	0	1	0	0	0	0	0	2003
10406	168	133.1	19278	0	0	0	0	0	0	0	1	0	0	0	0	2003
10449	44	134.8	19678	0	0	0	0	0	0	0	1	0	0	0	0	2003
10682	112	125.8	17663	0	0	0	0	0	0	0	1	0	0	0	1	2003
10422	168	133.0	19083	0	0	0	0	0	0	0	1	0	0	0	0	2003
10404	168	131.5	18786	0	0	0	0	0	0	0	0	1	0	0	0	2003
10358	168	133.3	19256	0	0	0	0	0	0	0	0	1	0	0	0	2003
10386	168	125.8	17462	0	0	0	0	0	0	0	0	1	0	0	0	2003
10393	168	133.8	19337	0	0	0	0	0	0	0	0	1	0	0	0	2003
10296	168	135.0	19621	0	0	0	0	0	0	0	0	0	1	0	0	2003
10350	168	135.8	19681	0	0	0	0	0	0	0	0	0	1	0	0	2003
10366	168	135.6	19731	0	0	0	0	0	0	0	0	0	1	0	0	2003
10303	169	138.2	20438	0	0	0	0	0	0	0	0	0	1	0	0	2003
10436	168	126.1	17681	0	0	0	0	0	0	0	0	0	1	0	0	2003
9972	168	146.3	22331	0	0	0	0	0	0	0	0	0	0	1	0	2003
10126	168	142.0	21320	0	0	0	0	0	0	0	0	0	0	1	0	2003
10176	168	138.4	20354	0	0	0	0	0	0	0	0	0	0	1	0	2003
10127	101	128.2	18390	0	0	0	0	0	0	0	0	0	0	1	0	2003
*12509	47	98.4	12272	0	0	0	0	0	0	0	0	0	0	0	2	2003
*63726	1	19.0	361	0	0	0	0	0	0	0	0	0	0	0	1	2003
10428	168	109.9	13662	1	0	0	0	0	0	0	0	0	0	0	0	2004
10177	168	149.5	22911	1	0	0	0	0	0	0	0	0	0	0	0	2004
10208	168	132.3	18602	1	0	0	0	0	0	0	0	0	0	0	0	2004
10173	168	136.2	19626	1	0	0	0	0	0	0	0	0	0	0	0	2004
10298	168	143.3	21374	0	1	0	0	0	0	0	0	0	0	0	0	2004
10227	168	136.6	19592	0	1	0	0	0	0	0	0	0	0	0	0	2004
10380	168	155.9	24558	0	1	0	0	0	0	0	0	0	0	0	0	2004
10410	168	150.5	23143	0	1	0	0	0	0	0	0	0	0	0	0	2004
10450	168	149.5	22876	0	1	0	0	0	0	0	0	0	0	0	0	2004
10197	168	147.9	22658	0	0	1	0	0	0	0	0	0	0	0	0	2004
10138	168	158.5	25347	0	0	1	0	0	0	0	0	0	0	0	0	2004
10146	168	159.1	25500	0	0	1	0	0	0	0	0	0	0	0	0	2004
10251	168	151.6	23573	0	0	1	0	0	0	0	0	0	0	0	0	2004
10137	167	155.4	24620	0	0	0	1	0	0	0	0	0	0	0	0	2004
10407	74	147.4	22584	0	0	0	1	0	0	0	0	0	0	0	1	2004
10161	168	143.6	21565	0	0	0	1	0	0	0	0	0	0	0	0	2004
10184	168	146.1	22236	0	0	0	1	0	0	0	0	0	0	0	0	2004
10356	168	121.1	16102	0	0	0	0	1	0	0	0	0	0	0	0	2004
10342	168	127.6	17900	0	0	0	0	1	0	0	0	0	0	0	0	2004

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10171	168	135.8	19903	0	0	0	0	1	0	0	0	0	0	0	0	2004
10158	168	130.7	18761	0	0	0	0	1	0	0	0	0	0	0	0	2004
10219	168	133.6	19390	0	0	0	0	1	0	0	0	0	0	0	0	2004
10206	168	128.1	18154	0	0	0	0	0	1	0	0	0	0	0	0	2004
10254	168	139.1	20515	0	0	0	0	0	1	0	0	0	0	0	0	2004
10267	168	132.0	18849	0	0	0	0	0	1	0	0	0	0	0	0	2004
10313	168	130.4	18762	0	0	0	0	0	1	0	0	0	0	0	0	2004

Data Base for SMITH 1 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10057	168	158.8	26498	0	0	0	0	0	0	1	0	0	0	0	0	2001
10375	168	175.4	31205	0	0	0	0	0	0	1	0	0	0	0	0	2001
10201	168	170.9	29831	0	0	0	0	0	0	1	0	0	0	0	0	2001
10199	168	169.2	29474	0	0	0	0	0	0	1	0	0	0	0	0	2001
10055	168	169.0	29507	0	0	0	0	0	0	0	1	0	0	0	0	2001
10272	168	174.0	30479	0	0	0	0	0	0	0	1	0	0	0	0	2001
10248	168	143.5	23373	0	0	0	0	0	0	0	1	0	0	0	0	2001
10156	168	162.4	27843	0	0	0	0	0	0	0	1	0	0	0	0	2001
10065	168	163.5	28315	0	0	0	0	0	0	0	1	0	0	0	0	2001
10263	168	142.8	22878	0	0	0	0	0	0	0	0	1	0	0	0	2001
10184	168	139.0	22098	0	0	0	0	0	0	0	0	1	0	0	0	2001
10200	151	136.0	20976	0	0	0	0	0	0	0	0	1	0	0	0	2001
*10441	1	12.0	144	0	0	0	0	0	0	0	0	1	0	0	0	2001
10265	49	165.2	29203	0	0	0	0	0	0	0	0	0	1	0	1	2001
10159	168	169.3	29887	0	0	0	0	0	0	0	0	0	1	0	0	2001
10211	168	172.2	30372	0	0	0	0	0	0	0	0	0	1	0	0	2001
10025	168	162.3	27754	0	0	0	0	0	0	0	0	0	1	0	0	2001
9887	169	155.2	25575	0	0	0	0	0	0	0	0	0	1	0	0	2001
10372	140	141.1	22372	0	0	0	0	0	0	0	0	0	0	1	1	2001
9982	168	152.9	25525	0	0	0	0	0	0	0	0	0	0	1	0	2001
10175	132	118.5	15701	0	0	0	0	0	0	0	0	0	0	1	1	2001
10046	168	122.7	15757	0	0	0	0	0	0	0	0	0	0	1	0	2001
9978	168	116.7	14023	0	0	0	0	0	0	0	0	0	0	0	0	2001
10123	168	118.8	15161	0	0	0	0	0	0	0	0	0	0	0	0	2001
10069	59	108.5	13076	0	0	0	0	0	0	0	0	0	0	0	0	2001
10113	94	121.4	16438	0	0	0	0	0	0	0	0	0	0	0	1	2001
11133	24	105.3	11732	0	0	0	0	0	0	0	0	0	0	0	0	2001
9866	168	144.7	21926	1	0	0	0	0	0	0	0	0	0	0	0	2002
9876	168	132.5	18353	1	0	0	0	0	0	0	0	0	0	0	0	2002
9882	168	119.9	14880	1	0	0	0	0	0	0	0	0	0	0	0	2002
9717	86	112.3	12732	1	0	0	0	0	0	0	0	0	0	0	0	2002
10523	70	106.1	12027	0	1	0	0	0	0	0	0	0	0	0	1	2002
9992	168	124.4	15887	0	1	0	0	0	0	0	0	0	0	0	0	2002
9935	168	120.7	14861	0	1	0	0	0	0	0	0	0	0	0	0	2002
9955	168	127.5	16840	0	1	0	0	0	0	0	0	0	0	0	0	2002
9898	98	149.9	23504	0	0	1	0	0	0	0	0	0	0	0	0	2002
*13940	27	45.9	2190	0	0	0	1	0	0	0	0	0	0	0	1	2002
10815	41	110.7	14466	0	0	0	0	1	0	0	0	0	0	0	1	2002
10007	161	141.2	22301	0	0	0	0	1	0	0	0	0	0	0	0	2002
10238	144	125.8	18286	0	0	0	0	1	0	0	0	0	0	0	1	2002
10120	168	131.8	20130	0	0	0	0	1	0	0	0	0	0	0	0	2002
10169	168	128.7	19309	0	0	0	0	1	0	0	0	0	0	0	0	2002
10636	64	113.7	14445	0	0	0	0	0	1	0	0	0	0	0	2	2002
10886	34	120.8	17626	0	0	0	0	0	1	0	0	0	0	0	1	2002
10483	13	124.5	16352	0	0	0	0	0	1	0	0	0	0	0	0	2002
10766	77	137.6	19856	0	0	0	0	0	0	1	0	0	0	0	2	2002
10756	110	133.1	18124	0	0	0	0	0	0	1	0	0	0	0	1	2002

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10784	128	132.0	17722	0	0	0	0	0	0	1	0	0	0	0	1	2002
10755	168	121.8	14851	0	0	0	0	0	0	1	0	0	0	0	0	2002
10744	168	119.6	14327	0	0	0	0	0	0	0	1	0	0	0	0	2002
10815	168	122.6	15027	0	0	0	0	0	0	0	1	0	0	0	0	2002
10768	168	122.0	14924	0	0	0	0	0	0	0	1	0	0	0	0	2002
10648	168	123.8	15331	0	0	0	0	0	0	0	1	0	0	0	0	2002
10478	164	125.5	16006	0	0	0	0	0	0	0	1	0	0	0	0	2002
10794	23	111.0	13129	0	0	0	0	0	0	0	0	1	0	0	1	2002
10638	138	122.9	15365	0	0	0	0	0	0	0	0	1	0	0	1	2002
10623	168	124.3	15473	0	0	0	0	0	0	0	0	1	0	0	0	2002
10439	168	124.7	15544	0	0	0	0	0	0	0	0	0	1	0	0	2002
10491	168	123.5	15269	0	0	0	0	0	0	0	0	0	1	0	0	2002
10612	132	121.7	15025	0	0	0	0	0	0	0	0	0	1	0	1	2002
10714	136	122.1	15067	0	0	0	0	0	0	0	0	0	1	0	1	2002
10695	168	119.1	14184	0	0	0	0	0	0	0	0	0	1	0	0	2002
10662	168	120.3	14475	0	0	0	0	0	0	0	0	0	0	1	0	2002
10625	168	120.1	14436	0	0	0	0	0	0	0	0	0	0	1	0	2002
10588	168	120.7	14610	0	0	0	0	0	0	0	0	0	0	1	0	2002
10569	168	121.5	14787	0	0	0	0	0	0	0	0	0	0	1	0	2002
10494	168	123.5	15254	0	0	0	0	0	0	0	0	0	0	0	0	2002
10485	168	122.9	15114	0	0	0	0	0	0	0	0	0	0	0	0	2002
10600	168	119.8	14506	0	0	0	0	0	0	0	0	0	0	0	0	2002
10704	168	121.6	14796	0	0	0	0	0	0	0	0	0	0	0	0	2002
10665	24	122.2	14936	0	0	0	0	0	0	0	0	0	0	0	0	2002
*14731	2	31.5	1175	1	0	0	0	0	0	0	0	0	0	0	0	2003
11076	68	91.6	9413	0	0	0	1	0	0	0	0	0	0	0	1	2003
10172	168	128.5	19067	0	0	0	1	0	0	0	0	0	0	0	0	2003
10124	168	152.7	25535	0	0	0	1	0	0	0	0	0	0	0	0	2003
10240	114	150.4	24717	0	0	0	0	1	0	0	0	0	0	0	1	2003
10244	168	144.9	23479	0	0	0	0	1	0	0	0	0	0	0	0	2003
10271	168	142.7	22894	0	0	0	0	1	0	0	0	0	0	0	0	2003
10330	168	132.6	20471	0	0	0	0	1	0	0	0	0	0	0	0	2003
10158	168	139.6	22195	0	0	0	0	1	0	0	0	0	0	0	0	2003
10206	161	143.9	22955	0	0	0	0	0	1	0	0	0	0	0	0	2003
10255	168	147.1	24013	0	0	0	0	0	1	0	0	0	0	0	0	2003
10319	168	133.8	21329	0	0	0	0	0	1	0	0	0	0	0	.0	2003
10123	144	152.9	25583	0	0	0	0	0	1	0	0	0	0	0	0	2003
10193	168	138.0	21844	0	0	0	0	0	0	1	0	0	0	0	0	2003
10233	168	149.5	24592	0	0	0	0	0	0	1	0	0	0	0	0	2003
10175	168	154.8	25836	0	0	0	0	0	0	1	0	0	0	0	0	2003
10308	168	156.7	26343	0	0	0	0	0	0	1	0	0	0	0	0	2003
10267	168	148.5	24173	0	0	0	0	0	0	0	1	0	0	0	0	2003
10147	168	143.0	22352	0	0	0	0	0	0	0	1	0	0	0	0	2003
10081	168	164.2	28299	0	0	0	0	0	0	0	1	0	0	0	0	2003
10174	168	154.1	25560	0	0	0	0	0	0	0	1	0	0	0	0	2003
10263	168	151.9	24799	0	0	0	0	0	0	0	1	0	0	0	0	2003
10135	168	153.9	25529	0	0	0	0	0	0	0	0	1	0	0	0	2003

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10155	168	152.7	25208	0	0	0	0	0	0	0	0	1	0	0	0	2003
10113	168	146.7	23773	0	0	0	0	0	0	0	0	1	0	0	0	2003
10186	168	155.6	26152	0	0	0	0	0	0	0	0	1	0	0	0	2003
10282	168	154.5	25940	0	0	0	0	0	0	0	0	0	1	0	0	2003
10288	168	162.0	27483	0	0	0	0	0	0	0	0	0	1	0	0	2003
10263	71	164.5	28415	0	0	0	0	0	0	0	0	0	1	0	0	2003
10194	148	151.9	25281	0	0	0	0	0	0	0	0	0	1	0	1	2003
10201	168	142.5	22864	0	0	0	0	0	0	0	0	0	1	0	0	2003
10046	168	165.3	28559	0	0	0	0	0	0	0	0	0	0	1	0	2003
10051	168	164.0	28237	0	0	0	0	0	0	0	0	0	0	1	0	2003
10115	168	159.9	26916	0	0	0	0	0	0	0	0	0	0	1	0	2003
10185	168	162.6	27751	0	0	0	0	0	0	0	0	0	0	1	0	2003
10124	168	168.7	29540	0	0	0	0	0	0	0	0	0	0	0	0	2003
10135	168	167.6	29239	0	0	0	0	0	0	0	0	0	0	0	0	2003
10184	168	165.0	28147	0	0	0	0	0	0	0	0	0	0	0	0	2003
10187	168	158.9	26571	0	0	0	0	0	0	0	0	0	0	0	0	2003
10161	24	180.3	32702	0	0	0	0	0	0	0	0	0	0	0	0	2003
10242	168	131.7	19173	1	0	0	0	0	0	0	0	0	0	0	0	2004
10081	168	176.0	31323	1	0	0	0	0	0	0	0	0	0	0	0	2004
10074	168	153.6	24865	1	0	0	0	0	0	0	0	0	0	0	0	2004
10101	168	154.4	25325	1	0	0	0	0	0	0	0	0	0	0	0	2004
10169	168	156.2	25804	0	1	0	0	0	0	0	0	0	0	0	0	2004
10094	168	156.7	25888	0	1	0	0	0	0	0	0	0	0	0	0	2004
10281	130	173.2	30759	0	1	0	0	0	0	0	0	0	0	0	1	2004
10209	168	172.5	30336	0	1	0	0	0	0	0	0	0	0	0	0	2004
10294	168	173.6	30639	0	1	0	0	0	0	0	0	0	0	0	0	2004
10177	144	162.2	27795	0	0	1	0	0	0	0	0	0	0	0	1	2004
9939	168	179.4	32528	0	0	1	0	0	0	0	0	0	0	0	0	2004
9719	168	181.0	32939	0	0	1	0	0	0	0	0	0	0	0	0	2004
9595	168	171.2	30251	0	0	1	0	0	0	0	0	0	0	0	0	2004
11455	47	178.4	32423	0	0	0	1	0	0	0	0	0	0	0	0	2004
10497	115	161.0	27685	0	0	0	1	0	0	0	0	0	0	0	1	2004
10379	168	164.9	28583	0	0	0	1	0	0	0	0	0	0	0	0	2004
10524	168	134.1	20086	0	0	0	0	1	0	0	0	0	0	0	0	2004
10355	168	143.1	22824	0	0	0	0	1	0	0	0	0	0	0	0	2004
10297	168	151.8	25088	0	0	0	0	1	0	0	0	0	0	0	0	2004
10333	168	146.5	23896	0	0	0	0	1	0	0	0	0	0	0	0	2004
10520	137	136.2	21172	0	0	0	0	1	0	0	0	0	0	0	1	2004
10343	168	148.6	24372	0	0	0	0	0	1	0	0	0	0	0	0	2004
10370	168	156.5	26208	0	0	0	0	0	1	0	0	0	0	0	0	2004
10456	168	146.9	23730	0	0	0	0	0	1	0	0	0	0	0	0	2004
10397	168	143.9	23298	0	0	0	0	0	1	0	0	0	0	0	0	2004

Data Base for SMITH 2 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10573	168	282.1	32423	0	0	0	0	0	0	1	0	0	0	0	0	2001
10626	168	248.5	15445	0	0	0	0	0	0	1	0	0	0	0	0	2001
10515	168	260.0	23897	0	0	0	0	0	0	1	0	0	0	0	0	2001
10525	168	265.6	27735	0	0	0	0	0	0	1	0	0	0	0	0	2001
10395	168	268.3	24484	0	0	0	0	0	0	0	1	0	0	0	0	2001
10628	168	324.9	59850	0	0	0	0	0	0	0	1	0	0	0	0	2001
10607	168	364.3	21198	0	0	0	0	0	0	0	1	0	0	0	0	2001
10611	168	348.7	12451	0	0	0	0	0	0	0	1	0	0	0	0	2001
11005	168	294.1	43426	0	0	0	0	0	0	0	1	0	0	0	0	2001
11152	168	276.4	28832	0	0	0	0	0	0	0	0	1	0	0	0	2001
10684	168	328.3	62058	0	0	0	0	0	0	0	0	1	0	0	0	2001
10507	168	369.6	25571	0	0	0	0	0	0	0	0	1	0	0	0	2001
10121	168	447.3	10891	0	0	0	0	0	0	0	0	1	0	0	0	2001
9772	168	443.4	10765	0	0	0	0	0	0	0	0	0	1	0	0	2001
9716	168	476.3	33613	0	0	0	0	0	0	0	0	0	1	0	0	2001
9923	168	466.6	26371	0	0	0	0	0	0	0	0	0	1	0	0	2001
9818	148	475.8	35092	0	0	0	0	0	0	0	0	0	1	0	0	2001
9817	169	441.2	11572	0	0	0	0	0	0	0	0	0	1	0	0	2001
10666	168	390.6	41263	0	0	0	0	0	0	0	0	0	0	1	0	2001
9872	168	451.1	14652	0	0	0	0	0	0	0	0	0	0	1	0	2001
10153	168	356.4	17956	0	0	0	0	0	0	0	0	0	0	1	0	2001
10064	168	373.6	30909	0	0	0	0	0	0	0	0	0	0	1	0	2001
10215	168	361.1	22603	0	0	0	0	0	0	0	0	0	0	0	0	2001
10209	168	366.0	23905	0	0	0	0	0	0	0	0	0	0	0	0	2001
10400	168	311.3	50949	0	0	0	0	0	0	0	0	0	0	0	0	2001
10706	168	278.3	30626	0	0	0	0	0	0	0	0	0	0	0	0	2001
11037	24	261.7	21546	0	0	0	0	0	0	0	0	0	0	0	0	2001
10182	168	375.1	25018	1	0	0	0	0	0	0	0	0	0	0	0	2002
10229	168	371.7	21187	1	0	0	0	0	0	0	0	0	0	0	0	2002
10798	168	237.7	42	1	0	0	0	0	0	0	0	0	0	0	0	2002
11491	47	184.6	40196	1	0	0	0	0	0	0	0	0	0	0	0	2002
11237	43	292.6	43148	0	1	0	0	0	0	0	0	0	0	0	1	2002
9778	168	327.4	60779	0	1	0	0	0	0	0	0	0	0	0	0	2002
10534	168	231.0	62792	0	1	0	0	0	0	0	0	0	0	0	0	2002
10418	168	348.4	5842	0	1	0	0	0	0	0	0	0	0	0	0	2002
10116	168	393.6	38371	0	0	1	0	0	0	0	0	0	0	0	0	2002
9924	168	448.9	13753	0	0	1	0	0	0	0	0	0	0	0	0	2002
9945	168	423.1	64139	0	0	1	0	0	0	0	0	0	0	0	0	2002
10029	168	431.0	2591	0	0	1	0	0	0	0	0	0	0	0	0	2002
9992	149	419.6	60760	0	0	1	0	0	0	0	0	0	0	0	0	2002
10934	56	276.9	28064	0	0	0	1	0	0	0	0	0	0	0	1	2002
10080	168	375.3	30653	0	0	0	1	0	0	0	0	0	0	0	0	2002
10161	115	357.1	18925	0	0	0	1	0	0	0	0	0	0	0	0	2002
10281	79	379.2	34717	0	0	0	1	0	0	0	0	0	0	0	1	2002
10094	168	403.0	50497	0	0	0	0	1	0	0	0	0	0	0	0	2002
10242	168	386.5	36504	0	0	0	0	1	0	0	0	0	0	0	0	2002
10310	168	351.8	13111	0	0	0	0	1	0	0	0	0	0	0	0	2002

Data Base for DANIEL 1 Target Heat Rate Equation

	HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
	10122	145	366.4	29820	0	0	0	0	1	0	0	0	0	0	0	0	2002
	10256	143	349.3	14987	0	0	0	0	1	0	0	0	0	0	0	1	2002
	10213	168	377.6	32391	0	0	0	0	0	1	0	0	0	0	0	0	2002
	10322	168	365.3	24171	0	0	0	0	0	1	0	0	0	0	0	0	2002
	10131	168	380.8	36120	0	0	0	0	0	1	0	0	0	0	0	0	2002
	10380	144	352.2	14138	0	0	0	0	0	1	0	0	0	0	0	0	2002
	10243	168	350.0	12325	0	0	0	0	0	0	1	0	0	0	0	0	2002
	10091	168	384.0	36777	0	0	0	0	0	0	1	0	0	0	0	0	2002
	9973	168	403.4	47136	0	0	0	0	0	0	1	0	0	0	0	0	2002
	10164	137	350.2	15054	0	0	0	0	0	0	1	0	0	0	0	1	2002
	10070	168	362.8	22966	0	0	0	0	0	0	0	1	0	0	0	0	2002
	9826	168	390.4	35868	0	0	0	0	0	0	0	1	0	0	0	0	2002
	10195	168	412.5	52312	0	0	0	0	0	0	0	1	0	0	0	0	2002
	10228	168	404.6	45644	0	0	0	0	0	0	0	1	0	0	0	0	2002
	10233	168	384.8	35812	0	0	0	0	0	0	0	1	0	0	0	0	2002
	10020	168	412.0	53376	0	0	0	0	0	0	0	0	1	0	0	0	2002
	9983	168	450.6	13979	0	0	0	0	0	0	0	0	1	0	0	0	2002
	9913	168	482.5	37714	0	0	0	0	0	0	0	0	1	0	0	0	2002
	10381	168	416.3	51307	0	0	0	0	0	0	0	0	1	0	0	0	2002
	10101	168	468.5	26490	0	0	0	0	0	0	0	0	0	1	0	0	2002
	9934	166	458.5	22951	0	0	0	0	0	0	0	0	0	1	0	0	2002
	10047	150	402.2	46877	0	0	0	0	0	0	0	0	0	1	0	0	2002
	9821	169	480.0	36406	0	0	0	0	0	0	0	0	0	1	0	0	2002
	10210	168	410.2	47483	0	0	0	0	0	0	0	0	0	1	0	0	2002
	9860	168	421.7	59169	0	0	0	0	0	0	0	0	0	0	1	0	2002
	9907	168	402.7	45328	0	0	0	0	0	0	0	0	0	0	1	0	2002
	9760	168	447.4	11327	0	0	0	0	0	0	0	0	0	0	1	0	2002
	9934	168	389.1	33713	0	0	0	0	0	0	0	0	0	0	1	0	2002
	9901	168	477.1	33951	0	0	0	0	0	0	0	0	0	0	0	0	2002
	9868	168	438.1	4372	0	0	0	0	0	0	0	0	0	0	0	0	2002
	10081	168	393.0	37818	0	0	0	0	0	0	0	0	0	0	0	0	2002
	10004	168	400.5	44691	0	0	0	0	0	0	0	0	0	0	0	0	2002
	10352	24	393.1	35916	0	0	0	0	0	0	0	0	0	0	0	0	2002
*	8608	99	401.3	48311	1	0	0	0	0	0	0	0	0	0	0	0	2003
	10713	112	414.8	61040	0	0	1	0	0	0	0	0	0	0	0	2	2003
	9765	167	473.6	33730	0	0	0	1	0	0	0	0	0	0	0	0	2003
	9908	168	465.4	29493	0	0	0	1	0	0	0	0	0	0	0	0	2003
	9690	168	454.6	21396	0	0	0	1	0	0	0	0	0	0	0	0	2003
	9698	168	443.3	12659	0	0	0	1	0	0	0	0	0	0	0	0	2003
	9661	124	437.6	10927	0	0	0	0	1	0	0	0	0	0	0	1	2003
	9528	168	428.6	2918	0	0	0	0	1	0	0	0	0	0	0	0	2003
	9556	168	410.6	57330	0	0	0	0	1	0	0	0	0	0	0	0	2003
	9742	168	395.2	48242	0	0	0	0	1	0	0	0	0	0	0	0	2003
	9690	168	400.9	45094	0	0	0	0	1	0	0	0	0	0	0	0	2003
	9998	168	425.8	558	0	0	0	0	0	1	0	0	0	0	0	0	2003
	9938	167	443.1	13389	0	0	0	0	0	1	0	0	0	0	0	0	2003
	9768	168	408.7	56475	0	0	0	0	0	1	0	0	0	0	0	0	2003

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
9969	101	454.8	22500	0	0	0	0	0	1	0	0	0	0	0	1	2003
10548	168	388.0	43399	0	0	0	0	0	0	1	0	0	0	0	0	2003
9997	168	473.2	32967	0	0	0	0	0	0	1	0	0	0	0	0	2003
9931	168	473.8	35796	0	0	0	0	0	0	1	0	0	0	0	0	2003
10157	168	490.7	47861	0	0	0	0	0	0	1	0	0	0	0	0	2003
9763	168	448.7	18702	0	0	0	0	0	0	0	1	0	0	0	0	2003
9658	168	438.8	9314	0	0	0	0	0	0	0	1	0	0	0	0	2003
9584	168	462.5	27452	0	0	0	0	0	0	0	1	0	0	0	0	2003
9632	168	463.4	27179	0	0	0	0	0	0	0	1	0	0	0	0	2003
9773	168	474.2	33098	0	0	0	0	0	0	0	1	0	0	0	0	2003
9707	168	452.1	19005	0	0	0	0	0	0	0	0	1	0	0	0	2003
9658	168	443.5	13033	0	0	0	0	0	0	0	0	1	0	0	0	2003
9761	167	412.1	58780	0	0	0	0	0	0	0	0	1	0	0	0	2003
9918	168	431.4	4095	0	0	0	0	0	0	0	0	1	0	0	0	2003
9611	168	418.0	55966	0	0	0	0	0	0	0	0	0	1	0	0	2003
9482	168	425.8	3365	0	0	0	0	0	0	0	0	0	1	0	0	2003
11158	168	209.2	56037	0	0	0	0	0	0	0	0	0	1	0	0	2003
9755	169	489.2	46207	0	0	0	0	0	0	0	0	0	1	0	0	2003
10040	117	429.2	5008	0	0	0	0	0	0	0	0	0	1	0	1	2003
10021	168	494.1	51167	0	0	0	0	0	0	0	0	0	0	1	0	2003
9915	168	501.3	56097	0	0	0	0	0	0	0	0	0	0	1	0	2003
10159	60	457.5	29819	0	0	0	0	0	0	0	0	0	0	1	0	2003
*11362	46	456.8	25862	0	0	0	0	0	0	0	0	0	0	0	1	2003
9729	168	505.6	60046	0	0	0	0	0	0	0	0	0	0	0	0	2003
10144	168	509.9	63559	0	0	0	0	0	0	0	0	0	0	0	0	2003
9796	168	453.9	21142	0	0	0	0	0	0	0	0	0	0	0	0	2003
9956	24	434.0	10156	0	0	0	0	0	0	0	0	0	0	0	0	2003
10339	168	430.0	6332	1	0	0	0	0	0	0	0	0	0	0	0	2004
10323	168	512.1	79	1	0	0	0	0	0	0	0	0	0	0	0	2004
10285	168	503.2	57982	1	0	0	0	0	0	0	0	0	0	0	0	2004
10215	168	502.4	58072	1	0	0	0	0	0	0	0	0	0	0	0	2004
10196	168	487.5	46948	0	1	0	0	0	0	0	0	0	0	0	0	2004
10179	168	469.0	32251	0	1	0	0	0	0	0	0	0	0	0	0	2004
10209	168	497.7	52844	0	1	0	0	0	0	0	0	0	0	0	0	2004
10004	168	504.1	57864	0	1	0	0	0	0	0	0	0	0	0	0	2004
10083	162	487.2	44710	0	1	0	0	0	0	0	0	0	0	0	0	2004
10185	45	441.4	10792	0	0	1	0	0	0	0	0	0	0	0	0	2004
10095	141	476.0	38323	0	0	1	0	0	0	0	0	0	0	0	1	2004
10086	168	485.8	42692	0	0	1	0	0	0	0	0	0	0	0	0	2004
10254	167	473.8	32895	0	0	0	1	0	0	0	0	0	0	0	0	2004
10166	168	473.8	35524	0	0	0	1	0	0	0	0	0	0	0	0	2004
10412	144	455.5	24068	0	0	0	1	0	0	0	0	0	0	0	0	2004
10519	119	468.7	30504	0	0	0	1	0	0	0	0	0	0	0	0	2004
10709	142	408.9	55451	0	0	0	0	1	0	0	0	0	0	0	1	2004
10434	168	429.9	4199	0	0	0	0	1	0	0	0	0	0	0	0	2004
10300	168	437.4	9870	0	0	0	0	1	0	0	0	0	0	0	0	2004
10661	168	421.8	64869	0	0	0	0	1	0	0	0	0	0	0	0	2004

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10382	119	384.5	40950	0	0	0	0	1	0	0	0	0	0	0	1	2004
10396	144	447.6	16441	0	0	0	0	0	1	0	0	0	0	0	0	2004
10402	167	481.7	40448	0	0	0	0	0	1	0	0	0	0	0	1	2004
10503	168	470.8	31681	0	0	0	0	0	1	0	0	0	0	0	0	2004
10288	116	468.6	33638	0	0	0	0	0	1	0	0	0	0	0	1	2004

Data Base for DANIEL 1 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11079	164	253.2	25541	0	0	0	0	0	0	1	0	0	0	0	0	2001
10434	168	309.1	60181	0	0	0	0	0	0	1	0	0	0	0	0	2001
10552	168	308.2	57091	0	0	0	0	0	0	1	0	0	0	0	0	2001
10439	168	339.1	8418	0	0	0	0	0	0	1	0	0	0	0	0	2001
10225	168	329.8	1405	0	0	0	0	0	0	0	1	0	0	0	0	2001
10455	168	382.2	33459	0	0	0	0	0	0	0	1	0	0	0	0	2001
10358	168	384.8	36588	0	0	0	0	0	0	0	1	0	0	0	0	2001
10397	168	357.6	20193	0	0	0	0	0	0	0	1	0	0	0	0	2001
10702	168	304.0	50137	0	0	0	0	0	0	0	1	0	0	0	0	2001
10737	168	290.8	36039	0	0	0	0	0	0	0	0	1	0	0	0	2001
10314	168	346.9	9632	0	0	0	0	0	0	0	0	1	0	0	0	2001
10184	168	388.8	42316	0	0	0	0	0	0	0	0	1	0	0	0	2001
9974	168	445.2	12532	0	0	0	0	0	0	0	0	1	0	0	0	2001
10015	144	409.1	52841	0	0	0	0	0	0	0	0	0	1	0	1	2001
9727	168	485.0	42862	0	0	0	0	0	0	0	0	0	1	0	0	2001
9897	168	486.3	44147	0	0	0	0	0	0	0	0	0	1	0	0	2001
9853	168	479.1	39032	0	0	0	0	0	0	0	0	0	1	0	0	2001
9941	169	459.0	27122	0	0	0	0	0	0	0	0	0	1	0	0	2001
10062	168	428.4	6319	0	0	0	0	0	0	0	0	0	0	1	0	2001
9869	168	508.7	62133	0	0	0	0	0	0	0	0	0	0	1	0	2001
9944	97	501.2	57404	0	0	0	0	0	0	0	0	0	0	1	0	2001
10137	103	476.6	36852	0	0	0	0	0	0	0	0	0	0	1	1	2001
9991	168	492.6	46440	0	0	0	0	0	0	0	0	0	0	0	0	2001
10071	168	460.6	25255	0	0	0	0	0	0	0	0	0	0	0	0	2001
9815	146	493.0	48508	0	0	0	0	0	0	0	0	0	0	0	0	2001
10167	87	471.0	37357	0	0	0	0	0	0	0	0	0	0	0	1	2001
9956	24	509.6	63111	0	0	0	0	0	0	0	0	0	0	0	0	2001
9342	168	507.9	61328	1	0	0	0	0	0	0	0	0	0	0	0	2002
9578	123	465.4	30083	1	0	0	0	0	0	0	0	0	0	0	1	2002
9451	95	475.9	36492	1	0	0	0	0	0	0	0	0	0	0	0	2002
14436	46	188.2	51440	0	0	0	1	0	0	0	0	0	0	0	1	2002
10514	151	392.5	37160	0	0	0	1	0	0	0	0	0	0	0	0	2002
10389	168	428.1	1577	0	0	0	1	0	0	0	0	0	0	0	0	2002
10568	100	356.8	21145	0	0	0	0	1	0	0	0	0	0	0	1	2002
10235	168	416.3	58174	0	0	0	0	1	0	0	0	0	0	0	0	2002
10110	168	351.7	12783	0	0	0	0	1	0	0	0	0	0	0	0	2002
10202	168	378.9	34204	0	0	0	0	1	0	0	0	0	0	0	0	2002
10270	167	378.6	32518	0	0	0	0	1	0	0	0	0	0	0	0	2002
10266	168	388.2	40055	0	0	0	0	0	1	0	0	0	0	0	0	2002
10152	168	376.0	32370	0	0	0	0	0	1	0	0	0	0	0	0	2002
10193	164	383.6	40772	0	0	0	0	0	1	0	0	0	0	0	0	2002
10271	144	369.9	29397	0	0	0	0	0	1	0	0	0	0	0	0	2002
10332	168	356.4	19478	0	0	0	0	0	0	1	0	0	0	0	0	2002
10182	119	379.7	31147	0	0	0	0	0	0	1	0	0	0	0	0	2002
10222	129	391.9	43558	0	0	0	0	0	0	1	0	0	0	0	1	2002
9962	168	384.7	38646	0	0	0	0	0	0	1	0	0	0	0	0	2002
10265	168	373.5	30987	0	0	0	0	0	0	0	1	0	0	0	0	2002

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10247	168	389.9	38057	0	0	0	0	0	0	0	1	0	0	0	0	2002
10123	168	413.2	53650	0	0	0	0	0	0	0	1	0	0	0	0	2002
10069	168	412.7	53111	0	0	0	0	0	0	0	1	0	0	0	0	2002
9552	168	382.3	35781	0	0	0	0	0	0	0	1	0	0	0	0	2002
10070	168	403.6	46885	0	0	0	0	0	0	0	0	1	0	0	0	2002
10289	168	457.4	20667	0	0	0	0	0	0	0	0	1	0	0	0	2002
10126	168	481.2	38302	0	0	0	0	0	0	0	0	1	0	0	0	2002
10640	168	412.7	51073	0	0	0	0	0	0	0	0	1	0	0	0	2002
10434	145	464.3	25892	0	0	0	0	0	0	0	0	0	1	0	0	2002
* 7393	36	347.5	6440	0	0	0	0	0	0	0	0	0	1	0	1	2002
9891	162	409.6	51410	0	0	0	0	0	0	0	0	0	1	0	0	2002
9966	169	449.8	13788	0	0	0	0	0	0	0	0	0	1	0	0	2002
10192	168	435.8	2777	0	0	0	0	0	0	0	0	0	1	0	0	2002
9955	162	414.0	57070	0	0	0	0	0	0	0	0	0	0	1	0	2002
9864	168	387.6	32513	0	0	0	0	0	0	0	0	0	0	1	0	2002
9470	168	439.6	5494	0	0	0	0	0	0	0	0	0	0	1	0	2002
9576	168	383.3	30334	0	0	0	0	0	0	0	0	0	0	1	0	2002
9717	168	463.5	22902	0	0	0	0	0	0	0	0	0	0	0	0	2002
9681	168	438.3	5936	0	0	0	0	0	0	0	0	0	0	0	0	2002
9751	168	389.5	37657	0	0	0	0	0	0	0	0	0	0	0	0	2002
9877	168	403.5	50500	0	0	0	0	0	0	0	0	0	0	0	0	2002
10059	24	406.9	48358	0	0	0	0	0	0	0	0	0	0	0	0	2002
9693	168	457.8	25725	1	0	0	0	0	0	0	0	0	0	0	0	2003
9613	168	492.5	50773	1	0	0	0	0	0	0	0	0	0	0	0	2003
9645	168	484.8	45324	1	0	0	0	0	0	0	0	0	0	0	0	2003
9787	168	419.8	62019	1	0	0	0	0	0	0	0	0	0	0	0	2003
9721	168	462.7	26646	0	1	0	0	0	0	0	0	0	0	0	0	2003
9983	157	431.4	4883	0	1	0	0	0	0	0	0	0	0	0	0	2003
9406	66	392.1	35805	0	1	0	0	0	0	0	0	0	0	0	0	2003
9668	119	421.1	2121	0	0	1	0	0	0	0	0	0	0	0	1	2003
9482	168	495.2	51263	0	0	1	0	0	0	0	0	0	0	0	0	2003
9525	168	495.8	50290	0	0	1	0	0	0	0	0	0	0	0	0	2003
9538	168	494.8	49468	0	0	1	0	0	0	0	0	0	0	0	0	2003
9569	168	507.1	60660	0	0	1	0	0	0	0	0	0	0	0	0	2003
10002	154	467.3	31665	0	0	0	1	0	0	0	0	0	0	0	0	2003
9894	168	458.1	26446	0	0	0	1	0	0	0	0	0	0	0	0	2003
9771	168	452.0	20389	0	0	0	1	0	0	0	0	0	0	0	0	2003
9791	168	445.7	14676	0	0	0	1	0	0	0	0	0	0	0	0	2003
9624	161	446.0	16821	0	0	0	0	1	0	0	0	0	0	0	0	2003
9696	168	442.0	11635	0	0	0	0	1	0	0	0	0	0	0	0	2003
9843	168	377.3	32875	0	0	0	0	1	0	0	0	0	0	0	0	2003
9917	168	370.9	25527	0	0	0	0	1	0	0	0	0	0	0	0	2003
9632	168	431.2	5317	0	0	0	0	1	0	0	0	0	0	0	0	2003
10048	168	423.6	60355	0	0	0	0	0	1	0	0	0	0	0	0	2003
10031	150	445.1	16412	0	0	0	0	0	1	0	0	0	0	0	0	2003
9873	168	419.1	63287	0	0	0	0	0	1	0	0	0	0	0	0	2003
9853	144	471.1	30204	0	0	0	0	0	1	0	0	0	0	0	0	2003

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10388	168	410.2	57816	0	0	0	0	0	0	1	0	0	0	0	0	2003
9811	168	470.3	30759	0	0	0	0	0	0	1	0	0	0	0	0	2003
10026	168	442.2	15238	0	0	0	0	0	0	1	0	0	0	0	0	2003
10077	168	464.6	29989	0	0	0	0	0	0	1	0	0	0	0	0	2003
9633	168	449.3	18993	0	0	0	0	0	0	0	1	0	0	0	0	2003
9637	168	438.0	8489	0	0	0	0	0	0	0	1	0	0	0	0	2003
9690	168	451.6	19773	0	0	0	0	0	0	0	1	0	0	0	0	2003
9648	168	433.0	6059	0	0	0	0	0	0	0	1	0	0	0	0	2003
9505	168	471.4	30750	0	0	0	0	0	0	0	1	0	0	0	0	2003
9574	168	448.8	16562	0	0	0	0	0	0	0	0	1	0	0	0	2003
9570	161	433.5	6487	0	0	0	0	0	0	0	0	1	0	0	0	2003
9541	161	419.0	62176	0	0	0	0	0	0	0	0	1	0	0	0	2003
9800	125	389.9	43337	0	0	0	0	0	0	0	0	1	0	0	1	2003
9770	168	432.5	5361	0	0	0	0	0	0	0	0	0	1	0	0	2003
9804	168	486.7	42033	0	0	0	0	0	0	0	0	0	1	0	0	2003
10197	168	473.7	33572	0	0	0	0	0	0	0	0	0	1	0	0	2003
9746	169	489.9	45541	0	0	0	0	0	0	0	0	0	1	0	0	2003
9736	168	468.7	31017	0	0	0	0	0	0	0	0	0	1	0	0	2003
9745	97	482.7	41436	0	0	0	0	0	0	0	0	0	0	1	0	2003
12438	75	196.4	52119	0	0	0	0	0	0	0	0	0	0	0	1	2003
10054	168	453.3	19480	0	0	0	0	0	0	0	0	0	0	0	0	2003
10264	24	437.9	11898	0	0	0	0	0	0	0	0	0	0	0	0	2003
9583	168	425.1	2813	1	0	0	0	0	0	0	0	0	0	0	0	2004
*26101	4	104.0	15667	1	0	0	0	0	0	0	0	0	0	0	1	2004
9461	168	491.4	47786	1	0	0	0	0	0	0	0	0	0	0	0	2004
9432	139	483.8	45067	1	0	0	0	0	0	0	0	0	0	0	1	2004
9614	141	470.9	34310	0	1	0	0	0	0	0	0	0	0	0	1	2004
9551	168	488.0	45364	0	1	0	0	0	0	0	0	0	0	0	0	2004
9536	168	498.5	53668	0	1	0	0	0	0	0	0	0	0	0	0	2004
9513	168	505.0	58863	0	1	0	0	0	0	0	0	0	0	0	0	2004
9536	168	499.4	53309	0	1	0	0	0	0	0	0	0	0	0	0	2004
9604	168	482.9	41789	0	0	1	0	0	0	0	0	0	0	0	0	2004
10090	125	461.5	28009	0	0	1	0	0	0	0	0	0	0	0	1	2004
9960	168	486.9	42549	0	0	1	0	0	0	0	0	0	0	0	0	2004
9791	168	487.2	43639	0	0	1	0	0	0	0	0	0	0	0	0	2004
9629	167	502.2	56029	0	0	0	1	0	0	0	0	0	0	0	0	2004
9922	168	464.5	30817	0	0	0	1	0	0	0	0	0	0	0	0	2004
10002	168	482.1	38366	0	0	0	1	0	0	0	0	0	0	0	0	2004
9812	168	474.9	35008	0	0	0	1	0	0	0	0	0	0	0	0	2004
9847	168	433.3	4703	0	0	0	0	1	0	0	0	0	0	0	0	2004
9823	168	444.9	11873	0	0	0	0	1	0	0	0	0	0	0	0	2004
9903	168	438.7	9012	0	0	0	0	1	0	0	0	0	0	0	0	2004
9997	168	432.2	4178	0	0	0	0	1	0	0	0	0	0	0	0	2004
9726	168	443.2	10986	0	0	0	0	1	0	0	0	0	0	0	0	2004
9946	168	453.1	19429	0	0	0	0	0	1	0	0	0	0	0	0	2004
9856	168	494.6	48761	0	0	0	0	0	1	0	0	0	0	0	0	2004
10094	168	469.5	30646	0	0	0	0	0	1	0	0	0	0	0	0	2004

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
9990	168	441.0	11011	0	0	0	0	0	1	0	0	0	0	0	0	2004

Data Base for DANIEL 2 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Calculation of
Target Average Net Operating Heat Rates
for January 2005 - December 2005

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKW * 10^3 Generation	(5) Weighted ANOHR Target
CRIST 4	Jan '05	64.3	4,318	10,855	47,556	
	Feb '05	69.4	4,952	10,477	46,354	
	Mar '05	68.6	4,852	10,643	50,738	
	Apr '05	66.1	4,540	10,685	47,234	
	May '05	63.3	4,196	10,638	46,874	
	Jun '05	64.6	4,355	10,596	46,287	
	Jul '05	67.4	4,701	10,521	49,894	
	Aug '05	67.9	4,764	10,509	50,222	
	Sep '05	65.9	4,515	10,559	47,152	
	Oct '05	66.5	4,589	10,543	49,283	
	Nov '05	65.6	4,478	10,567	46,960	
	Dec '05	60.3	3,835	10,751	41,749	10,610
CRIST 5	Jan '05	63.6	4,218	10,771	42,082	
	Feb '05	69.9	5,021	10,543	41,321	
	Mar '05	69.2	4,929	10,566	50,722	
	Apr '05	66.5	4,581	10,660	47,170	
	May '05	63.4	4,194	10,779	46,470	
	Jun '05	65.2	4,417	10,709	46,274	
	Jul '05	68.2	4,799	10,389	49,967	
	Aug '05	68.5	4,838	10,329	50,240	
	Sep '05	66.7	4,606	10,444	47,337	
	Oct '05	67.2	4,670	10,360	49,350	
	Nov '05	65.9	4,505	10,137	46,769	
	Dec '05	58.6	3,620	10,987	42,987	10,548
CRIST 6	Jan '05	247.9	66,140	10,790	179,724	
	Feb '05	267.1	74,413	10,211	174,932	
	Mar '05	264.0	73,075	10,224	123,533	
	Apr '05	252.1	67,946	10,280	141,431	
	May '05	234.7	60,476	10,376	170,127	
	Jun '05	241.0	63,177	10,339	169,166	
	Jul '05	256.9	70,013	10,509	186,289	
	Aug '05	259.1	70,961	10,521	187,833	
	Sep '05	245.0	64,894	10,317	51,704	
	Oct '05	0.0	0	-	0	
	Nov '05	231.5	59,106	10,396	54,179	
	Dec '05	228.3	57,737	10,416	149,507	10,416

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on page 2 of Schedule 1.

Column (5) = $(\Sigma ((3)*(4))) / (\Sigma (4))$

Calculation of
Target Average Net Operating Heat Rates
for January 2005 - December 2005

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKW • 10^3 Generation	(5) Weighted ANOHR Target
CRIST 7	Jan '05	417.2	182,789	10,181	266,595	
	Feb '05	0.0	0	-	0	
	Mar '05	0.0	0	-	0	
	Apr '05	392.9	165,738	10,356	116,679	
	May '05	385.1	160,299	10,373	272,660	
	Jun '05	393.0	165,808	10,356	269,201	
	Jul '05	416.9	182,578	10,410	295,163	
	Aug '05	419.8	184,623	10,304	297,222	
	Sep '05	398.5	169,654	10,473	272,949	
	Oct '05	401.8	171,965	10,224	239,043	
	Nov '05	402.1	172,175	10,337	192,617	
	Dec '05	383.5	159,185	10,377	271,526	10,340
SMITH 1	Jan '05	135.9	19,515	10,183	99,732	
	Feb '05	144.9	21,761	10,260	96,052	
	Mar '05	141.5	20,907	10,266	103,883	
	Apr '05	134.3	19,120	10,282	95,371	
	May '05	127.0	17,336	10,304	93,221	
	Jun '05	129.2	17,871	10,297	91,832	
	Jul '05	137.9	20,010	10,273	101,250	
	Aug '05	139.5	20,408	10,269	102,379	
	Sep '05	132.1	18,580	10,288	93,929	
	Oct '05	134.0	19,046	10,282	66,614	
	Nov '05	134.8	19,243	10,280	25,613	
	Dec '05	124.6	16,756	10,313	91,470	10,273
SMITH 2	Jan '05	161.9	27,685	9,909	80,776	
	Feb '05	166.7	29,057	10,052	68,025	
	Mar '05	0.0	0	-	0	
	Apr '05	0.0	0	-	0	
	May '05	145.5	22,947	10,362	98,965	
	Jun '05	149.5	24,110	10,394	101,629	
	Jul '05	160.5	27,283	10,204	112,797	
	Aug '05	162.1	27,742	10,200	113,984	
	Sep '05	154.0	25,412	10,220	104,700	
	Oct '05	155.9	25,960	10,215	102,565	
	Nov '05	154.8	25,643	10,218	105,253	
	Dec '05	145.7	23,005	10,245	92,514	10,213

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on page 2 of Schedule 1.

Column (5) = $(\Sigma ((4) * (5))) / (\Sigma (5))$

Calculation of
Target Average Net Operating Heat Rates
for January 2005 - December 2005

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKW * 10^3 Generation	(5) Weighted ANOHR Target
DANIEL 1	Jan '05	512.6	260,792	10,092	370,630	
	Feb '05	510.3	259,021	9,932	273,499	
	Mar '05	512.8	260,946	9,928	370,784	
	Apr '05	508.4	257,561	9,935	354,891	
	May '05	482.5	237,871	9,975	348,825	
	Jun '05	506.0	255,719	9,938	353,726	
	Jul '05	512.7	260,869	9,928	370,711	
	Aug '05	512.4	260,638	9,929	370,464	
	Sep '05	510.0	258,790	9,932	273,355	
	Oct '05	0.0	0	-	0	
	Nov '05	491.6	244,743	9,960	57,514	
	Dec '05	511.8	260,175	9,930	370,024	9,953
DANIEL 2	Jan '05	512.8	261,162	9,471	371,261	
	Feb '05	512.0	260,539	9,545	310,784	
	Mar '05	511.1	259,839	9,630	47,535	
	Apr '05	508.8	258,052	9,894	320,044	
	May '05	488.7	242,618	9,813	353,827	
	Jun '05	509.1	258,284	9,781	356,383	
	Jul '05	512.9	261,240	9,776	371,345	
	Aug '05	512.6	261,006	9,777	371,155	
	Sep '05	511.9	260,461	9,777	358,333	
	Oct '05	510.3	259,216	9,780	345,999	
	Nov '05	510.2	259,139	9,780	357,140	
	Dec '05	512.6	261,006	9,777	371,135	9,742

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on page 2 of Schedule 1.

Column (5) = $(\Sigma ((4)*(5))) / (\Sigma (5))$

Summary of Target, Maximum, and Minimum
Average Net Operating Heat Rates
for January 2005 - December 2005

Unit	Target Heat Rate BTU/KWH (0 Points)	Minimum Attainable Heat Rate (+ 10 Points)	Maximum Attainable Heat Rate (- 10 Points)
CRIST 4	10,610	10,292	10,928
CRIST 5	10,548	10,232	10,864
CRIST 6	10,416	10,104	10,728
CRIST 7	10,340	10,030	10,650
SMITH 1	10,273	9,965	10,581
SMITH 2	10,213	9,907	10,519
DANIEL 1	9,953	9,654	10,252
DANIEL 2	9,742	9,450	10,034

II. DETERMINATION OF EQUIVALENT AVAILABILITY TARGETS

Calculation of
Target Equivalent Availabilities
for January 2005 - December 2005

Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR *	Planned Outage Hours for Jan '05 - Dec '05	Reserve Shutdown Hours for Jan '05 - Dec '05	Target Equivalent Availability **
Crist 4	0.0115	0	0	98.8
Crist 5	0.0311	0	0	96.9
Crist 6	0.0924	1,729	0	72.9
Crist 7	0.0960	1,895	0	70.9
Smith 1	0.0194	721	0	90.0
Smith 2	0.1011	1,727	0	72.2
Daniel 1	0.0454	1,513	0	79.0
Daniel 2	0.0394	720	0	88.2

* For Period July 1999 Through June 2004.

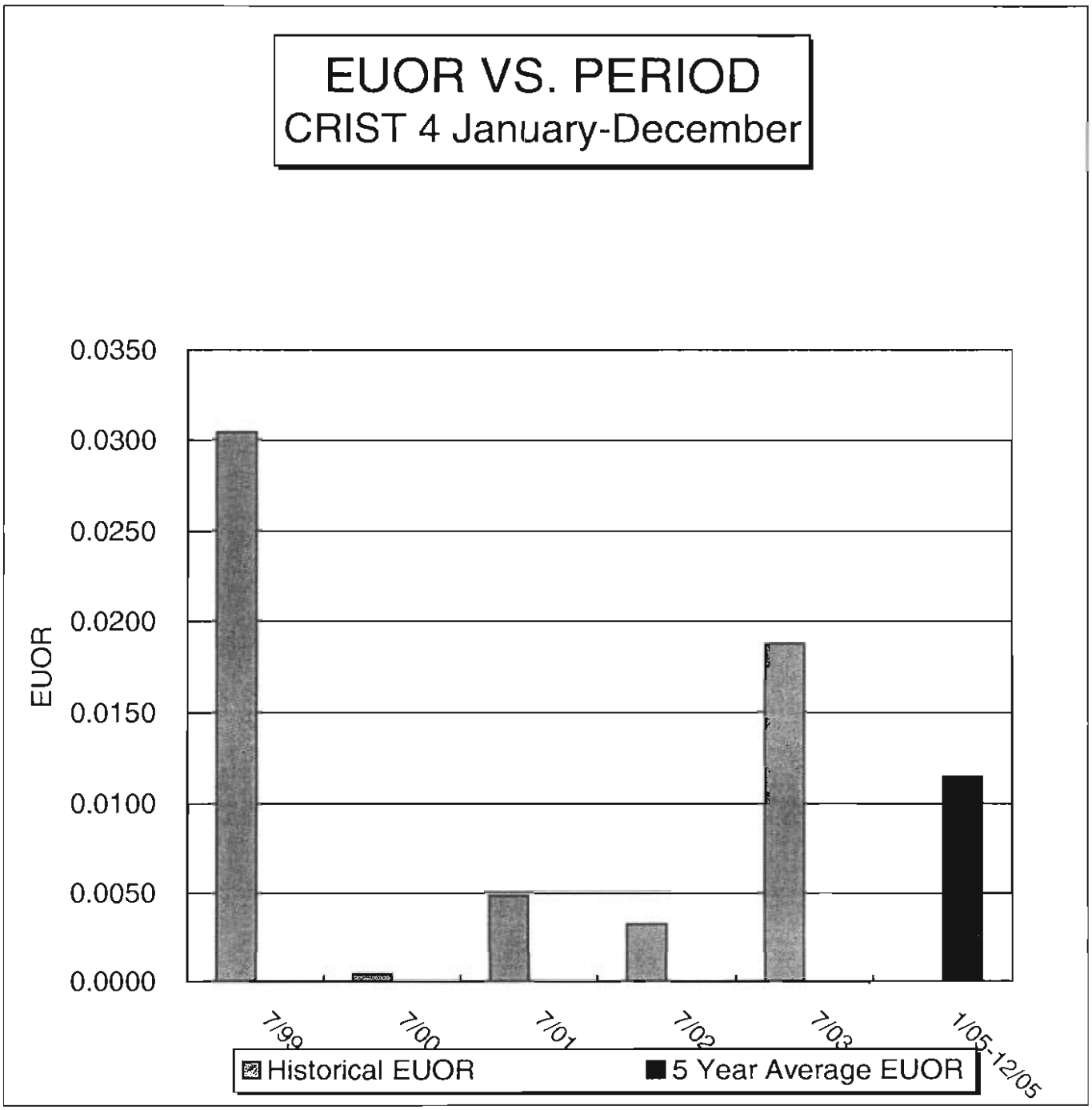
** EA = [1 - (POH + EUOR * (PH - POH - RSH)) / PH] * 100

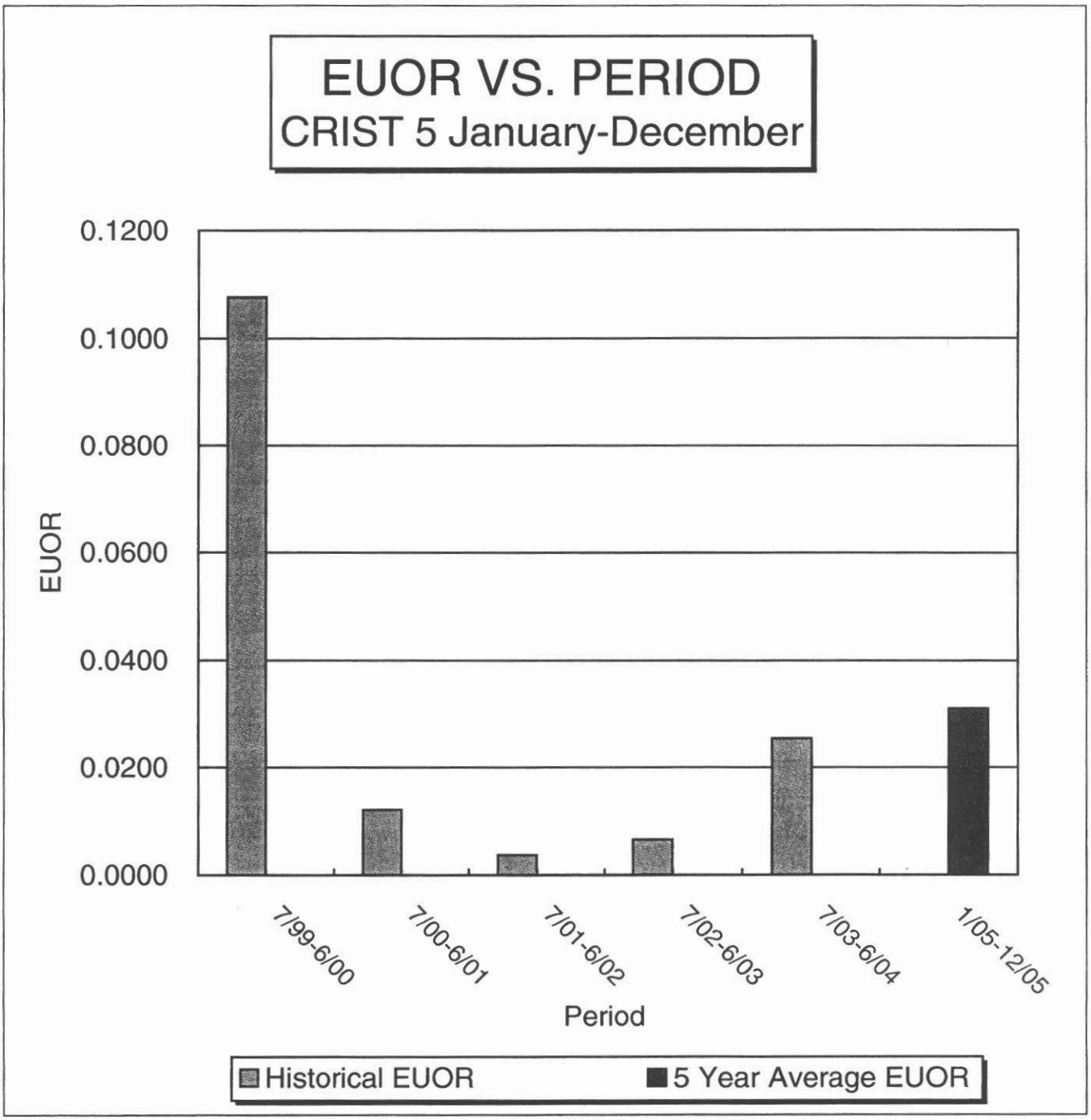
Calculation of Maximum and Minimum
Attainable Equivalent Availabilities
for January 2005 - December 2005

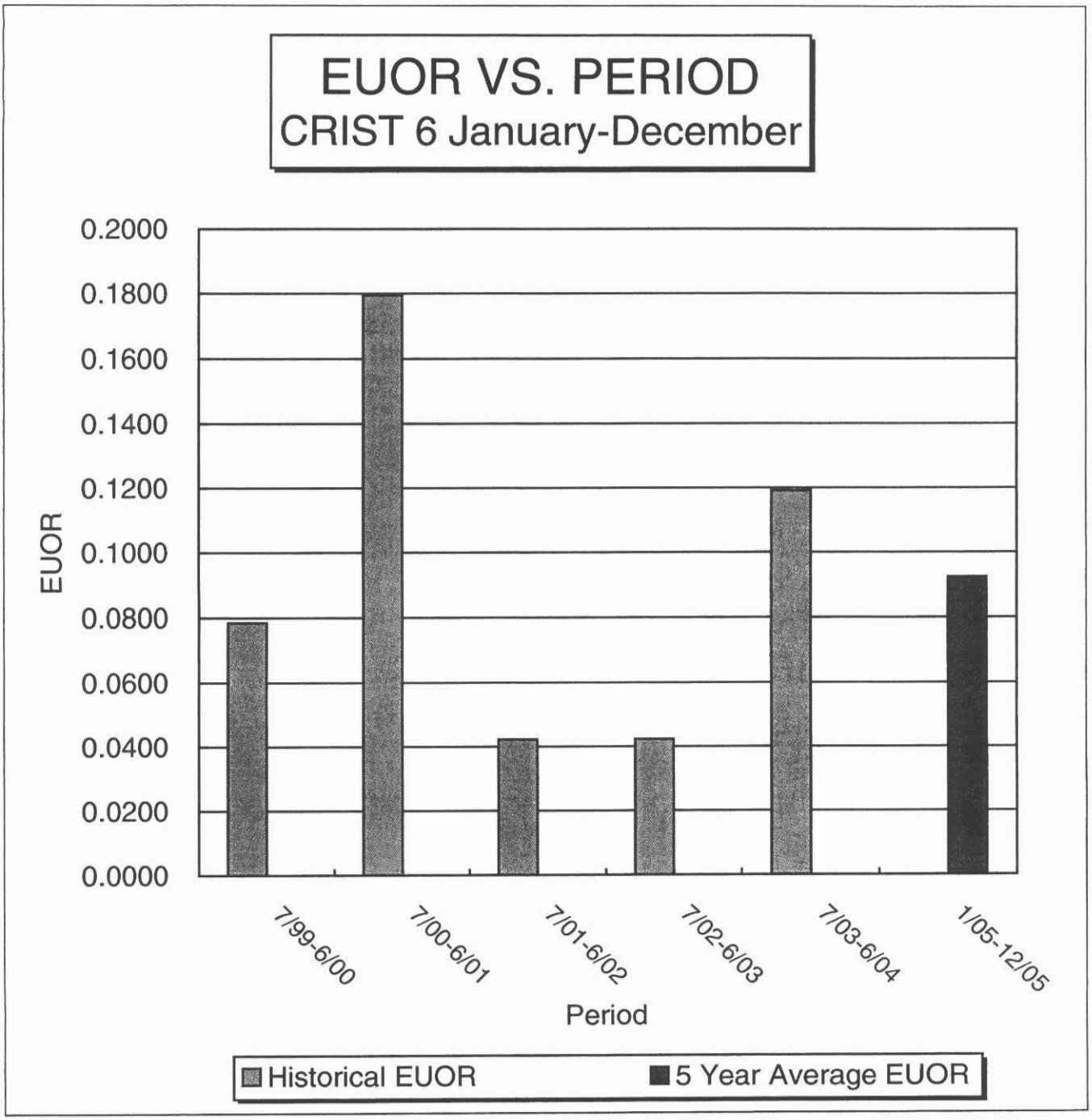
Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR (TARGET EUOR)	Minimum Attainable EUOR 70% of Target EUOR	Maximum Attainable Equivalent Availability	Maximum Attainable EUOR 145% of Target EUOR	Minimum Attainable Equivalent Availability
Crist 4	0.0115	0.0081	99.2	0.0167	98.3
Crist 5	0.0311	0.0218	97.8	0.0451	95.5
Crist 6	0.0924	0.0647	75.1	0.1340	69.5
Crist 7	0.0960	0.0672	73.1	0.1392	67.5
Smith 1	0.0194	0.0136	90.5	0.0281	89.2
Smith 2	0.1011	0.0708	74.6	0.1466	68.5
Daniel 1	0.0454	0.0318	80.1	0.0658	77.3
Daniel 2	0.0394	0.0276	89.2	0.0571	86.5

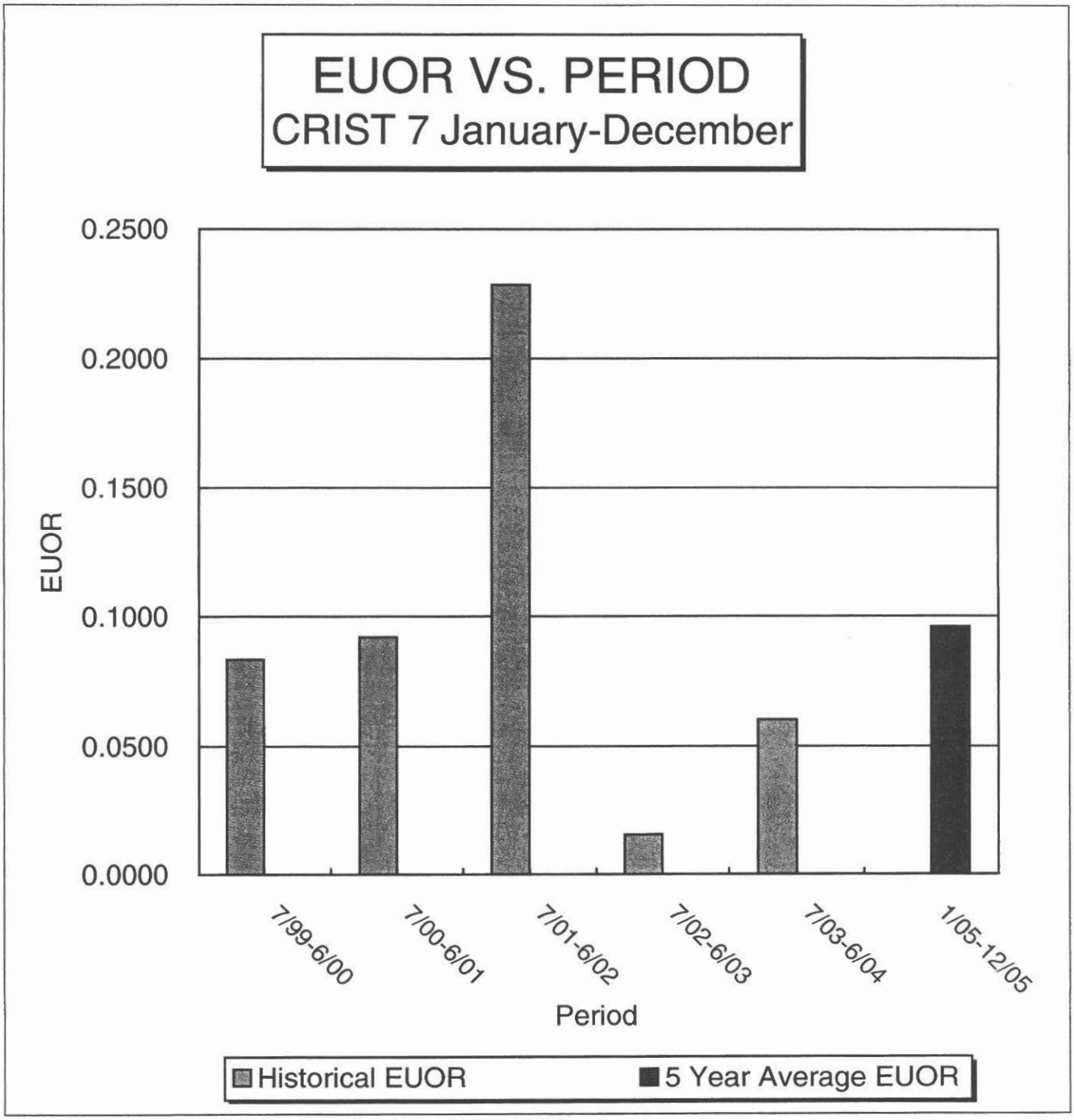
Summary of Target, Maximum, and Minimum
Equivalent Availabilities
for January 2005 - December 2005

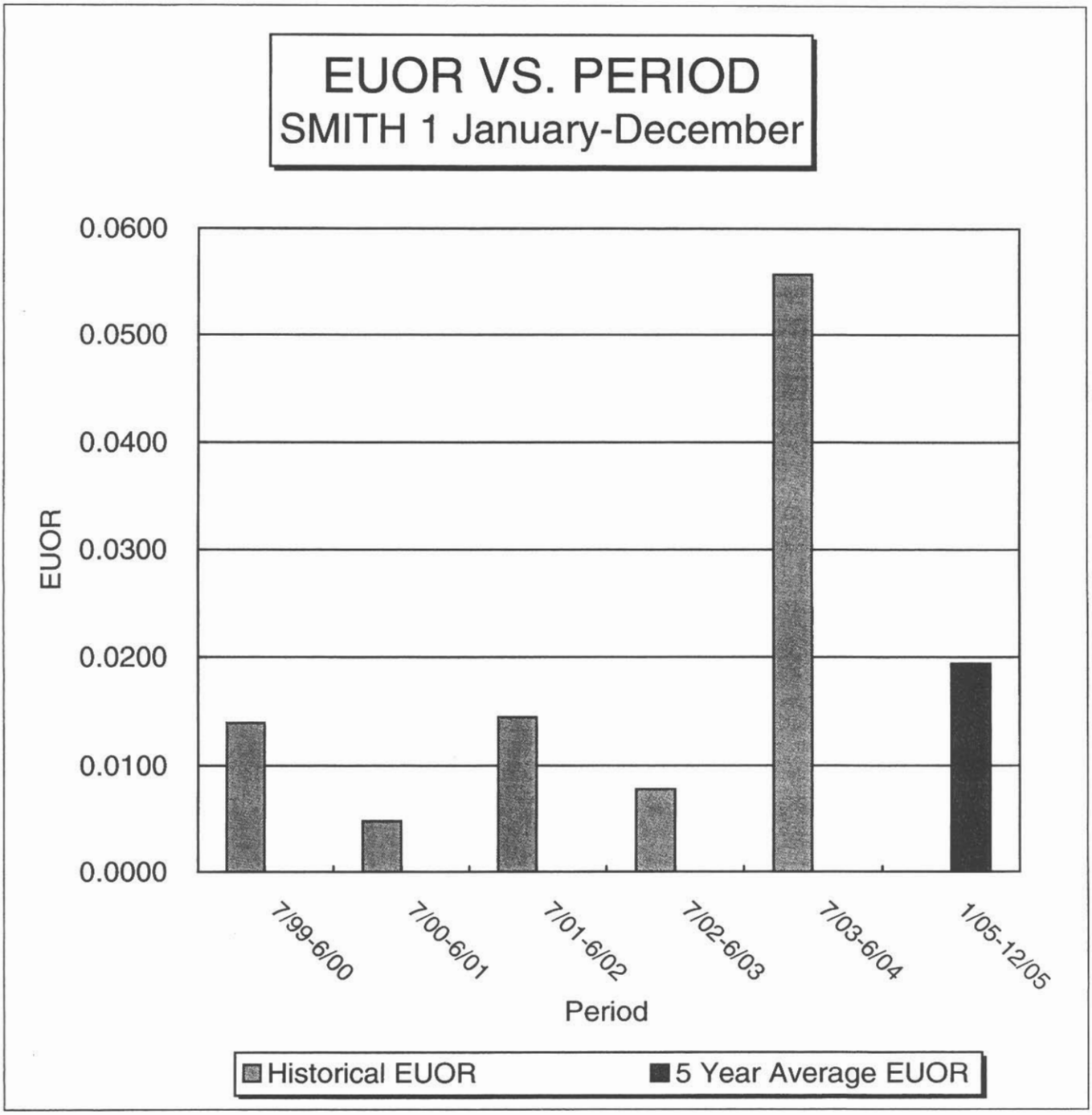
Unit	Target Equivalent Availability (0 Points)	Maximum Attainable Equivalent Availability (+10 Points)	Minimum Attainable Equivalent Availability (-10 Points)
Crist 4	98.8	99.2	98.3
Crist 5	96.9	97.8	95.5
Crist 6	72.9	75.1	69.5
Crist 7	70.9	73.1	67.5
Smith 1	90.0	90.5	89.2
Smith 2	72.2	74.6	68.5
Daniel 1	79.0	80.1	77.3
Daniel 2	88.2	89.2	86.5

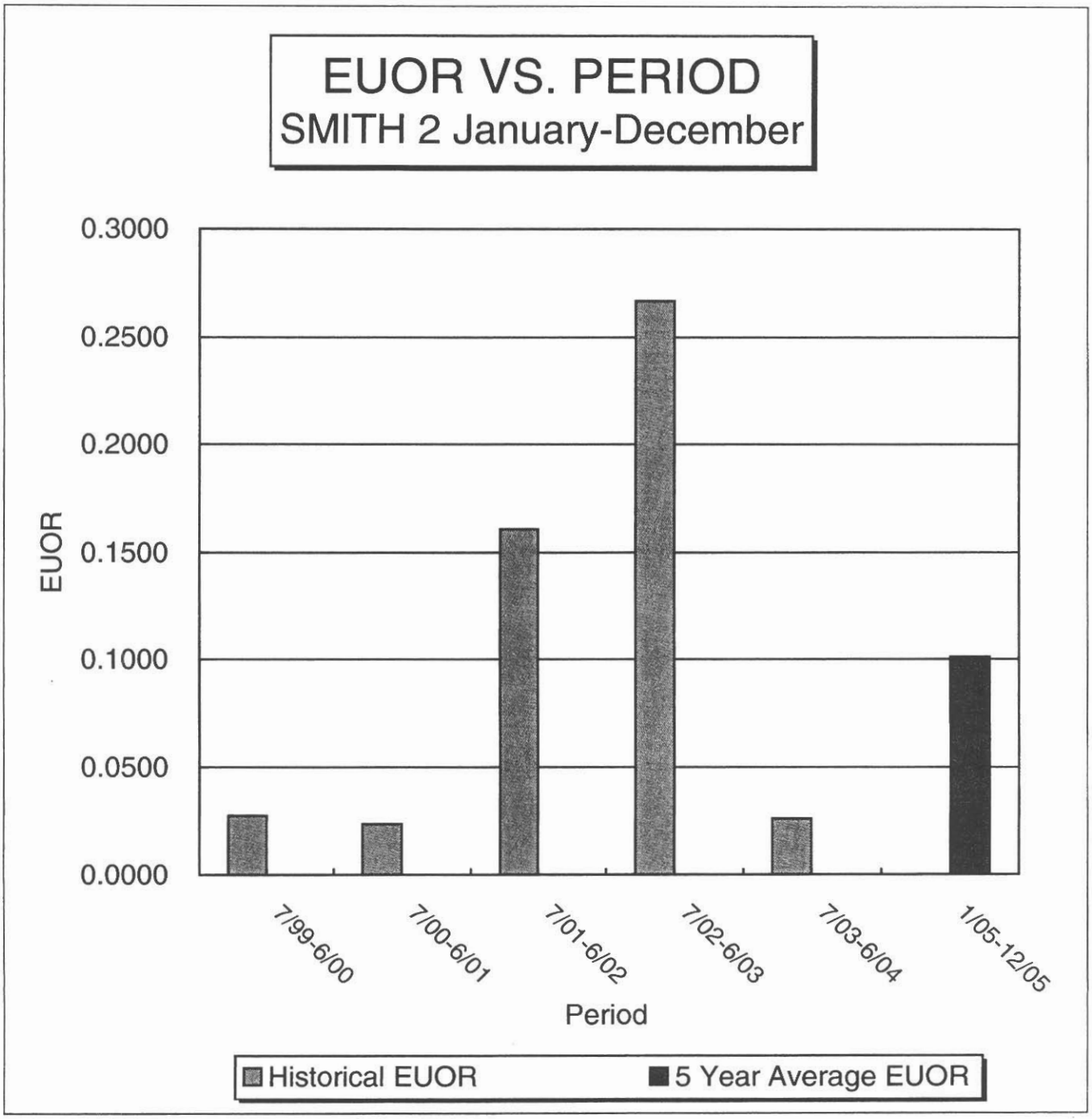

EUOR VS. PERIOD
CRIST 4 January-December
EUOR
0.0350
0.0300
0.0250
0.0200
0.0150
0.0100
0.0050
0.0000
7/99
7/00
7/01
7/02
7/03
1/05-12/05
Historical EUOR
5 Year Average EUOR

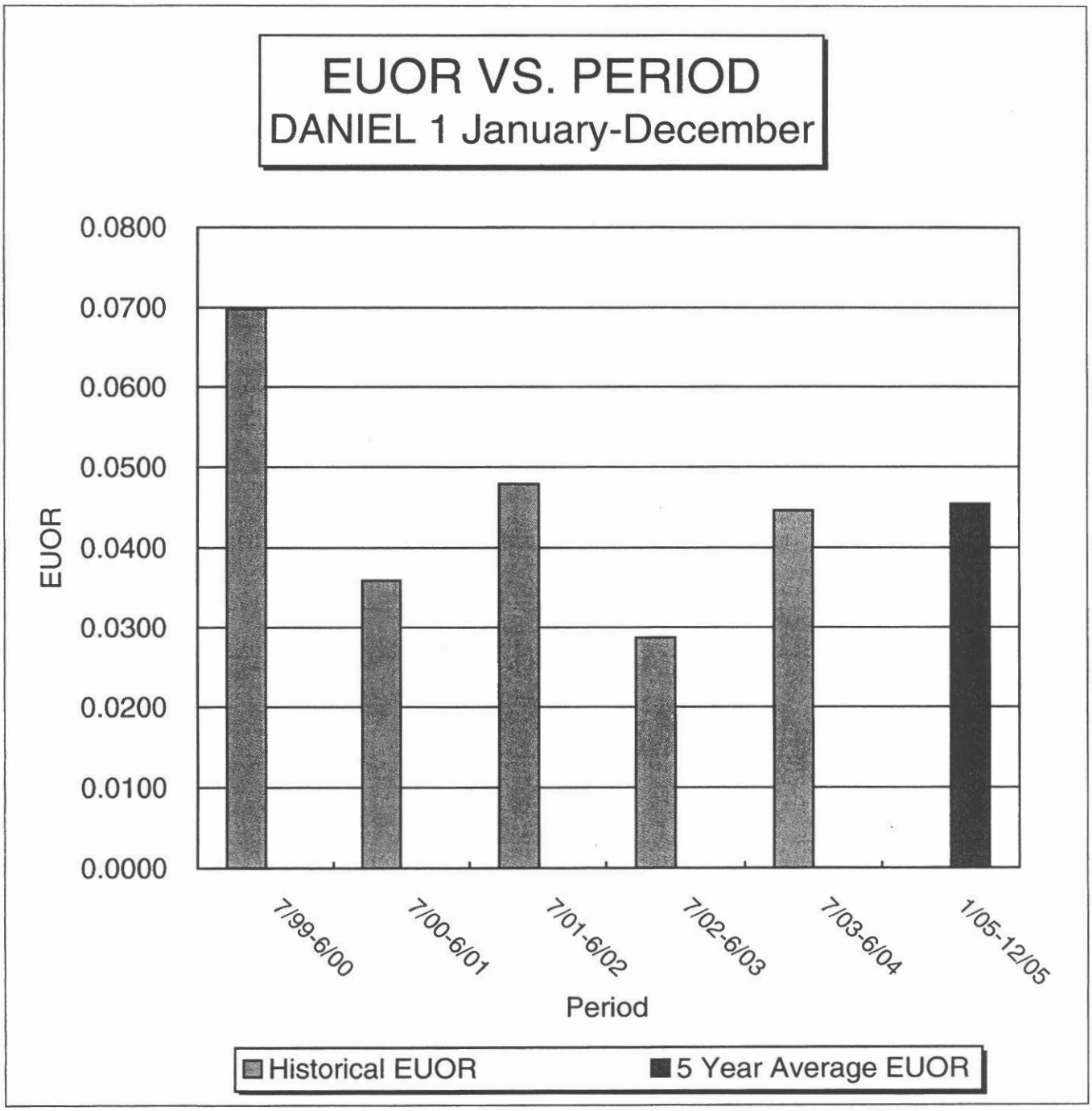

EUOR VS. PERIOD
CRIST 5 January-December
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
7/03-6/04
1/05-12/05
Period
Historical EUOR
5 Year Average EUOR

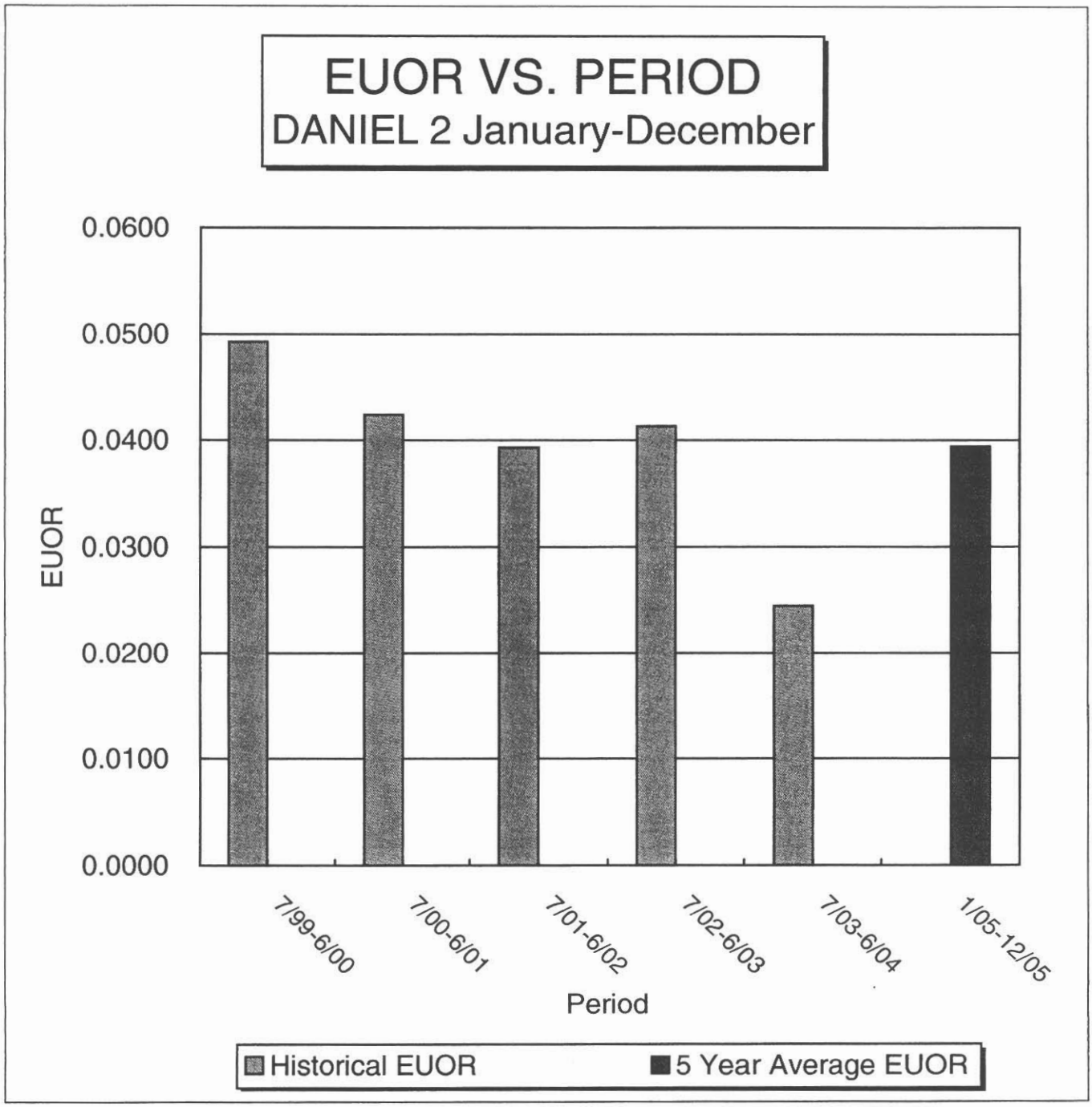

EUOR VS. PERIOD
CRIST 6 January-December
0.2000
0.1800
0.1600
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
7/03-6/04
1/05-12/05
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
CRIST 7 January-December
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
EUOR
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
7/03-6/04
1/05-12/05
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
SMITH 1 January-December
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
7/03-6/04
1/05-12/05
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
SMITH 2 January-December
0.3000
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
EUOR
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
7/03-6/04
1/05-12/05
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 1 January-December
0.0800
0.0700
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
7/03-6/04
1/05-12/05
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 2 January-December
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
7/03-6/04
1/05-12/05
Period
Historical EUOR
5 Year Average EUOR

III. GPIF MINIMUM FILING REQUIREMENTS FOR THE PERIOD JANUARY 2005 - DECEMBER 2005

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Generating Performance Incentive Factor

Estimated Reward/Penalty Table

Gulf Power Company

Period of: January 2005 - December 2005

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	6360	2342
+ 9	5724	2108
+ 8	5088	1873
+ 7	4452	1639
+ 6	3816	1405
+ 5	3180	1171
+ 4	2544	937
+ 3	1908	703
+ 2	1272	468
+ 1	636	234
0	0	0
- 1	-700	-234
- 2	-1400	-468
- 3	-2100	-703
- 4	-2800	-937
- 5	-3500	-1171
- 6	-4199	-1405
- 7	-4899	-1639
- 8	-5599	-1873
- 9	-6299	-2108
- 10	-6999	-2342
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Estimated

Gulf Power Company

Period of: January 2005 - December 2005

Line 1	Beginning of Period Balance of Common Equity	$595,286,000
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '05	$601,424,000
Line 3	Month of Feb '05	$588,659,000
Line 4	Month of Mar '05	$590,383,000
Line 5	Month of Apr '05	$575,263,000
Line 6	Month of May '05	$582,900,000
Line 7	Month of Jun '05	$593,586,000
Line 8	Month of Jul '05	$589,364,000
Line 9	Month of Aug '05	$601,648,000
Line 10	Month of Sep '05	$609,737,000
Line 11	Month of Oct '05	$597,781,000
Line 12	Month of Nov '05	$600,812,000
Line 13	Month of Dec '05	$609,932,000
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$595,136,538
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	61.3808%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$2,423,952
Line 18	Jurisdictional Sales (KWH)	10,851,023,000
Line 19	Total Territorial Sales (KWH)	11,231,382,000
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	96.6134%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$2,341,862

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GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2005 - December 2005

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Crist 4	0.3%	98.8	99.2	98.3	$17	($12)
Crist 5	0.3%	96.9	97.8	95.5	$20	($45)
Crist 6	2.1%	72.9	75.1	69.5	$132	($214)
Crist 7	7.3%	70.9	73.1	67.5	$465	($735)
Smith 1	0.5%	90.0	90.5	89.2	$34	($71)
Smith 2	3.6%	72.2	74.6	68.5	$231	($317)
Daniel 1	3.5%	79.0	80.1	77.3	$222	($305)
Daniel 2	2.8%	88.2	89.2	86.5	$178	($239)

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Min BTU/KWH	ANOHR Range Max BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Crist 4	4.5%	10,610	84.4	10,292	10,928	$289	($289)
Crist 5	4.3%	10,548	82.5	10,232	10,864	$276	($276)
Crist 6	11.2%	10,416	82.4	10,104	10,728	$710	($710)
Crist 7	19.0%	10,340	84.2	10,030	10,650	$1,206	($1,206)
Smith 1	6.5%	10,273	83.1	9,965	10,581	$414	($414)
Smith 2	5.9%	10,213	82.1	9,907	10,519	$375	($375)
Daniel 1	13.2%	9,953	98.7	9,654	10,252	$841	($841)
Daniel 2	14.9%	9,742	99.1	9,450	10,034	$950	($950)

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2005 - December 2005

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Target			Actual Performance 1st Prior Period Jul '03 - Jun '04			Actual Performance 2nd Prior Period Jul '02 - Jun '03		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 4	0.3%	1.3%	0.0000	0.0115	0.0115	0.0598	0.0176	0.0187	0.0581	0.0030	0.0032
Crist 5	0.3%	1.5%	0.0000	0.0311	0.0311	0.0571	0.0239	0.0254	0.0598	0.0061	0.0065
Crist 6	2.1%	10.2%	0.1974	0.0741	0.0924	0.0650	0.1112	0.1191	0.0589	0.0399	0.0424
Crist 7	7.3%	35.8%	0.2163	0.0751	0.0960	0.2192	0.0472	0.0604	0.1199	0.0136	0.0155
Smith 1	0.5%	2.6%	0.0823	0.0178	0.0194	0.0798	0.0512	0.0557	0.1019	0.0070	0.0078
Smith 2	3.6%	17.8%	0.1971	0.0812	0.1011	0.0388	0.0252	0.0262	0.3159	0.1825	0.2668
Daniel 1	3.5%	17.1%	0.1727	0.0376	0.0454	0.0870	0.0407	0.0446	0.2250	0.0222	0.0287
Daniel 2	2.8%	13.7%	0.0822	0.0362	0.0394	0.1328	0.0212	0.0245	0.0526	0.0391	0.0413
Weighted GPIF System Average			0.1755	0.0613	0.0760	0.1288	0.0445	0.0515	0.1551	0.0508	0.0682

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2005 - December 2005

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Actual Performance 3rd Prior Period Jul '01 - Jun '02			Actual Performance 4th Prior Period Jul '00 - Jun '01			Actual Performance 5th Prior Period Jul '99 - Jun '00		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 4	0.3%	1.3%	0.1009	0.0032	0.0048	0.1868	0.0003	0.0004	0.0974	0.0266	0.0304
Crist 5	0.3%	1.5%	0.1123	0.0024	0.0037	0.0372	0.0106	0.0121	0.2874	0.0745	0.1076
Crist 6	2.1%	10.2%	0.1562	0.0356	0.0423	0.1102	0.1580	0.1795	0.0988	0.0708	0.0786
Crist 7	7.3%	35.8%	0.1454	0.1952	0.2284	0.1224	0.0808	0.0920	0.1589	0.0703	0.0835
Smith 1	0.5%	2.6%	0.1105	0.0128	0.0145	0.0759	0.0044	0.0048	0.0589	0.0132	0.0140
Smith 2	3.6%	17.8%	0.1490	0.1303	0.1610	0.0920	0.0216	0.0237	0.0590	0.0260	0.0276
Daniel 1	3.5%	17.1%	0.0224	0.0466	0.0479	0.1153	0.0318	0.0359	0.1396	0.0601	0.0698
Daniel 2	2.8%	13.7%	0.2329	0.0291	0.0393	0.1167	0.0374	0.0424	0.0396	0.0473	0.0493
Weighted GPIF System Average			0.1361	0.1090	0.1288	0.1121	0.0597	0.0677	0.1139	0.0556	0.0639

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Average Net Operating Heat Rate

Gulf Power Company

Period of: January 2005 - December 2005

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Heat Rate Target	1st Prior Period Heat Rate Jul '03 - Jun '04	2nd Prior Period Heat Rate Jul '02 - Jun '03	3rd Prior Period Heat Rate Jul '01 - Jun '02
Crist 4	4.5%	5.7%	10,610	10,550	10,688	10,507
Crist 5	4.3%	5.5%	10,548	10,475	10,768	10,329
Crist 6	11.2%	14.0%	10,416	26,769	10,314	10,349
Crist 7	19.0%	23.8%	10,340	10,401	10,356	9,202
Smith 1	6.5%	8.2%	10,273	10,338	10,340	10,257
Smith 2	5.9%	7.4%	10,213	10,229	11,069	12,859
Daniel 1	13.2%	16.6%	9,953	10,070	9,765	9,978
Daniel 2	14.9%	18.8%	9,742	9,640	9,671	9,776
Weighted GPIF System Average:			10,186	12,494	10,216	10,093

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Example Calculation of Prior Season

Average Net Operating Heat Rate

Adjusted to Target Basis

Crist 6 Jul '02 - Jun '03

	Jul Jan	Aug Feb	Sep Mar	Oct Apr	Nov May	Dec Jun
1. Target Heat Rate*	10509.0 10790.0	10521.0 10211.0	10317.0 10224.0	- 10280.0	10396.0 10376.0	10416.0 10339.0
2. Target Heat Rate at Actual Conditions**	10999.0 10696.0	11043.0 10162.0	10528.0 10149.0	10719.0 10380.0	10874.0 10391.0	10823.0 10418.0
3. Adjustments to Actual Heat Rate (1-2)	-490.0 94.0	-522.0 49.0	-211.0 75.0	0.0 -100.0	-478.0 -15.0	-407.0 -79.0
4. Actual Heat Rate for Prior Period	10890.0 10214.0	10808.0 10351.0	10700.0 10374.0	10721.0 9958.0	11096.0 10383.0	10686.0 10353.0
5. Adjusted actual Heat Rate (4+3)	10400.0 10308.0	10286.0 10400.0	10489.0 10449.0	10721.0 9858.0	10618.0 10368.0	10279.0 10274.0
6. Forecast Net MWH Generation*	186288.5 179724.3	187833.1 174932.0	51704.1 123533.1	0.0 141431.4	54179.3 170126.8	149507.0 169165.6

7. Adjusted Actual Heat Rate for Jul '02 - Jun '03 = (Σ ((5) * (6)))/(Σ (6)) 10,314

* For the January 2005 - December 2005 time period.

** Based on the target heat rate equation from page 2 of Schedule 1 using actual rather than forecast variable values.

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Derivation of Weighting Factors

Gulf Power Company

Period of: January 2005 - December 2005

Plant & Unit	Unit Performance Indicator	Production Cost Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Crist 4	EA-1	$340,802	$340,785	$17	0.3%
Crist 4	ANOHR-1	$340,802	$340,513	$289	4.5%
Crist 5	EA-1	$340,802	$340,782	$20	0.3%
Crist 5	ANOHR-1	$340,802	$340,526	$276	4.3%
Crist 6	EA-1	$340,802	$340,670	$132	2.1%
Crist 6	ANOHR-1	$340,802	$340,092	$710	11.2%
Crist 7	EA-2	$340,802	$340,337	$465	7.3%
Crist 7	ANOHR-2	$340,802	$339,596	$1,206	19.0%
Smith 1	EA-3	$340,802	$340,768	$34	0.5%
Smith 1	ANOHR-3	$340,802	$340,388	$414	6.5%
Smith 2	EA-4	$340,802	$340,571	$231	3.6%
Smith 2	ANOHR-4	$340,802	$340,427	$375	5.9%
Daniel 1	EA-5	$340,802	$340,580	$222	3.5%
Daniel 1	ANOHR-5	$340,802	$339,961	$841	13.2%
Daniel 2	EA-6	$340,802	$340,624	$178	2.8%
Daniel 2	ANOHR-6	$340,802	$339,852	$950	14.9%

(1) Fuel Adjustment Base Case - All unit performance indicators at target.

(2) All other unit performance indicators at target.

(3) Expressed in replacement energy costs. Also includes variable operating and maintenance expense savings associated with availability improvements.

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2005 - December 2005

Crist 4

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	17	99.20	+ 10	289	10,292
+ 9	15	99.16	+ 9	260	10,316
+ 8	14	99.12	+ 8	231	10,341
+ 7	12	99.08	+ 7	202	10,365
+ 6	10	99.04	+ 6	173	10,389
+ 5	9	99.00	+ 5	145	10,414
+ 4	7	98.96	+ 4	116	10,438
+ 3	5	98.92	+ 3	87	10,462
+ 2	3	98.88	+ 2	58	10,486
+ 1	2	98.84	+ 1	29	10,511
				0	10,535
0	0	98.80	0	0	10,610
				0	10,685
- 1	(1)	98.75	- 1	(29)	10,709
- 2	(2)	98.70	- 2	(58)	10,734
- 3	(4)	98.65	- 3	(87)	10,758
- 4	(5)	98.60	- 4	(116)	10,782
- 5	(6)	98.55	- 5	(145)	10,807
- 6	(7)	98.50	- 6	(173)	10,831
- 7	(8)	98.45	- 7	(202)	10,855
- 8	(10)	98.40	- 8	(231)	10,879
- 9	(11)	98.35	- 9	(260)	10,904
- 10	(12)	98.30	- 10	(289)	10,928
Weighting Factor:		0.003	Weighting Factor:		0.045

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2005 - December 2005

Crist 5

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	20	97.80	+ 10	276	10,232
+ 9	18	97.71	+ 9	248	10,256
+ 8	16	97.62	+ 8	221	10,280
+ 7	14	97.53	+ 7	193	10,304
+ 6	12	97.44	+ 6	166	10,328
+ 5	10	97.35	+ 5	138	10,353
+ 4	8	97.26	+ 4	110	10,377
+ 3	6	97.17	+ 3	83	10,401
+ 2	4	97.08	+ 2	55	10,425
+ 1	2	96.99	+ 1	28	10,449
				0	10,473
0	0	96.90	0	0	10,548
				0	10,623
- 1	(5)	96.76	- 1	(28)	10,647
- 2	(9)	96.62	- 2	(55)	10,671
- 3	(14)	96.48	- 3	(83)	10,695
- 4	(18)	96.34	- 4	(110)	10,719
- 5	(23)	96.20	- 5	(138)	10,744
- 6	(27)	96.06	- 6	(166)	10,768
- 7	(32)	95.92	- 7	(193)	10,792
- 8	(36)	95.78	- 8	(221)	10,816
- 9	(41)	95.64	- 9	(248)	10,840
- 10	(45)	95.50	- 10	(276)	10,864
Weighting Factor:		0.003	Weighting Factor:		0.043

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2005 - December 2005

Crist 6

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	132	75.10	• 10	710	10,104
+ 9	119	74.88	+ 9	639	10,128
+ 8	106	74.66	+ 8	568	10,151
+ 7	92	74.44	+ 7	497	10,175
+ 6	79	74.22	+ 6	426	10,199
+ 5	66	74.00	+ 5	355	10,223
+ 4	53	73.78	+ 4	284	10,246
+ 3	40	73.56	+ 3	213	10,270
+ 2	26	73.34	+ 2	142	10,294
+ 1	13	73.12	+ 1	71	10,317
				0	10,341
0	0	72.90	0	0	10,416
				0	10,491
- 1	(21)	72.56	- 1	(71)	10,515
- 2	(43)	72.22	- 2	(142)	10,538
- 3	(64)	71.88	- 3	(213)	10,562
- 4	(86)	71.54	- 4	(284)	10,586
- 5	(107)	71.20	- 5	(355)	10,610
- 6	(128)	70.86	- 6	(426)	10,633
- 7	(150)	70.52	- 7	(497)	10,657
- 8	(171)	70.18	- 8	(568)	10,681
- 9	(193)	69.84	- 9	(639)	10,704
- 10	(214)	69.50	- 10	(710)	10,728
Weighting Factor:		0.021	Weighting Factor:		0.112

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2005 - December 2005

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	465	73.10	+ 10	1,206	10,030
+ 9	419	72.88	+ 9	1,085	10,054
+ 8	372	72.66	+ 8	965	10,077
+ 7	326	72.44	+ 7	844	10,101
+ 6	279	72.22	+ 6	724	10,124
+ 5	233	72.00	+ 5	603	10,148
+ 4	186	71.78	+ 4	482	10,171
+ 3	140	71.56	+ 3	362	10,195
+ 2	93	71.34	+ 2	241	10,218
+ 1	47	71.12	+ 1	121	10,242
				0	10,265
0	0	70.90	0	0	10,340
				0	10,415
- 1	(74)	70.56	- 1	(121)	10,439
- 2	(147)	70.22	- 2	(241)	10,462
- 3	(221)	69.88	- 3	(362)	10,486
- 4	(294)	69.54	- 4	(482)	10,509
- 5	(368)	69.20	- 5	(603)	10,533
- 6	(441)	68.86	- 6	(724)	10,556
- 7	(515)	68.52	- 7	(844)	10,580
- 8	(588)	68.18	- 8	(965)	10,603
- 9	(662)	67.84	- 9	(1,085)	10,627
- 10	(735)	67.50	- 10	(1,206)	10,650
Weighting Factor:		0.073	Weighting Factor:		0.190

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2005 - December 2005

Smith 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	34	90.50	+ 10	414	9,965
+ 9	31	90.45	+ 9	373	9,988
+ 8	27	90.40	+ 8	331	10,012
+ 7	24	90.35	+ 7	290	10,035
+ 6	20	90.30	+ 6	248	10,058
+ 5	17	90.25	+ 5	207	10,082
+ 4	14	90.20	+ 4	166	10,105
+ 3	10	90.15	+ 3	124	10,128
+ 2	7	90.10	+ 2	83	10,151
+ 1	3	90.05	+ 1	41	10,175
				0	10,198
0	0	90.00	0	0	10,273
				0	10,348
- 1	(7)	89.92	- 1	(41)	10,371
- 2	(14)	89.84	- 2	(83)	10,395
- 3	(21)	89.76	- 3	(124)	10,418
- 4	(28)	89.68	- 4	(166)	10,441
- 5	(36)	89.60	- 5	(207)	10,465
- 6	(43)	89.52	- 6	(248)	10,488
- 7	(50)	89.44	- 7	(290)	10,511
- 8	(57)	89.36	- 8	(331)	10,534
- 9	(64)	89.28	- 9	(373)	10,558
- 10	(71)	89.20	- 10	(414)	10,581
Weighting Factor:		0.005	Weighting Factor:		0.065

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2005 - December 2005

Smith 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	231	74.60	+ 10	375	9,907
+ 9	208	74.36	+ 9	338	9,930
+ 8	185	74.12	+ 8	300	9,953
+ 7	162	73.88	+ 7	263	9,976
+ 6	139	73.64	+ 6	225	9,999
+ 5	116	73.40	+ 5	188	10,023
+ 4	92	73.16	+ 4	150	10,046
+ 3	69	72.92	+ 3	113	10,069
+ 2	46	72.68	+ 2	75	10,092
+ 1	23	72.44	+ 1	38	10,115
				0	10,138
0	0	72.20	0	0	10,213
				0	10,288
- 1	(32)	71.83	- 1	(38)	10,311
- 2	(63)	71.46	- 2	(75)	10,334
- 3	(95)	71.09	- 3	(113)	10,357
- 4	(127)	70.72	- 4	(150)	10,380
- 5	(159)	70.35	- 5	(188)	10,404
- 6	(190)	69.98	- 6	(225)	10,427
- 7	(222)	69.61	- 7	(263)	10,450
- 8	(254)	69.24	- 8	(300)	10,473
- 9	(285)	68.87	- 9	(338)	10,496
- 10	(317)	68.50	- 10	(375)	10,519
Weighting Factor:		0.036	Weighting Factor:		0.059

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2005 - December 2005

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	222	80.10	+ 10	841	9,654
+ 9	200	79.99	+ 9	757	9,676
+ 8	178	79.88	+ 8	673	9,699
+ 7	155	79.77	+ 7	589	9,721
+ 6	133	79.66	+ 6	505	9,744
+ 5	111	79.55	+ 5	421	9,766
+ 4	89	79.44	+ 4	336	9,788
+ 3	67	79.33	+ 3	252	9,811
+ 2	44	79.22	+ 2	168	9,833
+ 1	22	79.11	+ 1	84	9,856
				0	9,878
0	0	79.00	0	0	9,953
				0	10,028
- 1	(31)	78.83	- 1	(84)	10,050
- 2	(61)	78.66	- 2	(168)	10,073
- 3	(92)	78.49	- 3	(252)	10,095
- 4	(122)	78.32	- 4	(336)	10,118
- 5	(153)	78.15	- 5	(421)	10,140
- 6	(183)	77.98	- 6	(505)	10,162
- 7	(214)	77.81	- 7	(589)	10,185
- 8	(244)	77.64	- 8	(673)	10,207
- 9	(275)	77.47	- 9	(757)	10,230
- 10	(305)	77.30	- 10	(841)	10,252
Weighting Factor:		0.035	Weighting Factor:		0.132

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2005 - December 2005

Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	178	89.20	+ 10	950	9,450
+ 9	160	89.10	+ 9	855	9,472
+ 8	142	89.00	+ 8	760	9,493
+ 7	125	88.90	+ 7	665	9,515
+ 6	107	88.80	+ 6	570	9,537
+ 5	89	88.70	+ 5	475	9,559
+ 4	71	88.60	+ 4	380	9,580
+ 3	53	88.50	+ 3	285	9,602
+ 2	36	88.40	+ 2	190	9,624
+ 1	18	88.30	+ 1	95	9,645
				0	9,667
0	0	88.20	0	0	9,742
				0	9,817
- 1	(24)	88.03	- 1	(95)	9,839
- 2	(48)	87.86	- 2	(190)	9,860
- 3	(72)	87.69	- 3	(285)	9,882
- 4	(96)	87.52	- 4	(380)	9,904
- 5	(120)	87.35	- 5	(475)	9,926
- 6	(143)	87.18	- 6	(570)	9,947
- 7	(167)	87.01	- 7	(665)	9,969
- 8	(191)	86.84	- 8	(760)	9,991
- 9	(215)	86.67	- 9	(855)	10,012
- 10	(239)	86.50	- 10	(950)	10,034
Weighting Factor:		0.028	Weighting Factor:		0.149

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ESTIMATED UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	CRIST 4	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	
1.	EAF (%)	99.5	99.3	99.3	99.4	99.5	99.4	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	0.5	0.7	0.7	0.6	0.5	0.6	
4.	EUOR (%)	0.5	0.7	0.7	0.6	0.5	0.6	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	740.0	668.0	740.0	715.0	740.0	716.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	4.0	4.0	4.0	4.0	4.0	4.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	4.0	5.0	5.0	4.0	4.0	4.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	516219.0	485654.0	539999.0	504695.0	498647.0	490455.0	
13.	Net Gen (MWH)	47555.9	46354.3	50737.5	47234.0	46874.1	46286.8	
14.	ANOHR (Btu/KWH)	10855.0	10477.0	10643.0	10685.0	10638.0	10596.0	
15.	NOF %	82.4	89.0	87.9	84.7	81.2	82.9	
16.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	

19.	ANOHR Equation	10^6 / AKW * [604.51 + 16.03 * JAN + 10.26 * MAR + 8.72 * APR] - 7798 + 0.13404 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	CRIST 4	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	Total
1.	EAF (%)	99.5	99.5	99.4	99.2	99.3	93.0	98.8
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	EUOF (%)	0.5	0.5	0.6	0.8	0.7	7.0	1.2
4.	EUOR (%)	0.5	0.5	0.6	0.8	0.7	7.0	1.2
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	740.0	740.0	716.0	741.0	716.0	692.0	8664.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	4.0	4.0	4.0	4.0	4.0	52.0	96.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	FOH & EFOH	4.0	4.0	4.0	6.0	5.0	4.0	53.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	48.0	48.0
12.	Oper MBtu	524933.0	527779.0	497877.0	519592.0	496226.0	448845.0	6050921.0
13.	Net Gen (MWH)	49893.8	50221.6	47151.9	49283.1	46960.0	41749.1	570302.1
14.	ANOHR (Btu/KWH)	10521.0	10509.0	10559.0	10543.0	10567.0	10751.0	10610.0
15.	NOF %	86.4	87.0	84.4	85.3	84.1	77.3	84.4
16.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	78.0

19.	ANOHR Equation	10^6 / AKW * [604.51 + 16.03 * JAN + 10.26 * MAR + 8.72 * APR] - 7798 + 0.13404 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	CRIST 5	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	
1.	EAF (%)	89.0	87.9	98.3	98.6	98.5	98.6	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	11.0	12.1	1.7	1.4	1.5	1.4	
4.	EUOR (%)	11.0	12.1	1.7	1.4	1.5	1.4	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	662.0	591.0	733.0	709.0	733.0	710.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	82.0	81.0	11.0	10.0	11.0	10.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	10.0	9.0	13.0	10.0	11.0	10.0	
11.	MOH & EMOH	72.0	72.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	453266.0	435642.0	535928.0	502833.0	500895.0	495551.0	
13.	Net Gen (MWH)	42082.1	41320.5	50721.9	47170.1	46469.5	46274.3	
14.	ANOHR (Btu/KWH)	10771.0	10543.0	10566.0	10660.0	10779.0	10709.0	
15.	NOF %	79.5	87.4	86.5	83.2	79.2	81.5	
16.	NPC (MW)	80.0	80.0	80.0	80.0	80.0	80.0	

19.	ANOHR Equation	10^6 / AKW * [160.95 - 14.39 * JUL - 17.85 * AUG - 13.91 * SEP - 18.50 * OCT - 35.97 * NOV] + 8,240

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GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	CRIST 5	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	Total
1.	EAF (%)	98.5	98.5	98.6	98.4	98.6	98.5	96.9
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	EUOF (%)	1.5	1.5	1.4	1.6	1.4	1.5	3.1
4.	EUOR (%)	1.5	1.5	1.4	1.6	1.4	1.5	3.1
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	733.0	733.0	710.0	734.0	710.0	733.0	8491.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	11.0	11.0	10.0	11.0	10.0	11.0	269.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	FOH & EFOH	11.0	11.0	10.0	12.0	10.0	11.0	128.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	144.0
12.	Oper MBtu	519111.0	518932.0	494386.0	511265.0	474094.0	472296.0	5914199.0
13.	Net Gen (MWH)	49967.4	50240.3	47336.8	49349.9	46768.7	42986.8	560688.3
14.	ANOHR (Btu/KWH)	10389.0	10329.0	10444.0	10360.0	10137.0	10987.0	10548.0
15.	NOF %	85.2	85.7	83.3	84.0	82.3	73.3	82.5
16.	NPC (MW)	80.0	80.0	80.0	80.0	80.0	80.0	80.0

19.	ANOHR Equation	10^6 / AKW * [160.95 - 14.39 * JUL - 17.85 * AUG - 13.91 * SEP - 18.50 * OCT - 35.97 * NOV] + 8,240

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GULF POWER COMPANY

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	CRIST 6	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	
1.	EAF (%)	97.4	97.5	62.6	78.0	97.4	97.5	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	2.6	2.5	37.4	22.0	2.6	2.5	
4.	EUOR (%)	2.6	2.5	37.4	22.0	2.6	2.5	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	725.0	655.0	468.0	561.0	725.0	702.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	19.0	17.0	276.0	158.0	19.0	18.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	19.0	17.0	14.0	14.0	19.0	18.0	
11.	MOH & EMOH	0.0	0.0	264.0	144.0	0.0	0.0	
12.	Oper MBtu	1939225.0	1786231.0	1263002.0	1453915.0	1765236.0	1749003.0	
13.	Net Gen (MWH)	179724.3	174932.0	123533.1	141431.4	170126.8	169165.6	
14.	ANOHR (Btu/KWH)	10790.0	10211.0	10224.0	10280.0	10376.0	10339.0	
15.	NOF %	82.1	88.4	87.4	83.5	77.7	79.8	
16.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	

19.	ANOHR Equation	10^6 / AKW * [1533.78 + 120.92 * JAN + 64.73 * JUL + 71.04 * AUG + 66.84 * OCT] - 3884 + 0.02998 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	CRIST 6	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	Total
1.	EAF (%)	97.4	97.4	29.3	0.0	32.2	88.0	72.9
2.	POF (%)	0.0	0.0	70.0	100.0	66.7	0.0	19.7
3.	EUOF (%)	2.6	2.6	0.7	0.0	1.1	12.0	7.4
4.	EUOR (%)	2.6	2.6	2.3	0.0	3.3	12.0	9.2
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	725.0	725.0	211.0	0.0	234.0	655.0	6386.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	19.0	19.0	509.0	745.0	486.0	89.0	2374.0
9.	POH	0.0	0.0	504.0	745.0	480.0	0.0	1729.0
10.	FOH & EFOH	19.0	19.0	5.0	0.0	8.0	17.0	169.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	72.0	480.0
12.	Oper MBtu	1957706.0	1976192.0	533431.0	0.0	563248.0	1557265.0	16544454.0
13.	Net Gen (MWH)	186288.5	187833.1	51704.1	0.0	54179.3	149507.0	1588425.2
14.	ANOHR (Btu/KWH)	10509.0	10521.0	10317.0	-	10396.0	10416.0	10416.0
15.	NOF %	85.1	85.8	81.1	0.0	76.7	75.6	82.4
16.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	302.0

19.	ANOHR Equation	10^6 / AKW * [1533.78 + 120.92 * JAN + 64.73 * JUL + 71.04 * AUG + 66.84 * OCT] - 3884 + 0.02998 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	CRIST 7	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	
1.	EAF (%)	85.9	0.0	0.0	41.3	95.2	95.1	
2.	POF (%)	9.7	100.0	100.0	56.6	0.0	0.0	
3.	EUOF (%)	4.4	0.0	0.0	2.1	4.8	4.9	
4.	EUOR (%)	4.9	0.0	0.0	4.8	4.8	4.9	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	639.0	0.0	0.0	297.0	708.0	685.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	105.0	672.0	744.0	422.0	36.0	35.0	
9.	POH	72.0	672.0	744.0	407.0	0.0	0.0	
10.	FOH & EFOH	33.0	0.0	0.0	15.0	36.0	35.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	2714207.0	0.0	0.0	1208323.0	2828301.0	2787843.0	
13.	Net Gen (MWH)	266595.3	0.0	0.0	116678.5	272659.9	269200.8	
14.	ANOHR (Btu/KWH)	10181.0	-	-	10356.0	10373.0	10356.0	
15.	NOF %	87.5	0.0	0.0	82.4	80.7	82.4	
16.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	

19.	ANOHR Equation	10^6 / AKW * [1414.12 - 52.99 * JAN - 235.50 * MAR + 42.16 * JUL + 51.30 * SEP - 45.57 * OCT] + 2,568 + 0.00993 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	CRIST 7	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	Total
1.	EAF (%)	95.2	95.2	95.1	79.5	66.3	95.2	70.9
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	21.6
3.	EUOF (%)	4.8	4.8	4.9	20.5	33.7	4.8	7.5
4.	EUOR (%)	4.8	4.8	4.9	20.5	33.8	4.8	9.6
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	708.0	708.0	685.0	595.0	479.0	708.0	6212.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	36.0	36.0	35.0	150.0	241.0	36.0	2548.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1895.0
10.	FOH & EFOH	36.0	36.0	35.0	33.0	27.0	36.0	322.0
11.	MOH & EMOH	0.0	0.0	0.0	120.0	216.0	0.0	336.0
12.	Oper MBtu	3072650.0	3062575.0	2858596.0	2443978.0	1991085.0	2817620.0	25785178.0
13.	Net Gen (MWH)	295163.3	297222.0	272949.1	239043.2	192617.3	271525.5	2493654.9
14.	ANOHR (Btu/KWH)	10410.0	10304.0	10473.0	10224.0	10337.0	10377.0	10340.0
15.	NOF %	87.4	88.0	83.5	84.2	84.3	80.4	84.2
16.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	477.0

19.	ANOHR Equation	10^6 / AKW * [1414.12 - 52.99 * JAN - 235.50 * MAR + 42.16 * JUL + 51.30 * SEP - 45.57 * OCT] + 2,568 + 0.00993 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	SMITH 1	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	
1.	EAF (%)	98.4	98.5	98.7	98.7	98.7	98.8	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	1.6	1.5	1.3	1.3	1.3	1.2	
4.	EUOR (%)	1.6	1.5	1.3	1.3	1.3	1.3	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	734.0	663.0	734.0	710.0	734.0	711.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	10.0	9.0	10.0	9.0	10.0	9.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	12.0	10.0	10.0	9.0	10.0	9.0	
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	1015574.0	985494.0	1066465.0	980601.0	960544.0	945597.0	
13.	Net Gen (MWH)	99732.3	96052.0	103883.2	95370.6	93220.5	91832.3	
14.	ANOHR (Btu/KWH)	10183.0	10260.0	10266.0	10282.0	10304.0	10297.0	
15.	NOF %	83.9	89.4	87.4	82.9	78.4	79.7	
16.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	

19.	ANOHR Equation	10^6 / AKW * [334.98 - 12.87 * JAN] + 4,856 + 0.02059 * LSRF / AKW

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PERIOD OF: January 2005 - December 2005

	SMITH 1	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	Total
1.	EAF (%)	98.7	98.7	98.8	66.7	26.4	98.7	90.0
2.	POF (%)	0.0	0.0	0.0	32.3	66.7	0.0	8.2
3.	EUOF (%)	1.3	1.3	1.2	1.0	6.9	1.3	1.8
4.	EUOR (%)	1.3	1.3	1.3	1.4	20.8	1.3	1.9
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	734.0	734.0	711.0	497.0	190.0	734.0	7886.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	10.0	10.0	9.0	248.0	530.0	10.0	874.0
9.	POH	0.0	0.0	0.0	241.0	480.0	0.0	721.0
10.	FOH & EFOH	10.0	10.0	9.0	7.0	2.0	10.0	108.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	48.0	0.0	48.0
12.	Oper MBtu	1040142.0	1051331.0	966345.0	684928.0	263304.0	943332.0	10903657.0
13.	Net Gen (MWH)	101250.1	102379.1	93929.3	66614.3	25613.2	91470.2	1061347.1
14.	ANOHR (Btu/KWH)	10273.0	10269.0	10288.0	10282.0	10280.0	10313.0	10273.0
15.	NOF %	85.1	86.1	81.5	82.7	83.2	76.9	83.1
16.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0

19.	ANOHR Equation	10^6 / AKW * [334.98 - 12.87 * JAN] + 4,856 + 0.02059 * LSRF / AKW

Issued by: S. N. Story

Filed: September 09, 2004
Suspended:
Effective: January 1, 2005
Docket No.: 040001-EI
Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	SMITH 2	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	
1.	EAF (%)	67.1	60.4	0.0	0.0	91.4	94.4	
2.	POF (%)	0.0	35.7	100.0	100.0	3.2	0.0	
3.	EUOF (%)	32.9	3.9	0.0	0.0	5.4	5.6	
4.	EUOR (%)	32.9	6.0	0.0	0.0	5.6	5.6	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	499.0	408.0	0.0	0.0	680.0	680.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	245.0	264.0	744.0	719.0	64.0	40.0	
9.	POH	0.0	240.0	744.0	719.0	24.0	0.0	
10.	POH & EFOH	29.0	26.0	0.0	0.0	40.0	40.0	
11.	MOH & EMOH	216.0	0.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	800407.0	683786.0	0.0	0.0	1025476.0	1056329.0	
13.	Net Gen (MWH)	80775.8	68024.9	0.0	0.0	98965.1	101628.7	
14.	ANOHR (Btu/KWH)	9909.0	10052.0	-	-	10362.0	10394.0	
15.	NOF %	85.6	88.2	0.0	0.0	77.0	79.1	
16.	NPC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	

19.	ANOHR Equation	10^6 / AKW * [-318.85 - 47.20 * JAN - 23.05 * FEB - 61.42 * MAR + 62.94 * APR + 16.98 * MAY + 24.15 * JUN] + 15,607 - 0.02010 * LSRF / AKW

Issued by: S. N. Story

Filed: September 09, 2004
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Docket No.: 040001-EI
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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	SMITH 2	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	Total
1.	EAF (%)	94.5	94.5	94.4	88.3	94.2	85.3	72.2
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	19.7
3.	EUOF (%)	5.5	5.5	5.6	11.7	5.8	14.7	8.1
4.	EUOR (%)	5.5	5.5	5.6	11.7	5.8	14.7	10.1
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	703.0	703.0	680.0	658.0	680.0	635.0	6326.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	41.0	41.0	40.0	87.0	40.0	109.0	2434.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1727.0
10.	FOH & EFOH	41.0	41.0	40.0	39.0	42.0	37.0	375.0
11.	MOH & EMOH	0.0	0.0	0.0	48.0	0.0	72.0	336.0
12.	Oper MBtu	1150979.0	1162641.0	1070030.0	1047696.0	1075474.0	947804.0	10020622.0
13.	Net Gen (MWH)	112796.8	113984.4	104699.6	102564.5	105252.9	92513.8	981206.5
14.	ANOHR (Btu/KWH)	10204.0	10200.0	10220.0	10215.0	10218.0	10245.0	10213.0
15.	NOF %	84.9	85.8	81.5	82.5	81.9	77.1	82.1
16.	NPC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	189.0

19.	ANOHR Equation	10^6 / AKW * [-318.85 - 47.20 * JAN - 23.05 * FEB - 61.42 * MAR + 62.94 * APR + 16.98 * MAY + 24.15 * JUN] + 15,607 - 0.02010 * LSRF / AKW

Issued by: S. N. Story

Filed: September 09, 2004
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Order No.:

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	DANIEL 1	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	
1.	EAF (%)	96.9	79.5	96.9	97.1	97.2	97.1	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	3.1	20.5	3.1	2.9	2.8	2.9	
4.	EUOR (%)	3.1	20.5	3.1	2.9	2.8	2.9	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	723.0	536.0	723.0	698.0	723.0	699.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	21.0	136.0	21.0	21.0	21.0	21.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	23.0	18.0	23.0	21.0	21.0	21.0	
11.	MOH & EMOH	0.0	120.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	3740398.0	2716392.0	3681146.0	3525840.0	3479527.0	3515333.0	
13.	Net Gen (MWH)	370630.0	273499.0	370784.2	354890.8	348824.8	353726.4	
14.	ANOHR (Btu/KWH)	10092.0	9932.0	9928.0	9935.0	9975.0	9938.0	
15.	NOF %	99.7	99.3	99.8	98.9	93.9	98.5	
16.	NPC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	

19.	ANOHR Equation	10^6 / AKW * [382.13 + 83.86 * JAN - 72.84 * OCT] + 9,183

Issued by: S. N. Story

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Docket No.: 040001-EI
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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	DANIEL 1	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	Total
1.	EAF (%)	97.2	97.2	74.4	0.0	16.3	97.2	79.0
2.	POF (%)	0.0	0.0	23.3	100.0	83.3	0.0	17.3
3.	EUOF (%)	2.8	2.8	2.3	0.0	0.4	2.8	3.7
4.	EUOR (%)	2.8	2.8	2.9	0.0	2.5	2.8	4.5
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	723.0	723.0	536.0	0.0	117.0	723.0	6924.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	21.0	21.0	184.0	745.0	603.0	21.0	1836.0
9.	POH	0.0	0.0	168.0	745.0	600.0	0.0	1513.0
10.	FOH & EFOH	21.0	21.0	16.0	0.0	3.0	21.0	209.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	120.0
12.	Oper MBtu	3680417.0	3678337.0	2714966.0	0.0	572843.0	3674340.0	34979539.0
13.	Net Gen (MWH)	370710.8	370464.0	273355.4	0.0	57514.4	370024.2	3514424.0
14.	ANOHR (Btu/KWH)	9928.0	9929.0	9932.0	-	9960.0	9930.0	9953.0
15.	NOF %	99.8	99.7	99.2	0.0	95.6	99.6	98.7
16.	NPC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	514.0
19.	ANOHR Equation	10^6 / AKW * [382.13 + 83.86 * JAN - 72.84 * OCT] + 9,183						

Issued by: S. N. Story

Filed: September 09, 2004
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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	DANIEL 2	Jan '05	Feb '05	Mar '05	Apr '05	May '05	Jun '05	
1.	EAF (%)	97.3	90.3	12.5	87.5	97.3	97.2	
2.	POF (%)	0.0	0.0	87.1	10.0	0.0	0.0	
3.	EUOF (%)	2.7	9.7	0.4	2.5	2.7	2.8	
4.	EUOR (%)	2.7	9.7	3.1	2.8	2.7	2.8	
5.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
6.	SH	724.0	607.0	93.0	629.0	724.0	700.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	20.0	65.0	651.0	90.0	20.0	20.0	
9.	POH	0.0	0.0	648.0	72.0	0.0	0.0	
10.	FOH & EFOH	20.0	17.0	3.0	18.0	20.0	20.0	
11.	MOH & EMOH	0.0	48.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	3516213.0	2966433.0	457762.0	3166515.0	3472108.0	3485778.0	
13.	Net Gen (MWH)	371261.0	310784.0	47535.0	320044.0	353827.4	356382.6	
14.	ANOHR (Btu/KWH)	9471.0	9545.0	9630.0	9894.0	9813.0	9781.0	
15.	NOF %	99.8	99.6	99.4	99.0	95.1	99.1	
16.	NPC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	

19.	ANOHR Equation	10^6 / AKW * [1305.50 - 156.38 * JAN - 119.09 * FEB - 75.83 * MAR + 57.36 * APR] + 3,696 + 0.00694 * LSRF / AKW

Issued by: S. N. Story

Filed: September 09, 2004
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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2005 - December 2005

	DANIEL 2	Jul '05	Aug '05	Sep '05	Oct '05	Nov '05	Dec '05	Total
1.	EAF (%)	97.3	97.3	97.2	91.0	96.9	97.0	88.2
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	8.2
3.	EUOF (%)	2.7	2.7	2.8	9.0	3.1	3.0	3.6
4.	EUOR (%)	2.7	2.7	2.8	9.0	3.1	3.0	3.9
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
6.	SH	724.0	724.0	700.0	678.0	700.0	724.0	7727.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	20.0	20.0	20.0	67.0	20.0	20.0	1033.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	720.0
10.	FOH & EFOH	20.0	20.0	20.0	19.0	22.0	22.0	221.0
11.	MOH & EMOH	0.0	0.0	0.0	48.0	0.0	0.0	96.0
12.	Oper MBtu	3630269.0	3628782.0	3503422.0	3383866.0	3492833.0	3628587.0	38332568.0
13.	Net Gen (MWH)	371345.0	371155.0	358333.0	345998.6	357140.4	371135.0	3934941.0
14.	ANOHR (Btu/KWH)	9776.0	9777.0	9777.0	9780.0	9780.0	9777.0	9742.0
15.	NOF %	99.8	99.7	99.6	99.3	99.3	99.7	99.1
16.	NPC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	514.0

19.	ANOHR Equation	10^6 / AKW * [1305.50 - 156.38 * JAN - 119.09 * FEB - 75.83 * MAR + 57.36 * APR] + 3,696 + 0.00694 * LSRF / AKW

Issued by: S. N. Story

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Order No.:

Planned Outage Schedules (Estimated)

Gulf Power Company

Period of: January 2005 - December 2005

Plant & Unit	Planned Outage Dates			Reason for Outage
Crist 6	09/10/05	-	11/20/05	SNCR installation and general boiler maintenance and inspection.
Crist 7	01/29/05	-	04/17/05	SCR tie-in and general boiler maintenance and inspection.
Smith 1	10/22/05	-	11/20/05	General boiler maintenance and inspection.
Smith 2	02/19/05	-	05/01/05	Major turbine outage and boiler inspection.
Daniel 1	09/24/05	-	11/25/05	General boiler maintenance and inspection.
Daniel 2	03/05/05	-	04/03/05	General boiler maintenance and inspection.

Notes Regarding Estimated Planned Outage Schedules

Gulf Power Company

Period of: January 2005 - December 2005

It is important to understand that estimated dates for planned outages and their bar chart schedules are frequently changed in timing and work scope due to system conditions, findings of inspections, subcontractor requirements, material availability and so on.

Please note that in addition to the outages scheduled for the target period of January 2005 - December 2005, the outages shown below are currently planned and could be rescheduled for the target period.

Plant & Unit	Planned Outage Dates	Reason for Outage

None

Filed: September 09, 2004
Suspended:
Effective: January 1, 2005
Docket No.: 040001-EI
Order No.:

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 040001-EI

Before me, the undersigned authority, personally appeared Lonzelle S. Noack, who being first duly sworn, deposes, and says that she is the Power Generation Specialist, Senior for Gulf Power Company, a Maine corporation, and that the foregoing is true and correct to the best of her knowledge, information, and belief. She is personally known to me.

Lonzelle S. Noack
Power Generation Specialist, Senior

Sworn to and subscribed before me this 7th day of September, 2004.

Linda C. Webb
Notary Public, State of Florida at Large

Commission Number: 110088

Commission Expires: May 31, 2006

LINDA C. WEBB
Notary Public-State of FL
Comm. Exp: May 31, 2006
Comm. No: DD 110088

GULF POWER COMPANY
PROJECTED PURCHASED POWER CONTRACT TRANSACTIONS
JANUARY 2005 - DECEMBER 2005

Contract		MW Purchase/(Sale)	Capacity ($) Costs/(Receipts)
Southern Company Intercompany Interchange (IIC)			
	January 2005	499.4	1,429,933
	February	437.5	507,409
	March	617.8	683,986
	April	132.4	71,941
	May	222.4	256,650
	June	383.0	2,419,583
	July	473.6	8,243,250
	August	393.7	6,754,806
	September	370.2	2,981,301
	October	491.5	279,189
	November	154.2	85,852
	December	788.3	151,825
	SUBTOTAL		23,865,725
Solutia			
	January 2005	19.0	62,202
	February	19.0	62,202
	March	19.0	62,202
	April	19.0	62,202
	May	19.0	62,202
	June	0.0	0
	July	0.0	0
	August	0.0	0
	September	0.0	0
	October	0.0	0
	November	0.0	0
	December	0.0	0
	SUBTOTAL		311,010

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 30
COMPANY/ Gulf
WITNESS: H. Homer Bell, III (HHB-1)
DATE: 11-08-04

GULF POWER COMPANY
PROJECTED PURCHASED POWER CONTRACT TRANSACTIONS
JANUARY 2005 - DECEMBER 2005

Contract		Capacity ($) Costs/(Receipts)
Market-Based Service Agreements		
	January 2005	(5,565)
	February	(5,565)
	March	(5,565)
	April	(5,565)
	May	(5,565)
	June	(5,565)
	July	(5,565)
	August	(5,565)
	September	(5,565)
	October	(5,565)
	November	(5,565)
	December	(5,565)
	SUBTOTAL	(66,780)
	TOTAL	**24,109,955**

PROGRESS ENERGY FLORIDA
EXHIBITS TO THE TESTIMONY OF
JAVIER PORTUONDO

Final True-Up Amount
January through December 2003

VARIANCE ANALYSIS (JP-1T)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO 31
COMPANY/ PEF
WITNESS: Javier Portuondo (JP-1T)
DATE 11-08-04

Progress Energy Florida, Inc.
Docket No. 040001-EI
Witness: Portuondo
Exhibit No. (JP-1T)
Sheet 1 of 4

PROGRESS ENERGY FLORIDA, INC.
Fuel Adjustment Clause
Summary of Final True-Up Amount
January through December 2003

Line No.	Description	Contribution to Over/(Under) Recovery Period to Date
	KWH Sales:	
1	Jurisdictional KWH Sales	90,937,565
2	Non-Jurisdictional KWH Sales	(114,057,278)
3	Total System KWH Sales Decrease Schedule A2, pg 2 of 4, Line C3	(23,119,713)
	System:	
4	Fuel and Net Purchased Power Costs - Difference Schedule A2, page 3 of 4, Line D4	$ 163,081,882
	Jurisdictional:	
5	Fuel Revenues - Difference Schedule A2, page 3 of 4, Line D3	$ (10,974,863)
6	Fuel and Net Purchased Power Costs - Difference Schedule A2, page 3 of 4, Line D6	161,821,669
7	True Up Amount for the Period Schedule A2, page 3 of 4, Line D7	(172,796,532)
8	True Up for the Prior Period - Actual Schedule A2, page 3 of 4, Lines D7 through D10	(37,777,646)
9	Interest Provision Schedule A2, page 3 of 4, Line D8	(653,510)
10	Actual True Up ending balance for the period January 2003 through December 2003	(211,227,688)
11	Estimated True Up ending balance for the period included in the Mid-Course Correction, filed February 18, 2003, Docket No. 030001-EI.	(37,777,646)
12	Final True Up for the period January 2003 through December 2003 (Line 12 - Line 13)	$ (173,450,042)

Progress Energy Florida, Inc.
Docket No. 040001-EI
Witness: Portuondo
Exhibit No. (JP-1T)
Sheet 2 of 4

FUEL AND NET POWER VARIANCE ANALYSIS
FOR THE PERIOD OF: JANUARY - DECEMBER 2003

	(A) ENERGY SOURCE	(B) MWH VARIANCES	(C) HEAT RATE VARIANCES	(D) PRICE VARIANCES	(E) TOTAL
1	Heavy Oil	$54,366,134	$12,697,887	($9,663,097)	$57,400,924
2	Light Oil	5,644,025	269,532	(1,360,891)	4,552,666
3	Coal	(14,348,247)	12,105,961	14,664,315	12,422,029
4	Gas	34,457,918	13,015,658	16,370,615	63,844,191
5	Nuclear	(252,793)	(621,358)	1,429,694	555,543
6	Other Fuel	0	0	0	0
7	Total Generation	79,867,037	37,467,680	21,440,636	138,775,353
8	Firm Purchases	9,770,968	0	4,592,653	14,363,621
9	Economy Purchases	(1,529,645)	0	18,405,475	16,875,830
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	(14,397,483)	0	29,380,132	14,982,649
12	Total Purchases	(6,156,160)	0	52,378,260	46,222,100
13	Economy Sales	0	0	(12,313)	(12,313)
14	Other Power Sales	5,286,881	0	93,000	5,379,881
15	Supplemental Sales	(44,243,061)	0	20,474,512	(23,768,549)
16	Total Sales	(38,956,180)	0	20,555,199	(18,400,981)
17	Nuclear Fuel Disposal Cost	0	0	18,853	18,853
18	Nuclear Decom & Decon	0	0	41,781	41,781
19	Other Jurisdictional Adjustments Sch A2 Page 1 of 4 Line 6b	0	0	(3,575,224)	(3,575,224)
20	Total Fuel and Net Power	$34,754,697	$37,467,680	$90,859,505	$163,081,882

GAS CONVERSION PROJECTS
SCHEDULE OF SYSTEM DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

		INTERCESSION CITY 7 & 9	INTERCESSION CITY 8 & 10	DEBARY 8	DEBARY 7 & 9	BARTOW 2 & 4	SUWANNEE 1 & 3	TOTAL
	PLANT INVESTMENT							
1	BEGINNING BALANCE	$ -	$ -	$ 1,230,945	$ -	$ -	$ 1,806,297	$ 3,037,242
2	PRIOR PERIOD ADJUSTMENT	-	-	-	-	-	-	-
3	ADD INVESTMENT	-	-	-	-	-	-	-
4	LESS RETIREMENTS	-	-	-	-	-	1,806,297	1,806,297
5	ENDING BALANCE	-	-	1,230,945	-	-	-	1,230,945
	ACCUMULATED DEPRECIATION							
6	BEG. BALANCE ACCUM. DEPRECIATION	-	-	834,874	-	-	1,623,745	2,458,619
7	PRIOR PERIOD ADJUSTMENT	-	-	-	-	-	-	-
8	DEPRECIATION EXPENSE	-	-	246,192	-	-	182,552	428,744
9	LESS RETIREMENTS	-	-	-	-	-	1,806,297	1,806,297
10	END. BALANCE ACCUM. DEPRECIATION	-	-	1,081,066	-	-	-	1,081,066
11	ENDING NET INVESTMENT (LINE 5 - 10)	$ -	$ -	$ 149,879	$ -	$ -	$ -	$ 149,879
12	TOTAL RETURN REQUIREMENTS	-	-	31,626	-	-	5,602	$ 37,228
13	TOTAL ACCUMULATED DEPRECIATION AND RETURN (LINE 8 + 12)	$ -	$ -	$ 277,818	$ -	$ -	$ 188,154	$ 465,972
14	ESTIMATED FUEL SAVINGS	-	-	382,026	-	-	(182,455)	199,571
15	TOTAL DEPRECIATION & RETURN (1)	-	-	277,818	-	-	188,154	465,972
16	NET BENEFIT (COST) TO RATEPAYER	$ -	$ -	$ 104,208	$ -	$ -	$ (370,609)	$ (266,401)

NOTES:
DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.
RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 8.37% (EQUITY 5.12%, DEBT 3.25%).
RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY INCOME TAX RATE OF 38.575%
(1) TOTAL AMOUNT DIFFERS FROM SCHEDULE A-2, PAGE 1 OF 4, LINE 6b BECAUSE A-2 EXCLUDES COST ASSIGNED TO SUPPLEMENTAL KWH SALES.

Progress Energy Florida, Inc.
Docket No. 040001-EI
Witness: Portuondo
Exhibit No. (JP-1T)
Sheet 4 of 4

HINES UNIT 2
SCHEDULE OF SYSTEM DEPRECIATION AND RETURN
FOR THE PERIOD OF JANUARY THROUGH DECEMBER 2003

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	BEGINNING BALANCE	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	ADD INVESTMENT	-	-	-	-	-	-	-	-	-	-	-	233,323,763	233,323,763
3	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	ENDING BALANCE	-	-	-	-	-	-	-	-	-	-	-	233,323,763	233,323,763
5	AVERAGE BALANCE	-	-	-	-	-	-	-	-	-	-	-	116,661,882	
6	DEPRECIATION RATE	0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	0.458333%	
7	DEPRECIATION EXPENSE	-	-	-	-	-	-	-	-	-	-	-	534,700	534,700
8	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
9	BEGINNING BALANCE DEPRECIATION	-	-	-	-	-	-	-	-	-	-	-	-	-
10	ENDING BALANCE DEPRECIATION	-	-	-	-	-	-	-	-	-	-	-	534,700	534,700
11	ENDING NET INVESTMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 232,789,063	$ 232,789,063
12	AVERAGE INVESTMENT	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 116,394,532	
13	ALLOWED EQUITY RETURN	.42667%	.42667%	.42667%	.42667%	.42667%	.42667%	.42667%	.42667%	.42667%	.42667%	.42667%	.42667%	
14	EQUITY COMPONENT AFTER-TAX	-	-	-	-	-	-	-	-	-	-	-	496,617	496,617
15	CONVERSION TO PRE-TAX	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	
16	EQUITY COMPONENT PRE-TAX	-	-	-	-	-	-	-	-	-	-	-	808,492	808,492
17	ALLOWED DEBT RETURN	.27083%	.27083%	.27083%	.27083%	.27083%	.27083%	.27083%	.27083%	.27083%	.27083%	.27083%	.27083%	
18	DEBT COMPONENT	-	-	-	-	-	-	-	-	-	-	-	315,235	315,235
19	TOTAL RETURN REQUIREMENTS	-	-	-	-	-	-	-	-	-	-	-	1,123,727	1,123,727
20	TOTAL DEPRECIATION & RETURN (1)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,658,427	$ 1,658,427
21	ESTIMATED FUEL SAVINGS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,156,930	1,156,930
22	TOTAL DEPRECIATION & RETURN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,658,427	$ 1,658,427
23	NET BENEFIT (COST) TO RATEPAYER	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (501,497)	$ (501,497)

DEPRECIATION EXPENSE IS CALCULATED BASED UPON AN ANNUAL RATE OF 5.5%.
RETURN ON AVERAGE INVESTMENT (THROUGH 12/31/03) IS CALCULATED USING AN ANNUAL RATE OF 8.37% (EQUITY 5.12%, DEBT 3.25%).
RETURN ON AVERAGE INVESTMENT (EFFECTIVE 1/1/04) IS CALCULATED USING AN ANNUAL RATE OF 9.18% (EQUITY 6.61%, DEBT 2.57%).
RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38.575%
(1) TOTAL AMOUNT DIFFERS FROM SCH. A2 PG 1 OF 4, LINE 6B BECAUSE SCH A2 EXCLUDES THE COST ASSIGNED TO STRATIFIED SALES.

PROGRESS ENERGY FLORIDA
EXHIBITS TO THE TESTIMONY OF
JAVIER PORTUONDO

Final True-Up Amount
January through December 2003

CAPACITY COST RECOVERY (JP-2T)

Progress Energy Florida, Inc.
Docket No. 040001-EI
Witness: Portuondo
Exhibit No. (JP-2T)
Sheet 1 of 3

PROGRESS ENERGY FLORIDA, INC.
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January through December 2003

Line No.	Description	Actual	Mid-Course Estimate	Variance
	Jurisdictional:			
1	Capacity Cost Recovery Revenues Sheet 2 of 3, Line 42	343,842,938	342,765,897	1,077,041
2	Capacity cost Recovery Expenses Sheet 2 of 3, Line 39	334,403,787	342,777,207	(8,373,420)
3	Plus/(Minus) Interest Provision Sheet 2 of 3, Line 44	(43,322)	(76,830)	33,508
4	Sub Total Current Period Over/(Under) Recovery	9,395,829	(88,140)	9,483,969
5	Prior Period True-up - January through December 2002 - Over/(Under) Recovery Sheet 2 of 3, Line 46	(4,408,138)	(4,408,138)	0
6	Prior Period True-up - January through December 2002 - (Refunded)/Collected (Midcourse Correction, filed February 18,2003) Sheet 2 of 3, Line 47	4,408,138	4,408,138	0
7	Actual True-up ending balance Over/(Under) recovery for the period January through December 2003 Sheet 2 of 3, Line 49	9,395,829	(88,140)	9,483,969

PROGRESS ENERGY FLORIDA, INC.
CAPACITY COST RECOVERY CLAUSE
TRUE-UP CALCULATION
FOR THE PERIOD JANUARY - DECEMBER 2003

		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	TOTAL
	Base Production Level Capacity Charges:													
1	Auburndale Power Partners, L.P. (AUBRDLFC)	419,050	497,250	445,740	445,740	445,740	445,740	445,740	445,740	445,740	445,740	445,740	445,740	5,373,700
2	Auburndale Power Partners, L.P. (AUBSET)	2,089,680	2,562,443	2,195,991	2,195,991	2,195,991	2,195,991	2,195,991	2,195,991	2,195,991	2,195,991	2,195,991	2,195,991	26,612,032
3	Bay County (BAYCOUNT)	206,910	267,300	219,890	219,890	219,890	219,890	219,890	219,890	219,890	219,890	219,890	219,890	2,673,110
4	Cargill Fertilizer, Inc. (CARGILLF)	432,750	537,000	454,950	454,950	454,950	454,950	454,950	454,950	454,950	454,950	454,950	454,950	5,519,250
5	Jefferson Power L.C. (JEFFPOWR)	54,298	55,677	59,883	54,680	89,743	52,335	42,893	0	17,000	17,000	17,000	17,000	477,509
6	Lake County (LAKCOUNT)	392,955	508,725	417,818	417,818	417,818	417,818	417,818	417,818	417,818	417,818	417,818	417,818	5,079,855
7	Lake Cogen Limited (LAKORDER)	2,174,703	2,425,765	2,263,142	2,300,521	2,305,627	2,305,627	2,305,627	2,305,627	2,305,627	2,305,627	2,305,627	2,305,627	27,609,143
8	Metro-Dade County (METRDADE)	775,309	944,077	823,326	806,820	831,675	852,690	852,690	852,690	852,690	852,690	834,070	797,841	10,076,568
9	Orange Cogen (ORANGECO)	1,873,899	2,307,184	1,966,690	1,966,690	1,966,690	1,966,690	1,966,690	1,966,690	1,966,690	1,966,690	1,966,690	1,966,690	23,847,984
10	Orlando Cogen Limited (ORLACOGL)	1,666,192	2,067,067	1,750,958	1,750,958	1,750,958	1,750,958	1,750,958	1,750,958	1,750,958	1,750,958	1,750,958	1,750,958	21,242,843
11	Pasco Cogen Limited (PASCCOGL)	2,827,455	2,685,623	2,950,375	2,950,375	2,950,375	2,950,375	2,950,375	2,950,375	2,950,375	2,950,375	2,950,375	2,950,375	35,016,828
12	Pasco County Resource Recovery (PASCOUNT)	708,860	917,930	753,710	753,710	753,710	753,710	753,710	753,710	753,710	753,710	753,710	753,710	9,163,890
13	Pinellas County Resource Recovery (PINCOUNT)	1,687,395	2,185,073	1,794,158	1,794,158	1,794,158	1,794,158	1,794,158	1,794,158	1,794,158	1,794,158	1,794,158	1,794,158	21,814,043
14	Polk Power Partners, L.P. (MULBERRY)	1,954,617	1,998,578	2,015,715	2,007,561	2,050,506	2,233,902	2,425,238	2,425,238	2,425,238	2,425,238	2,425,238	2,425,238	26,812,305
15	Polk Power Partners, L.P. (ROYSTER)	792,293	917,042	825,061	821,544	839,119	910,922	910,922	910,922	910,922	910,922	910,922	910,922	10,571,514
16	DG Telogia, LLC (TIMBER)	137,500	(63,336)	137,500	137,500	136,242	136,500	134,063	129,031	127,879	128,255	128,555	130,404	1,400,093
17	U.S Agri-Chemicals (AGRICHEM)	41,626	51,668	43,758	43,758	43,758	43,758	43,758	43,758	43,758	43,758	43,758	43,758	530,874
18	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	686,450	483,023	614,850	608,277	591,309	588,733	581,020	578,493	594,369	582,852	621,307	621,028	7,151,712
19	Tiger Bay Limited Partnnership (ECOPEAT)	1,213,028	1,213,028	1,213,028	1,213,028	1,213,028	1,213,028	1,213,028	1,213,028	1,213,028	0	0	0	10,917,252
20	Tiger Bay Limited Partnnership (GENPEAT)	4,499,352	4,499,352	4,499,352	4,499,352	4,499,352	4,499,352	4,499,352	4,499,352	4,499,352	0	0	0	40,494,168
21	Tiger Bay Limited Partnnership (TIMBER2)	157,320	157,320	157,320	157,320	157,320	157,320	157,320	157,320	157,320	0	0	0	1,415,880
22	Tiger Bay (EcoPeat lease credit)	(66,667)	(66,667)	(66,667)	(416,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	0	0	0	(950,003)
23	UPS Purchase (409 total mw) - Southern	4,051,119	4,265,922	3,788,442	3,925,202	3,701,633	3,967,206	4,600,651	4,111,954	3,772,505	4,072,858	4,123,154	4,059,771	48,440,417
24	Incremental Security (5060001 & 5240001)	0	0	0	197,728	0	0	289,444	0	0	339,821	0	670,325	1,497,319
25	Subtotal - Base Level Capacity Charges	28,776,095	31,417,044	29,324,988	29,306,903	29,342,924	29,844,985	30,939,618	30,111,025	29,803,299	24,629,299	24,359,910	24,932,194	342,788,285
26	Base Production Jurisdictional Responsibility	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	
27	Base Level Jurisdictional Capacity Charges	27,612,678	30,146,853	28,139,379	28,122,025	28,156,590	28,638,353	29,688,729	28,893,636	28,598,352	23,633,537	23,375,039	23,924,185	328,929,354
	Intermediate Production Level Capacity Charges:													
28	TECO Power Purchase (60 mw)	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	6,786,804
29	Schedule H Capacity Sales	(3,593)	(3,245)	(3,593)	(3,477)	(3,593)	(3,477)	(3,593)	(3,593)	(3,477)	(3,593)	(3,477)	(3,593)	(42,304)
30	Subtotal - Intermediate Level Capacity Charges	561,974	562,322	561,974	562,090	561,974	562,090	561,974	561,974	562,090	561,974	562,090	561,974	6,744,500
31	Intermediate Production Jurisdict. Responsibility	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	
32	Intermediate Level Jurisdict. Capacity Charges	486,523	486,824	486,523	486,624	486,523	486,624	486,523	486,523	486,624	486,523	486,624	486,523	5,838,983
	Peaking Production Level Capacity Charges:													
33	Reedy Creek	150,000	200,000	0	0	0	0	0	0	0	0	0	100,000	450,000
34	Reliant	884,800	884,800	0	0	0	0	0	0	0	0	0	0	1,769,600
35	Subtotal -Peaking Level Capacity Charges	1,034,800	1,084,800	0	0	0	0	0	0	0	0	0	100,000	2,219,600
36	Peaking Production Jurisdictional Responsibility	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	
37	Peaking Level Jurisdictional Capacity Charges	771,568	808,849	0	0	0	0	0	0	0	0	0	74,562	1,654,978
	Other Capacity Charges:													
38	Retail Wheeling	(361,936)	(835,914)	(182,755)	(113,525)	(48,143)	(26,384)	(13,938)	(29,176)	(38,789)	(5,532)	(124,746)	(238,691)	(2,019,529)
39	Total Jurisdictional Capacity Charges	28,508,833	30,606,611	28,443,147	28,495,124	28,594,970	29,098,593	30,161,315	29,350,984	29,046,186	24,114,528	23,736,916	24,246,580	334,403,787
40	Capacity Cost Recovery Revenues (net of tax)	30,746,795	28,983,600	24,247,953	24,296,838	27,928,411	32,162,523	32,763,177	32,098,676	34,244,504	29,061,760	26,419,218	25,297,620	348,251,076
41	Prior Period True-Up Provision	(742,168)	(742,168)	(742,168)	(242,404)	(242,404)	(242,404)	(242,404)	(242,404)	(242,404)	(242,404)	(242,404)	(242,404)	(4,408,138)
42	Current Period Revenues (net of tax) (line 40 + 41)	30,004,627	28,241,432	23,505,785	24,054,434	27,686,008	31,920,119	32,520,774	31,856,273	34,002,100	28,819,356	26,176,814	25,055,216	343,842,938
	True-Up Provision													
43	True-Up Provision - Over/(Under) Recov (line 42-39)	1,495,794	(2,365,179)	(4,937,362)	(4,440,690)	(908,963)	2,821,527	2,359,459	2,505,289	4,955,914	4,704,828	2,439,898	808,636	9,439,151
44	Interest Provision for the Month	(3,510)	(3,134)	(5,956)	(9,999)	(12,543)	(10,448)	(7,254)	(5,162)	(1,671)	2,792	5,942	7,622	(43,322)
45	Current Cycle Balance - Over/(Under) (line 43 + 44)	1,492,284	(876,029)	(5,819,347)	(10,270,037)	(11,191,542)	(8,380,463)	(6,028,258)	(3,528,131)	1,426,112	6,133,732	8,579,571	9,395,829	9,395,829
46	Plus Prior Period Balance	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	
47	Plus Cumulative True up Provision	742,168	1,484,336	2,226,504	2,468,908	2,711,311	2,953,715	3,196,119	3,438,522	3,680,926	3,923,330	4,165,733	4,408,138	
48	Net True-up Over/(Under) (lines 45 through 47)	(2,173,686)	(3,799,831)	(8,000,981)	(12,209,267)	(12,888,369)	(9,834,886)	(7,240,277)	(4,497,747)	698,900	5,648,923	8,337,167	9,395,829	9,395,829

PROGRESS ENERGY FLORIDA, INC.
CAPACITY COST RECOVERY CLAUSE
TRUE-UP CALCULATION
FOR THE PERIOD JANUARY - DECEMBER 2003

	Interest Provision Calculation::	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
1.	Beginning True-Up	($4,408,138)	($2,173,686)	($3,799,831)	($8,000,981)	($12,209,267)	($12,888,369)	($9,834,886)	($7,240,277)	($4,497,747)	$698,900	$5,648,923	$8,337,167
	Add Adjustments												
2.	Ending True-Up	($2,170,176)	($3,796,697)	($7,995,025)	($12,199,268)	($12,875,826)	($9,824,438)	($7,233,023)	($4,492,585)	$700,571	$5,646,132	$8,331,225	$9,388,207
3.	Total True-Up (line 1 + line 2)	($6,578,314)	($5,970,382)	($11,794,856)	($20,200,249)	($25,085,093)	($22,712,807)	($17,067,909)	($11,732,862)	($3,797,176)	$6,345,031	$13,980,148	$17,725,374
4.	Average True-Up (50% of line 3)	($3,289,157)	($2,985,191)	($5,897,428)	($10,100,125)	($12,542,547)	($11,356,403)	($8,533,955)	($5,866,431)	($1,898,588)	$3,172,516	$6,990,074	$8,862,687
5.	Interest Rate - First Day of Reporting Month	1.290%	1.270%	1.250%	1.180%	1.190%	1.210%	1.000%	1.050%	1.060%	1.060%	1.050%	1.000%
6.	Interest Rate - First Day of Subsequent Month	1.270%	1.250%	1.180%	1.190%	1.210%	1.000%	1.050%	1.060%	1.060%	1.050%	1.000%	1.060%
7.	Total Interest (line 5 + line 6)	2.560%	2.520%	2.430%	2.370%	2.400%	2.210%	2.050%	2.110%	2.120%	2.110%	2.050%	2.060%
8.	Average Interest Rate (50% of line 7)	1.280%	1.260%	1.215%	1.185%	1.200%	1.105%	1.025%	1.055%	1.060%	1.055%	1.025%	1.030%
9.	Monthly Average Interest Rate (line 8 / 12)	0.1067%	0.105%	0.101%	0.099%	0.100%	0.092%	0.085%	0.088%	0.088%	0.088%	0.085%	0.086%
10.	Interest Provision (line 4 x line 9)	($3,510)	($3,134)	($5,956)	($9,999)	($12,543)	($10,448)	($7,254)	($5,162)	($1,671)	$2,792	$5,942	$7,622
11.	Cumulative Interest for the Period Ending	($3,510)	($6,644)	($12,600)	($22,600)	($35,142)	($45,590)	($52,844)	($58,006)	($59,677)	($56,885)	($50,944)	($43,322)

PROGRESS ENERGY FLORIDA
EXHIBITS TO THE TESTIMONY OF
JAVIER PORTUONDO

Final True-Up Amount
January through December 2003

TIGER BAY REVENUES AND EXPENSES (JP-3T)

Progress Energy Florida, Inc.
Docket No. 040001-EI
Witness: Portuondo
Exhibit No. (JP-3T)
Sheet 1 of 1

TIGER BAY EXPENSE AND REVENUE TRACKING

		A	B	C	D	E	F	G	H	I	J	K	L
	Capacity Clause Revenues	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03
1	Retail Capacity Revenues	$ 5,568,416	$ 5,568,416	$ 5,568,416	$ 5,232,567	$ 5,568,416	$ 5,568,416	$ 5,568,416	$ 5,568,416	$ 5,568,416	$ -	$ -	$ -
2	Retail Related Interest on Reg. Asset	264,644	242,295	208,342	178,724	146,513	125,509	94,912	58,808	26,408			
3	Funds Available for Amortization	$ 5,303,772	$ 5,326,121	$ 5,360,074	$ 5,053,843	$ 5,421,903	$ 5,442,907	$ 5,473,504	$ 5,509,608	$ 5,542,008	$ -	$ -	$ -
	Fuel Adjustment Clause Revenues												
4	Retail Energy Revenues	$ 2,059,056	$ 3,712,863	$ 3,241,333	$ 3,847,698	$ 1,676,287	$ 3,301,157	$ 4,194,533	$ 3,569,485	$ 3,653,965			
5	Retail Fuel Expenses	3,427,282	3,060,305	3,385,863	3,229,507	3,399,706	3,315,502	3,326,100	3,387,486	3,269,388			
6	Funds Available for Amortization	$ (1,368,226)	$ 652,558	$ (144,530)	$ 618,191	$ (1,723,419)	$ (14,345)	$ 868,433	$ 181,999	$ 384,577	$ -	$ -	$ -
7	Underrecovery	-	-	-	-	-	-	-	-	-	-	-	-
	Tiger Bay Regulatory Asset - R												
8	Beginning Balance	$ 46,601,202	$ 42,665,656	$ 36,686,977	$ 31,471,432	$ 25,799,398	$ 22,100,914	$ 16,672,351	$ 10,330,414	$ 4,638,806	$ -	$ -	$ -
9	Amortization (Line 3 + Line 6 + Line 7)	(3,935,546)	(5,978,679)	(5,215,545)	(5,672,034)	(3,698,484)	(5,428,563)	(6,341,937)	(5,691,608)	(5,926,585)			
10	Amortization Adjustment (Note 1)	-	-	-	-	-	-	-	-	1,287,779	-	-	-
11	Ending Balance	$ 42,665,656	$ 36,686,977	$ 31,471,432	$ 25,799,398	$ 22,100,914	$ 16,672,351	$ 10,330,414	$ 4,638,806	$ -	$ -	$ -	$ -

Note 1: Final Tiger Bay amortization adjustment included in September's Fuel Adjustment Filing on schedule A2, page 1 of 4, line 6b.

PROGRESS ENERGY FLORIDA
EXHIBITS TO THE TESTIMONY OF
JAVIER PORTUONDO

Final True-Up Amount
January through December 2003

SCHEDULES A1 through A9 (JP-4T)
(Period-to-Date)

PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
YEAR TO DATE - DECEMBER 2003

		$				MWH				CENTS/KWH			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1	FUEL COST OF SYSTEM NET GENERATION (SCH A3)	1,045,484,844	879,714,905	165,769,939	18.8	35,493,465	33,288,840	2,204,625	6.6	2.9456	2.6427	0.3029	11.5
2	SPENT NUCLEAR FUEL DISPOSAL COST	5,689,420	5,670,567	18,853	0.3	6,038,641	6,110,531	(71,890)	(1.2)	0.0942	0.0928	0.0014	1.5
3	COAL CAR INVESTMENT	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3a	NUCLEAR DECOMMISSIONING AND DECONTAMINATION	1,768,401	0	1,768,401	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4	ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	(22,448,790)	9,847,640	(32,296,430)	(328.0)	(1,094,879)	0	(1,094,879)	0.0	2.0503	0.0000	2.0503	0.0
4a	ADJUSTMENTS TO FUEL COST - DISPOSAL COST REFUND	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
5	TOTAL COST OF GENERATED POWER	1,030,493,875	895,233,112	135,260,763	15.1	34,398,586	33,288,840	1,109,746	3.3	2.9957	2.6893	0.3064	11.4
6	ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	68,034,533	53,670,912	14,363,621	26.8	3,620,755	3,063,115	557,640	18.2	1.8790	1.7522	0.1268	7.2
7	ENERGY COST OF SCH C,X ECONOMY PURCH - BROKER (SCH A9)	281,400	214,400	67,000	31.3	4,320	3,050	1,270	41.6	6.5139	7.0295	(0.5156)	(7.3)
8	ENERGY COST OF ECONOMY PURCH - NON-BROKER (SCH A9)	43,687,919	26,879,089	16,808,830	62.5	749,350	795,717	(46,367)	(5.8)	5.8301	3.3780	2.4521	72.6
9	ENERGY COST OF SCH E PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10	CAPACITY COST OF ECONOMY PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
11	PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	171,149,235	156,166,586	14,982,649	9.6	6,176,174	6,803,406	(627,232)	(9.2)	2.7711	2.2954	0.4757	20.7
12	TOTAL COST OF PURCHASED POWER	283,153,087	236,930,987	46,222,100	19.5	10,550,599	10,665,288	(114,689)	(1.1)	2.6838	2.2215	0.4623	20.8
13	TOTAL AVAILABLE MWH					44,949,185	43,954,128	995,057	2.3				
14	FUEL COST OF ECONOMY SALES (SCH A6)	(10,663)	0	(10,663)	0.0	(400)	0	(400)	0.0	2.6658	0.0000	2.6658	0.0
14a	GAIN ON ECONOMY SALES - 100% (SCH A6)	(1,650)	0	(1,650)	0.0	(400)	0	(400)	0.0	0.4125	0.0000	0.4125	0.0
15	FUEL COST OF OTHER POWER SALES (SCH A6)	(29,158,429)	(38,890,209)	9,731,780	(25.0)	(962,784)	(1,094,034)	131,250	(12.0)	3.0286	3.5548	(0.5262)	(14.8)
15a	GAIN ON OTHER POWER SALES - 100% (SCH A6)	(9,843,110)	(5,179,019)	(4,664,091)	90.1	(962,784)	(1,094,034)	131,250	(12.0)	1.0224	0.4734	0.5490	116.0
15b	GAIN ON TOTAL POWER SALES - 20% (SCH A6)	312,192	0	312,192	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
16	FUEL COST OF SEMINOLE BACK-UP SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
17	FUEL COST OF SUPPLEMENTAL SALES	(74,829,609)	(51,061,060)	(23,766,549)	46.6	(2,493,969)	(1,336,198)	(1,157,771)	86.7	3.0004	3.8214	(0.8210)	(21.5)
18	TOTAL FUEL COST AND GAINS ON POWER SALES	(113,531,269)	(95,130,288)	(18,400,981)	19.3	(3,457,153)	(2,430,232)	(1,026,921)	42.3	3.2840	3.9145	(0.6305)	(16.1)
19	NET INADVERTENT AND WHEELED INTERCHANGE					(15,842)	1,481	(17,323)					
20	TOTAL FUEL AND NET POWER TRANSACTIONS	1,200,115,693	1,037,033,811	163,081,882	15.7	41,476,190	41,525,377	(49,187)	(0.1)	2.8935	2.4973	0.3962	15.9
21	NET UNBILLED	6,744,471	(2,890,115)	9,634,586	(333.4)	(233,090)	(226,192)	(6,898)	3.1	0.0173	(0.0074)	0.0247	(333.8)
22	COMPANY USE	3,430,706	3,488,986	(58,280)	(1.7)	(118,566)	(139,452)	20,886	(15.0)	0.0088	0.0090	(0.0002)	(2.2)
23	T & D LOSSES	64,910,609	54,490,124	10,420,485	19.1	(2,243,321)	(2,255,401)	12,080	(0.5)	0.1669	0.1401	0.0268	19.1
24	ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 4)	1,200,115,693	1,037,033,811	163,081,882	15.7	38,881,213	38,904,332	(23,119)	(0.1)	3.0866	2.6656	0.4210	15.8
25	WHOLESALE KWH SALES (EXCLUDING SUPPLEMENTAL SALES)	(26,608,998)	(25,970,138)	(638,860)	2.5	(867,260)	(981,317)	114,057	(11.6)	3.0682	2.6465	0.4217	15.9
26	JURISDICTIONAL KWH SALES	1,173,506,694	1,011,063,673	162,443,022	16.1	38,013,953	37,923,015	90,938	0.2	3.0870	2.6661	0.4209	15.8
27	JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00379	1,177,727,821	1,015,906,151	161,821,669	15.9	38,013,953	37,923,015	90,938	0.2	3.0981	2.6789	0.4192	15.7
28	PRIOR PERIOD TRUE-UP	(6,091,854)	(6,091,854)	(0)	0.0	38,013,953	37,923,015	90,938	0.2	(0.0160)	(0.0161)	0.0001	(0.6)
28a	MARKET PRICE TRUE-UP	0	0	0	0.0	38,013,953	37,923,015	90,938	0.2	0.0000	0.0000	0.0000	0.0
28b	RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	0	0	0	0.0	38,013,953	37,923,015	90,938	0.2	0.0000	0.0000	0.0000	0.0
29	TOTAL JURISDICTIONAL FUEL COST	1,171,635,966	1,009,814,297	161,821,669	16.0	38,013,953	37,923,015	90,938	0.2	3.0821	2.6628	0.4193	15.8
30	REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
31	FUEL COST ADJUSTED FOR TAXES									3.0843	2.6647	0.4196	15.8
32	GPIF	608,054	608,057			38,013,953	37,923,015			0.0016	0.0016	0.0000	100.0
33	TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									3.086	2.666	0.420	15.7

PROGRESS ENERGY FLORIDA
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2003

	CURRENT MONTH				YEAR TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
FUEL COSTS AND NET POWER TRANSACTIONS								
FUEL COST OF SYSTEM NET GENERATION	$74,048,024	61,645,679	$12,402,345	20.1	$1,045,484,844	$879,714,905	$165,769,939	18.8
a. NUCLEAR FUEL DISPOSAL COST	542,863	527,905	14,958	2.8	5,689,420	5,670,567	18,853	0.3
b. NUCLEAR DECOM & DECON	3,994	0	3,994	100.0	1,768,401	0	1,768,401	100.0
FUEL COST OF POWER SOLD	(4,545,722)	(3,112,200)	(1,433,522)	46.1	(29,169,093)	(38,890,209)	9,721,116	(25.0)
a. GAIN ON POWER SALES	(1,280,801)	(176,405)	(1,104,396)	626.1	(9,532,568)	(5,179,019)	(4,353,549)	84.1
FUEL COST OF PURCHASED POWER	4,788,746	4,288,841	497,905	11.6	68,034,533	53,670,912	14,363,621	26.8
a. ENERGY PAYMENTS TO QUALIFYING FAC.	10,562,392	11,487,820	(925,428)	(8.1)	171,149,235	156,166,586	14,982,649	9.6
b. DEMAND & NON FUEL COST OF PURCH POWER	0	0	0	0.0	0	0	0	0.0
ENERGY COST OF ECONOMY PURCHASES	743,240	3,053,000	(2,309,760)	(75.7)	43,969,319	27,093,489	16,875,830	62.3
TOTAL FUEL & NET POWER TRANSACTIONS	84,860,737	77,714,640	7,146,097	9.2	1,297,394,092	1,078,247,231	219,146,861	20.3
ADJUSTMENTS TO FUEL COST:								
a. FUEL COST OF SUPPLEMENTAL SALES	(5,022,747)	(4,165,961)	(856,786)	20.6	(74,829,609)	(51,061,060)	(23,768,549)	46.6
b. OTHER- JURISDICTIONAL ADJUSTMENTS (see detail below)	3,844,116	4,174,888	(330,772)	(7.9)	(22,448,790)	9,847,640	(32,296,430)	(328.0)
OTHER - PRIOR PERIOD ADJUSTMENT	0	0	0	0.0	0	0	0	0.0
ADJUSTED TOTAL FUEL & NET PWR TRNS	$83,682,108	$77,723,567	$5,958,539	7.7	$1,200,115,693	$1,037,033,811	$163,081,882	15.7

FOOTNOTE: DETAIL OF LINE 6B ABOVE

INSPECTION & FUEL ANALYSIS REPORTS (Wholesale Portion)	$1,805	$0	$1,805	$30,919	$223	$30,696
INEFFICIENT USE OF HINES 2	(756,984)	0	(756,984)	(2,447,134)	0	(2,447,134)
UNIV.OF FL STEAM REVENUE ALLOCATION (Wholesale Portion)	1,750	0	1,750	26,770	1,600	25,170
ADD'L ADJUSTMENT FOR 516.13 CLEANUP	(3,994)	0	(3,994)	(49,713)	1,726,622	(1,776,335)
GAS CONVERSION PROJECTS. (DEPRECIATION & RETURN)	20,632	19,000	1,632	438,144	427,023	11,120
EMISSIONS	3,029,946	800,000	2,229,946	7,472,794	5,711,450	1,761,344
TANK BOTTOM ADJUSTMENT (Grossed up)	0	0	0	50,500	0	50,500
FPSC FUEL AUDIT ADJUSTMENT	0	0	0	2,243,342	0	2,243,342
TIGER BAY NET GENERATION	0	0	0	(30,477,595)	(3,483,011)	(26,994,584)
FINAL ADJUSTMENT OF TIGER BAY	0	0	0	(1,287,779)	0	(1,287,779)
HEDGING	0	48,112	(48,112)	0	508,112	(508,112)
HINES 2 (DEPREC & RETURN)	1,550,961	3,309,776	(1,758,815)	1,550,961	4,955,620	(3,404,659)
SUBTOTAL LINE 6B SHOWN ABOVE	$3,844,116	$4,174,888	($330,772)	($22,448,790)	$9,847,640	($32,296,430)

PROGRESS ENERGY FLORIDA
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2003

	CURRENT MONTH				YEAR TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
SALES REVENUES (EXCLUDE REVENUE TAXES)								
JURISDICTIONAL SALES REVENUE								
a. BASE FUEL REVENUE	$0	$0	$0	0.0	$0	$0	$0	0.0
b. FUEL RECOVERY REVENUE	77,639,882	81,112,915	(3,473,033)	(4.3)	1,000,261,858	1,011,236,724	(10,974,866)	(1.1)
c. JURISDICTIONAL FUEL REVENUE	77,639,882	81,112,915	(3,473,033)	(4.3)	1,000,261,858	1,011,236,724	(10,974,866)	(1.1)
d. NON FUEL REVENUE	135,715,851	134,451,085	1,264,766	0.9	1,829,826,986	1,753,719,276	76,107,710	4.3
e. TOTAL JURISDICTIONAL SALES REVENUE	213,355,733	215,564,000	(2,208,267)	(1.0)	2,830,088,844	2,764,956,000	65,132,844	2.4
NON JURISDICTIONAL SALES REVENUE	12,406,020	11,594,000	812,020	7.0	189,626,766	102,726,000	86,900,766	84.6
TOTAL SALES REVENUE	$225,761,753	$227,158,000	($1,396,247)	(0.6)	$3,019,715,609	$2,867,682,000	$152,033,609	5.3
KWH SALES								
JURISDICTIONAL SALES	2,834,435,918	2,967,330,000	(132,894,082)	(4.5)	38,013,952,565	37,923,015,000	90,937,565	0.2
NON JURISDICTIONAL (WHOLESALE) SALES	50,413,653	75,736,000	(25,322,347)	(33.4)	867,259,722	981,317,000	(114,057,278)	(11.6)
TOTAL SALES	2,884,849,571	3,043,066,000	(158,216,429)	(5.2)	38,881,212,287	38,904,332,000	(23,119,713)	(0.1)
JURISDICTIONAL SALES % OF TOTAL SALES	98.25	97.51	0.74	0.8	97.77	97.48	0.29	0.3

PROGRESS ENERGY FLORIDA
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
TRUE UP CALCULATION								
JURISDICTIONAL FUEL REVENUE (LINE B1c)	$77,639,882	$81,112,915	($3,473,033)	(4.3)	$1,000,261,858	$1,011,236,724	($10,974,866)	(1.1)
ADJUSTMENTS: PRIOR PERIOD ADJ	0	0	0	0.0	0	0	0	0.0
a. TRUE UP PROVISION	(283,843)	(283,843)	0	0.0	6,091,854	6,091,854	0	0.0
b. INCENTIVE PROVISION	(50,671)	(50,676)	5	(0.0)	(608,054)	(608,057)	3	0.0
c. OTHER: MARKET PRICE TRUE UP	0	0	0	0.0	0	0	0	0.0
TOTAL JURISDICTIONAL FUEL REVENUE	77,305,368	80,778,396	(3,473,028)	(4.3)	1,005,745,658	1,016,720,521	(10,974,863)	(1.1)
ADJ TOTAL FUEL & NET PWR TRNS (LINE A7)	83,682,106	77,723,567	5,958,539	7.7	1,200,115,693	1,037,033,811	163,081,882	15.7
JURISDICTIONAL SALES % OF TOT SALES (LINE C4)	98.25	97.51	0.74	0.8	97.77	97.48	0.29	0.3
JURISDICTIONAL FUEL & NET POWER TRANSACTIONS (LINE D4 * LINE D5 * 1.00379 LOSS MULTIPLIER)	82,529,274	76,152,035	6,377,240	8.4	1,177,727,821	1,015,906,151	161,821,669	15.9
TRUE UP PROVISION FOR THE MONTH OVER/(UNDER) COLLECTION (LINE D3 - D6)	(5,223,907)	4,626,361	(9,850,268)	(212.9)	(171,982,162)	814,370	(172,796,532)	(21,218.4)
INTEREST PROVISION FOR THE MONTH (LINE E10)	(179,377)	(53,861)	(125,516)	233.0	(1,487,959)	(814,450)	(653,509)	80.2
TRUE UP & INT PROVISION BEG OF MONTH/PERIOD	(206,108,246)	(42,633,989)	(163,474,257)	383.4	(31,685,712)	(31,685,712)	(0)	0.0
TRUE UP COLLECTED (REFUNDED)	283,843	283,843	(0)	0.0	(6,091,854)	(6,091,854)	(0)	0.0
END OF PERIOD TOTAL NET TRUE UP (LINES D7 + D8 + D9 + D10)	(211,227,688)	(37,777,646)	(173,450,042)	459.1	(211,227,688)	(37,777,646)	(173,450,042)	459.1
OTHER:								
END OF PERIOD TOTAL NET TRUE UP (LINES D11 + D12)	($211,227,688)	(37,777,646)	(173,450,042)	459.1	($211,227,688)	(37,777,646)	(173,450,042)	459.1

PROGRESS ENERGY FLORIDA
CALCULATION OF TRUE-UP AND INTEREST PROVISION
DECEMBER 2003

	CURRENT MONTH				YEAR TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
INTEREST PROVISION								
BEGINNING TRUE UP (LINE D9)	($206,108,246)	N/A	--	--				
ENDING TRUE UP (LINES D7 + D9 + D10 +D12)	(211,048,310)	N/A	--	--				
TOTAL OF BEGINNING & ENDING TRUE UP	(417,156,557)	N/A	--	--				
AVERAGE TRUE UP (50% OF LINE E3)	(208,578,278)	N/A	--	--	NOT			
INTEREST RATE - FIRST DAY OF REPORTING MONTH	1.000	N/A	--	--				
INTEREST RATE - FIRST DAY OF SUBSEQUENT MONTH	1.060	N/A	--	--				
TOTAL (LINE E5 + LINE E6)	2.060	N/A	--	--				
AVERAGE INTEREST RATE (50% OF LINE E7)	1.030	N/A	--	--	APPLICABLE			
MONTHLY AVERAGE INTEREST RATE (LINE E8/12)	0.086	N/A	--	--				
INTEREST PROVISION (LINE E4 * LINE E9)	($179,377)	N/A	--	--				

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PROGRESS ENERGY FLORIDA, INC.

GENERATING SYSTEM COMPARATIVE DATA

Schedule A-3

01-2003 Thru 12-2003
FINAL

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
NET GENERATION ($)					
1	HEAVY OIL	288,137,027	230,736,103	57,400,924	24.9%
2	LIGHT OIL	38,637,993	34,085,327	4,552,666	13.4%
3	COAL	366,546,748	354,124,719	12,422,029	3.5%
4	GAS	330,111,281	239,272,506	90,838,775	38.0%
5	NUCLEAR	22,051,793	21,496,250	555,543	2.6%
6					
7					
8	TOTAL ($)	1,045,484,841	879,714,905	165,769,936	18.8%
SYSTEM NET GENERATION (MWH)					
9	HEAVY OIL	6,714,920	5,434,579	1,280,341	23.6%
10	LIGHT OIL	475,748	408,166	67,582	16.6%
11	COAL	16,111,850	16,792,239	-680,389	-4.1%
12	GAS	6,152,306	4,543,326	1,608,980	35.4%
13	NUCLEAR	6,038,641	6,110,529	-71,888	-1.2%
14					
15					
16	TOTAL (MWH)	35,493,465	33,288,839	2,204,626	6.6%
UNITS OF FUEL BURNED					
17	HEAVY OIL (BBL)	10,616,486	8,326,227	2,290,259	27.5%
18	LIGHT OIL (BBL)	1,072,389	912,656	159,733	17.5%
19	COAL (TON)	6,227,491	6,211,030	16,461	0.3%
20	GAS (MCF)	52,533,466	39,452,434	13,081,032	33.2%
21	NUCLEAR (MMBTU)	61,900,670	64,527,316	-2,626,646	-4.1%
22					
23					

PROGRESS ENERGY FLORIDA, INC.

GENERATING SYSTEM COMPARATIVE DATA

Schedule A-3

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
BTUS BURNED (MILLION BTU)					
24	HEAVY OIL	69,926,030	54,180,851	15,745,179	29.1%
25	LIGHT OIL	6,213,447	5,294,645	918,802	17.4%
26	COAL	155,007,595	156,001,154	-993,559	-0.6%
27	GAS	54,794,309	39,580,351	15,213,958	38.4%
28	NUCLEAR	61,900,670	64,527,316	-2,626,646	-4.1%
29					
30					
31	TOTAL (MILLION BTU)	347,842,049	319,584,317	28,257,732	8.8%
GENERATION MIX (% MWH)					
32	HEAVY OIL	18.9	16.33	2.6	15.9%
33	LIGHT OIL	1.3	1.23	0.1	9.3%
34	COAL	45.4	50.44	-5.1	-10.0%
35	GAS	17.3	13.65	3.7	27.0%
36	NUCLEAR	17.0	18.36	-1.3	-7.3%
37					
38					
39	TOTAL (% MWH)	100.0	100.0	0.0	0.0%

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PROGRESS ENERGY FLORIDA, INC.
GENERATING SYSTEM COMPARATIVE DATA
Schedule A-3

01-2003 Thru 12-2003
FINAL

	FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
	FUEL COST PER UNIT ($)				
40	HEAVY OIL ($/BBL)	27.14	27.71	-0.57	-2.1%
41	LIGHT OIL ($/BBL)	36.03	37.35	-1.32	-3.5%
42	COAL ($/TON)	58.86	57.02	1.84	3.2%
43	GAS ($/MCF)	6.28	6.06	0.22	3.6%
44	NUCLEAR ($/MBTU)	0.36	0.33	0.02	6.9%
45					
46					
	FUEL COST PER MILLION BTU ($/MILLION BTU)				
47	HEAVY OIL	4.12	4.26	-0.14	-3.2%
48	LIGHT OIL	6.22	6.44	-0.22	-3.4%
49	COAL	2.36	2.27	0.09	4.2%
50	GAS	6.02	6.05	-0.02	-0.3%
51	NUCLEAR	0.36	0.33	0.02	6.9%
52					
53					
54	SYSTEM ($/MBTU)	3.01	2.75	0.25	9.2%
	BTU BURNED PER KWH (BTU/KWH)				
55	HEAVY OIL	10,414	9,970	444	4.5%
56	LIGHT OIL	13,060	12,972	89	0.68%
57	COAL	9,621	9,290	331	3.6%
58	GAS	8,906	8,712	195	2.2%
59	NUCLEAR	10,251	10,560	-309	-2.9%
60					
61					
62	SYSTEM (BTU/KWH)	9,800	9,600	200	2.1%

PROGRESS ENERGY FLORIDA, INC.

GENERATING SYSTEM COMPARATIVE DATA

Schedule A-3

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATED FUEL COST PER KWH (CENTS/KWH)					
63	HEAVY OIL	4.29	4.25	0.05	1.1%
64	LIGHT OIL	8.12	8.35	-0.23	-2.7%
65	COAL	2.28	2.11	0.17	7.9%
66	GAS	5.37	5.27	0.10	1.9%
67	NUCLEAR	0.37	0.35	0.01	3.8%
68					
69					
70	SYSTEM (CENTS/KWH)	2.95	2.64	0.30	11.5%

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PROGRESS ENERGY FLORIDA, INC.
SYSTEM NET GENERATION AND FUEL COST
Schedule A-4

01-2003 Thru 12-2003
FINAL

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
Steam													
Anclote													
UNIT 1	510	1,842,889.00	41			10,183				18,766,157	78,517,550	4.261	
		1,823,976.48					#6	2,813,687	6.601	18,573,571	77,410,530	4.244	27.512
		16,872.20					GS	165,131	1.040	171,810	975,797	5.783	5.909
		2,040.32					#2	3,585	5.795	20,777	131,223	6.431	36.603
UNIT 2	509	2,180,280.00	49			10,202				22,243,590	95,351,969	4.373	
		2,122,180.16					#6	3,284,114	6.593	21,650,846	91,281,431	4.301	27.795
		55,728.77					GS	548,450	1.037	568,555	3,917,938	7.030	7.144
		2,371.07					#2	4,174	5.795	24,190	152,600	6.436	36.560
Bartow													
UNIT 1	122	622,571.00	58			10,715				6,670,841	25,901,887	4.160	
		621,988.09					#6	1,015,460	6.563	6,664,595	25,864,497	4.158	25.471
		582.91					#2	1,073	5.821	6,246	37,391	6.415	34.847
UNIT 2	120	581,591.00	55			10,641				6,188,688	24,133,332	4.150	
		581,591.00					#6	942,532	6.566	6,188,688	24,133,332	4.150	25.605
UNIT 3	206	1,109,875.00	62			10,186				11,305,261	43,653,964	3.933	
		1,109,874.59					#6	1,721,639	6.567	11,305,257	43,653,942	3.933	25.356
		0.41					GS	4	1.042	4	22	5.366	5.500
Crystal River 1 & 2													
UNIT 1	381	2,494,542.00	75			10,060				25,094,553	55,424,433	2.222	
		6,879.06					#2	12,148	5.697	69,202	454,759	6.611	37.435
		2,487,662.94					CA	991,851	25.231	25,025,351	54,969,675	2.210	55.421
UNIT 2	477	2,849,498.00	68			9,783				27,877,625	61,479,776	2.158	
		8,956.84					#2	15,016	5.836	87,628	589,090	6.577	39.231
		2,840,541.16					CA	1,101,755	25.223	27,789,997	60,890,686	2.144	55.267
Crystal River 4 & 5													
UNIT 4	717	5,360,309.00	85			9,475				50,790,899	125,613,898	2.343	
		24,210.25					#2	39,828	5.760	229,401	1,551,811	6.410	38.963
		5,336,098.75					CA	2,032,217	24.880	50,561,498	124,062,087	2.325	61.048
UNIT 5	725	5,472,620.00	86			9,478				51,869,904	128,258,270	2.344	
		25,232.48					#2	41,555	5.755	239,155	1,633,969	6.476	39.321
		5,447,387.52					CA	2,074,524	24.888	51,630,749	126,624,300	2.324	61.038

PROGRESS ENERGY FLORIDA, INC.

SYSTEM NET GENERATION AND FUEL COST

Schedule A-4

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
Suwannee Plant													
UNIT 1	33	124,033.00	43			12,870				1,596,278	7,476,045	6.027	
		123,964.42					#6	241,676	6.601	1,595,395	7,470,598	6.026	30.912
		68.58					#2	152	5.806	883	5,447	7.943	35.836
UNIT 2	32	128,444.00	46			13,063				1,677,896	7,842,308	6.106	
		128,359.61					#6	252,944	6.629	1,676,793	7,835,504	6.104	30.977
		84.39					#2	190	5.802	1,102	6,804	8.063	35.811
UNIT 3	81	212,660.00	30			11,260				2,394,585	11,250,768	5.290	
		201,674.34					#6	344,437	6.593	2,270,885	10,487,192	5.200	30.447
		10,688.19					GS	116,506	1.033	120,351	742,886	6.951	6.376
		297.48					#2	578	5.795	3,350	20,690	6.955	35.796
TOTAL	3,913	22,979,312.00				9,856				226,476,277	664,904,201	2.893	
Nuclear													
Crystal River 3													
UNIT 3	782	6,038,641.00	88			10,251				61,902,240	22,065,092	0.365	
		0					NF	61,900,670	1.000	61,900,670	22,051,793	0.000	0.356
		0					#2	278	5.649	1,570	13,298	0.000	47.835
TOTAL	782	6,038,641.00				10,251				61,902,240	22,065,092	0.365	
Gas Turbine													
Avon Park Peaker	56	15,307.00	3			16,872				258,263	1,609,126	10.512	
		5,298.33					#2	15,378	5.813	89,395	594,536	11.221	38.661
		10,008.67					GS	161,992	1.042	168,869	1,014,590	10.137	6.263
Bartow Peaker	205	64,604.00	4			17,502				1,130,685	6,943,686	10.748	
		10,474.96					#2	31,502	5.820	183,330	1,127,973	10.768	35.806
		54,129.04					GS	908,057	1.043	947,355	5,815,712	10.744	6.405
Bayboro Peaker	200	36,320.00	2			13,798				501,161	3,086,411	8.498	
		36,320.00					#2	86,044	5.824	501,161	3,086,411	8.498	35.870
Debary Peaker	644	492,989.00	9			13,666				6,736,993	42,344,174	8.589	
		135,309.83					#2	318,309	5.809	1,849,091	11,721,382	8.663	36.824
		357,679.17					GS	4,674,875	1.046	4,887,903	30,622,792	8.562	6.551

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PROGRESS ENERGY FLORIDA, INC.
SYSTEM NET GENERATION AND FUEL COST
Schedule A-4

01-2003 Thru 12-2003
FINAL

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
Higgins Peaker	126	32,771.00	3			17,725				580,864	3,185,075	9.719	
		263.03					#2	808	5.770	4,662	28,035	10.659	34.697
		32,507.97					GS	553,441	1.041	576,202	3,157,040	9.712	5.704
Hines Energy	1,097	3,186,000.00	33			7,466				23,787,455	164,157,714	5.152	
		23,888.03					#2	31,927	5.586	178,354	887,930	3.717	27.811
		3,162,111.97					GS	22,643,980	1.043	23,609,101	163,269,783	5.163	7.210
Intercession City Peaker	1,017	774,758.00	9			13,348				10,341,575	68,753,878	8.874	
		147,085.86					#2	338,295	5.804	1,963,322	11,867,941	8.069	35.082
		627,672.14					GS	8,022,432	1.044	8,378,253	56,885,937	9.063	7.091
Rio Pinar Peaker	15	2,968.00	2			17,091				50,726	319,727	10.772	
		2,968.00					#2	8,743	5.802	50,726	319,727	10.772	36.569
Suwannee Peaker	173	77,119.00	5			13,897				1,071,743	7,089,814	9.193	
		28,659.68					#2	68,275	5.834	398,291	2,448,083	8.542	35.856
		48,459.32					GS	652,222	1.033	673,452	4,641,731	9.579	7.117
Tiger Bay Cogen	215	1,425,739.00	76			7,754				11,055,827	40,717,713	2.856	
		1,425,739.00					GS	10,600,842	1.043	11,055,827	40,717,713	2.856	3.841
Turner Peaker	166	21,070.00	1			14,789				311,611	1,958,892	9.297	
		21,070.00					#2	53,708	5.802	311,611	1,958,892	9.297	36.473
Univ of Florida Cogen	48	345,867.00	82			10,510				3,635,045	18,349,340	5.305	
		345,867.00					GS	3,484,009	1.043	3,635,045	18,349,340	5.305	5.267
TOTAL	3,962	6,475,512.00				9,183				59,461,948	358,515,549	5.536	
SYSTEM TOTAL	8,657	35,493,465.00				9,800				347,840,465	1,045,484,841	2.946	

NOTE: Includes the following aerial survey adjustment:

Plant	Tons	Dollars	MMBTU
Crystal River 4 & 5	27,140	1,648,930.70	668,946.72

PROGRESS ENERGY FLORIDA, INC.

SYSTEM GENERATION FUEL COST

Schedule A-5

			Actual	Estimated	Difference	Difference (%)
HEAVY OIL	1	PURCHASES				
	2	Units (BBL)	10,438,994	7,912,673	2,526,321	31.9%
	3	Unit Cost ($/BBL)	27.33	29.16	-1.83	-6.3%
	4	Amount ($)	285,330,509	230,736,103	54,594,406	23.7%
	5	BURNED				
	6	Units (BBL)	10,616,486	7,912,673	2,703,813	34.2%
	7	Unit Cost ($/BBL)	27.14	29.16	-2.02	-6.9%
	8	Amount ($)	288,137,027	230,736,103	57,400,924	24.9%
	9	ADJUSTMENTS				
	10	Units (BBL)	-11,122			
	11	Amount ($)	-308,441			
	12	ENDING INVENTORY				
	13	Units (BBL)	901,971	800,000	101,971	12.7%
	14	Unit Cost ($/BBL)	27.23	27.92	-0.69	-2.5%
	15	Amount ($)	24,560,787	22,335,186	2,225,601	10.0%
	16					
	17	DAYS SUPPLY	0	0	0	0.0%
LIGHT OIL	18	PURCHASES				
	19	Units (BBL)	1,048,523	943,661	104,862	11.1%
	20	Unit Cost ($/BBL)	38.52	36.12	2.40	6.6%
	21	Amount ($)	40,390,643	34,085,327	6,305,316	18.5%
	22	BURNED				
	23	Units (BBL)	1,072,389	943,661	128,728	13.6%
	24	Unit Cost ($/BBL)	36.03	36.12	-0.09	-0.3%
	25	Amount ($)	38,637,993	34,085,327	4,552,666	13.4%
	26	ADJUSTMENTS				
	27	Units (BBL)	-38,295			
	28	Amount ($)	-194,950			
	29	ENDING INVENTORY				
	30	Units (BBL)	805,199	550,000	255,199	46.4%
	31	Unit Cost ($/BBL)	36.51	38.87	-2.36	-6.1%
	32	Amount ($)	29,400,800	21,378,196	8,022,604	37.5%
	33					
	34	DAYS SUPPLY	0	0	0	0.0%

PROGRESS ENERGY FLORIDA, INC.

SYSTEM GENERATION FUEL COST

Schedule A-5

			Actual	Estimated	Difference	Difference (%)
COAL	35	PURCHASES				
	36	Units (TON)	5,909,931	6,149,846	-239,915	-3.9%
	37	Unit Cost ($/TON)	58.74	57.58	1.16	2.0%
	38	Amount ($)	347,142,836	354,124,719	-6,981,883	-2.0%
	39	BURNED				
	40	Units (TON)	6,227,491	6,149,846	77,645	1.3%
	41	Unit Cost ($/TON)	58.86	57.58	1.28	2.2%
	42	Amount ($)	366,546,748	354,124,719	12,422,029	3.5%
	43	ADJUSTMENTS				
	44	Units (TON)	0			
	45	Amount ($)	-5,060			
	46	ENDING INVENTORY				
	47	Units (TON)	637,125	550,000	87,125	15.8%
	48	Unit Cost ($/TON)	56.61	54.61	2.00	3.7%
	49	Amount ($)	36,067,773	30,033,674	6,034,099	20.1%
	50					
	51	DAYS SUPPLY	0	0	0	0.0%
OTHER	52					
	53					
	54					
	55					
	56					
	57					
	58					
	59					
	60					
	61					
	62					
	63					
	64					
	65					

PROGRESS ENERGY FLORIDA, INC.

SYSTEM GENERATION FUEL COST

Schedule A-5

			Actual	Estimated	Difference	Difference (%)
GAS	66	BURNED				
	67	Units (MCF)	52,533,466	39,239,654	13,293,812	33.9%
	68	Unit Cost ($/MCF)	6.28	6.10	0.19	3.1%
	69	Amount ($)	330,111,281	239,272,506	90,838,775	38.0%
NUCLEAR	70	BURNED				
	71	Units (MM BTU)	61,900,670	64,406,489	-2,505,819	-3.9%
	72	Unit Cost ($/MM BTU)	0.36	0.33	0.02	6.7%
	73	Amount ($)	22,051,793	21,496,250	555,543	2.6%

NOTE: Purchase dollars and units do not include plant to plant transfers. See schedule A-5, Attachment #1 for detail of adjustments.

PROGRESS ENERGY FLORIDA, INC.
SCHEDULE A6

POWER SOLD
FOR THE MONTH OF:
DECEMBER, 2003

(1)	(2)	(3)	(4)	(5)	(6a)	(6b)	(7)	(8)	(9)	(10)
SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD (000)	KWH WHEELED FROM OTHER SYSTEMS (000)	KWH FROM OWN GENERATION (000)	FUEL COST C/KWH	TOTAL COST C/KWH	FUEL ADJ TOTAL $	TOTAL COST $	80% GAIN ON ENERGY SALES ECONOMY $	NONFUEL AMOUNT FOR FUEL ADJ $
ESTIMATED		84,000		84,000	3.705	3.705	3,112,200	3,112,200		176,405.00
ACTUAL										
Florida Municipal Power Agency	Schedule C	400		400	2.666	3.078	10,663.38	12,313.38		1,650.00
Sub Total - Gain on Economy Sales		400		400	2.666	3.078	10,663.38	12,313.38		1,650.00
Seminole Electric Cooperative, Inc.	Load Following	5,610		5,610	6.186	6.186	347,022.24	347,022.24		0.00
Cargill Power Markets, LLC	MR1	34,000		34,000	2.505	3.543	851,806.90	1,204,497.34		352,690.44
City of New Smyrna Beach, FL	Schedule I	0		0	0.000	0.000	8,355.12	8,355.12		0.00
City of New Smyrna Beach, FL	Schedule H	0		0	0.000	0.000	0.00	0.00		0.00
City of Homestead, FL	Schedule OS	30		30	3.692	4.754	1,107.51	1,426.11		318.60
City of New Smyrna Beach, FL	Schedule OS	2,025		2,025	2.713	4.196	54,936.52	84,971.57		30,035.05
City of Tallahassee, FL	Schedule OS	620		620	3.440	4.298	21,329.54	26,648.44		5,318.90
Duke Energy Trading & Marketing, L.L.C.	Schedule OS	69		69	3.454	4.907	2,383.04	3,385.61		1,002.57
Seminole Electric Cooperative, Inc	Schedule J	4,600		4,600	2.410	3.293	110,848.05	151,460.05		40,612.00
Seminole Electric Cooperative, Inc	Contract	500		500	2.914	4.892	14,567.68	24,461.68		9,894.00
Seminole Electric Cooperative, Inc	CR-1	1,655		1,655	2.848	4.307	47,134.66	71,285.41		24,150.75
Reedy Creek Improvement District	Schedule OS	1,950		1,950	2.224	2.839	43,365.36	55,365.76		12,000.40
Orlando Utilities Commission	Schedule OS	23,580		23,580	2.426	3.417	572,017.97	805,691.72		233,673.75
Oglethorpe Power Corp.	MR1	5,010		5,010	2.442	3.016	122,360.90	151,101.30		28,740.40
LG & E Energy Marketing, Inc	EEI	2,869		2,869	2.877	3.898	82,550.15	111,840.52		29,290.37
Florida Power & Light Company	CR-1	1,600		1,600	2.321	3.398	37,140.65	54,367.65		17,227.00
Florida Municipal Power Agency	CR-1	1,505		1,505	2.535	3.525	38,158.77	53,045.27		14,886.50
The Energy Authority, Inc.	Schedule OS	432		432	2.471	3.570	10,674.07	15,420.83		4,746.76
The Energy Authority, Inc.	Contract	3,385		3,385	5.987	1.775	202,659.87	60,091.40		(142,568.47)
Tampa Electric Company	CR-1	40,638		40,638	2.957	4.261	1,201,527.48	1,731,756.60		530,229.12
Southern Company Services, Inc	MR1	18,875		18,875	2.868	4.289	541,368.81	809,513.81		268,145.00
Seminole Electric Cooperative, Inc	Schedule OS	240		240	3.370	3.770	8,088.53	9,048.53		960.00
Cobb Electric Membership Corp.	EEI	7,933		7,933	2.482	4.060	196,862.16	322,046.02		125,183.86
City of Tallahassee, FL	Schedule A	250		250	4.718	4.718	11,793.97	11,793.97		0.00
Adjustments										
City of Tallahassee, FL	Schedule A	245		245	2.829	5.337	6,931.05	13,074.75		6,143.70
Oglethorpe Power Corp.	MR1	0		0	0.000	0.000	0.00	(50.00)		(50.00)
Reedy Creek Improvement District	Schedule OS	4		4	5.677	10.000	227.08	400.00		172.92
Southern Company Services, Inc	Schedule OS	0		0	0.000	0.000	0.00	0.00		0.00
Tampa Electric Company	CR-1	-60		-60	0.266	2.700	(159.42)	(1,620.00)		(1,460.58)
Sub Total - Gain on Other Power Sales		157,565		157,565	2.878	3.888	4,535,058.66	6,126,401.70		1,591,343.04
CURRENT MONTH TOTAL		157,965		157,965	2.878	3.886	4,545,722.04	6,138,715.08		1,592,993.04
DIFFERENCE		73,965		73,965	(0.827)	0.181	1,433,522.04	3,026,515.08		1,416,588.04
DIFFERENCE %		88.05		88.05	(22.33)	4.89	46.06	97.25		803.03
CUMULATIVE ACTUAL		963,184		963,184	3.028	4.051	29,169,092.86	39,013,854.22		9,844,761.36
CUMULATIVE ESTIMATED		1,061,007		1,061,007	3.570	3.570	37,873,270.00	37,873,270.00		4,211,800.00
DIFFERENCE		-97,823		-97,823	(0.541)	0.481	(8,704,177.14)	1,140,584.22		5,632,961.36
DIFFERENCE %		(9.22)		(9.22)	(15.16)	13.47	(22.98)	3.01		133.74

TOTAL YTD GAIN ON POWER SALES	9,844,761.36
THRESHOLD FOR 80/20 SHARING	8,283,799.00
GAIN SUBJECT TO SHARING	1,560,962.36
20% UTILITY SHARE OF GAIN	312,192.47
LESS PRIOR MONTH RECORDED 20% GAINS	0
CURRENT MONTH 20% GAIN	312,192.47

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PROGRESS ENERGY FLORIDA, INC.
SCHEDULE A7

PURCHASED POWER
EXCLUSIVE OF ECONOMY PURCHASES
FOR THE MONTH OF:
DECEMBER, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	KWH FOR UTILITIES (000)	KWH FOR INTERRUPTIBLE (000)	KWH FOR FIRM (000)	FUEL COST C/KWH	TOTAL COST C/KWH	TOTAL AMOUNT FOR FUEL ADJ $	FUEL COST $
ESTIMATED		235,061			235,061	1.825	1.825	4,288,841.00	4,288,841.00
ACTUAL									
Glades	Firm	9			9	10.381	10.381	934.26	934.26
Southern Company Services, Inc	Southern UPS	282,100			282,100	1.581	1.581	4,458,736.00	4,458,736.00
Tampa Electric Company	TECO AR1	16,260			16,260	4.063	4.063	660,677.35	660,677.35
ADJUSTMENTS									
Southern Company Services, Inc	Southern UPS	166			166	-224.155	-224.155	(372,097.88)	(372,097.88)
Tampa Electric Company	TECO AR1	0			0	0.000	0.000	38,495.83	38,495.83
CURRENT MONTH TOTAL		298,535			298,535	1.603	1.603	4,786,745.56	4,786,745.56
DIFFERENCE		63,474			63,474	(0.222)	(0.222)	497,904.56	497,904.56
DIFFERENCE %		27.0			27.0	(12.1)	(12.1)	11.6	11.6
CUMULATIVE ACTUAL		3,620,755			3,620,755	1.879	1.879	68,034,532.28	68,034,532.28
CUMULATIVE ESTIMATED		2,957,924			2,957,924	1.853	1.853	54,809,977.00	54,809,977.00
DIFFERENCE		662,831			662,831	0.026	0.026	13,224,555.28	13,224,555.28
DIFFERENCE %		22.4			22.4	1.4	1.4	24.1	24.1

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PROGRESS ENERGY FLORIDA, INC.
SCHEDULE A8

ENERGY PAYMENT TO QUALIFYING FACILITIES
FOR THE MONTH OF:
DECEMBER, 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL PURCHASED KWH (000)	(4) KWH FOR OTHER UTILITIES (000)	(5) KWH FOR INTERRUPTIBLE (000)	(6) KWH FOR FIRM (000)	(7) ENERGY COST C/KWH	(8) TOTAL COST C/KWH	(9) TOTAL AMOUNT FOR FUEL ADJ $
ESTIMATED		479,244	0	0	479,244	2.397	2.397	11,487,820.00
ACTUAL								
Auburndale Power Partners, L.P. (AUBRDLAS)	CO-GEN	1,975			1,975	5.745	5.745	113,447.09
ADJ		0			0			(16,593.31)
Auburndale Power Partners, L.P. (AUBRDLFC)	CO-GEN	7,735			7,735	2.202	2.202	170,324.70
ADJ		0			0			1,719.80
Auburndale Power Partners, L.P. (AUBSET)	CO-GEN	78,022			78,022	2.894	2.894	2,257,953.79
ADJ		0			0			544,047.29
Bay County (BAYCOUNT)	CO-GEN	5,713			5,713	2.148	2.148	122,715.24
ADJ		0			0			(1,703.94)
Cargill Fertilizer, Inc. (CARGILLF)	CO-GEN	5,086			5,086	2.125	2.125	108,077.50
ADJ		0			0			63,593.37
Central Power & Lime (FLACRUSH)	CO-GEN	0			0	0.000	0.000	0.00
ADJ		0			0			0.00
Citrus World (CITRUS)	CO-GEN	26			26	3.959	3.959	1,040.43
ADJ		20			20			840.91
Jefferson Power L.C. (JEFFPOWR)	CO-GEN	134			134	1.942	1.942	2,602.26
ADJ		0			0			0.00
Lake County (LAKCOUNT)	CO-GEN	8,338			8,338	2.200	2.200	183,436.00
ADJ		0			0			(1,709.35)
Lake Cogen Limited (LAKORDER)	CO-GEN	33,775			33,775	2.621	2.621	885,242.75
ADJ		0			0			(1,030,999.49)
Metro-Dade County (METRDADE)	CO-GEN	21,660			21,660	2.514	2.514	544,532.40
ADJ		0			0			(163,840.13)
Metro-Dade County (METRODAS)	CO-GEN	172			172	4.410	4.410	7,585.20
ADJ		0			0			(998.16)
Orange Cogen (ORANGEAS)	CO-GEN	6,923			6,923	5.293	5.293	366,434.39
ADJ		0			0			(41,186.35)
Orange Cogen (ORANGECO)	CO-GEN	25,942			25,942	2.465	2.465	639,470.30
ADJ		0			0			(33,659.06)
Orlando Cogen Limited (ORLACOGL)	CO-GEN	59,178			59,178	3.068	3.068	1,827,416.64
ADJ		0			0			(71,327.30)
Orlando Cogen Limited (ORLCOGAS)	CO-GEN	162			162	4.416	4.416	7,153.92
ADJ		0			0			259.07
Pasco Cogen Limited (PASCCOGL)	CO-GEN	48,611			48,611	2.291	2.291	1,113,678.01
ADJ		0			0			162,757.75
Pasco County Resource Recovery (PASCOUNT)	CO-GEN	17,180			17,180	2.200	2.200	377,960.00
ADJ		0			0			(4,030.47)
PCS Phosphate (OCSWFCRK)	CO-GEN	0			0	0.000	0.000	0.00
ADJ		-39			-39			(1,997.05)
PCS Phosphate (OCWHSPRS)	CO-GEN	95			95	4.521	4.521	4,289.52
ADJ		5			5			174.15
Perpetual Energy (PRPETUAL)	CO-GEN	0			0	0.000	0.000	0.00
ADJ		0			0			0.00
Pinellas County Resource Recovery (PINCOUNT)	CO-GEN	27,851			27,851	2.139	2.139	591,454.89
ADJ		0			0			(8,737.60)
Polk Power Partners, L.P. (MULBERRY)	CO-GEN	34,180			34,180	1.966	1.966	671,975.65
ADJ		0			0			12,794.11
Polk Power Partners, L.P. (ROYSTER)	CO-GEN	13,292			13,292	2.150	2.150	285,781.44
ADJ		0			0			(7,236.58)
St. Joe Forest Products (STJOEFOR)	CO-GEN	0			0	0.000	0.000	0.00
ADJ		0			0			0.00
DG Telogia, LLC (TIMBER)	CO-GEN	7,264			7,264	1.750	1.750	127,120.00
ADJ		0			0			0.00
U.S Agri-Chemicals (AGRICHEM)	CO-GEN	5,262			5,262	4.247	4.247	223,477.14
ADJ		0			0			(45,409.86)
Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	CO-GEN	15,849			15,849	3.531	3.531	559,628.19
ADJ		0			0			5,050.12
Jefferson Power L.C. (JEFFAS)	CO-GEN	127			127	6.289	6.289	7,987.03
ADJ		0			0			0.00
CURRENT MONTH TOTAL	—	424,336			424,336	2.489	2.489	10,562,392.42
DIFFERENCE		-54,906			-54,906	0.092	0.092	(925,427.58)
DIFFERENCE %		(11.5)			(11.5)	3.8	3.8	(8.1)
CUMULATIVE ACTUAL		6,176,173			6,176,173	2.771	2.771	171,149,234.11
CUMULATIVE ESTIMATED		6,838,960			6,838,960	2.406	2.406	164,543,104.00
CUMULATIVE DIFFERENCE		-662,787			-662,787	0.365	0.365	6,606,130.11
CUMULATIVE DIFFERENCE %		(9.7)			(9.7)	15.2	15.2	4.0

PROGRESS ENERGY FLORIDA, INC.
SCHEDULE A9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
FOR THE MONTH OF:
DECEMBER, 2003

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	ENERGY COST C/KWH	TOTAL AMOUNT FOR FUEL ADJ $	COST IF GENERATED C/KWH	COST IF GENERATED $	FUEL SAVINGS $
ESTIMATED		99,000	3.084	3,052,999.00	3.084	3,052,999.00	0.00
ACTUAL:							
Florida Power & Light Company	Schedule C	600	5.683	34,100.00	7.032	42,194.00	8,094.00
SubTotal - Energy Purchases (Broker)		600	5.683	34,100.00	7.032	42,194.00	8,094.00
Sepa	Hydro	3,097	2.035	63,014.96	2.035	63,014.96	0.00
Seminole	Load Following	159	14.929	23,737.29	14.929	23,737.29	0.00
Seminole	RPR Purchase	0	0.000	0.00	0.000	0.00	0.00
City of Homestead, FL	Schedule OS	30	2.733	820.00	3.733	1,120.00	300.00
Cobb Electric Membership Corp.	EEI	1,473	3.741	55,111.00	5.018	73,914.41	18,803.41
Florida Power & Light Company	Schedule OS	1,700	7.444	126,550.00	7.721	131,252.50	4,702.50
Florida Power & Light Company	Transmission Purchase	0	0.000	3,259.45	0.000	0.00	(3,259.45)
Georgia Transmission Corporation	Transmission Purchase	0	0.000	529.42	0.000	0.00	(529.42)
Jacksonville Electric Authority	Transmission Purchase	0	0.000	141,825.89	0.000	0.00	(141,825.89)
LG & E Energy Marketing, Inc	EEI	240	2.560	6,144.00	3.417	8,200.00	2,056.00
Orlando Utilities Commission	Schedule OS	300	2.700	8,100.00	3.354	10,063.00	1,963.00
Reedy Creek Improvement District	Schedule OS	360	4.711	16,960.00	6.810	24,515.00	7,555.00
Reliant Energy Services, Inc.	Schedule OS	2,696	9.578	258,212.00	9.639	259,877.86	1,665.86
Seminole Electric Cooperative, Inc	Schedule J	250	2.920	7,300.00	3.510	8,775.00	1,475.00
Seminole Electric Cooperative, Inc	Transmission Purchase	0	0.000	2,157.10	0.000	0.00	(2,157.10)
Southern Company Services, Inc	Contract	206	4.200	8,652.00	4.037	8,316.00	(336.00)
Southern Company Services, Inc	MR1	143	0.000	0.00	3.794	5,425.42	5,425.42
The Energy Authority, Inc.	Contract	48	4.500	2,160.00	4.896	2,350.00	190.00
ADJUSTMENTS							
Carolina Power Light Company	Transmission Purchase	0	0.000	(14,891.15)	0.000	0.00	14,891.15
Georgia Transmission Corporation	Transmission Purchase	0	0.000	110.51	0.000	0.00	(110.51)
Jacksonville Electric Authority	Transmission Purchase	0	0.000	(520.54)	0.000	0.00	520.54
Seminole Electric Cooperative, Inc	ReplacementPartialRequir	437	1.669	7,293.53	1.669	7,293.53	0.00
Seminole Electric Cooperative, Inc	Schedule J	15	8.300	1,245.00	6.667	1,000.05	(244.95)
Seminole Electric Cooperative, Inc	Transmission Purchase	0	0.000	225.53	0.000	0.00	(225.53)
Southern Company Services, Inc	Transmission Purchase	0	0.000	(8,806.02)	0.000	0.00	8,806.02
The Energy Authority, Inc.	Contract	-1	5.000	(50.00)	6.662	(66.62)	(16.62)
SubTotal - Energy Purchases (Non-Broker)		11,153	6.359	709,139.97	5.638	628,788.40	(80,351.57)
CURRENT MONTH TOTAL		11,753	6.324	743,239.97	5.709	670,982.40	(72,257.57)
DIFFERENCE		-87,247	3.240	(2,309,759.03)	2.625	(2,382,016.60)	(72,257.57)
DIFFERENCE %		(88.1)	105.1	(75.7)	85.1	(78.0)	0.0
CUMULATIVE ACTUAL		753,670	5.834	43,969,318.26	6.570	49,513,818.25	5,544,499.99
CUMULATIVE ESTIMATED		777,388	3.142	24,428,930.00	3.142	24,428,930.00	0.00
DIFFERENCE		-23,718	2.692	19,540,388.26	3.427	25,084,888.25	5,544,499.99
DIFFERENCE %		(3.1)	85.7	80.0	109.1	102.7	0.00

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

ESTIMATED/ACTUAL TRUE-UP AMOUNTS
JANUARY THROUGH DECEMBER 2004

PART A - SALES FORECAST ASSUMPTIONS

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 32
COMPANY/ PEF
WITNESS. Javier Portuondo (JP-1R)
DATE 11-08-04

SALES FORECAST ASSUMPTIONS

1. This forecast of customers, sales and peak demand was developed for use in the 2005 budget and 2005 - 2009 five-year Business Plan. This forecast was prepared in June 2004.

2. Normal weather conditions are assumed over the forecast horizon. For kilowatt-hour sales projections normal weather is based on a historical thirty-year average of service area weighted billing month degree days. Seasonal peak demand projections are based on a thirty-year historical average of system-weighted temperatures at time of seasonal peak.

3. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida as published in "Florida Population Studies Bulletin No. 138 (February 2004) provide the basis for development of the customer forecast. State and national economic assumptions produced by Economy.Com in their national and Florida forecasts (February, 2004) are also incorporated.

4. Within the Progress Energy Florida (PEF) service area the phosphate mining industry is the dominant sector in the industrial sales class. Six major customers accounted for nearly 30% of the industrial class MWh sales in 2003. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. Both supply and demand conditions for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. Load and energy consumption at the PEF-served mining or chemical processing sites depend heavily on plant operations which are heavily influenced by the state of these global conditions as well as local conditions. After years of excess mining capacity and weak product pricing power, the industry has consolidated down to fewer players in time to take advantage of better market conditions. A weaker U.S currency value on the foreign exchange is expected to help the industry in two ways. First, American farm commodities will be more competitive overseas and lead to higher crop production at home. This will result in greater demand for fertilizer products. Second, a weak U.S. dollar results in U.S. fertilizer producers to become more price competitive relative to foreign producers. Going forward, energy consumption is expected to increase -- as we have recently experienced - to the levels just below that experienced in the late 1990 boom period. A significant risk to this projection lies in the continued high price of natural gas which is a major factor of production. Operations at several sites in the U.S. have already

scaled back or shutdown due to profitability concerns caused by high energy prices. The energy projection for this industry assumes no major reductions or shutdowns of operations in the service territory.

5. Progress Energy Florida supplies load and energy service to wholesale customers on a "full", "partial" and "supplemental" requirement basis. Full requirements customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Partial requirements customer load is assumed to reflect the current contractual obligations received by PEF in an annual "declaration letter" as of May 31, 2004. The forecast of energy and demand to partial requirements customers reflect the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for partial requirements service included in this forecast are with FMPA, the cities of New Smyrna Beach, Tallahassee and Homestead, and other utilities such as Reedy Creek Utilities, Florida Power & Light and Tampa Electric Company. PEF's arrangement with Seminole Electric Cooperative, Inc. (SECI) is to serve "supplemental" service over and above stated levels they commit to supply themselves. SECI's projection of their system's requirements in the PEF control area has been incorporated into this forecast. This forecast also incorporates a 150 MW stratified intermediate demand firm power contract with SECI.

6. This forecast assumes that PEF will successfully renew all future franchise agreements.

7. This forecast incorporates demand and energy reductions from PEF'S dispatchable and non-dispatchable DSM programs required to meet the approved goals set by the Florida Public Service Commission.

8. Expected energy and demand reductions from self-service cogeneration are also included in this forecast. PEF will supply the supplemental load of self-service cogeneration customers. While PEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for standby power.

9. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. The ability of wholesale customers to switch suppliers has ended the company's obligation to serve these customers beyond their contract life. As a result, the company does not plan for generation resources unless a long-term contract is in place. Current "all requirements" customers are assumed to not renew their contracts with PEF. Current "partial requirements" contracts are projected to terminate as terms reach their expiration date.

10. The economic outlook for this forecast calls for a gradual strengthening of national and State economic growth as the recovery from the recent recession takes hold and terrorism fears subside. As this forecast was developed signs of an improving economy were beginning to be reflected in reported GDP growth. Employment growth had just commenced after a long period of contraction. Monetary policy announcements suggested a return to more normal levels of interest rates and monetary growth. A fifty-year low in market interest rates - coaxed by the Federal Reserve Board (FED) – and lower Federal tax rates appear to have stimulated the U.S. economy enough to warrant a less accommodative monetary policy.

    The extremely accommodative fiscal and monetary policies since late 2001, the passage of time from the terror attack of 9/11, and the working off of excess investment of the "bubble" economy, have set up the U.S. and Florida economy on track for reasonable consistent growth for the foreseeable future. As consumer confidence rebounds more reasonable returns on investment will enable businesses to resume hiring. A weaker dollar should make domestic producers more competitive.

    Particular sectors of the economy that have been performing well include the housing industry and the individual consumer. Both have been credited with fueling the limited economic advances of the past two years. The multi-generational low in interest rates and expansion of credit has stimulated an unprecedented level of housing construction. The record level of mortgage refinancing and lowering of Federal taxes have acted to put added money in people's pockets, further stimulating demand.

    While most signs point toward an improving economic environment, there are some risks that were considered in the development of this forecast. Market prices for energy have been very high for an extended period at this point. Historically, high oil prices have resulted in starving economic growth. Fears of a shortage in supplies has kept natural gas prices high as well and has placed increased burden on manufacturers who rely upon reasonably priced fuel as a major source of production.

    An additional risk comes as the FED increases interest rates. Some economists believe that the housing sector has been over-simulated by record-low interest rates. Others believe that Americans have "loaded up" on debt and will be negatively impacted by higher debt-service as interest rates rise. The FED must carefully balance the risks staving off higher inflation without starving economic growth. Higher inflation could force up market-driven interest rates faster than the FED would prefer. This event would certainly hurt the housing sector as well as consumer spending. This forecast tries to balance this and other risks by incorporating the National and State economic projections developed by Economy.Com.

Growth in energy consumption is directly tied to the levels of economic activity in the State, nation and around the world, but demographic forces play a major role as well. Factors that influence in-migration rates to Florida impact residential customer growth, especially since the difference between births and deaths contribute little to Florida's growing population. Obviously, many factors influence the pace of in-migration to Florida but there is one broad, demographically created influence one can expect during the next few years. The University of Florida's latest population projection (February 2004) shows a return to more normal levels of growth in Florida population as we move into the mid-decade. This is due to economy-related conditions and characteristics of the age cohorts reaching retirement age this decade.

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

ESTIMATED/ACTUAL TRUE-UP AMOUNTS
JANUARY THROUGH DECEMBER 2004

PART B - FUEL PRICE FORECAST ASSUMPTIONS

FUEL PRICE FORECAST ASSUMPTIONS

A. Residual Oil and Light Oil

The oil price forecast is based on expectations of normal weather and no radical changes in world energy markets (OPEC actions, governmental rule changes, etc.). Prices are based on expected contract structures, specifications, and market conditions during 2004 & 2005.

PEF Residual Fuel Oil (#6) and Distillate Fuel Oil (#2) prices were derived from PIRA Energy Group forecasts and current market information.

The oil prices listed on Part C do not include transportation costs to individual plant locations.

B. Coal

Coal price projections are provided by Progress Fuels and represent an estimate of the price to Progress Energy Florida for coal delivered to the plant sites in accordance with the delivery schedules projected. The forecast is consistent with the coal supply and transportation agreements which Progress Fuels has, or expects to have, in place during 2004 & 2005 and estimated spot purchase volumes and prices for the period. It assumes environmental restrictions on coal quality remain in effect as per current permits: 2.1 lbs. per million BTU sulfur dioxide limit for Crystal River Units 1 and 2, and 1.2 lbs. per million BTU sulfur dioxide limit for Crystal River Units 4 and 5.

C. Natural Gas

The natural gas price forecast is based on the expectation of average weather conditions and a steady trend in supply and demand. Prices are based on expected contract structures and spot market purchases for 2004 & 2005. Gas supply prices were derived from PIRA Energy Group forecasts and current market information.

Transportation costs for Florida Gas Transmission and Gulfstream pipeline firm transportation services are based on expected tariff rates. Interruptible transportation rates and availability are based on expected tariff rates and market conditions.

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

ESTIMATED/ACTUAL TRUE-UP AMOUNTS
JANUARY THROUGH DECEMBER 2004

PART C - FUEL PRICE FORECAST

Progress Energy Florida
Docket No. 040001-EI
Witness: J. Portuondo
Part C
Sheet 1 of 2

FUEL PRICE FORECAST
#6 Fuel Oil

	1.0%		1.5%		2.5%	
Month	**$/barrel**	**$/MMBtu (1)**	**$/barrel**	**$/MMBtu (1)**	**$/barrel**	**$/MMBtu (1)**
Aug 2004	29.77	4.58	29.06	4.47	27.82	4.28
Sep 2004	31.79	4.89	30.94	4.76	29.51	4.54
Oct 2004	32.50	5.00	31.59	4.86	30.03	4.62
Nov 2004	32.18	4.95	31.33	4.82	29.71	4.57
Dec 2004	31.92	4.91	31.07	4.78	29.51	4.54

(1) 6.5 MMBtu/Bbl

FUEL PRICE FORECAST
#2 Fuel Oil

Month	$/barrel	¢/gallon	$/MMBtu(1)
Aug 2004	46.40	110.48	8.00
Sep 2004	47.21	112.41	8.14
Oct 2004	47.56	113.24	8.20
Nov 2004	54.93	130.78	9.47
Dec 2004	55.10	131.19	9.50

(1) 5.8 MMBtu/Bbl & 42 gallon/Bbl

FUEL PRICE FORECAST
Natural Gas Supply [1]

Month	$/MMBtu
Aug 2004	5.82
Sep 2004	6.12
Oct 2004	6.21
Nov 2004	7.51
Dec 2004	7.04

[1] Transport costs not included

FUEL PRICE FORECAST
Coal

	Crystal River 1 & 2			Crystal River 4 & 5		
Month	BTU/lb.	$/ton	$/MMBtu	BTU/lb.	$/ton	$/MMBtu
Aug - Dec 2004	12,500	52.51	2.101	12,500	54.93	2.197

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

ESTIMATED/ACTUAL TRUE-UP AMOUNTS
JANUARY THROUGH DECEMBER 2004

PART D - CAPACITY COST RECOVERY CALCULATIONS

PROGRESS ENERGY FLORIDA
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED / ACTUAL TRUE-UP
For the Year 2004

Progress Energy Florida
Docket 040001-EI
Witness: Portuondo
Exhibit No.
Part D

		Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Actual Jun-04	Actual Jul-04	Estimated Aug-04	Estimated Sep-04	Estimated Oct-04	Estimated Nov-04	Estimated Dec-04	Total 2004
	Base Production Level Capacity Charges:													
1	Payments to Qualifying Facilities	20,160,892	21,180,647	21,190,611	21,213,185	21,197,052	21,038,038	20,720,322	21,294,679	21,294,679	21,294,679	21,294,679	21,294,679	253,174,142
2	UPS Purchase (409 MW)	4,281,772	4,750,723	3,894,737	3,841,737	3,993,872	4,099,574	4,121,419	4,215,321	4,079,343	4,215,321	4,079,343	4,215,321	49,788,483
3	Incremental Security Costs	0	17,831	7,667	192,964	33,033	140,821	1,058,349	451,048	451,048	451,048	451,048	451,050	3,705,907
4	Subtotal - Base Level Capacity Charges	24,442,664	25,949,201	25,093,015	25,247,886	25,223,957	25,278,433	25,900,090	25,961,048	25,825,070	25,961,048	25,825,070	25,961,050	306,668,532
5	Base Production Jurisdictional %	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%
6	Base Level Jurisdictional Capacity Charges	23,454,447	24,900,075	24,078,504	24,227,114	24,204,152	24,256,426	24,852,949	24,911,443	24,780,962	24,911,443	24,780,962	24,911,445	294,269,923
	Intermediate Production Level Capacity Charges:													
7	TECO Power Purchase	565,567	565,567	565,567	565,567	565,567	565,567	565,567	566,000	566,000	566,000	566,000	566,000	6,788,969
8	Capacity Sales	(3,593)	(3,361)	(3,593)	(3,477)	(79,195)	(117,060)	(4,195)	(3,500)	(3,500)	(3,500)	(3,500)	(3,500)	(231,974)
9	Subtotal - Intermediate Level Capacity Charges	561,974	562,206	561,974	562,090	486,372	448,507	561,372	562,500	562,500	562,500	562,500	562,500	6,556,995
10	Intermediate Production Jurisdictional %	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%
11	Intermediate Level Jurisdictional Capacity Charg	486,523	486,724	486,523	486,624	421,072	388,290	486,002	486,979	486,979	486,979	486,979	486,979	5,676,653
	Peaking Production Level Capacity Charges:													
12	City of Chattahoochee	4,839	11,541	13,056	12,231	12,366	12,218	12,782	12,500	12,500	12,500	12,500	12,500	141,533
13	Peaking Purchases - Summer Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Peaking Purchases - Winter Peak	100,000	100,000	0	0	0	0	0	0	0	0	0	897,900	1,097,900
15	Capacity Sales	0	0	0	(120,000)	(400,000)	0	0	0	0	0	0	0	(520,000)
16	Subtotal - Peaking Level Capacity Charges	104,839	111,541	13,056	(107,769)	(387,634)	12,218	12,782	12,500	12,500	12,500	12,500	910,400	719,433
17	Peaking Production Jurisdictional %	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%
18	Peaking Level Jurisdictional Capacity Charges	78,170	83,167	9,735	(80,355)	(289,028)	9,110	9,531	9,320	9,320	9,320	9,320	678,812	536,424
19	Transmission Revenues from Economy Sales	(353,548)	(232,511)	(146,789)	(128,892)	(81,256)	(4,004)	(365)	(106,411)	(134,414)	(125,080)	(188,553)	(242,692)	(1,744,515)
20	Jurisdictional Capacity Payments (Lines 6 + 11 + 18 + 19)	23,665,593	25,237,455	24,427,974	24,504,491	24,254,940	24,649,822	25,348,117	25,301,331	25,142,847	25,282,662	25,088,708	25,834,544	298,738,485
21	Capacity Cost Recovery Revenues	23,661,189	20,668,671	21,039,724	20,087,370	22,534,692	28,521,089	30,855,867	29,758,961	29,993,106	27,196,073	23,430,581	22,869,352	300,616,655
22	Prior Period True-Up Provision	275,762	275,762	275,762	275,762	275,762	275,762	275,762	275,762	275,762	275,762	275,762	6,362,447	9,395,829
23	Current Period Capacity Revenues (Lines 21+22)	23,936,951	20,944,433	21,315,486	20,363,132	22,810,454	28,796,851	31,131,629	30,034,723	30,268,868	27,471,835	23,706,323	29,231,799	310,012,484
24	Current Period Over/(Under) Rec. (Lines 23-20)	271,358	(4,293,022)	(3,112,488)	(4,141,359)	(1,444,486)	4,147,029	5,783,512	4,733,392	5,126,021	2,189,173	(1,382,385)	3,397,255	11,273,999
25	Interest Provision for Month	8,182	5,977	2,577	(636)	(3,291)	(2,727)	2,261	8,093	13,548	17,520	17,690	15,006	84,200
26	Current Cycle Balance	279,540	(4,007,505)	(7,117,416)	(11,259,411)	(12,707,188)	(8,562,887)	(2,777,114)	1,964,371	7,103,940	9,310,633	7,945,938	11,358,199	11,358,199
27	Plus: Prior Period Balance	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829
28	Plus: Cumulative True-Up Provision	(275,762)	(551,524)	(827,286)	(1,103,048)	(1,378,810)	(1,654,572)	(1,930,334)	(2,206,096)	(2,481,858)	(2,757,620)	(3,033,382)	(9,395,829)	(9,395,829)
29	End of Period Net True-Up (Lines 26+27+28)	9,399,607	4,836,800	1,451,127	(2,966,630)	(4,690,169)	(821,630)	4,688,381	9,154,104	14,017,911	15,948,842	14,308,385	11,358,199	11,358,199

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

ESTIMATED/ACTUAL TRUE-UP AMOUNTS
JANUARY THROUGH DECEMBER 2004

SCHEDULES E1 THROUGH E9

SCHEDULE E3
Reprojected 8/04

PROGRESS ENERGY FLORIDA
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD OF: AUGUST THROUGH DECEMBER 2004

			Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Total
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL		36,231,528	36,325,858	31,321,968	16,076,816	24,532,485	144,488,455
2	LIGHT OIL		14,435,343	5,365,689	3,939,305	74,813	333,471	24,148,621
3	COAL		29,174,057	28,243,253	30,727,014	30,606,511	31,647,210	150,398,046
4	GAS		62,463,736	55,175,636	30,696,021	22,189,111	22,171,609	192,696,112
5	NUCLEAR		2,033,264	1,968,492	2,033,264	1,967,157	2,031,885	10,034,062
6	OTHER		0	0	0	0	0	0
7	TOTAL	$	144,337,928	127,078,728	98,717,572	70,914,408	80,716,659	521,765,296
	SYSTEM NET GENERATION (MWH)							
8	HEAVY OIL		784,548	738,844	609,934	313,227	495,738	2,942,291
9	LIGHT OIL		121,026	45,185	32,831	631	2,599	202,272
10	COAL		1,407,908	1,352,622	1,487,954	1,498,627	1,549,632	7,306,743
11	GAS		1,075,075	952,558	516,068	365,553	386,184	3,295,436
12	NUCLEAR		558,106	540,327	558,106	551,511	569,658	2,777,708
13	OTHER		0	0	0	0	0	0
14	TOTAL	MWH	3,946,663	3,639,536	3,204,891	2,729,549	3,003,811	16,524,450
	UNITS OF FUEL BURNED							
15	HEAVY OIL	BBL	1,251,975	1,180,882	998,602	517,373	792,668	4,741,500
16	LIGHT OIL	BBL	302,931	110,987	80,773	1,326	5,888	501,905
17	COAL	TON	537,542	520,394	567,256	565,247	584,498	2,774,938
18	GAS	MCF	9,423,480	8,014,491	4,511,617	2,867,670	3,053,527	27,870,784
19	NUCLEAR	MMBTU	5,809,325	5,624,264	5,809,325	5,620,449	5,805,385	28,668,748
20	OTHER	BBL	0	0	0	0	0	0
	BTUS BURNED (MMBTU)							
21	HEAVY OIL		8,137,835	7,675,733	6,490,915	3,362,922	5,152,341	30,819,747
22	LIGHT OIL		1,756,997	643,723	468,485	7,693	34,148	2,911,046
23	COAL		13,508,017	13,077,107	14,257,172	14,207,139	14,691,093	69,740,528
24	GAS		9,423,480	8,014,491	4,511,617	2,867,670	3,053,527	27,870,784
25	NUCLEAR		5,809,325	5,624,264	5,809,325	5,620,449	5,805,385	28,668,748
26	OTHER		0	0	0	0	0	0
27	TOTAL	MMBTU	38,635,655	35,035,318	31,537,514	26,065,873	28,736,493	160,010,853
	GENERATION MIX (% MWH)							
28	HEAVY OIL		19.88%	20.30%	19.03%	11.48%	16.50%	17.81%
29	LIGHT OIL		3.07%	1.24%	1.02%	0.02%	0.09%	1.22%
30	COAL		35.67%	37.44%	46.43%	54.90%	51.59%	44.22%
31	GAS		27.24%	26.17%	16.10%	13.39%	12.86%	19.94%
32	NUCLEAR		14.14%	14.85%	17.41%	20.21%	18.97%	16.81%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT							
35	HEAVY OIL	$/BBL	28.94	30.76	31.37	31.07	30.95	30.47
36	LIGHT OIL	$/BBL	47.65	48.35	48.77	56.40	56.64	48.11
37	COAL	$/TON	54.27	54.27	54.17	54.15	54.14	54.20
38	GAS	$/MCF	6.63	6.88	6.80	7.74	7.26	6.91
39	NUCLEAR	$/MMBTU	0.35	0.35	0.35	0.35	0.35	0.35
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)							
41	HEAVY OIL		4.45	4.73	4.83	4.78	4.76	4.69
42	LIGHT OIL		8.22	8.34	8.41	9.72	9.77	8.30
43	COAL		2.16	2.16	2.16	2.15	2.15	2.16
44	GAS		6.63	6.88	6.80	7.74	7.26	6.91
45	NUCLEAR		0.35	0.35	0.35	0.35	0.35	0.35
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	3.74	3.63	3.13	2.72	2.81	3.26
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL		10,373	10,389	10,642	10,736	10,393	10,475
49	LIGHT OIL		14,518	14,246	14,270	12,192	13,139	14,392
50	COAL		9,594	9,597	9,582	9,480	9,480	9,545
51	GAS		8,765	8,414	8,742	7,845	7,907	8,457
52	NUCLEAR		10,409	10,409	10,409	10,191	10,191	10,321
53	OTHER		0	0	0	0	0	0
54	TOTAL	BTU/KWH	9,789	9,628	9,840	9,550	9,567	9,683
	GENERATED FUEL COST PER KWH (C/KWH)							
55	HEAVY OIL		4.62	4.92	5.14	5.13	4.95	4.91
56	LIGHT OIL		11.93	11.87	12.00	11.86	12.83	11.94
57	COAL		2.07	2.07	2.07	2.04	2.04	2.06
58	GAS		5.81	5.79	5.95	6.07	5.74	5.85
59	NUCLEAR		0.36	0.36	0.36	0.36	0.36	0.36
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	3.66	3.49	3.08	2.60	2.69	3.16

SCHEDULE E4
Reprojected 8/04

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Aug-04

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	769	556,106	97.5	97.0	100.0	10,409	NUCLEAR	5,809,325 MMBTU	1.00	5,809,325	2,033,264	0.36
2 ANCLOTE	1	498	257,332	69.5	95.5	71.0	10,055	HEAVY OIL	398,073 BBLS	6.50	2,587,473	11,695,379	4.54
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	495	258,617	70.2	94.4	72.8	10,057	HEAVY OIL	400,140 BBLS	6.50	2,600,911	11,756,118	4.55
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	121	50,312	55.9	85.9	69.6	10,875	HEAVY OIL	84,176 BBLS	6.50	547,143	2,351,031	4.67
7 BARTOW	2	119	51,858	58.6	95.5	68.4	11,165	HEAVY OIL	89,076 BBLS	6.50	578,995	2,487,895	4.80
8 BARTOW	3	204	100,460	66.2	90.4	70.6	10,228	HEAVY OIL	158,078 BBLS	6.50	1,027,505	4,415,109	4.39
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	180,438	64.0	93.8	67.2	10,348	COAL	74,094 TONS	25.20	1,867,172	3,894,388	2.16
11 CRYSTAL RIVER	2	486	221,336	61.2	81.4	74.1	9,443	COAL	82,940 TONS	25.20	2,090,076	4,359,301	1.97
12 CRYSTAL RIVER	4	720	506,245	94.5	94.5	98.6	9,499	COAL	191,587 TONS	25.10	4,808,821	10,533,426	2.08
13 CRYSTAL RIVER	5	717	499,889	93.7	93.7	98.5	9,486	COAL	188,922 TONS	25.10	4,741,947	10,386,942	2.08
14 SUWANNEE	1	32	15,296	64.2	97.1	79.5	12,502	HEAVY OIL	29,420 BBLS	6.50	191,231	818,467	5.35
15 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	31	15,388	66.7	98.2	80.5	13,309	HEAVY OIL	31,508 BBLS	6.50	204,799	876,539	5.70
17 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	80	35,285	59.3	93.1	74.8	11,330	HEAVY OIL	61,504 BBLS	6.50	399,779	1,830,988	5.19
19 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	52	3,674	9.5	100.0	148.7	17,446	LIGHT OIL	11,051 BBLS	5.80	64,095	512,758	13.96
21 BARTOW	1-4	187	4,332	14.6	100.0	57.3	14,746	LIGHT OIL	11,014 BBLS	5.80	63,880	511,037	11.80
22 BARTOW	1-4		16,012				15,226	GAS	243,799 MCF	1.00	243,799	1,417,595	8.85
23 BAYBORO	1-4	184	22,363	16.3	100.0	64.0	14,532	LIGHT OIL	56,030 BBLS	5.80	324,974	2,599,788	11.63
24 DEBARY	1-10	687	45,399	20.6	100.0	60.5	13,942	LIGHT OIL	109,131 BBLS	5.80	632,959	5,209,255	11.47
25 DEBARY	1-10		56,752				13,864	GAS	786,791 MCF	1.00	786,791	4,574,885	8.06
26 HIGGINS	1-4	122	1,119	10.6	100.0	145.1	18,038	LIGHT OIL	3,480 BBLS	5.80	20,185	188,725	16.87
27 HIGGINS	1-4		8,486				16,239	GAS	137,804 MCF	1.00	137,804	801,278	9.44
28 HINES	1-2	998	666,474	89.8	97.2	45.9	6,957	GAS	4,636,326 MCF	1.00	4,636,326	26,958,449	4.04
29 HINES	1-2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	898	20,138	29.3	100.0	62.4	14,395	LIGHT OIL	49,979 BBLS	5.80	289,880	2,391,508	11.88
31 INT CITY	1-14		175,876				13,379	GAS	2,353,095 MCF	1.00	2,353,095	13,682,341	7.78
32 RIO PINAR	1	13	371	3.8	100.0	81.5	18,536	LIGHT OIL	1,186 BBLS	5.80	6,877	57,215	15.42
33 SUWANNEE	1-3	164	17,659	14.5	100.0	64.1	14,223	LIGHT OIL	43,304 BBLS	5.80	251,164	2,089,684	11.83
34 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	207	125,557	81.5	94.7	85.7	8,101	GAS	1,017,137 MCF	1.00	1,017,137	3,631,180	2.89
36 TURNER	1-4	154	5,971	5.2	100.0	68.8	17,248	LIGHT OIL	17,756 BBLS	5.80	102,985	875,371	14.66
37 UNIV OF FLA.	1	35	25,918	99.5	99.5	99.9	9,589	GAS	248,528 MCF	1.00	248,528	995,093	3.84
38 OTHER - START UP		-	0	-	-	-	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
39 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	10,402,914	-
40 TOTAL		8,332	3,946,663				9,789				38,635,655	144,337,928	3.66

SCHEDULE E4
Reprojected 8/04

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Sep-04

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC 3	769	540,327	97.6	97.1	100.0	10,409	NUCLEAR	5,624,264 MMBTU	1.00	5,624,264	1,968,492	0.36
2 ANCLOTE 1	498	240,833	67.2	95.5	68.6	10,076	HEAVY OIL	373,328 BBLS	6.50	2,426,633	11,670,240	4.85
3 ANCLOTE 1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE 2	495	244,777	68.7	94.4	71.2	10,069	HEAVY OIL	379,178 BBLS	6.50	2,464,660	11,853,117	4.84
5 ANCLOTE 2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW 1	121	49,779	57.1	85.9	70.8	10,847	HEAVY OIL	83,070 BBLS	6.50	539,953	2,460,523	4.94
7 BARTOW 2	119	49,267	57.5	95.5	68.1	11,202	HEAVY OIL	84,906 BBLS	6.50	551,889	2,514,915	5.10
8 BARTOW 3	204	94,965	64.7	90.4	68.9	10,238	HEAVY OIL	149,609 BBLS	6.50	972,456	4,431,409	4.67
9 BARTOW 3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER 1	379	174,670	64.0	93.8	67.2	10,349	COAL	71,733 TONS	25.20	1,807,660	3,770,262	2.16
11 CRYSTAL RIVER 2	486	214,415	61.3	81.4	74.1	9,443	COAL	80,346 TONS	25.20	2,024,721	4,222,989	1.97
12 CRYSTAL RIVER 4	720	489,924	94.5	94.5	98.6	9,499	COAL	185,410 TONS	25.10	4,653,788	10,193,835	2.08
13 CRYSTAL RIVER 5	717	483,613	93.7	93.7	98.5	9,493	COAL	182,906 TONS	25.10	4,590,938	10,056,167	2.08
14 SUWANNEE 1	32	14,054	61.0	97.1	78.3	12,593	HEAVY OIL	27,228 BBLS	6.50	176,982	803,498	5.72
15 SUWANNEE 1		0				0	GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE 2	31	13,695	61.4	98.2	76.6	13,430	HEAVY OIL	28,296 BBLS	6.50	183,924	835,014	6.10
17 SUWANNEE 2		0				0	GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE 3	80	31,454	54.8	93.1	69.3	11,421	HEAVY OIL	55,267 BBLS	6.50	359,236	1,756,941	5.59
19 SUWANNEE 3		0				0	GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK 1-2	52	442	1.2	100.0	170.0	17,547	LIGHT OIL	1,337 BBLS	5.80	7,756	63,128	14.28
21 BARTOW 1-4	187	691	7.7	100.0	59.8	14,746	LIGHT OIL	1,757 BBLS	5.80	10,189	82,939	12.00
22 BARTOW 1-4		9,675				15,255	GAS	147,587 MCF	1.00	147,587	902,458	9.33
23 BAYBORO 1-4	184	9,560	7.2	100.0	53.2	14,546	LIGHT OIL	23,975 BBLS	5.80	139,057	1,131,879	11.84
24 DEBARY 1-10	867	22,675	12.1	100.0	60.0	13,959	LIGHT OIL	54,573 BBLS	5.80	316,524	2,649,193	11.68
25 DEBARY 1-10		35,479				13,873	GAS	492,188 MCF	1.00	492,188	3,009,604	8.48
26 HIGGINS 1-4	122	23	5.8	100.0	692.2	19,132	LIGHT OIL	76 BBLS	5.80	440	4,176	18.16
27 HIGGINS 1-4		5,044				16,292	GAS	82,174 MCF	1.00	82,174	502,475	9.96
28 HINES 1-2	998	632,983	88.1	97.2	45.0	6,964	GAS	4,407,777 MCF	1.00	4,407,777	26,952,417	4.26
29 HINES 1-2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY 1-14	898	3,674	20.0	100.0	60.3	14,428	LIGHT OIL	9,140 BBLS	5.80	53,010	444,733	12.10
31 INT CITY 1-14		125,793				13,384	GAS	1,683,560 MCF	1.00	1,683,560	10,294,531	8.18
32 RIO PINAR 1	13	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 SUWANNEE 1-3	164	7,418	6.3	100.0	62.2	14,243	LIGHT OIL	18,216 BBLS	5.80	105,652	893,780	12.05
34 SUWANNEE 1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY 1	207	118,504	79.5	94.7	83.6	8,107	GAS	960,712 MCF	1.00	960,712	3,429,742	2.89
36 TURNER 1-4	154	702	0.6	100.0	91.2	15,806	LIGHT OIL	1,913 BBLS	5.80	11,095	95,861	13.66
37 UNIV OF FLA. 1	35	25,080	99.5	99.5	99.9	9,589	GAS	240,492 MCF	1.00	240,492	1,045,547	4.17
38 OTHER - START UP	-	0	-	-	-	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
39 OTHER - GAS TRANSP.	-	0	-	-	-	-	GAS TRANSP.	- -	-	-	9,038,862	-
40 TOTAL	8,332	3,639,536				9,626				35,035,318	127,078,728	3.49

SCHEDULE E4
Reprojected 8/04

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Oct-04

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	769	558,106	97.5	97.0	100.0	10,409	NUCLEAR	5,809,325 MMBTU	1.00	5,809,325	2,033,264	0.36
2 ANCLOTE	1	498	200,750	54.2	95.5	54.9	10,324	HEAVY OIL	318,853 BBLS	6.50	2,072,543	10,174,592	5.07
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	495	196,817	53.4	94.4	55.4	10,360	HEAVY OIL	313,696 BBLS	6.50	2,039,024	10,010,040	5.09
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	121	37,099	41.2	85.9	57.5	11,157	HEAVY OIL	63,679 BBLS	6.50	413,914	1,919,285	5.17
7 BARTOW	2	119	39,842	45.0	95.5	55.6	11,516	HEAVY OIL	70,588 BBLS	6.50	458,820	2,127,515	5.34
8 BARTOW	3	204	84,606	55.7	90.4	63.7	10,389	HEAVY OIL	135,226 BBLS	6.50	878,972	4,075,724	4.82
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	232,408	82.4	91.6	86.7	10,147	COAL	93,581 TONS	25.20	2,358,244	4,918,623	2.12
11 CRYSTAL RIVER	2	466	259,717	71.8	77.8	86.9	9,393	COAL	96,806 TONS	25.20	2,439,522	5,088,145	1.96
12 CRYSTAL RIVER	4	720	504,808	94.2	67.1	138.5	9,501	COAL	191,007 TONS	25.10	4,794,281	10,501,576	2.08
13 CRYSTAL RIVER	5	717	491,221	92.1	93.7	96.8	9,497	COAL	185,862 TONS	25.10	4,665,126	10,218,670	2.08
14 SUWANNEE	1	32	12,629	53.0	97.1	67.9	12,672	HEAVY OIL	24,621 BBLS	6.50	160,035	739,360	5.85
15 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	31	12,022	52.1	98.2	66.6	13,700	HEAVY OIL	25,339 BBLS	6.50	164,701	760,920	6.33
17 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	80	26,169	44.0	93.1	59.0	11,575	HEAVY OIL	46,601 BBLS	6.50	302,906	1,514,531	5.79
19 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	52	752	1.9	100.0	1446.2	17,474	LIGHT OIL	2,266 BBLS	5.80	13,140	107,752	14.33
21 BARTOW	1-4	187	75	4.6	100.0	47.9	15,049	LIGHT OIL	195 BBLS	5.80	1,129	9,255	12.34
22 BARTOW	1-4		6,371				15,256	GAS	97,193 MCF	1.00	97,193	603,392	9.47
23 BAYBORO	1-4	184	4,809	3.5	100.0	58.4	14,585	LIGHT OIL	12,093 BBLS	5.80	70,139	575,142	11.96
24 DEBARY	1-10	667	12,762	7.6	100.0	49.0	13,995	LIGHT OIL	30,794 BBLS	5.80	178,606	1,505,649	11.80
25 DEBARY	1-10		24,794				13,875	GAS	344,017 MCF	1.00	344,017	2,135,723	8.61
26 HIGGINS	1-4	122	0	0.0	100.0	893.7	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
27 HIGGINS	1-4		3,271				16,295	GAS	53,301 MCF	1.00	53,301	330,903	10.12
28 HINES	1-2	998	303,726	40.9	57.3	33.7	7,083	GAS	2,151,139 MCF	1.00	2,151,139	13,354,690	4.40
29 HINES	1-2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	1,041	9,626	11.0	100.0	43.0	14,190	LIGHT OIL	23,550 BBLS	5.80	136,590	1,154,183	11.99
31 INT CITY	1-14		75,539				13,305	GAS	1,005,059 MCF	1.00	1,005,059	6,239,601	8.26
32 RIO PINAR	1	13	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 SUWANNEE	1-3	164	4,647	3.8	100.0	48.9	14,271	LIGHT OIL	11,434 BBLS	5.80	66,319	565,037	12.16
34 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	207	88,155	57.2	73.3	77.7	8,220	GAS	724,634 MCF	1.00	724,634	2,586,944	2.93
36 TURNER	1-4	154	160	0.1	100.0	155.8	16,011	LIGHT OIL	442 BBLS	5.80	2,562	22,287	13.93
37 UNIV OF FLA.	1	35	14,210	54.6	54.6	100.0	9,590	GAS	136,274 MCF	1.00	136,274	421,015	2.96
38 OTHER - START UP		-	0	-	-	-	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
39 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	5,023,754	-
40 TOTAL		6,475	3,204,891				9,840				31,537,514	98,717,572	3.08

SCHEDULE E4
Reprojected 8/04

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Nov-04

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	788	551,511	97.2	97.1	100.0	10,191	NUCLEAR	5,620,449 MMBTU	1.00	5,620,449	1,967,157	0.36
2 ANCLOTE	1	522	148,560	39.5	94.8	40.2	10,487	HEAVY OIL	239,684 BBLS	6.50	1,557,949	7,586,012	5.11
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	522	58,293	15.5	81.5	18.6	10,816	HEAVY OIL	97,000 BBLS	6.50	630,497	3,070,036	5.27
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	123	15,632	17.7	85.8	32.8	11,103	HEAVY OIL	26,702 BBLS	6.50	173,562	796,249	5.09
7 BARTOW	2	121	16,689	19.2	95.5	35.2	11,741	HEAVY OIL	30,145 BBLS	6.50	195,946	898,938	5.39
8 BARTOW	3	208	57,459	38.4	90.2	43.4	10,460	HEAVY OIL	92,465 BBLS	6.50	601,021	2,757,300	4.80
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	383	238,340	86.4	91.5	90.8	10,066	COAL	95,204 TONS	25.20	2,399,130	5,003,901	2.10
11 CRYSTAL RIVER	2	491	269,148	78.1	77.7	92.1	9,299	COAL	99,318 TONS	25.20	2,502,807	5,220,141	1.94
12 CRYSTAL RIVER	4	735	499,524	94.4	12.7	738.7	9,375	COAL	186,575 TONS	25.10	4,683,038	10,257,904	2.05
13 CRYSTAL RIVER	5	732	491,615	93.3	93.6	98.0	9,402	COAL	184,150 TONS	25.10	4,622,184	10,124,565	2.06
14 SUWANNEE	1	33	4,815	20.3	97.1	57.0	12,641	HEAVY OIL	9,364 BBLS	6.50	60,866	278,206	5.78
15 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	32	3,542	15.4	98.2	38.6	13,587	HEAVY OIL	7,404 BBLS	6.50	48,125	219,969	6.21
17 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	81	8,237	14.1	93.0	34.9	11,528	HEAVY OIL	14,609 BBLS	6.50	94,956	470,106	5.71
19 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	64	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
21 BARTOW	1-4	219	0	0.2	100.0	43.8	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
22 BARTOW	1-4		240				14,797	GAS	3,551 MCF	1.00	3,551	26,669	11.11
23 BAYBORO	1-4	232	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
24 DEBARY	1-10	762	0	0.0	100.0	42.9	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
25 DEBARY	1-10		1,340				13,491	GAS	18,077 MCF	1.00	18,077	135,762	10.13
26 HIGGINS	1-4	134	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
27 HIGGINS	1-4		0				0	GAS	0 MCF	1.00	0	0	0.00
28 HINES	1-2	1,111	227,635	28.5	74.8	24.5	7,122	GAS	1,621,216 MCF	1.00	1,621,216	12,175,317	5.35
29 HINES	1-2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	1,206	601	1.4	100.0	39.9	12,131	LIGHT OIL	1,257 BBLS	5.80	7,291	70,871	11.79
31 INT CITY	1-14		11,572				12,949	GAS	149,840 MCF	1.00	149,840	1,125,297	9.72
32 RIO PINAR	1	16	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 SUWANNEE	1-3	201	30	0.0	100.0	5.0	13,420	LIGHT OIL	69 BBLS	5.80	403	3,942	13.14
34 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	223	95,394	59.4	94.6	62.4	8,382	GAS	799,593 MCF	1.00	799,593	2,854,545	2.99
36 TURNER	1-4	194	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 UNIV OF FLA.	1	41	29,372	99.5	99.5	99.9	9,376	GAS	275,392 MCF	1.00	275,392	1,643,190	5.59
38 OTHER - START UP		-	0	-	-	-	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
39 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	4,228,331	-
40 TOTAL		9,174	2,729,549				9,550				26,065,873	70,914,408	2.60

SCHEDULE E4
Reprojected 8/04

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Dec-04

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	788	569,658	97.2	97.0	100.0	10,191	NUCLEAR	5,805,385 MMBTU	1.00	5,805,385	2,031,885	0.36
2 ANCLOTE	1	522	190,109	49.0	94.8	52.9	10,132	HEAVY OIL	296,336 BBLS	6.50	1,926,184	9,301,989	4.89
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	522	171,021	44.0	83.7	69.1	10,309	HEAVY OIL	271,239 BBLS	6.50	1,763,055	8,514,202	4.98
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	123	23,267	25.4	85.8	50.9	10,907	HEAVY OIL	39,042 BBLS	6.50	253,773	1,156,425	4.97
7 BARTOW	2	121	22,509	25.0	95.5	46.2	11,504	HEAVY OIL	39,837 BBLS	6.50	258,944	1,179,986	5.24
8 BARTOW	3	206	66,221	42.8	90.2	46.1	10,174	HEAVY OIL	103,651 BBLS	6.50	673,732	3,070,147	4.64
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	383	248,132	87.1	91.5	96.0	10,061	COAL	99,066 TONS	25.20	2,496,456	5,206,894	2.10
11 CRYSTAL RIVER	2	491	278,513	76.2	77.7	92.2	9,301	COAL	102,796 TONS	25.20	2,590,449	5,402,937	1.94
12 CRYSTAL RIVER	4	735	516,175	94.4	94.4	98.5	9,375	COAL	192,794 TONS	25.10	4,839,141	10,599,839	2.05
13 CRYSTAL RIVER	5	732	506,812	93.1	93.6	97.9	9,402	COAL	189,842 TONS	25.10	4,765,046	10,437,540	2.06
14 SUWANNEE	1	33	5,306	21.6	97.1	64.8	12,636	HEAVY OIL	10,315 BBLS	6.50	67,047	304,392	5.74
15 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	32	4,718	19.8	98.2	78.4	13,709	HEAVY OIL	9,951 BBLS	6.50	64,679	293,643	6.22
17 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	81	12,587	20.9	93.0	51.3	11,514	HEAVY OIL	22,296 BBLS	6.50	144,927	711,702	5.65
19 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	64	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
21 BARTOW	1-4	219	75	0.4	100.0	35.3	14,191	LIGHT OIL	184 BBLS	5.80	1,064	10,111	13.48
22 BARTOW	1-4		563				14,664	GAS	8,256 MCF	1.00	8,256	58,091	10.32
23 BAYBORO	1-4	232	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
24 DEBARY	1-10	762	489	0.7	100.0	59.6	13,973	LIGHT OIL	1,178 BBLS	5.80	6,833	66,482	13.60
25 DEBARY	1-10		3,464				13,480	GAS	46,694 MCF	1.00	46,694	328,562	9.49
26 HIGGINS	1-4	134	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
27 HIGGINS	1-4		0				0	GAS	0 MCF	1.00	0	0	0.00
28 HINES	1-2	1,111	237,707	28.8	97.1	24.2	7,151	GAS	1,699,724 MCF	1.00	1,699,724	11,960,194	5.03
29 HINES	1-2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	1,206	1,061	1.8	100.0	42.2	12,167	LIGHT OIL	2,226 BBLS	5.80	12,909	125,865	11.86
31 INT CITY	1-14		12,887				13,048	GAS	168,150 MCF	1.00	168,150	1,183,193	9.18
32 RIO PINAR	1	16	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 SUWANNEE	1-3	201	974	0.7	100.0	33.0	13,698	LIGHT OIL	2,300 BBLS	5.80	13,342	131,014	13.45
34 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	223	101,211	61.0	94.7	64.1	8,360	GAS	846,124 MCF	1.00	846,124	3,020,683	2.98
36 TURNER	1-4	194	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 UNIV OF FLA.	1	41	30,352	99.5	99.5	99.9	9,376	GAS	284,580 MCF	1.00	284,580	1,527,464	5.03
38 OTHER - START UP		-	0	-	-	-	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
39 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	4,093,443	-
40 TOTAL		9,174	3,003,811				9,567				28,736,493	80,716,659	2.69

SCHEDULE E4
Reprojected 8/04

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD OF: Aug-04 THROUGH Dec-04

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	780	2,777,708	44.3	97.0	41.7	10,321 NUCLEAR	28,668,748 MMBTU	1.00	28,668,748	10,034,062	0.36
2 ANCLOTE	1	510	1,037,584	25.3	93.7	25.3	10,188 HEAVY OIL	1,826,274 BBLS	6.50	10,570,783	50,428,211	4.86
3 ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	509	929,525	22.7	87.4	24.5	10,218 HEAVY OIL	1,461,253 BBLS	6.50	9,498,147	45,203,513	4.86
5 ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	122	176,089	18.0	85.7	21.4	10,951 HEAVY OIL	296,668 BBLS	6.50	1,928,345	8,683,514	4.93
7 BARTOW	2	120	180,165	18.7	96.0	22.4	11,348 HEAVY OIL	314,553 BBLS	6.50	2,044,593	9,209,249	5.11
8 BARTOW	3	206	403,731	24.4	85.5	25.4	10,288 HEAVY OIL	639,029 BBLS	6.50	4,153,687	18,749,690	4.64
9 BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	361	1,073,988	35.1	81.1	39.0	10,176 COAL	433,677 TONS	25.20	10,928,663	22,794,068	2.12
11 CRYSTAL RIVER	2	489	1,243,129	31.7	82.5	33.1	9,370 COAL	462,205 TONS	25.20	11,647,575	24,293,514	1.95
12 CRYSTAL RIVER	4	728	2,516,478	43.0	85.0	45.5	9,449 COAL	947,373 TONS	25.10	23,779,068	52,086,580	2.07
13 CRYSTAL RIVER	5	725	2,473,150	42.5	93.7	40.7	9,456 COAL	931,682 TONS	25.10	23,385,222	51,223,884	2.07
14 SUWANNEE	1	33	52,100	19.9	94.2	29.9	12,594 HEAVY OIL	100,948 BBLS	6.50	656,160	2,943,924	5.65
15 SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	32	49,365	19.5	94.9	29.4	13,496 HEAVY OIL	102,497 BBLS	6.50	666,228	2,986,086	6.05
17 SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	81	113,732	17.6	94.7	26.0	11,446 HEAVY OIL	200,278 BBLS	6.50	1,301,804	5,284,268	5.53
19 SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	58	4,866	1.0	100.0	63.1	17,459 LIGHT OIL	14,654 BBLS	5.80	84,991	683,637	14.04
21 BARTOW	1-4	203	5,173	2.3	100.0	27.1	14,742 LIGHT OIL	13,149 BBLS	5.80	76,262	613,343	11.86
22 BARTOW	1-4		32,861				15,227 GAS	500,386 MCF	1.00	500,386	3,008,205	9.15
23 BAYBORO	1-4	206	36,732	2.2	100.0	25.5	14,542 LIGHT OIL	92,098 BBLS	5.80	534,170	4,306,809	11.72
24 DEBARY	1-10	715	81,325	3.5	100.0	28.8	13,955 LIGHT OIL	195,676 BBLS	5.80	1,134,922	9,430,579	11.60
25 DEBARY	1-10		121,829				13,854 GAS	1,687,787 MCF	1.00	1,687,787	10,184,535	8.36
26 HIGGINS	1-4	128	1,142	1.7	100.0	80.1	18,080 LIGHT OIL	3,556 BBLS	5.80	20,625	192,901	16.89
27 HIGGINS	1-4		16,801				16,266 GAS	273,279 MCF	1.00	273,279	1,634,655	9.73
28 HINES	1-2	1,055	2,068,525	24.4	89.4	15.1	7,018 GAS	14,516,183 MCF	1.00	14,516,183	91,401,067	4.42
29 HINES	1-2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	1,076	35,100	5.0	100.0	32.6	14,236 LIGHT OIL	86,152 BBLS	5.80	499,679	4,187,160	11.93
31 INT CITY	1-14		401,667				13,344 GAS	5,359,703 MCF	1.00	5,359,703	32,524,963	8.10
32 RIO PINAR	1	15	371	0.3	100.0	36.0	18,536 LIGHT OIL	1,186 BBLS	5.80	6,877	57,215	15.42
33 SUWANNEE	1-3	183	30,728	2.1	100.0	29.0	14,218 LIGHT OIL	75,324 BBLS	5.80	436,879	3,683,457	11.99
34 SUWANNEE	1-3		0				0 GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	215	526,821	30.6	89.5	31.0	8,222 GAS	4,348,200 MCF	1.00	4,348,200	15,523,073	2.94
36 TURNER	1-4	174	6,833	0.5	100.0	30.8	17,070 LIGHT OIL	20,111 BBLS	5.80	116,642	993,519	14.54
37 UNIV OF FLA.	1	38	124,932	40.9	91.7	40.9	9,487 GAS	1,185,266 MCF	1.00	1,185,266	5,632,308	4.51
38 OTHER - START UP		-	0	-	-	-	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
39 OTHER - GAS TRANSP.		-	0	-	-	-	- GAS TRANSP.	-	-	-	32,787,304	-
40 TOTAL	8,778	16,524,450				9,683				160,010,853	521,765,296	3.16

SCHEDULE E5
Reprojected 8/04

PROGRESS ENERGY FLORIDA
INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD OF: AUGUST THROUGH DECEMBER 2004

	HEAVY OIL		Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Total
1	PURCHASES:							
2	UNITS	BBL	1,251,975	1,180,882	998,602	517,373	792,668	4,741,500
3	UNIT COST	$/BBL	28.94	30.76	31.37	31.07	30.95	30.47
4	AMOUNT	$	36,231,528	36,325,658	31,321,968	16,076,816	24,532,485	144,488,455
5	BURNED:							
6	UNITS	BBL	1,251,975	1,180,882	998,602	517,373	792,668	4,741,500
7	UNIT COST	$/BBL	28.94	30.76	31.37	31.07	30.95	30.47
8	AMOUNT	$	36,231,528	36,325,658	31,321,968	16,076,816	24,532,485	144,488,455
9	ENDING INVENTORY:							
10	UNITS	BBL	800,000	800,000	800,000	800,000	800,000	
11	UNIT COST	$/BBL	28.94	30.76	31.37	31.07	30.95	
12	AMOUNT	$	23,151,600	24,609,200	25,092,640	24,859,200	24,759,440	
13	DAYS SUPPLY:		20	20	25	46	31	
	LIGHT OIL							
14	PURCHASES:							
15	UNITS	BBL	302,931	110,987	80,773	1,326	5,888	501,905
16	UNIT COST	$/BBL	47.65	48.35	48.77	56.40	56.64	48.11
17	AMOUNT	$	14,435,343	5,365,689	3,939,305	74,813	333,471	24,148,621
18	BURNED:							
19	UNITS	BBL	302,931	110,987	80,773	1,326	5,888	501,905
20	UNIT COST	$/BBL	47.65	48.35	48.77	56.40	56.64	48.11
21	AMOUNT	$	14,435,343	5,365,689	3,939,305	74,813	333,471	24,148,621
22	ENDING INVENTORY:							
23	UNITS	BBL	550,000	550,000	550,000	550,000	550,000	
24	UNIT COST	$/BBL	47.65	48.35	48.77	56.40	56.64	
25	AMOUNT	$	26,207,500	26,592,500	26,823,500	31,020,000	31,152,000	
26	DAYS SUPPLY:		56	149	211	12439	2896	
	COAL							
27	PURCHASES:							
28	UNITS	TON	537,542	520,394	567,256	565,247	584,498	2,774,938
29	UNIT COST	$/TON	54.27	54.27	54.17	54.15	54.14	54.20
30	AMOUNT	$	29,174,057	28,243,253	30,727,014	30,606,511	31,647,210	150,398,046
31	BURNED:							
32	UNITS	TON	537,542	520,394	567,256	565,247	584,498	2,774,938
33	UNIT COST	$/TON	54.27	54.27	54.17	54.15	54.14	54.20
34	AMOUNT	$	29,174,057	28,243,253	30,727,014	30,606,511	31,647,210	150,398,046
35	ENDING INVENTORY:							
36	UNITS	TON	550,000	550,000	550,000	550,000	550,000	
37	UNIT COST	$/TON	54.27	54.27	54.17	54.15	54.14	
38	AMOUNT	$	29,850,150	29,850,040	29,792,290	29,780,960	29,779,310	
39	DAYS SUPPLY:		32	32	30	29	29	
	GAS							
40	BURNED:							
41	UNITS	MCF	9,423,480	8,014,491	4,511,617	2,867,670	3,053,527	27,870,784
42	UNIT COST	$/MCF	6.63	6.88	6.80	7.74	7.26	6.91
43	AMOUNT	$	62,463,736	55,175,636	30,696,021	22,189,111	22,171,609	192,696,112
	NUCLEAR							
44	BURNED:							
45	UNITS	MMBTU	5,809,325	5,624,264	5,809,325	5,620,449	5,805,385	28,668,748
46	UNIT COST	$/MMBTU	0.35	0.35	0.35	0.35	0.35	0.35
47	AMOUNT	$	2,033,264	1,968,492	2,033,264	1,967,157	2,031,885	10,034,062

SCHEDULE E6
Reprojected 8/04

PROGRESS ENERGY FLORIDA
FUEL COST OF POWER SOLD
ESTIMATED FOR THE PERIOD OF: AUGUST THROUGH DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
						C/MWH				
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Aug-04	ECONSALE	--	57,000		57,000	4.197	4.880	2,392,005	2,781,600	389,595
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	244,030		244,030	3.338	3.338	8,145,147	8,145,147	0
	TOTAL		301,030		301,030	3.500	3.630	10,537,152	10,926,747	389,595
Sep-04	ECONSALE	--	72,000		72,000	4.051	4.744	2,916,864	3,415,824	498,960
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	245,133		245,133	3.371	3.371	8,262,591	8,262,591	0
	TOTAL		317,133		317,133	3.525	3.682	11,179,455	11,678,415	498,960
Oct-04	ECONSALE	--	67,000		67,000	3.981	4.529	2,667,471	3,034,698	367,227
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	248,659		248,659	3.170	3.170	7,882,382	7,882,382	0
	TOTAL		315,659		315,659	3.342	3.459	10,549,853	10,917,080	367,227
Nov-04	ECONSALE	--	101,000		101,000	3.442	3.874	3,476,218	3,912,892	436,674
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	223,489		223,489	2.937	2.937	6,564,448	6,564,448	0
	TOTAL		324,489		324,489	3.094	3.229	10,040,666	10,477,339	436,674
Dec-04	ECONSALE	--	130,000		130,000	2.909	3.214	3,782,220	4,177,615	395,395
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	210,151		210,151	2.758	2.758	5,796,859	5,796,859	0
	TOTAL		340,151		340,151	2.816	2.932	9,579,079	9,974,474	395,395

SCHEDULE E7
Reprojected 8/04

PROGRESS ENERGY FLORIDA
PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGEN PURCHASES)
ESTIMATED FOR THE PERIOD OF: AUGUST THROUGH DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH			C/MWH		TOTAL $
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	FOR FUEL ADJ (7) x (8)(B)
Aug-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	26,887			26,887	3.948	3.948	1,061,501
	UPS PURCHASE	UPS	308,016			308,016	1.514	1.514	4,662,742
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		334,903	0	0	334,903	1.709	1.709	5,724,243
Sep-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	27,282			27,282	3.948	3.948	1,077,091
	UPS PURCHASE	UPS	298,080			298,080	1.514	1.514	4,512,331
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		325,362	0	0	325,362	1.718	1.718	5,589,422
Oct-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	23,525			23,525	3.948	3.948	928,768
	UPS PURCHASE	UPS	308,016			308,016	1.516	1.516	4,669,523
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		331,541	0	0	331,541	1.689	1.689	5,598,291
Nov-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	21,662			21,662	3.948	3.948	855,196
	UPS PURCHASE	UPS	298,080			298,080	1.516	1.516	4,519,484
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		319,742	0	0	319,742	1.681	1.681	5,374,680
Dec-04	REEDY CREEK	A&B	882			882	5.000	5.000	44,100
	TECO	--	24,599			24,599	3.948	3.948	971,172
	UPS PURCHASE	UPS	308,016			308,016	1.515	1.515	4,667,062
	VANDOLAH	--	5,179			5,179	12.536	12.536	649,226
	TOTAL		338,676	0	0	338,676	1.870	1.870	6,331,560

SCHEDULE E8
Reprojected 8/04

PROGRESS ENERGY FLORIDA
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD OF: AUGUST THROUGH DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	C/MWH (A) ENERGY COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Aug-04	QUAL. FACILITIES	COGEN	401,431			401,431	2.598	8.089	10,429,043
Sep-04	QUAL. FACILITIES	COGEN	373,103			373,103	2.622	8.113	9,783,419
Oct-04	QUAL. FACILITIES	COGEN	375,611			375,611	2.527	8.018	9,492,244
Nov-04	QUAL. FACILITIES	COGEN	387,009			387,009	2.497	7.988	9,664,344
Dec-04	QUAL. FACILITIES	COGEN	402,012			402,012	2.519	8.010	10,126,621

SCHEDULE E9
Reprojected 8/04

PROGRESS ENERGY FLORIDA
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD OF: AUGUST THROUGH DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/MWH	TOTAL COST C/MWH	FOR FUEL ADJ (4) x (5)	(A) C/MWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Aug-04	ECONPURCH	--	55,000	4.953	4.953	2,724,398	6.954	3,824,956	1,100,558
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		55,000	4953.451	4953.451	2,724,398	6.954	3,824,956	1,100,558
Sep-04	ECONPURCH	--	55,000	4.808	4.808	2,644,633	6.478	3,562,674	918,041
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		55,000	4808.424	4808.424	2,644,633	6.478	3,562,674	918,041
Oct-04	ECONPURCH	--	42,000	4.746	4.746	1,993,253	5.564	2,337,076	343,823
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		42,000	4745.840	4745.840	1,993,253	5.564	2,337,076	343,823
Nov-04	ECONPURCH	--	20,000	4.541	4.541	908,120	5.521	1,104,272	196,152
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		20,000	4540.600	4540.600	908,120	5.521	1,104,272	196,152
Dec-04	ECONPURCH	--	16,000	3.827	3.827	612,240	5.436	869,762	257,522
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		16,000	3826.500	3826.500	612,240	5.436	869,762	257,522

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS JANUARY THROUGH DECEMBER 2005

PART A - SALES FORECAST ASSUMPTIONS

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 33
COMPANY/ PEF
WITNESS. Javier Portuondo (JP-1P)
DATE 11-08-04

SALES FORECAST ASSUMPTIONS

1. This forecast of customers, sales and peak demand was developed for use in the 2005 budget and 2005 - 2009 five-year Business Plan. This forecast was prepared in June 2004.

2. Normal weather conditions are assumed over the forecast horizon. For kilowatt-hour sales projections normal weather is based on a historical thirty-year average of service area weighted billing month degree days. Seasonal peak demand projections are based on a thirty-year historical average of system-weighted temperatures at time of seasonal peak.

3. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida as published in "Florida Population Studies Bulletin No. 138 (February 2004) provide the basis for development of the customer forecast. State and national economic assumptions produced by Economy.Com in their national and Florida forecasts (February, 2004) are also incorporated.

4. Within the Progress Energy Florida (PEF) service area the phosphate mining industry is the dominant sector in the industrial sales class. Six major customers accounted for nearly 30% of the industrial class MWh sales in 2003. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. Both supply and demand conditions for their products are dictated by global conditions that include, but are not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. Load and energy consumption at the PEF-served mining or chemical processing sites depend heavily on plant operations which are heavily influenced by the state of these global conditions as well as local conditions. After years of excess mining capacity and weak product pricing power, the industry has consolidated down to fewer players in time to take advantage of better market conditions. A weaker U.S currency value on the foreign exchange is expected to help the industry in two ways. First, American farm commodities will be more competitive overseas and lead to higher crop production at home. This will result in greater demand for fertilizer products. Second, a weak U.S. dollar results in U.S. fertilizer producers to become more price competitive relative to foreign producers. Going forward, energy consumption is expected to increase – as we have recently experienced - to the levels just below that experienced in the late 1990 boom period. A significant risk to this projection lies in the continued high price of natural gas which is a major factor of production. Operations at several sites in the U.S. have already

scaled back or shutdown due to profitability concerns caused by high energy prices. The energy projection for this industry assumes no major reductions or shutdowns of operations in the service territory.

5. Progress Energy Florida supplies load and energy service to wholesale customers on a "full", "partial" and "supplemental" requirement basis. Full requirements customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Partial requirements customer load is assumed to reflect the current contractual obligations received by PEF in an annual "declaration letter" as of May 31, 2004. The forecast of energy and demand to partial requirements customers reflect the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for partial requirements service included in this forecast are with FMPA, the cities of New Smyrna Beach, Tallahassee and Homestead, and other utilities such as Reedy Creek Utilities, Florida Power & Light and Tampa Electric Company. PEF's arrangement with Seminole Electric Cooperative, Inc. (SECI) is to serve "supplemental" service over and above stated levels they commit to supply themselves. SECI's projection of their system's requirements in the PEF control area has been incorporated into this forecast. This forecast also incorporates a 150 MW stratified intermediate demand firm power contract with SECI.

6. This forecast assumes that PEF will successfully renew all future franchise agreements.

7. This forecast incorporates demand and energy reductions from PEF'S dispatchable and non-dispatchable DSM programs required to meet the approved goals set by the Florida Public Service Commission.

8. Expected energy and demand reductions from self-service cogeneration are also included in this forecast. PEF will supply the supplemental load of self-service cogeneration customers. While PEF offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for standby power.

9. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. The ability of wholesale customers to switch suppliers has ended the company's obligation to serve these customers beyond their contract life. As a result, the company does not plan for generation resources unless a long-term contract is in place. Current "all requirements" customers are assumed to not renew their contracts with PEF. Current "partial requirements" contracts are projected to terminate as terms reach their expiration date.

10. The economic outlook for this forecast calls for a gradual strengthening of national and State economic growth as the recovery from the recent recession takes hold and terrorism fears subside. As this forecast was developed signs of an improving economy were beginning to be reflected in reported GDP growth. Employment growth had just commenced after a long period of contraction. Monetary policy announcements suggested a return to more normal levels of interest rates and monetary growth. A fifty-year low in market interest rates - coaxed by the Federal Reserve Board (FED) – and lower Federal tax rates appear to have stimulated the U.S. economy enough to warrant a less accommodative monetary policy.

    The extremely accommodative fiscal and monetary policies since late 2001, the passage of time from the terror attack of 9/11, and the working off of excess investment of the "bubble" economy, have set up the U.S. and Florida economy on track for reasonable consistent growth for the foreseeable future. As consumer confidence rebounds more reasonable returns on investment will enable businesses to resume hiring. A weaker dollar should make domestic producers more competitive.

    Particular sectors of the economy that have been performing well include the housing industry and the individual consumer. Both have been credited with fueling the limited economic advances of the past two years. The multi-generational low in interest rates and expansion of credit has stimulated an unprecedented level of housing construction. The record level of mortgage refinancing and lowering of Federal taxes have acted to put added money in people's pockets, further stimulating demand.

    While most signs point toward an improving economic environment, there are some risks that were considered in the development of this forecast. Market prices for energy have been very high for an extended period at this point. Historically, high oil prices have resulted in starving economic growth. Fears of a shortage in supplies has kept natural gas prices high as well and has placed increased burden on manufacturers who rely upon reasonably priced fuel as a major source of production.

    An additional risk comes as the FED increases interest rates. Some economists believe that the housing sector has been over-simulated by record-low interest rates. Others believe that Americans have "loaded up" on debt and will be negatively impacted by higher debt-service as interest rates rise. The FED must carefully balance the risks staving off higher inflation without starving economic growth. Higher inflation could force up market-driven interest rates faster than the FED would prefer. This event would certainly hurt the housing sector as well as consumer spending. This forecast tries to balance this and other risks by incorporating the National and State economic projections developed by Economy.Com.

Growth in energy consumption is directly tied to the levels of economic activity in the State, nation and around the world, but demographic forces play a major role as well. Factors that influence in-migration rates to Florida impact residential customer growth, especially since the difference between births and deaths contribute little to Florida's growing population. Obviously, many factors influence the pace of in-migration to Florida but there is one broad, demographically created influence one can expect during the next few years. The University of Florida's latest population projection (February 2004) shows a return to more normal levels of growth in Florida population as we move into the mid-decade. This is due to economy-related conditions and characteristics of the age cohorts reaching retirement age this decade.

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS JANUARY THROUGH DECEMBER 2005

PART B - FUEL PRICE FORECAST ASSUMPTIONS

FUEL PRICE FORECAST ASSUMPTIONS

A. Residual Oil and Light Oil

The oil price forecast is based on expectations of normal weather and no radical changes in world energy markets (OPEC actions, governmental rule changes, etc.). Prices are based on expected contract structures, specifications, and market conditions during 2004 & 2005.

PEF Residual Fuel Oil (#6) and Distillate Fuel Oil (#2) prices were derived from PIRA Energy Group forecasts and current market information.

The oil prices listed on Part C do not include transportation costs to individual plant locations.

B. Coal

Coal price projections are provided by Progress Fuels and represent an estimate of the price to Progress Energy Florida for coal delivered to the plant sites in accordance with the delivery schedules projected. The forecast is consistent with the coal supply and transportation agreements which Progress Fuels has, or expects to have, in place during 2004 & 2005 and estimated spot purchase volumes and prices for the period. It assumes environmental restrictions on coal quality remain in effect as per current permits: 2.1 lbs. per million BTU sulfur dioxide limit for Crystal River Units 1 and 2, and 1.2 lbs. per million BTU sulfur dioxide limit for Crystal River Units 4 and 5.

C. Natural Gas

The natural gas price forecast is based on the expectation of average weather conditions and a steady trend in supply and demand. Prices are based on expected contract structures and spot market purchases for 2004 & 2005. Gas supply prices were derived from PIRA Energy Group forecasts and current market information.

Transportation costs for Florida Gas Transmission and Gulfstream pipeline firm transportation services are based on expected tariff rates. Interruptible transportation rates and availability are based on expected tariff rates and market conditions.

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS JANUARY THROUGH DECEMBER 2005

PART C - FUEL PRICE FORECAST

Progress Energy Florida
Docket No. 040001-EI
Witness: J. Portuondo
Part C
Sheet 1 of 3

FUEL PRICE FORECAST
#6 Fuel Oil

	1.0%		1.5%		2.5%	
Month	**$/barrel**	**$/MMBtu (1)**	**$/barrel**	**$/MMBtu (1)**	**$/barrel**	**$/MMBtu (1)**
Jan 2005	35.82	5.51	34.91	5.37	33.22	5.11
Feb 2005	36.01	5.54	35.10	5.40	33.41	5.14
Mar 2005	36.86	5.67	35.88	5.52	34.19	5.26
Apr 2005	36.99	5.69	36.01	5.54	34.32	5.28
May 2005	36.27	5.58	35.36	5.44	33.67	5.18
Jun 2005	35.82	5.51	34.91	5.37	33.22	5.11
Jul 2005	36.92	5.68	35.95	5.53	34.26	5.27
Aug 2005	36.53	5.62	35.56	5.47	33.87	5.21
Sep 2005	36.21	5.57	35.30	5.43	33.61	5.17
Oct 2005	36.40	5.60	35.49	5.46	33.80	5.20
Nov 2005	36.47	5.61	35.56	5.47	33.80	5.20
Dec 2005	36.47	5.61	35.56	5.47	33.80	5.20

(1) 6.5 mmbtu/bbl

FUEL PRICE FORECAST
#2 Fuel Oil

Month	$/barrel	¢/gallon	$/MMBtu[1]
Jan 2005	56.09	133.54	9.67
Feb 2005	55.62	132.43	9.59
Mar 2005	55.22	131.47	9.52
Apr 2005	49.24	117.24	8.49
May 2005	47.27	112.55	8.15
Jun 2005	46.34	110.34	7.99
Jul 2005	45.94	109.37	7.92
Aug 2005	46.11	109.79	7.95
Sep 2005	46.34	110.34	7.99
Oct 2005	46.52	110.75	8.02
Nov 2005	49.88	118.76	8.60
Dec 2005	49.94	118.90	8.61

[1] 5.8 MMBtu/Bbl & 42 gallon/Bbl

FUEL PRICE FORECAST
Natural Gas Supply [1]

Month	$/MMBtu
Jan 2005	7.29
Feb 2005	7.27
Mar 2005	7.36
Apr 2005	6.68
May 2005	6.31
Jun 2005	6.32
Jul 2005	6.35
Aug 2005	6.37
Sep 2005	6.39
Oct 2005	6.53
Nov 2005	7.37
Dec 2005	7.34

[1] Transport costs not included

FUEL PRICE FORECAST
Coal

	Crystal River 1 & 2			Crystal River 4 & 5		
Month	BTU/lb.	$/ton	$/MMBtu	BTU/lb.	$/ton	$/MMBtu
Jan – Dec 2005	12,500	67.43	2.697	12,500	60.52	2.421

PART D - CAPACITY COST RECOVERY CALCULATIONS

PROGRESS ENERGY FLORIDA
CAPACITY COST RECOVERY CLAUSE
PROJECTED CAPACITY PAYMENTS
For the Year 2005

Progress Energy Florida
Docket 040001-EI
Witness: J. Portuondo
Part D
Sheet 1 of 5

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total
Base Production Level Capacity Charges:													
1 Payments to Qualifying Facilities	22,336,728	22,336,728	22,336,728	22,336,728	22,336,728	22,336,728	22,336,728	22,336,728	22,336,728	22,336,728	22,336,728	22,336,728	268,040,736
2 UPS Purchase (414 MW)	4,370,000	3,950,000	4,370,000	4,229,000	4,370,000	4,229,000	4,370,000	4,370,000	4,229,000	4,370,000	4,229,000	4,370,000	51,456,000
3 Incremental Security Costs	0	0	595,730	0	0	595,730	0	0	595,730	0	0	595,730	2,382,920
4 Subtotal - Base Level Capacity Charges	26,706,728	26,286,728	27,302,458	26,565,728	26,706,728	27,161,458	26,706,728	26,706,728	27,161,458	26,706,728	26,565,728	27,302,458	321,879,656
5 Base Production Jurisdictional %	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	
6 Base Jurisdictional Capacity Charges	25,626,975	25,223,956	26,198,620	25,491,676	25,626,975	26,063,320	25,626,975	25,626,975	26,063,320	25,626,975	25,491,676	26,198,620	308,866,062
Intermediate Production Level Capacity Charges:													
7 TECO Power Purchase	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	659,767	7,917,204
8 Other Power Sales	(3,500)	(3,500)	(3,500)	(3,500)	(3,500)	(3,500)	(3,500)	(3,500)	(3,500)	(3,500)	(3,500)	(3,500)	(42,000)
9 Subtotal - Intermediate Level Capacity Charges	656,267	656,267	656,267	656,267	656,267	656,267	656,267	656,267	656,267	656,267	656,267	656,267	7,875,204
10 Intermediate Production Jurisdictional %	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	
11 Intermediate Jurisdictional Capacity Charges	568,157	568,157	568,157	568,157	568,157	568,157	568,157	568,157	568,157	568,157	568,157	568,157	6,817,879
Peaking Production Level Capacity Charges:													
12 City of Chattahoochee	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	12,500	150,000
13 Reliant Energy Services (Vandolah)	0	0	0	0	0	1,365,000	1,365,000	1,365,000	1,365,000	1,365,000	1,365,000	1,365,000	9,555,000
14 Peaking Purchases - Summer Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
15 Peaking Purchases - Winter Peak	947,900	897,900	0	0	0	0	0	0	0	0	0	0	1,845,800
16 Capacity Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
17 Subtotal - Peaking Level Capacity Charges	960,400	910,400	12,500	12,500	12,500	1,377,500	1,377,500	1,377,500	1,377,500	1,377,500	1,377,500	1,377,500	11,550,800
18 Peaking Production Jurisdictional %	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	
19 Peaking Jurisdictional Capacity Charges	716,093	678,812	9,320	9,320	9,320	1,027,092	1,027,092	1,027,092	1,027,092	1,027,092	1,027,092	1,027,092	8,612,507
20 Transmission Revenues from Economy Sales	(280,218)	(328,007)	(319,700)	(209,368)	(102,304)	(75,328)	(110,145)	(105,478)	(129,933)	(111,825)	(167,644)	(220,289)	(2,160,237)
21 Jurisdictional Capacity Payments (Lines 6 + 11 + 19 + 20)	26,631,009	26,142,918	26,456,396	25,859,784	26,102,148	27,583,240	27,112,078	27,116,745	27,528,635	27,110,398	26,919,280	27,573,579	322,136,211
22 Estimated/Actual True-Up Provision for the Period January through December 2004													(11,358,199)
23 Total (Sum of lines 21 & 22)													310,778,012
24 Revenue Tax Multiplier													1.00072
25 Total Recoverable Capacity Payments													311,001,772

PROGRESS ENERGY FLORIDA
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED / ACTUAL TRUE-UP
For the Year 2004

Progress Energy Florida
Docket 040001-EI
Witness: Portuondo
Exhibit No.
Part D
Sheet 2 of 5

		Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Actual Jun-04	Actual Jul-04	Estimated Aug-04	Estimated Sep-04	Estimated Oct-04	Estimated Nov-04	Estimated Dec-04	Total 2004
	Base Production Level Capacity Charges:													
1	Payments to Qualifying Facilities	20,160,892	21,180,647	21,190,611	21,213,185	21,197,052	21,038,038	20,720,322	21,294,679	21,294,679	21,294,679	21,294,679	21,294,679	253,174,142
2	UPS Purchase (409 MW)	4,281,772	4,750,723	3,894,737	3,841,737	3,993,872	4,099,574	4,121,419	4,215,321	4,079,343	4,215,321	4,079,343	4,215,321	49,788,483
3	Incremental Security Costs	0	17,831	7,867	192,964	33,033	140,821	1,058,349	451,048	451,048	451,048	451,048	451,050	3,705,907
4	Subtotal - Base Level Capacity Charges	24,442,664	25,949,201	25,093,015	25,247,886	25,223,957	25,278,433	25,900,090	25,961,048	25,825,070	25,961,048	25,825,070	25,961,050	306,668,532
5	Base Production Jurisdictional %	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%
6	Base Level Jurisdictional Capacity Charges	23,454,447	24,900,075	24,078,504	24,227,114	24,204,152	24,256,426	24,852,949	24,911,443	24,780,962	24,911,443	24,780,962	24,911,445	294,269,923
	Intermediate Production Level Capacity Charges:													
7	TECO Power Purchase	565,567	565,567	565,567	565,567	565,567	565,567	565,567	566,000	566,000	566,000	566,000	566,000	6,788,969
8	Capacity Sales	(3,593)	(3,361)	(3,593)	(3,477)	(79,195)	(117,060)	(4,195)	(3,500)	(3,500)	(3,500)	(3,500)	(3,500)	(231,974)
9	Subtotal - Intermediate Level Capacity Charges	561,974	562,206	561,974	562,090	486,372	448,507	561,372	562,500	562,500	562,500	562,500	562,500	6,556,995
10	Intermediate Production Jurisdictional %	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%
11	Intermediate Level Jurisdictional Capacity Charg	486,523	486,724	486,523	486,624	421,072	388,290	486,002	486,979	486,979	486,979	486,979	486,979	5,676,853
	Peaking Production Level Capacity Charges:													
12	City of Chattahoochee	4,839	11,541	13,056	12,231	12,366	12,218	12,782	12,500	12,500	12,500	12,500	12,500	141,533
13	Peaking Purchases - Summer Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Peaking Purchases - Winter Peak	100,000	100,000	0	0	0	0	0	0	0	0	0	897,900	1,097,900
15	Capacity Sales	0	0	0	(120,000)	(400,000)	0	0	0	0	0	0	0	(520,000)
16	Subtotal - Peaking Level Capacity Charges	104,839	111,541	13,056	(107,769)	(387,634)	12,218	12,782	12,500	12,500	12,500	12,500	910,400	719,433
17	Peaking Production Jurisdictional %	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%
18	Peaking Level Jurisdictional Capacity Charges	78,170	83,167	9,735	(80,355)	(289,028)	9,110	9,531	9,320	9,320	9,320	9,320	678,812	536,424
19	Transmission Revenues from Economy Sales	(353,548)	(232,511)	(146,789)	(128,892)	(81,256)	(4,004)	(365)	(106,411)	(134,414)	(125,080)	(188,553)	(242,892)	(1,744,515)
20	Jurisdictional Capacity Payments (Lines 6 + 11 + 18 + 19)	23,665,593	25,237,455	24,427,974	24,504,491	24,254,940	24,649,822	25,348,117	25,301,331	25,142,847	25,282,662	25,088,708	25,834,544	298,738,485
21	Capacity Cost Recovery Revenues	23,661,189	20,668,871	21,039,724	20,087,370	22,534,692	28,521,089	30,855,867	29,758,981	29,993,106	27,196,073	23,430,561	22,869,352	300,616,655
22	Prior Period True-Up Provision	275,762	275,762	275,762	275,762	275,762	275,762	275,762	275,762	275,762	275,762	275,762	6,362,447	9,395,829
23	Current Period Capacity Revenues (Lines 21+22)	23,936,951	20,944,433	21,315,486	20,363,132	22,810,454	28,796,851	31,131,629	30,034,723	30,268,868	27,471,835	23,706,323	29,231,799	310,012,484
24	Current Period Over/(Under) Rec. (Lines 23-20)	271,358	(4,293,022)	(3,112,488)	(4,141,359)	(1,444,486)	4,147,029	5,783,512	4,733,392	5,126,021	2,189,173	(1,382,385)	3,397,255	11,273,999
25	Interest Provision for Month	8,182	5,977	2,577	(636)	(3,291)	(2,727)	2,261	8,093	13,548	17,520	17,690	15,008	84,200
26	Current Cycle Balance	279,540	(4,007,505)	(7,117,416)	(11,259,411)	(12,707,188)	(8,562,887)	(2,777,114)	1,964,371	7,103,940	9,310,633	7,945,938	11,358,199	11,358,199
27	Plus: Prior Period Balance	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829	9,395,829
28	Plus: Cumulative True-Up Provision	(275,762)	(551,524)	(827,286)	(1,103,048)	(1,378,810)	(1,654,572)	(1,930,334)	(2,206,096)	(2,481,858)	(2,757,620)	(3,033,382)	(9,395,829)	(9,395,829)
29	End of Period Net True-Up (Lines 26+27+28)	9,399,607	4,836,800	1,451,127	(2,966,630)	(4,690,169)	(821,630)	4,688,381	9,154,104	14,017,911	15,948,842	14,308,385	11,358,199	11,358,199

PROGRESS ENERGY FLORIDA
DEVELOPMENT OF JURISDICTIONAL DELIVERY LOSS MULTIPLIERS
BASED ON ACTUAL CALENDAR YEAR 2003 DATA
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Energy Delivered				Energy Required @ Source			
Class Loads	Sales Mwh	Unbilled Mwh	Total Mwh	% of Total	Delivery Efficiency	Mwh (3) / (5)	% of Total	Jurisdictional Loss Multiplier
I. CLASS LOADS:								
A. RETAIL								
1. Transmission	471,323	1,834	473,157		0.9764000	484,593		
2. Distribution Primary	4,481,316	17,436	4,498,752		0.9664000	4,655,166		
3. Distribution Secondary	33,004,050	128,415	33,132,465		0.9421658	35,166,279		
Total Retail	37,956,689	147,685	38,104,374	91.75%	0.9453763	40,306,038	92.09%	1.00375
B. WHOLESALE								
1. Source Level	1,996,908	66,373	2,063,281		1.0000000	2,063,281		
2. Transmission	1,251,862	19,562	1,271,424		0.9764000	1,302,155		
3. Distribution Primary	93,981	(530)	93,451		0.9664000	96,700		
4. Distribution Secondary	-	-	0		0.9421658	0		
Total Wholesale	3,342,751	85,405	3,428,156	8.25%	0.9901850	3,462,136	7.91%	0.95833
Total Class Loads	41,299,440	233,090	41,532,530	100.00%	0.9489208	43,768,174	100.00%	1.00000
II. NON-CLASS LOADS								
1. Sepa	16,679	-	16,679		0.9764000	17,082		
2. Interchange	963,184	-	963,184		1.0000000	963,184		
3. Company Use	118,576	-	118,576		0.9421658	125,855		
Total Non-Class Loads	1,098,439	-	1,098,439		0.9930550	1,106,121		
Total System	42,397,879	233,090	42,630,969		0.9500087	44,874,295		

PROGRESS ENERGY FLORIDA
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF AVERAGE 12 CP AND ANNUAL AVERAGE DEMAND
For the Year 2005

Progress Energy Florida
Docket 040001-EI
Witness: J. Portuondo
Part D
Sheet 4 of 5

Rate Class	(1) Mwh Sales @ Meter Level	(2) 12 CP Load Factor	(3) Average CP MW @ Meter Level (1)/8760hrs/(2)	(4) Delivery Efficiency Factor	(5) Average CP MW @ Source Level (3)/(4)	(6) Mwh Sales @ Meter Level	(7) Delivery Efficiency Factor	(8) Source Level Mwh (6)/(7)	(9) Annual Average Demand (8)/8760hrs
I. Residential Service	20,046,231	0.548	4,175.88	0.9421658	4,432.21	20,046,231	0.9421658	21,276,755	2,428.85
II. General Service Non-Demand									
Transmission	2,205	0.609	0.41	0.9764000	0.42	2,205	0.9764000	2,258	0.26
Primary	9,250	0.609	1.73	0.9664000	1.79	9,250	0.9664000	9,572	1.09
Secondary	1,333,086	0.609	249.88	0.9421658	265.22	1,333,086	0.9421658	1,414,917	161.52
Total Gen Serv Non-Demand	1,344,541		252.02		267.43	1,344,541		1,426,747	162.87
III. GS - 100% L.F.	85,275	1.000	9.73	0.9421658	10.33	85,275	0.9421658	90,510	10.33
IV. General Service Demand									
SS-1 - Transmission	8,332	3.733	0.25			8,332			
GSD-1 - Transmission	156	0.698	0.03			156			
Total Transmission	8,488		0.28	0.9764000	0.29	8,488	0.9764000	8,693	0.99
SS-1 - Primary	9,174	3.733	0.28			9,174			
GSD-1 - Primary	2,762,073	0.698	451.73			2,762,073			
Total Primary	2,771,247		452.01	0.9664000	467.73	2,771,247	0.9664000	2,867,598	327.35
GSD - Secondary	12,851,526	0.698	2,101.82	0.9421658	2,230.84	12,851,526	0.9421658	13,640,408	1,557.12
Total Gen Serv Demand	15,631,261		2,554.11		2,698.86	15,631,261		16,516,699	1,885.46
V. Curtailable Service									
CS - Primary	202,249	0.779	29.64			202,249			
SS-3 - Primary	4,310	0.480	1.03			4,310			
Total Primary	206,559		30.67	0.9664000	31.74	206,559	0.9664000	213,741	24.40
CS - Secondary	375	0.779	0.05	0.9421658	0.05	375	0.9421658	398	0.05
Total Curtailable Service	206,934		30.72		31.79	206,934		214,139	24.45
VI. Interruptible Service									
IS - Transmission	451,210	0.940	54.80			451,210			
SS-2 - Transmission	74,811	0.748	11.42			74,811			
Total Transmission	526,021		66.22	0.9764000	67.82	526,021	0.9764000	538,735	61.50
IS - Primary	1,899,879	0.940	230.72			1,899,879			
SS-2 - Primary	80,926	0.748	12.35			80,926			
Total Primary	1,980,805		243.07	0.9664000	251.52	1,980,805	0.9664000	2,049,674	233.98
IS - Secondary	147,996	0.940	17.97	0.9421658	19.07	147,996	0.9421658	157,081	17.93
Total Interruptible Service	2,654,822		327.26		338.41	2,654,822		2,745,490	313.41
VII. Lighting Service	323,633	4.650	7.95	0.9421658	8.44	323,633	0.9421658	343,499	39.21
Total Retail	**40,292,697**				**7,787.47**	**40,292,697**		**42,613,839**	**4,864.58**

PROGRESS ENERGY FLORIDA
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF CAPACITY COST RECOVERY FACTOR
For the Year 2005

	(1) Average 12 CP Demand Mw	(2) Average 12 CP Demand %	(3) Annual Average Demand Mw	(4) Annual Average Demand %	(5) 12/13 of 12 CP 12/13 * (2)	(6) 1/13 of Annual Demand 1/13 * (4)	(7) Demand Allocation (5) + (6)	(8) Dollar Allocation (7) * Total	(9) Effective Mwh's @ Secondary Level Year 2005	(10) Capacity Cost Recovery Factor (c/Kwh)
I. Residential Service	4,432.21	56.915%	2,428.85	49.929%	52.537%	3.841%	56.378%	175,336,579	20,046,231	0.875
II. General Service Non-Demand										
Transmission									2,161	0.777
Primary									9,158	0.785
Secondary									1,333,086	0.793
Total Gen Serv Non-Demand	267.43	3.434%	162.87	3.348%	3.170%	0.257%	3.427%	10,658,031	1,344,405	
III. GS - 100% L.F.	10.33	0.133%	10.33	0.212%	0.123%	0.016%	0.139%	432,292	85,275	0.507
IV. General Service Demand										
Transmission									8,318	0.683
Primary									2,743,535	0.690
Secondary									12,851,526	0.697
Total Gen Service Demand	2,698.86	34.656%	1,885.46	38.759%	31.990%	2.981%	34.971%	108,760,430	15,603,379	
V. Curtailable Service										
Transmission									0	0.617
Primary									204,493	0.624
Secondary									375	0.630
Total Curtailable Service	31.79	0.408%	24.45	0.503%	0.376%	0.039%	0.415%	1,290,657	204,868	
VI. Interruptible Service										
Transmission									515,501	0.524
Primary									1,960,997	0.529
Secondary									147,996	0.534
Total Interruptible Service	338.41	4.346%	313.41	6.443%	4.012%	0.496%	4.508%	14,019,960	2,624,494	
VII. Lighting Service	8.44	0.108%	39.21	0.806%	0.100%	0.062%	0.162%	503,823	323,633	0.156
Total Retail	**7,787.47**	**100.000%**	**4,864.58**	**100.000%**	**92.308%**	**7.692%**	**100.000%**	**311,001,772**	**40,232,285**	**0.77186**

EXHIBITS TO THE TESTIMONY OF
JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS
JANUARY THROUGH DECEMBER 2005

PART E - HINES UNIT 2 DEPRECIATION & RETURN CALCULATION

PROGRESS ENERGY FLORIDA, INC.
DOCKET NO. 040001-E1
WITNESS: J. PORTUONDO
PART E - PAGE 1 OF 2

HINES UNIT 2
SCHEDULE OF SYSTEM DEPRECIATION AND RETURN
FOR THE PERIOD OF JANUARY THROUGH DECEMBER 2005

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	Hines Unit 2 - Land													
1	BEGINNING BALANCE	$ 2,204,142	$ 2,204,142	$ 2,204,142	$ 2,204,142	$ 2,204,142	$ 2,204,142	$ 2,204,142	$ 2,204,142	$ 2,204,142	$ 2,204,142	$ 2,204,142	$ 2,204,142	$ 2,204,142
2	ADD INVESTMENT	-	-	-	-	-	-	-	-	-	-	-	-	-
3	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	ENDING BALANCE	2,204,142	2,204,142	2,204,142	2,204,142	2,204,142	2,204,142	2,204,142	2,204,142	2,204,142	2,204,142	2,204,142	2,204,142	2,204,142
5	**Hines Unit 2 - Production Plant**													
6	BEGINNING BALANCE	$ 237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334
7	ADD INVESTMENT	-	-	-	-	-	-	-	-	-	-	-	-	-
8	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
9	ENDING BALANCE	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334
10	AVERAGE BALANCE	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	237,802,334	
11	DEPRECIATION RATE (2)	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	
12	DEPRECIATION EXPENSE	733,223	733,223	733,223	733,223	733,223	733,223	733,223	733,223	733,223	733,223	733,223	733,223	8,798,676
13	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
14	BEGINNING BALANCE DEPRECIATION	9,091,612	9,824,835	10,558,058	11,291,281	12,024,504	12,757,727	13,490,950	14,224,173	14,957,396	15,690,619	16,423,842	17,157,065	9,091,612
15	ENDING BALANCE DEPRECIATION	9,824,835	10,558,058	11,291,281	12,024,504	12,757,727	13,490,950	14,224,173	14,957,396	15,690,619	16,423,842	17,157,065	17,890,288	17,890,288
16	**Hines Unit 2 - Transmission Station Equipment**													
17	BEGINNING BALANCE	$ 4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092
18	ADD INVESTMENT	-	-	-	-	-	-	-	-	-	-	-	-	-
19	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
20	ENDING BALANCE	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092
21	AVERAGE BALANCE	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	4,898,092	
22	DEPRECIATION RATE (3)	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	
23	DEPRECIATION EXPENSE	8,980	8,980	8,980	8,980	8,980	8,980	8,980	8,980	8,980	8,980	8,980	8,980	107,760
24	LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
25	BEGINNING BALANCE DEPRECIATION	$ 111,348	120,326	129,306	138,286	147,266	156,246	165,226	174,206	183,186	192,166	201,146	210,126	111,348
26	ENDING BALANCE DEPRECIATION	120,326	129,306	138,286	147,266	156,246	165,226	174,206	183,186	192,166	201,146	210,126	219,106	219,106
27	**Hines Unit 2 - Total**													
28	TOTAL DEPRECIATION EXPENSE	$ 742,203	$ 742,203	$ 742,203	$ 742,203	$ 742,203	$ 742,203	$ 742,203	$ 742,203	$ 742,203	$ 742,203	$ 742,203	$ 742,203	$ 8,906,436
29	TOTAL END BALANCE DEPRECIATION	$ 9,945,161	$ 10,687,364	$ 11,429,567	$ 12,171,770	$ 12,913,973	$ 13,656,176	$ 14,398,379	$ 15,140,582	$ 15,882,785	$ 16,624,988	$ 17,367,191	$ 18,109,394	$ 18,109,394

(1) – Land is not depreciated.

(2) – Depreciation Expense for Hines Unit 2 - Production Plant is calculated based on an annual rate of 3.70%.

(3) – Depreciation Expense for Hines Unit 2 - Transmission Station Equipment is calculated based on an annual rate of 2.20%.

HINES UNIT 2
SCHEDULE OF SYSTEM DEPRECIATION AND RETURN
FOR THE PERIOD OF JANUARY THROUGH DECEMBER 2005

	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1 BEGINNING NET INVESTMENT	$ 235,701,610	$ 234,959,407	$ 234,217,204	$ 233,475,001	$ 232,732,798	$ 231,990,595	$ 231,248,392	$ 230,506,189	$ 229,763,986	$ 229,021,783	$ 228,279,580	$ 227,537,377	
2 ENDING NET INVESTMENT	234,959,407	234,217,204	233,475,001	232,732,798	231,990,595	231,248,392	230,506,189	229,763,986	229,021,783	228,279,580	227,537,377	226,795,174	
3 AVERAGE INVESTMENT	$ 235,330,509	$ 234,588,306	$ 233,846,103	$ 233,103,900	$ 232,361,697	$ 231,619,494	$ 230,877,291	$ 230,135,088	$ 229,392,885	$ 228,650,682	$ 227,908,479	$ 227,166,276	
4 ALLOWED EQUITY RETURN (1)	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	
5 EQUITY COMPONENT AFTER-TAX	1,296,271	1,292,183	1,288,094	1,284,006	1,279,918	1,275,830	1,271,741	1,267,653	1,263,565	1,259,477	1,255,388	1,251,300	15,285,426
6 CONVERSION TO PRE-TAX	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	
7 EQUITY COMPONENT PRE-TAX	2,110,329	2,103,674	2,097,017	2,090,362	2,083,707	2,077,051	2,070,394	2,063,739	2,057,084	2,050,429	2,043,772	2,037,116	24,884,674
8 ALLOWED DEBT RETURN (1)	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	
9 DEBT COMPONENT	504,007	502,418	500,826	499,239	497,649	496,059	494,470	492,880	491,291	489,701	488,112	486,522	5,943,176
10 TOTAL RETURN REQUIREMENTS (2)	2,614,338	2,608,092	2,597,845	2,589,601	2,581,358	2,573,110	2,564,864	2,556,619	2,548,375	2,540,130	2,531,884	2,523,638	30,827,850
11 TOTAL DEPRECIATION & RETURN	$ 3,356,539	$ 3,348,295	$ 3,340,048	$ 3,331,804	$ 3,323,559	$ 3,315,313	$ 3,307,067	$ 3,298,822	$ 3,290,578	$ 3,282,333	$ 3,274,087	$ 3,265,841	$ 39,734,286
12 FUEL SAVINGS	$ 1,469,952	$ 2,202	$ 874,368	$ 1,644,552	$ 3,585,708	$ 7,580,160	$ 6,771,920	$ 9,486,720	$ 6,772,813	$ 1,913,011	$ 858,240	$ 459,264	$ 43,418,910
13 TOTAL DEPRECIATION & RETURN	3,356,539	3,348,295	3,340,048	3,331,804	3,323,559	3,315,313	3,307,067	3,298,822	3,290,578	3,282,333	3,274,087	3,265,841	39,734,286
14 NET BENEFIT (COST) TO RATEPAYER	$ (1,886,587)	$ (3,346,093)	$ (2,485,680)	$ (1,687,252)	$ 262,149	$ 4,264,847	$ 5,464,853	$ 6,187,898	$ 3,482,235	$ (1,369,322)	$ (2,415,847)	$ (2,806,577)	$ 3,684,624

(1) -- Return on Average Investment (through 12/31/03) is calculated using an annual rate of 8.37% (Equity 5.12%, Debt 3.25%).
Return on Average Investment (effective 1/1/04) is calculated using an annual rate of 9.16% (Equity 6.61%, Debt 2.57%).

(2) -- Return Requirements is calculated based on a combined statutory rate of 38.575%

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS JANUARY THROUGH DECEMBER 2005

SCHEDULES E1 THROUGH E10 AND H1

SCHEDULE E1
Revised 11/04

Docket No. 040001
Progress Energy Florida
Exhibit No. ____ (JP - 1SR)
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PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

			DOLLARS	MWH		CENTS/KWH
1.	Fuel Cost of System Net Generation		1,429,852,257	39,262,465		3.64178
2.	Spent Nuclear Fuel Disposal Cost		5,730,430	6,128,802	*	0.09350
3.	Coal Car Investment		0	0		0.00000
4.	Adjustment to Fuel Cost		39,438,402	0		0.00000
5.	TOTAL COST OF GENERATED POWER		1,475,021,089	39,262,465		3.75682
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		93,895,836	4,196,258		2.23761
7.	Energy Cost of Sch. C,X Economy Purchases (Broker) (E9)		0	0		0.00000
8.	Energy Cost of Economy Purchases (Non-Broker) (E9)		23,678,334	471,160		5.02554
9.	Energy Cost of Schedule E Economy Purchases (E9)		0	0		0.00000
10.	Capacity Cost of Economy Purchases (E9)		0	0	*	0.00000
11.	Payments to Qualifying Facilities (E8)		120,730,408	4,728,731		2.55312
12.	TOTAL COST OF PURCHASED POWER		238,304,578	9,396,149		2.53619
13.	TOTAL AVAILABLE KWH			48,658,614		
14.	Fuel Cost of Economy Sales	(E6)	0	0		0.00000
14a.	Gain on Economy Sales - 80%	(E6)	0	0	*	0.00000
15.	Fuel Cost of Other Power Sales	(E6)	(52,847,025)	(1,157,150)		4.56700
15a.	Gain on Other Power Sales	(E6)	(6,891,443)	(1,157,150)	*	0.59555
16.	Fuel Cost of Unit Power Sales	(E6)	0	0		0.00000
16a.	Gain on Unit Power Sales	(E6)	0	0		0.00000
17.	Fuel Cost of Stratified Sales	(E6)	(81,110,043)	(2,243,088)		3.61600
18.	TOTAL FUEL COST AND GAINS ON POWER SALES		(140,848,511)	(3,400,238)		4.14231
19.	Net Inadvertent Interchange			0		
20.	TOTAL FUEL AND NET POWER TRANSACTIONS		1,572,477,156	45,258,376		3.47444
21.	Net Unbilled		(1,215,079)	34,972		(0.00290)
22.	Company Use		5,003,200	(144,000)		0.01180
23.	T & D Losses		91,566,726	(2,635,435)		0.21538
24.	Adjusted System KWH Sales		1,572,477,156	42,513,913		3.69872
25.	Wholesale KWH Sales (Excluding Supplemental Sales)		(81,810,023)	(2,221,216)		3.68312
26.	*Jurisdictional KWH Sales*		1,490,667,133	40,292,697		3.69960
27.	Jurisdictional KWH Sales Adjusted for Line Losses x 1.0038		1,496,331,668	40,292,697		3.71365
28.	Prior Period True-Up (Sch E1-A)		76,802,024	40,292,697		0.19061
29.	Total Jurisdictional Fuel Cost		1,573,133,692	40,292,697		3.90426
30.	Revenue Tax Factor					1.00072
31.	Fuel Cost Adjusted for Taxes		1,574,266,348	40,292,697		3.90707
32.	GPIF		2,139,695	40,292,697		0.00531
33.	*Fuel Factor Adjusted for taxes including GPIF*		1,576,406,043	40,292,697		3.91238
34.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)					3.912

* For Informational Purposes Only

Docket No. 040001
Progress Energy Florida
Exhibit No. ____ (JP - 1SR)
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PROGRESS ENERGY FLORIDA
CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

1.	ACTUAL OVER/(UNDER) RECOVERY JANUARY - DECEMBER 2003 (Schedule E1-B, Line 19 - Dec '04)	$ (211,227,688)
2.	PROJECTED DECEMBER 2003 UNDER RECOVERY COLLECTED THROUGH DECEMBER 2004 (Schedule E1-B, Line 20 - Dec '04)	210,426,260
3.	ESTIMATED OVER/(UNDER) RECOVERY JANUARY - DECEMBER 2004 (Schedule E1-B, Line 18 - Dec '04)	(155,157,866)
4.	TOTAL OVER/(UNDER) RECOVERY (Lines 1 through 3)	$ (155,959,294)
5.	AMOUNT OF TOTAL OVER/(UNDER) RECOVERY DEFERRED TO 2006 (Direct Testimony - Javier Portuondo)	79,157,270
6.	TOTAL OVER/(UNDER) RECOVERY APPLICABLE TO 2005 (Lines 4 through 5)	$ (76,802,024)
6.	JURISDICTIONAL MWH SALES (Projected Period)	40,292,697 Mwh
7.	TRUE-UP FACTOR (Line 4 / Line 5 / 10)	0.19061 Cents/kwh

SCHEDULE E1-B
Reprojected 8/04

PROGRESS ENERGY FLORIDA
CALCULATION OF ESTIMATED TRUE-UP
REPROJECTED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

DESCRIPTION	ACTUAL Jan-04	ACTUAL Feb-04	ACTUAL Mar-04	ACTUAL Apr-04	ACTUAL May-04	ACTUAL Jun-04	ACTUAL Jul-04	ESTIMATED Aug-04	ESTIMATED Sep-04	ESTIMATED Oct-04	ESTIMATED Nov-04	ESTIMATED Dec-04	TOTAL PERIOD
REVENUE													
1 Jurisdictional MWH Sales	3,057,664	2,669,366	2,749,583	2,644,923	2,946,846	3,656,601	3,830,002	3,843,521	3,873,762	3,512,511	3,026,176	2,953,693	38,764,669
2 Jurisdictional Fuel Factor (Pre-Tax)	3.411	3.421	3.422	3.426	3.441	3.440	3.439	3.450	3.450	3.450	3.450	3.450	
3 Total Jurisdictional Fuel Revenue	104,291,788	91,320,638	94,103,528	90,618,177	101,414,235	125,790,175	131,731,690	132,605,933	133,649,283	121,185,704	104,406,582	101,905,835	1,333,023,567
4 Less: True-Up Provision	(17,535,522)	(17,535,522)	(17,535,522)	(17,535,522)	(17,535,522)	(17,535,522)	(17,535,522)	(17,535,522)	(17,535,522)	(17,535,522)	(17,535,522)	(17,535,516)	(210,426,260)
5 Less: GPIF Provision	(231,769)	(231,769)	(231,769)	(231,769)	(231,769)	(231,769)	(231,769)	(231,769)	(231,769)	(231,769)	(231,769)	(231,764)	(2,781,223)
6 Less: Other	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Net Fuel Revenue	86,524,497	73,553,347	76,336,237	72,850,886	83,646,944	108,022,884	113,964,399	114,838,642	115,881,992	103,418,413	86,639,291	84,138,553	1,119,816,084
FUEL EXPENSE													
8 Total Cost of Generated Power	79,180,754	71,195,503	70,085,620	70,773,624	104,438,588	130,862,260	133,525,701	148,254,725	130,970,573	104,361,722	74,800,201	84,611,270	1,203,058,940
9 Total Cost of Purchased Power	17,267,497	17,007,856	17,729,137	17,425,962	20,067,587	26,545,410	25,735,570	18,877,684	18,017,474	17,083,788	15,947,144	17,070,421	228,775,529
10 Total Cost of Interchange Sales	(8,130,039)	(5,522,122)	(5,445,455)	(5,288,773)	(3,127,555)	(916,787)	(593,278)	(2,781,600)	(3,415,824)	(3,034,698)	(3,912,892)	(4,177,615)	(46,346,637)
11 Total Cost of Stratified Sales	(4,959,124)	(4,779,011)	(7,144,401)	(5,627,641)	(5,529,282)	(6,662,662)	(8,484,696)	(8,145,147)	(8,262,591)	(7,882,382)	(6,564,446)	(5,796,859)	(80,048,243)
12 Total Fuel and Net Power	83,359,088	77,902,225	75,225,100	77,083,373	115,847,339	149,828,221	150,173,297	156,205,662	137,309,632	110,528,430	80,270,006	91,707,217	1,305,439,589
13 Jurisdictional Percentage	97.91%	97.44%	97.72%	97.45%	97.68%	95.51%	94.77%	95.03%	94.86%	94.68%	94.18%	94.78%	95.80%
14 Jurisdictional Loss Multiplier	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038
15 Jurisdictional Fuel Cost	81,926,211	76,192,583	73,785,630	75,399,438	113,584,029	143,637,563	142,852,930	148,998,899	130,740,361	105,040,749	75,881,785	87,246,051	1,255,286,230
COST RECOVERY													
16 Net Fuel Revenue Less Expense	4,598,286	(2,639,236)	2,550,607	(2,548,552)	(29,937,085)	(35,614,678)	(28,888,532)	(34,160,257)	(14,858,370)	(1,622,336)	10,757,506	(3,107,498)	(135,470,145)
17 Interest Provision (1)	(174,140)	(152,729)	(134,875)	(123,547)	(125,483)	(159,664)	(206,098)	(222,706)	(231,126)	(220,521)	(194,918)	(170,155)	(2,115,962)
18 Current Cycle Balance	4,424,146	1,632,181	4,047,913	1,375,814	(28,686,754)	(64,461,096)	(93,555,726)	(127,938,689)	(143,028,185)	(144,871,042)	(134,308,454)	(137,586,107)	
19 Plus: Prior Period True-Up Balance	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	
20 Plus: Cumulative True-Up Provision	17,535,522	35,071,044	52,606,566	70,142,088	87,677,610	105,213,132	122,748,654	140,284,176	157,819,698	175,355,220	192,890,742	210,426,260	
21 Total Retail Balance	(189,268,020)	(174,524,463)	(154,573,209)	(139,709,786)	(152,236,832)	(170,475,652)	(182,034,760)	(198,882,201)	(198,436,174)	(180,743,509)	(152,645,400)	(138,387,535)	

(1) Interest for the August through December 2004 period calculated at the July 2004 monthly rate of .117%

SCHEDULE E1-C
Revised 11/04

Docket No. 040001
Progress Energy Florida
Exhibit No. ____ (JP - 1SR)
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PROGRESS ENERGY FLORIDA
CALCULATION OF GENERATING PERFORMANCE INCENTIVE AND TRUE-UP ADJUSTMENT FACTORS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

1. TOTAL AMOUNT OF ADJUSTMENTS:		
A. Generating Performance Incentive Reward / (Penalty)	$ 2,139,695	
B. True-Up (Over) / Under Recovery	$ 76,802,024	
2. JURISDICTIONAL MWH SALES	40,292,697	Mwh
3. ADJUSTMENT FACTORS:		
A. Generating Performance Incentive Factor	0.00531	Cents/kwh
B. True-Up Factor	0.19061	Cents/kwh

SCHEDULE E1-D
Revised 11/04

Docket No. 040001
Progress Energy Florida
Exhibit No. ____ (JP - 1SR)
Page ~~6 of 10~~ 4 of 9

PROGRESS ENERGY FLORIDA
CALCULATION OF LEVELIZED FUEL ADJUSTMENT FACTORS
(PROJECTED PERIOD)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

1.	Period Jurisdictional Fuel Cost (E1, line 27)	$ 1,496,331,668	
2.	Prior Period True-Up (E1, line 28)	76,802,024	
3.	Other Adjustments	0	
4.	Regulatory Assessment Fee (E1, line 30)	1,132,656	
5.	Generating Performance Incentive Factor (GPIF) (E1, line 32)	2,139,695	
6.	Total Jurisdictional Fuel Cost (E1, line 33)	$ 1,576,406,043	
7.	Jurisdictional Sales (E1, line 26)	40,292,697	Mwh
8.	Jurisdictional Cost per Kwh Sold (Line 6 / Line 7 / 10)	3.912	Cents/kwh
9.	Effective Jurisdictional Sales (See Below)	40,232,285	Mwh

LEVELIZED FUEL FACTORS:

10.	Fuel Factor at Secondary Metering (Line 6 / Line 9 / 10)	**3.918**	Cents/kwh
11.	Fuel Factor at Primary Metering (Line 10 * 99%)	**3.879**	Cents/kwh
12.	Fuel Factor at Transmission Metering (Line 10 * 98%)	**3.840**	Cents/kwh

	JURISDICTIONAL SALES (MWH)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	34,788,122	34,788,122
Distribution Primary	4,967,861	4,918,183
Transmission	536,714	525,980
Total	40,292,697	40,232,285

SCHEDULE E1-E
Revised 11/04

PROGRESS ENERGY FLORIDA
CALCULATION OF FINAL FUEL COST FACTORS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

Line:	Metering Voltage	(1) Levelized Factors Cents/Kwh	(2) Time of Use On-Peak Multiplier 1.288	(3) Time of Use Off-Peak Multiplier 0.877
1.	Distribution Secondary	3.918	5.046	3.436
2.	Distribution Primary	3.879	4.996	3.402
3.	Transmission	3.840	4.946	3.368
4.	Lighting Service	3.737	--	--

Line 4 Calculated as secondary rate 3.918 * (18.7% * On-Peak Multiplier 1.288 + 81.3% * Off-Peak Multiplier 0.877).

DEVELOPMENT OF TIME OF USE MULTIPLIERS

	ON-PEAK PERIOD			OFF-PEAK PERIOD			TOTAL		
Mo/Yr	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)
Jan-05	934,416	56,926,599	6.092	2,793,554	128,584,401	4.603	3,727,970	185,511,000	4.976
Feb-05	904,948	58,358,558	6.449	2,449,462	110,966,431	4.530	3,354,410	169,324,990	5.048
Mar-05	929,664	55,002,581	5.916	2,664,951	143,796,494	5.396	3,594,615	198,799,075	5.530
Apr-05	1,094,814	71,425,578	6.524	2,379,607	101,637,065	4.271	3,474,421	173,062,643	4.981
May-05	1,397,202	108,462,240	7.763	2,796,698	125,744,189	4.496	4,193,900	234,206,429	5.584
Jun-05	1,493,751	132,792,979	8.890	2,883,722	152,816,576	5.299	4,377,473	285,609,555	6.525
Jul-05	1,462,793	137,638,152	9.409	3,273,062	203,983,146	6.232	4,735,855	341,621,299	7.214
Aug-05	1,621,966	160,971,691	9.924	3,152,051	192,704,065	6.114	4,774,017	353,675,757	7.408
Sep-05	1,438,032	125,185,871	8.705	2,917,874	167,026,010	5.724	4,355,906	292,211,881	6.708
Oct-05	1,207,943	89,233,739	7.387	2,694,841	129,633,130	4.810	3,902,784	218,866,869	5.608
Nov-05	860,288	50,255,273	5.842	2,512,158	148,223,624	5.900	3,372,446	198,478,897	5.885
Dec-05	897,852	43,745,890	4.872	2,748,271	128,911,233	4.691	3,646,123	172,657,124	4.735
TOTAL	14,243,670	1,089,999,152	7.653	33,266,253	1,734,026,366	5.213	47,509,922	2,824,025,518	5.944

	ON-PEAK	OFF-PEAK	AVERAGE
MARGINAL FUEL COST			
WEIGHTING MULTIPLIER	1.288	0.877	1.000

PROGRESS ENERGY FLORIDA
DEVELOPMENT OF JURISDICTIONAL DELIVERY LOSS MULTIPLIERS
BASED ON ACTUAL CALENDAR YEAR 2003 DATA
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Energy Delivered				Energy Required @ Source			
Class Loads	Sales Mwh	Unbilled Mwh	Total Mwh	% of Total	Delivery Efficiency	Mwh (3) / (5)	% of Total	Jurisdictional Loss Multiplier
I. CLASS LOADS:								
A. RETAIL								
1. Transmission	471,323	1,834	473,157		0.9764000	484,593		
2. Distribution Primary	4,481,316	17,436	4,498,752		0.9664000	4,655,166		
3. Distribution Secondary	33,004,050	128,415	33,132,465		0.9421658	35,166,279		
Total Retail	37,956,689	147,685	38,104,374	91.75%	0.9453763	40,306,038	92.09%	1.00375
B. WHOLESALE								
1. Source Level	1,996,908	66,373	2,063,281		1.0000000	2,063,281		
2. Transmission	1,251,862	19,562	1,271,424		0.9764000	1,302,155		
3. Distribution Primary	93,981	(530)	93,451		0.9664000	96,700		
4. Distribution Secondary	-	-	0		0.9421658	0		
Total Wholesale	3,342,751	85,405	3,428,156	8.25%	0.9901850	3,462,136	7.91%	0.95833
Total Class Loads	41,299,440	233,090	41,532,530	100.00%	0.9489208	43,768,174	100.00%	1.00000
II. NON-CLASS LOADS								
1. Sepa	16,679	-	16,679		0.9764000	17,082		
2. Interchange	963,184	-	963,184		1.0000000	963,184		
3. Company Use	118,576	-	118,576		0.9421658	125,855		
Total Non-Class Loads	1,098,439	-	1,098,439		0.9930550	1,106,121		
Total System	42,397,879	233,090	42,630,969		0.9500087	44,874,295		

SCHEDULE E2
Revised 11/04

PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

	DESCRIPTION		Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	TOTAL
1	Fuel Cost of System Net Generation		$106,862,206	$92,409,911	$102,219,446	$91,214,748	$123,764,021	$139,215,805	$159,456,702	$164,291,812	$137,888,874	$113,380,840	$103,732,170	$94,017,418	$1,428,853,257
1a	Nuclear Fuel Disposal Cost		532,630	480,900	532,630	515,663	521,829	505,206	521,829	521,829	505,206	353,427	206,580	532,630	5,730,430
1b	Adjustments to Fuel Cost		3,162,195	3,130,656	3,109,251	3,085,251	3,100,661	3,126,661	3,160,383	3,177,085	3,189,814	4,903,733	3,445,743	3,141,739	39,436,402
2	Fuel Cost of Power Sold		(6,384,132)	(7,208,139)	(7,295,875)	(5,256,987)	(2,747,800)	(2,074,073)	(3,256,300)	(3,163,765)	(3,694,806)	(2,882,885)	(3,911,954)	(4,960,080)	(52,647,025)
2a	Fuel Cost of Stratified Sales		(6,136,829)	(7,246,044)	(7,880,922)	(8,574,647)	(7,703,859)	(7,569,595)	(6,776,525)	(6,863,298)	(6,680,042)	(6,100,330)	(5,175,210)	(4,569,742)	(81,110,043)
2b	Gains on Power Sales		(661,596)	(650,581)	(642,575)	(698,578)	(372,856)	(332,295)	(321,130)	(300,670)	(617,100)	(386,803)	(486,150)	(520,260)	(6,891,443)
3	Energy Cost of Purchased Power		6,263,508	6,985,646	5,999,972	5,486,719	5,847,851	8,195,598	10,954,044	10,945,895	8,970,620	7,761,943	7,392,786	6,169,460	93,895,638
3a	Capacity Cost of Economy Purchases		-	-	-	-	-	-	-	-	-	-	-	-	-
3b	Payments to Qualifying Facilities		11,416,711	10,011,221	10,139,532	9,160,780	9,844,701	9,904,025	10,570,411	10,502,564	9,861,115	9,480,558	9,855,180	10,083,820	120,730,408
4	Energy Cost of Economy Purchases		1,035,892	469,340	910,472	1,220,295	2,879,989	2,952,741	3,947,869	3,419,483	3,218,879	1,993,253	908,120	612,940	23,678,334
5	Total Fuel & Net Power Transactions		$118,109,826	$98,182,000	$105,991,831	$96,164,877	$135,334,877	$154,906,074	$177,080,293	$182,640,476	$152,401,999	$130,503,837	$115,606,227	$104,508,465	$1,572,477,158
6	Adjusted System Sales	MWH	3,254,372	3,115,752	3,038,122	3,092,620	3,217,807	3,840,651	4,151,123	4,252,681	4,224,387	3,827,028	3,303,839	3,224,531	42,513,913
7	System Cost per KWH Sold	c/kwh	3.6292	3.1512	3.5201	3.1095	4.2058	4.0851	4.3838	4.2947	3.6076	3.4100	3.5010	3.2410	3.6987
7a	Jurisdictional Loss Multiplier	x	1.0036	1.0036	1.0036	1.0036	1.0036	1.0036	1.0036	1.0036	1.0036	1.0036	1.0036	1.0036	1.0036
7b	Jurisdictional Cost per KWH Sold	c/kwh	3.6430	3.1631	3.5335	3.1213	4.2216	4.0805	4.2821	4.3110	3.6214	3.4230	3.5143	3.2533	3.7137
8	Prior Period True-Up	c/kwh	0.2077	0.2163	0.2230	0.2191	0.2105	0.1788	0.1616	0.1580	0.1585	0.1786	0.2060	0.2066	0.1906
9	Total Jurisdictional Fuel Expense	c/kwh	3.8507	3.3794	3.7565	3.3404	4.4323	4.2573	4.4436	4.4691	3.7809	3.5997	3.7202	3.4631	3.9043
10	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
11	Fuel Cost Factor Adjusted for Taxes	c/kwh	3.8535	3.3819	3.7592	3.3428	4.4355	4.2603	4.4470	4.4723	3.7836	3.6022	3.7229	3.4656	3.9071
12	GPIF	c/kwh	0.0058	0.0060	0.0062	0.0061	0.0059	0.0049	0.0045	0.0044	0.0044	0.0049	0.0057	0.0058	0.0053
13	Total Fuel Cost Factor (rounded .001)	c/kwh	3.859	3.388	3.765	3.349	4.441	4.265	4.452	4.477	3.788	3.607	3.729	3.471	3.912

PROGRESS ENERGY FLORIDA
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

			Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		27,242,200	24,403,542	30,701,317	27,039,776	33,535,843	39,481,874	182,404,552
2	LIGHT OIL		6,034,285	2,257,873	1,191,068	746,887	7,710,903	11,035,206	28,888,221
3	COAL		32,547,427	31,283,212	28,947,373	33,156,527	35,675,632	33,270,741	194,880,912
4	GAS		39,026,410	32,629,395	39,437,802	28,302,402	44,809,794	53,459,490	237,665,294
5	NUCLEAR		2,031,886	1,834,888	2,031,885	1,967,158	2,031,850	1,968,494	11,866,161
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	106,882,208	92,408,911	102,219,446	91,214,749	123,764,021	139,215,805	655,705,140
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		483,986	420,524	535,825	446,980	562,489	685,689	3,115,493
9	LIGHT OIL		42,334	16,954	8,802	6,866	61,104	87,227	223,287
10	COAL		1,343,522	1,299,969	1,186,433	1,376,758	1,475,605	1,383,286	8,065,573
11	GAS		639,781	557,947	706,547	493,119	803,347	912,702	4,113,453
12	NUCLEAR		569,658	514,428	569,658	551,511	558,106	540,327	3,303,688
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,059,291	2,809,822	3,007,265	2,875,234	3,460,651	3,609,231	18,821,494
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	765,168	683,934	841,632	734,618	929,389	1,108,502	5,063,241
16	LIGHT OIL	BBL	96,115	37,382	18,714	14,063	146,313	213,339	525,926
17	COAL	TON	513,222	494,020	451,803	523,756	565,063	530,028	3,077,893
18	GAS	MCF	5,261,614	4,419,738	5,232,979	3,979,897	6,586,062	7,780,020	33,260,310
19	NUCLEAR	MMBTU	5,805,388	5,242,538	5,805,386	5,620,450	5,805,285	5,624,269	33,903,316
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		4,973,591	4,445,572	5,470,606	4,775,004	6,041,030	7,205,263	32,911,066
22	LIGHT OIL		557,468	216,818	108,541	81,566	848,613	1,237,364	3,050,370
23	COAL		12,830,568	12,350,506	11,295,083	13,093,905	14,126,563	13,250,705	76,947,322
24	GAS		5,261,614	4,419,738	5,232,979	3,979,897	6,586,062	7,780,020	33,260,310
25	NUCLEAR		5,805,388	5,242,538	5,805,386	5,620,450	5,805,285	5,624,269	33,903,316
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	29,428,621	26,675,172	27,912,595	27,550,822	33,407,553	35,097,621	180,072,384
	GENERATION MIX (% MWH)								
28	HEAVY OIL		15.17%	14.97%	17.82%	15.55%	16.25%	19.00%	16.55%
29	LIGHT OIL		1.38%	0.60%	0.29%	0.24%	1.77%	2.42%	1.19%
30	COAL		43.92%	46.27%	39.45%	47.88%	42.64%	38.33%	42.85%
31	GAS		20.91%	19.86%	23.50%	17.15%	23.21%	25.29%	21.86%
32	NUCLEAR		18.62%	18.31%	18.94%	19.18%	16.13%	14.97%	17.55%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	35.60	35.68	36.48	36.81	36.08	35.62	36.03
36	LIGHT OIL	$/BBL	62.78	60.40	58.84	53.25	52.70	51.73	54.93
37	COAL	$/TON	63.42	63.32	64.07	63.31	63.14	62.77	63.32
38	GAS	$/MCF	7.42	7.38	7.54	7.11	6.80	6.87	7.15
39	NUCLEAR	$/MMBTU	0.35	0.35	0.35	0.35	0.35	0.35	0.35
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		5.48	5.49	5.61	5.66	5.55	5.48	5.54
42	LIGHT OIL		10.82	10.41	10.14	9.18	9.09	8.92	9.47
43	COAL		2.54	2.53	2.56	2.53	2.53	2.51	2.53
44	GAS		7.42	7.38	7.54	7.11	6.80	6.87	7.15
45	NUCLEAR		0.35	0.35	0.35	0.35	0.35	0.35	0.35
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	3.63	3.46	3.66	3.31	3.71	3.97	3.64
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,719	10,572	10,210	10,683	10,740	10,508	10,564
49	LIGHT OIL		13,168	12,789	12,331	11,880	13,888	14,186	13,661
50	COAL		9,550	9,501	9,520	9,511	9,573	9,579	9,540
51	GAS		8,224	7,921	7,406	8,071	8,198	8,524	8,086
52	NUCLEAR		10,191	10,191	10,191	10,191	10,402	10,409	10,262
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	9,619	9,494	9,282	9,582	9,654	9,724	9,567
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		5.87	5.80	5.73	6.05	5.96	5.76	5.85
56	LIGHT OIL		14.25	13.32	12.51	10.91	12.62	12.65	12.94
57	COAL		2.42	2.41	2.44	2.41	2.42	2.41	2.42
58	GAS		6.10	5.85	5.58	5.74	5.58	5.86	5.78
59	NUCLEAR		0.36	0.36	0.36	0.36	0.36	0.36	0.36
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	3.49	3.29	3.40	3.17	3.58	3.86	3.48

PROGRESS ENERGY FLORIDA
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

			Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		46,927,315	46,350,205	40,690,790	30,288,268	36,827,146	14,797,464	396,285,740
2	LIGHT OIL		11,810,934	16,650,185	6,691,074	3,710,400	325,234	750,736	68,826,765
3	COAL		33,305,176	33,306,395	32,252,406	35,878,496	28,975,799	35,068,987	393,668,171
4	GAS		64,380,012	66,251,583	58,365,810	44,126,375	36,827,259	41,397,372	547,013,705
5	NUCLEAR		2,033,266	2,033,265	1,968,494	1,377,101	776,732	2,002,858	22,057,876
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	158,456,702	164,591,612	137,968,574	115,380,640	103,732,170	94,017,418	1,429,852,257
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		801,469	800,200	705,062	502,250	647,658	253,962	6,826,094
9	LIGHT OIL		94,157	131,710	53,186	31,075	3,413	8,289	545,117
10	COAL		1,385,671	1,385,671	1,341,099	1,482,127	1,193,191	1,449,366	16,302,698
11	GAS		1,094,007	1,108,229	985,904	788,159	641,477	728,525	9,459,754
12	NUCLEAR		558,106	558,106	540,327	377,997	220,920	559,658	6,128,802
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,933,410	3,983,916	3,625,578	3,181,608	2,706,659	3,009,800	39,262,465
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	1,280,047	1,277,768	1,128,704	831,354	1,015,627	408,640	11,005,381
16	LIGHT OIL	BBL	229,459	323,065	128,717	71,754	6,317	14,845	1,300,083
17	COAL	TON	531,987	531,987	514,894	567,569	454,549	550,543	6,229,422
18	GAS	MCF	9,356,791	9,589,454	8,139,518	6,348,348	4,728,776	5,345,852	76,769,049
19	NUCLEAR	MMBTU	5,809,330	5,809,329	5,624,268	3,934,574	2,251,396	5,805,386	63,137,599
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		8,320,305	8,305,491	7,336,575	5,403,804	6,601,575	2,656,162	71,534,978
22	LIGHT OIL		1,330,860	1,873,779	746,560	416,173	36,638	86,100	7,540,480
23	COAL		13,299,681	13,299,681	12,872,343	14,189,224	11,363,727	13,763,574	155,735,552
24	GAS		9,356,791	9,589,454	8,139,518	6,348,348	4,728,776	5,345,852	76,769,049
25	NUCLEAR		5,809,330	5,809,329	5,624,268	3,934,574	2,251,396	5,805,386	63,137,599
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	38,116,967	38,877,734	34,719,264	30,292,123	24,982,112	27,657,074	374,717,658
	GENERATION MIX (% MWH)								
28	HEAVY OIL		20.38%	20.09%	19.45%	15.79%	23.93%	8.44%	17.39%
29	LIGHT OIL		2.39%	3.31%	1.47%	0.98%	0.13%	0.28%	1.39%
30	COAL		35.23%	34.78%	36.99%	46.58%	44.08%	48.16%	41.52%
31	GAS		27.81%	27.82%	27.19%	24.77%	23.70%	24.21%	24.09%
32	NUCLEAR		14.19%	14.01%	14.90%	11.88%	8.16%	18.93%	15.61%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	36.66	36.27	38.05	36.43	36.26	36.21	36.19
36	LIGHT OIL	$/BBL	51.47	51.54	51.98	51.71	51.49	50.57	52.94
37	COAL	$/TON	62.61	62.61	62.64	63.21	63.75	63.70	63.20
38	GAS	$/MCF	6.88	6.91	6.93	6.95	7.79	7.74	7.13
39	NUCLEAR	$/MMBTU	0.35	0.35	0.35	0.35	0.35	0.35	0.35
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		5.64	5.58	5.55	5.61	5.58	5.57	5.57
42	LIGHT OIL		8.88	8.89	8.96	8.92	8.88	8.72	9.13
43	COAL		2.50	2.50	2.51	2.53	2.55	2.55	2.53
44	GAS		6.88	6.91	6.93	6.95	7.79	7.74	7.13
45	NUCLEAR		0.35	0.35	0.35	0.35	0.35	0.35	0.35
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	4.16	4.23	3.97	3.81	4.15	3.40	3.82
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,381	10,379	10,406	10,759	10,193	10,459	10,480
49	LIGHT OIL		14,134	14,227	14,037	13,393	10,735	10,387	13,833
50	COAL		9,598	9,598	9,598	9,574	9,524	9,496	9,553
51	GAS		8,553	8,653	8,256	8,055	7,372	7,338	8,115
52	NUCLEAR		10,409	10,409	10,409	10,409	10,191	10,191	10,302
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	9,691	9,759	9,576	9,521	9,230	9,189	9,544
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		5.86	5.79	5.77	6.03	5.69	5.83	5.83
56	LIGHT OIL		12.54	12.64	12.58	11.94	9.53	9.06	12.63
57	COAL		2.40	2.40	2.40	2.42	2.43	2.42	2.41
58	GAS		5.88	5.98	5.72	5.60	5.74	5.68	5.78
59	NUCLEAR		0.36	0.36	0.36	0.36	0.35	0.35	0.36
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	4.03	4.13	3.81	3.63	3.83	3.12	3.64

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jan-05

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	788	589,658	97.2	97.0	10,191	NUCLEAR	5,805,388 MMBTU	1.00	5,805,388	2,031,886	0.36
2 ANCLOTE	1	522	152,619	39.3	94.8	42.7	10,504 HEAVY OIL	246,637 BBLS	6.50	1,603,138	8,839,002	5.79
3 ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	522	145,294	37.4	94.1	39.3	10,506 HEAVY OIL	234,834 BBLS	6.50	1,526,424	8,416,034	5.79
5 ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	123	30,000	32.8	95.8	56.9	10,972 HEAVY OIL	50,640 BBLS	6.50	329,158	1,725,256	5.75
7 BARTOW	2	121	30,969	34.4	95.5	55.5	11,462 HEAVY OIL	54,610 BBLS	6.50	354,967	1,860,532	6.01
8 BARTOW	3	208	66,372	42.9	90.2	49.3	10,372 HEAVY OIL	105,906 BBLS	6.50	688,390	3,608,142	5.44
9 BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	383	214,089	75.1	91.5	80.2	10,163 COAL	87,029 TONS	25.00	2,175,715	5,903,121	2.76
11 CRYSTAL RIVER	2	491	264,196	72.3	79.7	85.4	9,322 COAL	98,512 TONS	25.00	2,462,807	6,682,056	2.53
12 CRYSTAL RIVER	4	735	425,280	77.8	91.4	83.7	9,490 COAL	161,441 TONS	25.00	4,036,024	9,834,930	2.31
13 CRYSTAL RIVER	5	732	439,957	80.8	91.6	86.9	9,446 COAL	166,241 TONS	25.00	4,156,014	10,127,320	2.30
14 SUWANNEE	1	33	9,782	39.8	97.1	73.9	12,539 HEAVY OIL	18,870 BBLS	6.50	122,655	700,454	7.16
15 SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	32	8,911	37.4	98.2	70.7	13,510 HEAVY OIL	18,522 BBLS	6.50	120,390	687,520	7.72
17 SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	81	20,039	33.3	93.0	60.2	11,401 HEAVY OIL	35,149 BBLS	6.50	228,469	1,405,260	7.01
19 SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	64	190	0.4	100.0	59.4	17,142 LIGHT OIL	562 BBLS	5.80	3,257	39,602	20.84
21 BARTOW	1-4	219	0	2.8	100.0	43.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
22 BARTOW	1-4		4,835				14,449 GAS	68,970 MCF	1.00	68,970	533,805	11.52
23 BAYBORO	1-4	232	2,772	1.6	100.0	62.1	14,312 LIGHT OIL	6,840 BBLS	5.80	39,672	414,203	14.94
24 DEBARY	1-10	762	11,975	5.7	100.0	72.1	13,634 LIGHT OIL	28,150 BBLS	5.80	163,270	1,809,819	15.11
25 DEBARY	1-10		20,102				13,451 GAS	270,395 MCF	1.00	270,395	2,128,690	10.59
26 HIGGINS	1-4	134	427	0.6	100.0	76.7	17,462 LIGHT OIL	1,285 BBLS	5.80	7,454	192,028	44.98
27 HIGGINS	1-4		138				16,970 GAS	2,344 MCF	1.00	2,344	17,534	12.70
28 HINES	1-2	1,111	418,048	50.6	97.1	34.3	7,101 GAS	2,968,572 MCF	1.00	2,968,572	24,063,865	5.76
29 HINES	1-2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	1,206	10,749	7.9	100.0	51.6	12,667 LIGHT OIL	23,476 BBLS	5.80	136,160	1,450,198	13.49
31 INT CITY	1-14		60,078				12,968 GAS	779,119 MCF	1.00	779,119	6,033,047	10.04
32 RIO PINAR	1	18	56	0.5	100.0	70.0	17,911 LIGHT OIL	173 BBLS	5.80	1,003	10,572	18.88
33 SUWANNEE	1-3	201	8,463	5.7	100.0	48.4	13,599 LIGHT OIL	19,843 BBLS	5.80	115,088	1,221,163	14.43
34 SUWANNEE	1-3		0				0 GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	223	106,438	64.2	94.7	67.4	8,358 GAS	889,641 MCF	1.00	889,641	4,003,386	3.76
36 TURNER	1-4	194	782	0.5	100.0	55.0	15,253 LIGHT OIL	2,057 BBLS	5.80	11,928	126,564	16.18
37 UNIV OF FLA.	1	41	30,352	99.5	99.5	99.9	9,376 GAS	284,573 MCF	1.00	284,573	2,246,103	7.40
38 OTHER - START UP		-	6,920	-		-	11,508 LIGHT OIL	13,730 BBLS	5.80	79,636	770,135	11.13
39 OTHER												
40 TOTAL	9,174	3,059,291				9,619				29,428,621	106,882,208	3.49

SCHEDULE E4

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Feb-05

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3 788	514,426	97.1	97.0	100.0	10,191	NUCLEAR	5,242,538 MMBTU	1.00	5,242,538	1,834,888	0.36
2 ANCLOTE	1 522	156,350	44.6	94.8	47.5	10,354	HEAVY OIL	249,048 BBLS	6.50	1,618,809	8,972,724	5.74
3 ANCLOTE	1	0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2 522	141,551	40.4	94.1	42.0	10,448	HEAVY OIL	227,522 BBLS	6.50	1,478,893	8,197,198	5.79
5 ANCLOTE	2	0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1 123	23,650	28.6	85.8	63.9	10,921	HEAVY OIL	39,736 BBLS	6.50	258,281	1,361,309	5.76
7 BARTOW	2 121	23,058	28.4	95.5	51.2	11,421	HEAVY OIL	40,515 BBLS	6.50	263,345	1,388,000	6.02
8 BARTOW	3 208	57,205	40.9	90.2	58.6	10,296	HEAVY OIL	90,610 BBLS	6.50	588,968	3,104,235	5.43
9 BARTOW	3	0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1 383	196,405	76.3	91.5	85.0	10,135	COAL	79,625 TONS	25.00	1,990,613	5,399,779	2.75
11 CRYSTAL RIVER	2 491	250,596	75.9	79.7	89.7	9,304	COAL	93,262 TONS	25.00	2,331,547	6,324,604	2.52
12 CRYSTAL RIVER	4 735	434,165	87.9	91.4	94.7	9,402	COAL	163,283 TONS	25.00	4,082,066	9,944,817	2.29
13 CRYSTAL RIVER	5 732	418,803	85.1	91.6	91.4	9,423	COAL	157,851 TONS	25.00	3,946,280	9,614,012	2.30
14 SUWANNEE	1 33	7,894	35.6	97.1	69.7	12,500	HEAVY OIL	15,180 BBLS	6.50	98,673	566,383	7.17
15 SUWANNEE	1	0				0	GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2 32	7,211	33.5	98.2	79.1	13,517	HEAVY OIL	14,995 BBLS	6.50	97,469	559,472	7.76
17 SUWANNEE	2	0				0	GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3 81	3,605	6.6	36.6	60.1	11,411	HEAVY OIL	6,329 BBLS	6.50	41,136	254,220	7.05
19 SUWANNEE	3	0				0	GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2 64	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
21 BARTOW	1-4 218	0	1.7	100.0	54.5	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
22 BARTOW	1-4	2,476				14,461	GAS	35,806 MCF	1.00	35,806	281,969	11.39
23 BAYBORO	1-4 232	600	0.4	100.0	35.7	14,343	LIGHT OIL	1,484 BBLS	5.80	8,606	89,155	14.86
24 DEBARY	1-10 762	4,809	3.2	100.0	76.9	13,654	LIGHT OIL	10,850 BBLS	5.80	62,929	672,060	14.58
25 DEBARY	1-10	11,743				13,454	GAS	157,994 MCF	1.00	157,994	1,297,819	11.05
26 HIGGINS	1-4 134	0	0.0	100.0	#DIV/0!	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
27 HIGGINS	1-4	15				18,267	GAS	274 MCF	1.00	274	4,411	29.41
28 HINES	1-2 1,111	387,416	51.9	97.1	28.7	7,089	GAS	2,746,381 MCF	1.00	2,746,381	22,135,370	5.71
29 HINES	1-2	0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14 1,206	3,851	4.5	100.0	47.3	12,257	LIGHT OIL	8,138 BBLS	5.80	47,200	498,888	12.95
31 INT CITY	1-14	32,382				12,942	GAS	419,227 MCF	1.00	419,227	3,216,081	9.93
32 RIO PINAR	1 16	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 SUWANNEE	1-3 201	4,468	3.3	100.0	57.5	13,616	LIGHT OIL	10,489 BBLS	5.80	60,838	640,603	14.34
34 SUWANNEE	1-3	0				0	GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1 223	96,491	64.4	92.5	69.2	8,322	GAS	803,043 MCF	1.00	803,043	3,564,338	3.69
36 TURNER	1-4 194	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 UNIV OF FLA.	1 41	27,414	99.5	99.5	99.9	9,375	GAS	257,013 MCF	1.00	257,013	2,129,407	7.77
38 OTHER - START UP	-	3,426	-	-	-	10,871	LIGHT OIL	6,422 BBLS	5.80	37,245	357,167	10.43
39 OTHER												
40 TOTAL	9,174	2,809,822				9,494				26,675,172	92,408,911	3.29

SCHEDULE E4

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Mar-05

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	766	569,658	97.2	97.0	100.0	10,191 NUCLEAR	5,805,386 MMBTU	1.00	5,805,386	2,031,885	0.36
2	ANCLOTE	1	522	209,664	54.0	94.8	70.5	9,956 HEAVY OIL	321,130 BBLS	6.50	2,087,346	11,820,209	5.64
3	ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4	ANCLOTE	2	522	202,047	52.0	94.1	65.6	10,120 HEAVY OIL	314,578 BBLS	6.50	2,044,754	11,579,019	5.73
5	ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6	BARTOW	1	123	24,394	26.7	49.8	2833.2	10,669 HEAVY OIL	40,039 BBLS	6.50	260,253	1,402,934	5.75
7	BARTOW	2	121	25,227	28.0	95.5	93.5	11,374 HEAVY OIL	44,142 BBLS	6.50	286,924	1,546,708	6.13
8	BARTOW	3	208	61,549	39.8	90.2	87.5	10,126 HEAVY OIL	95,888 BBLS	6.50	623,271	3,359,837	5.46
9	BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	383	259,356	91.0	91.5	97.2	10,044 COAL	104,199 TONS	25.00	2,604,975	7,058,042	2.72
11	CRYSTAL RIVER	2	491	290,390	79.5	79.7	93.9	9,293 COAL	107,943 TONS	25.00	2,698,578	7,311,655	2.52
12	CRYSTAL RIVER	4	735	139,077	25.4	91.4	27.4	9,429 COAL	52,454 TONS	25.00	1,311,344	3,190,562	2.29
13	CRYSTAL RIVER	5	732	497,610	91.4	91.6	98.2	9,405 COAL	187,207 TONS	25.00	4,680,186	11,387,114	2.29
14	SUWANNEE	1	33	5,879	23.9	97.1	171.3	12,594 HEAVY OIL	11,391 BBLS	6.50	74,043	433,892	7.38
15	SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
16	SUWANNEE	2	32	5,603	23.5	98.2	143.5	13,695 HEAVY OIL	11,805 BBLS	6.50	76,732	449,650	8.03
17	SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
18	SUWANNEE	3	81	1,462	2.4	18.0	36.1	11,821 HEAVY OIL	2,659 BBLS	6.50	17,283	109,069	7.46
19	SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
20	AVON PARK	1-2	64	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
21	BARTOW	1-4	219	0	0.7	100.0	61.4	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
22	BARTOW	1-4		1,110				14,493 GAS	16,087 MCF	1.00	16,087	126,896	11.43
23	BAYBORO	1-4	232	690	0.4	100.0	#DIV/0!	14,355 LIGHT OIL	1,708 BBLS	5.80	9,905	101,929	14.77
24	DEBARY	1-10	762	2,094	0.8	100.0	86.0	13,648 LIGHT OIL	4,927 BBLS	5.80	28,579	303,243	14.48
25	DEBARY	1-10		2,558				13,473 GAS	34,464 MCF	1.00	34,464	284,175	11.11
26	HIGGINS	1-4	134	0	0.0	100.0	#DIV/0!	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
27	HIGGINS	1-4		162				16,907 GAS	2,739 MCF	1.00	2,739	34,844	21.51
28	HINES	1-2	1,111	539,561	65.3	87.7	40.4	6,878 GAS	3,711,301 MCF	1.00	3,711,301	30,398,225	5.63
29	HINES	1-2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
30	INT CITY	1-14	1,206	570	2.4	100.0	107.4	14,149 LIGHT OIL	1,391 BBLS	5.80	8,065	84,688	14.86
31	INT CITY	1-14		21,199				12,868 GAS	272,784 MCF	1.00	272,784	2,095,077	9.88
32	RIO PINAR	1	16	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
33	SUWANNEE	1-3	201	1,638	1.1	100.0	78.9	13,640 LIGHT OIL	3,852 BBLS	5.80	22,342	233,713	14.27
34	SUWANNEE	1-3		0				0 GAS	0 MCF	1.00	0	0	0.00
35	TIGER BAY	1	223	111,605	67.3	87.4	76.5	8,163 GAS	911,031 MCF	1.00	911,031	4,101,748	3.68
36	TURNER	1-4	194	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
37	UNIV OF FLA.	1	41	30,352	99.5	99.5	99.9	9,376 GAS	284,573 MCF	1.00	284,573	2,396,838	7.90
38	OTHER - START UP		-	3,810	-	-	-	10,407 LIGHT OIL	6,836 BBLS	5.80	39,650	377,495	9.91
39	OTHER												
40	TOTAL		8,174	3,007,265				9,282			27,912,595	102,219,446	3.40

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Apr-05

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	788	551,511	97.2	97.1	100.0	10,191 NUCLEAR	5,620,450 MMBTU	1.00	5,620,450	1,967,158	0.36
2 ANCLOTE	1	522	156,077	41.5	94.8	44.9	10,522 HEAVY OIL	252,644 BBLS	6.50	1,642,187	9,332,209	5.98
3 ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	522	147,760	39.3	94.1	41.9	10,451 HEAVY OIL	237,574 BBLS	6.50	1,544,229	8,775,534	5.94
5 ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	123	15,728	17.8	82.9	27.2	11,105 HEAVY OIL	26,871 BBLS	6.50	174,663	945,041	6.01
7 BARTOW	2	121	16,375	18.8	50.9	49.0	11,381 HEAVY OIL	28,672 BBLS	6.50	186,369	1,008,378	6.16
8 BARTOW	3	208	70,785	47.3	90.2	82.9	10,368 HEAVY OIL	112,909 BBLS	6.50	733,910	3,970,932	5.61
9 BARTOW	3		0	0.0			0 GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	383	220,247	79.9	91.5	84.8	10,108 COAL	89,048 TONS	25.00	2,226,190	6,031,595	2.74
11 CRYSTAL RIVER	2	491	265,957	75.2	79.7	88.8	9,305 COAL	98,966 TONS	25.00	2,474,662	6,704,800	2.52
12 CRYSTAL RIVER	4	735	448,794	84.8	91.4	91.8	9,422 COAL	169,148 TONS	25.00	4,228,697	10,288,336	2.29
13 CRYSTAL RIVER	5	732	441,760	83.8	91.6	90.1	9,427 COAL	166,574 TONS	25.00	4,164,356	10,131,796	2.29
14 SUWANNEE	1	33	9,779	41.2	97.1	60.1	12,558 HEAVY OIL	18,893 BBLS	6.50	122,803	722,082	7.38
15 SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	32	10,126	43.9	98.2	65.7	13,610 HEAVY OIL	21,202 BBLS	6.50	137,812	810,335	8.00
17 SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	81	20,350	34.9	93.0	53.5	11,451 HEAVY OIL	35,851 BBLS	6.50	233,031	1,475,265	7.25
19 SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	64	47	0.1	100.0	#DIV/0!	17,617 LIGHT OIL	143 BBLS	5.80	828	14,056	29.91
21 BARTOW	1-4	219	0	1.1	100.0	116.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
22 BARTOW	1-4		1,715				14,488 GAS	24,847 MCF	1.00	24,847	192,732	11.24
23 BAYBORO	1-4	232	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
24 DEBARY	1-10	762	394	1.9	100.0	99.9	13,769 LIGHT OIL	935 BBLS	5.80	5,425	51,970	13.19
25 DEBARY	1-10		9,861				13,458 GAS	132,708 MCF	1.00	132,708	1,127,197	11.43
26 HIGGINS	1-4	134	0	0.0	100.0	#DIV/0!	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
27 HIGGINS	1-4		237				16,966 GAS	4,021 MCF	1.00	4,021	107,088	45.18
28 HINES	1-2	1,111	325,699	40.7	61.5	34.8	6,990 GAS	2,276,479 MCF	1.00	2,276,479	17,695,251	5.43
29 HINES	1-2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	1,206	2,534	6.0	100.0	60.2	12,130 LIGHT OIL	5,299 BBLS	5.80	30,737	291,089	11.49
31 INT CITY	1-14		49,790				12,928 GAS	643,687 MCF	1.00	643,687	4,649,356	9.34
32 RIO PINAR	1	16	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 SUWANNEE	1-3	201	1,035	0.7	100.0	44.1	13,729 LIGHT OIL	2,450 BBLS	5.80	14,210	133,995	12.95
34 SUWANNEE	1-3		0				0 GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	223	84,277	52.5	67.6	77.3	8,261 GAS	696,190 MCF	1.00	696,190	3,199,867	3.80
36 TURNER	1-4	194	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 UNIV OF FLA.	1	41	21,540	73.0	73.0	99.9	9,376 GAS	201,965 MCF	1.00	201,965	1,330,910	6.18
38 OTHER - START UP		-	2,856	-	-	-	10,632 LIGHT OIL	5,236 BBLS	5.80	30,366	257,797	9.03
39 OTHER												
40 TOTAL	9,174	2,875,234				9,582				27,550,822	91,214,749	3.17

SCHEDULE E4

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: May-05

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	769	558,106	97.5	97.0	100.0	10,402 NUCLEAR	5,805,285 MMBTU	1.00	5,805,285	2,031,850	0.36
2 ANCLOTE	1	498	176,611	47.7	95.5	49.5	10,462 HEAVY OIL	284,254 BBLS	6.50	1,847,653	10,315,065	5.84
3 ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	495	183,857	49.9	94.4	51.7	10,468 HEAVY OIL	296,081 BBLS	6.50	1,924,525	10,744,225	5.84
5 ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	121	36,407	40.4	85.9	57.8	11,203 HEAVY OIL	62,749 BBLS	6.50	407,866	2,166,035	5.95
7 BARTOW	2	119	37,580	42.4	95.5	53.5	11,511 HEAVY OIL	66,553 BBLS	6.50	432,595	2,297,362	6.11
8 BARTOW	3	204	77,545	51.1	90.4	57.4	10,404 HEAVY OIL	124,122 BBLS	6.50	806,791	4,284,587	5.53
9 BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	243,392	86.3	91.6	90.7	10,083 COAL	98,162 TONS	25.00	2,454,055	6,632,092	2.72
11 CRYSTAL RIVER	2	486	280,412	77.6	79.8	91.6	9,352 COAL	104,896 TONS	25.00	2,622,395	7,087,031	2.53
12 CRYSTAL RIVER	4	720	482,248	90.0	91.5	96.9	9,510 COAL	183,439 TONS	25.00	4,585,977	11,126,054	2.31
13 CRYSTAL RIVER	5	717	469,553	88.0	91.7	95.0	9,507 COAL	178,565 TONS	25.00	4,464,136	10,830,455	2.31
14 SUWANNEE	1	32	11,823	49.7	97.1	72.6	12,659 HEAVY OIL	23,026 BBLS	6.50	149,668	865,081	7.32
15 SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	31	11,947	51.8	98.2	72.9	13,683 HEAVY OIL	25,150 BBLS	6.50	163,474	944,880	7.91
17 SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	80	26,719	44.9	93.1	64.6	11,545 HEAVY OIL	47,455 BBLS	6.50	308,456	1,918,609	7.18
19 SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	52	978	2.5	100.0	117.5	17,397 LIGHT OIL	2,933 BBLS	5.80	17,014	181,689	18.58
21 BARTOW	1-4	187	0	4.3	100.0	43.5	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
22 BARTOW	1-4		6,034				15,222 GAS	91,849 MCF	1.00	91,849	660,082	10.94
23 BAYBORO	1-4	184	8,801	6.4	100.0	69.8	14,506 LIGHT OIL	22,011 BBLS	5.80	127,663	1,136,754	12.94
24 DEBARY	1-10	867	17,576	8.2	100.0	56.2	13,942 LIGHT OIL	42,250 BBLS	5.80	245,052	2,264,280	12.88
25 DEBARY	1-10		23,087				13,865 GAS	320,092 MCF	1.00	320,092	2,671,025	11.57
26 HIGGINS	1-4	122	116	2.7	100.0	39.0	18,147 LIGHT OIL	363 BBLS	5.80	2,105	18,945	16.33
27 HIGGINS	1-4		2,372				16,263 GAS	38,576 MCF	1.00	38,576	389,919	16.44
28 HINES	1-2	998	551,935	74.3	97.3	38.1	7,038 GAS	3,884,400 MCF	1.00	3,884,400	27,489,237	4.98
29 HINES	1-2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	1,041	20,139	13.2	100.0	47.1	13,512 LIGHT OIL	46,915 BBLS	5.80	272,109	2,484,355	12.34
31 INT CITY	1-14		82,197				13,338 GAS	1,096,364 MCF	1.00	1,096,364	7,723,895	9.40
32 RIO PINAR	1	13	109	1.1	100.0	167.7	18,505 LIGHT OIL	348 BBLS	5.80	2,017	18,193	16.69
33 SUWANNEE	1-3	164	6,826	5.6	100.0	51.4	14,134 LIGHT OIL	16,634 BBLS	5.80	96,476	876,967	12.85
34 SUWANNEE	1-3		0				0 GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	207	116,827	75.9	92.6	81.6	8,170 GAS	954,436 MCF	1.00	954,436	4,272,536	3.66
36 TURNER	1-4	154	1,732	1.5	100.0	54.4	15,587 LIGHT OIL	4,654 BBLS	5.80	26,996	245,394	14.17
37 UNIV OF FLA.	1	35	20,895	80.2	80.2	100.0	9,588 GAS	200,345 MCF	1.00	200,345	1,803,099	7.67
38 OTHER - START UP		-	4,827	-	-	-	12,260 LIGHT OIL	10,204 BBLS	5.80	59,181	482,325	9.99
39 OTHER												
40 TOTAL	8,475	3,460,651				9,654				33,407,553	123,764,021	3.58

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jun-05

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	769	540,327	97.6	97.1	100.0	10,409	NUCLEAR	5,624,269 MMBTU	1.00	5,624,269	1,968,494	0.36
2 ANCLOTE	1	498	219,005	61.1	95.5	61.9	10,200	HEAVY OIL	343,686 BBLS	6.50	2,233,960	12,317,078	5.62
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	495	220,090	61.8	94.4	64.0	10,210	HEAVY OIL	345,726 BBLS	6.50	2,247,218	12,390,177	5.63
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	121	44,586	51.2	85.9	85.2	10,986	HEAVY OIL	75,368 BBLS	6.50	489,892	2,567,731	5.76
7 BARTOW	2	119	48,605	56.7	95.5	86.5	11,234	HEAVY OIL	84,007 BBLS	6.50	546,043	2,862,042	5.89
8 BARTOW	3	204	93,901	63.9	90.4	68.1	10,264	HEAVY OIL	148,279 BBLS	6.50	963,813	5,051,751	5.38
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	203,093	74.4	93.1	78.6	10,166	COAL	82,584 TONS	25.00	2,064,598	5,566,687	2.74
11 CRYSTAL RIVER	2	486	245,049	70.0	82.2	82.7	9,379	COAL	91,936 TONS	25.00	2,298,395	6,197,063	2.53
12 CRYSTAL RIVER	4	720	471,499	91.0	91.5	97.9	9,506	COAL	179,288 TONS	25.00	4,482,210	10,846,307	2.30
13 CRYSTAL RIVER	5	717	463,645	89.8	91.7	96.5	9,502	COAL	176,220 TONS	25.00	4,405,502	10,660,684	2.30
14 SUWANNEE	1	32	14,136	61.4	97.1	76.3	12,526	HEAVY OIL	27,241 BBLS	6.50	177,066	1,011,183	7.15
15 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	31	14,254	63.9	98.2	76.3	13,429	HEAVY OIL	29,449 BBLS	6.50	191,420	1,093,155	7.67
17 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	80	31,112	54.0	93.1	68.7	11,438	HEAVY OIL	54,746 BBLS	6.50	355,851	2,188,757	7.04
19 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	52	1,011	2.7	100.0	61.7	17,655	LIGHT OIL	3,077 BBLS	5.80	17,849	169,745	16.79
21 BARTOW	1-4	187	0	8.1	100.0	42.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
22 BARTOW	1-4		10,870				15,232	GAS	165,568 MCF	1.00	165,568	1,147,539	10.56
23 BAYBORO	1-4	184	17,074	12.9	100.0	67.6	14,508	LIGHT OIL	42,709 BBLS	5.80	247,712	2,169,872	12.71
24 DEBARY	1-10	667	33,134	14.8	100.0	54.5	13,938	LIGHT OIL	79,811 BBLS	5.80	461,743	4,192,467	12.65
25 DEBARY	1-10		38,167				13,868	GAS	529,317 MCF	1.00	529,317	4,024,049	10.54
26 HIGGINS	1-4	122	466	6.4	100.0	79.7	18,378	LIGHT OIL	1,477 BBLS	5.80	8,564	75,703	16.25
27 HIGGINS	1-4		5,128				16,239	GAS	83,276 MCF	1.00	83,276	852,151	16.62
28 HINES	1-2	998	588,153	81.9	97.2	41.9	6,994	GAS	4,113,419 MCF	1.00	4,113,419	29,623,325	5.04
29 HINES	1-2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	998	14,441	21.6	100.0	56.0	14,379	LIGHT OIL	35,802 BBLS	5.80	207,649	1,862,540	12.90
31 INT CITY	1-14		124,982				13,374	GAS	1,671,534 MCF	1.00	1,671,534	11,647,965	9.32
32 RIO PINAR	1	13	95	1.0	100.0	81.2	18,505	LIGHT OIL	303 BBLS	5.80	1,758	15,575	16.40
33 SUWANNEE	1-3	164	12,667	10.7	100.0	62.5	14,056	LIGHT OIL	30,697 BBLS	5.80	178,042	1,589,854	12.55
34 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	207	120,322	80.7	94.7	84.9	8,115	GAS	976,425 MCF	1.00	976,425	4,354,409	3.62
36 TURNER	1-4	154	3,252	2.9	100.0	74.5	15,785	LIGHT OIL	8,851 BBLS	5.80	51,334	458,395	14.10
37 UNIV OF FLA.	1	35	25,080	99.5	99.5	99.9	9,589	GAS	240,481 MCF	1.00	240,481	1,810,052	7.22
38 OTHER - START UP		-	5,087	-	-	-	12,328	LIGHT OIL	10,813 BBLS	5.80	62,713	501,055	9.85
39 OTHER													
40 TOTAL		8,332	3,609,231				9,724				35,097,621	139,215,805	3.86

SCHEDULE E4

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jul-05

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	769	558,106	97.5	97.0	100.0	10,409	NUCLEAR	5,809,330 MMBTU	1.00	5,809,330	2,033,266	0.36
2 ANCLOTE	1	498	257,677	69.5	95.6	70.5	10,076	HEAVY OIL	399,422 BBLS	6.50	2,596,243	14,729,947	5.72
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	495	255,944	69.5	94.4	72.0	10,082	HEAVY OIL	396,981 BBLS	6.50	2,580,377	14,639,930	5.72
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	121	55,950	62.2	85.9	74.5	10,785	HEAVY OIL	92,832 BBLS	6.50	603,405	3,259,245	5.83
7 BARTOW	2	119	57,723	65.2	95.5	72.0	11,067	HEAVY OIL	98,284 BBLS	6.50	638,847	3,450,682	5.98
8 BARTOW	3	204	105,078	69.2	90.4	74.3	10,184	HEAVY OIL	164,635 BBLS	6.50	1,070,127	5,780,207	5.50
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	180,596	64.0	93.8	67.3	10,345	COAL	74,731 TONS	25.00	1,868,273	5,039,428	2.79
11 CRYSTAL RIVER	2	486	226,384	62.6	83.4	73.9	9,439	COAL	85,473 TONS	25.00	2,136,837	5,763,846	2.55
12 CRYSTAL RIVER	4	720	489,862	91.4	91.5	98.5	9,502	COAL	186,181 TONS	25.00	4,654,527	11,268,462	2.30
13 CRYSTAL RIVER	5	717	488,829	91.6	91.7	98.4	9,492	COAL	185,602 TONS	25.00	4,640,044	11,233,419	2.30
14 SUWANNEE	1	32	16,283	68.4	97.1	80.6	12,473	HEAVY OIL	31,246 BBLS	6.50	203,097	1,192,336	7.32
15 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	31	15,969	69.2	98.2	83.9	13,286	HEAVY OIL	32,642 BBLS	6.50	212,170	1,245,601	7.80
17 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	80	36,845	61.9	93.1	74.9	11,292	HEAVY OIL	64,006 BBLS	6.50	416,039	2,629,366	7.14
19 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	52	415	1.1	100.0	49.9	17,441	LIGHT OIL	1,248 BBLS	5.80	7,238	96,121	23.16
21 BARTOW	1-4	187	0	0.0	100.0	41.4	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
22 BARTOW	1-4		13,577				15,232	GAS	206,811 MCF	1.00	206,811	1,459,116	10.75
23 BAYBORO	1-4	184	20,675	15.1	100.0	69.9	14,507	LIGHT OIL	51,713 BBLS	5.80	299,935	2,606,642	12.61
24 DEBARY	1-10	667	38,012	17.3	100.0	53.1	13,942	LIGHT OIL	91,373 BBLS	5.80	529,962	4,775,323	12.56
25 DEBARY	1-10		47,626				13,866	GAS	663,151 MCF	1.00	663,151	5,095,419	10.65
26 HIGGINS	1-4	122	350	7.3	100.0	29.2	17,903	LIGHT OIL	1,080 BBLS	5.80	6,266	54,957	15.70
27 HIGGINS	1-4		8,234				16,294	GAS	101,576 MCF	1.00	101,576	795,181	12.76
28 HINES	1-2	998	704,810	94.9	97.3	48.4	6,927	GAS	4,882,341 MCF	1.00	4,882,341	34,951,962	4.96
29 HINES	1-2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	898	14,250	26.7	100.0	59.5	14,367	LIGHT OIL	35,298 BBLS	5.80	204,731	1,822,247	12.79
31 INT CITY	1-14		163,820				13,381	GAS	2,192,100 MCF	1.00	2,192,100	15,569,436	9.50
32 RIO PINAR	1	13	72	0.7	100.0	92.3	18,583	LIGHT OIL	231 BBLS	5.80	1,338	11,762	16.34
33 SUWANNEE	1-3	164	14,055	11.5	100.0	62.4	14,006	LIGHT OIL	33,941 BBLS	5.80	196,858	1,744,298	12.41
34 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	207	131,822	85.6	94.7	89.9	8,059	GAS	1,062,298 MCF	1.00	1,062,298	4,770,891	3.62
36 TURNER	1-4	154	2,054	1.8	100.0	75.5	15,555	LIGHT OIL	5,506 BBLS	5.80	31,949	283,090	13.78
37 UNIV OF FLA.	1	35	25,918	99.5	99.5	99.9	9,588	GAS	248,514 MCF	1.00	248,514	1,738,006	6.71
38 OTHER - START UP		-	4,274	-	-	-	12,303	LIGHT OIL	9,066 BBLS	5.80	52,583	416,494	9.74
39 OTHER													
40 TOTAL		8,332	3,933,410				9,691				38,116,967	158,456,702	4.03

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Aug-05

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	769	558,106	97.6	97.0	100.0	10,409 NUCLEAR	5,809,329 MMBTU	1.00	5,809,329	2,033,265	0.36
2	ANCLOTE	1	498	256,345	69.2	95.5	70.6	10,065 HEAVY OIL	396,949 BBLS	6.50	2,580,166	14,483,923	5.65
3	ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4	ANCLOTE	2	495	256,455	69.6	94.4	72.2	10,076 HEAVY OIL	397,542 BBLS	6.50	2,584,022	14,505,569	5.66
5	ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6	BARTOW	1	121	55,907	62.1	85.9	72.5	10,800 HEAVY OIL	92,893 BBLS	6.50	603,802	3,225,161	5.77
7	BARTOW	2	119	56,990	64.4	95.6	70.5	11,094 HEAVY OIL	97,265 BBLS	6.50	632,223	3,376,970	5.93
8	BARTOW	3	204	104,775	69.0	90.4	74.7	10,176 HEAVY OIL	164,024 BBLS	6.50	1,066,157	5,694,794	5.44
9	BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	379	180,596	64.0	93.8	67.3	10,345 COAL	74,731 TONS	25.00	1,868,273	5,039,600	2.79
11	CRYSTAL RIVER	2	486	226,384	62.6	83.4	73.9	9,439 COAL	85,473 TONS	25.00	2,136,837	5,764,042	2.55
12	CRYSTAL RIVER	4	720	489,862	91.4	91.5	98.5	9,502 COAL	186,161 TONS	25.00	4,654,527	11,268,909	2.30
13	CRYSTAL RIVER	5	717	488,829	91.6	91.7	98.4	9,492 COAL	185,602 TONS	25.00	4,640,044	11,233,845	2.30
14	SUWANNEE	1	32	16,249	68.3	97.1	79.6	12,472 HEAVY OIL	31,178 BBLS	6.50	202,655	1,177,581	7.25
15	SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
16	SUWANNEE	2	31	16,460	71.4	98.2	82.7	13,263 HEAVY OIL	33,586 BBLS	6.50	218,309	1,268,543	7.71
17	SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
18	SUWANNEE	3	80	37,019	62.2	93.1	73.8	11,296 HEAVY OIL	64,332 BBLS	6.50	418,157	2,617,663	7.07
19	SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
20	AVON PARK	1-2	52	940	2.4	100.0	46.4	17,684 LIGHT OIL	2,866 BBLS	5.80	16,623	174,446	18.56
21	BARTOW	1-4	187	0	11.5	100.0	44.3	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
22	BARTOW	1-4		15,973				15,224 GAS	243,177 MCF	1.00	243,177	1,693,176	10.60
23	BAYBORO	1-4	184	26,359	19.3	100.0	72.1	14,500 LIGHT OIL	65,897 BBLS	5.80	382,204	3,332,819	12.64
24	DEBARY	1-10	667	49,378	21.2	100.0	58.7	13,930 LIGHT OIL	118,596 BBLS	5.80	687,857	6,218,227	12.59
25	DEBARY	1-10		55,640				13,864 GAS	771,366 MCF	1.00	771,366	5,792,676	10.41
26	HIGGINS	1-4	122	426	9.2	100.0	93.3	18,655 LIGHT OIL	1,370 BBLS	5.80	7,947	69,934	16.42
27	HIGGINS	1-4		7,908				16,247 GAS	128,480 MCF	1.00	128,480	1,194,392	15.10
28	HINES	1-2	998	701,168	94.4	97.3	48.1	6,930 GAS	4,858,777 MCF	1.00	4,858,777	34,897,904	4.98
29	HINES	1-2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
30	INT CITY	1-14	898	24,091	29.2	100.0	59.8	14,377 LIGHT OIL	59,716 BBLS	5.80	346,350	3,092,906	12.84
31	INT CITY	1-14		170,729				13,375 GAS	2,283,563 MCF	1.00	2,283,563	16,242,090	9.51
32	RIO PINAR	1	13	276	2.9	100.0	88.5	18,572 LIGHT OIL	884 BBLS	5.80	5,126	45,211	16.38
33	SUWANNEE	1-3	184	19,095	15.6	100.0	68.1	14,072 LIGHT OIL	46,329 BBLS	5.80	268,707	2,388,805	12.51
34	SUWANNEE	1-3		0				0 GAS	0 MCF	1.00	0	0	0.00
35	TIGER BAY	1	207	130,893	85.0	94.7	89.3	8,064 GAS	1,055,577 MCF	1.00	1,055,577	4,755,980	3.63
36	TURNER	1-4	154	4,306	3.8	100.0	69.9	15,823 LIGHT OIL	11,747 BBLS	5.80	68,133	605,702	14.07
37	UNIV OF FLA.	1	35	25,918	99.5	99.5	99.9	9,588 GAS	248,514 MCF	1.00	248,514	1,675,365	6.46
38	OTHER - START UP		-	6,839	-	-	-	13,281 LIGHT OIL	15,661 BBLS	5.80	90,832	722,114	10.56
39	OTHER												
40	TOTAL	8,332	3,983,916				9,759				38,877,734	164,591,612	4.13

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Sep-05

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	769	540,327	97.6	97.1	100.0	10,409	NUCLEAR	5,624,268 MMBTU	1.00	5,624,268	1,968,494	0.36
2 ANCLOTE	1	498	239,258	66.7	95.5	67.7	10,094	HEAVY OIL	371,537 BBLS	6.50	2,414,988	13,460,087	5.63
3 ANCLOTE	1		0		94.4		0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	495	236,799	66.4		66.8	10,105	HEAVY OIL	368,148 BBLS	6.50	2,392,963	13,337,329	5.63
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	121	47,731	54.8	85.9	67.2	10,878	HEAVY OIL	79,882 BBLS	6.50	519,232	2,752,668	5.77
7 BARTOW	2	119	48,479	56.8	95.5	65.1	11,208	HEAVY OIL	83,590 BBLS	6.50	543,336	2,880,453	5.94
8 BARTOW	3	204	74,225	50.5	69.3	71.3	10,199	HEAVY OIL	116,469 BBLS	6.50	757,047	4,013,426	5.41
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	174,843	64.1	93.8	67.2	10,346	COAL	72,359 TONS	25.00	1,808,976	4,881,874	2.79
11 CRYSTAL RIVER	2	486	219,147	62.6	83.4	73.9	9,440	COAL	82,750 TONS	25.00	2,068,740	5,582,897	2.55
12 CRYSTAL RIVER	4	720	474,070	91.4	91.5	98.4	9,502	COAL	180,189 TONS	25.00	4,504,717	10,911,751	2.30
13 CRYSTAL RIVER	5	717	473,039	91.6	91.7	96.5	9,492	COAL	179,596 TONS	25.00	4,489,910	10,875,884	2.30
14 SUWANNEE	1	32	13,843	59.2	97.1	74.7	12,558	HEAVY OIL	26,358 BBLS	6.50	171,330	968,706	7.25
15 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	31	13,784	61.8	98.2	76.5	13,401	HEAVY OIL	28,419 BBLS	6.50	184,723	1,065,994	7.73
17 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	80	31,143	54.1	93.1	72.0	11,333	HEAVY OIL	54,301 BBLS	6.50	352,956	2,192,128	7.04
19 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	52	399	1.1	100.0	78.7	17,301	LIGHT OIL	1,190 BBLS	5.80	6,903	86,248	21.62
21 BARTOW	1-4	187	0	7.0	100.0	54.7	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
22 BARTOW	1-4		9,492				15,230	GAS	144,562 MCF	1.00	144,562	1,022,976	10.78
23 BAYBORO	1-4	184	8,744	6.6	100.0	67.6	14,537	LIGHT OIL	21,916 BBLS	5.80	127,110	1,113,440	12.73
24 DEBARY	1-10	667	26,207	12.6	100.0	57.4	13,934	LIGHT OIL	62,962 BBLS	5.80	365,181	3,315,718	12.65
25 DEBARY	1-10		34,292				13,867	GAS	475,517 MCF	1.00	475,517	3,759,531	10.99
26 HIGGINS	1-4	122	408	5.0	100.0	93.0	17,821	LIGHT OIL	1,254 BBLS	5.80	7,271	64,273	15.75
27 HIGGINS	1-4		4,016				16,255	GAS	65,282 MCF	1.00	65,282	887,759	22.11
28 HINES	1-2	998	673,720	93.8	97.2	47.7	6,930	GAS	4,669,150 MCF	1.00	4,669,150	33,312,421	4.94
29 HINES	1-2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	898	4,856	18.7	100.0	60.1	14,396	LIGHT OIL	12,053 BBLS	5.80	69,908	627,051	12.91
31 INT CITY	1-14		116,023				13,363	GAS	1,550,359 MCF	1.00	1,550,359	11,338,159	9.77
32 RIO PINAR	1	13	121	1.3	100.0	103.4	18,504	LIGHT OIL	386 BBLS	5.80	2,239	19,837	16.39
33 SUWANNEE	1-3	184	7,836	6.6	100.0	65.8	13,915	LIGHT OIL	18,799 BBLS	5.80	109,037	973,663	12.43
34 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	207	123,281	82.7	90.4	91.1	8,064	GAS	994,167 MCF	1.00	994,167	4,440,781	3.60
36 TURNER	1-4	154	1,348	1.2	100.0	69.1	15,915	LIGHT OIL	3,699 BBLS	5.80	21,454	191,577	14.21
37 UNIV OF FLA.	1	35	25,060	99.5	99.5	99.9	9,589	GAS	240,481 MCF	1.00	240,481	1,594,184	6.36
38 OTHER - START UP		-	3,267	-	-	-	11,465	LIGHT OIL	6,456 BBLS	5.80	37,457	299,269	9.16
39 OTHER													
40 TOTAL		8,332	3,625,578				9,576				34,719,264	137,968,574	3.81

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Oct-05

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	769	377,997	66.1	85.7	100.0	10,409 NUCLEAR	3,934,574 MMBTU	1.00	3,934,574	1,377,101	0.36
2 ANCLOTE	1	498	182,923	49.4	95.5	50.0	10,453 HEAVY OIL	294,155 BBLS	6.50	1,912,006	10,712,574	5.86
3 ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	495	190,841	51.8	94.4	54.5	10,418 HEAVY OIL	305,886 BBLS	6.50	1,988,261	11,139,815	5.84
5 ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	121	37,613	41.8	85.9	58.1	11,201 HEAVY OIL	64,816 BBLS	6.50	421,307	2,245,841	5.97
7 BARTOW	2	119	41,358	46.7	95.5	61.1	11,484 HEAVY OIL	73,071 BBLS	6.50	474,960	2,531,847	6.12
8 BARTOW	3	204	0	0.0	0.0	0.0	0 HEAVY OIL	0 BBLS	6.50	0	0	0.00
9 BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	379	246,449	87.4	91.6	91.8	10,073 COAL	99,300 TONS	25.00	2,482,504	6,715,687	2.72
11 CRYSTAL RIVER	2	486	282,185	78.0	79.8	92.2	9,352 COAL	105,564 TONS	25.00	2,639,092	7,139,290	2.53
12 CRYSTAL RIVER	4	720	479,030	89.4	91.5	97.0	9,513 COAL	182,286 TONS	25.00	4,557,142	11,068,418	2.31
13 CRYSTAL RIVER	5	717	474,463	88.9	91.7	95.5	9,507 COAL	180,419 TONS	25.00	4,510,486	10,955,100	2.31
14 SUWANNEE	1	32	11,348	47.7	97.1	66.2	12,666 HEAVY OIL	22,114 BBLS	6.50	143,739	833,686	7.35
15 SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	31	11,328	49.1	98.2	65.3	13,629 HEAVY OIL	23,751 BBLS	6.50	154,384	895,427	7.90
17 SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	80	26,839	45.1	93.1	62.1	11,519 HEAVY OIL	47,561 BBLS	6.50	309,147	1,929,077	7.19
19 SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	52	103	0.3	100.0	56.6	18,019 LIGHT OIL	320 BBLS	5.80	1,856	19,129	18.57
21 BARTOW	1-4	187	0	2.5	100.0	45.1	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
22 BARTOW	1-4		3,439				15,252 GAS	52,452 MCF	1.00	52,452	374,119	10.88
23 BAYBORO	1-4	184	2,374	1.7	100.0	54.3	14,586 LIGHT OIL	5,971 BBLS	5.80	34,633	304,448	12.82
24 DEBARY	1-10	667	8,160	6.0	100.0	55.3	13,973 LIGHT OIL	19,659 BBLS	5.80	114,020	1,038,801	12.73
25 DEBARY	1-10		21,758				13,879 GAS	301,970 MCF	1.00	301,970	2,240,530	10.30
26 HIGGINS	1-4	122	32	0.5	100.0	56.5	18,344 LIGHT OIL	101 BBLS	5.80	587	5,207	16.27
27 HIGGINS	1-4		416				16,397 GAS	6,821 MCF	1.00	6,821	246,332	59.21
28 HINES	1-2	998	562,660	75.8	97.3	38.8	7,029 GAS	3,954,892 MCF	1.00	3,954,892	29,130,921	5.18
29 HINES	1-2		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	1,041	12,030	10.4	100.0	47.4	13,101 LIGHT OIL	27,173 BBLS	5.80	157,601	1,418,518	11.79
31 INT CITY	1-14		68,853				13,417 GAS	923,828 MCF	1.00	923,828	6,661,423	9.67
32 RIO PINAR	1	13	23	0.2	100.0	88.5	18,522 LIGHT OIL	73 BBLS	5.80	426	3,787	16.47
33 SUWANNEE	1-3	164	4,369	3.6	100.0	62.0	14,008 LIGHT OIL	10,552 BBLS	5.80	61,199	548,385	12.55
34 SUWANNEE	1-3		0				0 GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	207	105,115	68.3	79.0	86.1	8,180 GAS	859,870 MCF	1.00	859,870	3,847,563	3.66
36 TURNER	1-4	154	283	0.2	100.0	50.1	18,420 LIGHT OIL	801 BBLS	5.80	4,647	41,640	14.71
37 UNIV OF FLA.	1	35	25,918	99.5	99.5	99.9	9,589 GAS	248,515 MCF	1.00	248,515	1,625,487	6.27
38 OTHER - START UP		-	3,701	-	-	-	11,133 LIGHT OIL	7,104 BBLS	5.80	41,204	330,484	8.93
39 OTHER												
40 TOTAL	8,475	3,181,608				9,521				30,292,123	115,380,640	3.63

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Nov-05

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	788	220,920	38.9	38.9	100.0	10,191	NUCLEAR	2,251,396 MMBTU	1.00	2,251,396	776,732	0.35
2 ANCLOTE	1	522	241,051	64.1	94.8	65.0	9,948	HEAVY OIL	368,909 BBLS	6.50	2,397,908	13,460,806	5.58
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	522	220,567	58.7	94.1	66.6	9,985	HEAVY OIL	338,817 BBLS	6.50	2,202,312	12,362,816	5.61
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	123	32,257	36.4	86.8	73.9	10,678	HEAVY OIL	52,989 BBLS	6.50	344,429	1,836,031	5.69
7 BARTOW	2	121	32,305	37.1	95.5	82.2	11,064	HEAVY OIL	54,987 BBLS	6.50	357,414	1,905,250	5.90
8 BARTOW	3	208	81,506	54.4	78.2	90.7	10,010	HEAVY OIL	125,525 BBLS	6.50	815,912	4,349,343	5.34
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	383	252,095	91.4	91.5	95.9	10,047	COAL	101,311 TONS	25.00	2,532,765	6,841,094	2.71
11 CRYSTAL RIVER	2	491	281,004	79.5	79.7	94.0	9,306	COAL	104,605 TONS	25.00	2,615,128	7,063,559	2.51
12 CRYSTAL RIVER	4	735	483,337	91.3	93.4	98.3	9,401	COAL	181,782 TONS	25.00	4,544,054	11,017,685	2.28
13 CRYSTAL RIVER	5	732	176,755	33.5	33.6	98.2	9,458	COAL	66,871 TONS	25.00	1,671,780	4,053,461	2.29
14 SUWANNEE	1	33	9,153	38.5	97.1	76.4	12,504	HEAVY OIL	17,608 BBLS	6.50	114,452	663,822	7.25
15 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	32	9,574	41.6	98.2	76.5	13,528	HEAVY OIL	19,925 BBLS	6.50	129,515	751,187	7.85
17 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	81	21,245	36.4	93.0	66.1	11,280	HEAVY OIL	36,867 BBLS	6.50	239,633	1,497,891	7.05
19 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	64	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
21 BARTOW	1-4	219	0	0.0	100.0	#DIV/0!	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
22 BARTOW	1-4		30				14,933	GAS	448 MCF	1.00	448	3,410	11.37
23 BAYBORO	1-4	232	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
24 DEBARY	1-10	762	0	0.0	100.0	93.2	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
25 DEBARY	1-10		5,893				13,452	GAS	79,270 MCF	1.00	79,270	638,396	10.83
26 HIGGINS	1-4	134	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
27 HIGGINS	1-4		0				0	GAS	0 MCF	1.00	0	0	0.00
28 HINES	1-2	1,111	489,686	61.2	66.3	45.7	6,777	GAS	3,320,013 MCF	1.00	3,320,013	28,248,077	5.77
29 HINES	1-2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	1,208	788	3.2	100.0	49.0	12,145	LIGHT OIL	1,650 BBLS	5.80	9,570	91,681	11.63
31 INT CITY	1-14		27,018				12,822	GAS	346,415 MCF	1.00	346,415	2,679,113	9.92
32 RIO PINAR	1	16	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33 SUWANNEE	1-3	201	60	0.0	100.0	12.6	13,633	LIGHT OIL	141 BBLS	5.80	818	7,804	13.01
34 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	223	102,985	64.1	75.7	84.3	8,115	GAS	835,892 MCF	1.00	835,892	3,834,733	3.72
36 TURNER	1-4	194	0	0.0	100.0	0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
37 UNIV OF FLA.	1	41	15,665	53.1	53.1	99.8	9,380	GAS	146,938 MCF	1.00	146,938	1,423,530	9.09
38 OTHER - START UP		-	2,665	-	-	-	10,234	LIGHT OIL	4,526 BBLS	5.80	26,250	225,750	8.80
39 OTHER													
40 TOTAL		9,174	2,706,659				9,230				24,982,112	103,732,170	3.83

SCHEDULE E4

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Dec-05

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT	NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	788	569,658	97.2	97.0	100.0	10,191 NUCLEAR	5,805,386 MMBTU	1.00	5,805,386	2,002,858	0.35
2	ANCLOTE	1	522	79,725	20.5	94.8	44.5	10,499 HEAVY OIL	128,771 BBLS	6.50	837,009	4,698,602	5.89
3	ANCLOTE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
4	ANCLOTE	2	522	113,330	29.2	94.1	46.7	10,386 HEAVY OIL	180,731 BBLS	6.50	1,174,753	6,594,549	5.82
5	ANCLOTE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
6	BARTOW	1	123	6,593	7.2	85.8	67.0	10,754 HEAVY OIL	10,908 BBLS	6.50	70,902	377,954	5.73
7	BARTOW	2	121	5,352	5.9	95.5	49.7	11,314 HEAVY OIL	9,316 BBLS	6.50	60,553	322,787	6.03
8	BARTOW	3	208	40,717	26.3	90.2	100.9	10,116 HEAVY OIL	63,371 BBLS	6.50	411,911	2,195,754	5.39
9	BARTOW	3		0				0 GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	383	251,339	88.2	91.5	92.7	10,055 COAL	101,088 TONS	25.00	2,527,204	6,873,644	2.73
11	CRYSTAL RIVER	2	491	287,953	78.6	79.7	93.1	9,294 COAL	107,049 TONS	25.00	2,676,232	7,278,979	2.53
12	CRYSTAL RIVER	4	735	488,413	89.3	91.4	96.2	9,378 COAL	183,222 TONS	25.00	4,580,559	11,192,416	2.29
13	CRYSTAL RIVER	5	732	421,661	77.4	79.8	95.5	9,438 COAL	159,183 TONS	25.00	3,979,579	9,723,947	2.31
14	SUWANNEE	1	33	2,019	8.2	97.1	63.1	12,866 HEAVY OIL	3,934 BBLS	6.50	25,572	148,318	7.35
15	SUWANNEE	1		0				0 GAS	0 MCF	1.00	0	0	0.00
16	SUWANNEE	2	32	1,980	8.3	98.2	67.3	13,665 HEAVY OIL	4,163 BBLS	6.50	27,057	156,931	7.93
17	SUWANNEE	2		0				0 GAS	0 MCF	1.00	0	0	0.00
18	SUWANNEE	3	81	4,246	7.0	93.0	39.4	11,400 HEAVY OIL	7,447 BBLS	6.50	48,405	302,568	7.13
19	SUWANNEE	3		0				0 GAS	0 MCF	1.00	0	0	0.00
20	AVON PARK	1-2	64	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
21	BARTOW	1-4	219	0	0.1	100.0	18.2	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
22	BARTOW	1-4		169				14,479 GAS	2,447 MCF	1.00	2,447	22,126	13.09
23	BAYBORO	1-4	232	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
24	DEBARY	1-10	762	70	0.2	100.0	39.6	13,843 LIGHT OIL	167 BBLS	5.80	969	9,400	13.43
25	DEBARY	1-10		1,017				13,488 GAS	13,717 MCF	1.00	13,717	179,141	17.61
26	HIGGINS	1-4	134	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
27	HIGGINS	1-4		0				0 GAS	0 MCF	1.00	0	0	0.00
28	HINES	1-3	1,693	567,307	46.6	87.7	20.7	7,018 GAS	4,121,624 MCF	1.00	4,121,624	34,658,968	5.90
29	HINES	1-3		0				0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
30	INT CITY	1-14	1,206	410	0.5	100.0	29.4	12,105 LIGHT OIL	856 BBLS	5.80	4,963	47,597	11.61
31	INT CITY	1-14		4,453				12,824 GAS	57,105 MCF	1.00	57,105	499,090	11.21
32	RIO PINAR	1	16	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
33	SUWANNEE	1-3	201	270	0.2	100.0	25.2	13,656 LIGHT OIL	636 BBLS	5.80	3,687	35,212	13.04
34	SUWANNEE	1-3		0				0 GAS	0 MCF	1.00	0	0	0.00
35	TIGER BAY	1	223	105,227	63.4	88.3	71.5	8,233 GAS	866,386 MCF	1.00	866,386	3,866,447	3.67
36	TURNER	1-4	194	0	0.0	100.0	0.0	0 LIGHT OIL	0 BBLS	5.80	0	0	0.00
37	UNIV OF FLA.	1	41	30,352	99.5	99.5	99.9	9,378 GAS	284,573 MCF	1.00	284,573	2,171,600	7.15
38	OTHER - START UP		-	7,539	-	-	-	10,145 LIGHT OIL	13,186 BBLS	5.80	76,481	658,528	8.73
39	OTHER												
40	TOTAL		9,756	3,009,800				9,189			27,657,074	94,017,418	3.12

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD OF: Jan-05 THROUGH Dec-05

(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	779	6,128,802	89.9	89.6	99.9	10,302	NUCLEAR	63,137,599 MMBTU	1.00	63,137,599	22,057,876	0.36
2 ANCLOTE	1	510	2,327,305	52.1	95.2	57.5	10,214	HEAVY OIL	3,657,140 BBLS	6.50	23,771,413	133,142,226	5.72
3 ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4 ANCLOTE	2	509	2,314,535	52.0	86.4	57.1	10,235	HEAVY OIL	3,644,420 BBLS	6.50	23,688,731	132,682,197	5.73
5 ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6 BARTOW	1	122	410,816	38.4	82.6	65.9	10,913	HEAVY OIL	689,722 BBLS	6.50	4,483,190	23,865,206	5.81
7 BARTOW	2	120	424,021	40.3	91.8	63.1	11,267	HEAVY OIL	735,012 BBLS	6.50	4,777,576	25,431,010	6.00
8 BARTOW	3	206	833,658	46.2	80.0	69.2	10,228	HEAVY OIL	1,311,738 BBLS	6.50	8,526,295	45,413,010	5.45
9 BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	381	2,622,500	78.6	92.2	83.2	10,145	COAL	1,064,166 TONS	25.00	26,604,141	71,982,643	2.74
11 CRYSTAL RIVER	2	489	3,119,657	72.9	80.8	86.1	9,348	COAL	1,166,450 TONS	25.00	29,161,250	78,899,822	2.53
12 CRYSTAL RIVER	4	728	5,305,637	83.3	91.6	89.7	9,466	COAL	2,008,874 TONS	25.00	50,221,844	121,958,669	2.30
13 CRYSTAL RIVER	5	725	5,254,904	82.8	85.9	95.0	9,467	COAL	1,989,933 TONS	25.00	49,748,317	120,827,037	2.30
14 SUWANNEE	1	33	127,988	45.0	97.1	74.8	12,546	HEAVY OIL	247,039 BBLS	6.50	1,605,753	9,303,523	7.27
15 SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
16 SUWANNEE	2	32	127,147	46.1	98.2	76.2	13,476	HEAVY OIL	263,608 BBLS	6.50	1,713,455	9,928,894	7.81
17 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
18 SUWANNEE	3	81	260,624	37.0	82.1	65.5	11,390	HEAVY OIL	456,702 BBLS	6.50	2,968,565	18,519,875	7.11
19 SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
20 AVON PARK	1-2	58	4,083	0.8	100.0	58.2	17,528	LIGHT OIL	12,339 BBLS	5.80	71,568	781,037	19.13
21 BARTOW	1-4	203	0	3.9	100.0	42.6	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
22 BARTOW	1-4		69,520				15,118	GAS	1,051,024 MCF	1.00	1,051,024	7,517,945	10.81
23 BAYBORO	1-4	208	88,089	4.8	100.0	61.6	14,502	LIGHT OIL	220,248 BBLS	5.80	1,277,440	11,271,262	12.80
24 DEBARY	1-10	715	191,609	7.4	100.0	55.2	13,908	LIGHT OIL	459,480 BBLS	5.80	2,664,967	24,651,308	12.87
25 DEBARY	1-10		271,944				13,789	GAS	3,749,961 MCF	1.00	3,749,961	29,248,648	10.76
26 HIGGINS	1-4	128	2,225	2.6	100.0	53.8	18,066	LIGHT OIL	6,930 BBLS	5.80	40,194	481,046	21.62
27 HIGGINS	1-4		26,626				16,277	GAS	433,389 MCF	1.00	433,389	4,529,611	17.01
28 HINES	1-3	1,103	6,530,363	67.6	90.1	37.9	6,969	GAS	45,507,349 MCF	1.00	45,507,349	346,605,526	5.31
29 HINES	1-3		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30 INT CITY	1-14	1,076	108,709	10.9	100.0	65.6	13,753	LIGHT OIL	257,766 BBLS	5.80	1,495,043	13,771,736	12.67
31 INT CITY	1-14		921,534				13,278	GAS	12,236,085 MCF	1.00	12,236,085	88,354,733	9.59
32 RIO PINAR	1	15	752	0.6	100.0	86.4	18,493	LIGHT OIL	2,398 BBLS	5.80	13,907	124,938	16.61
33 SUWANNEE	1-3	183	80,782	5.1	100.0	56.5	13,955	LIGHT OIL	194,362 BBLS	5.80	1,127,302	10,394,482	12.87
34 SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
35 TIGER BAY	1	215	1,335,283	70.9	87.7	80.4	8,167	GAS	10,904,756 MCF	1.00	10,904,756	49,012,660	3.67
36 TURNER	1-4	174	13,757	0.9	100.0	60.7	15,733	LIGHT OIL	37,317 BBLS	5.80	216,441	1,952,363	14.19
37 UNIV OF FLA.	1	38	304,484	91.5	91.8	99.5	9,480	GAS	2,886,485 MCF	1.00	2,886,485	21,744,581	7.14
38 OTHER - START UP		-	55,111	-	-	-	11,497	LIGHT OIL	109,241 BBLS	5.80	633,598	5,398,613	9.80
39 OTHER		-	0	-	-	-	-		- -	-	-	0	-
40 TOTAL		8,825	39,262,465				9,544				374,717,658	1,429,852,257	3.64

PROGRESS ENERGY FLORIDA
INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

	HEAVY OIL		Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Subtotal
1	PURCHASES:								
2	UNITS	BBL	765,168	683,934	841,632	734,616	929,389	1,108,502	5,063,241
3	UNIT COST	$/BBL	35.60	35.68	36.48	36.81	36.08	35.62	36.03
4	AMOUNT	$	27,242,200	24,403,542	30,701,317	27,039,776	33,535,843	39,481,874	182,404,552
5	BURNED:								
6	UNITS	BBL	765,168	683,934	841,632	734,616	929,389	1,108,502	5,063,241
7	UNIT COST	$/BBL	35.60	35.68	36.48	36.81	36.08	35.62	36.03
8	AMOUNT	$	27,242,200	24,403,542	30,701,317	27,039,776	33,535,843	39,481,874	182,404,552
9	ENDING INVENTORY:								
10	UNITS	BBL	800,000	800,000	800,000	800,000	800,000	800,000	
11	UNIT COST	$/BBL	35.60	35.68	36.48	36.81	36.08	35.62	
12	AMOUNT	$	28,482,320	28,544,880	29,182,640	29,446,400	28,866,960	28,493,840	
13	DAYS SUPPLY:		32	33	29	33	27	22	
	LIGHT OIL								
14	PURCHASES:								
15	UNITS	BBL	96,115	37,382	18,714	14,063	146,313	213,339	525,926
16	UNIT COST	$/BBL	62.78	60.40	58.84	53.25	52.70	51.73	54.93
17	AMOUNT	$	6,034,285	2,257,873	1,101,088	748,887	7,710,903	11,035,206	28,888,221
18	BURNED:								
19	UNITS	BBL	96,115	37,382	18,714	14,063	146,313	213,339	525,926
20	UNIT COST	$/BBL	62.78	60.40	58.84	53.25	52.70	51.73	54.93
21	AMOUNT	$	6,034,285	2,257,873	1,101,088	748,887	7,710,903	11,035,206	28,888,221
22	ENDING INVENTORY:								
23	UNITS	BBL	550,000	550,000	550,000	550,000	550,000	550,000	
24	UNIT COST	$/BBL	62.78	60.40	58.84	53.25	52.70	51.73	
25	AMOUNT	$	34,529,000	33,220,000	32,362,000	29,287,500	28,985,000	28,451,500	
26	DAYS SUPPLY:		177	412	911	1173	117	77	
	COAL								
27	PURCHASES:								
28	UNITS	TON	513,222	494,020	451,803	523,756	565,063	530,028	3,077,893
29	UNIT COST	$/TON	63.42	63.32	64.07	63.31	63.14	62.77	63.32
30	AMOUNT	$	32,547,427	31,283,212	28,947,373	33,158,527	35,675,832	33,270,741	194,880,912
31	BURNED:								
32	UNITS	TON	513,222	494,020	451,803	523,756	565,063	530,028	3,077,893
33	UNIT COST	$/TON	63.42	63.32	64.07	63.31	63.14	62.77	63.32
34	AMOUNT	$	32,547,427	31,283,212	28,947,373	33,156,527	35,675,832	33,270,741	194,880,912
35	ENDING INVENTORY:								
36	UNITS	TON	550,000	550,000	550,000	550,000	550,000	550,000	
37	UNIT COST	$/TON	63.42	63.32	64.07	63.31	63.14	62.77	
38	AMOUNT	$	34,879,790	34,828,035	35,238,885	34,817,915	34,724,635	34,524,380	
39	DAYS SUPPLY:		33	31	38	32	30	31	
	GAS								
40	BURNED:								
41	UNITS	MCF	5,261,614	4,419,738	5,232,979	3,979,897	6,586,062	7,780,020	33,260,310
42	UNIT COST	$/MCF	7.42	7.38	7.54	7.11	6.80	6.87	7.15
43	AMOUNT	$	39,026,410	32,629,395	39,437,802	28,302,402	44,809,794	53,459,490	237,865,294
	NUCLEAR								
44	BURNED:								
45	UNITS	MMBTU	5,805,388	5,242,538	5,805,386	5,620,450	5,805,285	5,624,269	33,903,316
46	UNIT COST	$/MMBTU	0.35	0.35	0.35	0.35	0.35	0.35	0.35
47	AMOUNT	$	2,031,886	1,834,888	2,031,885	1,967,158	2,031,850	1,968,494	11,866,161

PROGRESS ENERGY FLORIDA
INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

	HEAVY OIL		Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Total
1	PURCHASES:								
2	UNITS	BBL	1,280,047	1,277,768	1,128,704	831,354	1,015,627	408,640	11,005,381
3	UNIT COST	$/BBL	36.66	36.27	36.05	36.43	36.26	36.21	36.19
4	AMOUNT	$	46,927,315	46,350,205	40,690,790	30,288,268	36,827,146	14,797,464	398,285,740
5	BURNED:								
6	UNITS	BBL	1,280,047	1,277,768	1,128,704	831,354	1,015,627	408,640	11,005,381
7	UNIT COST	$/BBL	36.66	36.27	36.05	36.43	36.26	36.21	36.19
8	AMOUNT	$	46,927,315	46,350,205	40,690,790	30,288,268	36,827,146	14,797,464	398,285,740
9	ENDING INVENTORY:								
10	UNITS	BBL	800,000	800,000	800,000	800,000	800,000	800,000	
11	UNIT COST	$/BBL	36.66	36.27	36.05	36.43	36.26	36.21	
12	AMOUNT	$	29,328,480	29,019,520	28,840,720	29,145,920	29,008,400	28,969,200	
13	DAYS SUPPLY:		19	19	21	30	24	61	
	LIGHT OIL								
14	PURCHASES:								
15	UNITS	BBL	229,459	323,065	128,717	71,754	6,317	14,845	1,300,083
16	UNIT COST	$/BBL	51.47	51.54	51.98	51.71	51.49	50.57	52.94
17	AMOUNT	$	11,810,934	16,650,165	6,691,074	3,710,400	325,234	750,736	68,826,765
18	BURNED:								
19	UNITS	BBL	229,459	323,065	128,717	71,754	6,317	14,845	1,300,083
20	UNIT COST	$/BBL	51.47	51.54	51.98	51.71	51.49	50.57	52.94
21	AMOUNT	$	11,810,934	16,650,165	6,691,074	3,710,400	325,234	750,736	68,826,765
22	ENDING INVENTORY:								
23	UNITS	BBL	550,000	550,000	550,000	550,000	550,000	550,000	
24	UNIT COST	$/BBL	51.47	51.54	51.98	51.71	51.49	50.57	
25	AMOUNT	$	28,308,500	28,347,000	28,589,000	28,440,500	28,319,500	27,813,500	
26	DAYS SUPPLY:		74	53	128	238	2612	1149	
	COAL								
27	PURCHASES:								
28	UNITS	TON	531,987	531,987	514,894	567,569	454,549	550,543	6,229,422
29	UNIT COST	$/TON	62.61	62.61	62.64	63.21	63.75	63.70	63.19
30	AMOUNT	$	33,305,176	33,306,395	32,252,406	35,878,496	28,975,799	35,068,987	393,668,171
31	BURNED:								
32	UNITS	TON	531,987	531,987	514,894	567,569	454,549	550,543	6,229,422
33	UNIT COST	$/TON	62.61	62.61	62.64	63.21	63.75	63.70	63.20
34	AMOUNT	$	33,305,176	33,306,395	32,252,406	35,878,496	28,975,799	35,068,987	393,668,171
35	ENDING INVENTORY:								
36	UNITS	TON	550,000	550,000	550,000	550,000	550,000	550,000	
37	UNIT COST	$/TON	62.61	62.61	62.64	63.21	63.75	63.70	
38	AMOUNT	$	34,432,860	34,434,125	34,451,450	34,767,865	35,060,410	35,034,395	
39	DAYS SUPPLY:		32	32	32	30	36	31	
	GAS								
40	BURNED:								
41	UNITS	MCF	9,356,791	9,589,454	8,139,518	6,348,348	4,728,776	5,345,852	76,769,049
42	UNIT COST	$/MCF	6.88	6.91	6.93	6.95	7.79	7.74	7.13
43	AMOUNT	$	64,380,012	66,251,583	56,365,810	44,126,375	36,827,259	41,397,372	547,013,705
	NUCLEAR								
44	BURNED:								
45	UNITS	MMBTU	5,809,330	5,809,329	5,624,268	3,934,574	2,251,396	5,805,386	63,137,599
46	UNIT COST	$/MMBTU	0.35	0.35	0.35	0.35	0.35	0.35	0.35
47	AMOUNT	$	2,033,266	2,033,265	1,968,494	1,377,101	776,732	2,002,858	22,057,876

PROGRESS ENERGY FLORIDA
FUEL COST OF POWER SOLD
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
						C/KWH				
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jan-05	ECONSALE	–	150,100		150,100	4.253	4.694	6,384,132	7,045,688	661,556
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	STRATIFIED	–	200,151		200,151	3.067	3.067	6,138,829	6,138,829	0
	TOTAL		350,251		350,251	3.575	3.764	12,522,961	13,184,517	661,556
Feb-05	ECONSALE	–	175,700		175,700	4.103	4.587	7,208,139	8,058,720	850,581
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	STRATIFIED	–	216,485		216,485	3.347	3.347	7,246,044	7,246,044	0
	TOTAL		392,185		392,185	3.686	3.902	14,454,183	15,304,764	850,581
Mar-05	ECONSALE	–	171,250		171,250	4.260	4.811	7,295,975	8,238,550	942,575
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	STRATIFIED	–	225,455		225,455	3.411	3.411	7,690,922	7,690,922	0
	TOTAL		396,705		396,705	3.778	4.015	14,986,897	15,929,472	942,575
Apr-05	ECONSALE	–	112,150		112,150	4.687	5.311	5,256,567	5,956,144	699,578
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	STRATIFIED	–	247,226		247,226	3.468	3.468	8,574,647	8,574,647	0
	TOTAL		359,376		359,376	3.849	4.043	13,831,213	14,530,791	699,578
May-05	ECONSALE	–	54,800		54,800	5.014	5.695	2,747,860	3,120,816	372,956
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	STRATIFIED	–	230,912		230,912	3.336	3.336	7,703,859	7,703,859	0
	TOTAL		285,712		285,712	3.658	3.789	10,451,719	10,824,675	372,956
Jun-05	ECONSALE	–	40,350		40,350	5.140	5.964	2,074,073	2,406,367	332,295
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	SALE OTHER	–	0		0	0.000	0.000	0	0	0
	STRATIFIED	–	227,186		227,186	3.341	3.341	7,589,595	7,589,595	0
	TOTAL		267,536		267,536	3.612	3.736	9,663,667	9,995,962	332,295

PROGRESS ENERGY FLORIDA
FUEL COST OF POWER SOLD
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
						C/KWH				
MONTH	SOLD TO	TYPE & SCHED	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jul-05	ECONSALE	--	59,000		59,000	5.519	6.402	3,256,300	3,777,420	521,120
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	161,398		161,398	4.199	4.199	6,776,525	6,776,525	0
	TOTAL		220,398		220,398	4.552	4.789	10,032,825	10,553,945	521,120
Aug-05	ECONSALE	--	56,500		56,500	5.582	6.468	3,153,785	3,654,455	500,670
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	162,745		162,745	4.217	4.217	6,863,298	6,863,298	0
	TOTAL		219,245		219,245	4.569	4.797	10,017,083	10,517,753	500,670
Sep-05	ECONSALE	--	69,600		69,600	5.309	6.195	3,694,896	4,311,996	617,100
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	161,107		161,107	4.146	4.146	6,680,042	6,680,042	0
	TOTAL		230,707		230,707	4.497	4.765	10,374,938	10,992,038	617,100
Oct-05	ECONSALE	--	59,900		59,900	4.812	5.458	2,882,685	3,269,288	386,603
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	148,137		148,137	4.118	4.118	6,100,330	6,100,330	0
	TOTAL		208,037		208,037	4.318	4.504	8,983,015	9,369,618	386,603
Nov-05	ECONSALE	--	89,800		89,800	4.356	4.898	3,911,954	4,398,104	486,150
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	134,899		134,899	3.837	3.837	5,176,210	5,176,210	0
	TOTAL		224,699		224,699	4.045	4.261	9,088,164	9,574,314	486,150
Dec-05	ECONSALE	--	118,000		118,000	4.221	4.662	4,980,660	5,500,920	520,260
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	127,387		127,387	3.587	3.587	4,569,742	4,569,742	0
	TOTAL		245,387		245,387	3.892	4.104	9,550,402	10,070,662	520,260
Jan-05	ECONSALE	--	1,157,150		1,157,150	4.567	5.163	52,847,025	59,738,468	6,891,443
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-05	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	2,243,088		2,243,088	3.616	3.616	81,110,043	81,110,043	0
	TOTAL		3,400,238		3,400,238	3.940	4.142	133,957,068	140,848,511	6,891,443

PROGRESS ENERGY FLORIDA
PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGEN PURCHASES)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jan-05	REEDY CREEK	--	3,410			3,410	5.000	5.000	170,495
	TECO	--	20,470			20,470	3.948	3.948	808,136
	UPS PURCHASE	UPS	308,016			308,016	1.531	1.531	4,716,960
	VANDOLAH	--	16,468			16,468	15.593	15.593	2,567,918
	TOTAL		348,364	0	0	348,364	2.372	2.372	8,263,509
Feb-05	REEDY CREEK	--	1,586			1,586	4.999	4.999	79,290
	TECO	--	21,890			21,890	3.948	3.948	864,209
	UPS PURCHASE	UPS	278,208			278,208	1.536	1.536	4,272,723
	VANDOLAH	--	10,865			10,865	16.286	16.286	1,769,424
	TOTAL		312,549	0	0	312,549	2.235	2.235	6,985,646
Mar-05	REEDY CREEK	--	0			0	0.000	0.000	0
	TECO	--	32,077			32,077	3.948	3.948	1,266,386
	UPS PURCHASE	UPS	308,016			308,016	1.537	1.537	4,733,586
	VANDOLAH	--	0			0	0.000	0.000	0
	TOTAL		340,093	0	0	340,093	1.764	1.764	5,999,972
Apr-05	REEDY CREEK	--	0			0	0.000	0.000	0
	TECO	--	22,693			22,693	3.948	3.948	895,907
	UPS PURCHASE	UPS	298,080			298,080	1.541	1.541	4,592,812
	VANDOLAH	--	0			0	0.000	0.000	0
	TOTAL		320,773	0	0	320,773	1.711	1.711	5,488,719
May-05	REEDY CREEK	--	0			0	0.000	0.000	0
	TECO	--	27,521			27,521	3.948	3.948	1,086,544
	UPS PURCHASE	UPS	308,016			308,016	1.546	1.546	4,761,307
	VANDOLAH	--	0			0	0.000	0.000	0
	TOTAL		335,537	0	0	335,537	1.743	1.743	5,847,851
Jun-05	REEDY CREEK	--	0			0	0.000	0.000	0
	TECO	--	29,461			29,461	3.948	3.948	1,163,119
	UPS PURCHASE	UPS	298,080			298,080	1.546	1.546	4,609,503
	VANDOLAH	--	35,242			35,242	9.713	9.713	3,422,976
	TOTAL		362,783	0	0	362,783	2.535	2.535	9,195,598

PROGRESS ENERGY FLORIDA
PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGEN PURCHASES)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jul-05	REEDY CREEK	--	0			0	0.000	0.000	0
	TECO	--	33,139			33,139	3.948	3.948	1,308,328
	UPS PURCHASE	UPS	308,016			308,016	1.548	1.548	4,768,699
	VANDOLAH	--	46,094			46,094	10.581	10.581	4,877,017
	TOTAL		387,249	0	0	387,249	2.829	2.829	10,954,044
Aug-05	REEDY CREEK	--	0			0	0.000	0.000	0
	TECO	--	33,139			33,139	3.948	3.948	1,308,328
	UPS PURCHASE	UPS	308,016			308,016	1.549	1.549	4,772,393
	VANDOLAH	--	45,570			45,570	10.676	10.676	4,864,945
	TOTAL		386,725	0	0	386,725	2.830	2.830	10,945,666
Sep-05	REEDY CREEK	--	0			0	0.000	0.000	0
	TECO	--	32,070			32,070	3.948	3.948	1,266,124
	UPS PURCHASE	UPS	298,080			298,080	1.549	1.549	4,617,851
	VANDOLAH	--	33,935			33,935	8.801	8.801	2,986,645
	TOTAL		364,085	0	0	364,085	2.436	2.436	8,870,620
Oct-05	REEDY CREEK	--	0			0	0.000	0.000	0
	TECO	--	27,858			27,858	3.948	3.948	1,099,828
	UPS PURCHASE	UPS	308,016			308,016	1.551	1.551	4,776,104
	VANDOLAH	--	20,643			20,643	9.136	9.136	1,886,011
	TOTAL		356,517	0	0	356,517	2.177	2.177	7,761,943
Nov-05	REEDY CREEK	--	0			0	0.000	0.000	0
	TECO	--	32,070			32,070	3.948	3.948	1,266,124
	UPS PURCHASE	UPS	298,080			298,080	1.551	1.551	4,622,035
	VANDOLAH	--	16,108			16,108	9.341	9.341	1,504,629
	TOTAL		346,258	0	0	346,258	2.135	2.135	7,392,788
Dec-05	REEDY CREEK	--	0			0	0.000	0.000	0
	TECO	--	24,753			24,753	3.948	3.948	977,247
	UPS PURCHASE	UPS	308,016			308,016	1.551	1.551	4,776,717
	VANDOLAH	--	2,556			2,556	17.039	17.039	435,516
	TOTAL		335,325	0	0	335,325	1.846	1.846	6,189,480
Jan-05	REEDY CREEK	--	4,996			4,996	5.000	5.000	249,785
THRU	TECO	--	337,141			337,141	3.948	3.948	13,310,280
Dec-05	UPS PURCHASE	UPS	3,626,640			3,626,640	1.545	1.545	56,020,690
	VANDOLAH	--	227,481			227,481	10.689	10.689	24,315,081
	TOTAL		4,196,258	0	0	4,196,258	2.238	2.238	93,895,836

SCHEDULE E8

PROGRESS ENERGY FLORIDA
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	C/KWH (A) ENERGY COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Jan-05	QUAL. FACILITIES	COGEN	448,138			448,138	2.548	7.989	11,416,711
Feb-05	QUAL. FACILITIES	COGEN	397,740			397,740	2.517	7.959	10,011,221
Mar-05	QUAL. FACILITIES	COGEN	399,513			399,513	2.538	7.980	10,139,532
Apr-05	QUAL. FACILITIES	COGEN	365,566			365,566	2.506	7.948	9,160,790
May-05	QUAL. FACILITIES	COGEN	392,919			392,919	2.531	7.973	9,944,701
Jun-05	QUAL. FACILITIES	COGEN	387,088			387,088	2.559	8.000	9,904,025
Jul-05	QUAL. FACILITIES	COGEN	400,268			400,268	2.641	8.082	10,570,411
Aug-05	QUAL. FACILITIES	COGEN	400,544			400,544	2.622	8.064	10,502,564
Sep-05	QUAL. FACILITIES	COGEN	373,192			373,192	2.589	8.030	9,661,115
Oct-05	QUAL. FACILITIES	COGEN	375,434			375,434	2.525	7.967	9,480,558
Nov-05	QUAL. FACILITIES	COGEN	386,329			386,329	2.551	7.993	9,855,160
Dec-05	QUAL. FACILITIES	COGEN	402,000			402,000	2.508	7.950	10,083,620
TOTAL	QUAL. FACILITIES	COGEN	4,728,731			4,728,731	2.553	7.995	120,730,408

PROGRESS ENERGY FLORIDA
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL MWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jan-05	ECONPURCH	–	22,000	4.709	4.709	1,035,892	5.650	1,243,090	207,198
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	TOTAL		22,000	4.709	4.709	1,035,892	5650.409	1,243,090	207,198
Feb-05	ECONPURCH	–	10,000	4.693	4.693	469,340	5.632	563,176	93,836
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	TOTAL		10,000	4.693	4.693	469,340	5631.760	563,176	93,836
Mar-05	ECONPURCH	–	19,000	4.792	4.792	910,472	5.750	1,092,521	182,049
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	TOTAL		19,000	4.792	4.792	910,472	5750.111	1,092,521	182,049
Apr-05	ECONPURCH	–	25,000	4.921	4.921	1,230,296	5.905	1,476,316	246,020
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	TOTAL		25,000	4.921	4.921	1,230,296	5905.264	1,476,316	246,020
May-05	ECONPURCH	–	59,000	5.051	5.051	2,979,969	6.061	3,575,952	595,983
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	TOTAL		59,000	5.051	5.051	2,979,969	6060.936	3,575,952	595,983
Jun-05	ECONPURCH	–	57,000	5.180	5.180	2,952,741	6.216	3,543,403	590,662
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	TOTAL		57,000	5.180	5.180	2,952,741	6216.496	3,543,403	590,662

PROGRESS ENERGY FLORIDA
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL mWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jul-05	ECONPURCH	–	72,000	5.483	5.483	3,947,869	6.580	4,737,788	789,919
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	TOTAL		72,000	5.483	5.483	3,947,869	6580.261	4,737,788	789,919
Aug-05	ECONPURCH	–	59,000	5.796	5.796	3,419,463	6.954	4,103,135	683,672
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	TOTAL		59,000	5.796	5.796	3,419,463	6954.466	4,103,135	683,672
Sep-05	ECONPURCH	–	59,160	5.441	5.441	3,218,679	6.478	3,832,142	613,463
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	TOTAL		59,160	5.441	5.441	3,218,679	6477.590	3,832,142	613,463
Oct-05	ECONPURCH	–	49,000	4.068	4.068	1,993,253	5.564	2,726,588	733,335
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	TOTAL		49,000	4.068	4.068	1,993,253	5564.465	2,726,588	733,335
Nov-05	ECONPURCH	–	23,000	3.948	3.948	908,120	5.521	1,269,913	361,793
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	TOTAL		23,000	3.948	3.948	908,120	5521.361	1,269,913	361,793
Dec-05	ECONPURCH	–	17,000	3.601	3.601	612,240	5.436	924,122	311,882
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	OTHER	–	0	0.000	0.000	0	0.000	0	0
	TOTAL		17,000	3.601	3.601	612,240	5436.012	924,122	311,882
Jan-05	ECONPURCH	–	471,160	5.026	5.026	23,678,334	6173.730	29,088,146	5,409,812
THRU	OTHER	–	0	0.000	0.000	0	0.000	0	0
Dec-05	OTHER	–	0	0.000	0.000	0	0.000	0	0
	TOTAL		471,160	5.026	5.026	23,678,334	6173.730	29,088,146	5,409,812

PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

	DESCRIPTION		Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Period Average	Prior Residential Bill (a)	Jan-05 vs. Prior
1	Base Rate Revenues	($)	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	0.00
2	Fuel Recovery Factor	(c/kwh)	3.869	3.869	3.869	3.869	3.869	3.869	3.869	3.869	3.869	3.869	3.869	3.869	3.869	3.453	
3	Fuel Cost Recovery Revenues	($)	38.75	38.75	38.75	38.75	38.75	38.75	38.75	38.75	38.75	38.75	38.75	38.75	38.75	34.58	4.17
4	Capacity Cost Recovery Revenues	($)	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.77	-0.02
5	Energy Conservation Cost Revenues (b)	($)	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.74	-0.05
6	Environmental Cost Recovery Revenues	($)	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	0.61	0.66
7	Gross Receipt Taxes	($)	2.35	2.35	2.35	2.35	2.35	2.35	2.35	2.35	2.35	2.35	2.35	2.35	2.35	2.23	0.12
8	Total Revenues	($)	93.99	93.99	93.99	93.99	93.99	93.99	93.99	93.99	93.99	93.99	93.99	93.99	93.99	89.11	4.88

(a) Actual Residential Billing for December 2004.
(b) This is a preliminary number, the Energy Conservation Clause is not due to be filed until 9/24/04.

SCHEDULE E10
Revised 11/04

PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

	DESCRIPTION		Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Period Average	Prior Residential Bill (a)	Jan-05 vs. Prior
1	Base Rate Revenues	($)	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	0.00
2	Fuel Recovery Factor	(c/kwh)	3.912	3.912	3.912	3.912	3.912	3.912	3.912	3.912	3.912	3.912	3.912	3.912	3.912	3.453	
3	Fuel Cost Recovery Revenues	($)	39.18	39.18	39.18	39.18	39.18	39.18	39.18	39.18	39.18	39.18	39.18	39.18	39.18	34.58	4.60
4	Capacity Cost Recovery Revenues	($)	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.77	-0.02
5	Energy Conservation Cost Revenues	($)	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.74	-0.05
6	Environmental Cost Recovery Revenue	($)	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	0.61	0.66
7	Gross Receipt Taxes	($)	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.36	2.23	0.13
8	Total Revenues	($)	94.43	94.43	94.43	94.43	94.43	94.43	94.43	94.43	94.43	94.43	94.43	94.43	94.43	89.11	5.32

(a) Actual Residential Billing for December 2004.

PROGRESS ENERGY FLORIDA
DOCKET NO. 040001-EI
WITNESS: J. PORTUONDO
PART E - REVISED

HINES UNIT 2
SCHEDULE OF SYSTEM DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2005 THRU DECEMBER 2005

	Jan-05 EST	Feb-05 EST	Mar-05 EST	Apr-05 EST	May-05 EST	Jun-05 EST	Jul-05 EST	Aug-05 EST	Sep-05 EST	Oct-05 EST	Nov-05 EST	Dec-05 EST	TOTAL
1 Hines Unit 2 - Land													
2 Beginning Balance	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196
3 Add Investment	-	-	-	-	-	-	-	-	-	-	-	-	-
4 Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
5 Ending Balance	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196
6 Hines Unit 2 - Production Plant													
7 Beginning Balance	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941
8 Add Investment													
9 Less Retirements													
10 Ending Balance	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941
11 Average Balance	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	
12 rate)	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	
13 Depreciation Expense	733,906	733,906	733,906	733,906	733,906	733,906	733,906	733,906	733,906	733,906	733,906	733,906	8,806,872
14 Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
15 Beginning Balance Depreciation	9,094,003	9,827,909	10,561,815	11,295,721	12,029,627	12,763,533	13,497,439	14,231,345	14,965,251	15,699,157	16,433,063	17,166,969	9,094,003
16 Ending Balance Depreciation	9,827,909	10,561,815	11,295,721	12,029,627	12,763,533	13,497,439	14,231,345	14,965,251	15,699,157	16,433,063	17,166,969	17,900,875	17,900,875
Hines Unit 2 - Transmission Station Equipment													
17 Beginning Balance	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657
18 Add Investment	-	-	-	-	-	-	-	-	-	-	-	-	-
19 Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
20 Ending Balance	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657
21 Average Balance	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	
22 rate)	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	
23 Depreciation Expense	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	107,856
24 Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Beginning Balance Depreciation	111,374	120,362	129,350	138,338	147,326	156,314	165,302	174,290	183,278	192,266	201,254	210,242	111,374
26 Ending Balance Depreciation	120,362	129,350	138,338	147,326	156,314	165,302	174,290	183,278	192,266	201,254	210,242	219,230	219,230
27 Hines Unit 2 - Total Depreciation													
28 Total Depreciation Expense	742,894	742,894	742,894	742,894	742,894	742,894	742,894	742,894	742,894	742,894	742,894	742,894	8,914,728
29 Total End Balance Depreciation	9,948,271	10,691,165	11,434,059	12,176,953	12,919,847	13,662,741	14,405,635	15,148,529	15,891,423	16,634,317	17,377,211	18,120,105	18,120,105
30 Return:													
31 Beginning Net Investment	235,927,417	235,184,523	234,441,629	233,698,735	232,955,841	232,212,947	231,470,053	230,727,159	229,984,265	229,241,371	228,498,477	227,755,583	
32 Ending Net Investment	235,184,523	234,441,629	233,698,735	232,955,841	232,212,947	231,470,053	230,727,159	229,984,265	229,241,371	228,498,477	227,755,583	227,012,689	
33 Average Investment	235,555,970	234,813,076	234,070,182	233,327,288	232,584,394	231,841,500	231,098,606	230,355,712	229,612,818	228,869,924	228,127,030	227,384,136	
34 Allowed Equity Return (1)	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	
35 Equity Component After Tax	1,297,513	1,293,421	1,289,329	1,285,237	1,281,145	1,277,053	1,272,960	1,268,868	1,264,776	1,260,684	1,256,592	1,252,500	
36 Conversion to Pre-tax	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	
37 Equity Component Pre-Tax	2,112,351	2,105,689	2,099,028	2,092,368	2,085,704	2,079,042	2,072,379	2,065,717	2,059,055	2,052,394	2,045,732	2,039,070	24,908,527
38 Allowed Debt Return (1)	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	
39 Debt Component	504,490	502,899	501,308	499,717	498,126	496,535	494,944	493,353	491,762	490,171	488,580	486,989	5,948,874
40 Total Return Requirements (2)	2,616,841	2,608,588	2,600,336	2,592,083	2,583,830	2,575,577	2,567,323	2,559,070	2,550,817	2,542,565	2,534,312	2,526,059	30,857,401

PROGRESS ENERGY FLORIDA
DOCKET NO. 040001-EI
WITNESS: J. PORTUONDO
PART E - REVISED

HINES UNIT 2
SCHEDULE OF SYSTEM DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2005 THRU DECEMBER 2005

	Jan-05 EST	Feb-05 EST	Mar-05 EST	Apr-05 EST	May-05 EST	Jun-05 EST	Jul-05 EST	Aug-05 EST	Sep-05 EST	Oct-05 EST	Nov-05 EST	Dec-05 EST	TOTAL
Net System Benefit/(Cost):													
Total Depreciation & Return	$3,359,735	$3,351,482	$3,343,230	$3,334,977	$3,326,724	$3,318,471	$3,310,217	$3,301,964	$3,293,711	$3,285,459	$3,277,206	$3,268,953	$39,772,129
Total Fuel Savings	2,723,548	533,549	86,864	739,105	3,585,223	7,944,249	9,811,245	11,281,953	5,286,463	2,438,511	169,902	-	44,602,512
Total Net Benefit/(Cost)	($636,187)	($2,817,933)	($3,256,366)	($2,595,872)	$258,499	$4,625,778	$6,501,028	$7,979,989	$1,994,752	($846,948)	($3,107,304)	($3,268,953)	$4,830,483
Net Retail Benefit (Cost):													
Retail Depreciation & Return	$2,996,817	$2,975,701	$2,939,174	$2,917,103	$2,932,812	$2,975,998	$3,038,972	$3,026,430	$3,013,239	$2,994,844	$2,961,390	$2,975,232	$35,747,512
Retail Fuel Savings	2,429,351	473,725	76,366	646,495	3,160,703	7,124,387	9,001,357	10,347,357	4,836,129	2,222,665	153,529	-	40,474,074
Retail Net Benefit (cost)	($567,466)	($2,501,976)	($2,862,808)	($2,270,608)	$227,891	$4,148,389	$5,964,385	$7,318,927	$1,824,890	($771,979)	($2,807,861)	($2,975,232)	$4,726,562
Hines 2 System Savings:													
Hines Unit 2 Displaced Fuel Exp.	$12,431,661	$8,899,947	$13,867,217	$6,187,990	$13,586,557	$19,958,266	$24,367,244	$26,237,382	$18,427,084	$12,909,132	$13,935,009	$6,022,348	$176,869,839
All Purchase Power Fuel Savings	207,198	93,836	162,049	246,020	595,983	590,662	789,919	683,672	613,463	733,335	361,793	311,882	5,409,812
Hines Unit 2 Actual Fuel Exp.	(9,915,311)	(8,460,234)	(13,962,402)	(5,694,905)	(10,597,317)	(12,604,681)	(15,365,918)	(15,639,101)	(13,752,084)	(11,203,956)	(14,126,900)	(6,366,686)	(137,696,497)
Hines 2 Fixed Transport Costs													-
Fuel Savings	$2,723,548	$533,549	$86,864	$739,105	$3,585,223	$7,944,249	$9,811,245	$11,281,953	$5,286,463	$2,438,511	$169,902	$0	$44,602,512
Development of Factors:													
MWH													
Retail Sales	3,081,182	2,958,866	2,870,063	2,921,388	3,040,446	3,621,077	3,956,372	4,049,622	4,012,063	3,623,553	3,107,367	3,050,708	40,292,697
Wholesale Avg Sales	173,190	156,886	169,069	171,232	177,361	189,574	194,751	203,059	212,324	203,475	196,472	173,823	2,221,216
Subtotal	3,254,372	3,115,752	3,039,122	3,092,620	3,217,807	3,810,651	4,151,123	4,252,681	4,224,387	3,827,028	3,303,839	3,224,531	42,513,913
Stratified Sales	200,151	218,485	225,455	247,226	230,912	227,186	161,398	162,745	161,107	148,137	134,899	127,387	2,243,086
Total Sales	3,454,523	3,332,237	3,264,577	3,339,846	3,448,719	4,037,837	4,312,521	4,415,426	4,385,494	3,975,165	3,438,738	3,351,916	44,757,001
Check	0	0	0	0	0	0	0	0	0	0	0	0	
PERCENT													
Retail & Whls Avg Cost Sales	94.21%	93.50%	93.09%	92.60%	93.30%	94.37%	96.26%	96.31%	96.33%	96.27%	96.08%	96.20%	
Stratified Sales	5.79%	6.50%	6.91%	7.40%	6.70%	5.63%	3.74%	3.69%	3.67%	3.73%	3.92%	3.80%	
Total Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
RETAIL FACTOR	94.58%	94.96%	94.44%	94.46%	94.49%	95.03%	95.31%	95.23%	94.97%	94.68%	94.05%	94.81%	

PROGRESS ENERGY FLORIDA
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

			2002	2003	2004	2005	2003 vs. 2002	2004 vs. 2003	2005 vs. 2004
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		221,008,292	288,137,027	316,554,795	398,285,740	30.4%	9.9%	25.8%
2	LIGHT OIL		52,447,821	38,637,993	48,692,597	68,826,765	-26.3%	26.0%	41.3%
3	COAL		322,518,187	366,546,748	340,430,181	393,668,171	13.7%	-7.1%	15.6%
4	GAS		237,581,107	330,111,281	426,279,117	547,013,705	38.9%	29.1%	28.3%
5	NUCLEAR		22,334,715	22,051,793	24,125,913	22,057,876	-1.3%	9.4%	-8.6%
6	OTHER		0	0	0	0	0.0%	0.0%	0.0%
7	TOTAL	$	855,890,122	1,045,484,842	1,156,082,603	1,429,852,257	22.2%	10.6%	23.7%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		6,261,481	6,714,920	6,902,356	6,826,094	7.2%	2.8%	-1.1%
9	LIGHT OIL		683,473	475,748	448,830	545,117	-30.4%	-5.7%	21.5%
10	COAL		14,406,461	16,111,850	16,168,943	16,302,698	11.8%	0.4%	0.8%
11	GAS		6,429,397	6,152,306	7,658,033	9,459,754	-4.3%	24.5%	23.5%
12	NUCLEAR		6,700,267	6,038,641	6,717,391	6,128,802	-9.9%	11.2%	-8.8%
13	OTHER		0	0	0	0	0.0%	0.0%	0.0%
14	TOTAL	MWH	34,481,079	35,493,465	37,895,553	39,262,465	2.9%	6.8%	3.6%
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	9,850,631	10,616,486	10,995,770	11,005,381	7.8%	3.6%	0.1%
16	LIGHT OIL	BBL	1,547,027	1,072,389	1,060,443	1,300,083	-30.7%	-1.1%	22.6%
17	COAL	TON	5,564,857	6,227,491	6,225,388	6,229,422	11.9%	0.0%	0.1%
18	GAS	MCF	56,163,957	52,533,466	63,202,038	76,769,049	-6.5%	20.3%	21.5%
19	NUCLEAR	MMBTU	68,947,790	61,900,670	69,080,768	63,137,599	-10.2%	11.6%	-8.6%
20	OTHER	BBL	0	0	0	0	0.0%	0.0%	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		64,868,317	69,926,030	71,877,288	71,534,978	7.8%	2.8%	-0.5%
22	LIGHT OIL		8,977,691	6,213,447	6,163,215	7,540,480	-30.8%	-0.8%	22.3%
23	COAL		138,370,054	155,007,595	155,005,949	155,735,552	12.0%	0.0%	0.5%
24	GAS		58,186,575	54,794,309	64,409,152	76,769,049	-5.8%	17.5%	19.2%
25	NUCLEAR		68,947,790	61,900,670	69,080,768	63,137,599	-10.2%	11.6%	-8.6%
26	OTHER		0	0	0	0	0.0%	0.0%	0.0%
27	TOTAL	MMBTU	339,350,427	347,842,051	366,536,372	374,717,658	2.5%	5.4%	2.2%
	GENERATION MIX (% MWH)								
28	HEAVY OIL		18.16%	18.92%	18.21%	17.39%	4.4%	-3.7%	-4.4%
29	LIGHT OIL		1.98%	1.34%	1.18%	1.39%	-30.3%	-14.9%	16.9%
30	COAL		41.78%	45.39%	42.67%	41.52%	8.6%	-5.9%	-2.6%
31	GAS		18.65%	17.33%	20.21%	24.09%	-7.0%	16.7%	19.3%
32	NUCLEAR		19.43%	17.01%	17.73%	15.61%	-12.4%	4.1%	-11.8%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.0%	0.0%	0.0%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	0.0%	0.0%	0.0%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	22.44	27.14	28.79	36.19	21.0%	6.1%	25.7%
36	LIGHT OIL	$/BBL	33.90	36.03	45.92	52.94	6.3%	27.4%	15.3%
37	COAL	$/TON	57.96	58.86	54.68	63.20	1.6%	-7.1%	15.6%
38	GAS	$/MCF	4.23	6.28	6.74	7.13	48.6%	7.3%	5.6%
39	NUCLEAR	$/MMBTU	0.32	0.36	0.35	0.35	9.9%	-2.0%	0.0%
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		3.41	4.12	4.40	5.57	21.0%	6.9%	26.4%
42	LIGHT OIL		5.84	6.22	7.90	9.13	6.4%	27.1%	15.5%
43	COAL		2.33	2.37	2.20	2.53	1.5%	-7.1%	15.1%
44	GAS		4.08	6.03	6.62	7.13	47.6%	9.8%	7.7%
45	NUCLEAR		0.32	0.36	0.35	0.35	9.9%	-2.0%	0.0%
46	OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47	TOTAL	$/MMBTU	2.52	3.01	3.15	3.82	19.2%	4.9%	21.0%
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,360	10,414	10,413	10,480	0.5%	0.0%	0.6%
49	LIGHT OIL		13,135	13,060	13,732	13,833	-0.6%	5.1%	0.7%
50	COAL		9,605	9,621	9,587	9,553	0.2%	-0.4%	-0.4%
51	GAS		9,050	8,906	8,411	8,115	-1.6%	-5.6%	-3.5%
52	NUCLEAR		10,290	10,251	10,284	10,302	-0.4%	0.3%	0.2%
53	OTHER		0	0	0	0	0.0%	0.0%	0.0%
54	TOTAL	BTU/KWH	9,842	9,800	9,672	9,544	-0.4%	-1.3%	-1.3%
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		3.53	4.29	4.59	5.83	21.6%	6.9%	27.2%
56	LIGHT OIL		7.67	8.12	10.85	12.63	5.8%	33.6%	16.4%
57	COAL		2.24	2.28	2.11	2.41	1.6%	-7.5%	14.7%
58	GAS		3.70	5.37	5.57	5.78	45.2%	3.7%	3.9%
59	NUCLEAR		0.33	0.37	0.36	0.36	9.6%	-1.6%	0.3%
60	OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61	TOTAL	C/KWH	2.48	2.95	3.05	3.64	18.7%	3.6%	19.4%

SCHEDULE E1
Revised 10/04

PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

			DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation		1,429,852,257	39,262,465	3.64178
2.	Spent Nuclear Fuel Disposal Cost		5,730,430	6,128,802 *	0.09350
3.	Coal Car Investment		0	0	0.00000
4.	Adjustment to Fuel Cost		39,438,402	0	0.00000
5.	TOTAL COST OF GENERATED POWER		1,475,021,089	39,262,465	3.75682
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		93,895,836	4,196,258	2.23761
7.	Energy Cost of Sch. C,X Economy Purchases (Broker) (E9)		0	0	0.00000
8.	Energy Cost of Economy Purchases (Non-Broker) (E9)		23,678,334	471,160	5.02554
9.	Energy Cost of Schedule E Economy Purchases (E9)		0	0	0.00000
10.	Capacity Cost of Economy Purchases (E9)		0	0 *	0.00000
11.	Payments to Qualifying Facilities (E8)		120,730,408	4,728,731	2.55312
12.	TOTAL COST OF PURCHASED POWER		238,304,578	9,396,149	2.53619
13.	TOTAL AVAILABLE KWH			48,658,614	
14.	Fuel Cost of Economy Sales	(E6)	0	0	0.00000
14a.	Gain on Economy Sales - 80%	(E6)	0	0 *	0.00000
15.	Fuel Cost of Other Power Sales	(E6)	(52,847,025)	(1,157,150)	4.56700
15a.	Gain on Other Power Sales	(E6)	(6,891,443)	(1,157,150) *	0.59555
16.	Fuel Cost of Unit Power Sales	(E6)	0	0	0.00000
16a.	Gain on Unit Power Sales	(E6)	0	0	0.00000
17.	Fuel Cost of Stratified Sales	(E6)	(81,110,043)	(2,243,088)	3.61600
18.	TOTAL FUEL COST AND GAINS ON POWER SALES		(140,848,511)	(3,400,238)	4.14231
19.	Net Inadvertent Interchange			0	
20.	TOTAL FUEL AND NET POWER TRANSACTIONS		1,572,477,156	45,258,376	3.47444
21.	Net Unbilled		(1,215,079)	34,972	(0.00290)
22.	Company Use		5,003,200	(144,000)	0.01180
23.	T & D Losses		91,566,726	(2,635,435)	0.21538
24.	Adjusted System KWH Sales		1,572,477,156	42,513,913	3.69872
25.	Wholesale KWH Sales (Excluding Supplemental Sales)		(81,810,023)	(2,221,216)	3.68312
26.	Jurisdictional KWH Sales		1,490,667,133	40,292,697	3.69960
27.	Jurisdictional KWH Sales Adjusted for Line Losses x	1.0038	1,496,331,668	40,292,697	3.71365
28.	Prior Period True-Up (Sch E1-A)		84,589,752	40,292,697	0.20994
29.	Total Jurisdictional Fuel Cost		1,580,921,420	40,292,697	3.92359
30.	Revenue Tax Factor				1.00072
31.	Fuel Cost Adjusted for Taxes		1,582,059,683	40,292,697	3.92641
32.	GPIF		2,139,695	40,292,697	0.00531
33.	Fuel Factor Adjusted for taxes including GPIF		1,584,199,378	40,292,697	3.93173
34.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)				3.932

* For Informational Purposes Only

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 34
COMPANY/ PEF
WITNESS. Javier Portuondo (JP-1S)
DATE: 11-08-04

SCHEDULE E1-A
Revised 10/04

PROGRESS ENERGY FLORIDA
CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

1.	ACTUAL OVER/(UNDER) RECOVERY JANUARY - DECEMBER 2003 (Schedule E1-B, Line 19 - Dec '04)	$ (211,227,688)	
2.	PROJECTED DECEMBER 2003 UNDER RECOVERY COLLECTED THROUGH DECEMBER 2004 (Schedule E1-B, Line 20 - Dec '04)	210,426,260	
3.	ESTIMATED OVER/(UNDER) RECOVERY JANUARY - DECEMBER 2004 (Schedule E1-B, Line 18 - Dec '04)	(162,945,594)	
4.	TOTAL OVER/(UNDER) RECOVERY (Lines 1 through 3)	$ (163,747,022)	
5.	AMOUNT OF TOTAL OVER/(UNDER) RECOVERY DEFERRED TO 2006 (Direct Testimony - Javier Portuondo)	79,157,270	
6.	TOTAL OVER/(UNDER) RECOVERY APPLICABLE TO 2005 (Lines 4 through 5)	$ (84,589,752)	
6.	JURISDICTIONAL MWH SALES (Projected Period)	40,292,697	Mwh
7.	TRUE-UP FACTOR (Line 4 / Line 5 / 10)	0.20994	Cents/kwh

SCHEDULE E1-B
Reprojected 8/04
Revised 10/04

PROGRESS ENERGY FLORIDA
CALCULATION OF ESTIMATED TRUE-UP
2004 REPROJECTION (Filed 8/04)

DESCRIPTION	ACTUAL Jan-04	ACTUAL Feb-04	ACTUAL Mar-04	ACTUAL Apr-04	ACTUAL May-04	ACTUAL Jun-04	ACTUAL Jul-04	ESTIMATED Aug-04	ESTIMATED Sep-04	ESTIMATED Oct-04	ESTIMATED Nov-04	ESTIMATED Dec-04	TOTAL PERIOD
6 Less: Other	0	0	0	0	0	0	0	0	0	0	0	0	0
7 Net Fuel Revenue	86,524,497	73,553,347	76,336,237	72,850,886	83,646,944	108,022,884	113,964,399	114,838,642	115,881,992	103,418,413	86,639,291	84,138,553	1,119,816,084
FUEL EXPENSE													
8 Total Cost of Generated Power	79,160,754	71,195,503	70,085,820	70,773,824	104,436,588	130,862,260	133,525,701	148,254,725	142,638,402	110,343,065	83,781,501	84,611,270	1,229,687,412
9 Total Cost of Purchased Power	17,267,497	17,007,856	17,729,137	17,425,962	20,067,587	26,545,410	25,735,570	18,677,684	18,017,474	17,083,788	15,947,144	17,070,421	228,775,529
10 Total Cost of Interchange Sales	(8,130,039)	(5,522,122)	(5,445,455)	(5,288,773)	(3,127,555)	(916,787)	(593,278)	(2,781,600)	(3,415,824)	(3,034,698)	(3,912,892)	(4,177,615)	(46,346,637)
11 Total Cost of Stratified Sales	(4,959,124)	(4,779,011)	(7,144,401)	(5,827,641)	(5,529,282)	(6,662,662)	(8,494,696)	(8,145,147)	(8,262,591)	(7,882,382)	(6,564,448)	(5,796,859)	(80,048,243)
12 Total Fuel and Net Power	83,359,088	77,902,225	75,225,100	77,083,373	115,847,339	149,828,221	150,173,297	156,205,662	148,975,461	116,509,773	89,251,306	91,707,217	1,332,068,061
13 Jurisdictional Percentage	97.91%	97.44%	97.72%	97.45%	97.68%	95.51%	94.77%	95.03%	94.86%	94.68%	94.18%	94.78%	95.77%
14 Jurisdictional Loss Multiplier	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038
15 Jurisdictional Fuel Cost	81,926,211	76,192,583	73,785,630	75,399,438	113,584,029	143,637,563	142,852,930	148,998,899	141,848,065	110,725,121	84,372,094	87,248,051	1,280,568,614
COST RECOVERY													
16 Net Fuel Revenue Less Expense	4,598,286	(2,639,236)	2,550,807	(2,548,552)	(29,937,085)	(35,614,678)	(28,888,532)	(34,160,257)	(25,966,073)	(7,306,708)	2,267,198	(3,107,498)	(180,752,529)
17 Interest Provision (1)	(174,140)	(152,729)	(134,875)	(123,547)	(125,483)	(159,564)	(206,098)	(222,706)	(237,624)	(236,850)	(219,559)	(199,791)	(2,193,065)
18 Current Cycle Balance	4,424,146	1,632,181	4,047,913	1,375,814	(28,686,754)	(64,481,096)	(93,555,726)	(127,938,689)	(154,142,386)	(161,685,945)	(159,638,306)	(162,945,594)	
19 Plus: Prior Period True-Up Balance	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	(211,227,688)	
20 Plus: Cumulative True-Up Provision	17,535,522	35,071,044	52,606,566	70,142,088	87,677,610	105,213,132	122,748,654	140,284,176	157,819,698	175,355,220	192,890,742	210,426,260	
21 Total Retail Balance	(189,268,020)	(174,524,463)	(154,573,209)	(139,709,786)	(152,236,832)	(170,475,652)	(182,034,760)	(198,882,201)	(207,550,376)	(197,558,412)	(177,975,251)	(163,747,022)	

(1) Interest for the August through December 2004 period calculated at the July 2004 monthly rate of .117%

SCHEDULE E1-C
Revised 10/04

PROGRESS ENERGY FLORIDA
CALCULATION OF GENERATING PERFORMANCE INCENTIVE AND TRUE-UP ADJUSTMENT FACTORS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward / (Penalty)	$ 2,139,695	
	B. True-Up (Over) / Under Recovery	$ 84,589,752	
2.	JURISDICTIONAL MWH SALES	40,292,697	Mwh
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor	0.00531	Cents/kwh
	B. True-Up Factor	0.20994	Cents/kwh

PROGRESS ENERGY FLORIDA
CALCULATION OF LEVELIZED FUEL ADJUSTMENT FACTORS
(PROJECTED PERIOD)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

1.	Period Jurisdictional Fuel Cost (E1, line 27)	$ 1,496,331,668	
2.	Prior Period True-Up (E1, line 28)	84,589,752	
3.	Other Adjustments	0	
4.	Regulatory Assessment Fee (E1, line 30)	1,138,263	
5.	Generating Performance Incentive Factor (GPIF) (E1, line 32)	2,139,695	
6.	Total Jurisdictional Fuel Cost (E1, line 33)	$ 1,584,199,378	
7.	Jurisdictional Sales (E1, line 26)	40,292,697	Mwh
8.	Jurisdictional Cost per Kwh Sold (Line 6 / Line 7 / 10)	3.932	Cents/kwh
9.	Effective Jurisdictional Sales (See Below)	40,232,285	Mwh

LEVELIZED FUEL FACTORS:

10.	Fuel Factor at Secondary Metering (Line 6 / Line 9 / 10)	**3.938**	Cents/kwh
11.	Fuel Factor at Primary Metering (Line 10 * 99%)	**3.899**	Cents/kwh
12.	Fuel Factor at Transmission Metering (Line 10 * 98%)	**3.859**	Cents/kwh

	JURISDICTIONAL SALES (MWH)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	34,788,122	34,788,122
Distribution Primary	4,967,861	4,918,183
Transmission	536,714	525,980
Total	40,292,697	40,232,285

PROGRESS ENERGY FLORIDA
CALCULATION OF FINAL FUEL COST FACTORS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

Line:	Metering Voltage	(1) Levelized Factors Cents/Kwh	(2) Time of Use On-Peak Multiplier 1.288	(3) Time of Use Off-Peak Multiplier 0.877
1.	Distribution Secondary	3.938	5.072	3.454
2.	Distribution Primary	3.899	5.022	3.419
3.	Transmission	3.859	4.970	3.384
4.	Lighting Service	3.756	--	--

Line 4 Calculated as secondary rate 3.938 * (18.7% * On-Peak Multiplier 1.288 + 81.3% * Off-Peak Multiplier 0.877).

DEVELOPMENT OF TIME OF USE MULTIPLIERS

	ON-PEAK PERIOD			OFF-PEAK PERIOD			TOTAL		
Mo/Yr	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)
Jan-05	934,416	56,926,599	6.092	2,793,554	128,584,401	4.603	3,727,970	185,511,000	4.976
Feb-05	904,948	58,358,558	6.449	2,449,462	110,966,431	4.530	3,354,410	169,324,990	5.048
Mar-05	929,664	55,002,581	5.916	2,664,951	143,796,494	5.396	3,594,615	198,799,075	5.530
Apr-05	1,094,814	71,425,578	6.524	2,379,607	101,637,065	4.271	3,474,421	173,062,643	4.981
May-05	1,397,202	108,462,240	7.763	2,796,698	125,744,189	4.496	4,193,900	234,206,429	5.584
Jun-05	1,493,751	132,792,979	8.890	2,883,722	152,816,576	5.299	4,377,473	285,609,555	6.525
Jul-05	1,462,793	137,638,152	9.409	3,273,062	203,983,146	6.232	4,735,855	341,621,299	7.214
Aug-05	1,621,966	160,971,691	9.924	3,152,051	192,704,065	6.114	4,774,017	353,675,757	7.408
Sep-05	1,438,032	125,185,871	8.705	2,917,874	167,026,010	5.724	4,355,906	292,211,881	6.708
Oct-05	1,207,943	89,233,739	7.387	2,694,841	129,633,130	4.810	3,902,784	218,866,869	5.608
Nov-05	860,288	50,255,273	5.842	2,512,158	148,223,624	5.900	3,372,446	198,478,897	5.885
Dec-05	897,852	43,745,890	4.872	2,748,271	128,911,233	4.691	3,646,123	172,657,124	4.735
TOTAL	14,243,670	1,089,999,152	7.653	33,266,253	1,734,026,366	5.213	47,509,922	2,824,025,518	5.944
MARGINAL FUEL COST			ON-PEAK			OFF-PEAK			AVERAGE
WEIGHTING MULTIPLIER			1.288			0.877			1.000

SCHEDULE E2
Revised 10/04

PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

	DESCRIPTION		Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	TOTAL
1	Fuel Cost of System Net Generation		$106,882,208	$92,408,911	$102,219,446	$91,214,749	$123,764,021	$139,215,805	$158,456,702	$164,591,612	$137,968,574	$115,380,640	$103,732,170	$94,017,418	$1,429,852,257
1a	Nuclear Fuel Disposal Cost		532,630	480,990	532,630	515,663	521,829	505,206	521,829	521,829	505,206	353,427	206,560	532,630	5,730,430
1b	Adjustments to Fuel Cost		3,162,195	3,130,656	3,109,251	3,085,251	3,100,881	3,128,661	3,183,383	3,177,095	3,169,814	4,903,733	3,145,743	3,141,739	39,438,402
2	Fuel Cost of Power Sold		(5,384,132)	(7,208,139)	(7,295,975)	(5,256,567)	(2,747,860)	(2,074,073)	(3,256,300)	(3,153,785)	(3,694,896)	(2,882,585)	(3,911,954)	(4,980,660)	(52,847,025)
2a	Fuel Cost of Stratified Sales		(6,138,829)	(7,246,044)	(7,690,922)	(8,574,647)	(7,703,859)	(7,589,595)	(6,776,525)	(6,863,298)	(6,680,042)	(6,100,330)	(5,176,210)	(4,569,742)	(81,110,043)
2b	Gains on Power Sales		(661,556)	(850,581)	(942,575)	(699,578)	(372,956)	(332,295)	(521,120)	(500,670)	(617,100)	(386,603)	(486,150)	(520,260)	(6,891,443)
3	Energy Cost of Purchased Power		8,263,509	6,985,646	5,999,972	5,488,719	5,847,851	9,195,598	10,954,044	10,945,666	8,870,620	7,761,943	7,392,788	6,189,480	93,895,836
3a	Capacity Cost of Economy Purchases														
3b	Payments to Qualifying Facilities		11,416,711	10,011,221	10,139,532	9,160,790	9,944,701	9,904,025	10,570,411	10,502,564	9,661,115	9,480,558	9,855,160	10,083,620	120,730,408
4	Energy Cost of Economy Purchases		1,035,892	469,340	910,472	1,230,296	2,979,969	2,952,741	3,947,869	3,419,463	3,218,679	1,993,253	908,120	612,240	23,676,334
5	Total Fuel & Net Power Transactions		$118,108,628	$98,182,000	$106,981,831	$96,164,677	$135,334,577	$154,906,074	$177,080,293	$182,640,476	$152,401,969	$130,503,937	$115,666,227	$104,506,465	$1,572,477,156
6	Adjusted System Sales	MWH	3,254,372	3,115,752	3,039,122	3,092,620	3,217,807	3,810,651	4,151,123	4,252,681	4,224,387	3,827,028	3,303,839	3,224,531	42,513,913
7	System Cost per KWH Sold	c/kwh	3.6292	3.1512	3.5201	3.1095	4.2056	4.0651	4.2658	4.2947	3.6076	3.4100	3.5010	3.2410	3.6987
7a	Jurisdictional Loss Multiplier	x	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038
7b	Jurisdictional Cost per KWH Sold	c/kwh	3.6430	3.1631	3.5335	3.1213	4.2218	4.0805	4.2821	4.3110	3.6214	3.4230	3.5143	3.2533	3.7137
8	Prior Period True-Up	c/kwh	0.2288	0.2382	0.2456	0.2413	0.2319	0.1947	0.1782	0.1741	0.1757	0.1945	0.2269	0.2311	0.2099
9	Total Jurisdictional Fuel Expense	c/kwh	3.8718	3.4014	3.7791	3.3626	4.4536	4.2752	4.4602	4.4851	3.7971	3.6176	3.7411	3.4844	3.9236
10	Revenue Tax Multiplier	x	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
11	Fuel Cost Factor Adjusted for Taxes	c/kwh	3.8746	3.4038	3.7819	3.3650	4.4568	4.2783	4.4634	4.4883	3.7998	3.6202	3.7438	3.4869	3.9264
12	GPIF	c/kwh	0.0058	0.0060	0.0062	0.0061	0.0059	0.0049	0.0045	0.0044	0.0044	0.0049	0.0057	0.0058	0.0053
13	Total Fuel Cost Factor (rounded .001)	c/kwh	3.880	3.410	3.788	3.371	4.463	4.283	4.468	4.493	3.804	3.625	3.750	3.493	3.932

SCHEDULE E10
Revised 10/04

PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2005

	DESCRIPTION		Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	Period Average	Prior Residential Bill (a)	Jan-05 vs. Prior
1	Base Rate Revenues	($)	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	0.00
2	Fuel Recovery Factor	(c/kwh)	3.932	3.932	3.932	3.932	3.932	3.932	3.932	3.932	3.932	3.932	3.932	3.932	3.932	3.453	
3	Fuel Cost Recovery Revenues	($)	39.38	39.38	39.38	39.38	39.38	39.38	39.38	39.38	39.38	39.38	39.38	39.38	39.38	34.58	4.80
4	Capacity Cost Recovery Revenues	($)	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.75	8.77	-0.02
5	Energy Conservation Cost Revenues	($)	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.69	1.74	-0.05
6	Environmental Cost Recovery Revenues	($)	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	0.61	0.66
7	Gross Receipt Taxes	($)	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.23	0.14
8	Total Revenues	($)	94.64	94.64	94.64	94.64	94.64	94.64	94.64	94.64	94.64	94.64	94.64	94.64	94.64	89.11	5.53

(a) Actual Residential Billing for December 2004.

PROGRESS ENERGY FLORIDA
DOCKET NO. 040001-EI
WITNESS: J. PORTUONDO
PART E - REVISED

HINES UNIT 2
SCHEDULE OF SYSTEM DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2005 THRU DECEMBER 2005

		Jan-05 EST	Feb-05 EST	Mar-05 EST	Apr-05 EST	May-05 EST	Jun-05 EST	Jul-05 EST	Aug-05 EST	Sep-05 EST	Oct-05 EST	Nov-05 EST	Dec-05 EST	TOTAL
1	Hines Unit 2 - Land													
2	Beginning Balance	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196	$2,206,196
3	Add Investment	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Ending Balance	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196	2,206,196
6	Hines Unit 2 - Production Plant													
7	Beginning Balance	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941
8	Add Investment													
9	Less Retirements													
10	Ending Balance	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941
11	Average Balance	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	238,023,941	
12	rate)	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	0.308333%	
13	Depreciation Expense	733,906	733,906	733,906	733,906	733,906	733,906	733,906	733,906	733,906	733,906	733,906	733,906	8,806,872
14	Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Beginning Balance Depreciation	9,094,003	9,827,909	10,561,815	11,295,721	12,029,627	12,763,533	13,497,439	14,231,345	14,965,251	15,699,157	16,433,063	17,166,969	9,094,003
16	Ending Balance Depreciation	9,827,909	10,561,815	11,295,721	12,029,627	12,763,533	13,497,439	14,231,345	14,965,251	15,699,157	16,433,063	17,166,969	17,900,875	17,900,875
17	Hines Unit 2 - Transmission Station Equipment													
18	Beginning Balance	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657
19	Add Investment	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Ending Balance	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657
22	Average Balance	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	4,902,657	
23	rate)	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	0.183333%	
24	Depreciation Expense	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	8,988	107,856
25	Less Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Beginning Balance Depreciation	111,374	120,362	129,350	138,338	147,326	156,314	165,302	174,290	183,278	192,266	201,254	210,242	111,374
27	Ending Balance Depreciation	120,362	129,350	138,338	147,326	156,314	165,302	174,290	183,278	192,266	201,254	210,242	219,230	219,230
28	Hines Unit 2 - Total Depreciation													
29	Total Depreciation Expense	742,894	742,894	742,894	742,894	742,894	742,894	742,894	742,894	742,894	742,894	742,894	742,894	8,914,728
30	Total End Balance Depreciation	9,948,271	10,691,165	11,434,059	12,176,953	12,919,847	13,662,741	14,405,635	15,148,529	15,891,423	16,634,317	17,377,211	18,120,105	18,120,105
31	Return:													
32	Beginning Net Investment	235,927,417	235,184,523	234,441,629	233,698,735	232,955,841	232,212,947	231,470,053	230,727,159	229,984,265	229,241,371	228,498,477	227,755,583	
33	Ending Net Investment	235,184,523	234,441,629	233,698,735	232,955,841	232,212,947	231,470,053	230,727,159	229,984,265	229,241,371	228,498,477	227,755,583	227,012,689	
34	Average Investment	235,555,970	234,813,076	234,070,182	233,327,288	232,584,394	231,841,500	231,098,606	230,355,712	229,612,818	228,869,924	228,127,030	227,384,136	
35	Allowed Equity Return (1)	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	.55083%	
36	Equity Component After Tax	1,297,513	1,293,421	1,289,329	1,285,237	1,281,145	1,277,053	1,272,960	1,268,868	1,264,776	1,260,684	1,256,592	1,252,500	
37	Conversion to Pre-tax	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	1.62800	
38	Equity Component Pre-Tax	2,112,351	2,105,689	2,099,028	2,092,368	2,085,704	2,079,042	2,072,379	2,065,717	2,059,055	2,052,394	2,045,732	2,039,070	24,908,527
39	Allowed Debt Return (1)	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	.21417%	
40	Debt Component	504,490	502,899	501,308	499,717	498,126	496,535	494,944	493,353	491,762	490,171	488,580	486,989	5,948,874
41	Total Return Requirements (2)	2,616,841	2,608,588	2,600,336	2,592,083	2,583,830	2,575,577	2,567,323	2,559,070	2,550,817	2,542,565	2,534,312	2,526,059	30,857,401

HINES UNIT 2
SCHEDULE OF SYSTEM DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY 2005 THRU DECEMBER 2005

	Jan-05 EST	Feb-05 EST	Mar-05 EST	Apr-05 EST	May-05 EST	Jun-05 EST	Jul-05 EST	Aug-05 EST	Sep-05 EST	Oct-05 EST	Nov-05 EST	Dec-05 EST	TOTAL
Net System Benefit/(Cost):													
Total Depreciation & Return	$3,359,735	$3,351,482	$3,343,230	$3,334,977	$3,326,724	$3,318,471	$3,310,217	$3,301,964	$3,293,711	$3,285,459	$3,277,206	$3,268,953	$39,772,129
Total Fuel Savings	2,723,548	533,549	86,864	739,105	3,585,223	7,944,249	9,811,245	11,281,953	5,288,463	2,438,511	169,902	-	44,602,612
Total Net Benefit/(Cost)	($636,187)	($2,817,933)	($3,256,368)	($2,595,872)	$258,499	$4,625,778	$6,501,028	$7,979,989	$1,994,752	($846,948)	($3,107,304)	($3,268,953)	$4,830,483
Net Retail Benefit (Cost):													
Retail Depreciation & Return	$2,996,817	$2,975,701	$2,939,174	$2,917,103	$2,932,812	$2,975,998	$3,036,972	$3,028,430	$3,013,239	$2,994,644	$2,961,390	$2,975,232	$35,747,512
Retail Fuel Savings	2,429,351	473,725	76,366	646,495	3,160,703	7,124,387	9,001,357	10,347,357	4,838,129	2,222,665	153,529	-	40,474,074
Retail Net Benefit (cost)	($567,466)	($2,501,976)	($2,862,808)	($2,270,608)	$227,891	$4,148,389	$5,964,395	$7,318,927	$1,824,890	($771,979)	($2,807,861)	($2,975,232)	$4,726,562
Hines 2 System Savings:													
Hines Unit 2 Displaced Fuel Exp.	$12,431,661	$8,699,947	$13,887,217	$6,187,990	$13,586,557	$19,958,268	$24,367,244	$26,237,382	$18,427,084	$12,909,132	$13,935,009	$6,022,348	$176,869,839
A9 Purchase Power Fuel Savings	207,198	93,836	182,049	246,020	595,983	590,662	789,919	683,672	613,463	733,335	361,793	311,882	5,409,812
Hines Unit 2 Actual Fuel Exp.	(9,915,311)	(8,460,234)	(13,982,402)	(5,694,905)	(10,597,317)	(12,604,681)	(15,365,918)	(15,639,101)	(13,752,084)	(11,203,956)	(14,126,900)	(6,356,688)	(137,698,497)
Hines 2 Fixed Transport Costs													-
Fuel Savings	$2,723,548	$533,549	$86,864	$739,105	$3,585,223	$7,944,249	$9,811,245	$11,281,953	$5,288,463	$2,438,511	$169,902	$0	$44,602,612
Development of Factors:													
MWH													
Retail Sales	3,081,182	2,958,866	2,870,053	2,921,388	3,040,446	3,621,077	3,956,372	4,049,622	4,012,063	3,623,553	3,107,367	3,050,708	40,292,697
Wholesale Avg Sales	173,190	156,886	169,069	171,232	177,361	189,574	194,751	203,059	212,324	203,475	196,472	173,823	2,221,216
Subtotal	3,254,372	3,115,752	3,039,122	3,092,620	3,217,807	3,810,651	4,151,123	4,252,681	4,224,387	3,827,028	3,303,839	3,224,531	42,513,913
Stratified Sales	200,151	218,485	225,455	247,226	230,912	227,186	161,398	162,745	161,107	148,137	134,899	127,387	2,243,088
Total Sales	3,454,523	3,332,237	3,264,577	3,339,846	3,448,719	4,037,837	4,312,521	4,415,426	4,385,494	3,975,165	3,438,738	3,351,918	44,757,001
Check	0	0	0	0	0	0	0	0	0	0	0	0	
PERCENT													
Retail & Whls Avg Cost Sales	94.21%	93.50%	93.09%	92.60%	93.30%	94.37%	96.26%	96.31%	96.33%	96.27%	96.08%	96.20%	
Stratified Sales	5.79%	6.50%	6.91%	7.40%	6.70%	5.63%	3.74%	3.69%	3.67%	3.73%	3.92%	3.80%	
Total Sales	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
RETAIL FACTOR	94.68%	94.96%	94.44%	94.46%	94.49%	95.03%	95.31%	95.23%	94.97%	94.68%	94.05%	94.61%	

Progress Energy Florida
Docket No. 040001-EI
Witness: Murphy
Exhibit No. ___ (PRM-1T)

SUMMARY OF THE SUCCESS OF RISK MANAGEMENT PLAN

The Risk Management Plan of Progress Energy Florida (Progress Energy) for 2003 (the Plan) was developed in mid-2002 to identify certain risks associated with fossil fuel and wholesale power requirements. The Plan also identified, among other things, the controls, oversight, risk reporting, and processes that PEF would follow to carry out its Plan. To that end, the following summarizes the various items listed above for 2003:

I. Risk Identification – Force Majeure Events

A. FGT Pipeline Leak - March 6 – To the extent necessary, PEF continued to serve customer load through the increased use of #6 and #2 fuel oil in addition to working with the interstate pipelines to use a portion of existing gas in the pipeline until production deliveries resumed.

B. Tropical Storm Claudette – July 14-16 – During the force majeure event, PEF again used fuel oil to the extent necessary, and worked with Gulfstream Natural Gas and Florida Gas Transmission to use a portion of the existing gas in the pipeline until production deliveries resumed.

II. Daily Management Activities

A. Fuel Oil – 8.3 million barrels of #6 oil were projected vs. an actual of 10.6 million barrels and .9 million barrels of #2 oil were projected vs. an actual of 1.1 million barrels. Month-to-month variances were handled by working with suppliers to change delivery schedules as necessary.

B. Natural Gas – Month-end gas imbalances were either traded with third-party counterparties or cashed out by FGT. Due to PEF's Operational Balance Agreement with Gulfstream, PEF is allowed to carryover imbalances to the next month without penalty. The monthly imbalances were a result of balancing actual burns versus nominations with FGT that could not be mitigated due to alert day restrictions and/or end-of-month timing.

C. Coal – One coal supplier was behind in deliveries and the missed shipments were replaced with a lower spot market price coal.

D. Daily dispatch continues on an economic basis for its ratepayers. This dispatch is updated twice daily for next-day projected load forecasts. This process may, on occasion, deviate from economic dispatch due to operational problems at plant sites or forces beyond our control.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 35
COMPANY/ PEF
WITNESS. Pamela R. Murphy (PRM-1T)
DATE 11-08-04

III. Monitoring of Industry Events

A. Weekly gas storage injection/withdrawal amounts published by EIA are being followed to determine short- and long-term effects to future gas prices. In addition, rig counts are also followed to monitor the increase/decrease of drilling activity for replacement reserves.

B. Defaults by suppliers based on bankruptcies or announcements to exit the market are monitored by our credit section, as well as the respective front office personnel. Industry events that occurred in 2002 have seen marketing companies like Dynegy, Aquila, Reliant, and El Paso either exit the business totally or reduce staff to return to its core business of managing its existing generation portfolio. As a result, liquidity in the natural gas and power markets have been reduced by these events where major marketing companies have elected to exit the business line of "market making" activities.

C. During the 3rd and 4th quarters, domestic and import coal prices began rising. To mitigate the potential additional cost to the ratepayer, PEF began purchasing some of their 2004 requirements early to meet its needs.

IV. Price Risk Mitigation

A. Natural Gas – Progress Energy met all of its hedging strategy objectives to 1) mitigate price risk and volatility, 2) provide gas price certainty, 3) maintain a diverse portfolio, and 4) provide potential for ratepayer's savings. Progress Energy elected to enter into a zero-cost collar for 20,000 MMBtu's per day supply of gas for the three-month period of December 2002 through February 2003. The contract was exercised in February 2003, resulting in a value to the ratepayers of $190,400. For March 2003, Progress Energy elected to exercise a contractual option to convert the price of a term deal from index to daily. This price conversion resulted in a savings to the ratepayers of $875,300. Progress Energy also had several fixed price contracts that resulted in stabilizing prices for a portion of its natural gas requirements for the ratepayers and provided an additional value to the ratepayers of $18,706,426. Additionally, as of December 31, 2003 the fixed priced contracts had a favorable mark-to-market value through 2010 of approximately $61 million.

B. Wholesale Power – Savings from wholesale sales & purchases for 2003 were as follows:
   1. Sales $9,844,761
   2. Purchases $5,544,500

C. Fuel Oil – For 2003, PEF exercised a contractual option to fix the price on 704,818 bbls of residual oil, which resulted in a net additional cost to customers of $1,229,174.

D. Total Value Created: $35,794,881

V. Process and Guidelines

A. The Mid Office – Risk Reporting incorporated forward curves and market pricing to provide daily reporting of mark-to-market and stress testing to Senior Management, where appropriate.

B. Audit Services continues to provide the services outlines in the Plan for fuel and wholesale power purchases. Their audits in 2003 included various aspects related to compliance, trading and procurement, and operational perspectives for portfolio management, fuel procurement and wholesale power purchases. The audits completed in 2003 had no major findings.

C. PEF natural gas, fuel oil, and wholesale power processes/procedures continue to be refined as part of our overall effort to improve business practices.

D. The guidelines referenced in the Plan have been adhered to and no trading and/or credit violations occurred in 2003.

Progress Energy Florida
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Exhibit No. PRM-2T

PROGRESS ENERGY FLORIDA

Hedging Information for the 2003 True-up Period

Hedging Instrument	Fuel Type	Total 2003 Volume Hedged		Avg Period of Hedge	Total Cost of Hedge
Fixed Price Contact*	Heavy Oil	704,818	bbls	daily	$0
Fixed Price Contact*	Natural Gas	14,398,435	mmbtu	daily	$0
Daily Price Contract*	Natural Gas	310,000	mmbtu	daily	$0
Zero Cost Collar*	Natural Gas	1,180,000	mmbtu	daily	$0

* Physical Hedge

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO 35
COMPANY/ P.E.F.
WITNESS: Pamela R. Murphy (PRM-2T)
DATE: 11-04-04

Redacted Document

Progress Energy Florida, Inc.
Risk Management Plan
Fuel Procurement and Wholesale Power Purchases

I. Objective

The objective of Progress Energy Florida, Inc.'s, (PEF) Risk Management plan is to provide the mechanisms to manage PEF's overall fuel costs and wholesale power purchases to provide reliable service to PEF's customers. As a result, this should ultimately reduce the number of mid-course corrections to the fuel factor portion of the customer's bill. The risk management plan allows for the use of various tools to reduce price volatility of natural gas and oil using approved products to hedge either financially and/or physically.

Progress Energy Carolinas, Inc., acts as agent for PEF. PEF has adopted Progress Ventures' risk management policies and practices.

II. Fossil Fuel and Purchased Power Future Needs

A. Fossil Fuel

1. Coal
   - PEF plans to burn approximately 6.4 million tons of coal in 2005 and in 2006

2. Residual Oil
   - PEF plans to burn approximately 10.7 million bbls. of #6 fuel oil in 2005 and 10.8 million bbls. in 2006

3. Distillate Oil
   - PEF plans to burn approximately 1.3 million bbls. of #2 fuel oil per year in 2005 and 1 million bbls. in 2006

4. Natural Gas
   - PEF plans to burn approximately 76 Bcf in 2005 and approximately 73 Bcf in 2006

B. Purchased Power - PEF plans to purchase approximately 0.5 million MWH/year and sell approximately 1.2 million MWH/year on the wholesale market in 2005 and 2006.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 36
COMPANY/ P.E.F.
WITNESS: Pamela R. Murphy (PRM-1P)
DATE: 11-08-04

III. Risk Management Profile

A. Risk Identification * The primary risks PEF has identified with procurement of fossil fuels and purchased power are:

1. Coal

- Plant availability due to unscheduled outages
- Supply or transport problems due to labor disputes, weather, or other unforeseen delays
- Coal quality errors
- Financial strength of suppliers
- Changes in laws regulating mining, transportation or burning of coal
- Price volatility

2. Oil (Residual and Distillate)

- Differences between forecasted/scheduled requirements and actual requirements due to economic changes, overall power demand, weather changes, change in price relationships between competing fuels, plant availability (maintenance/unexpected shutdowns or startups), out-of-economic plant dispatch (e.g., due to transmission system constraints), power market changes, etc.
- Differences between forecasted/scheduled deliveries and actual deliveries due to supply or transport problems, loading and unloading delays, etc.
- Fuel quality problems such as blending errors, off-spec deliveries, changes in SO2 values, changes in plant fuel handling capability, etc.
- Changes in laws, regulations, plant permits, etc. that affect the amount, cost, testing requirements or quality of oil required
- Impact of regulatory, management, internal and external audit reviews
- General industry changes that impact overall availability/cost/quality of fuel oil
- Price volatility and fuel oil market related factors

3. Natural Gas

- Imbalance penalties with interstate pipelines as a result of over/under burns based on differences between forecasted /scheduled gas and actual requirements due to, but not limited to, changes in weather, plant availability, and alert day tolerances
- Deliveries by interstate pipelines and suppliers impacted by force majeure events, such as pipeline disruptions, production outages, hurricanes, etc.

- Natural gas storage level deviation from expected norms
- Crude oil prices
- Degree day deviations from expected monthly norms
- Defaults by suppliers (for example, bankruptcy)
- Price risk based on volatility in the natural gas industry caused by commodity funds (technical trading)
- Contractual disputes regarding payment and deliveries

4. Purchased Power

- Default risk – inability of the supplier to obtain adequate resources to deliver the power per contract or agreement
- Directional price risk – e.g., purchased power contracts in which the price of the purchased power is tied to an index
- Physical risk – inability of electrical grid to reliably support power transfer
- Credit risk – inability of contract counterparty to deliver per contract resulting in purchase of higher cost purchased power
- Basis risk – e.g., supplier(s) can experience adverse weather as compared with Florida Power's service territory

*Acts of terrorism are considered beyond PEF's control

B. Risk Quantification

- Quantification of various risks, including stop-loss limits and Value-at-Risk (VaR) calculations, are included in Progress Ventures Risk Management Guidelines Appendix 13.

C. Risk Management (Daily Management Activities)

1. Coal

- Review actual conditions and adjust delivery schedules as needed
- Maintain contacts with plants and suppliers
- Monitor market prices and spot market options
- Monitor suppliers financial strength
- Build flexibility on volume terms etc., into agreements
- Develop alternative supply sources whenever possible

2. Oil

- Monitor actual conditions and consumption levels vs. forecasted levels and update forecasts frequently as conditions change. Adjust delivery schedules as needed
- Monitor actual delivery status and maintain frequent contact with suppliers and receiving plants to anticipate problems and take corrective action
- Keep current on market prices and activity. Utilize contract price options, inventory, and spot market options as appropriate. PEF is currently hedging its projected No. 6 residual requirements to reduce price volatility for the ratepayers using financial over-the-counter swaps.
- Continue to scrutinize a supplier's financial strength in order to assess ongoing creditworthiness.

3. Natural Gas

- Monitor plant gas burns vs. forecasted gas burns. If gas burn is projected to be out of tolerance on the pipeline, reschedule gas and re-allocate gas to different plants, or switching to alternative fuels, like oil
- Use fuel oil, where applicable, to maintain load
- Build additional optionality into seasonal/term contracts by specifying the use of a daily or a monthly market index (with the right to select either one), include take or release triggers on volumes to allow added flexibility, as well as the right to mutually agree to a fixed price
- Implement term contracts that allow swing volumes
- PEF is hedging natural gas to reduce price volatility for the ratepayers
- Evaluate zero cost collars for physical natural gas requirements in lieu of, or in conjunction with, fixed-price natural gas
- Evaluate the premium cost of purchasing a call option for a percentage of the utility's monthly natural gas requirements
- Use physical fuel oil inventory, where applicable, to dispatch at lowest fuel price. Logistics of physical fuel oil inventory levels must also be managed with this alternative
- Re-market any excess gas supplies/capacity, separately or bundled, on a daily basis
- Continue to scrutinize a supplier's financial strength in order to assess ongoing creditworthiness

4. Purchased Power

- PEF assesses each supplier's ability to deliver power based on historical reliability as a supplier (default risk) and credit ratings

- PEF utilizes both fixed price contracts (next day purchases) and variable price contracts tied to a specific counterparty's incremental cost
- PEF utilizes firm transmission paths where available for reliable purchased power

5. Portfolio Management

   - PEF will manage its risks associated with meeting its forecasted load requirements by maintaining a generation fleet with the capability of fuel switching, contracting for a diverse fuel supply and transportation portfolio, and the use of sales and purchases of energy to and from outside sources.

D. Acceptable Level of Risk

1. Oil and Coal - The amount of risk considered acceptable is based on past experiences with what has been successful and evaluating the risk profile of any problems or opportunities based on this experience.

2. Natural Gas - Decisions regarding acceptable risk are based on the circumstances at the time natural gas is purchased. The circumstances at the time may include scenarios involving all or a part of the following: force majeure events, fuel oil inventories, competitive fuel pricing, supply constraints, forward pricing trends etc. For example, if the utility views a strong directional market trend for natural gas based on industry reports, events in the marketplace, demand, national storage levels, etc., the utility would consider implementing the risk management tools identified for managing natural gas risk.

3. Purchased Power- Considerations for purchasing power on a long term and mid-term basis include, but are not limited to the following:
   - Price curves – directional price risk associated with fuel and power
   - Generator outages
   - Load forecast
   - Physical risk associated with transfer capability of transmission system
   - Credit worthiness of potential supplier(s)
   - Default risk of potential supplier(s)
   - Basis risk – e.g., supplier(s) can experience adverse weather as compared with PEF's service territory

IV. Fuel Procurement and Wholesale Purchased Power Plans for 2005

1. Coal
   - Approximately [redacted] of purchases are made on mid-term contracts in 2005 and [redacted] in 2006.

2. Oil
   - The majority of the fuel oil is covered by [redacted] supply contracts with flexible volume provisions and market based pricing. The spot market is utilized when contracts allow as a supplemental source of supply.

3. Natural Gas
   - Approximately [redacted] of the natural gas requirements for 2005 are currently covered by long-term (greater than 3 years) contracts. PEF will be initiating an RFP in second half of [redacted] to contract for additional gas for [redacted] under long-term contracts. The remaining natural gas requirements for [redacted] will be covered by short term and spot market contracts.

4. Purchased Power
   - Long-term firm purchased power is usually solicited by a request-for-proposal from credible counterparties. Mid-term purchased power is usually solicited via a survey of credible counterparties by requesting bids for the nomination and terms for the product needed.
   - Short-term firm purchased power is obtained through market assessment of bids and offers and negotiation with credible counterparties.

V. Guidelines

1. The Board of Directors has established a Risk Management Policy which directs the Risk Management Committee (RMC) to oversee Progress Energy's management of financial risks. The Risk Management Policy states the RMC shall regularly report on activities related to and carried out under the Policy to the Chief Executive Officer (CEO), the Board of Directors and the Finance Committee. The CEO is ultimately responsible for the company's management of risk.

2. The Risk Management Committee Guidelines identify the roles, responsibilities and decision making process of the RMC and its agents.

3. Progress Ventures Regulated Commercial Operations Risk Management Guidelines provide a methodology to assess, report, and mitigate risk associated with trading and marketing activities and procurement for the regulated fleet. In addition, there is a product approval process to provide a structure to validate that

all significant product risks have been identified and integrated into the risk control structure.

4. Corporate Credit Risk Management Guidelines provide a methodology to evaluate, measure, mitigate, and report credit risk associated with Ventures trading, marketing, and procurement activities as well as Corporate Credit provides credit governance and oversight on an enterprise-wide basis.

VI. Processes (Front Office)

PEF's Oil Process Analysis, PEF's Natural Gas Process Analysis, and Progress Fuels' Coal Purchasing Procedures provide the procedures utilized to implement PEF's risk management plan. To date, "Zainet" is PEF's natural gas and power transaction software system utilized to track and verify natural gas and power transactions. Zainet is the system of record to track and verify natural gas,oil financial hedges and power transactions. "FMS" (Fuel Management System) is the system used to track and verify coal and physical oil transactions.

VII. Risk Reporting (Middle Office)

Risk control generates reports and distributes to both trading and senior management on a daily basis. This is the primary mechanism to communicate group performance to management, the RMC, and the Board of Directors. The reports include all current positions and updates according to the markets. Market changes include pricing, correlation, volatility, et cetera. In addition, as conditions differ from day-to-day, gas scheduling updates deals with best-available information to correctly reflect how much gas is received and delivered at their respective delivery and receipt points.

A. Risk control manages all of the following activities:

1. Forward Curves - Forward curves provide prices for delivery of products at future dates. Forward curves provide the critical data necessary to calculate mark-to-market, value-at-risk, and stress testing. These curves are generated daily.

2. Market Pricing – Daily prices received from index providers are updated on a daily basis to settle or to mark all positions to the correct market price as of close of business.

3. Mark-to-Market (MTM) - MTM is a methodology utilized to value all physical and financial instruments, including those associated with assets. MTM measures unrealized gains and losses (forward positions) prior to contract settlement by calculating the difference between the transaction price and the forward curve.

4. Stress Testing - Stress testing is used to simulate extreme market conditions (e.g., hurricane), and the results are delivered in the daily reports.

VIII. Controls and Oversight

1. The Risk Management Committee (RMC) – The RMC oversees Progress Energy's management of financial risks.

Committee Members

- Chief Financial Officer - Progress Energy, Inc. (Chair)
- President – Progress Energy Service Company, LLC
- President – Energy Supply
- President – Progress Ventures
- President – Energy Delivery
- SVP & General Counsel – Progress Energy, Inc.
- Chief Risk Officer (CRO)

Committee Members Responsibilities

- Identifies, assesses, and monitors corporate financial risks
- Approves:
  - (i) Risk guidelines for various company activities
  - (ii) New and existing trading, marketing, procurements and hedging products
  - (iii) Analytical methodologies, models and assumptions
  - (iv) Organization structure to ensure adequate segregation of duties

- Reviews:
  - (i) Aggregate market and credit capital for approval by the BOD

(ii) Summary positions and financial reports
(iii) Broad trading, marketing, hedging, and procurement strategies
(iv) General business conditions, market and credit risk exposures

- Presents to the CEO, BOD and Finance Committee:
  (i) Recommended aggregate market and credit limits and modifications for approval
  (ii) Summary positions and financial reports
  (iii) Summary of valuation methods, key controls, limit exceptions and violations
  (iv) Special studies as requested

- Creates sub-committees to provide greater attention to risk issues in various company activities

2. Trading, Marketing and Fuels Sub-Committee - The Trading, Marketing and Fuels Subcommittee's objective is to review market and credit risk exposure and business development and proposal opportunities associated with trading, marketing and procurement activities.

Sub-Committee Members
- VP – Regulated Commercial Operations
- VP – Ventures Finance
- VP and Chief Risk Officer
- Director – RCO Power Trading Operations
- Director – Gas and Oil Trading
- Director or Manager – Enterprise Risk Management
- Controller – RCO

Sub-Committee Responsibilities - Reviews, at a minimum:
- Commodity market trends
- Trading, hedging, procurement and marketing strategies
- Aggregate commodity risk exposures
- Market and credit exposure versus defined limits
- New products and services for RMC approval
- Model and model assumptions
- Key operational controls
- Credit exposure versus defined limits
- Pricing methodologies
- Summary exception reports
- Conducts special studies requested by the RMC
- Approves liquidity limits

3. Auditing Department – Audit Services provides independent assurance and consulting services that ensure regulatory compliance, effective corporate governance, operational excellence, and appropriate risk management for all major activities including fuel procurement. Activities are audited based on relative priority rather than a fixed cycle. Within that framework, Audit Services' oversight of fuel procurement risk management activities is addressed from the following perspectives:
    - Compliance
    - Trading and procurement
    - Operational

Progress Energy Florida
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Witness: Jacob
Exhibit No. _____ (MFJ-1T)

GPIF REWARD/PENALTY SCHEDULES

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 37
COMPANY/ PEF
WITNESS. Michael F. Jacob (MFJ-1T)
DATE 11-09-04

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ACTUAL

Progress Energy Florida
January 2003 - December 2003

	Generating Performance Incentive Points (GPIF)	Fuel Savings/Loss ($)	Generating Performance Incentive Factor ($)
	10	$45,340,085	$8,164,346
	9	$40,806,077	$7,347,912
	8	$36,272,068	$6,531,477
	7	$31,738,060	$5,715,042
	6	$27,204,051	$4,898,608
	5	$22,670,043	$4,082,173
	4	$18,136,034	$3,265,738
	3	$13,602,026	$2,449,304
****	2.621	$11,882,633	$2,139,695
	2	$9,068,017	$1,632,869
	1	$4,534,009	$816,435
	0	$0	$0
	-1	($5,213,709)	($816,435)
	-2	($10,427,417)	($1,632,869)
	-3	($15,641,126)	($2,449,304)
	-4	($20,854,834)	($3,265,738)
	-5	($26,068,543)	($4,082,173)
	-6	($31,282,251)	($4,898,608)
	-7	($36,495,960)	($5,715,042)
	-8	($41,709,668)	($6,531,477)
	-9	($46,923,377)	($7,347,912)
	-10	($52,137,085)	($8,164,346)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

Progress Energy Florida
January 2003 - December 2003

1	Beginning of period balance of common equity	$2,050,734,235
2	END OF MONTH BALANCE OF COMMON EQUITY:	
	Month of JANUARY 2003	$2,089,115,874
3	Month of FEBRUARY 2003	$2,034,568,815
4	Month of MARCH 2003	$1,996,248,459
5	Month of APRIL 2003	$1,997,660,335
6	Month of MAY 2003	$1,967,905,224
7	Month of JUNE 2003	$1,977,447,100
8	Month of JULY 2003	$2,018,576,201
9	Month of AUGUST 2003	$2,054,062,840
10	Month of SEPTEMBER 2003	$2,091,788,664
11	Month of OCTOBER 2003	$2,112,161,592
12	Month of NOVEMBER 2003	$2,120,529,814
13	Month of DECEMBER 2003	$2,142,543,737
14	Average common equity for the period	$ 2,050,257,145
15	25 Basis Points	0.0025
16	Revenue Expansion Factor	61.3808%
17	Maximum allowed incentive dollars	$8,350,564
18	Jurisdictional Sales *	38,013,952 MWH
19	Total Sales *	38,881,212 MWH
20	Jurisdictional Separation Factor	97.77%
21	Maximum allowed jurisdictional incentive dollars	$8,164,346

* Net sales (Sales - Interruptible)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF SYSTEM ACTUAL GPIF POINTS

Progress Energy Florida
January 2003 - December 2003

Plant/Unit	Performance Indicator EAF or ANOHR	Weighting Factor %	Unit Points	Weighted Unit Points
Anclote 2	EAF	3.75	1.666	0.062
	ANOHR	4.33	-0.558	-0.024
Crystal River 1	EAF	5.77	1.094	0.063
	ANOHR	3.11	-9.703	-0.302
Crystal River 2	EAF	13.39	10.000	1.339
	ANOHR	3.58	-1.409	-0.050
Crystal River 3	EAF	8.95	3.289	0.294
	ANOHR	13.61	0.218	0.030
Crystal River 4	EAF	8.59	10.000	0.859
	ANOHR	6.54	0.000	0.000
Crystal River 5	EAF	8.43	3.390	0.286
	ANOHR	6.56	0.000	0.000
Hines 1	EAF	1.82	3.518	0.064
	ANOHR	11.59	0.000	0.000
GPIF System		100.00		2.621

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GENERATION PERFORMANCE INCENTIVE FACTOR
GPIF UNIT PERFORMANCE SUMMARY

Progress Energy Florida
January 2003 - December 2003

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	EAF Adjusted Actual (%)	Estimated Fuel Savings/ Loss ($000)
Anclote 2	3.75	89.79	91.89	85.49	$1,699	($1,829)	90.14	$283.0
Crystal River 1	5.77	90.83	95.10	82.36	$2,614	($2,687)	91.30	$286.1
Crystal River 2	13.39	62.57	69.94	49.06	$6,071	($11,937)	70.12	$6,071.0
Crystal River 3	8.95	88.96	90.55	85.67	$4,059	($4,667)	89.49	$1,334.9
Crystal River 4	8.59	91.57	94.62	85.42	$3,894	($4,209)	96.75	$3,894.0
Crystal River 5	8.43	94.62	97.14	89.51	$3,821	($3,614)	95.48	$1,295.3
Hines 1	1.82	85.80	87.97	81.32	$826	($838)	86.56	$290.6
GPIF System	50.69				$22,984	($29,781)		$13,454.8

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (Btu/kwh)	ANOHR RANGE Max. (Btu/kwh)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	ANOHR Adjusted Actual (Btu/kwh)	Estimated Fuel Savings/ Loss ($000)
Anclote 2	4.33	10091	54.0	9774	10408	$1,963	($1,963)	10179	($109.5)
Crystal River 1	3.11	9742	91.8	9515	9969	$1,410	($1,410)	9965	($1,368.2)
Crystal River 2	3.58	9566	89.6	9276	9856	$1,623	($1,623)	9672	($228.7)
Crystal River 3	13.61	10327	100.0	10118	10536	$6,169	($6,169)	10249	$134.3
Crystal River 4	6.54	9323	95.7	9105	9542	$2,963	($2,963)	9341	$0.0
Crystal River 5	6.56	9340	93.8	9121	9560	$2,972	($2,972)	9391	$0.0
Hines 1	11.59	7259	81.0	6748	7770	$5,255	($5,255)	7314	$0.0
GPIF System	49.31					$22,356	($22,356)		($1,572.2)

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GENERATION PERFORMANCE INCENTIVE FACTOR
ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida
January 2003 - December 2003

Plant/Unit	ACTUAL EAF %	ADJUSTMENTS (1) TO EAF %	ADJUSTED ACTUAL EAF %
Anclote 2	93.25	-3.11	90.14
Crystal River 1	91.30	0.00	91.30
Crystal River 2	78.01	-7.89	70.12
Crystal River 3	88.28	1.21	89.49
Crystal River 4	97.11	-0.36	96.75
Crystal River 5	95.48	0.00	95.48
Hines 1	87.40	-0.84	86.56

Plant/Unit	ACTUAL ANOHR BTU/KWH	ADJUSTMENTS (2) TO ANOHR BTU/KWH	ADJUSTED ACTUAL ANOHR BTU/KWH
Anclote 2	10202.9	-23.4	10179.5
Crystal River 1	10060.2	-95.6	9964.6
Crystal River 2	9783.1	-111.5	9671.6
Crystal River 3	10251.0	-1.8	10249.2
Crystal River 4	9413.0	-72.5	9340.5
Crystal River 5	9417.0	-25.9	9391.1
Hines 1	7348.8	-34.7	7314.1

(1) For documentation of adjustments to actual EAF, see sheet 6.
(2) For documentation of adjustments to actual ANOHR, see sheet 7.

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GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO EAF ACTUAL

Progress Energy Florida
January 2003 - December 2003

EAF adjustments for Planned Outage Hours			AN2	CR1	CR2	CR3	CR4	CR5	HN1
1	Actual POH	Hrs.	219.30	0.00	1070.97	781.25	136.12	0.00	763.58
2	Target POH	Hrs.	504.00	0.00	1848.00	672.00	168.00	0.00	840.00
3	Adj. Factor (PH-POHT/PH-POHA)		0.97	1.00	0.90	1.01	1.00	1.00	0.99
4	Actual EUOH	Hrs.	371.94	762.24	855.54	245.60	116.76	396.14	340.42
5	Adj. EUOH (3*4)	Hrs.	359.54	762.24	769.08	248.96	116.33	396.14	337.17
6	Actual EAF	%	93.25	91.30	78.01	88.28	97.11	95.48	87.40
7	Adjusted EAF (using 2 & 5)	%	90.14	91.30	70.12	89.49	96.75	95.48	86.56
8	Difference (7-6)	%	-3.11	0.00	-7.89	1.21	-0.36	0.00	-0.84
9	Total adj. to EAF	%	-3.11	0.00	-7.89	1.21	-0.36	0.00	-0.84

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GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO ANOHR ACTUAL

Progress Energy Florida
January 2003 - December 2003

ANOHR adjustments for Target NOF			AN2	CR1	CR2	CR3	CR4	CR5	HN1
1	Target NOF	%	54.0	91.8	89.6	100.0	95.7	93.8	81.0
2	Target ANOHR	Btu/kwh	10091.0	9741.9	9566.3	10327.1	9323.2	9340.5	7258.8
3	Actual NOF	%	52.2	78.2	82.3	99.8	86.6	88.9	78.8
4	Calc. ANOHR (using 3)	Btu/kwh	10114.4	9837.4	9677.8	10328.9	9395.7	9366.3	7293.5
5	Total adj. to ANOHR (2-4)	Btu/kwh	-23.4	-95.6	-111.5	-1.8	-72.5	-25.9	-34.7

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2003 - December 2003

Unit: Anclote 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$1,699,000	91.89	10	$1,963,040	9773.9	
	9	$1,529,100	91.68	9	$1,766,736	9798.1	
	8	$1,359,200	91.47	8	$1,570,432	9822.3	
	7	$1,189,300	91.26	7	$1,374,128	9846.5	
	6	$1,019,400	91.05	6	$1,177,824	9870.7	
	5	$849,500	90.84	5	$981,520	9894.9	
	4	$679,600	90.63	4	$785,216	9919.2	
	3	$509,700	90.42	3	$588,912	9943.4	
	2	$339,800	90.21	2	$392,608	9967.6	
****	1.666	$282,976	90.14	1	$196,304	9991.8	
	1	$169,900	90.00	0	$0	10016.0	
		$0	89.79	0	$0	10091.0	
	0	$0	89.79	0	$0	10166.0	
		$0	89.79	-0.558	($109,488)	10179.5	****
	-1	($182,900)	89.36	-1	($196,304)	10190.2	
	-2	($365,800)	88.93	-2	($392,608)	10214.4	
	-3	($548,700)	88.50	-3	($588,912)	10238.6	
	-4	($731,600)	88.07	-4	($785,216)	10262.8	
	-5	($914,500)	87.64	-5	($981,520)	10287.0	
	-6	($1,097,400)	87.21	-6	($1,177,824)	10311.2	
	-7	($1,280,300)	86.78	-7	($1,374,128)	10335.4	
	-8	($1,463,200)	86.35	-8	($1,570,432)	10359.6	
	-9	($1,646,100)	85.92	-9	($1,766,736)	10383.9	
	-10	($1,829,000)	85.49	-10	($1,963,040)	10408.1	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.75%	4.33%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2003 - December 2003

Unit: Crystal River 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$2,614,000	95.10	10	$1,410,107	9514.6	
	9	$2,352,600	94.67	9	$1,269,096	9529.8	
	8	$2,091,200	94.24	8	$1,128,085	9545.0	
	7	$1,829,800	93.82	7	$987,075	9560.3	
	6	$1,568,400	93.39	6	$846,064	9575.5	
	5	$1,307,000	92.96	5	$705,053	9590.7	
	4	$1,045,600	92.54	4	$564,043	9606.0	
	3	$784,200	92.11	3	$423,032	9621.2	
	2	$522,800	91.68	2	$282,021	9636.4	
****	1.094	$286,062	91.30	1	$141,011	9651.6	
	1	$261,400	91.26	0	$0	9666.9	
		$0	90.83	0	$0	9741.9	
	0	$0	90.83	0	$0	9816.9	
		$0	90.83	-1	($141,011)	9832.1	
	-1	($268,700)	89.98	-2	($282,021)	9847.3	
	-2	($537,400)	89.14	-3	($423,032)	9862.6	
	-3	($806,100)	88.29	-4	($564,043)	9877.8	
	-4	($1,074,800)	87.44	-5	($705,053)	9893.0	
	-5	($1,343,500)	86.60	-6	($846,064)	9908.3	
	-6	($1,612,200)	85.75	-7	($987,075)	9923.5	
	-7	($1,880,900)	84.90	-8	($1,128,085)	9938.7	
	-8	($2,149,600)	84.05	-9	($1,269,096)	9953.9	
	-9	($2,418,300)	83.21	-9.703	($1,368,184)	9964.6	****
	-10	($2,687,000)	82.36	-10	($1,410,107)	9969.2	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.77%	3.11%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2003 - December 2003

Unit: Crystal River 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10.000	$6,071,000	70.12	10	$1,623,402	9276.4	
	10	$6,071,000	69.94	9	$1,461,062	9297.9	
	9	$5,463,900	69.20	8	$1,298,722	9319.4	
	8	$4,856,800	68.47	7	$1,136,382	9340.9	
	7	$4,249,700	67.73	6	$974,041	9362.4	
	6	$3,642,600	66.99	5	$811,701	9383.9	
	5	$3,035,500	66.26	4	$649,361	9405.4	
	4	$2,428,400	65.52	3	$487,021	9426.9	
	3	$1,821,300	64.78	2	$324,680	9448.4	
	2	$1,214,200	64.05	1	$162,340	9469.9	
	1	$607,100	63.31	0	$0	9491.3	
		$0	62.57	0	$0	9566.3	
	0	$0	62.57	0	$0	9641.3	
		$0	62.57	-1	($162,340)	9662.8	
	-1	($1,193,700)	61.22	-1.409	($228,747)	9671.6	****
	-2	($2,387,400)	59.87	-2	($324,680)	9684.3	
	-3	($3,581,100)	58.52	-3	($487,021)	9705.8	
	-4	($4,774,800)	57.17	-4	($649,361)	9727.3	
	-5	($5,968,500)	55.82	-5	($811,701)	9748.8	
	-6	($7,162,200)	54.47	-6	($974,041)	9770.3	
	-7	($8,355,900)	53.11	-7	($1,136,382)	9791.8	
	-8	($9,549,600)	51.76	-8	($1,298,722)	9813.3	
	-9	($10,743,300)	50.41	-9	($1,461,062)	9834.8	
	-10	($11,937,000)	49.06	-10	($1,623,402)	9856.3	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
13.39%	3.58%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2003 - December 2003

Unit: Crystal River 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$4,059,000	90.55	10	$6,168,642	10117.8	
	9	$3,653,100	90.39	9	$5,551,778	10131.2	
	8	$3,247,200	90.24	8	$4,934,914	10144.7	
	7	$2,841,300	90.08	7	$4,318,049	10158.1	
	6	$2,435,400	89.92	6	$3,701,185	10171.5	
	5	$2,029,500	89.76	5	$3,084,321	10185.0	
	4	$1,623,600	89.60	4	$2,467,457	10198.4	
****	3.289	$1,334,935	89.49	3	$1,850,593	10211.8	
	3	$1,217,700	89.44	2	$1,233,728	10225.3	
	2	$811,800	89.28	1	$616,864	10238.7	
	1	$405,900	89.12	0.218	$134,264	10249.2	****
		$0	88.96	0	$0	10252.1	
	0	$0	88.96	0	$0	10327.1	
		$0	88.96	0	$0	10402.1	
	-1	($466,700)	88.64	-1	($616,864)	10415.6	
	-2	($933,400)	88.31	-2	($1,233,728)	10429.0	
	-3	($1,400,100)	87.98	-3	($1,850,593)	10442.4	
	-4	($1,866,800)	87.65	-4	($2,467,457)	10455.9	
	-5	($2,333,500)	87.32	-5	($3,084,321)	10469.3	
	-6	($2,800,200)	86.99	-6	($3,701,185)	10482.7	
	-7	($3,266,900)	86.66	-7	($4,318,049)	10496.2	
	-8	($3,733,600)	86.33	-8	($4,934,914)	10509.6	
	-9	($4,200,300)	86.00	-9	($5,551,778)	10523.0	
	-10	($4,667,000)	85.67	-10	($6,168,642)	10536.5	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
8.95%	13.61%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2003 - December 2003

Unit: Crystal River 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10.000	$3,894,000	96.75	10	$2,963,394	9104.9	
	10	$3,894,000	94.62	9	$2,667,055	9119.2	
	9	$3,504,600	94.32	8	$2,370,716	9133.5	
	8	$3,115,200	94.01	7	$2,074,376	9147.9	
	7	$2,725,800	93.71	6	$1,778,037	9162.2	
	6	$2,336,400	93.40	5	$1,481,697	9176.5	
	5	$1,947,000	93.10	4	$1,185,358	9190.9	
	4	$1,557,600	92.79	3	$889,018	9205.2	
	3	$1,168,200	92.49	2	$592,679	9219.5	
	2	$778,800	92.18	1	$296,339	9233.9	
	1	$389,400	91.88	0	$0	9248.2	
		$0	91.57	0	$0	9323.2	
	0	$0	91.57	0.000	$0	9340.5	****
		$0	91.57	0	$0	9398.2	
	-1	($420,900)	90.96	-1	($296,339)	9412.6	
	-2	($841,800)	90.34	-2	($592,679)	9426.9	
	-3	($1,262,700)	89.73	-3	($889,018)	9441.2	
	-4	($1,683,600)	89.11	-4	($1,185,358)	9455.6	
	-5	($2,104,500)	88.50	-5	($1,481,697)	9469.9	
	-6	($2,525,400)	87.88	-6	($1,778,037)	9484.2	
	-7	($2,946,300)	87.26	-7	($2,074,376)	9498.6	
	-8	($3,367,200)	86.65	-8	($2,370,716)	9512.9	
	-9	($3,788,100)	86.03	-9	($2,667,055)	9527.2	
	-10	($4,209,000)	85.42	-10	($2,963,394)	9541.6	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
8.59%	6.54%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2003 - December 2003

Unit: Crystal River 5

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$3,821,000	97.14	10	$2,972,401	9121.0	
	9	$3,438,900	96.89	9	$2,675,161	9135.5	
	8	$3,056,800	96.64	8	$2,377,920	9149.9	
	7	$2,674,700	96.39	7	$2,080,680	9164.4	
	6	$2,292,600	96.14	6	$1,783,440	9178.8	
	5	$1,910,500	95.88	5	$1,486,200	9193.2	
	4	$1,528,400	95.63	4	$1,188,960	9207.7	
****	3.390	$1,295,263	95.48	3	$891,720	9222.1	
	3	$1,146,300	95.38	2	$594,480	9236.6	
	2	$764,200	95.13	1	$297,240	9251.0	
	1	$382,100	94.88	0	$0	9265.5	
		$0	94.62	0	$0	9340.5	
	0	$0	94.62	0.000	$0	9391.1	****
		$0	94.62	0	$0	9415.5	
	-1	($361,400)	94.11	-1	($297,240)	9429.9	
	-2	($722,800)	93.60	-2	($594,480)	9444.4	
	-3	($1,084,200)	93.09	-3	($891,720)	9458.8	
	-4	($1,445,600)	92.58	-4	($1,188,960)	9473.3	
	-5	($1,807,000)	92.07	-5	($1,486,200)	9487.7	
	-6	($2,168,400)	91.56	-6	($1,783,440)	9502.2	
	-7	($2,529,800)	91.05	-7	($2,080,680)	9516.6	
	-8	($2,891,200)	90.53	-8	($2,377,920)	9531.1	
	-9	($3,252,600)	90.02	-9	($2,675,161)	9545.5	
	-10	($3,614,000)	89.51	-10	($2,972,401)	9560.0	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
8.43%	6.56%

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Filed:
Suspended:
Effective:
Docket No.:
Order No.:

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2003 - December 2003

Unit: Hines 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$826,000	87.97	10	$5,255,099	6747.7	
	9	$743,400	87.75	9	$4,729,589	6791.3	
	8	$660,800	87.54	8	$4,204,079	6834.9	
	7	$578,200	87.32	7	$3,678,570	6878.5	
	6	$495,600	87.10	6	$3,153,060	6922.1	
	5	$413,000	86.88	5	$2,627,550	6965.7	
	4	$330,400	86.67	4	$2,102,040	7009.3	
****	3.518	$290,552	86.56	3	$1,576,530	7053.0	
	3	$247,800	86.45	2	$1,051,020	7096.6	
	2	$165,200	86.23	1	$525,510	7140.2	
	1	$82,600	86.01	0	$0	7183.8	
		$0	85.80	0	$0	7258.8	
	0	$0	85.80	0.000	$0	7314.1	****
		$0	85.80	0	$0	7333.8	
	-1	($83,800)	85.35	-1	($525,510)	7377.4	
	-2	($167,600)	84.90	-2	($1,051,020)	7421.0	
	-3	($251,400)	84.45	-3	($1,576,530)	7464.6	
	-4	($335,200)	84.01	-4	($2,102,040)	7508.2	
	-5	($419,000)	83.56	-5	($2,627,550)	7551.8	
	-6	($502,800)	83.11	-6	($3,153,060)	7595.4	
	-7	($586,600)	82.66	-7	($3,678,570)	7639.0	
	-8	($670,400)	82.22	-8	($4,204,079)	7682.7	
	-9	($754,200)	81.77	-9	($4,729,589)	7726.3	
	-10	($838,000)	81.32	-10	($5,255,099)	7769.9	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.82%	11.59%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Anclote 2	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-Dec Period
1. EAF	98.35	98.34	98.50	66.41	94.92	98.07	92.36	97.25	90.63	98.27	95.54	90.10	93.25
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	744.0	672.0	744.0	493.7	718.0	720.0	731.8	744.0	720.0	745.0	720.0	679.7	8432.3
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	0.0	225.3	26.0	0.0	12.2	0.0	0.0	0.0	0.0	64.3	327.7
6. POH	0.0	0.0	0.0	219.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	219.3
7. FOH	0.0	0.0	0.0	6.0	0.0	0.0	12.2	0.0	0.0	0.0	0.0	64.3	82.4
8. MOH	0.0	0.0	0.0	0.0	26.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.0
9. PFOH	7.9	1.6	0.0	6.9	6.5	1.6	173.1	2.3	715.0	0.0	108.1	35.1	1058.0
10. LR PF (MW)	135.4	156.3	0.0	12.0	77.8	204.3	81.9	34.0	38.0	0.0	68.1	87.0	51.1
11. PMOH	33.1	33.8	35.5	53.6	34.2	42.0	66.4	64.3	57.6	41.0	62.7	10.3	534.3
12. LR PM (MW)	151.4	156.0	156.0	148.7	156.0	156.0	119.3	156.0	108.7	156.0	136.3	155.0	143.0
13. NSC (MW)	495	495	495	495	495	495	495	495	495	495	495	495	495
14. OPER MBTU	1610658	1290665	1610071	1297012	2189003	2240702	2165611	2159191	2095289	2245372	1865901	1475898	22245175
15. NET GEN (MWH)	154825	123718	154301	128063	214012	221463	212671	213248	206141	227714	184092	140032	2180280
16. ANOHR (BTU/KWH)	10403.1	10432.3	10434.6	10127.9	10228.4	10117.7	10182.9	10125.3	10164.3	9860.5	10135.7	10538.3	10202.9
17. NOF (%)	42.04	37.19	41.90	52.40	60.22	62.14	58.71	57.90	57.84	61.75	51.65	41.62	52.24
18. NPC (MW)	495	495	495	495	495	495	495	495	495	495	495	495	495
ANOHR EQUATION:	ANOHR=	-13.287	x NOF +	10808.5									

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ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 1	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-Dec Period
1. EAF	97.47	96.68	89.33	96.59	96.40	77.98	92.00	90.95	96.35	94.70	95.77	71.94	91.30
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	734.7	672.0	736.4	719.0	744.0	639.5	727.9	718.7	720.0	745.0	711.7	549.4	8418.3
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	9.3	0.0	7.6	0.0	0.0	80.5	16.1	25.4	0.0	0.0	8.3	194.6	341.8
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	9.3	0.0	7.5	0.0	0.0	80.5	16.1	25.4	0.0	0.0	8.3	194.6	341.6
8. MOH	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
9. PFOH	0.2	19.5	6.8	13.5	33.6	51.7	39.8	31.9	28.4	9.8	34.4	21.9	291.4
10. LR PF (MW)	75.8	189.0	79.9	75.0	74.5	252.3	79.7	61.6	189.0	18.0	97.6	100.3	127.1
11. PMOH	47.5	48.1	196.0	64.0	65.3	158.6	116.6	88.2	40.2	114.5	58.1	21.6	1018.6
12. LR PM (MW)	75.7	99.5	136.1	129.1	117.1	104.2	114.0	158.1	114.4	129.1	87.2	147.6	120.1
13. NSC (MW)	379	379	379	379	379	379	379	379	379	379	379	379	379
14. OPER MBTU	2298084	1882113	1873980	2235837	2251655	1642218	2299342	2255098	2356676	2399127	2109265	1492241	25095633
15. NET GEN (MWH)	234306	190781	186716	218840	222165	159368	223051	218298	233944	242748	210613	153712	2494542
16. ANOHR (BTU/KWH)	9808.0	9865.3	10036.5	10216.8	10135.1	10304.6	10308.6	10330.4	10073.7	9883.2	10014.9	9708.0	10060.2
17. NOF (%)	84.15	74.91	66.90	80.31	78.79	65.76	80.85	80.15	85.73	85.97	78.08	73.82	78.19
18. NPC (MW)	379	379	379	379	379	379	379	379	379	379	379	379	379
ANOHR EQUATION:	ANOHR=	-7.020	x NOF +	10386.3									

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ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 2	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-Dec Period
1. EAF	98.18	76.58	22.73	18.82	88.89	80.77	87.47	95.48	76.28	97.44	94.28	97.56	78.01
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	744.0	530.5	169.4	167.8	692.3	624.2	684.9	727.3	571.0	745.0	720.0	744.0	7120.4
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	141.5	574.6	551.2	51.7	95.9	59.1	16.7	149.0	0.0	0.0	0.0	1639.6
6. POH	0.0	0.0	574.6	496.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1071.0
7. FOH	0.0	96.1	0.0	54.8	9.0	59.6	0.0	16.7	149.0	0.0	0.0	0.0	385.2
8. MOH	0.0	45.4	0.0	0.0	42.7	36.3	59.1	0.0	0.0	0.0	0.0	0.0	183.4
9. PFOH	35.9	36.8	1.0	121.0	52.9	6.0	0.0	33.3	5.7	8.2	80.0	30.6	411.4
10. LR PF (MW)	45.9	89.6	123.4	61.4	147.5	202.7	0.0	33.3	229.8	295.9	153.0	121.3	102.8
11. PMOH	47.6	23.3	0.0	49.3	40.9	206.6	132.7	61.6	40.7	37.9	30.3	36.2	707.0
12. LR PM (MW)	103.4	189.5	0.0	169.5	177.8	94.4	125.0	115.5	227.5	180.7	255.8	141.5	137.4
13. NSC (MW)	486	486	486	486	486	486	486	486	486	486	486	486	486
14. OPER MBTU	3094834	2005482	643420	547658	2716127	2326431	2774115	2966173	2279250	3179515	2648879	2695025	27876910
15. NET GEN (MWH)	322146	207672	63867	49172	278052	231053	278633	297586	230446	333227	272081	285563	2849498
16. ANOHR (BTU/KWH)	9606.9	9657.0	10074.4	11137.6	9768.4	10068.8	9956.2	9967.4	9890.6	9541.6	9735.6	9437.6	9783.1
17. NOF (%)	89.09	80.55	77.58	60.30	82.64	76.17	83.71	84.19	83.04	92.03	77.76	78.98	82.34
18. NPC (MW)	486	486	486	486	486	486	486	486	486	486	486	486	486
ANOHR EQUATION:	ANOHR=	-15.283	x NOF +	10936.3									

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ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 3	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-Dec Period
1. EAF	100.00	100.00	99.96	97.68	99.49	99.89	100.00	99.93	86.23	7.23	71.61	98.65	88.28
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	744.0	672.0	744.0	719.0	744.0	720.0	744.0	744.0	720.0	72.0	554.3	734.9	7912.2
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	673.0	165.7	9.2	847.8
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	673.0	108.3	0.0	781.3
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	57.4	9.2	66.6
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.0	0.0	24.9	2.2	47.1
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	155.3	0.0	478.9	313.3	333.7
11. PMOH	0.0	0.0	6.6	76.1	55.1	6.6	0.0	8.5	1015.1	72.0	58.3	0.0	1298.3
12. LR PM (MW)	0.0	0.0	37.0	167.7	52.9	95.0	0.0	45.0	71.7	192.7	303.4	0.0	93.4
13. NSC (MW) **	765	765	765	765	765	765	765	765	765	765	765	765	765
14. OPER MBTU	5927531	5366701	5924674	5602168	5888102	5731452	5985156	5979011	4991520	427544	4192702	5885680	61902241
15. NET GEN (MWH)	581978	527379	587346	553949	575196	559213	575095	575560	475965	41024	407561	578375	6038641
16. ANOHR (BTU/KWH)	10185.1	10176.2	10087.2	10113.1	10236.7	10249.1	10407.2	10388.2	10487.2	10421.8	10287.3	10176.2	10251.0
17. NOF (%)	102.25	102.59	103.20	100.71	101.06	101.53	101.04	101.12	86.41	74.46	96.11	102.88	99.77
18. NPC (MW)	765	765	765	765	765	765	765	765	765	765	765	765	765
ANOHR EQUATION:	ANOHR=	-6.499	x NOF +	10977.4									

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ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 4	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-Dec Period
1. EAF	99.99	97.62	99.24	99.78	98.12	97.80	98.69	97.10	97.77	99.88	98.23	81.35	97.11
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	744.0	672.0	744.0	719.0	733.5	720.0	744.0	744.0	712.2	745.0	714.4	606.0	8598.1
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	0.0	0.0	10.5	0.0	0.0	0.0	7.8	0.0	5.6	138.1	161.9
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.6	130.5	136.1
7. FOH	0.0	0.0	0.0	0.0	10.5	0.0	0.0	0.0	7.8	0.0	0.0	7.5	25.8
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PFOH	0.4	0.0	16.6	19.8	13.4	16.1	49.2	1.7	13.8	2.3	17.6	1.6	152.4
10. LR PF (MW)	101.2	0.0	69.8	56.8	54.9	110.4	82.5	102.1	435.0	102.3	292.0	53.9	134.6
11. PMOH	0.0	157.7	16.5	0.0	4.7	17.4	29.2	95.1	0.0	4.2	0.0	4.0	328.7
12. LR PM (MW)	0.0	73.0	176.2	0.0	386.8	553.3	102.0	161.3	0.0	101.9	0.0	102.1	136.9
13. NSC (MW)	720	720	720	720	720	720	720	720	720	720	720	720	720
14. OPER MBTU	4549440	3777035	4333126	4213791	4365085	4206694	4637668	4487801	4281869	4257189	3981719	3365008	50456425
15. NET GEN (MWH)	485462	403454	459868	448938	474231	433201	492551	478274	447537	453982	423722	359089	5360309
16. ANOHR (BTU/KWH)	9371.4	9361.7	9422.5	9386.1	9204.6	9710.7	9415.6	9383.3	9567.6	9377.4	9397.0	9371.0	9413.0
17. NOF (%)	90.63	83.39	85.85	86.72	89.79	83.57	91.95	89.28	87.27	84.63	82.38	82.31	86.59
18. NPC (MW)	720	720	720	720	720	720	720	720	720	720	720	720	720
ANOHR EQUATION:	ANOHR=	-7.908	x NOF +	10080.4									

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ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 5	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-Dec Period
1. EAF	93.63	92.46	98.20	89.54	80.14	98.62	97.81	99.75	98.65	97.94	98.96	99.84	95.48
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	699.1	661.0	744.0	646.6	707.5	720.0	744.0	744.0	720.0	731.4	720.0	744.0	8581.5
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	44.9	11.0	0.0	72.5	36.6	0.0	0.0	0.0	0.0	13.6	0.0	0.0	178.5
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	44.9	11.0	0.0	0.0	36.6	0.0	0.0	0.0	0.0	13.6	0.0	0.0	106.0
8. MOH	0.0	0.0	0.0	72.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	72.5
9. PFOH	8.7	49.7	3.2	19.8	305.0	20.0	15.0	2.2	27.7	12.0	7.6	6.0	476.9
10. LR PF (MW)	206.1	70.1	203.5	99.0	115.2	197.7	404.7	98.8	226.1	102.9	168.2	114.2	131.5
11. PMOH	0.0	135.7	40.1	0.0	116.0	30.4	9.8	3.3	7.0	0.0	7.5	1.8	351.5
12. LR PM (MW)	0.0	183.8	223.3	0.0	384.5	104.2	575.0	337.1	99.0	0.0	546.0	99.1	265.5
13. NSC (MW)	717	717	717	717	717	717	717	717	717	717	717	717	717
14. OPER MBTU	4312021	3475838	4345726	3764241	3553477	4459524	4607969	4663167	4651692	4616201	4416736	4668838	51535431
15. NET GEN (MWH)	459470	370254	465338	403830	380581	466822	487708	491524	494323	487668	466210	498892	5472620
16. ANOHR (BTU/KWH)	9384.8	9387.7	9338.9	9321.4	9337.0	9552.9	9448.2	9487.2	9410.2	9465.9	9473.7	9358.4	9417.0
17. NOF (%)	91.66	78.12	87.23	87.11	75.03	90.43	91.43	92.14	95.75	92.99	90.31	93.52	88.94
18. NPC (MW)	717	717	717	717	717	717	717	717	717	717	717	717	717

ANOHR EQUATION: ANOHR= -5.270 x NOF + 9835.1

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ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Hines 1	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-Dec Period
1. EAF	89.76	94.40	99.84	84.93	48.45	97.01	99.46	98.70	100.00	98.08	39.74	98.17	87.40
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	686.7	672.0	744.0	669.4	372.1	698.5	740.0	734.3	720.0	735.1	321.4	730.4	7823.7
4. RSH	57.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	56.6	0.0	114.0
5. UH	0.0	0.0	0.0	49.7	371.9	21.5	4.1	9.7	0.0	9.9	342.0	13.6	822.3
6. POH	0.0	0.0	0.0	49.7	371.9	0.0	0.0	0.0	0.0	0.0	342.0	0.0	763.6
7. FOH	0.0	0.0	0.0	0.0	0.0	21.5	4.1	9.7	0.0	9.9	0.0	13.6	58.7
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PFOH	96.8	72.0	4.0	0.0	0.0	0.0	0.0	0.0	0.0	8.3	0.0	0.0	181.0
10. LR PF (MW)	247.0	252.0	146.9	0.0	0.0	0.0	0.0	0.0	0.0	257.0	0.0	0.0	247.2
11. PMOH	51.9	0.0	0.0	113.2	23.3	0.0	0.0	0.0	0.0	0.0	169.1	0.0	357.5
12. LR PM (MW)	247.0	0.0	0.0	250.0	240.0	0.0	0.0	0.0	0.0	0.0	262.0	0.0	254.6
13. NSC (MW)	482	482	482	482	482	482	482	482	482	482	482	482	482
14. OPER MBTU	1946338	1754496	2024584	1661576	1076487	1947631	2150016	2173760	2039665	2307721	663830	2102221	21848325
15. NET GEN (MWH)	260541	239124	284286	228280	141039	264972	294699	294784	288229	304083	88056	284948	2973041
16. ANOHR (BTU/KWH)	7470.4	7337.2	7121.6	7278.7	7632.5	7350.3	7295.6	7374.1	7076.5	7589.1	7538.7	7377.6	7348.8
17. NOF (%)	78.72	73.83	79.27	70.76	78.64	78.70	82.63	83.29	83.05	85.82	56.84	80.94	78.84
18. NPC (MW)	482	482	482	482	482	482	482	482	482	482	482	482	482

ANOHR EQUATION: ANOHR= -15.964 x NOF + 8552.1

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PLANNED OUTAGE SCHEDULES
ACTUAL

Progress Energy Florida
January 2003 - December 2003

Plant/Unit	Planned Outage Dates	Reason for Outage
Anclote 2	4/11 (0001) - 4/20 (2400)	Boiler Outage
Crystal River 2	3/08 (0001) - 4/21 (2400)	Major Boiler Outage
Crystal River 3	10/04 (0001) - 11/05 (2400)	Refueling
Crystal River 4	11/30 (0001) - 12/06 (2400)	Boiler Outage
Hines 1	4/28 (0001) - 5/16 (2400)	Combustion Inspection
Hines 1	11/08 (0001) - 11/22 (2400)	Combustion Inspection

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Planned Outage Schedule - Actual

Progress Energy Florida
January 2003 - December 2003

	January	February	March	April	May	June	July	August	September	October	November	December
Anclote 2				Boiler Outage 4/11 – 4/20 10 days								
Crystal River 2			Major Boiler Outage 3/08 – 4/21 45 days									
Crystal River 3										Refueling 10/04 – 11/05 33 days		
Crystal River 4											Boiler Outage 11/30 – 12/06 7 days	
Hines 1				Comb. Inspection 4/28 – 5/16 19 days							Comb. Inspection 11/08 – 11/22 15 days	

Progress Energy Florida
Docket No. 040001-EI
Witness: Jacob
Exhibit No. ____ (MFJ-1)

GPIF Targets and Ranges for January through December 2005

STANDARD FORM GPIF SCHEDULES

Description	Page
Index	1
Reward/Penalty Table (Estimated)	2
Maximum Incentive Dollars (Estimated)	3
Target and Range Summary	4
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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 38
COMPANY/ PEF
WITNESS. Michael F. Jacob (MFJ-1P
DATE: 11-08-04

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ESTIMATED

Progress Energy Florida
Period of: January 2005 - December 2005

Generating Performance Incentive Points (GPIF)	Fuel Saving/Loss ($)	Generating Performance Incentive Factor ($)
10	$68,748,899	$9,314,504
9	$61,874,009	$8,383,054
8	$54,999,119	$7,451,603
7	$48,124,230	$6,520,153
6	$41,249,340	$5,588,702
5	$34,374,450	$4,657,252
4	$27,499,560	$3,725,802
3	$20,624,670	$2,794,351
2	$13,749,780	$1,862,901
1	$6,874,890	$931,450
0	$0	$0
-1	($5,745,990)	($931,450)
-2	($11,491,980)	($1,862,901)
-3	($17,237,970)	($2,794,351)
-4	($22,983,960)	($3,725,802)
-5	($28,729,950)	($4,657,252)
-6	($34,475,940)	($5,588,702)
-7	($40,221,930)	($6,520,153)
-8	($45,967,919)	($7,451,603)
-9	($51,713,909)	($8,383,054)
-10	($57,459,899)	($9,314,504)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

Progress Energy Florida
Period of: January 2005 - December 2005

1	*Beginning of period balance of common equity*	$2,293,573,792	
	END OF MONTH BALANCE OF COMMON EQUITY:		
2	Month of JANUARY 2005	$2,327,436,558	
3	Month of FEBRUARY 2005	$2,319,504,873	
4	Month of MARCH 2005	$2,328,130,003	
5	Month of APRIL 2005	$2,341,309,523	
6	Month of MAY 2005	$2,350,128,392	
7	Month of JUNE 2005	$2,391,884,589	
8	Month of JULY 2005	$2,440,191,794	
9	Month of AUGUST 2005	$2,467,996,262	
10	Month of SEPTEMBER 2005	$2,508,952,222	
11	Month of OCTOBER 2005	$2,536,400,558	
12	Month of NOVEMBER 2005	$2,524,186,061	
13	Month of DECEMBER 2005	$2,537,733,955	
14	Average common equity for the period (Summation of LINE 1 through LINE 13 divided by 13)	$2,412,879,122	
15	25 Basis Points	0.0025	
16	Revenue Expansion Factor	61.3808%	
17	Maximum allowed incentive dollars (LINE 14 times LINE 15 divided by LINE 16)	$9,827,499	
18	Jurisdictional Sales	40,292,697	MWH
19	Total Sales	42,513,913	MWH
20	Jurisdictional Separation Factor (LINE 18 divided by LINE 19)	94.78%	
21	Maximum allowed jurisdictional incentive dollars (LINE 17 times LINE 20)	$9,314,504	

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GPIF TARGET AND RANGE SUMMARY

Progress Energy Florida
Period of: January 2005 - December 2005

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
Anclote 1	1.52	94.72	97.21	89.56	1,048	(1,341)
Anclote 2	3.15	94.87	97.28	89.91	2,164	(2,883)
Crystal River 1	5.26	92.42	95.97	85.21	3,618	(1,591)
Crystal River 2	16.79	85.71	92.26	73.18	11,540	(8,324)
Crystal River 3	2.14	90.52	91.38	88.73	1,474	(1,286)
Crystal River 4	10.56	89.58	91.78	85.04	7,262	(3,395)
Crystal River 5	7.57	90.14	91.82	86.67	5,205	(1,599)
Hines 1	0.75	88.98	90.57	85.66	513	(1,299)
Tiger Bay	0.52	91.36	93.62	86.73	359	(176)
GPIF System	48.27				33,183	(21,894)

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (BTU/KWH)	ANOHR RANGE Max. (BTU/KWH)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
Anclote 1	9.05	10117	56.0	9632	10602	6,221	(6,221)
Anclote 2	5.37	10128	57.0	9833	10424	3,689	(3,689)
Crystal River 1	3.54	9921	82.9	9576	10267	2,432	(2,432)
Crystal River 2	5.72	9662	85.9	9222	10101	3,929	(3,929)
Crystal River 3	10.52	10298	100.1	10109	10488	7,235	(7,235)
Crystal River 4	3.22	9342	96.0	9177	9508	2,215	(2,215)
Crystal River 5	3.47	9390	95.1	9209	9571	2,384	(2,384)
Hines 1	7.10	7317	81.6	7092	7541	4,878	(4,878)
Tiger Bay	3.75	7903	79.3	7638	8168	2,582	(2,582)
GPIF System	51.73					35,566	(35,566)

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COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE AVAILABILITY

Progress Energy Florida
Period of: January 2005 - December 2005

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Target POF	Target EUOF	Target EUOR	Actual Performance 1st Prior Period Jan-Jun 2004 POF	Actual Performance 1st Prior Period Jan-Jun 2004 EUOF	Actual Performance 1st Prior Period Jan-Jun 2004 EUOR	Actual Performance 2nd Prior Period Jan-Dec 2003 POF	Actual Performance 2nd Prior Period Jan-Dec 2003 EUOF	Actual Performance 2nd Prior Period Jan-Dec 2003 EUOR
Anclote 1	1.52	3.16	0.00	5.28	5.50	0.00	4.51	4.79	11.48	5.55	6.76
Anclote 2	3.15	6.52	0.00	5.13	5.48	6.91	3.30	3.62	0.00	6.75	6.75
Crystal River 1	5.26	10.90	0.00	7.58	7.66	25.89	6.56	8.86	0.00	8.70	8.70
Crystal River 2	16.79	34.78	0.00	14.29	14.37	0.00	22.27	22.27	12.23	9.77	11.13
Crystal River 3	2.14	4.44	7.67	1.81	1.96	0.00	2.09	2.09	8.92	2.80	3.08
Crystal River 4	10.56	21.88	5.75	4.67	4.95	0.00	6.49	6.49	1.55	1.33	1.35
Crystal River 5	7.57	15.69	6.30	3.56	3.82	4.54	1.08	1.13	0.00	4.52	4.52
Hines 1	0.75	1.55	7.67	3.35	3.94	8.26	8.99	9.80	8.72	3.89	4.32
Tiger Bay	0.52	1.08	3.84	4.81	5.00	11.52	1.45	1.95	2.66	6.48	6.97
GPIF System Wghtd. Avg.	48.27	100.00	2.75	8.06	8.25	4.24	10.66	10.96	5.51	6.22	6.76

Plant/Unit	Actual Performance 3rd Prior Period Jan-Dec 2002 POF	Actual Performance 3rd Prior Period Jan-Dec 2002 EUOF	Actual Performance 3rd Prior Period Jan-Dec 2002 EUOR	Actual Performance 4th Prior Period Jan-Dec 2001 POF	Actual Performance 4th Prior Period Jan-Dec 2001 EUOF	Actual Performance 4th Prior Period Jan-Dec 2001 EUOR	Actual Performance 5th Prior Period Jan-Dec 2000 POF	Actual Performance 5th Prior Period Jan-Dec 2000 EUOF	Actual Performance 5th Prior Period Jan-Dec 2000 EUOR
Anclote 1	5.85	3.44	4.17	12.04	5.12	6.25	0.00	12.13	13.01
Anclote 2	0.00	2.90	3.06	0.00	7.31	7.87	12.55	3.60	4.43
Crystal River 1	0.00	7.08	7.08	9.38	7.97	8.84	0.00	10.94	10.94
Crystal River 2	0.00	16.39	16.39	15.35	8.41	9.93	0.00	37.25	37.25
Crystal River 3	0.00	1.31	1.31	7.27	4.54	4.89	0.00	3.23	3.23
Crystal River 4	17.65	3.86	4.69	0.00	6.24	6.24	9.73	6.22	6.89
Crystal River 5	11.48	1.32	1.49	10.25	6.43	7.17	0.00	7.05	7.05
Hines 1	9.27	1.48	1.63	15.62	1.87	2.60	10.36	5.01	5.90
Tiger Bay	5.22	4.88	5.14	9.33	3.78	4.17	12.17	3.86	4.49
GPIF System Wghtd. Avg.	6.05	7.95	8.20	9.02	7.08	7.92	3.24	17.50	17.75

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COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE
AVERAGE NET OPERATING HEAT RATE

Progress Energy Florida
Period of: January 2005 - December 2005

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Average Heat Rate Target	1st Prior HR Jan 2003 - Dec 2003	2nd Prior HR Jan 2002 - Dec 2002	3rd Prior HR Jan 2001 - Dec 2001
Anclote 1	9.05	17.49	10117	10120	10319	10017
Anclote 2	5.37	10.37	10128	10176	10086	10156
Crystal River 1	3.54	6.84	9921	9993	9792	9777
Crystal River 2	5.72	11.05	9662	9777	9620	9554
Crystal River 3	10.52	20.34	10298	10256	10319	10375
Crystal River 4	3.22	6.23	9342	9321	9329	9308
Crystal River 5	3.47	6.70	9390	9382	9438	9333
Hines 1	7.10	13.72	7317	7326	7332	7269
Tiger Bay	3.75	7.26	7903	7935	7904	7814
GPIF System Weighted Avg.	51.73	100.00	9450	9466	9476	9410

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DERIVATION OF WEIGHTING FACTORS

Progress Energy Florida
Period of: January 2005 - December 2005

Unit Performance Indicator	Production Costing Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Anclote 1 EA	1977339	1976291	1048	1.52
Anclote 1 HR	1977339	1971118	6221	9.05
Anclote 2 EA	1977339	1975175	2164	3.15
Anclote 2 HR	1977339	1973650	3689	5.37
Crystal River 1 EA	1977339	1973721	3618	5.26
Crystal River 1 HR	1977339	1974907	2432	3.54
Crystal River 2 EA	1977339	1965799	11540	16.79
Crystal River 2 HR	1977339	1973410	3929	5.72
Crystal River 3 EA	1977339	1975865	1474	2.14
Crystal River 3 HR	1977339	1970104	7235	10.52
Crystal River 4 EA	1977339	1970077	7262	10.56
Crystal River 4 HR	1977339	1975124	2215	3.22
Crystal River 5 EA	1977339	1972134	5205	7.57
Crystal River 5 HR	1977339	1974955	2384	3.47
Hines 1 EA	1977339	1976826	513	0.75
Hines 1 HR	1977339	1972461	4878	7.10
Tiger Bay EA	1977339	1976980	359	0.52
Tiger Bay HR	1977339	1974757	2582	3.75

1. Fuel Adjustment Base Case - all unit performance indicators at Target.
2. All other unit performance indicators at Target.
3. Expressed in replacement costs.

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INCENTIVE POINTS TABLES

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2005 - December 2005

Anclote 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$1,048,000	97.21	10	$6,221,128	9631.9
9	$943,200	96.96	9	$5,599,015	9672.9
8	$838,400	96.71	8	$4,976,902	9713.9
7	$733,600	96.47	7	$4,354,790	9754.9
6	$628,800	96.22	6	$3,732,677	9795.9
5	$524,000	95.97	5	$3,110,564	9836.8
4	$419,200	95.72	4	$2,488,451	9877.8
3	$314,400	95.47	3	$1,866,338	9918.8
2	$209,600	95.22	2	$1,244,226	9959.8
1	$104,800	94.97	1	$622,113	10000.8
					10041.8
0	$0	94.72	0	$0	10116.8
					10191.8
-1	($134,100)	94.20	-1	($622,113)	10232.8
-2	($268,200)	93.69	-2	($1,244,226)	10273.8
-3	($402,300)	93.17	-3	($1,866,338)	10314.8
-4	($536,400)	92.66	-4	($2,488,451)	10355.8
-5	($670,500)	92.14	-5	($3,110,564)	10396.8
-6	($804,600)	91.63	-6	($3,732,677)	10437.8
-7	($938,700)	91.11	-7	($4,354,790)	10478.8
-8	($1,072,800)	90.59	-8	($4,976,902)	10519.8
-9	($1,206,900)	90.08	-9	($5,599,015)	10560.8
-10	($1,341,000)	89.56	-10	($6,221,128)	10601.8

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
1.52%	9.05%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2005 - December 2005

Anclote 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$2,164,000	97.28	10	$3,689,090	9832.5
9	$1,947,600	97.04	9	$3,320,181	9854.6
8	$1,731,200	96.80	8	$2,951,272	9876.6
7	$1,514,800	96.56	7	$2,582,363	9898.7
6	$1,298,400	96.32	6	$2,213,454	9920.8
5	$1,082,000	96.07	5	$1,844,545	9942.8
4	$865,600	95.83	4	$1,475,636	9964.9
3	$649,200	95.59	3	$1,106,727	9986.9
2	$432,800	95.35	2	$737,818	10009.0
1	$216,400	95.11	1	$368,909	10031.1
					10053.1
0	$0	94.87	0	$0	10128.1
					10203.1
-1	($288,300)	94.37	-1	($368,909)	10225.2
-2	($576,600)	93.88	-2	($737,818)	10247.2
-3	($864,900)	93.38	-3	($1,106,727)	10269.3
-4	($1,153,200)	92.88	-4	($1,475,636)	10291.3
-5	($1,441,500)	92.39	-5	($1,844,545)	10313.4
-6	($1,729,800)	91.89	-6	($2,213,454)	10335.5
-7	($2,018,100)	91.40	-7	($2,582,363)	10357.5
-8	($2,306,400)	90.90	-8	($2,951,272)	10379.6
-9	($2,594,700)	90.41	-9	($3,320,181)	10401.6
-10	($2,883,000)	89.91	-10	($3,689,090)	10423.7

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.15%	5.37%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2005 - December 2005

Crystal River 1

Equivalent Availability (Points)	*Fuel* Savings/Loss ($)	*Equivalent* Availability (%)	*Average* Heat Rate (Points)	*Fuel* Savings/Loss ($)	*Average* Heat Rate (BTU/KWH)
10	$3,618,000	95.97	10	$2,431,922	9575.8
9	$3,256,200	95.62	9	$2,188,730	9602.9
8	$2,894,400	95.26	8	$1,945,538	9629.9
7	$2,532,600	94.91	7	$1,702,345	9656.9
6	$2,170,800	94.55	6	$1,459,153	9684.0
5	$1,809,000	94.20	5	$1,215,961	9711.0
4	$1,447,200	93.84	4	$972,769	9738.1
3	$1,085,400	93.49	3	$729,577	9765.1
2	$723,600	93.13	2	$486,384	9792.2
1	$361,800	92.78	1	$243,192	9819.2
					9846.3
0	$0	92.42	0	$0	9921.3
					9996.3
-1	($159,100)	91.70	-1	($243,192)	10023.3
-2	($318,200)	90.98	-2	($486,384)	10050.4
-3	($477,300)	90.26	-3	($729,577)	10077.4
-4	($636,400)	89.53	-4	($972,769)	10104.4
-5	($795,500)	88.81	-5	($1,215,961)	10131.5
-6	($954,600)	88.09	-6	($1,459,153)	10158.5
-7	($1,113,700)	87.37	-7	($1,702,345)	10185.6
-8	($1,272,800)	86.65	-8	($1,945,538)	10212.6
-9	($1,431,900)	85.93	-9	($2,188,730)	10239.7
-10	($1,591,000)	85.21	-10	($2,431,922)	10266.7

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.26%	3.54%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2005 - December 2005

Crystal River 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$11,540,000	92.26	10	$3,929,119	9222.5
9	$10,386,000	91.61	9	$3,536,207	9258.9
8	$9,232,000	90.95	8	$3,143,295	9295.3
7	$8,078,000	90.30	7	$2,750,383	9331.8
6	$6,924,000	89.64	6	$2,357,471	9368.2
5	$5,770,000	88.99	5	$1,964,559	9404.6
4	$4,616,000	88.33	4	$1,571,647	9441.0
3	$3,462,000	87.68	3	$1,178,736	9477.4
2	$2,308,000	87.02	2	$785,824	9513.9
1	$1,154,000	86.37	1	$392,912	9550.3
					9586.7
0	$0	85.71	0	$0	9661.7
					9736.7
-1	($832,400)	84.46	-1	($392,912)	9773.1
-2	($1,664,800)	83.20	-2	($785,824)	9809.6
-3	($2,497,200)	81.95	-3	($1,178,736)	9846.0
-4	($3,329,600)	80.70	-4	($1,571,647)	9882.4
-5	($4,162,000)	79.44	-5	($1,964,559)	9918.8
-6	($4,994,400)	78.19	-6	($2,357,471)	9955.3
-7	($5,826,800)	76.94	-7	($2,750,383)	9991.7
-8	($6,659,200)	75.69	-8	($3,143,295)	10028.1
-9	($7,491,600)	74.43	-9	($3,536,207)	10064.5
-10	($8,324,000)	73.18	-10	($3,929,119)	10100.9

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
16.79%	5.72%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2005 - December 2005

Crystal River 3

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$1,474,000	91.38	10	$7,235,426	10109.0
9	$1,326,600	91.29	9	$6,511,883	10120.4
8	$1,179,200	91.20	8	$5,788,341	10131.8
7	$1,031,800	91.12	7	$5,064,798	10143.3
6	$884,400	91.03	6	$4,341,256	10154.7
5	$737,000	90.95	5	$3,617,713	10166.1
4	$589,600	90.86	4	$2,894,170	10177.5
3	$442,200	90.78	3	$2,170,628	10189.0
2	$294,800	90.69	2	$1,447,085	10200.4
1	$147,400	90.61	1	$723,543	10211.8
					10223.3
0	$0	90.52	0	$0	10298.3
					10373.3
-1	($128,600)	90.34	-1	($723,543)	10384.7
-2	($257,200)	90.16	-2	($1,447,085)	10396.1
-3	($385,800)	89.98	-3	($2,170,628)	10407.5
-4	($514,400)	89.81	-4	($2,894,170)	10419.0
-5	($643,000)	89.63	-5	($3,617,713)	10430.4
-6	($771,600)	89.45	-6	($4,341,256)	10441.8
-7	($900,200)	89.27	-7	($5,064,798)	10453.3
-8	($1,028,800)	89.09	-8	($5,788,341)	10464.7
-9	($1,157,400)	88.91	-9	($6,511,883)	10476.1
-10	($1,286,000)	88.73	-10	($7,235,426)	10487.5

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.14%	10.52%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2005 - December 2005

Crystal River 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$7,262,000	91.78	10	$2,215,377	9176.7
9	$6,535,800	91.56	9	$1,993,839	9185.8
8	$5,809,600	91.34	8	$1,772,302	9194.8
7	$5,083,400	91.12	7	$1,550,764	9203.9
6	$4,357,200	90.90	6	$1,329,226	9213.0
5	$3,631,000	90.68	5	$1,107,689	9222.0
4	$2,904,800	90.46	4	$886,151	9231.1
3	$2,178,600	90.24	3	$664,613	9240.1
2	$1,452,400	90.02	2	$443,075	9249.2
1	$726,200	89.80	1	$221,538	9258.2
					9267.3
0	$0	89.58	0	$0	9342.3
					9417.3
-1	($339,500)	89.12	-1	($221,538)	9426.3
-2	($679,000)	88.67	-2	($443,075)	9435.4
-3	($1,018,500)	88.22	-3	($664,613)	9444.4
-4	($1,358,000)	87.76	-4	($886,151)	9453.5
-5	($1,697,500)	87.31	-5	($1,107,689)	9462.5
-6	($2,037,000)	86.86	-6	($1,329,226)	9471.6
-7	($2,376,500)	86.40	-7	($1,550,764)	9480.6
-8	($2,716,000)	85.95	-8	($1,772,302)	9489.7
-9	($3,055,500)	85.49	-9	($1,993,839)	9498.7
-10	($3,395,000)	85.04	-10	($2,215,377)	9507.8

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
10.56%	3.22%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2005 - December 2005

Crystal River 5

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$5,205,000	91.82	10	$2,384,446	9209.4
9	$4,684,500	91.65	9	$2,146,002	9219.9
8	$4,164,000	91.48	8	$1,907,557	9230.5
7	$3,643,500	91.32	7	$1,669,112	9241.1
6	$3,123,000	91.15	6	$1,430,668	9251.7
5	$2,602,500	90.98	5	$1,192,223	9262.3
4	$2,082,000	90.81	4	$953,778	9272.9
3	$1,561,500	90.64	3	$715,334	9283.5
2	$1,041,000	90.48	2	$476,889	9294.1
1	$520,500	90.31	1	$238,445	9304.7
					9315.3
0	$0	90.14	0	$0	9390.3
					9465.3
-1	($159,900)	89.79	-1	($238,445)	9475.9
-2	($319,800)	89.45	-2	($476,889)	9486.5
-3	($479,700)	89.10	-3	($715,334)	9497.1
-4	($639,600)	88.75	-4	($953,778)	9507.6
-5	($799,500)	88.40	-5	($1,192,223)	9518.2
-6	($959,400)	88.06	-6	($1,430,668)	9528.8
-7	($1,119,300)	87.71	-7	($1,669,112)	9539.4
-8	($1,279,200)	87.36	-8	($1,907,557)	9550.0
-9	($1,439,100)	87.02	-9	($2,146,002)	9560.6
-10	($1,599,000)	86.67	-10	($2,384,446)	9571.2

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
7.57%	3.47%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2005 - December 2005

Hines 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$513,000	90.57	10	$4,877,887	7092.5
9	$461,700	90.41	9	$4,390,099	7107.4
8	$410,400	90.25	8	$3,902,310	7122.3
7	$359,100	90.09	7	$3,414,521	7137.2
6	$307,800	89.93	6	$2,926,732	7152.1
5	$256,500	89.77	5	$2,438,944	7167.1
4	$205,200	89.62	4	$1,951,155	7182.0
3	$153,900	89.46	3	$1,463,366	7196.9
2	$102,600	89.30	2	$975,577	7211.8
1	$51,300	89.14	1	$487,789	7226.7
					7241.6
0	$0	88.98	0	$0	7316.6
					7391.6
-1	($129,900)	88.65	-1	($487,789)	7406.6
-2	($259,800)	88.32	-2	($975,577)	7421.5
-3	($389,700)	87.99	-3	($1,463,366)	7436.4
-4	($519,600)	87.65	-4	($1,951,155)	7451.3
-5	($649,500)	87.32	-5	($2,438,944)	7466.2
-6	($779,400)	86.99	-6	($2,926,732)	7481.1
-7	($909,300)	86.66	-7	($3,414,521)	7496.0
-8	($1,039,200)	86.33	-8	($3,902,310)	7511.0
-9	($1,169,100)	85.99	-9	($4,390,099)	7525.9
-10	($1,299,000)	85.66	-10	($4,877,887)	7540.8

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.75%	7.10%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2005 - December 2005

Tiger Bay

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$359,000	93.62	10	$2,581,504	7638.5
9	$323,100	93.39	9	$2,323,354	7657.5
8	$287,200	93.16	8	$2,065,203	7676.5
7	$251,300	92.94	7	$1,807,053	7695.4
6	$215,400	92.71	6	$1,548,902	7714.4
5	$179,500	92.49	5	$1,290,752	7733.4
4	$143,600	92.26	4	$1,032,602	7752.4
3	$107,700	92.03	3	$774,451	7771.3
2	$71,800	91.81	2	$516,301	7790.3
1	$35,900	91.58	1	$258,150	7809.3
					7828.3
0	$0	91.36	0	$0	7903.3
					7978.3
-1	($17,600)	90.89	-1	($258,150)	7997.3
-2	($35,200)	90.43	-2	($516,301)	8016.2
-3	($52,800)	89.97	-3	($774,451)	8035.2
-4	($70,400)	89.50	-4	($1,032,602)	8054.2
-5	($88,000)	89.04	-5	($1,290,752)	8073.2
-6	($105,600)	88.58	-6	($1,548,902)	8092.2
-7	($123,200)	88.12	-7	($1,807,053)	8111.1
-8	($140,800)	87.65	-8	($2,065,203)	8130.1
-9	($158,400)	87.19	-9	($2,323,354)	8149.1
-10	($176,000)	86.73	-10	($2,581,504)	8168.1

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.52%	3.75%

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UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2005 - December 2005

PLANT/UNIT **Anclote 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94.86	94.50	94.70	94.53	94.50	94.54	94.50	94.50	94.50	94.81	94.54	96.14	94.72
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	5.14	5.50	5.30	5.47	5.50	5.46	5.50	5.50	5.50	5.19	5.46	3.86	5.28
4. EUOR	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50	5.50
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	685.9	663.2	707.6	705.7	734.3	704.7	734.3	734.3	710.6	692.8	704.7	515.2	8293.2
7. RSH	49.0	0.0	27.0	5.0	0.0	6.0	0.0	0.0	0.0	42.0	6.0	222.0	357.0
8. UH	9.1	8.8	9.4	9.3	9.7	9.3	9.7	9.7	9.4	9.2	9.3	6.8	109.8
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	14.2	13.7	14.6	14.6	15.2	14.6	15.2	15.2	14.7	14.3	14.6	10.7	171.5
11. MOH & PMOH	24.1	23.3	24.8	24.8	25.8	24.7	25.8	25.8	24.9	24.3	24.7	18.1	291.0
12. Oper. Btu(MBtu)	1605892	1609507	2081488	1571161	1858952	2118243	2366550	2436976	2224221	1827037	2339090	1259364	23416513
13. Net Gen. (MWH)	153231.1	154494.6	207670.0	148750.7	179776.7	212444.3	241733.6	251049.7	225388.9	178056.9	240977.5	121035.8	2314609.8
14. ANOHR (Btu/KWH)	10480	10418	10023	10562	10340	9971	9790	9707	9868	10261	9707	10405	10117
15. NOF (%)	44.9	46.8	58.9	42.3	49.2	60.5	66.1	68.7	63.7	51.6	68.7	47.2	56.0
16. NSC (MW)	498	498	498	498	498	498	498	498	498	498	498	498	498
17. ANOHR Equation	ANOHR=	-32.486 x NOF +		11937.5									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
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PLANT/UNIT **Anclote 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94.68	94.55	95.20	94.88	94.62	94.58	94.52	94.52	94.56	94.68	94.52	97.02	94.87
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	5.32	5.45	4.80	5.12	5.38	5.42	5.48	5.48	5.44	5.32	5.48	2.98	5.13
4. EUOR	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48	5.48
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	701.9	650.4	633.9	654.3	709.7	692.2	723.3	723.3	695.1	701.9	700.0	392.8	7979.0
7. RSH	22.0	3.0	92.0	47.0	14.0	8.0	0.0	0.0	5.0	22.0	0.0	340.0	553.0
8. UH	20.1	18.6	18.1	18.7	20.3	19.8	20.7	20.7	19.9	20.1	20.0	11.2	228.0
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	7.1	6.6	6.4	6.6	7.2	7.0	7.3	7.3	7.0	7.1	7.1	4.0	80.6
11. MOH & PMOH	32.5	30.1	29.3	30.3	32.8	32.0	33.5	33.5	32.2	32.5	32.4	18.2	369.1
12. Oper. Btu(MBtu)	1515220	1425225	1808347	1386046	1871947	2171674	2475626	2564996	2270282	1885895	2391016	972272	22789431
13. Net Gen. (MWH)	147262.3	138615.8	178533.3	134588.5	183899.4	215837.7	247732.7	257448.0	226330.1	185477.8	239226.6	95164.5	2250116.7
14. ANOHR (Btu/KWH)	10289	10282	10129	10298	10179	10062	9993	9963	10031	10168	9995	10217	10128
15. NOF (%)	42.4	43.1	56.9	41.6	52.3	63.0	69.2	71.9	65.8	53.4	69.0	48.9	57.0
16. NSC (MW)	495	495	495	495	495	495	495	495	495	495	495	495	495
17. ANOHR Equation	ANOHR=	-11.046 x NOF +		10757.4									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2005 - December 2005

PLANT/UNIT **Crystal River 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	92.48	92.45	92.34	92.67	92.55	92.34	92.34	92.34	92.34	92.34	92.54	92.34	92.42
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	7.52	7.55	7.66	7.33	7.45	7.66	7.66	7.66	7.66	7.66	7.46	7.66	7.58
4. EUOR	7.66	7.66	7.66	7.66	7.66	7.66	7.66	7.66	7.66	7.66	7.66	7.66	7.66
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	698.4	633.3	711.8	659.2	691.7	688.8	711.8	711.8	688.8	711.8	670.7	711.8	8289.9
7. RSH	14.0	10.0	0.0	31.0	21.0	0.0	0.0	0.0	0.0	0.0	19.0	0.0	95.0
8. UH	31.6	28.7	32.2	29.8	31.3	31.2	32.2	32.2	31.2	32.2	30.3	32.2	375.1
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	36.4	33.0	37.1	34.3	36.0	35.9	37.1	37.1	35.9	37.1	34.9	37.1	431.5
11. MOH & PMOH	19.6	17.8	20.0	18.5	19.4	19.3	20.0	20.0	19.3	20.0	18.8	20.0	232.5
12. Oper. Btu(MBtu)	2098164	2016215	2519188	2088090	2313113	2047148	1839160	1839160	1779914	2401415	2380789	2465116	25832726
13. Net Gen. (MWH)	210568.4	203756.9	258253.0	210890.4	235255.6	205194.2	181693.7	181693.7	175841.5	244527.6	244173.0	251925.2	2603773.2
14. ANOHR (Btu/KWH)	9964	9895	9755	9901	9832	9977	10122	10122	10122	9821	9750	9785	9921
15. NOF (%)	79.6	84.9	95.7	84.4	89.7	78.6	67.4	67.4	67.4	90.6	96.1	93.4	82.9
16. NSC (MW)	379	379	379	379	379	379	379	379	379	379	379	379	379
17. ANOHR Equation	ANOHR=	-12.952 x NOF +		10994.7									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2005 - December 2005

PLANT/UNIT **Crystal River 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	85.88	85.71	85.75	85.63	85.78	85.77	85.63	85.76	85.67	85.63	85.63	85.67	85.71
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	14.12	14.29	14.25	14.37	14.22	14.23	14.37	14.24	14.33	14.37	14.37	14.33	14.29
4. EUOR	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37	14.37
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	663.3	606.2	669.7	653.4	667.9	647.0	675.1	668.8	651.5	675.1	653.4	673.3	7904.8
7. RSH	13.0	4.0	6.0	0.0	8.0	7.0	0.0	7.0	2.0	0.0	0.0	2.0	49.0
8. UH	67.7	61.8	68.3	66.6	68.1	66.0	68.9	68.2	66.5	68.9	66.6	68.7	806.2
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	52.8	48.3	53.3	52.0	53.2	51.5	53.8	53.3	51.9	53.8	52.0	53.6	629.5
11. MOH & PMOH	52.2	47.7	52.7	51.4	52.6	50.9	53.2	52.7	51.3	53.2	51.4	53.0	622.4
12. Oper. Btu(MBtu)	2637051	2517729	2901207	2705135	2816354	2527485	2411797	2386809	2329006	2853002	2833111	2906643	31879884
13. Net Gen. (MWH)	271913.8	262689.5	306461.5	281992.5	295118.7	259461.7	242542.0	239980.0	234248.0	299142.7	299354.7	306705.0	3299610.1
14. ANOHR (Btu/KWH)	9698	9584	9467	9593	9543	9741	9944	9946	9942	9537	9464	9477	9662
15. NOF (%)	84.3	89.2	94.2	88.8	90.9	82.5	73.9	73.8	74.0	91.2	94.3	93.7	85.9
16. NSC (MW)	486	486	486	486	486	486	486	486	486	486	486	486	486
17. ANOHR Equation	ANOHR=	-23.569 x NOF +		11686.1									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2005 - December 2005

PLANT/UNIT **Crystal River 3**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	98.04	98.04	98.04	98.04	98.04	98.04	98.04	98.04	98.04	66.41	39.22	98.04	90.52
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.26	60.00	0.00	7.67
3. EUOF	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.33	0.78	1.96	1.81
4. EUOR	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	737.8	666.4	737.8	714.0	737.8	714.0	737.8	737.8	714.0	499.8	285.6	737.8	8021.1
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. UH	6.2	5.6	6.2	6.0	6.2	6.0	6.2	6.2	6.0	244.2	434.4	6.2	738.9
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	240.0	432.0	0.0	672.0
10. FOH & PFOH	5.5	5.0	5.5	5.3	5.5	5.3	5.5	5.5	5.3	3.7	2.1	5.5	59.8
11. MOH & PMOH	9.1	8.2	9.1	8.8	9.1	8.8	9.1	9.1	8.8	6.1	3.5	9.1	98.7
12. Oper. Btu(MBtu)	5844607	5282148	5844607	5662124	5844607	5662124	5844607	5844607	5662124	3959734	2264850	5844607	63560751
13. Net Gen. (MWH)	567522.0	512923.0	567522.0	549835.0	567522.0	549835.0	567522.0	567522.0	549835.0	384500.0	219934.0	567522.0	6171994.0
14. ANOHR (Btu/KWH)	10298	10298	10298	10298	10298	10298	10298	10298	10298	10298	10298	10298	10298
15. NOF (%)	100.0	100.1	100.0	100.1	100.0	100.1	100.0	100.0	100.1	100.0	100.1	100.0	100.1
16. NSC (MW)	769	769	769	769	769	769	769	769	769	769	769	769	769
17. ANOHR Equation	ANOHR=	-5.379 x NOF +		10836.5									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2005 - December 2005

PLANT/UNIT **Crystal River 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	95.05	95.05	30.67	95.05	95.05	95.05	95.05	95.05	95.05	95.05	95.05	95.05	89.58
2. POF	0.00	0.00	67.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.75
3. EUOF	4.95	4.95	1.59	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.67
4. EUOR	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95	4.95
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	720.1	650.4	231.3	696.9	720.1	696.9	720.1	720.1	696.9	720.1	696.9	720.1	7990.1
7. RSH	0.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
8. UH	23.9	21.6	511.7	23.1	23.9	23.1	23.9	23.9	23.1	23.9	23.1	23.9	768.9
9. POH	0.0	0.0	504.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	504.0
10. FOH & PFOH	28.9	26.1	9.3	28.0	28.9	28.0	28.9	28.9	28.0	28.9	28.0	28.9	320.5
11. MOH & PMOH	8.0	7.2	2.6	7.7	8.0	7.7	8.0	8.0	7.7	8.0	7.7	8.0	88.5
12. Oper. Btu(MBtu)	4118951	4172677	1537037	4357111	4688004	4571630	4764374	4764374	4610684	4619260	4610685	4759744	51584485
13. Net Gen. (MWH)	435436.2	446331.1	165063.7	464758.1	502274.6	490231.1	511397.8	511397.8	494901.1	494094.1	494901.2	510843.7	5521630.5
14. ANOHR (Btu/KWH)	9459	9349	9312	9375	9334	9325	9316	9316	9316	9349	9316	9317	9342
15. NOF (%)	84.0	95.3	99.1	92.6	96.9	97.7	98.6	98.6	98.6	95.3	98.6	98.5	96.0
16. NSC (MW)	720	720	720	720	720	720	720	720	720	720	720	720	720
17. ANOHR Equation	ANOHR=	-9.760 x NOF +		10279.0									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
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PLANT/UNIT **Crystal River 5**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	96.18	96.20	96.18	96.18	96.19	96.18	96.18	96.43	96.18	96.18	35.26	83.77	90.14
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	63.33	12.90	6.30
3. EUOF	3.82	3.80	3.82	3.82	3.81	3.82	3.82	3.57	3.82	3.82	1.40	3.33	3.56
4. EUOR	3.82	3.82	3.82	3.82	3.82	3.82	3.82	3.82	3.82	3.82	3.82	3.82	3.82
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	726.6	652.4	726.6	703.2	723.7	703.2	726.6	678.8	703.2	726.6	257.8	632.9	7961.7
7. RSH	0.0	4.0	0.0	0.0	3.0	0.0	0.0	49.0	0.0	0.0	0.0	0.0	56.0
8. UH	17.4	15.6	17.4	16.8	17.3	16.8	17.4	16.2	16.8	17.4	462.2	111.1	742.3
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	456.0	96.0	552.0
10. FOH & PFOH	20.7	18.5	20.7	20.0	20.6	20.0	20.7	19.3	20.0	20.7	7.3	18.0	226.3
11. MOH & PMOH	7.8	7.0	7.8	7.5	7.8	7.5	7.8	7.3	7.5	7.8	2.8	6.8	85.4
12. Oper. Btu(MBtu)	4254537	4024113	4813033	4305447	4604125	4560877	4816467	4487805	4661097	4628455	1710457	4132791	51003381
13. Net Gen. (MWH)	451019.1	427694.4	513487.9	457423.5	490127.4	486025.7	513874.6	478741.6	497298.0	492749.6	182498.9	440569.9	5431510.6
14. ANOHR (Btu/KWH)	9433	9409	9373	9412	9394	9384	9373	9374	9373	9393	9372	9381	9390
15. NOF (%)	86.6	91.4	98.6	90.7	94.5	96.4	98.6	98.4	98.6	94.6	98.7	97.1	95.1
16. NSC (MW)	717	717	717	717	717	717	717	717	717	717	717	717	717
17. ANOHR Equation	ANOHR=	-5.000 x NOF +		9866.0									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2005 - December 2005

PLANT/UNIT **Hines 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	97.08	96.92	77.75	70.57	96.06	96.06	96.06	96.07	96.07	96.10	51.27	97.16	88.98
2. POF	0.00	0.00	19.35	26.67	0.00	0.00	0.00	0.00	0.00	0.00	46.67	0.00	7.67
3. EUOF	2.92	3.08	2.89	2.77	3.94	3.94	3.94	3.93	3.93	3.90	2.07	2.84	3.35
4. EUOR	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94	3.94
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	548.3	523.4	544.3	503.5	740.3	716.4	740.3	738.3	714.4	734.3	376.1	534.3	7414.0
7. RSH	193.0	146.0	53.0	22.0	0.0	0.0	0.0	2.0	2.0	6.0	6.0	207.0	637.0
8. UH	2.7	2.6	146.7	194.5	3.7	3.6	3.7	3.7	3.6	3.7	337.9	2.7	709.0
9. POH	0.0	0.0	144.0	192.0	0.0	0.0	0.0	0.0	0.0	0.0	336.0	0.0	672.0
10. FOH & PFOH	5.1	4.9	5.1	4.7	6.9	6.7	6.9	6.9	6.7	6.8	3.5	5.0	69.1
11. MOH & PMOH	16.6	15.8	16.5	15.2	22.4	21.7	22.4	22.3	21.6	22.2	11.4	16.2	224.2
12. Oper. Btu(MBtu)	1350264	1256367	1436935	1362506	2149641	2172237	2397321	2398781	2247637	2123683	1064898	1349047	21343039
13. Net Gen. (MWH)	180874.6	167808.8	194109.2	184643.7	294169.2	299201.4	333775.6	334169.1	311418.3	290446.0	145201.1	181238.3	2917055.3
14. ANOHR (Btu/KWH)	7465	7487	7403	7379	7307	7260	7182	7178	7217	7312	7334	7443	7317
15. NOF (%)	68.4	66.5	74.0	76.1	82.4	86.6	93.5	93.9	90.4	82.1	80.1	70.4	81.6
16. NSC (MW)	482	482	482	482	482	482	482	482	482	482	482	482	482
17. ANOHR Equation	ANOHR=	-11.268 x NOF +		8236.4									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2005 - December 2005

PLANT/UNIT Tiger Bay	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	95.00	95.00	95.00	72.83	95.00	95.00	95.00	95.00	95.00	85.81	82.33	95.00	91.36
2. POF	0.00	0.00	0.00	23.33	0.00	0.00	0.00	0.00	0.00	9.68	13.33	0.00	3.84
3. EUOF	5.00	5.00	5.00	3.83	5.00	5.00	5.00	5.00	5.00	4.52	4.33	5.00	4.81
4. EUOR	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8760
6. SH	710.7	641.9	710.7	527.3	710.7	687.8	710.7	710.7	687.8	641.9	596.1	710.7	8047.1
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. UH	33.3	30.1	33.3	192.7	33.3	32.2	33.3	33.3	32.2	102.1	123.9	33.3	712.9
9. POH	0.0	0.0	0.0	168.0	0.0	0.0	0.0	0.0	0.0	72.0	96.0	0.0	336.0
10. FOH & PFOH	11.2	10.1	11.2	8.3	11.2	10.8	11.2	11.2	10.8	10.1	9.4	11.2	126.6
11. MOH & PMOH	26.0	23.5	26.0	19.3	26.0	25.2	26.0	26.0	25.2	23.5	21.8	26.0	294.7
12. Oper. Btu(MBtu)	831019	753911	868102	653700	923515	939136	1015652	1020844	959525	828010	786617	847911	10438244
13. Net Gen. (MWH)	103531.9	93982.8	108827.5	82130.7	116885.2	119856.6	130696.2	131490.8	122927.1	104673.3	99810.6	105934.8	1320747.5
14. ANOHR (Btu/KWH)	8027	8022	7977	7959	7901	7835	7771	7764	7806	7910	7881	8004	7903
15. NOF (%)	70.4	70.7	74.0	75.2	79.4	84.2	88.8	89.4	86.3	78.8	80.9	72.0	79.3
16. NSC (MW)	207	207	207	207	207	207	207	207	207	207	207	207	207
17. ANOHR Equation	ANOHR=	-13.843 x NOF +		9000.9									

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PLANNED OUTAGE SCHEDULES

Progress Energy Florida
Period of: January 2005 - December 2005

Plant/Unit	Planned Outage Dates	Reason for Outage
Crystal River 3	10/22 (0001) - 11/18 (2400)	Refueling
Crystal River 4	03/05 (0001) - 03/25 (2400)	Boiler inspection and repair
Crystal River 5	11/12 (0001) - 12/04 (2400)	Boiler inspection and repair
Hines 1	03/26 (0001) - 04/08 (2400)	1A Combustion inspection & BOP maintenance
Hines 1	11/12 (0001) - 11/25 (2400)	1B Combustion inspection & BOP maintenance
Tiger Bay	04/23 (0001) - 04/29 (2400)	BOP maintenance and inlet filter change out
Tiger Bay	10/29 (0001) - 11/04 (2400)	BOP maintenance

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AVERAGE NET OPERATING HEAT RATE CURVES

PROGRESS ENERGY FLORIDA

ANCLOTE UNIT 1

ANOHR -32.486 * NOF + 11937.48

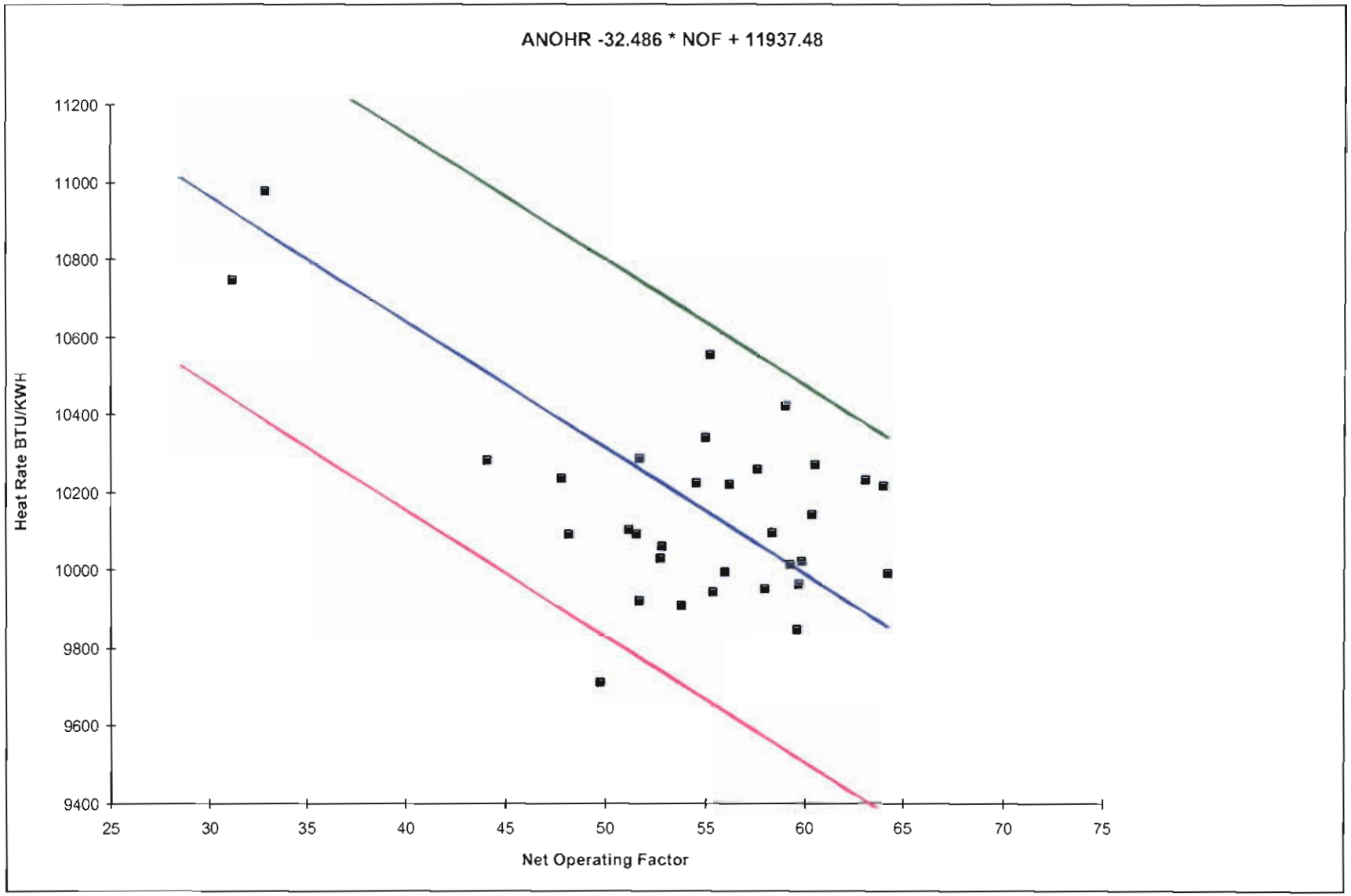
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-01	58.4	10095.0	10041.4	53.6	485.0
Aug-01	59.1	10419.0	10018.9	400.1	485.0
Sep-01	51.7	10283.0	10256.5	26.5	485.0
Oct-01	64.2	9990.0	9852.4	137.6	485.0
Nov-01	47.8	10234.0	10384.6	-150.6	485.0
Dec-01	53.8	9909.0	10188.3	-279.3	485.0
Jan-02	55.4	9945.0	10139.0	-194.0	485.0
Feb-02	39.5	11653.0	10655.1	997.9	485.0
Mar-02	56.0	9994.0	10117.5	-123.5	485.0
Apr-02	58.0	9950.0	10052.5	-102.5	485.0
May-02	57.7	10256.0	10064.6	191.4	485.0
Jun-02	54.6	10221.0	10163.7	57.3	485.0
Jul-02	55.0	10339.5	10149.3	190.2	485.0
Aug-02	55.2	10550.6	10144.1	406.6	485.0
Sep-02	63.1	10231.1	9888.0	343.2	485.0
Oct-02	64.0	10213.6	9858.3	355.3	485.0
Dec-02	33.0	10973.5	10866.7	106.8	485.0
Jan-03	44.1	10280.7	10504.1	-223.4	485.0
Feb-03	31.2	10744.5	10923.0	-178.5	485.0
Mar-03	28.8	11406.7	11000.7	406.0	485.0
Apr-03	52.7	10027.6	10224.1	-196.5	485.0
May-03	59.7	9963.8	9997.6	-33.8	485.0
Jun-03	59.3	10012.1	10011.7	0.4	485.0
Jul-03	60.4	10139.3	9976.1	163.1	485.0
Aug-03	56.2	10219.4	10112.4	107.0	485.0
Sep-03	60.6	10268.1	9969.2	298.9	485.0
Oct-03	59.9	10020.6	9991.6	28.9	485.0
Dec-03	51.7	9921.6	10257.8	-336.1	485.0
Jan-04	48.2	10089.9	10370.4	-280.4	485.0
Feb-04	52.8	10059.8	10221.7	-161.9	485.0
Mar-04	49.7	9710.3	10321.5	-611.2	485.0
Apr-04	51.6	10089.0	10261.4	-172.4	485.0
May-04	51.2	10101.5	10275.2	-173.7	485.0
Jun-04	59.6	9847.3	10000.1	-152.8	485.0

Regression Output:

Constant	11937.48
Std Err of Y Est	299.2427795
R Squared	0.486821156
No. of Observations	34
Degrees of Freedom	33
X Coefficient	-32.48615635
Std Err of Coef.	5.896210661

Anclote Unit 1



PROGRESS ENERGY FLORIDA

ANCLOTE UNIT 2

ANOHR -11.046 * NOF + 10757.44

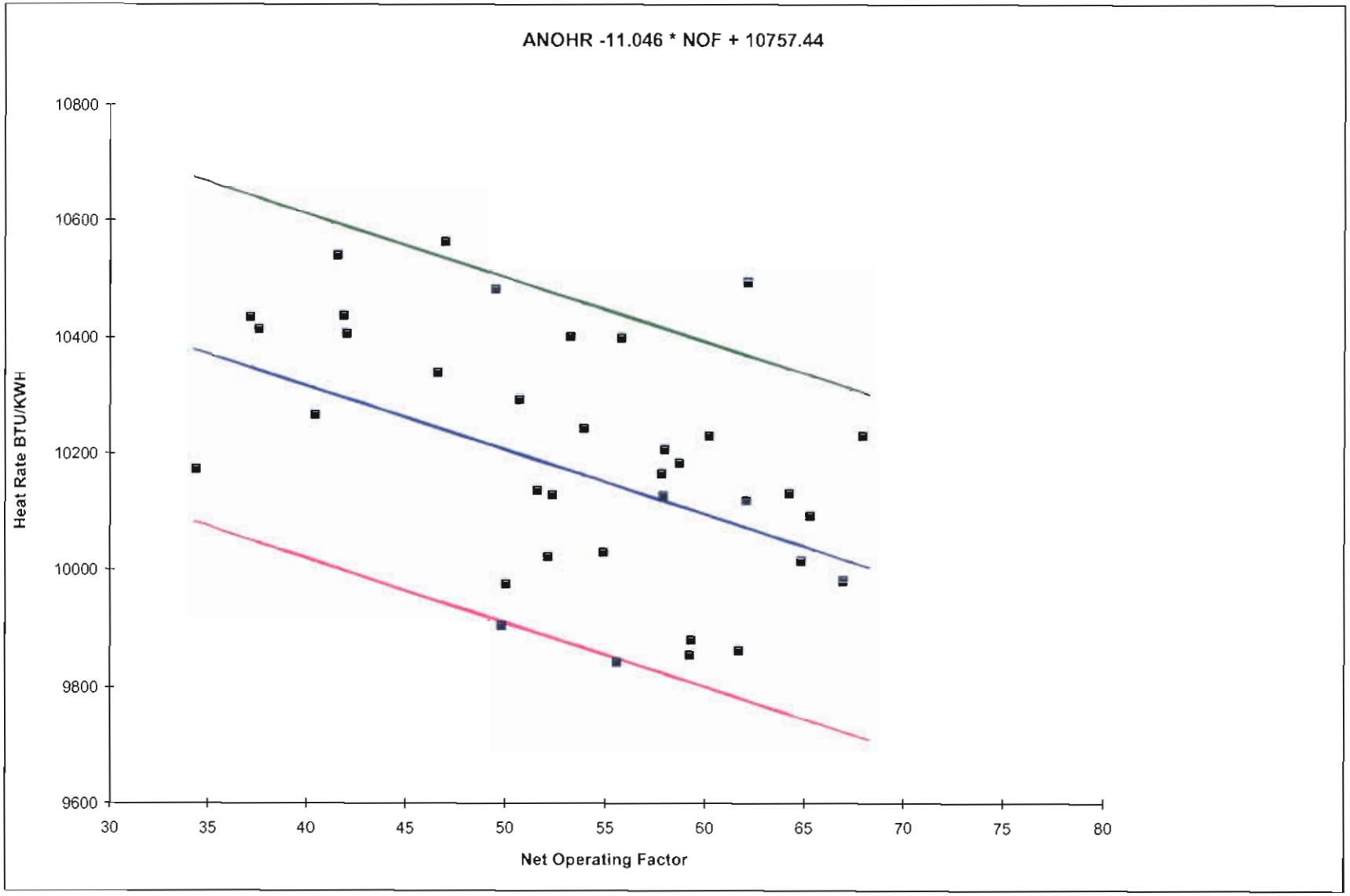
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-01	65.3	10091.0	10035.6	55.4	295.6
Aug-01	68.0	10228.0	10006.6	221.4	295.6
Sep-01	53.3	10398.0	10168.6	229.4	295.6
Oct-01	64.3	10130.0	10047.7	82.3	295.6
Nov-01	47.0	10562.0	10238.4	323.6	295.6
Dec-01	55.6	9840.0	10143.3	-303.3	295.6
Jan-02	50.1	9975.0	10204.4	-229.4	295.6
Feb-02	34.4	10172.0	10376.9	-204.9	295.6
Mar-02	59.4	9880.0	10101.7	-221.7	295.6
Apr-02	59.3	9853.0	10102.6	-249.6	295.6
May-02	58.0	10206.0	10117.0	89.0	295.6
Jun-02	54.9	10029.0	10151.0	-122.0	295.6
Jul-02	55.8	10397.0	10140.9	256.1	295.6
Aug-02	54.0	10242.0	10161.1	80.9	295.6
Sep-02	64.9	10013.7	10041.0	-27.3	295.6
Oct-02	67.0	9978.9	10017.5	-38.6	295.6
Nov-02	46.6	10336.3	10242.4	93.9	295.6
Dec-02	37.6	10413.2	10341.9	71.3	295.6
Jan-03	42.0	10403.1	10293.0	110.0	295.6
Feb-03	37.2	10432.3	10346.6	85.7	295.6
Mar-03	41.9	10434.6	10294.6	140.0	295.6
Apr-03	52.4	10127.9	10178.6	-50.7	295.6
May-03	60.2	10228.4	10092.3	136.1	295.6
Jun-03	62.1	10117.7	10071.0	46.7	295.6
Jul-03	58.7	10182.9	10108.9	74.0	295.6
Aug-03	57.9	10125.3	10117.8	7.5	295.6
Sep-03	57.8	10164.3	10118.5	45.8	295.6
Oct-03	61.7	9860.5	10075.3	-214.8	295.6
Nov-03	51.7	10135.7	10186.9	-51.2	295.6
Dec-03	41.6	10538.3	10297.7	240.6	295.6
Jan-04	40.5	10265.1	10310.4	-45.2	295.6
Feb-04	52.2	10021.1	10180.9	-159.8	295.6
Mar-04	49.5	10480.5	10210.4	270.1	295.6
Apr-04	49.9	9902.5	10206.6	-304.2	295.6
May-04	50.7	10290.7	10197.0	93.7	295.6
Jun-04	62.2	10493.4	10070.9	422.6	295.6

Regression Output:

Constant	10757.44
Std Err of Y Est	182.2324136
R Squared	0.232716674
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-11.04649138
Std Err of Coef.	3.439925438

Anclote Unit 2



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 1

ANOHR -12.952 * NOF + 10994.67

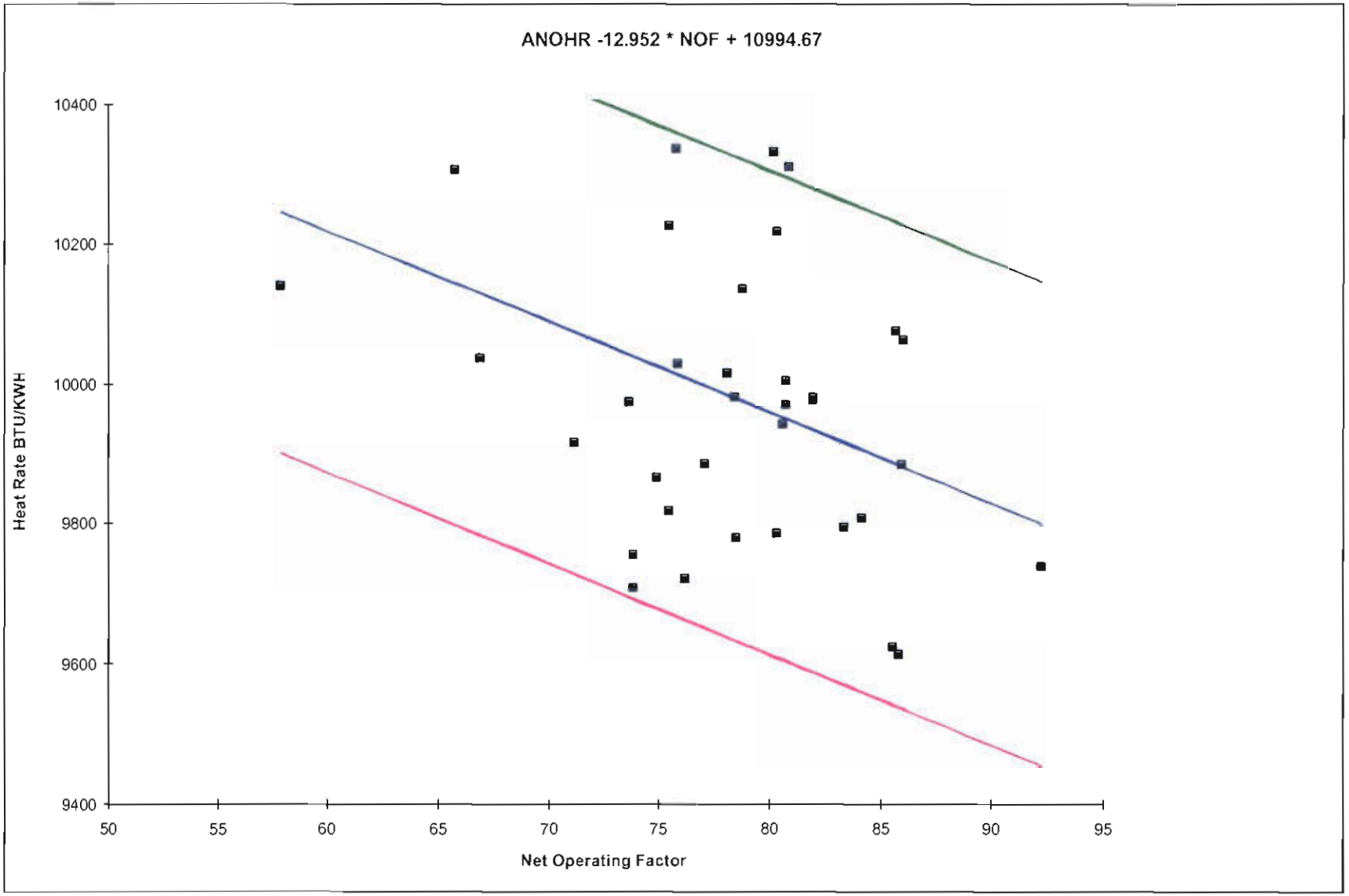
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-01	78.4	9980.0	9978.7	1.3	345.5
Aug-01	75.9	10028.0	10012.1	15.9	345.5
Sep-01	73.7	9973.0	10040.4	-67.4	345.5
Oct-01	77.1	9884.0	9996.6	-112.6	345.5
Nov-01	71.2	9916.0	10073.1	-157.1	345.5
Dec-01	57.9	10139.0	10245.2	-106.2	345.5
Jan-02	73.8	9756.0	10038.2	-282.2	345.5
Feb-02	76.2	9722.0	10007.4	-285.4	345.5
Mar-02	85.6	9625.0	9885.9	-260.9	345.5
Apr-02	85.8	9613.0	9883.3	-270.3	345.5
May-02	83.3	9794.0	9915.4	-121.4	345.5
Jun-02	80.6	9942.0	9950.7	-8.7	345.5
Jul-02	80.7	9969.1	9948.8	20.3	345.5
Aug-02	81.9	9975.7	9933.4	42.3	345.5
Sep-02	82.0	9979.7	9933.0	46.7	345.5
Oct-02	92.3	9737.7	9799.7	-62.0	345.5
Nov-02	80.3	9786.1	9954.2	-168.1	345.5
Dec-02	78.5	9778.9	9978.1	-199.2	345.5
Jan-03	84.1	9808.0	9904.8	-96.7	345.5
Feb-03	74.9	9865.3	10024.4	-159.1	345.5
Mar-03	66.9	10036.5	10128.1	-91.6	345.5
Apr-03	80.3	10216.8	9954.5	262.3	345.5
May-03	78.8	10135.1	9974.2	160.9	345.5
Jun-03	65.8	10304.6	10143.0	161.6	345.5
Jul-03	80.9	10308.6	9947.4	361.2	345.5
Aug-03	80.1	10330.4	9956.6	373.8	345.5
Sep-03	85.7	10073.7	9884.2	189.4	345.5
Oct-03	86.0	9883.2	9881.1	2.1	345.5
Nov-03	78.1	10014.9	9983.4	31.5	345.5
Dec-03	73.8	9708.0	10038.6	-330.5	345.5
Jan-04	75.5	9818.6	10016.9	-198.4	345.5
Feb-04	86.0	10061.8	9880.2	181.6	345.5
Mar-04	80.8	10003.9	9948.8	55.2	345.5
Apr-04	69.2	10639.4	10098.8	540.6	345.5
May-04	75.4	10224.9	10017.6	207.3	345.5
Jun-04	75.8	10336.3	10012.5	323.9	345.5

Regression Output:

Constant	10994.67
Std Err of Y Est	212.9846775
R Squared	0.143924836
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-12.95231256
Std Err of Coef.	5.417462759

Crystal River Unit 1



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 2

ANOHR -23.569 * NOF + 11686.06

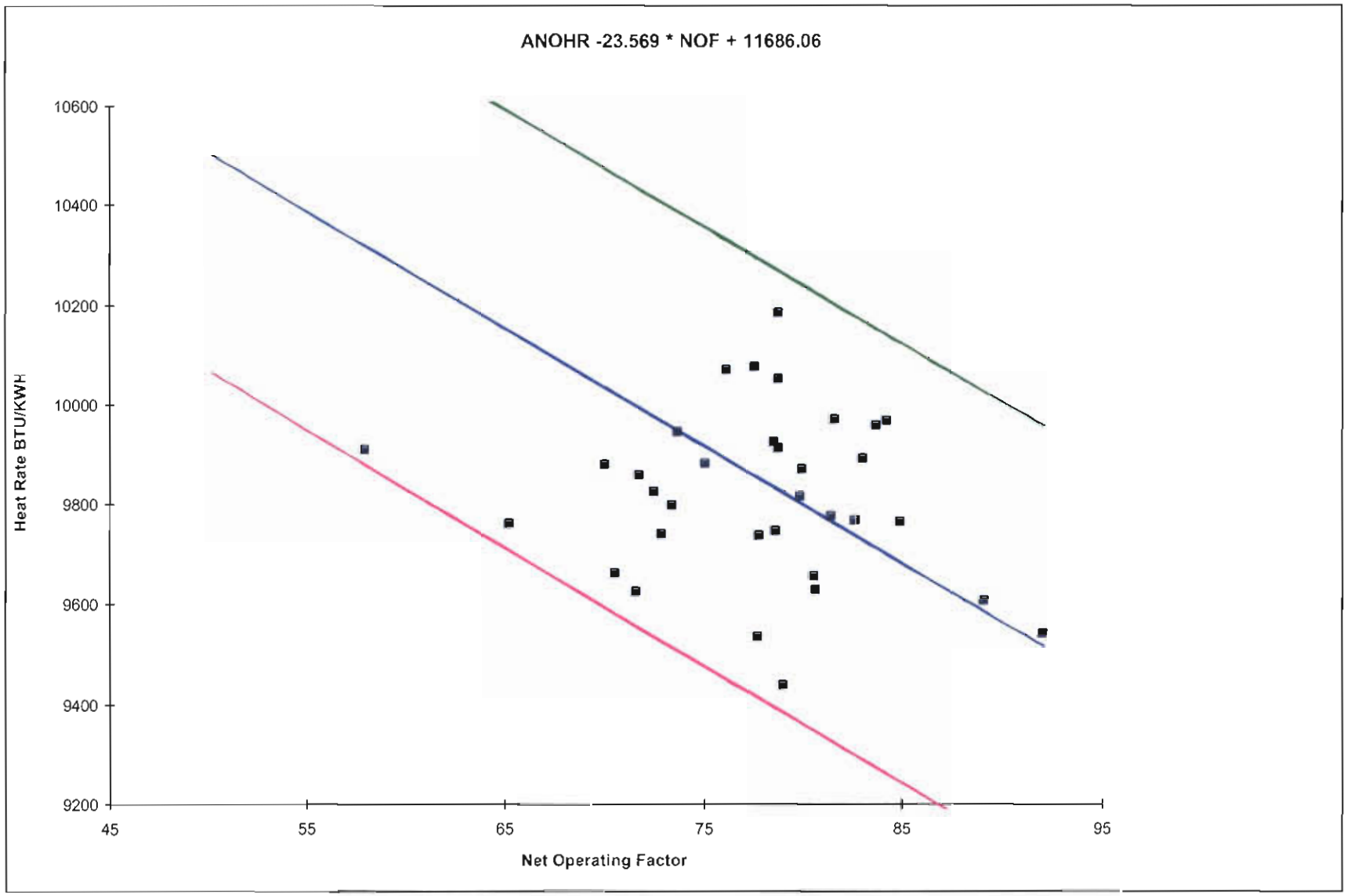
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-01	78.7	9912.0	9830.3	81.7	439.2
Aug-01	78.8	10052.0	9829.3	222.7	439.2
Sep-01	71.8	9857.0	9994.2	-137.2	439.2
Oct-01	71.6	9626.0	9997.4	-371.4	439.2
Nov-01	58.0	9908.0	10318.1	-410.1	439.2
Dec-01	65.2	9762.0	10148.3	-386.3	439.2
Jan-02	70.6	9663.0	10021.3	-358.3	439.2
Feb-02	77.7	9534.0	9854.2	-320.2	439.2
Mar-02	70.1	9878.0	10034.6	-156.6	439.2
Apr-02	78.6	9746.0	9833.9	-87.9	439.2
May-02	84.9	9765.0	9684.5	80.5	439.2
Jun-02	79.9	9815.0	9802.9	12.1	439.2
Jul-02	78.5	9922.9	9834.7	88.2	439.2
Aug-02	81.6	9968.7	9762.3	206.4	439.2
Sep-02	78.7	10183.2	9830.4	352.8	439.2
Oct-02	79.9	9869.1	9801.8	67.3	439.2
Nov-02	73.5	9796.7	9954.8	-158.1	439.2
Dec-02	72.9	9740.1	9966.9	-226.7	439.2
Jan-03	89.1	9606.9	9586.2	20.7	439.2
Feb-03	80.5	9657.0	9787.5	-130.6	439.2
Mar-03	77.6	10074.4	9857.6	216.7	439.2
Apr-03	60.3	11137.6	10264.9	872.7	439.2
May-03	82.6	9768.4	9738.3	30.1	439.2
Jun-03	76.2	10068.8	9890.8	178.1	439.2
Jul-03	83.7	9956.2	9713.2	243.0	439.2
Aug-03	84.2	9967.4	9701.8	265.7	439.2
Sep-03	83.0	9890.6	9728.7	161.9	439.2
Oct-03	92.0	9541.6	9516.9	24.7	439.2
Nov-03	77.8	9735.6	9853.4	-117.8	439.2
Dec-03	79.0	9437.6	9824.7	-387.1	439.2
Jan-04	73.7	9945.6	9948.0	-2.4	439.2
Feb-04	50.3	10958.9	10501.3	457.7	439.2
Mar-04	80.6	9628.8	9786.2	-157.4	439.2
Apr-04	81.5	9777.3	9766.0	11.3	439.2
May-04	75.1	9881.4	9916.3	-34.9	439.2
Jun-04	72.5	9825.3	9976.5	-151.2	439.2

Regression Output:

Constant	11686.06
Std Err of Y Est	270.7965252
R Squared	0.34755679
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-23.56938796
Std Err of Coef.	5.538183177

Crystal River Unit 2



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 3

ANOHR -5.379 * NOF + 10836.49

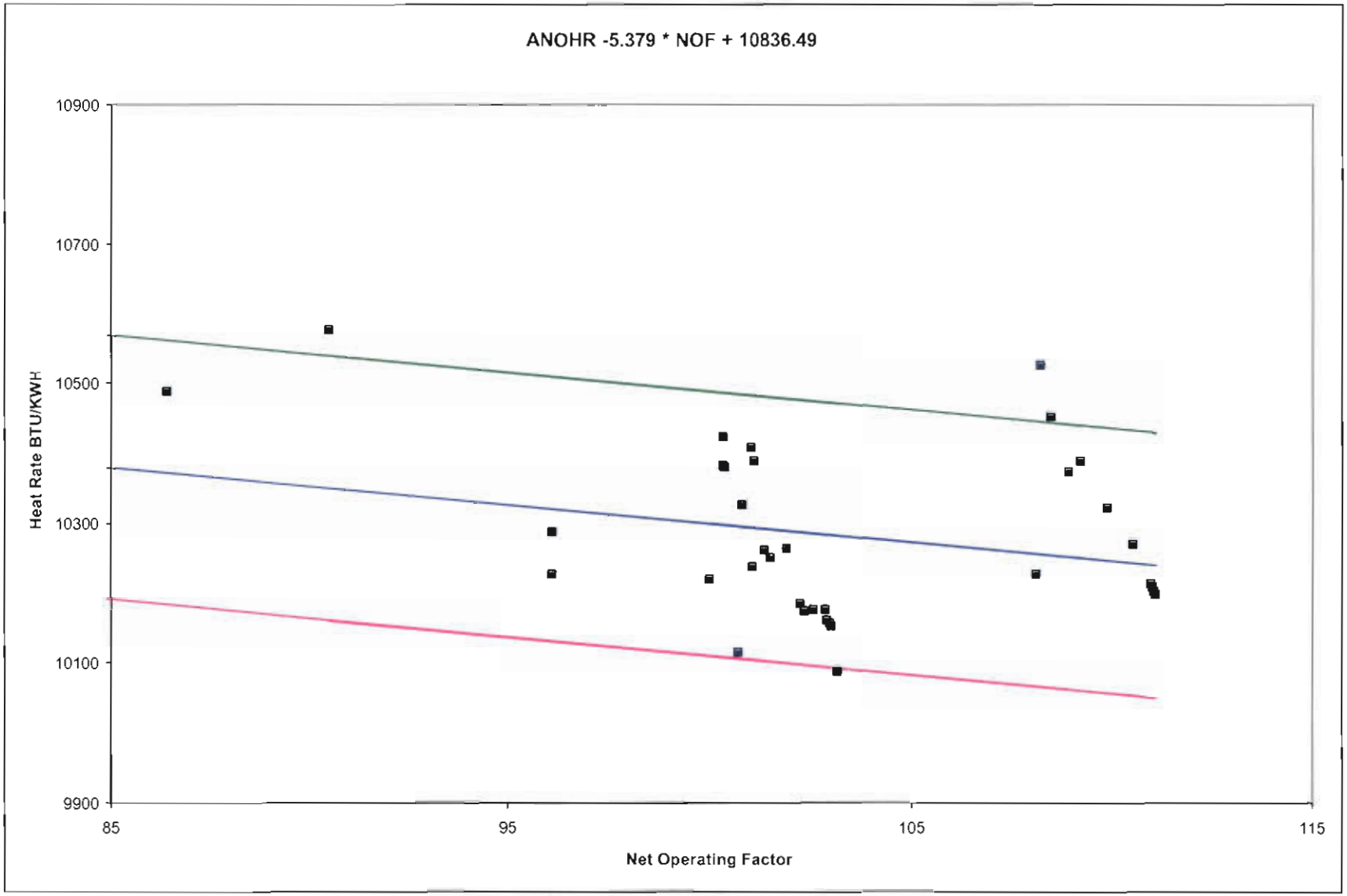
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-01	109.2	10388.0	10248.9	139.1	189.3
Aug-01	108.5	10450.0	10252.8	197.2	189.3
Sep-01	108.9	10374.0	10250.5	123.5	189.3
Oct-01	90.5	10576.0	10349.5	226.5	189.3
Nov-01	111.1	10203.0	10239.0	-36.0	189.3
Dec-01	108.1	10226.0	10254.8	-28.8	189.3
Jan-02	111.0	10214.0	10239.4	-25.4	189.3
Feb-02	111.1	10199.0	10238.8	-39.8	189.3
Mar-02	111.0	10208.0	10239.2	-31.2	189.3
Apr-02	110.5	10270.0	10241.9	28.1	189.3
May-02	108.3	10525.0	10254.1	270.9	189.3
Jun-02	109.9	10322.0	10245.3	76.7	189.3
Jul-02	100.4	10379.2	10296.6	82.6	189.3
Aug-02	100.3	10381.2	10296.7	84.5	189.3
Sep-02	100.8	10326.4	10294.1	32.2	189.3
Oct-02	101.4	10261.2	10291.3	-30.1	189.3
Nov-02	96.1	10225.2	10319.6	-94.4	189.3
Dec-02	102.4	10175.2	10285.9	-110.6	189.3
Jan-03	102.3	10185.1	10286.5	-101.3	189.3
Feb-03	102.6	10176.2	10284.7	-108.5	189.3
Mar-03	103.2	10087.2	10281.4	-194.2	189.3
Apr-03	100.7	10113.1	10294.8	-181.6	189.3
May-03	101.1	10236.7	10292.9	-56.2	189.3
Jun-03	101.5	10249.1	10290.4	-41.2	189.3
Jul-03	101.0	10407.2	10293.0	114.3	189.3
Aug-03	101.1	10388.2	10292.5	95.6	189.3
Sep-03	86.4	10487.2	10371.7	115.5	189.3
Oct-03	74.5	10421.8	10436.0	-14.2	189.3
Nov-03	96.1	10287.3	10319.5	-32.2	189.3
Dec-03	102.9	10176.2	10283.1	-106.8	189.3
Jan-04	103.0	10156.5	10282.5	-126.0	189.3
Feb-04	103.0	10153.3	10282.3	-128.9	189.3
Mar-04	100.0	10219.2	10298.5	-79.3	189.3
Apr-04	102.9	10162.2	10282.8	-120.5	189.3
May-04	101.9	10262.3	10288.2	-25.9	189.3
Jun-04	100.3	10423.3	10296.7	126.5	189.3

Regression Output:

Constant	10836.49
Std Err of Y Est	116.6980231
R Squared	0.106426552
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-5.379132478
Std Err of Coef.	2.673085894

Crystal River Unit 3



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 4

ANOHR -9.760 * NOF + 10279.05

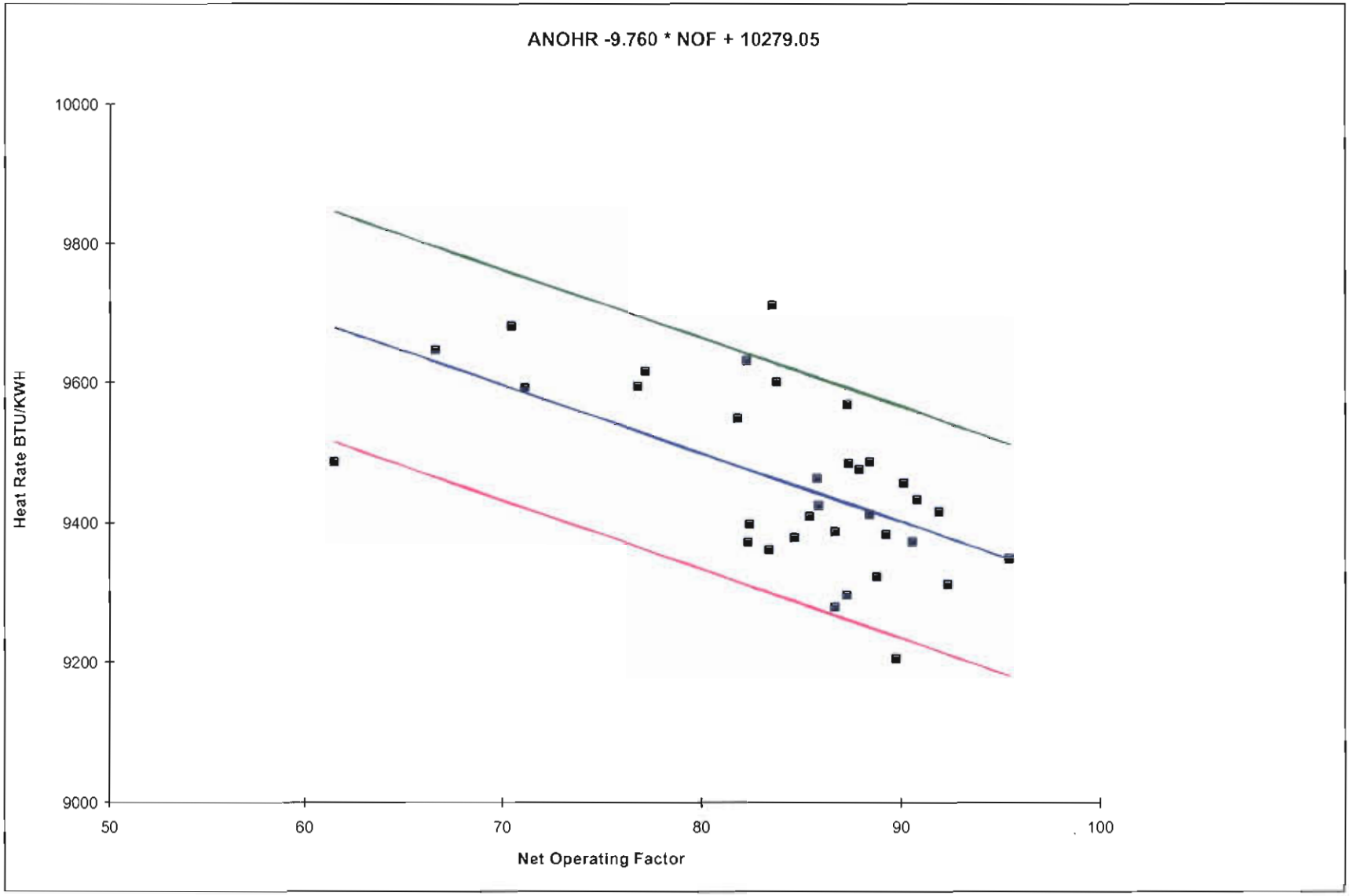
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-01	82.3	9631.0	9476.2	154.8	165.5
Aug-01	87.3	9483.0	9426.5	56.5	165.5
Sep-01	81.8	9549.0	9480.5	68.5	165.5
Oct-01	76.8	9595.0	9529.5	65.5	165.5
Nov-01	71.2	9591.0	9584.5	6.5	165.5
Dec-01	61.5	9487.0	9678.6	-191.6	165.5
Jan-02	70.5	9681.0	9591.2	89.8	165.5
Feb-02	66.6	9645.0	9629.2	15.8	165.5
Mar-02	88.4	9411.0	9415.8	-4.8	165.5
Jun-02	87.3	9296.0	9427.0	-131.0	165.5
Jul-02	88.8	9321.5	9412.0	-90.5	165.5
Aug-02	90.8	9431.4	9392.5	38.9	165.5
Sep-02	95.5	9348.2	9346.9	1.3	165.5
Oct-02	92.4	9311.5	9377.0	-65.5	165.5
Nov-02	87.9	9475.1	9421.3	53.8	165.5
Dec-02	85.4	9408.9	9445.8	-36.9	165.5
Jan-03	90.6	9371.4	9394.5	-23.2	165.5
Feb-03	83.4	9361.7	9465.2	-103.4	165.5
Mar-03	85.8	9422.5	9441.2	-18.6	165.5
Apr-03	86.7	9386.1	9432.6	-46.5	165.5
May-03	89.8	9204.6	9402.7	-198.1	165.5
Jun-03	83.6	9710.7	9463.4	247.3	165.5
Jul-03	91.9	9415.6	9381.6	34.0	165.5
Aug-03	89.3	9383.3	9407.6	-24.3	165.5
Sep-03	87.3	9567.6	9427.2	140.4	165.5
Oct-03	84.6	9377.4	9453.0	-75.5	165.5
Nov-03	82.4	9397.0	9475.0	-78.0	165.5
Dec-03	82.3	9371.0	9475.7	-104.8	165.5
Jan-04	86.7	9279.5	9432.7	-153.2	165.5
Feb-04	77.2	9615.3	9526.0	89.3	165.5
Mar-04	85.8	9462.3	9441.6	20.8	165.5
Apr-04	88.4	9485.8	9416.1	69.6	165.5
May-04	83.7	9599.6	9461.7	137.8	165.5
Jun-04	90.1	9454.9	9399.5	55.4	165.5

Regression Output:

Constant	10279.05
Std Err of Y Est	102.1262839
R Squared	0.346474115
No. of Observations	34
Degrees of Freedom	33
X Coefficient	-9.7602638
Std Err of Coef.	2.369641059

Crystal River Unit 4



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 5

ANOHR -5.000 * NOF + 9865.98

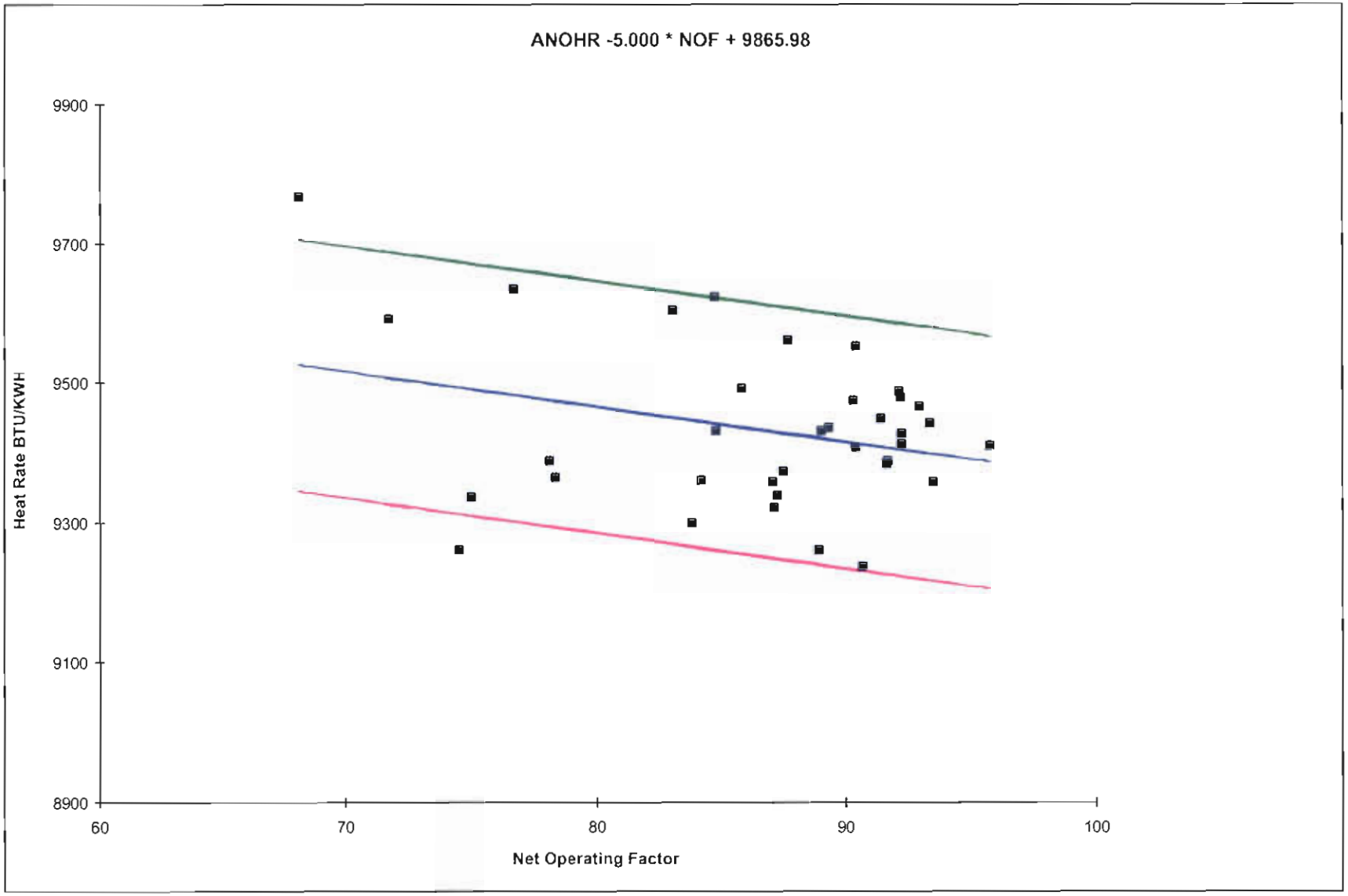
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-01	84.8	9431.0	9442.0	-11.0	180.9
Aug-01	84.2	9361.0	9444.9	-83.9	180.9
Sep-01	83.9	9299.0	9446.6	-147.6	180.9
Oct-01	90.7	9238.0	9412.4	-174.4	180.9
Nov-01	78.4	9365.0	9474.2	-109.2	180.9
Dec-01	74.5	9261.0	9493.3	-232.3	180.9
Jan-02	76.7	9635.0	9482.5	152.5	180.9
Feb-02	71.8	9591.0	9507.2	83.8	180.9
Mar-02	87.5	9374.0	9428.5	-54.5	180.9
Apr-02	92.2	9479.0	9405.1	73.9	180.9
May-02	84.8	9624.0	9442.2	181.8	180.9
Jun-02	85.8	9491.0	9437.0	54.0	180.9
Jul-02	89.3	9435.6	9419.5	16.1	180.9
Aug-02	89.1	9430.4	9420.7	9.7	180.9
Sep-02	93.4	9441.7	9399.2	42.6	180.9
Oct-02	88.9	9260.1	9421.3	-161.3	180.9
Nov-02	68.1	9766.9	9525.4	241.5	180.9
Dec-02	87.1	9358.2	9430.7	-72.5	180.9
Jan-03	91.7	9384.8	9407.7	-22.9	180.9
Feb-03	78.1	9387.7	9475.4	-87.7	180.9
Mar-03	87.2	9338.9	9429.8	-91.0	180.9
Apr-03	87.1	9321.4	9430.4	-109.1	180.9
May-03	75.0	9337.0	9490.9	-153.9	180.9
Jun-03	90.4	9552.9	9413.9	139.1	180.9
Jul-03	91.4	9448.2	9408.9	39.3	180.9
Aug-03	92.1	9487.2	9405.3	81.9	180.9
Sep-03	95.8	9410.2	9387.2	23.0	180.9
Oct-03	93.0	9465.9	9401.0	64.8	180.9
Nov-03	90.3	9473.7	9414.5	59.2	180.9
Dec-03	93.5	9358.4	9398.4	-40.0	180.9
Jan-04	92.3	9412.5	9404.7	7.7	180.9
Feb-04	87.6	9560.5	9427.8	132.7	180.9
Mar-04	91.7	9387.9	9407.6	-19.6	180.9
Apr-04	90.4	9407.4	9414.0	-6.6	180.9
May-04	83.0	9603.1	9450.8	152.3	180.9
Jun-04	92.2	9426.5	9404.8	21.7	180.9

Regression Output:

Constant	9865.98
Std Err of Y Est	111.5413707
R Squared	0.086977682
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-4.999717898
Std Err of Coef.	2.778067699

Crystal River Unit 5



PROGRESS ENERGY FLORIDA

HINES UNIT 1

ANOHR -11.268 * NOF + 8236.41

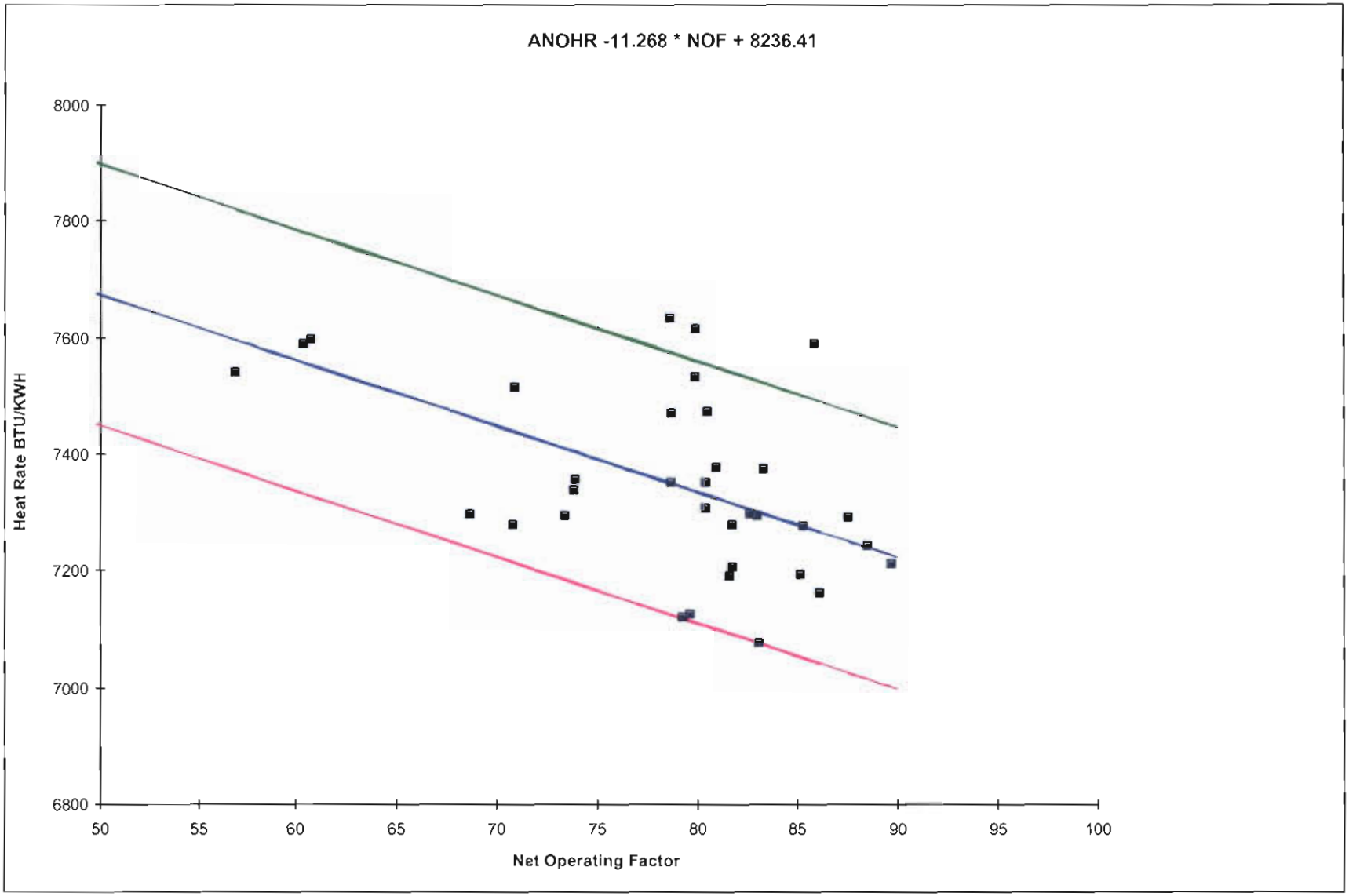
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-01	88.5	7242 0	7239.1	2.9	224.2
Aug-01	87.6	7291.0	7249.7	41.3	224.2
Sep-01	89.7	7211.0	7225.6	-14.6	224.2
Oct-01	79.7	7127.0	7338.5	-211.5	224.2
Dec-01	85.2	7192.0	7276.3	-84.3	224.2
Jan-02	68.6	7297.0	7463.0	-166.0	224.2
Feb-02	83 0	7295.0	7300.9	-5.9	224.2
Mar-02	86.2	7163.0	7265.5	-102.5	224.2
Apr-02	81.7	7206.0	7315.4	-109.4	224.2
May-02	80.4	7352.0	7330.8	21.2	224.2
Jun-02	80.5	7472.0	7329.4	142.6	224.2
Jul-02	79.9	7532 8	7336.4	196.4	224.2
Aug-02	79.9	7615.8	7336.0	279.8	224.2
Sep-02	80.4	7308.2	7330.7	-22.5	224.2
Oct-02	85.3	7275.6	7275.1	0.4	224.2
Nov-02	81.6	7189.9	7317.3	-127.3	224.2
Dec-02	70.9	7512.9	7437.7	75.2	224.2
Jan-03	78.7	7470 4	7349.4	121.0	224.2
Feb-03	73.8	7337.2	7404.6	-67.4	224.2
Mar-03	79.3	7121.6	7343.2	-221.5	224.2
Apr-03	70.8	7278 7	7439.2	-160.5	224.2
May-03	78.6	7632.5	7350.3	282.3	224.2
Jun-03	78.7	7350.3	7349.6	0.7	224.2
Jul-03	82.6	7295 6	7305.4	-9.8	224.2
Aug-03	83.3	7374.1	7298.0	76.1	224.2
Sep-03	83.1	7076.5	7300.6	-224.1	224.2
Oct-03	85.8	7589.1	7269.4	319.7	224.2
Nov-03	56.8	7538.7	7595.9	-57.2	224.2
Dec-03	80.9	7377.6	7324.4	53.1	224.2
Jan-04	60.7	7595 8	7552.3	43.5	224.2
Feb-04	73 4	7293.6	7409.2	-115.6	224.2
Mar-04	81.7	7279.0	7315.7	-36.7	224.2
Apr-04	39.8	7882.5	7788.0	94.5	224.2
May-04	60.4	7589.1	7556.1	33.1	224.2
Jun-04	73 9	7356.1	7403.2	-47.1	224.2

Regression Output:

Constant	8236.41
Std Err of Y Est	138.2535109
R Squared	0.413639262
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-11.26761551
Std Err of Coef.	2 335321155

Hines Unit 1


ANOHR -11.268 * NOF + 8236.41
Heat Rate BTU/KWH
8000
7800
7600
7400
7200
7000
6800
50
55
60
65
70
75
80
85
90
95
100
Net Operating Factor

PROGRESS ENERGY FLORIDA

TIGER BAY

ANOHR -13.843 * NOF + 9000.86

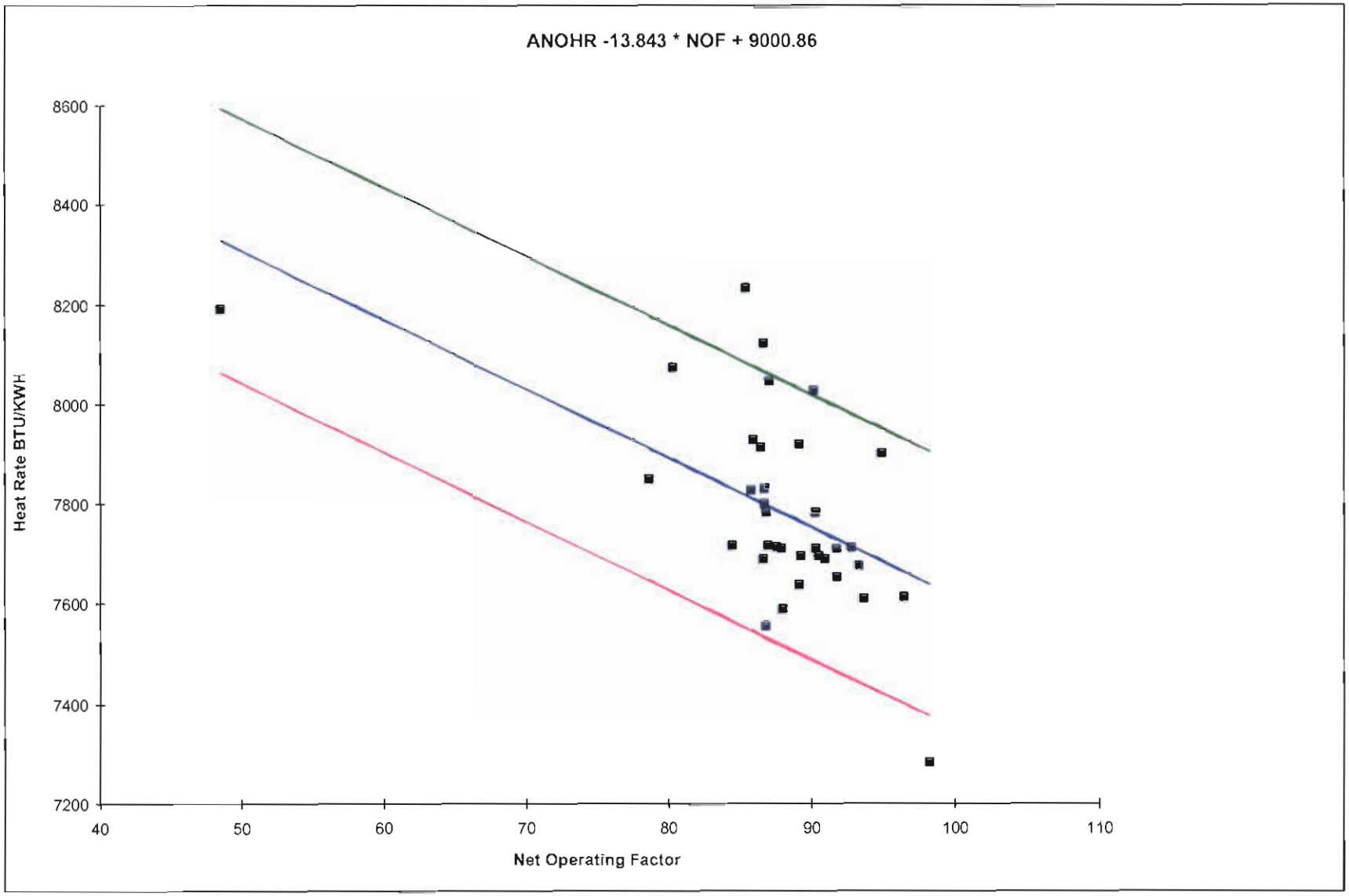
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-01	93.6	7609.0	7704.7	-95.7	264.8
Aug-01	91.7	7654 0	7731.3	-77.3	264.8
Sep-01	48.5	8189.0	8328.9	-139.9	264.8
Oct-01	96.5	7613.0	7665.5	-52.5	264.8
Nov-01	86.9	7717.0	7797.7	-80.7	264.8
Dec-01	89.2	7694.0	7765.9	-71.9	264.8
Jan-02	84.4	7716.0	7831.8	-115.8	264.8
Feb-02	78.5	7849.0	7913.5	-64.5	264.8
Mar-02	85 4	8233.0	7819.2	413.8	264.8
Apr-02	90.3	7711.0	7750.8	-39.8	264.8
May-02	88.0	7590.0	7783.3	-193.3	264.8
Jun-02	86.7	7800.0	7800.7	-0.7	264.8
Jul-02	86.9	7557.5	7798.4	-240.8	264.8
Aug-02	87.1	8045.4	7795.3	250.1	264.8
Sep-02	87.6	7714.4	7788.3	-73.9	264.8
Oct-02	85.9	7927.0	7812.4	114.6	264.8
Nov-02	90.5	7696.2	7747.7	-51.5	264.8
Dec-02	85.8	7828.2	7813.4	14.8	264.8
Jan-03	92.8	7713.0	7715.8	-2.7	264.8
Feb-03	87.9	7709.7	7783.7	-74.0	264.8
Mar-03	86.8	7782.9	7798.9	-16.0	264.8
Apr-03	86.5	7911.2	7804.1	107.1	264.8
May-03	90.9	7687.4	7743.0	-55.7	264.8
Jun-03	91.7	7710.3	7731.1	-20.8	264.8
Jul-03	86 7	8121.1	7801.1	320.0	264.8
Aug-03	98.2	7282.4	7642.0	-359.6	264.8
Sep-03	90.3	7781.3	7750.6	30.7	264.8
Oct-03	94.8	7900.5	7688.0	212.5	264.8
Nov-03	93.3	7677.6	7708.7	-31.1	264.8
Dec-03	90.2	8026.9	7752.0	274.9	264.8
Jan-04	80.2	8071.2	7890.3	180.9	264.8
Feb-04	89.1	7636.8	7767.3	-130.5	264.8
Apr-04	89 2	7918.3	7766.7	151.7	264.8
May-04	86.6	7690 3	7801.9	-111.6	264.8
Jun-04	86 8	7829.2	7799.9	29.2	264.8

Regression Output:

Constant	9000.86
Std Err of Y Est	163.3157563
R Squared	0.314878504
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-13.84295091
Std Err of Coef	3.554544851

Tiger Bay


ANOHR -13.843 * NOF + 9000.86
Heat Rate BTU/KWH
8600
8400
8200
8000
7800
7600
7400
7200
40
50
60
70
80
90
100
110
Net Operating Factor

UNPLANNED OUTAGE RATE TABLES AND GRAPHS

UNIT UNAVAILABLE OUTAGE RATE SUMMARY

Progress Energy Florida
Period of: January 2005 - December 2005

UNIT	RATE	LOW RANGE	HIGH RANGE	TARGET
Anclote 1	FOR	0.35	1.35	0.68
	MOR	0.34	1.28	0.64
	FOR&MOR	0.69	2.63	1.32
	PFOR	0.73	2.78	1.39
	PMOR	1.50	5.73	2.86
	EUOR	2.91	10.88	5.50
	EUOF	2.79	10.44	5.28
Anclote 2	FOR	0.21	0.79	0.39
	MOR	1.26	4.81	2.40
	FOR&MOR	1.47	5.59	2.80
	PFOR	0.32	1.23	0.61
	PMOR	1.14	4.33	2.16
	EUOR	2.90	10.77	5.48
	EUOF	2.72	10.09	5.13
Crystal River 1	FOR	2.03	7.74	3.87
	MOR	0.26	0.99	0.50
	FOR&MOR	2.29	8.73	4.37
	PFOR	0.62	2.36	1.18
	PMOR	1.21	4.61	2.30
	EUOR	4.07	14.96	7.66
	EUOF	4.03	14.79	7.58
Crystal River 2	FOR	2.60	9.89	4.95
	MOR	2.50	9.52	4.76
	FOR&MOR	5.09	19.41	9.70
	PFOR	1.45	5.52	2.76
	PMOR	1.51	5.76	2.88
	EUOR	7.78	26.97	14.37
	EUOF	7.74	26.82	14.29
Crystal River 3	FOR	0.30	1.15	0.57
	MOR	0.13	0.51	0.26
	FOR&MOR	0.44	1.66	0.83
	PFOR	0.09	0.33	0.17
	PMOR	0.51	1.95	0.97
	EUOR	1.03	3.89	1.96
	EUOF	0.95	3.60	1.81
Crystal River 4	FOR	1.58	6.03	3.02
	MOR	0.11	0.41	0.20
	FOR&MOR	1.69	6.44	3.22
	PFOR	0.47	1.80	0.90
	PMOR	0.47	1.80	0.90
	EUOR	2.62	9.77	4.95
	EUOF	2.47	9.21	4.67
Crystal River 5	FOR	1.08	4.10	2.05
	MOR	0.15	0.59	0.29
	FOR&MOR	1.23	4.69	2.35
	PFOR	0.39	1.50	0.75
	PMOR	0.41	1.55	0.78
	EUOR	2.02	7.55	3.82
	EUOF	1.88	7.03	3.56
Hines 1	FOR	0.21	0.80	0.40
	MOR	0.05	0.20	0.10
	FOR&MOR	0.26	1.00	0.50
	PFOR	0.28	1.06	0.53
	PMOR	1.54	5.85	2.93
	EUOR	2.07	7.84	3.94
	EUOF	1.76	6.67	3.35
Tiger Bay	FOR	0.56	2.12	1.06
	MOR	1.83	6.97	3.49
	FOR&MOR	2.39	9.09	4.55
	PFOR	0.26	1.00	0.50
	PMOR	0.03	0.10	0.05
	EUOR	2.65	9.81	5.00
	EUOF	2.55	9.44	4.81

Anclote
Unit 1

	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
PER HOURS	744.00	744 00	720.00	745.00	720.00	744 00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	744.00	720.00	691.10	720.00	373.31	245.23	130.37	744.00	719.00	743.48	720.00	744.00	743 17	720.00	745.00	200.38	744.00
RSH	0.00	0.00	0.00	53.90	0.00	281.64	494.85	541.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	0.00	0.00	89.05	3.92	0.00	0.00	0.00	0.52	0.00	0.00	0.83	0.00	0.00	519.70	0.00
POH	0 00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	512.32	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	3 92	0.00	0.00	0.00	0.00	0.00	0.00	0.83	0.00	0.00	7.38	0.00
MOH	0.00	0.00	0.00	0.00	0.00	89.05	0 00	0 00	0.00	0.00	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	63.48	787.00	0.00	30.18	0.00	0.00	62.22	2.13	0.00	13.33	5.52	0.17	45.82	34.45	4.03	107.47	48.43	0.27
LRPF	68 12	30.38	0.00	23.00	0.00	0.00	6.40	198.26	0.00	56.19	61.98	108.41	61.82	36.86	33.00	62.08	256.01	254.52
EFOH	8.68	48.01	0 00	1.39	0.00	0.00	0.80	0.85	0.00	1.50	0.69	0.04	5.69	2.55	0.27	13.40	24.90	0.14
PMOH	71.38	82.17	66.65	86.05	55.28	15.50	10.12	10.00	56.18	105.73	123.07	82.27	72.25	91.22	83.10	104.52	0.00	11.40
LRPM	168.54	139.58	149.16	149.12	139.13	140.94	147.67	153.49	159.01	151 71	158.99	158.99	158.75	158.99	158.99	158.99	0.00	159.01
EMOH	24.16	23.03	19.96	25.77	15.44	4.39	3.00	3.08	17.94	32.21	39 29	26.27	23.03	29.12	26.53	33.37	0.00	3.64
NPC	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00

MONTHLY	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	0.00	0.00	0.00	0.00	0.00	0.00	1.57	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	3.55	0.00
MOR	0.00	0.00	0.00	0.00	0.00	19.26	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	1.17	6.45	0.00	0.20	0.00	0.00	0.33	0.65	0.00	0.21	0.09	0.01	0.76	0.34	0.04	1.80	12.42	0.02
PMOR	3.25	3.10	2.77	3.73	2.14	1.18	1.22	2.36	2.41	4.48	5.28	3.65	3.10	3.92	3.68	4.48	0.00	0.49
EUOR	4.41	9.55	2.77	3.93	2.14	20.21	3.10	3.01	2.41	4.69	5.44	3.65	3.86	4.37	3.72	6.28	15.54	0.51
EUOF	4.41	9.55	2.77	3.65	2.14	12.56	1.04	0.58	2.41	4.69	5.44	3.65	3.86	4.37	3.72	6.28	4.48	0.51
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.16	0.00
EAF	95.59	90.45	97.23	96.35	97.86	87.44	98.96	99.42	97.59	95.31	94.56	96.35	96.14	95.63	96.28	93.72	24.36	99.49

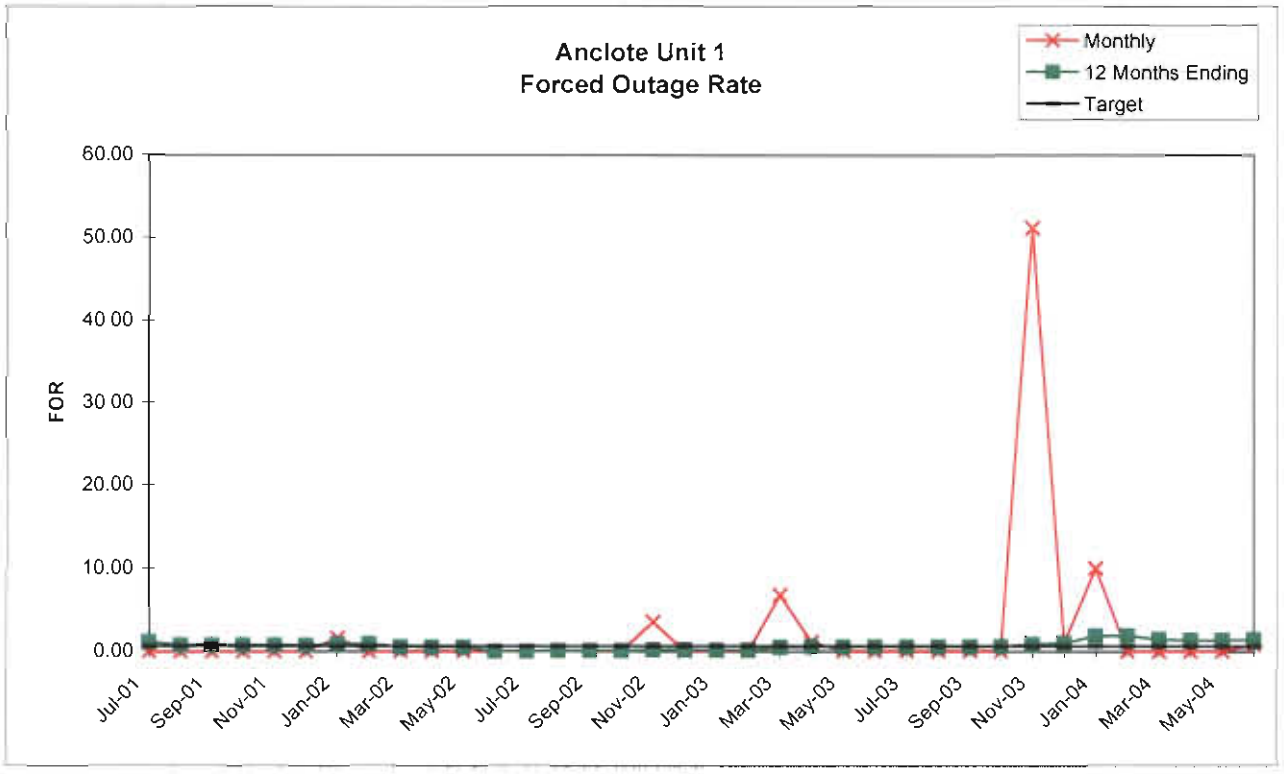
12 MONTHS	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	1.13	0.79	0.78	0.78	0.78	0.75	0.85	0.91	0.56	0.52	0.52	0.05	0.05	0.07	0.07	0.06	0.18	0.17
MOR	1.35	1.35	0.95	0.40	0.40	1.67	1.76	1.89	1.73	1.61	1.62	1.21	1.21	1.21	1.21	1.20	1.29	0.01
PFOR	1.12	1.77	1.51	1.51	1.51	1.59	1.69	1.46	1.29	1.14	1.05	0.85	0.81	0.19	0.19	0.35	0.74	0.71
PMOR	3.07	2.18	2.22	2.29	2.28	2.37	2.55	2.57	2.62	2.88	3.13	3.22	3.20	3.28	3.37	3.45	3.49	3.30
EUOR	6.53	5.98	5.39	4.92	4.92	6.25	6.72	6.69	6.10	6.05	6.22	5.28	5.22	4.70	4.79	5.02	5.64	4.17
EUOF	5.55	5.08	4.58	4.19	4.18	5.12	5.21	4.83	4.79	5.11	5.25	4.45	4.40	3.96	4.04	4.27	4.46	3.44
POF	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	5.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.85	5.85
EAF	82.41	82.88	83.39	83.78	83.78	82.85	82.76	83.13	89.48	94.89	94.75	95.55	95.60	96.04	95.96	95.73	89.69	90.72

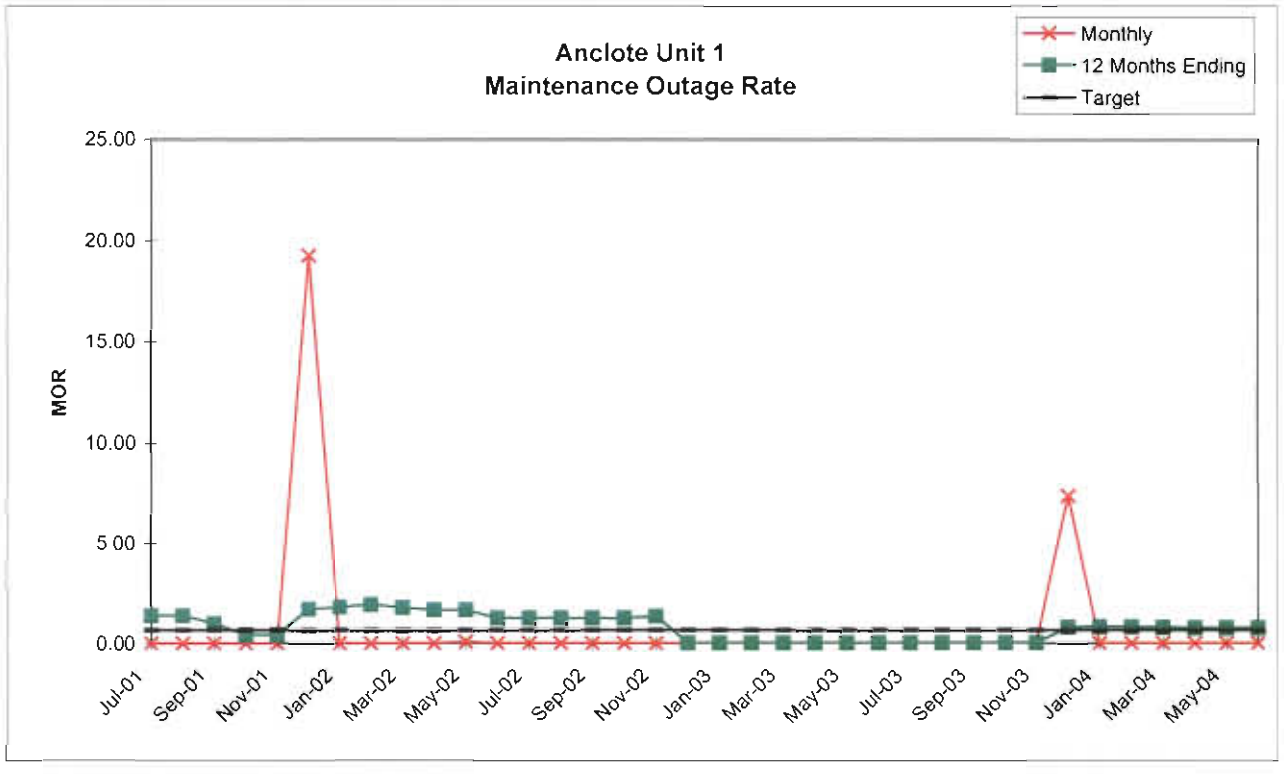
Anclote
Unit 1

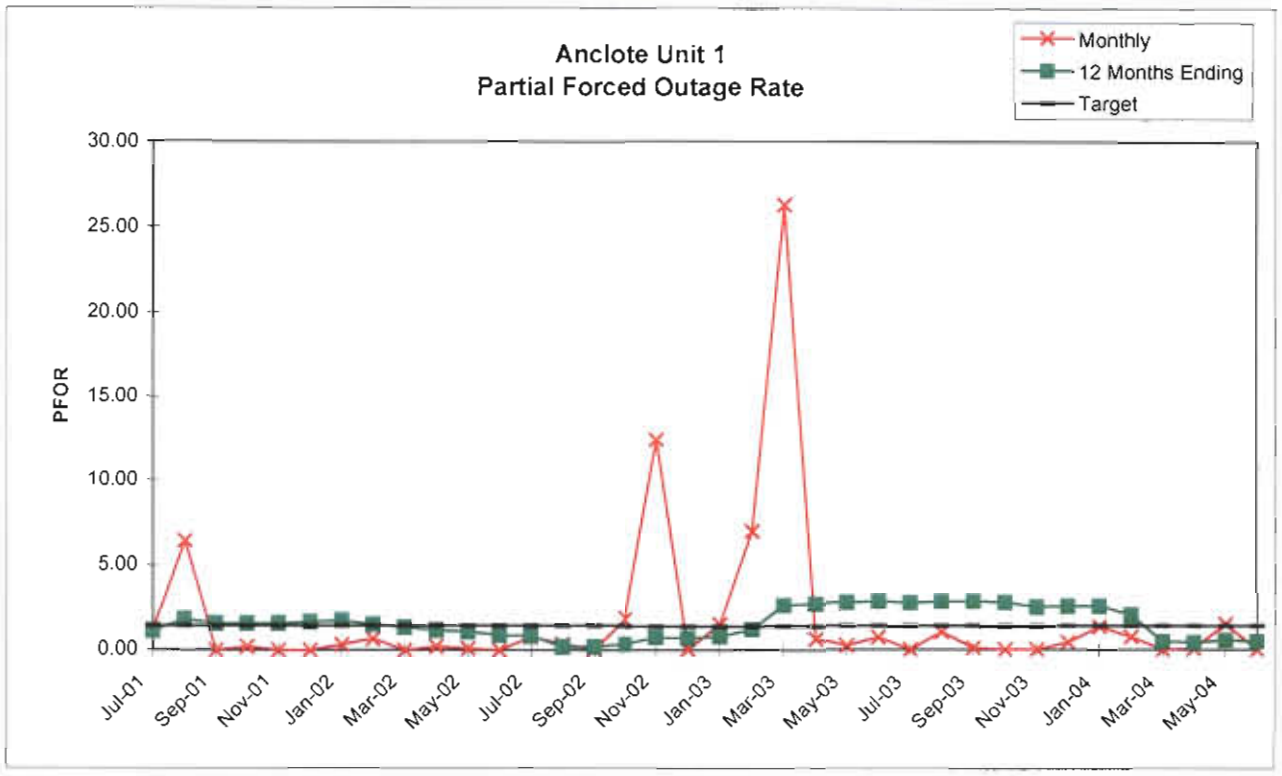
	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	696.00	744.00	719.00	744.00	720.00
SER HOURS	744.00	565.00	397.76	576.88	744.00	720.00	744.00	744.00	720.00	407.25	25.65	679.94	577.22	560.28	724.58	719.00	744.00	714.12
RSH	0.00	107.00	317.50	135.45	0.00	0 00	0.00	0.00	0.00	0.00	0.00	2.90	102.43	135.72	19.42	0.00	0.00	0.00
UH	0.00	0.00	28.73	6.67	0.00	0.00	0.00	0.00	0.00	337.75	694.35	61.16	64.35	0.00	0.00	0.00	0 00	5.88
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	337.75	667.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	28.73	6.67	0.00	0.00	0 00	0.00	0.00	0.00	26.87	7.03	64.35	0.00	0.00	0.00	0.00	5.88
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	54.13	0.00	0.00	0.00	0.00	0 00	0.00
PFOH	414 87	577.47	624.57	11.75	36.33	29.37	0.00	12.25	12.02	0.00	0.00	9.40	23.13	13.17	0.00	49.58	85.82	0.00
LRPF	13.57	33.99	83.31	159.00	24.78	88.61	0.00	308.44	25.02	0.00	0.00	157.98	164.77	158.97	0.00	4.00	64.82	0.00
EFOH	11.30	39.41	104.48	3.75	1.81	5.23	0.00	7.59	0.60	0.00	0.00	2.98	7.65	4.20	0.00	0.40	11.17	0.00
PMOH	31.32	17.87	4.33	53.80	97.82	85 05	101.08	73.77	65.97	47.07	0.00	6.38	0.00	52.43	11.15	30.68	108.93	124.02
LRPM	144.41	150.46	159.06	159.00	159.00	159.01	158.95	158.99	159.00	158.99	0.00	159.08	0.00	159.00	159.00	159.01	158.23	154.34
EMOH	9.08	5.40	1.38	17.18	31.23	27.16	32.26	23.55	21.06	15.03	0.00	2.04	0.00	16.74	3.56	9.80	34.61	38.44
NPC	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498 00

MONTHLY	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	0.00	0.00	6.74	1.14	0.00	0.00	0.00	0.00	0.00	0.00	51.16	1.02	10.03	0.00	0.00	0.00	0.00	0.82
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.37	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	1.52	6.97	26.27	0.65	0.24	0.73	0.00	1.02	0.08	0.00	0.00	0.44	1.33	0.75	0.00	0.06	1.50	0.00
PMOR	1.22	0.96	0.35	2.98	4.20	3.77	4.34	3.17	2.93	3.69	0.00	0.30	0.00	2.99	0.49	1.36	4.65	5.38
EUOR	2.74	7.93	31.56	4.73	4.44	4.50	4.34	4.19	3.01	3.69	51.16	8.93	11.22	3.74	0.49	1.42	6.15	6.15
EUOF	2.74	6.67	18.09	3.84	4.44	4.50	4.34	4.19	3.01	2.02	3.73	8.90	9.68	3.01	0.48	1.42	6.15	6.15
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	45.34	92.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	97.26	93.33	81.91	96.16	95.56	95.50	95.66	95.81	96.99	52.65	3.56	91.10	90.32	96.99	99.52	98.58	93.85	93.85

12 MONTHS	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	0.11	0.10	0.47	0.57	0.57	0.57	0.57	0.56	0.56	0.58	0.87	0.97	1.90	1.90	1.43	1.32	1.32	1.40
MOR	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.76	0.78	0.78	0.74	0.73	0.73	0.73
PFOR	0.80	1.23	2.62	2.70	2.72	2.79	2.71	2.78	2.78	2.73	2.44	2.51	2.51	2.01	0.47	0.41	0.54	0.47
PMOR	3.16	3.02	2.95	2.80	2.70	2.71	2.83	2.76	2.69	2.56	2.62	2.62	2.55	2.72	2.63	2.48	2.52	2.68
EUOR	4.07	4.35	6.02	6.05	5.95	6.03	6.08	6.06	5.99	5.84	5.89	6.76	7.58	7.25	5.18	4.86	5.03	5.19
EUOF	3.58	4.05	5.38	5.31	5.22	5.29	5.33	5.32	5.26	4.90	4.84	5.55	6.14	5.85	4.36	4.16	4.30	4.44
POF	5.85	5.85	5.85	5.85	5.85	5.85	5.85	5.85	5.85	9.70	11.48	11.48	11.48	11.44	11.44	11.44	11.44	11.44
EAF	90.57	90.10	88.77	88.84	88.93	88.86	88.82	88.83	88.89	85.40	83.69	82.98	82.39	82.71	84.20	84.40	84.25	84.12


Anclote Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Anclote Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Anclote Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
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Nov-02
Jan-03
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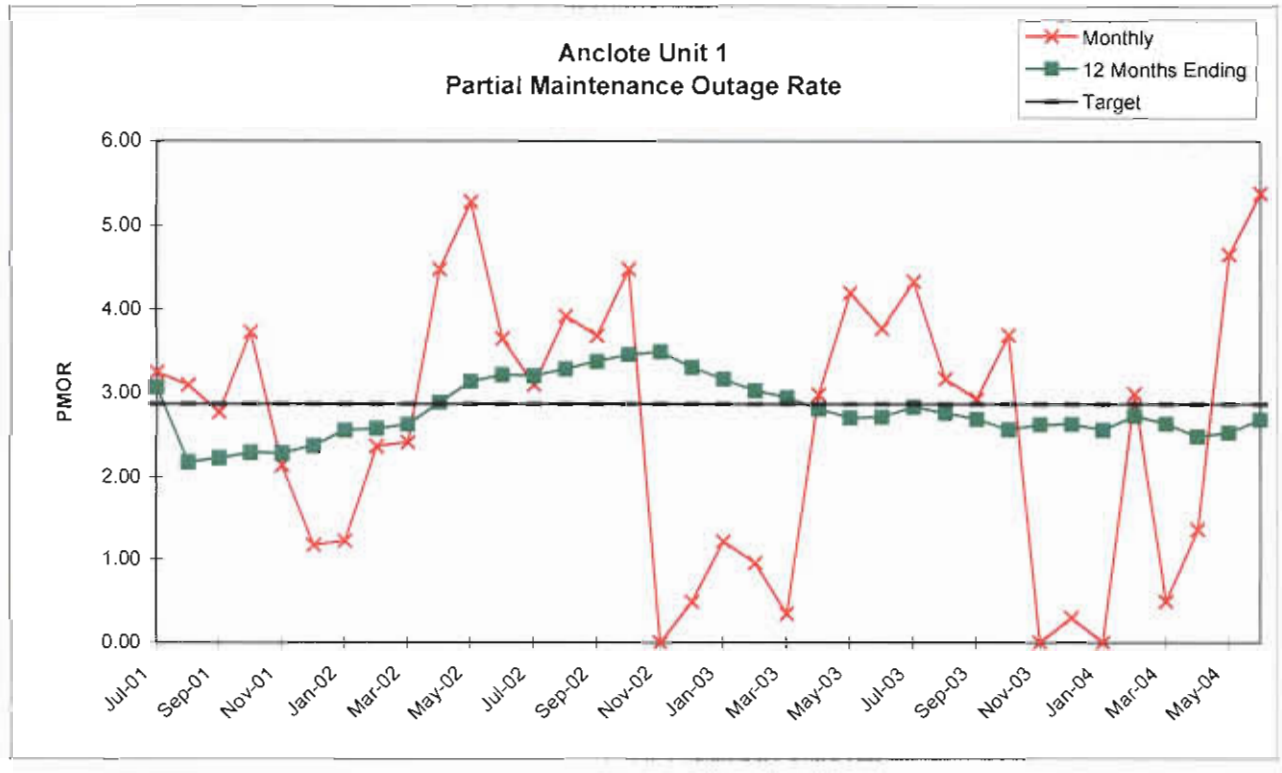
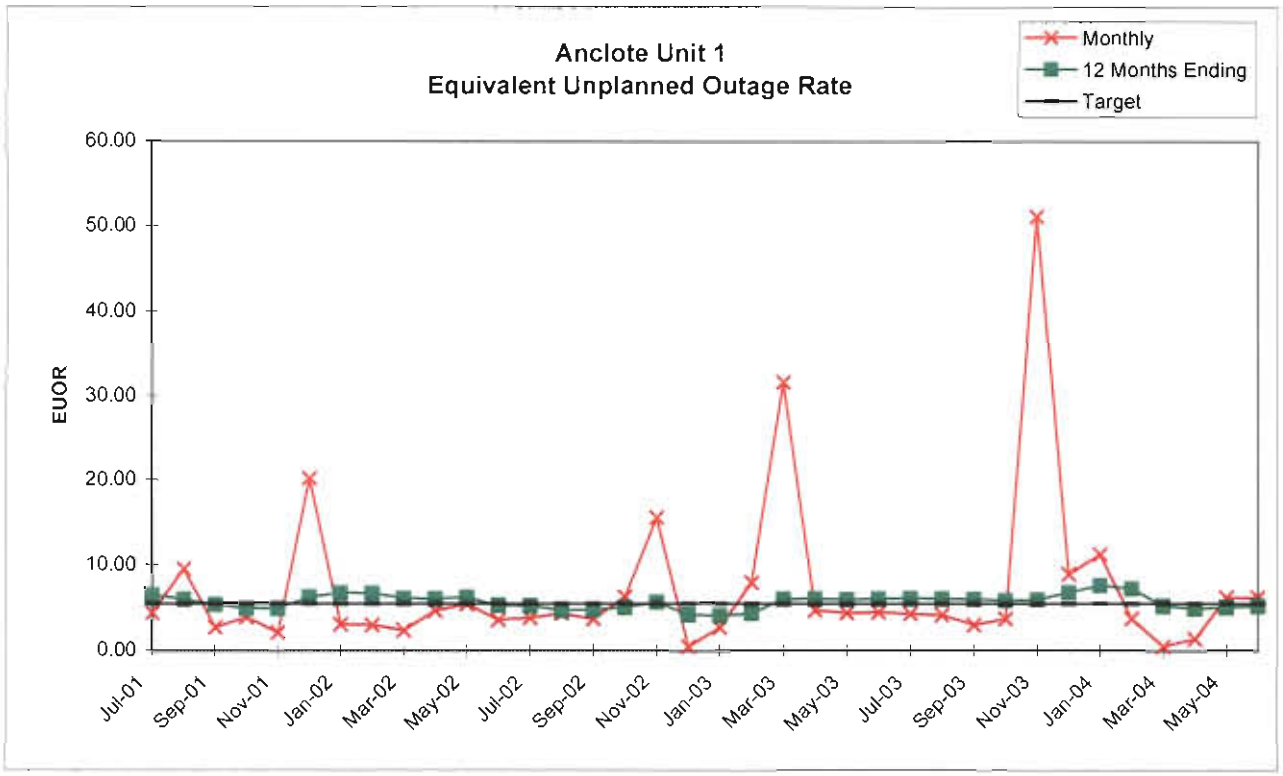
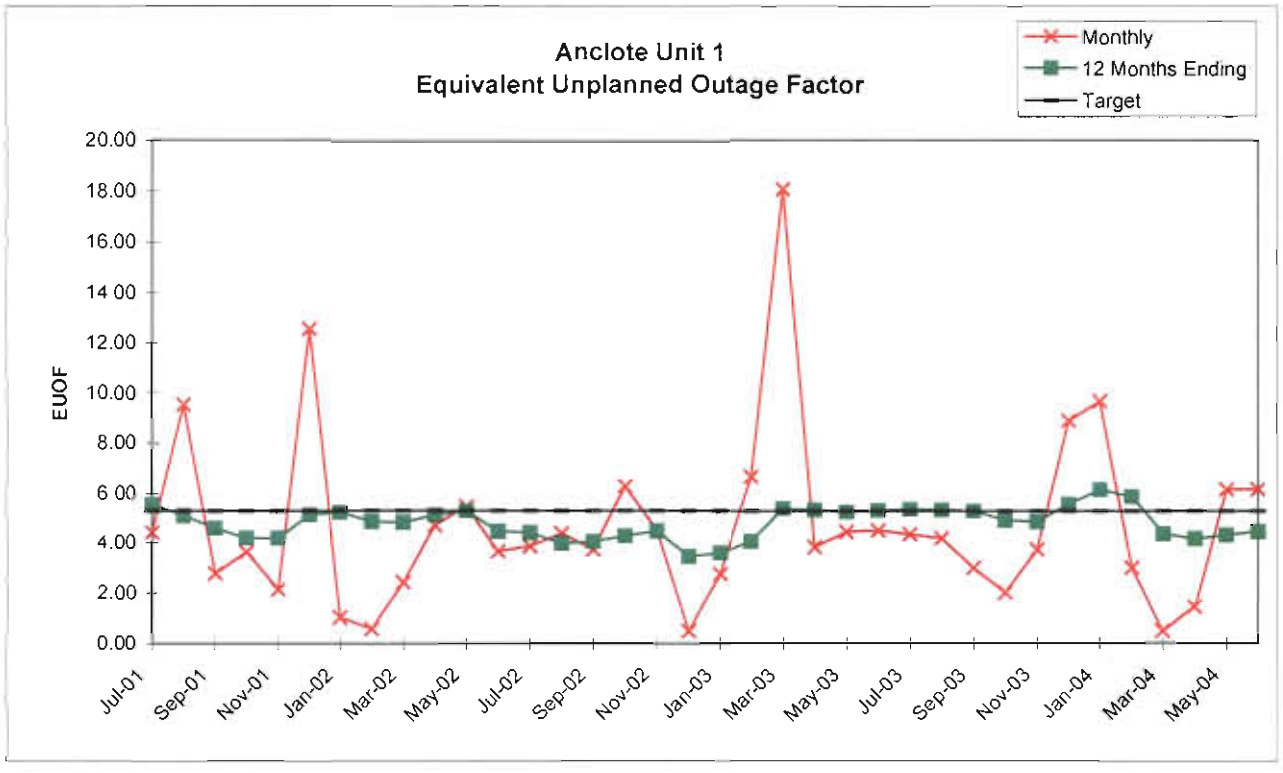
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Anclote Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Anclote Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Anclote Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04

Anclote
Unit 2

	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
PER HOURS	744.00	744.00	720.00	745 00	720.00	744.00	744.00	672.00	744.00	719 00	744.00	720.00	744.00	744.00	720.00	745 00	720.00	744.00
SER HOURS	744.00	740.30	720.00	745 00	358.30	669.22	698.47	672.00	501.38	719.00	744.00	720.00	744.00	744.00	720.00	745 00	720.00	520.10
RSH	0 00	0.00	0.00	0.00	39.18	74.78	45.53	0.00	192.39	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	223.90
UH	0.00	3.70	0.00	0.00	322.52	0.00	0.00	0.00	50.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00
FOH	0.00	3 70	0.00	0.00	11.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	311.12	0.00	0.00	0.00	50.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.50	8.63	0.00	0.00	0.00	0.00	0.43	0.00	4.00	0.67	9.48	0.00	9.25	7.58	0.00	0.00	0.00	2.67
LRPF	118.27	18.94	0 00	0.00	0.00	0.00	484.65	0 00	229.06	251.94	71.74	0.00	91.46	285.11	0.00	0.00	0.00	251.76
EFOH	0.12	0.33	0.00	0.00	0.00	0.00	0.42	0.00	1.85	0.34	1.37	0.00	1.71	4.37	0.00	0 00	0.00	1.36
PMOH	43.60	47.70	48.40	39.95	19.12	40.30	25.12	10.50	39.23	54.75	133.48	85.62	44 17	55.85	53.48	65.85	11.68	25.73
LRPM	165.64	161.07	145.55	145.57	137.22	135.02	144.97	207.76	156.02	156 00	156.01	156.00	155.52	155.82	156.02	156.01	185.37	167.39
EMOH	14.59	15 52	14.23	11.75	5 30	10.99	7.36	4.41	12.37	17.26	42.07	26.98	13.88	17.58	16.86	20.75	4.37	8.70
NPC	495.00	495.00	495 00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00

MONTHLY	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	0.00	0.50	0.00	0.00	3.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	46.48	0.00	0.00	0.00	9.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.02	0.04	0.00	0.00	0.00	0.00	0.06	0.00	0.37	0.05	0.18	0.00	0.23	0.59	0.00	0.00	0.00	0.26
PMOR	1.96	2.10	1.98	1.58	1.48	1.64	1.05	0.66	2.47	2.40	5.65	3.75	1.87	2.36	2.34	2.79	0.61	1.67
EUOR	1.98	2.63	1.98	1.58	48.15	1.64	1.11	0.66	11.68	2.45	5.84	3.75	2.09	2.95	2.34	2.79	0.61	1.93
EUOF	1.98	2.63	1.98	1.58	45.53	1.48	1.05	0.66	8.66	2.45	5.84	3.75	2.09	2.95	2.34	2.79	0.61	1.35
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	98.02	97.37	98.02	98.42	54.47	98.52	98.95	99.34	91.34	97.55	94.16	96.25	97.91	97.05	97.66	97.21	99.39	98.65

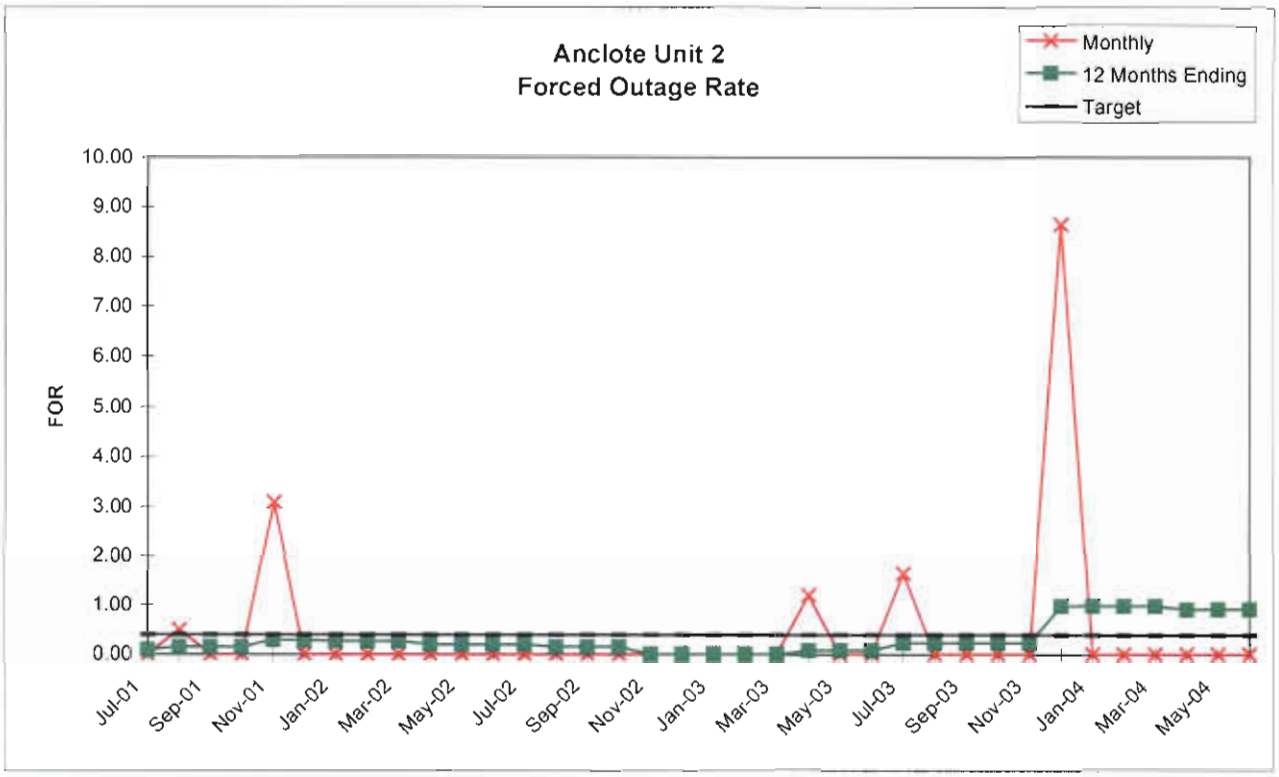
12 MONTHS	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	0.08	0.14	0.14	0.13	0.28	0.27	0.27	0.25	0.26	0.19	0.19	0.19	0.19	0.14	0.14	0.14	0.00	0.00
MOR	3.55	3.55	3.55	2.55	6.29	6.09	5.98	5.47	5.03	5.03	5.03	4.31	4.31	4.30	4.30	4.30	0.59	0.61
PFOR	0.18	0.15	0.14	0.13	0.13	0.12	0.12	0.12	0.14	0.14	0.06	0.06	0.08	0.13	0.13	0.13	0.12	0.14
PMOR	1.35	1.39	1.40	1.42	1.42	1.52	1.59	1.58	1.69	1.78	2.10	2.28	2.27	2.29	2.32	2.44	2.32	2.33
EUOR	5.10	5.17	5.17	4.19	7.99	7.87	7.82	7.29	7.00	7.03	7.25	6.70	6.71	6.74	6.77	6.88	3.02	3.06
EUOF	4.01	4.07	4.06	3.45	7.19	7.31	7.40	7.16	6.72	6.75	6.96	6.43	6.45	6.47	6.50	6.61	2.91	2.90
POF	12.58	12.58	12.58	10.79	2.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	83.40	83.35	83.35	85.76	90.24	92.69	92.60	92.84	93.28	93.25	93.04	93.57	93.55	93.53	93.50	93.39	97.09	97.10

Anclote
Unit 2

	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
PER HOURS	744.00	672 00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	696.00	744.00	719.00	744.00	720.00
SER HOURS	744.00	672.00	744.00	493.73	718.00	720.00	731.82	744.00	720.00	745.00	720.00	679.73	663.05	696.00	744.00	502.95	658 40	720.00
RSH	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	80.95	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	225.27	26.00	0.00	12.18	0.00	0.00	0.00	0.00	64 27	0.00	0.00	0.00	216.05	85.60	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	216.05	85.60	0.00
FOH	0.00	0.00	0.00	5 97	0.00	0.00	12.18	0.00	0.00	0.00	0.00	64.27	0.00	0.00	0.00	0.00	0.00	0 00
MOH	0.00	0.00	0.00	219.30	26.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	7.87	1.58	0.00	6.87	6.53	1.58	173.10	2.33	715.00	0.00	108.07	35.07	0.00	1.67	3.98	9.38	40.85	4.28
LRPF	135.35	156.34	0.00	11.96	77.77	204.27	81.88	33.99	37.98	0.00	68.06	86.99	0.00	15.12	156.09	305.87	255.06	270.17
EFOH	2.15	0.50	0.00	0.17	1.03	0.65	28.63	0.16	54.86	0.00	14 86	6.16	0.00	0.05	1.26	5.80	21.05	2.34
PMOH	33.10	33.83	35.48	53.60	34 15	41.97	66.37	64.32	57.57	40.95	62.67	10.28	30 93	49.17	66.70	34.70	65.75	113 80
LRPM	151.43	156.02	156.02	148.75	155.99	155.99	119.32	155.98	108.66	155.98	136.31	155.05	155.99	155.99	156.01	155.99	156.01	156.00
EMOH	10.13	10.66	11.18	16.11	10.76	13.23	16.00	20.27	12.64	12.90	17.26	3.22	9.75	15.50	21.02	10.94	20.72	35.86
NPC	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495 00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00

MONTHLY	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	0.00	0.00	0.00	1.19	0.00	0.00	1.64	0.00	0.00	0.00	0.00	8.64	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	30.76	3.49	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.29	0.07	0.00	0.03	0.14	0.09	3.91	0.02	7.62	0.00	2.06	0.91	0.00	0.01	0.17	1.15	3.20	0.32
PMOR	1.36	1.59	1.50	3.26	1.50	1.84	2.19	2.72	1.76	1.73	2.40	0.47	1.47	2.23	2.83	2.17	3.15	4.98
EUOR	1.65	1.66	1.50	33.59	5.08	1.93	7.64	2.75	9.37	1.73	4.46	9.90	1.47	2.23	2.99	3.33	6.34	5.31
EUOF	1.65	1.66	1.50	33.59	5.08	1.93	7.64	2.75	9.37	1.73	4.46	9.90	1.31	2.23	2.99	2.33	5.61	5.31
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.05	11.51	0.00
EAF	98.35	98.34	98.50	66.41	94.92	98.07	92.36	97.25	90.63	98.27	95.54	90.10	98.69	97.77	97.01	67.62	82.88	94.69

12 MONTHS	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	0.00	0.00	0.00	0.07	0.07	0.07	0.22	0.22	0.22	0.22	0.22	0.97	0.98	0.97	0.97	0.90	0.91	0.91
MOR	0.60	0.60	0.00	2.57	2.88	2.88	2.88	2.88	2.88	2.88	2.88	2.83	2.85	2.85	2.85	0.31	0.00	0.00
PFOR	0.16	0.16	0.14	0.14	0.14	0.14	0.47	0.42	1.08	1.08	1.26	1.29	1.28	1.27	1.29	1.35	1.60	1.62
PMOR	2.36	2.43	2.35	2.40	2.03	1.86	1.89	1.92	1.87	1.78	1.93	1.83	1.84	1.90	2.01	1.95	2.08	2.36
EUOR	3.10	3.18	2.49	5.11	5.04	4.89	5.37	5.36	5.95	5.86	6.18	6.75	6.78	6.81	6.94	4.47	4.56	4.85
EUOF	2.95	3.03	2.42	4.98	4.91	4.76	5.24	5.22	5.80	5.71	6.02	6.75	6.72	6.75	6.88	4.32	4.36	4.64
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.46	3.43	3.43
EAF	97.05	96.97	97.58	95.02	95.09	95.24	94.76	94.78	94.20	94.29	93.98	93.25	93.28	93.25	93.12	93.22	92.20	91.92


Anclote Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
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Sep-03
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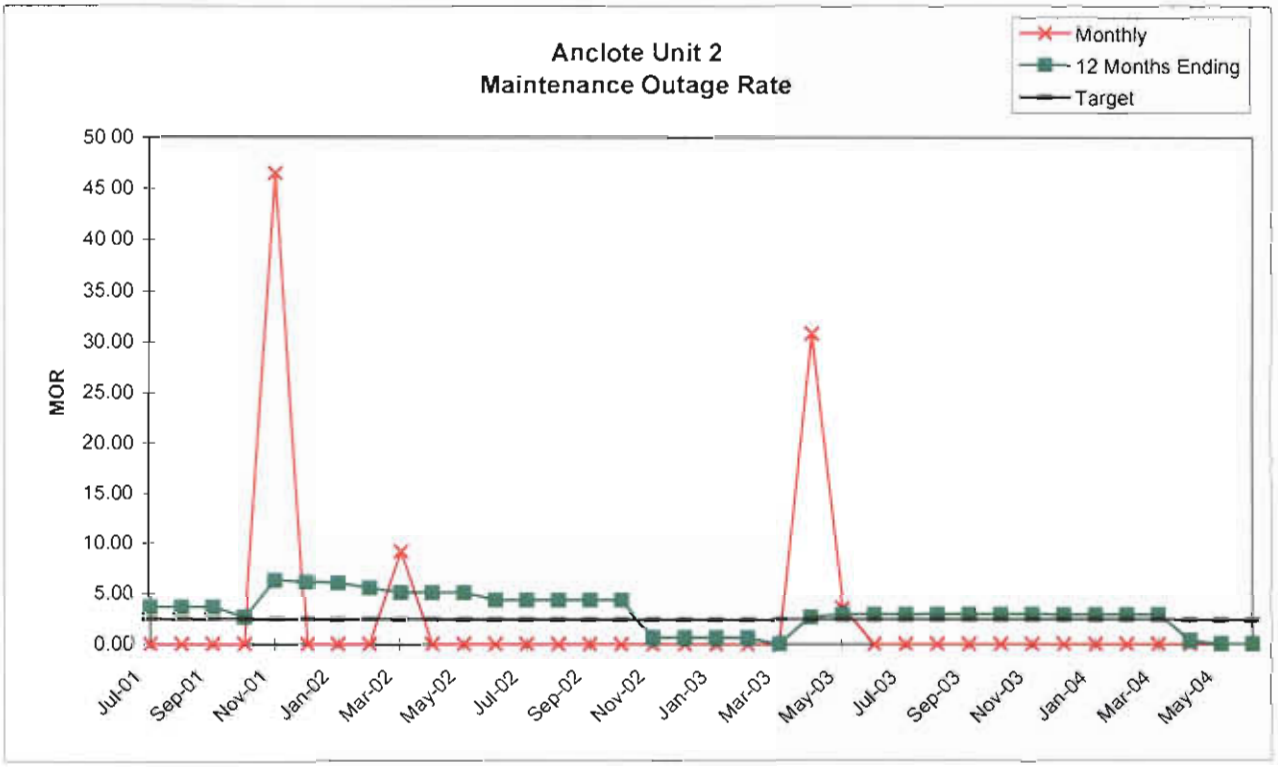
Jan-04
Mar-04
May-04


Anclote Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
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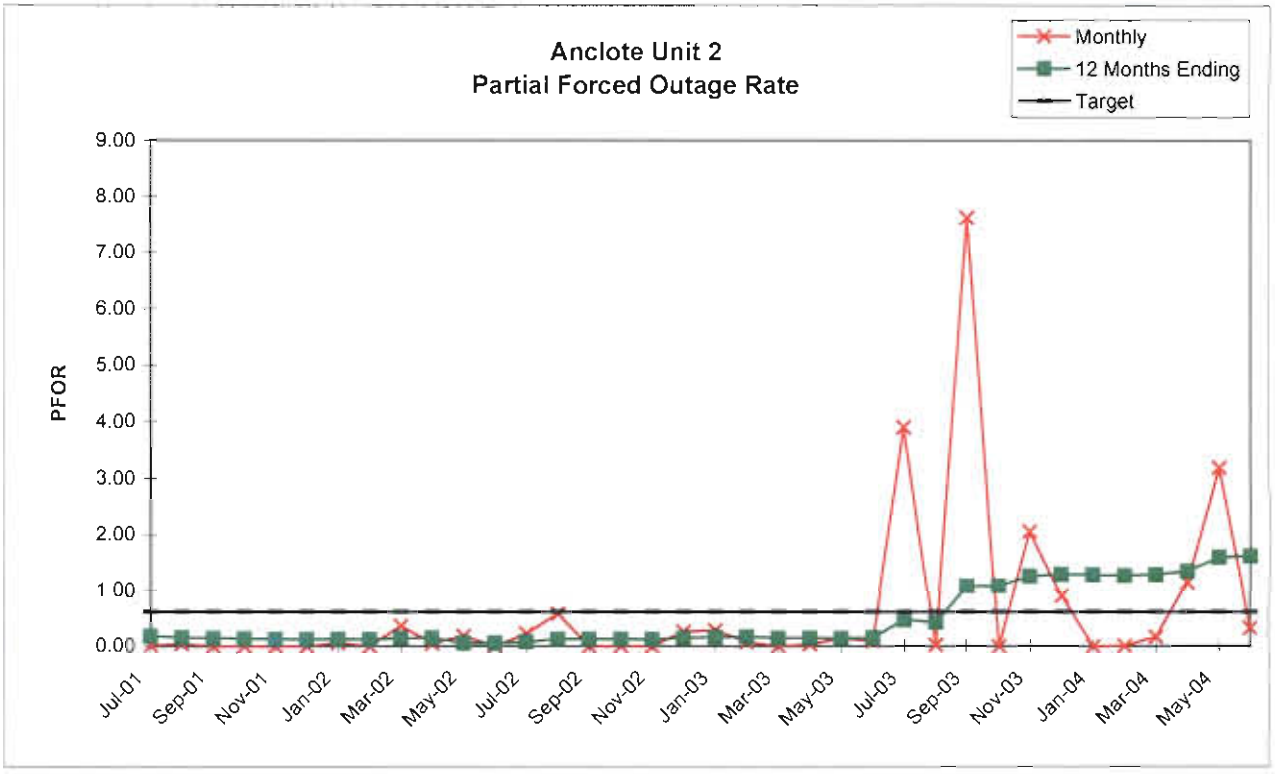
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Anclote Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1 00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
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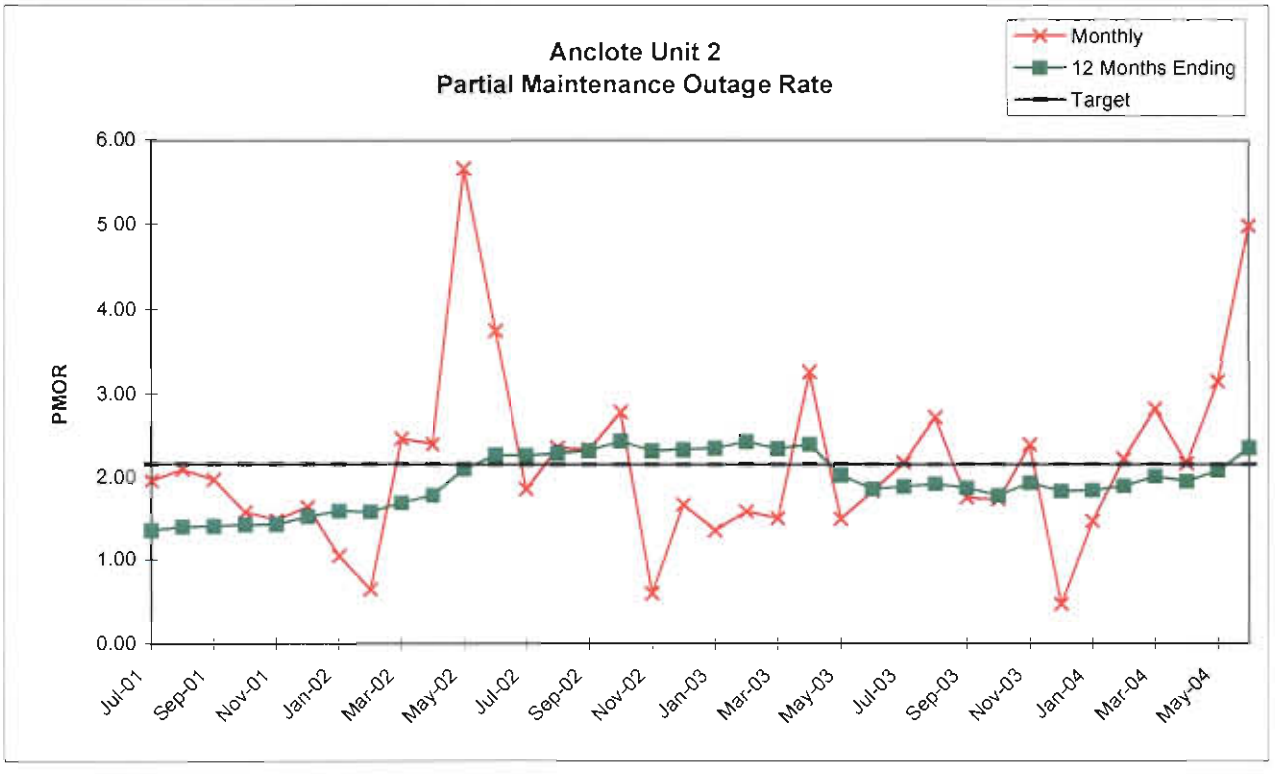
Anclote Unit 2
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
6.00
5 00
4.00
3.00
2.00
1.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
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May-03
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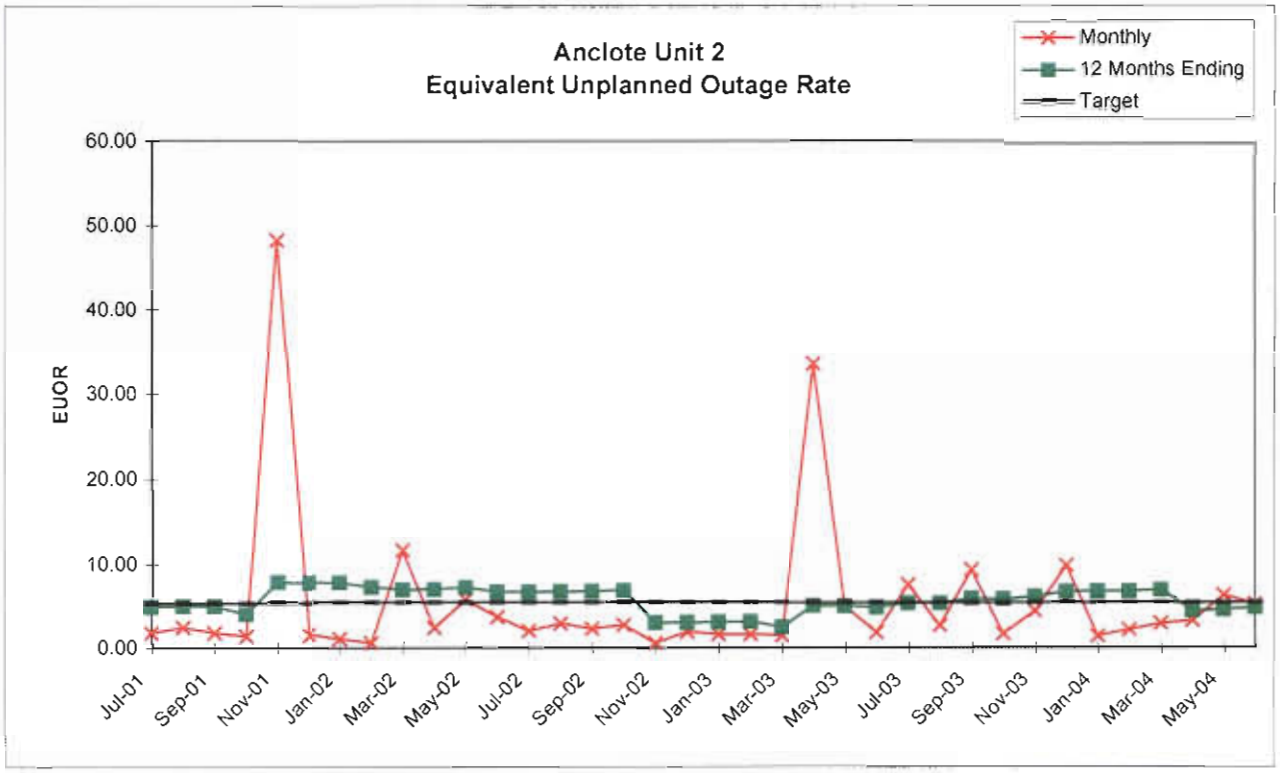
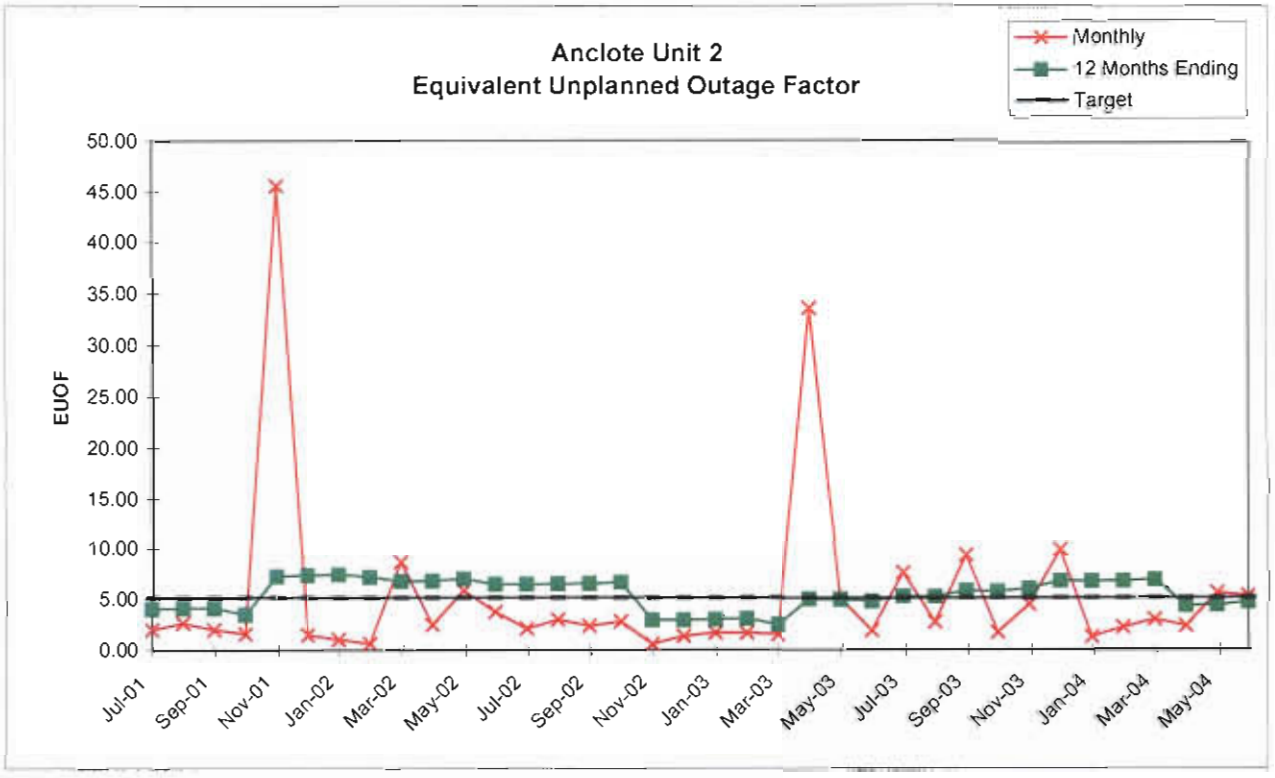
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Anclote Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Anclote Unit 2
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04

Crystal River
Unit 1

	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744 00	720 00	745.00	720.00	744.00
SER HOURS	698.98	744.00	720.00	740.00	263.87	368 37	744.00	672.00	691.10	719.00	744.00	497.95	668.98	744.00	628.50	745.00	720.00	744 00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	45.02	0.00	0.00	5.00	456.13	375.63	0.00	0.00	52.90	0.00	0.00	222.05	75.02	0.00	91.50	0.00	0.00	0.00
POH	0.00	0.00	0 00	0 00	456.13	365.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	45.02	0.00	0.00	5.00	0.00	10.15	0.00	0.00	0.00	0.00	0.00	222.05	75.02	0.00	91.50	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	52.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	35 05	127.22	55.10	87.47	0 00	258.55	13.95	0.00	8 25	3.77	36.02	1.50	53.60	54.32	26.63	0.92	23.80	0.00
LRPF	113.06	182.12	106.86	49.41	0.00	3.79	168.99	0.00	58.99	77.91	159.78	75.04	42.42	118.42	231.53	55.62	119.37	0.00
EFOH	10.46	61.13	15.54	11.40	0.00	2.59	6.22	0.00	1.28	0.78	15.19	0.30	6.00	16.97	16.27	0 14	7.50	0.00
PMOH	0.00	33.02	32.73	32.20	0.00	0.00	0.00	6.67	0.00	87.88	0.00	39.23	36.17	24.68	23.37	39.13	11.00	111.94
LRPM	0.00	198.11	100.53	109.08	0.00	0.00	0.00	21.99	0.00	44.25	0.00	112.90	100.49	174.72	166.01	121.27	222.68	121.76
EMOH	0.00	17.26	8.68	9.27	0.00	0.00	0.00	0.39	0.00	10.26	0.00	11 69	9.59	11.38	10.24	12.52	6.46	35.96
NPC	379.00	379 00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00

MONTHLY	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	6.05	0.00	0.00	0.67	0.00	2.68	0.00	0.00	0.00	0.00	0.00	30.84	10.08	0.00	12.71	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	1.50	8.22	2.16	1.54	0.00	0.70	0.84	0.00	0.19	0.11	2.04	0.06	0.90	2.28	2.59	0.02	1.04	0.00
PMOR	0.00	2.32	1.21	1.25	0.00	0.00	0.00	0.06	0.00	1.43	0.00	2.35	1.43	1.53	1.63	1.68	0.90	4.83
EUOR	7.46	10.54	3.36	3.45	0.00	3.36	0.84	0.06	7.28	1.53	2.04	32.50	12.18	3.81	16.39	1.70	1.94	4.83
EUOF	7.46	10.54	3.36	3.45	0.00	1.71	0.84	0.06	7.28	1.53	2.04	32.50	12.18	3.81	16.39	1.70	1.94	4.83
POF	0.00	0.00	0.00	0.00	63.35	49.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	92.54	89.46	96.64	96.55	36.65	49.16	99.16	99.94	92.72	98.47	97.96	67.50	87.82	96.19	83.61	98.30	98.06	95.17

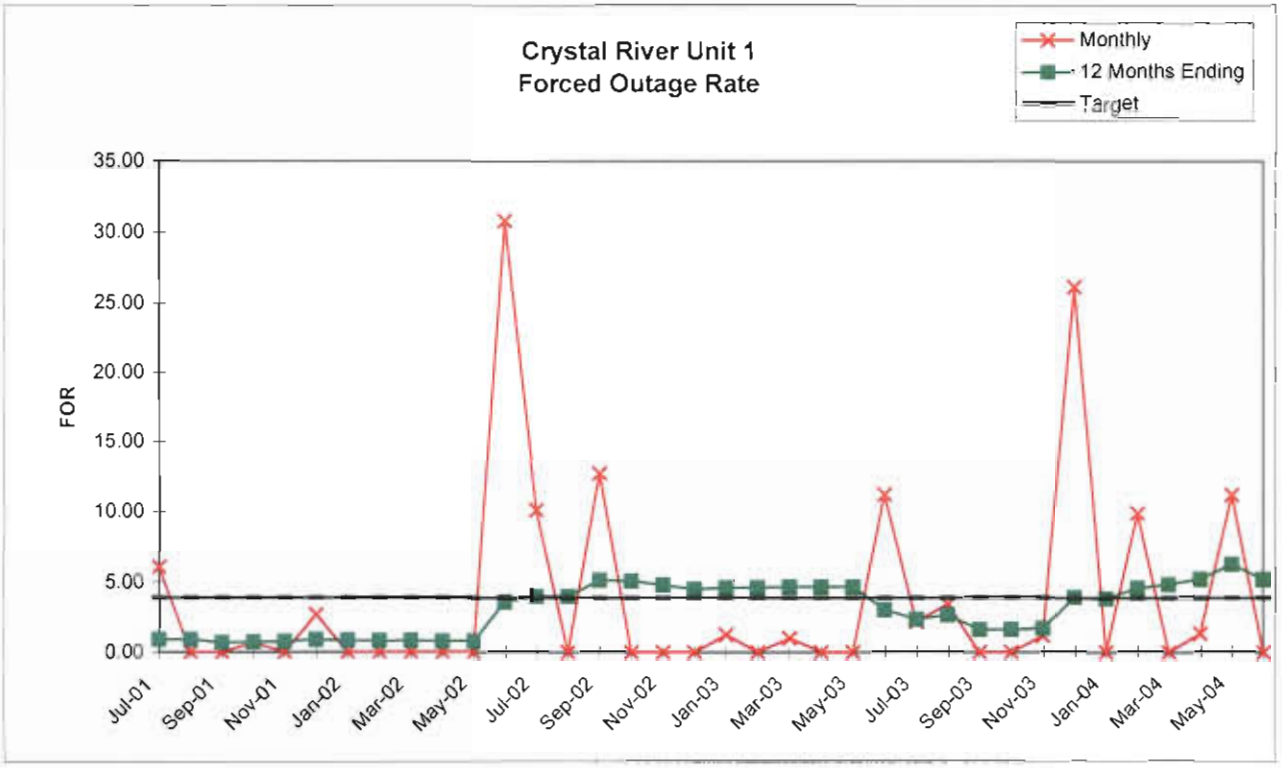
12 MONTHS	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	0.92	0.92	0.67	0.72	0.76	0.89	0.84	0.82	0.82	0.76	0.76	3.58	3.96	3.96	5.12	5.06	4.78	4.46
MOR	7.06	7.06	6.20	5.38	5.68	4.39	3.12	0.00	0.68	0.67	0.67	0.69	0.69	0.69	0.70	0.70	0.66	0.63
PFOR	1.04	1.74	1.91	2.02	2.13	2.22	1.76	1.67	1.55	1.54	1.71	1.64	1.59	1.01	1.03	0.88	0.92	0.85
PMOR	2.00	1.97	1.78	1.66	1.62	1.63	1.56	1.49	1.23	1.15	0.89	0.76	0.89	0.81	0.84	0.88	0.91	1.30
EUOR	10.65	11.27	10.23	9.48	9.87	8.84	7.11	3.95	4.23	4.07	3.99	6.52	6.96	6.33	7.51	7.35	7.12	7.08
EUOF	10.60	11.22	10.18	9.43	9.32	7.97	6.41	3.56	3.81	3.69	3.61	5.91	6.31	5.74	6.81	6.66	6.82	7.08
POF	0.00	0.00	0.00	0.00	5.21	9.38	9.38	9.38	9.38	9.38	9.38	9.38	9.38	9.38	9.38	9.38	4.17	0.00
EAF	89.40	88.78	89.82	90.57	85.48	82.65	84.21	87.06	86.81	86.93	87.01	84.71	84.31	84.88	83.81	83.96	89.01	92.92

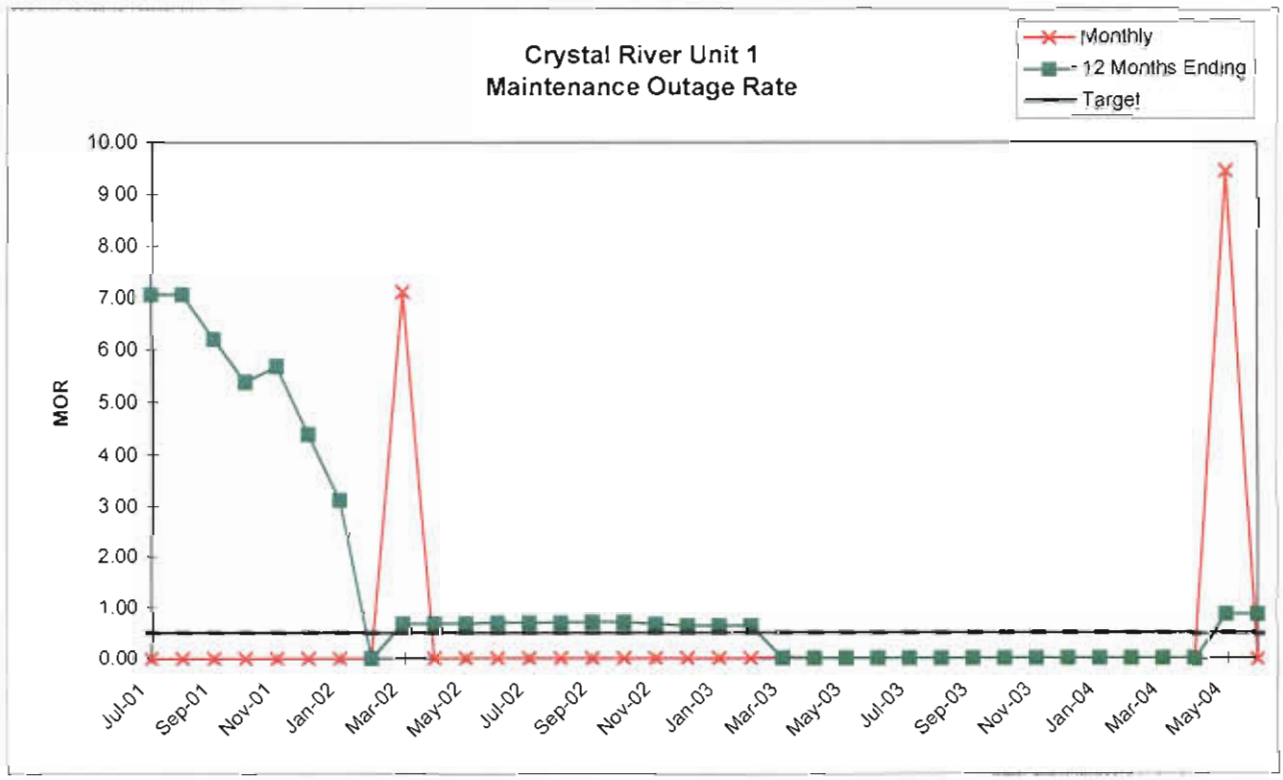
Crystal River
Unit 1

	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	696.00	744.00	719.00	744.00	720.00
SER HOURS	734.70	672.00	736.38	719.00	744 00	639.48	727.88	718.65	720.00	745.00	711.73	549 43	744.00	627.35	119.38	210.10	604.67	720.00
RSH	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	9.30	0.00	7.62	0.00	0.00	80.52	16.12	25.35	0 00	0.00	8.27	194.57	0.00	68 65	624.62	508.90	139 33	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	624.62	506.05	0.00	0.00
FOH	9.30	0.00	7.45	0.00	0.00	80.52	16.12	25.35	0.00	0.00	8.27	194.57	0.00	68.65	0.00	2.85	76.08	0.00
MOH	0.00	0.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	63.25	0.00
PFOH	0.23	19.47	6.75	13 52	33.55	51.70	39.78	31.93	28.40	9.82	34.40	21.85	4.93	0.80	0.00	0.00	0.00	10.52
LRPF	75 78	188.97	79.90	74.99	74.53	252.31	79.67	61.60	189.01	17.98	97.59	100.33	66.04	74.85	0.00	0.00	0.00	155.78
EFOH	0 05	9.71	1.42	2.68	6.60	34.42	8.36	5.19	14.16	0.47	8.86	5.78	0 86	0.16	0.00	0.00	0.00	4.32
PMOH	47 48	48.07	195.97	64.02	65.32	158.57	116.55	88.22	40.18	114 52	58 10	21.60	65.23	17 58	0.00	0.00	18.70	164.63
LRPM	75.72	99.45	136 06	129.10	117.12	104.18	114.03	158.06	114.37	129.09	87.16	147.56	93.79	152.42	0.00	0.00	188.99	87.37
EMOH	9.49	12.61	70.36	21.81	20.19	43.59	35.07	36.79	12.13	39.01	13.36	8.41	16.14	7.07	0.00	0.00	9.33	37.95
NPC	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379 00	379 00	379.00	379.00	379.00	379.00	379.00	379.00	379.00

MONTHLY	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	1.25	0.00	1.00	0.00	0.00	11.18	2.17	3.41	0.00	0.00	1.15	26.15	0.00	9.86	0.00	1.34	11.18	0.00
MOR	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.47	0.00
PFOR	0.01	1.44	0.19	0.37	0.89	5.38	1.15	0.72	1.97	0.06	1.24	1.05	0.12	0.03	0.00	0.00	0.00	0.60
PMOR	1.29	1.88	9.55	3.03	2.71	6.82	4.82	5.12	1.68	5.24	1.88	1.53	2.17	1.13	0.00	0.00	1.54	5.27
EUOR	2.53	3.32	10.67	3.41	3.60	22.02	8.00	9.05	3.65	5.30	4.23	28.06	2.29	10.90	0.00	1.34	19.98	5.87
EUOF	2.53	3.32	10.67	3.41	3.60	22.02	8.00	9.05	3.65	5.30	4.23	28.06	2.29	10.90	0.00	0.40	19.98	5.87
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	83.95	70.38	0.00	0.00
EAF	97.47	96.68	89.33	96.59	96.40	77.98	92.00	90.95	96.35	94.70	95.77	71.94	97.71	89.10	16.05	29.22	80.02	94.13

12 MONTHS	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	4.57	4.57	4.63	4.63	4.63	3.01	2.34	2.63	1.58	1.58	1.68	3.90	3.79	4.56	4.82	5.18	6.22	5.16
MOR	0.63	0.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.88	0.87
PFOR	0.78	0.89	0.89	0.91	0.81	1.20	1.22	1.08	1.05	1.05	1.07	1.16	1.17	1.06	1.13	1.17	1.10	0.67
PMOR	1.42	1.57	2.40	2.54	2.78	3.11	3.39	3.69	3.68	3.98	4.07	3.83	3.91	3.86	3.26	3.19	3.10	2.99
EUOR	7.23	7.48	7.77	7.92	8.05	7.19	6.84	7.28	6.23	6.54	6.73	8.70	8.68	9.27	9.00	9.32	10.91	9.39
EUOF	7.23	7.48	7.77	7.92	8.05	7.19	6.84	7.28	6.23	6.54	6.73	8.70	8.68	9.27	8.36	8.12	9.50	8.18
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.11	12.87	12.87	12.87
EAF	92.77	92.52	92.23	92.08	91.95	92.81	93.16	92.72	93.77	93.46	93.27	91.30	91.32	90.73	84.53	79.01	77.62	78.95


Crystal River Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
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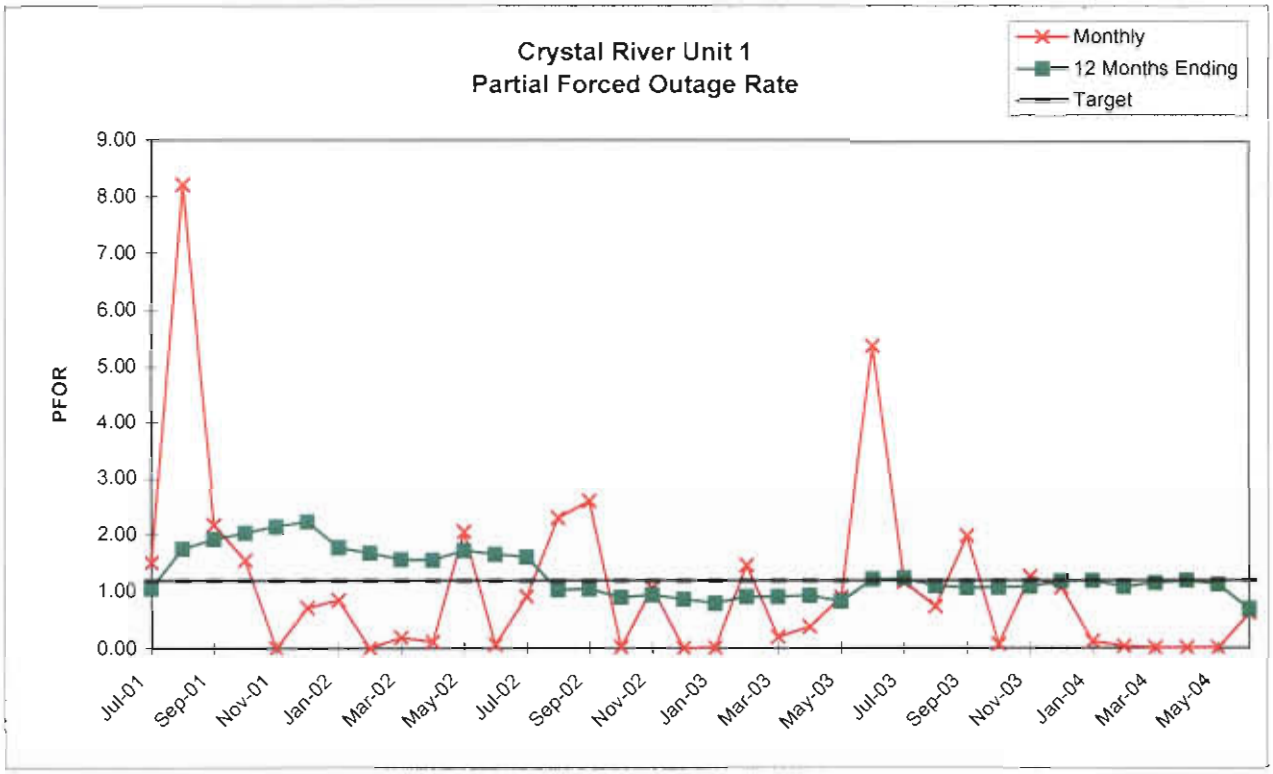
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
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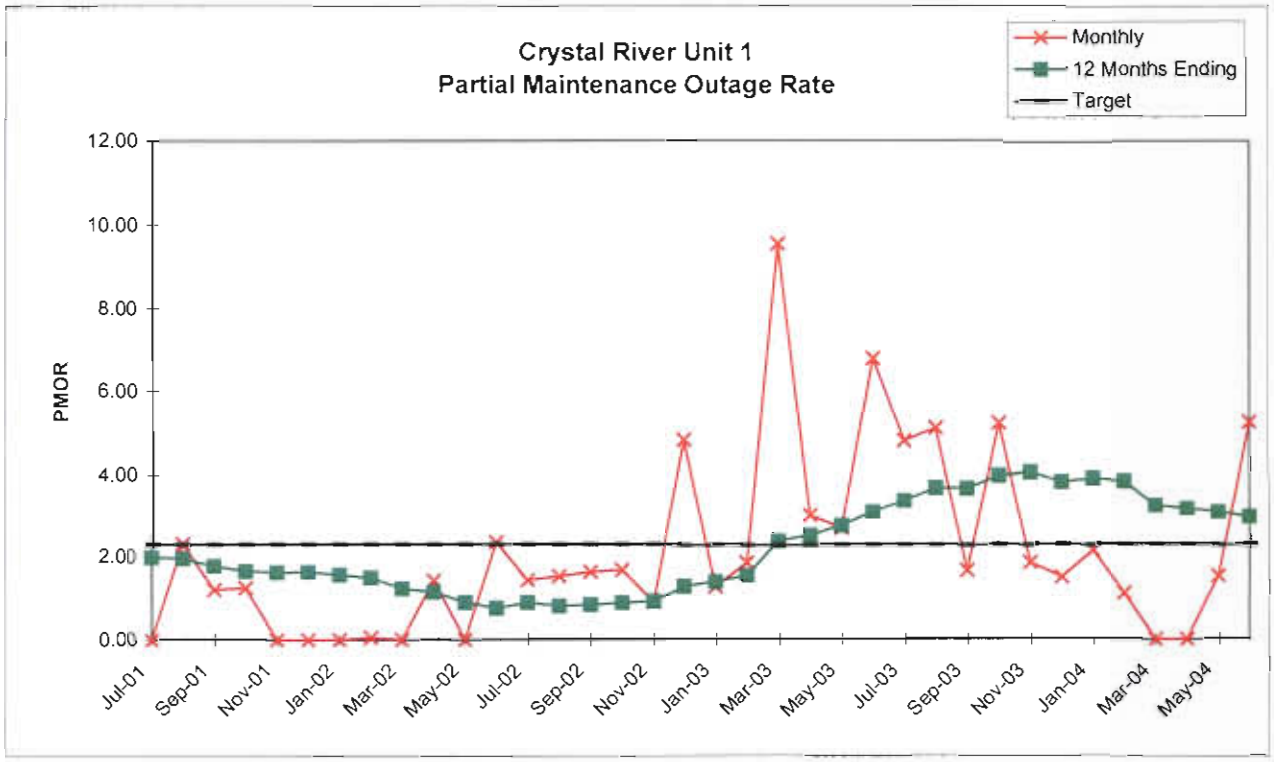
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
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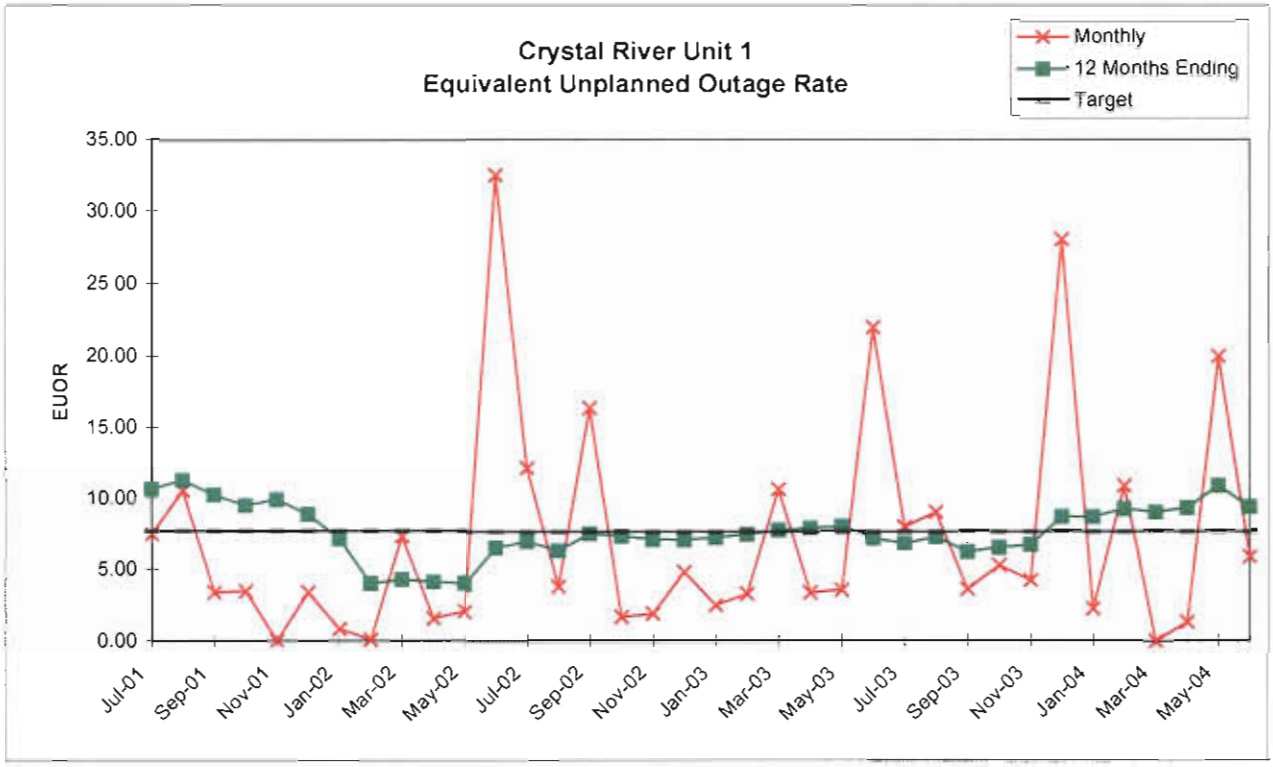
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
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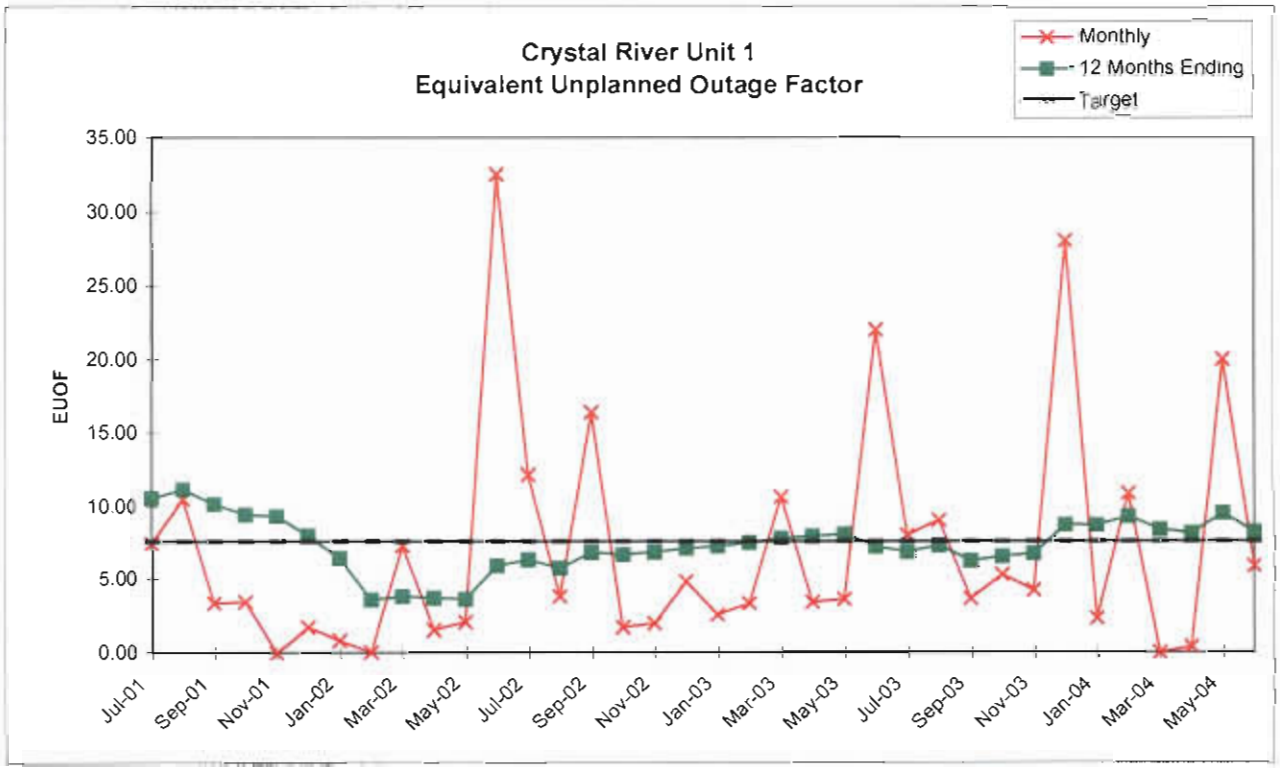
Mar-04
May-04


Crystal River Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04

Crystal River
Unit 2

	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672 00	744.00	719.00	744.00	720 00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	659 63	676.00	459.00	503.80	697.93	674.48	672.00	557.60	719.00	667.23	618.07	741.38	744.00	393.07	745.00	720.00	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00
UH	0.00	84.37	44.00	286.00	216.20	46.07	69 52	0.00	186.40	0.00	76.77	101.93	2.62	0 00	326.93	0.00	0.00	0.00
POH	0.00	0.00	0.00	286.00	209.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	84.37	0 00	0.00	1.00	46.07	0.00	0.00	110.10	0.00	0.00	101.93	2.62	0.00	326.93	0.00	0.00	0.00
MOH	0.00	0.00	44.00	0 00	5.42	0.00	69.52	0.00	76.30	0.00	76.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	43.00	199.77	49.38	6.78	0.00	140 10	179.13	262.00	93.80	122.28	45.25	13.37	73.52	42 17	34.63	731.00	775 93	22.88
LRPF	212.76	45.94	76.05	179.48	0.00	119.34	78.39	50.72	167.66	170.84	105.00	133.04	195.91	171.27	208.17	61.00	59.93	67.02
EFOH	18.82	18.89	7.73	2.50	0.00	34.40	28.89	27.34	32.36	42.98	9.78	3.66	29.64	14.86	14.83	91.75	95.68	3.16
PMOH	6.25	31.87	26.43	38.00	1.77	0.00	309.25	76.90	106.68	20.57	17 50	26.12	85.98	36.33	21 67	57.85	75.02	410.63
LRPM	106.92	229.68	145.90	34.99	258.08	0.00	75.86	52.76	82.93	253.96	193.26	242.76	76.54	105.01	163.52	113.68	52.20	142.83
EMOH	1.37	15.06	7.93	2.74	0.94	0.00	48.27	8.35	18.20	10.75	6.96	13.05	13.54	7.85	7.29	13.53	8.06	120.68
NPC	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00

MONTHLY	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	0.00	11.34	0.00	0.00	0.20	6.19	0.00	0.00	16.49	0.00	0.00	14.16	0.35	0.00	45.41	0.00	0.00	0.00
MOR	0.00	0.00	6.11	0.00	1.06	0.00	9.34	0.00	12.04	0.00	10.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	2.53	2.86	1.14	0.55	0.00	4.93	4.28	4.07	5.80	5.98	1.47	0.59	4.00	2.00	3.77	12.32	13.29	0.42
PMOR	0.18	2.28	1.17	0.60	0.19	0.00	7.16	1.24	3.26	1.49	1.04	2.11	1.83	1.06	1.85	1.82	1.12	16.22
EUOR	2.71	15.90	8.29	1.14	1.44	10.82	19.72	5.31	31.85	7.47	12.57	16.48	6.16	3.05	48.48	14.13	14.41	16.64
EUOF	2.71	15.90	8.29	0.70	1.02	10.82	19.72	5.31	31.85	7.47	12.57	16.48	6.16	3.05	48.48	14.13	14.41	16.64
POF	0.00	0.00	0.00	38.39	29.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	97.29	84.10	91.71	60.91	69.84	89.18	80.28	94.69	68.15	92.53	87.43	83.52	93.84	96.95	51.52	85.87	85.59	83.36

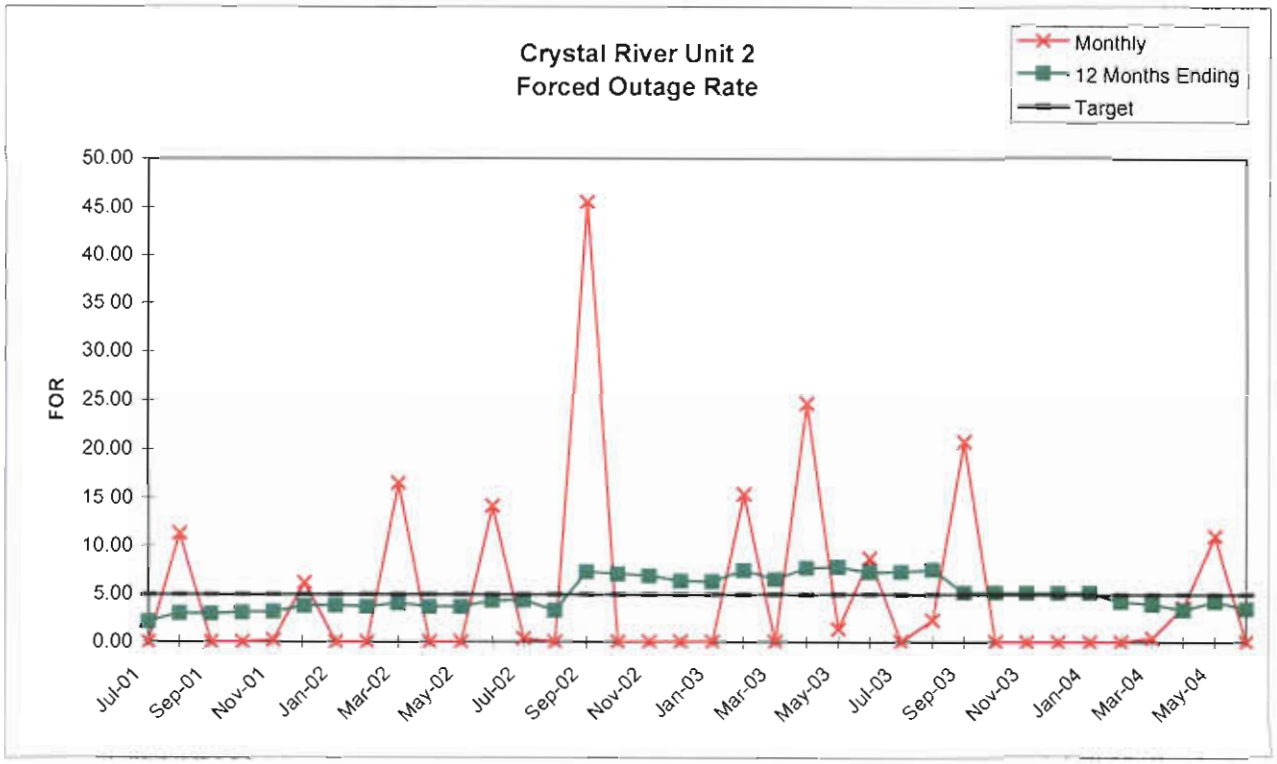
12 MONTHS	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	2.10	3.00	2.92	3.03	3.14	3.75	3.79	3.65	4.03	3.66	3.64	4.30	4.33	3.27	7.32	7.07	6.88	6.34
MOR	13.22	3.68	2.70	2.80	2.96	2.30	3.27	3.15	3.90	3.89	3.41	3.43	3.44	3.40	2.97	2.86	2.72	2.71
PFOR	3.63	3.57	2.64	2.18	2.17	2.63	2.83	2.40	2.55	2.96	3.01	2.97	3.11	3.03	3.24	4.27	5.36	4.94
PMOR	1.98	2.00	2.09	1.94	1.80	1.68	2.20	2.24	2.34	2.19	1.97	1.75	1.91	1.79	1.85	1.92	1.96	3.46
EUOR	19.59	11.68	9.94	9.56	9.65	9.93	11.51	10.92	12.15	12.05	11.45	11.82	12.13	10.97	14.47	15.16	15.89	16.39
EUOF	17.69	10.55	8.98	8.32	8.17	8.41	9.74	9.57	11.46	11.36	10.80	11.15	11.44	10.35	13.65	14.79	15.89	16.39
POF	9.69	9.69	9.69	12.96	15.35	15.35	15.35	12.31	5.66	5.66	5.66	5.66	5.66	5.66	5.66	2.39	0.00	0.00
EAF	72.62	79.76	81.33	78.72	76.48	76.24	74.91	78.12	82.88	82.98	83.54	83.19	82.90	83.99	80.69	82.81	84.11	83.61

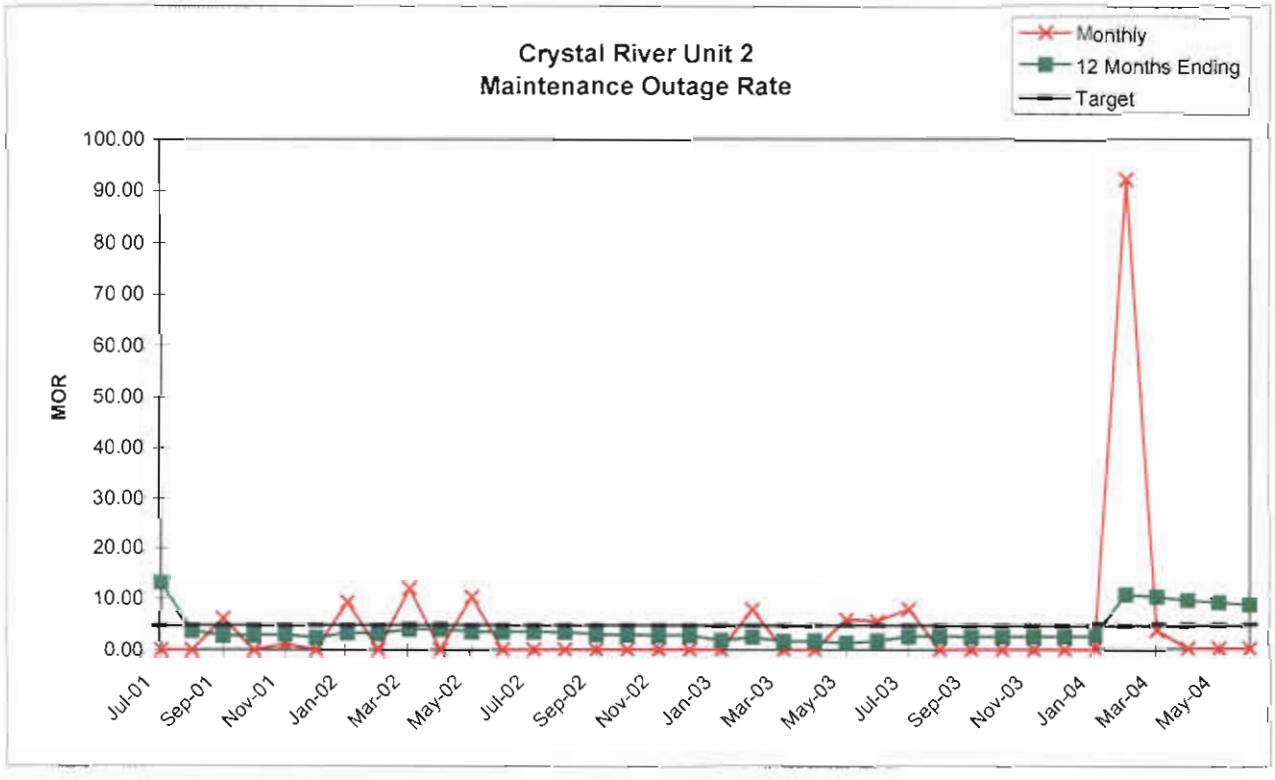
Crystal River
Unit 2

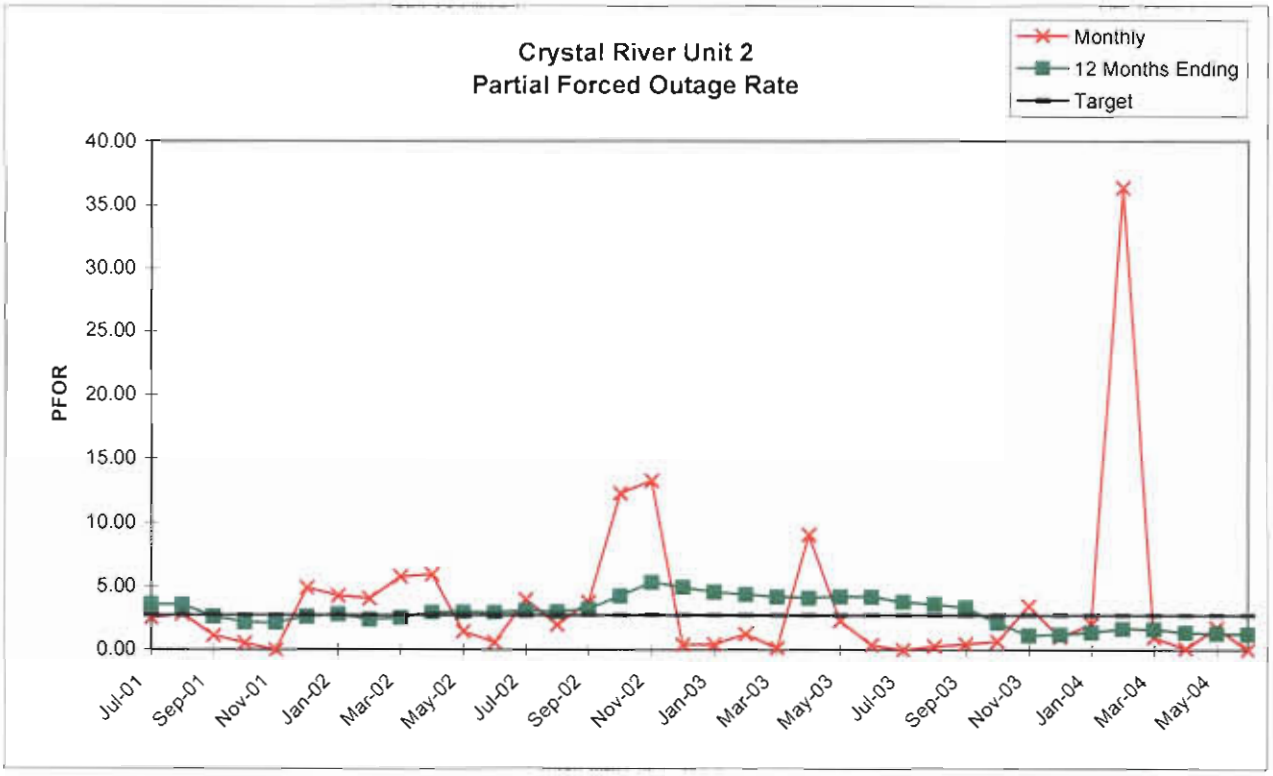
	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
PER HOURS	744 00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	696.00	744.00	719.00	744 00	720.00
SER HOURS	744.00	530.49	169.40	167.80	692.33	624.15	684.92	727.32	570.98	745.00	720.00	744.00	744.00	56.20	715.26	693 50	662.23	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	141.51	574.60	551 20	51.67	95.85	59.08	16.68	149.02	0.00	0.00	0.00	0.00	639.80	28.74	25.50	81.77	0.00
POH	0.00	0.00	574.60	496.37	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	96 13	0.00	54.83	9.00	59.57	0.00	16.68	149.02	0.00	0.00	0.00	0.00	0.00	2.62	25.50	81.77	0.00
MOH	0.00	45.38	0.00	0.00	42.67	36.28	59.08	0.00	0.00	0.00	0.00	0.00	0.00	639.80	26.12	0.00	0.00	0 00
PFOH	35.93	36.80	1 02	120.98	52.85	6.00	0.00	33.30	5.72	8.17	80.02	30.58	40.50	49.90	29.70	4.42	20.33	0.00
LRPF	45.95	89.57	123.40	61.37	147.49	202.66	0.00	33.32	229.83	295.88	153.00	121.26	181.41	199.00	118.59	78.40	276.04	0.00
EFOH	3.40	6.78	0.26	15.28	16.04	2.50	0 00	2.28	2.71	4.97	25.19	7.63	15.12	20.43	7.25	0.71	11.55	0.00
PMOH	47.60	23.25	0.00	49.33	40.85	206.60	132.68	61.63	40.67	37.85	30.33	36.20	53.95	0.00	73.02	58.53	28.82	362.52
LRPM	103.37	189.47	0.00	169.51	177.78	94.40	124.98	115.53	227.48	180.69	255.82	141.53	254.35	0.00	123.02	121.29	278.28	85.51
EMOH	10.12	9.06	0.00	17.21	14.94	40.13	34.12	14.65	19.04	14.07	15.97	10.54	28.24	0.00	18.48	14.61	16.50	63.78
NPC	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00

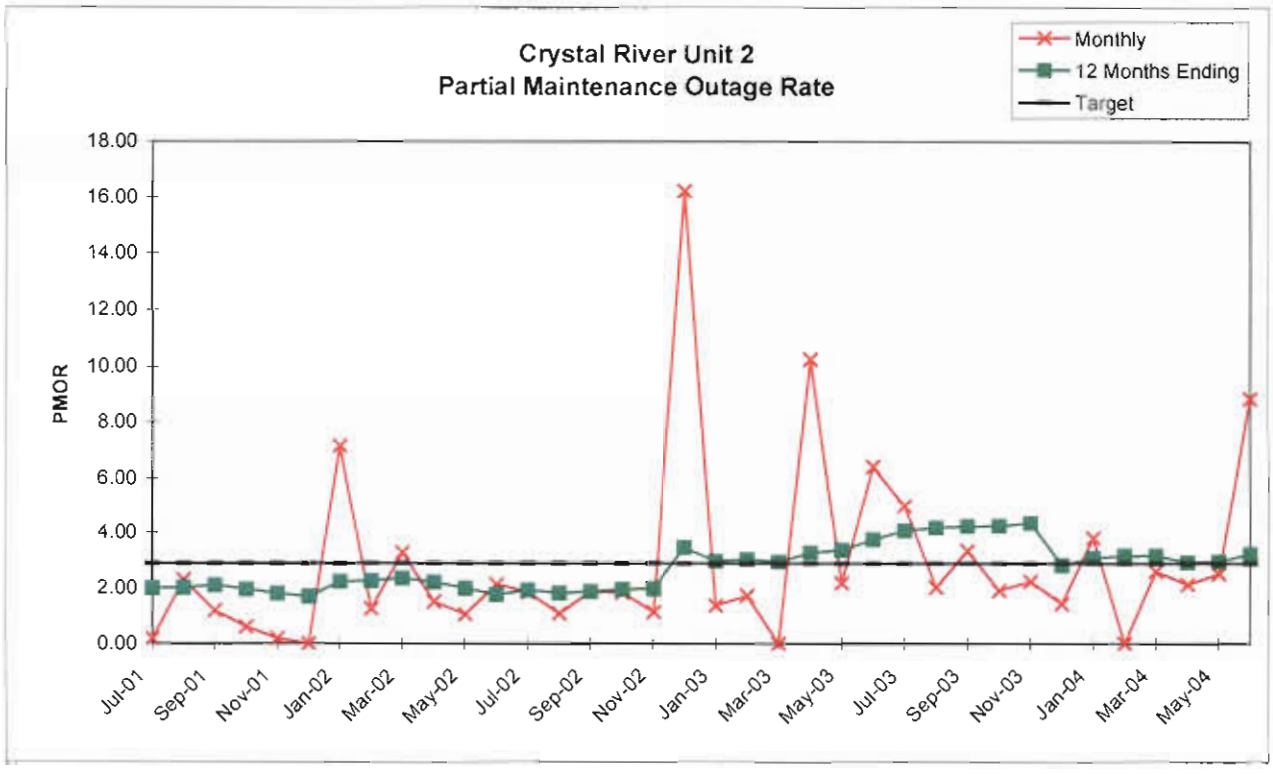
MONTHLY	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	0.00	15.34	0.00	24.63	1.28	8.71	0.00	2.24	20.70	0.00	0.00	0.00	0.00	0.00	0.36	3.55	10.99	0.00
MOR	0.00	7.88	0.00	0.00	5.81	5.49	7.94	0.00	0.00	0.00	0.00	0.00	0.00	91.93	3.52	0.00	0.00	0.00
PFOR	0.46	1.28	0.15	9.10	2.32	0.40	0.00	0.31	0.47	0.67	3.50	1.03	2.03	36.36	1.01	0.10	1.74	0.00
PMOR	1.36	1.71	0.00	10.25	2.16	6.43	4.98	2.01	3.33	1.89	2.22	1.42	3.80	0.00	2.58	2.11	2.49	8.86
EUOR	1.82	23.42	0.15	39.22	11.11	19.23	12.53	4.52	23.72	2.56	5.72	2.44	5.83	94.86	7.32	5.68	14.76	8.86
EUOF	1.82	23.42	0.03	12.14	11.11	19.23	12.53	4.52	23.72	2.56	5.72	2.44	5.83	94.86	7.32	5.68	14.76	8.86
POF	0.00	0.00	77.23	69.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	98.18	76.58	22.73	18.82	88.89	80.77	87.47	95.48	76.28	97.44	94.28	97.56	94.17	5.14	92.68	94.32	85.24	91.14

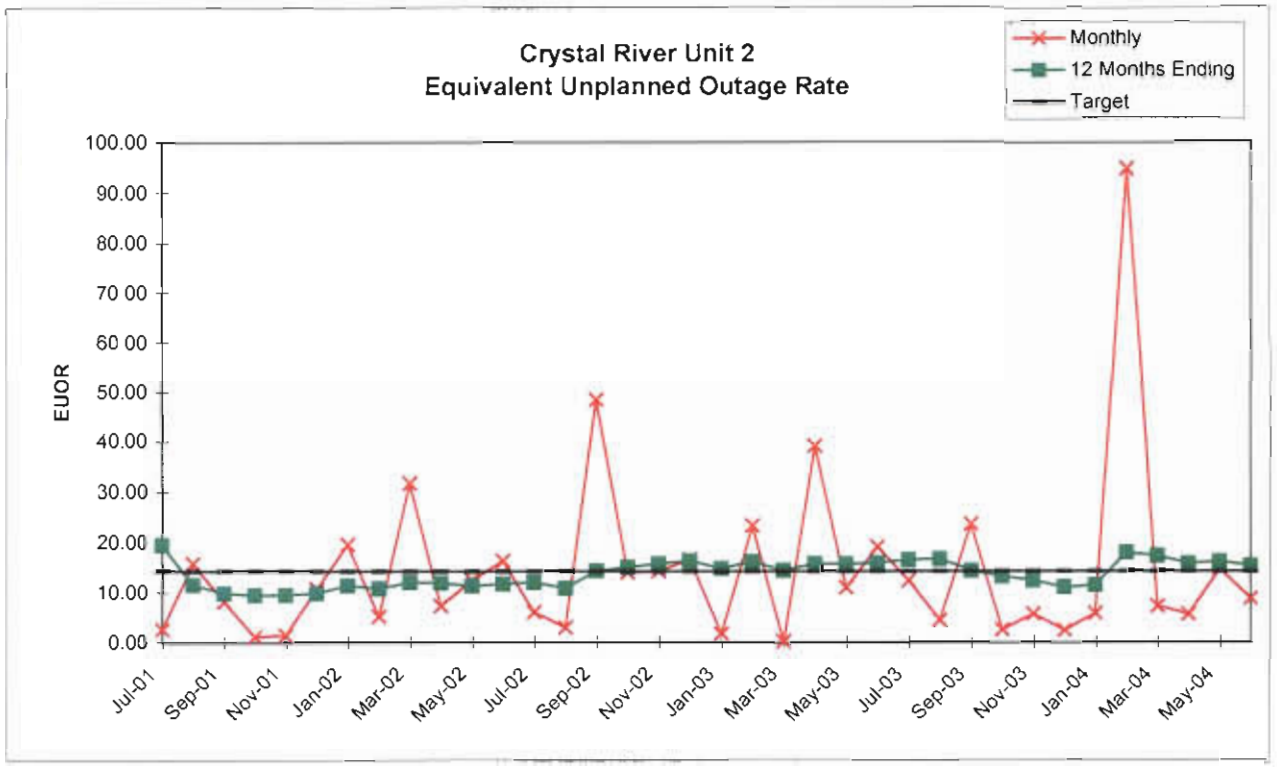
12 MONTHS	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	6.29	7.45	6.54	7.70	7.78	7.26	7.28	7.50	5.13	5.13	5.13	5.13	5.13	4.17	3.90	3.29	4.18	3.42
MOR	1.86	2.44	1.60	1.72	1.24	1.74	2.57	2.57	2.51	2.51	2.51	2.51	2.51	10.48	10.05	9.43	9.01	8.52
PFOR	4.58	4.40	4.20	4.14	4.21	4.19	3.80	3.63	3.37	2.15	1.16	1.22	1.39	1.69	1.66	1.36	1.31	1.26
PMOR	2.96	3.02	2.93	3.26	3.36	3.74	4.07	4.17	4.23	4.24	4.35	2.81	3.06	3.14	3.16	2.91	2.94	3.21
EUOR	14.87	16.26	14.51	15.88	15.74	16.00	16.61	16.76	14.44	13.31	12.50	11.13	11.51	18.00	17.40	15.89	16.20	15.35
EUOF	14.87	16.26	13.56	13.94	13.81	14.04	14.58	14.71	12.67	11.69	10.97	9.77	10.11	15.80	16.42	15.89	16.20	15.35
POF	0.00	0.00	6.56	12.23	12.23	12.23	12.23	12.23	12.23	12.23	12.23	12.23	12.23	12.19	5.65	0.00	0.00	0.00
EAF	85.13	83.74	79.89	73.84	73.96	73.73	73.19	73.07	75.10	76.09	76.80	78.01	77.67	72.00	77.93	84.11	83.80	84.65

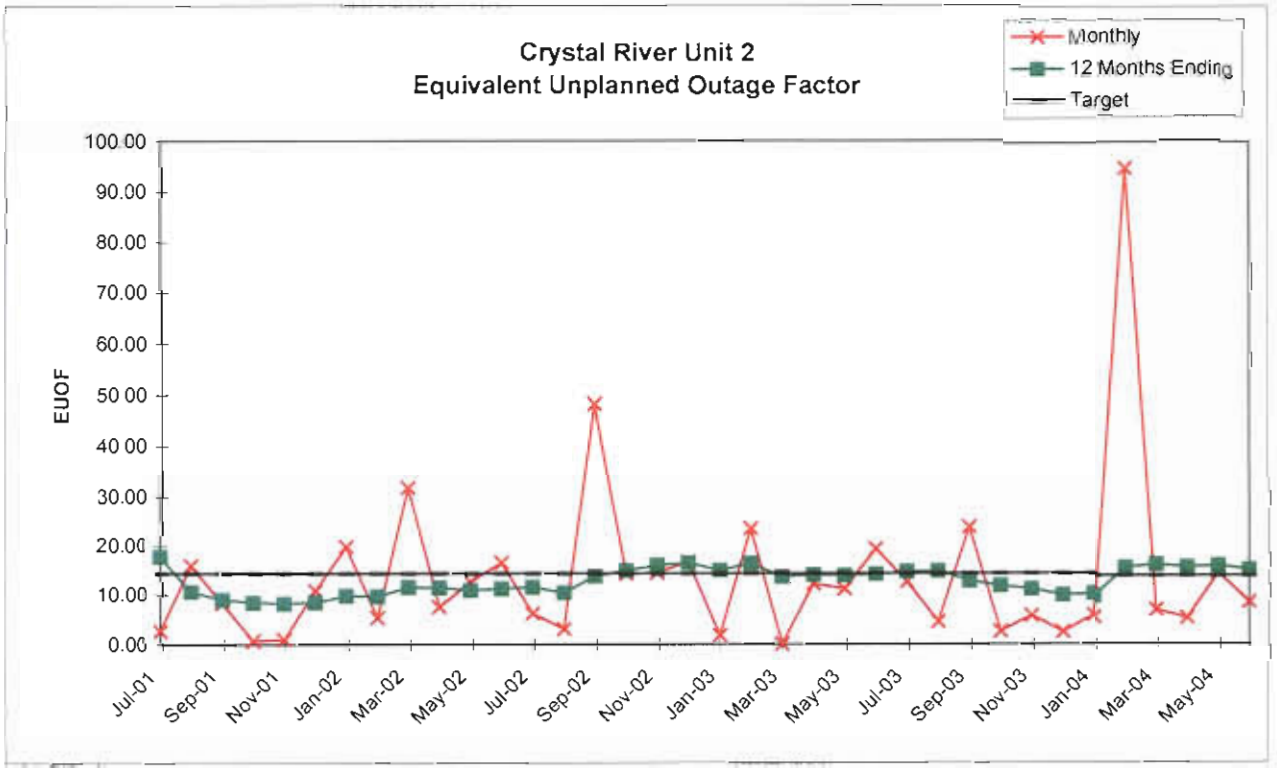

Crystal River Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 2
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 2
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
100.00
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04

Crystal River
Unit 3

	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
PER HOURS	744.00	744 00	720.00	745.00	720.00	744 00	744 00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	744.00	672.00	156.30	720.00	744.00	744.00	672.00	744.00	719.00	717.40	720.00	744.00	744.00	720.00	745.00	679.02	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0 00
UH	0.00	0.00	48.00	588.70	0.00	0.00	0.00	0.00	0.00	0.00	26.60	0.00	0.00	0.00	0.00	0 00	40.97	0.00
POH	0.00	0.00	48.00	588.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0 00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.97	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26 60	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	10.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.52	50.15	0.00
LRPF	0.00	26.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.52	150.51	0.00
EFOH	0 00	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.74	9.87	0 00
PMOH	0.00	0.00	12.00	74.58	168.42	42.22	0.00	0 00	0.00	0.00	38.27	66.56	0.00	0 00	7.17	0.00	171.93	0.00
LRPM	0.00	0.00	68.65	199.36	1.91	270.88	0.00	0.00	0.00	0.00	165.41	0.09	0.00	0.00	27.95	0.00	123.06	0.00
EMOH	0 00	0.00	1.08	19.44	0.42	14.95	0.00	0.00	0.00	0.00	8.28	0.01	0.00	0.00	0.26	0.00	27.66	0.00
NPC	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765 00	765.00	765 00

MONTHLY	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.69	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	1.45	0.00
PMOR	0.00	0.00	0.16	12.44	0.06	2.01	0.00	0.00	0.00	0.00	1.15	0.00	0.00	0.00	0.04	0.00	4.07	0.00
EUOR	0.00	0.05	0.16	12.44	0.06	2.01	0.00	0.00	0.00	0.00	4.69	0.00	0.00	0.00	0.04	0.10	10.90	0.00
EUOF	0.00	0.05	0.15	2.61	0.06	2.01	0.00	0.00	0.00	0.00	4.69	0.00	0.00	0.00	0.04	0.10	10.90	0.00
POF	0.00	0.00	6.67	79.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	99.95	93.18	18.37	99.94	97.99	100.00	100.00	100.00	100.00	95.31	100.00	100.00	100.00	99.96	99.90	89.10	100.00

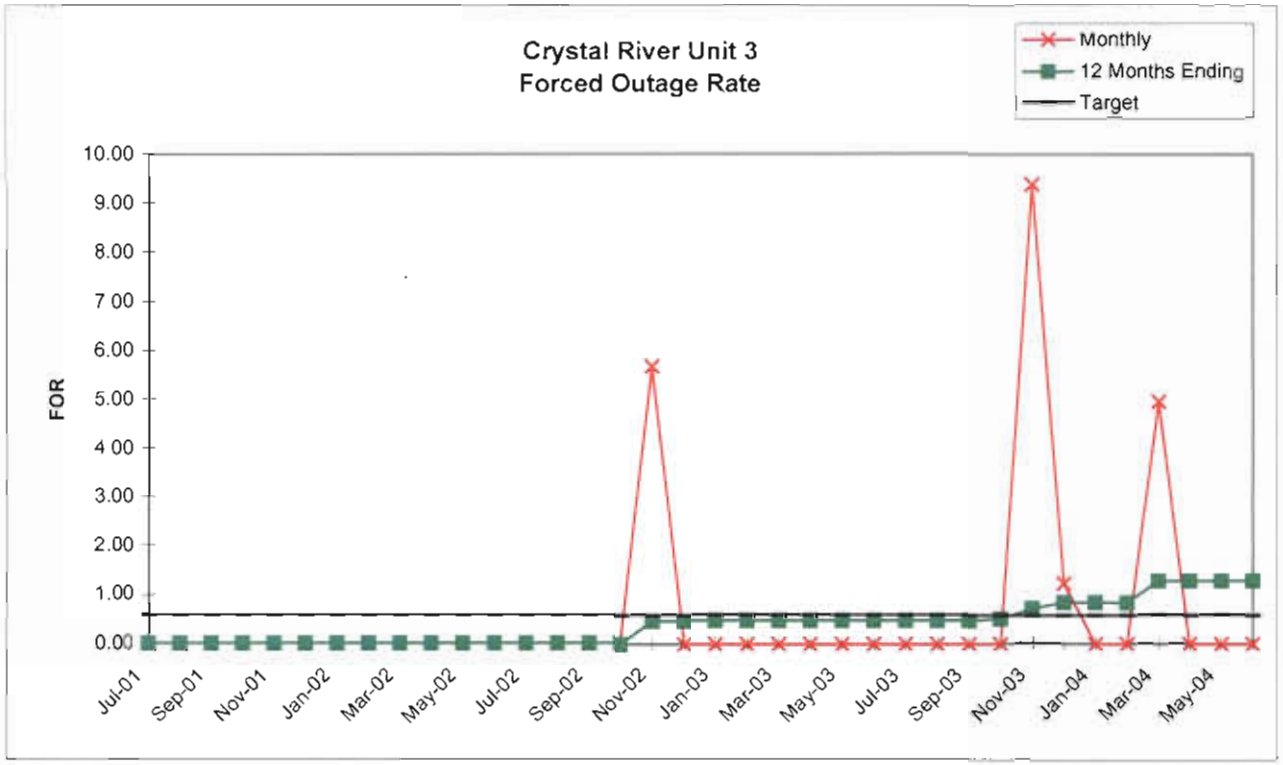
12 MONTHS	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.47
MOR	5.84	5.84	3.88	4.16	4.16	4.16	4.16	4.16	4.16	4.16	0.41	0.33	0.33	0.33	0.33	0.30	0.31	0.31
PFOR	0.36	0.28	0.28	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.06	0.00	0.00	0.00	0.00	0.01	0.12	0.12
PMOR	0.25	0.25	0.15	0.27	0.27	0.47	0.47	0.46	0.46	0.46	0.55	0.55	0.55	0.55	0.53	0.27	0.59	0.42
EUOR	6.41	6.34	4.29	4.70	4.71	4.89	4.89	4.89	4.89	4.89	1.01	0.88	0.88	0.87	0.86	0.59	1.48	1.31
EUOF	6.41	6.34	4.27	4.36	4.37	4.54	4.54	4.53	4.53	4.53	0.93	0.81	0.81	0.81	0.80	0.59	1.46	1.31
POF	0.00	0.00	0.55	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	6.72	0.00	0.00	0.00
EAF	93.59	93.66	95.19	88.37	88.37	88.20	88.20	88.20	88.20	88.20	91.80	91.92	91.92	91.92	92.48	99.41	98.52	98.69

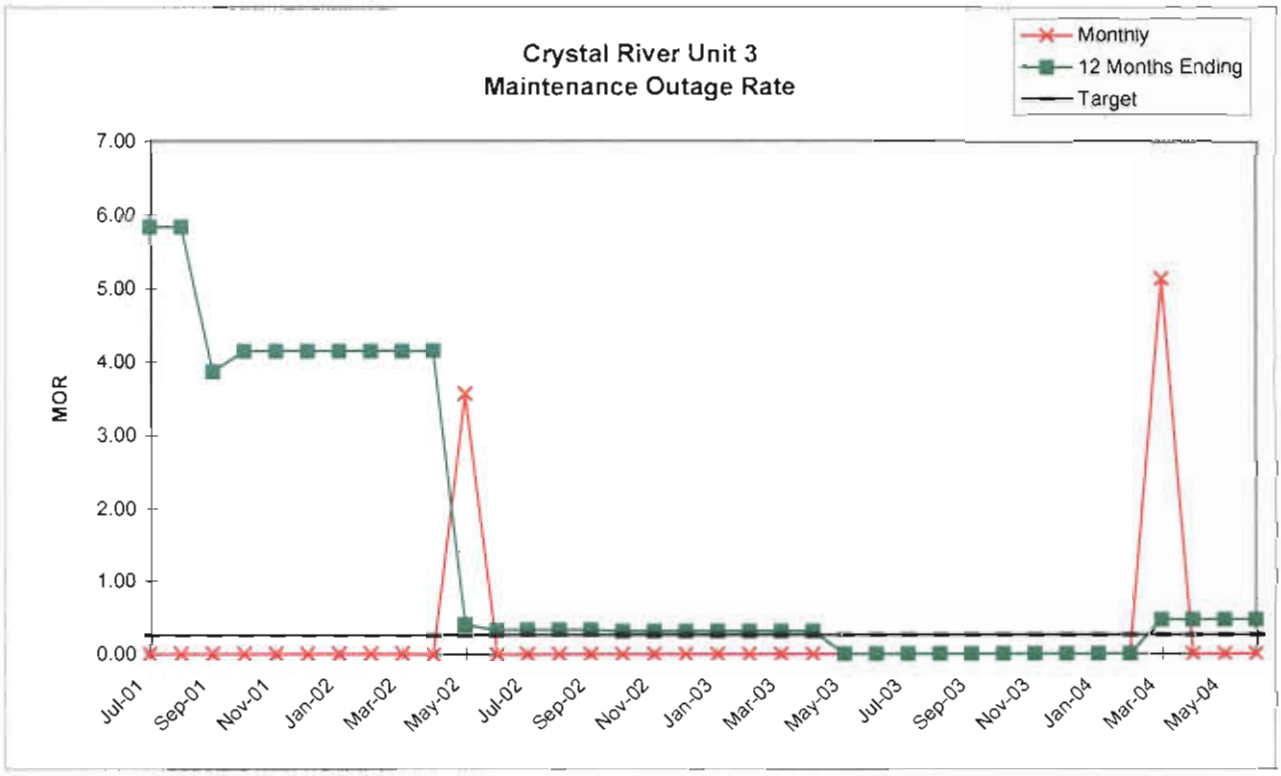
Crystal River
Unit 3

	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
PER HOURS	744.00	672 00	744.00	719.00	744.00	720.00	744.00	744 00	720.00	745.00	720.00	744.00	744.00	696.00	744 00	719.00	744.00	720.00
SER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	72.02	554.33	734.85	744.00	696 00	672.34	719.00	744.00	720 00
RSH	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	0 00	0.00	0 00	0.00	0.00	0.00	672.98	165.67	9.15	0.00	0.00	71.66	0.00	0.00	0 00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	672.98	108.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.40	9.15	0.00	0.00	35.13	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.53	0.00	0.00	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.02	0.00	24.92	2.20	0.00	0.00	21.30	0.00	0.00	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	155.25	0.00	478.92	313.30	0.00	0.00	353.02	0.00	0.00	0.00
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.06	0.00	15.60	0.90	0.00	0.00	9.78	0.00	0.00	0.00
PMOH	0.00	0.00	6.58	76.08	55.10	6.60	0.00	8.52	1015.13	72.00	58.30	0.00	0.00	0 00	22.03	0.00	0.00	44.70
LRPM	0.00	0.00	36.97	167.68	52.90	95.05	0.00	44.98	71.67	192.66	303.44	0.00	0.00	0.00	341.88	0.00	0.00	2 00
EMOH	0.00	0.00	0.32	16.68	3.81	0.82	0.00	0.50	95.10	18.13	23.13	0.00	0.00	0.00	9.79	0.00	0.00	0.12
NPC	765.00	765 00	765 00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	769.00	769.00	769.00	769 00	769.00	769.00

MONTHLY	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.38	1.23	0.00	0.00	4.97	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.15	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.56	0.00	2.81	0.12	0.00	0.00	1.45	0.00	0.00	0.00
PMOR	0.00	0.00	0.04	2.32	0.51	0.11	0.00	0.07	13.21	25.18	4.17	0.00	0.00	0.00	1.46	0.00	0.00	0.02
EUOR	0.00	0.00	0.04	2.32	0.51	0.11	0.00	0.07	13.77	25.18	15.71	1.35	0.00	0.00	12.26	0.00	0.00	0.02
EUOF	0.00	0.00	0.04	2.32	0.51	0.11	0.00	0.07	13.77	2.43	13.35	1.35	0.00	0.00	12.26	0.00	0.00	0.02
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	90.33	15.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	100.00	99.96	97.68	99.49	99.89	100.00	99.93	86.23	7.23	71.61	98.65	100.00	100.00	87.74	100.00	100.00	99.98

12 MONTHS	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.51	0.72	0.83	0.83	0.83	1.28	1.28	1.28	1.28
MOR	0.31	0.31	0.31	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.46	0.46	0.46	0.46
PFOR	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.17	0.17	0.25	0.26	0.26	0.26	0.39	0.39	0.39	0.39
PMOR	0.42	0.42	0.42	0.61	0.56	0.57	0.57	0.57	1.66	2.03	2.00	2.00	2.00	2.00	2.14	1.92	1.88	1.87
EUOR	1.31	1.31	1.31	1.50	1.15	1.15	1.15	1.16	2.29	2.69	2.95	3.08	3.08	3.07	4.20	4.00	3.95	3.94
EUOF	1.31	1.31	1.31	1.50	1.15	1.15	1.15	1.16	2.29	2.49	2.69	2.80	2.80	2.80	3.83	3.64	3.60	3.59
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.68	8.92	8.92	8.92	8.89	8.89	8.89	8.89	8.89
EAF	98.69	98.69	98.69	98.50	98.85	98.85	98.85	98.84	97.71	89.83	88.39	88.28	88.28	88.31	87.28	87.46	87.51	87.52


Crystal River Unit 3
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 3
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
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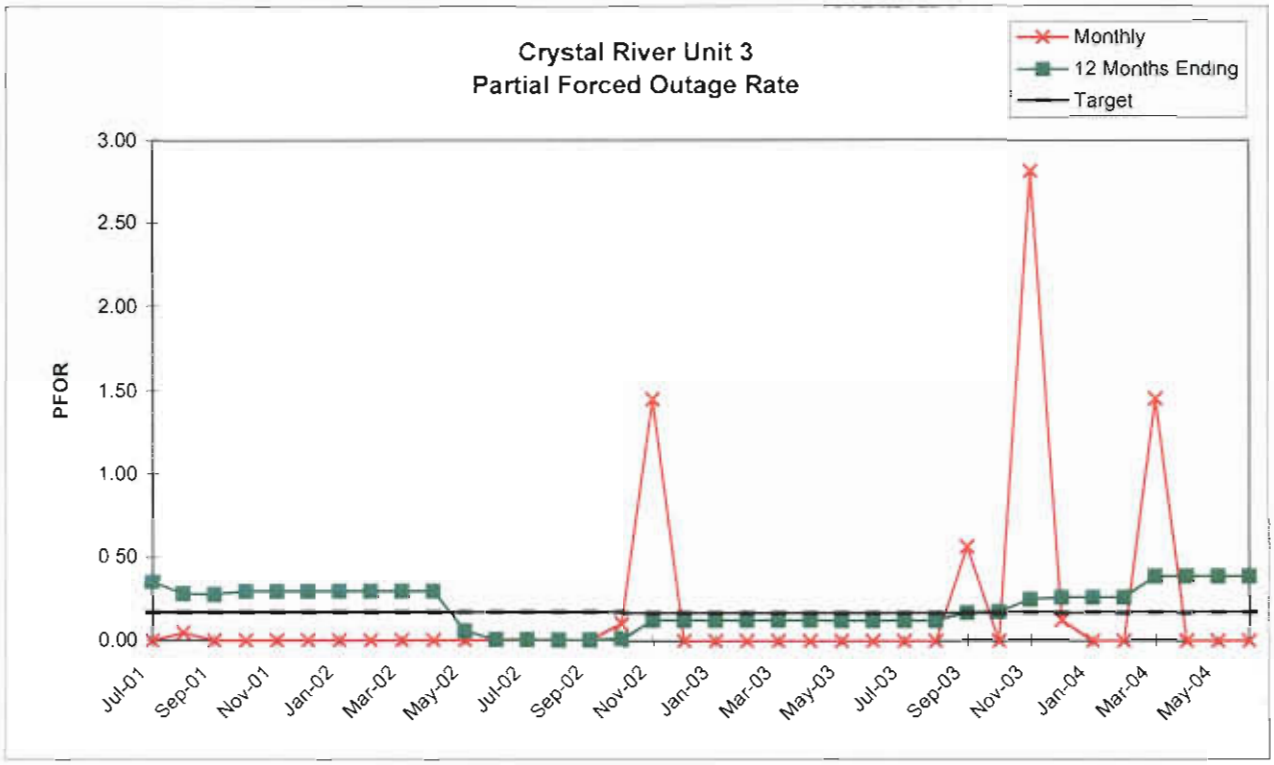
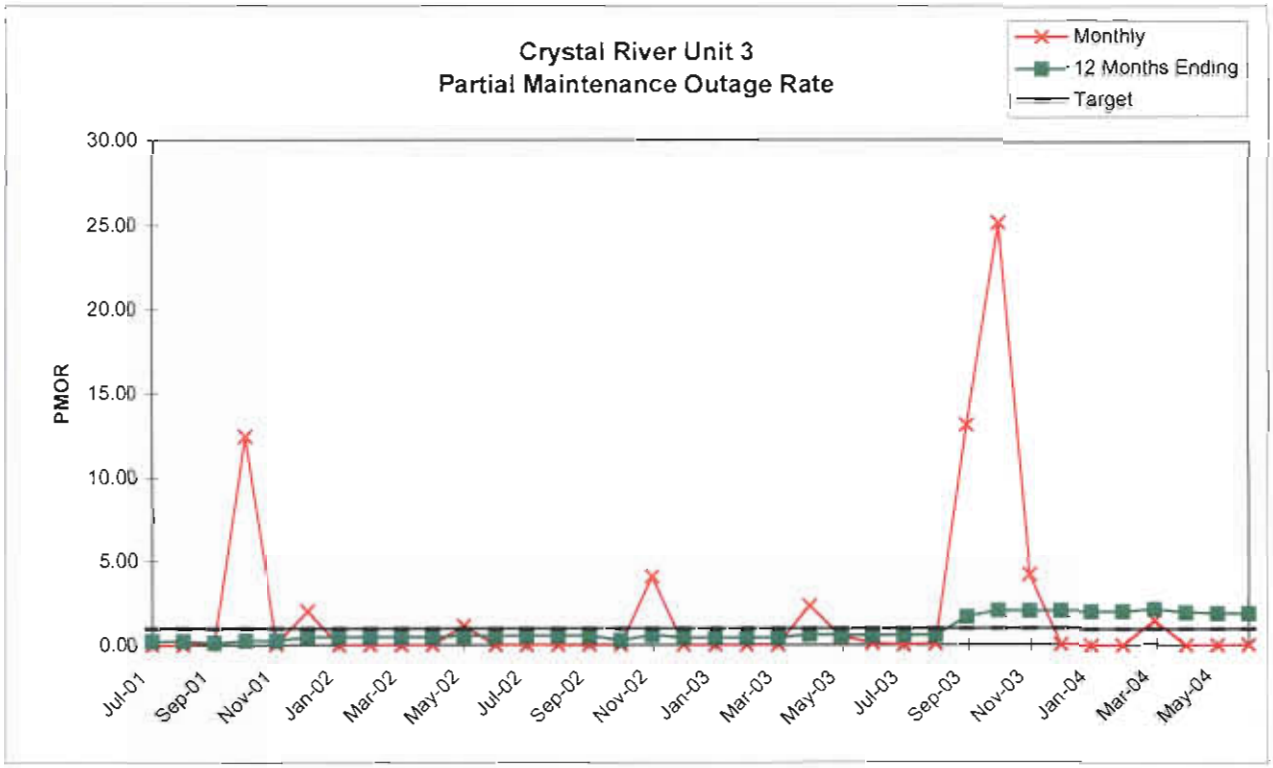
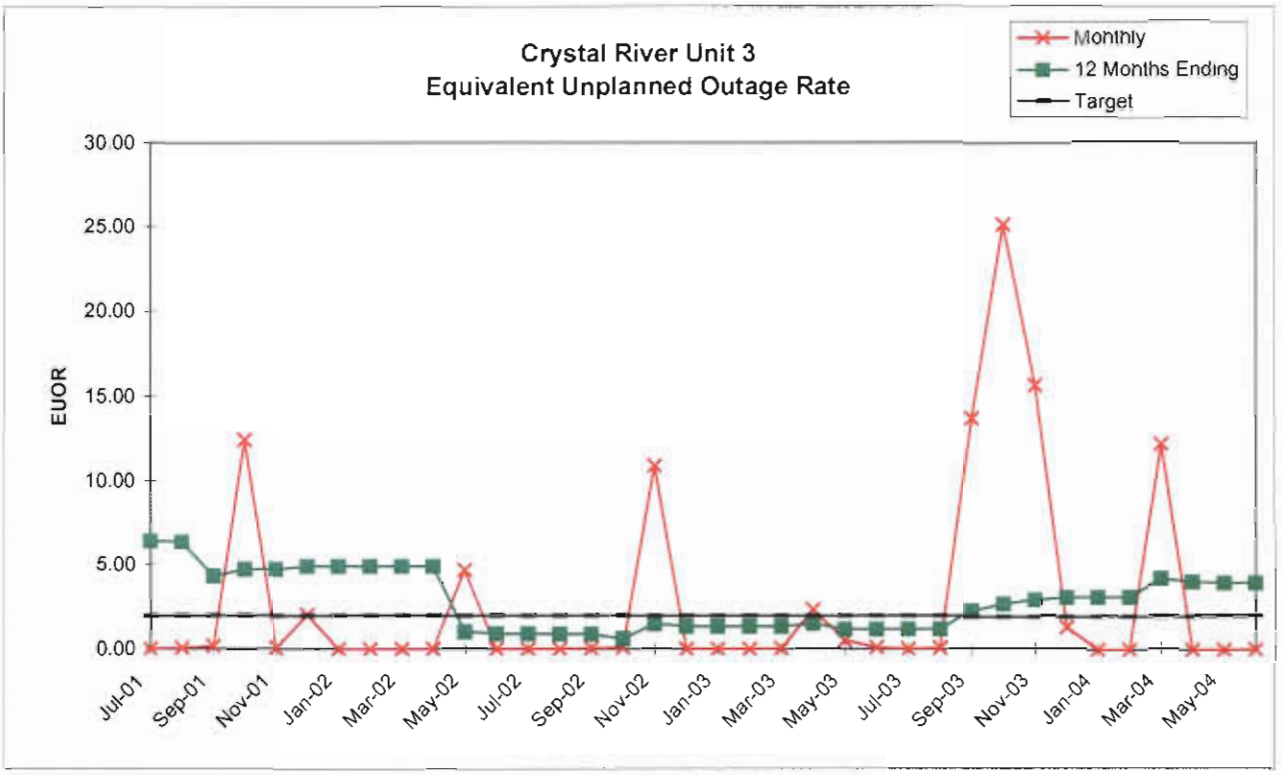
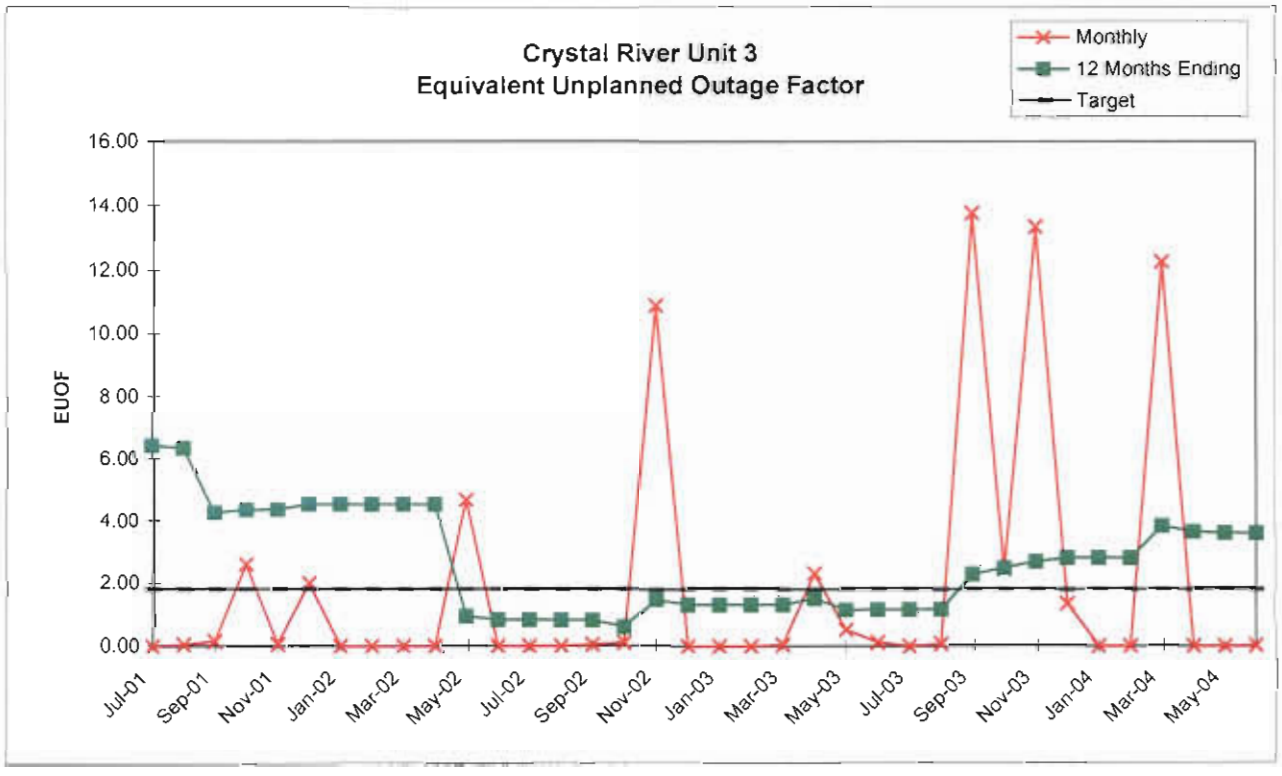
Jan-04
Mar-04
May-04


Crystal River Unit 3
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
3.00
2.50
2.00
1.50
1.00
0 50
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 3
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 3
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 3
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04

Crystal River
Unit 4

	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	744.00	720.00	612.00	720.00	507.64	744.00	672 00	195 10	0.00	311.40	708.90	696.20	744.00	720.00	710.33	720.00	744.00
RSH	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0 00
UH	0.00	0.00	0.00	133.00	0.00	236.37	0.00	0.00	548.90	719 00	432.60	11.10	47.80	0.00	0.00	34.67	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0 00	548.90	719.00	278.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	133.00	0.00	236.37	0.00	0.00	0.00	0.00	105 50	11.10	47.80	0.00	0.00	34.67	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	48.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	100.05	7.02	27.90	42.98	29.88	14.13	12.00	19.40	7.50	0.00	0.00	53.73	7.33	4.58	21.42	54.28	0.83	3.55
LRPF	293.30	175.87	59.18	333.82	136.32	69.05	589.44	124.70	69 98	0.00	0.00	165.15	132.21	92.12	40.71	147.08	78 07	118.04
EFOH	40.76	1.71	2.29	19.93	5.66	1.36	9.82	3.36	0.73	0.00	0.00	12.32	1.35	0.59	1.21	11.09	0.09	0.58
PMOH	19.00	0.00	58.17	4.50	0.00	169.77	10.43	0.00	0 00	0.00	63.30	0.00	0.00	22.48	0.00	9.00	3.00	0.00
LRPM	98.62	0 00	261 49	69.12	0.00	69.04	388.10	0 00	0.00	0.00	434.00	0.00	0.00	92.02	0.00	132.16	149.04	0.00
EMOH	2.60	0.00	21.13	0.43	0.00	16 28	5.62	0.00	0.00	0.00	38.16	0 00	0.00	2.87	0.00	1.65	0.62	0.00
NPC	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00

MONTHLY	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	0.00	0.00	0.00	17.85	0.00	31.77	0.00	0.00	0.00	0.00	25.31	1.54	6.42	0.00	0.00	4.65	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	5.48	0.23	0.32	3.26	0.79	0.27	1.32	0.50	0.37	0.00	0.00	1.74	0.19	0.08	0.17	1.56	0.01	0.08
PMOR	0.35	0.00	2.93	0.07	0.00	3.21	0.76	0.00	0.00	0.00	12.25	0.00	0.00	0.39	0.00	0.23	0.09	0.00
EUOR	5.83	0.23	3.25	20.59	0.79	34.14	2.08	0.50	0.37	0.00	41.34	3.25	6.61	0.46	0.17	6.36	0.10	0.08
EUOF	5.83	0.23	3.25	20.59	0.79	34.14	2.08	0.50	0.10	0.00	25.88	3.25	6.61	0.46	0.17	6.36	0.10	0.08
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.78	100.00	37.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	94.17	99.77	96.75	79.41	99.21	65.86	97.92	99.50	26.13	0.00	36.73	96.75	93.39	99.54	99.83	93.64	99.90	99.92

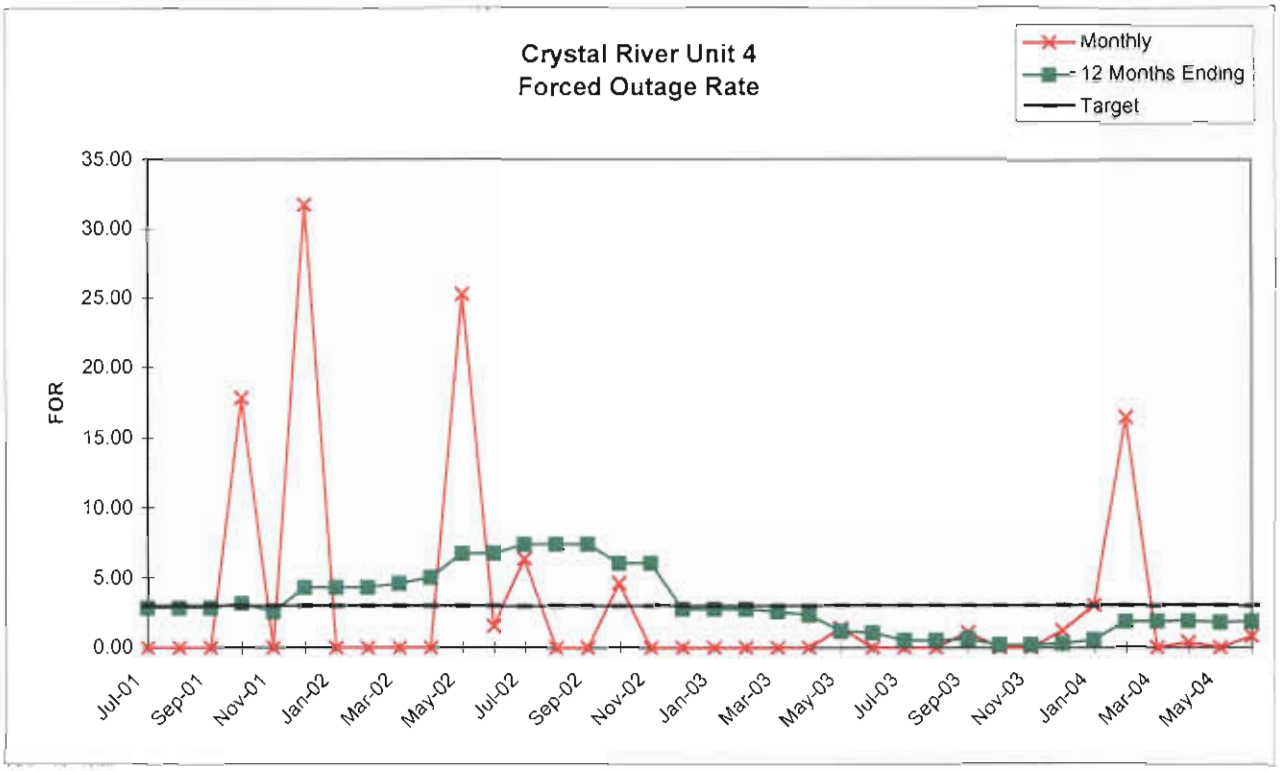
12 MONTHS	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	2.85	2.85	2.85	3.18	2.58	4.33	4.33	4.33	4.62	5.06	6.77	6.78	7.45	7.45	7.45	6.08	6.08	2.78
MOR	2.32	2.32	2.32	1.98	1.03	0.00	0.00	0.00	0.00	0.00	0.73	0.73	0.73	0.73	0.73	0.72	0.72	0.70
PFOR	1.32	1.29	1.32	1.44	1.15	1.17	1.19	1.20	1.16	1.28	1.36	1.47	0.88	0.87	0.85	0.71	0.62	0.59
PMOR	0.54	0.52	0.78	0.78	0.67	0.83	0.83	0.83	0.88	0.76	1.34	1.26	1.23	1.27	0.96	0.96	0.97	0.70
EUOR	6.82	6.77	7.04	7.15	5.31	6.24	6.26	6.27	6.57	7.00	9.89	9.94	10.02	10.04	9.74	8.27	8.20	4.69
EUOF	6.82	6.77	7.04	7.15	5.31	6.24	6.26	6.27	6.16	5.99	8.15	8.19	8.25	8.27	8.02	6.81	6.75	3.86
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.27	14.47	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65
EAF	93.18	93.23	92.96	92.85	94.69	93.76	93.74	93.73	87.57	79.54	74.20	74.17	74.10	74.08	74.33	75.54	75.60	78.49

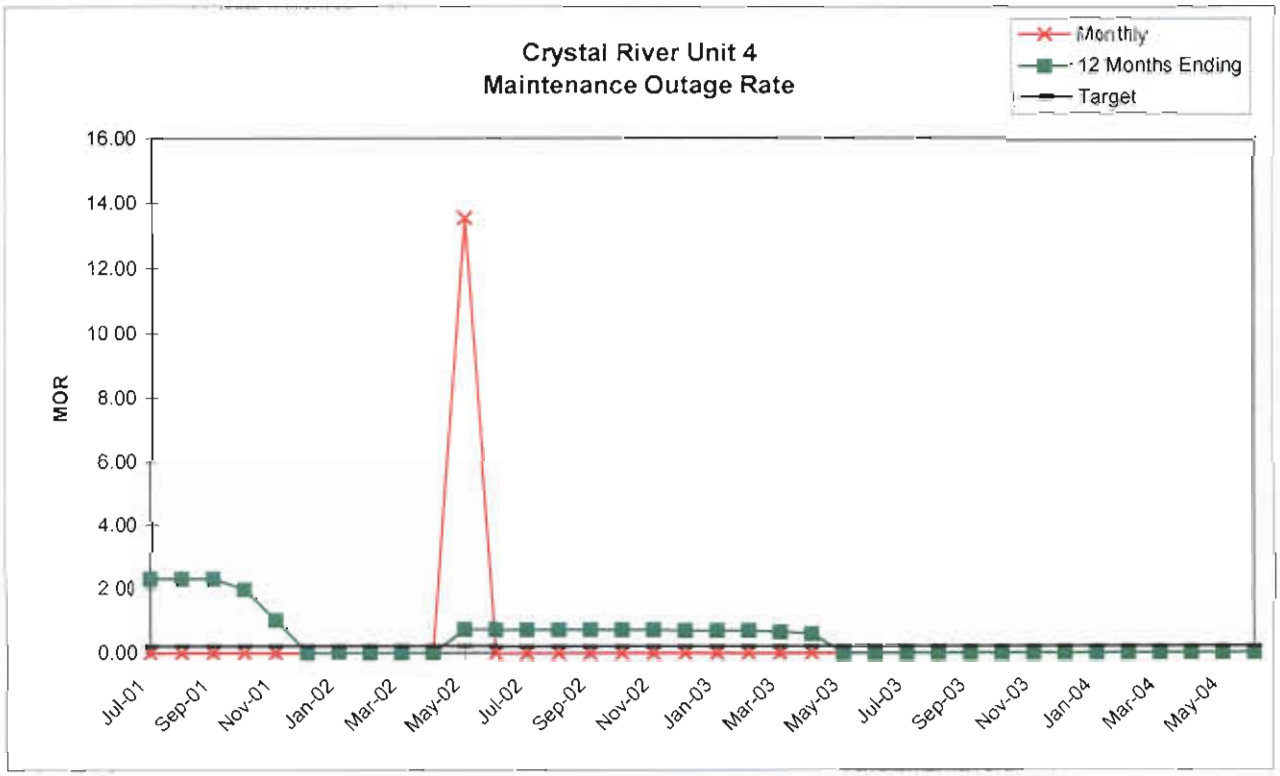
Crystal River
Unit 4

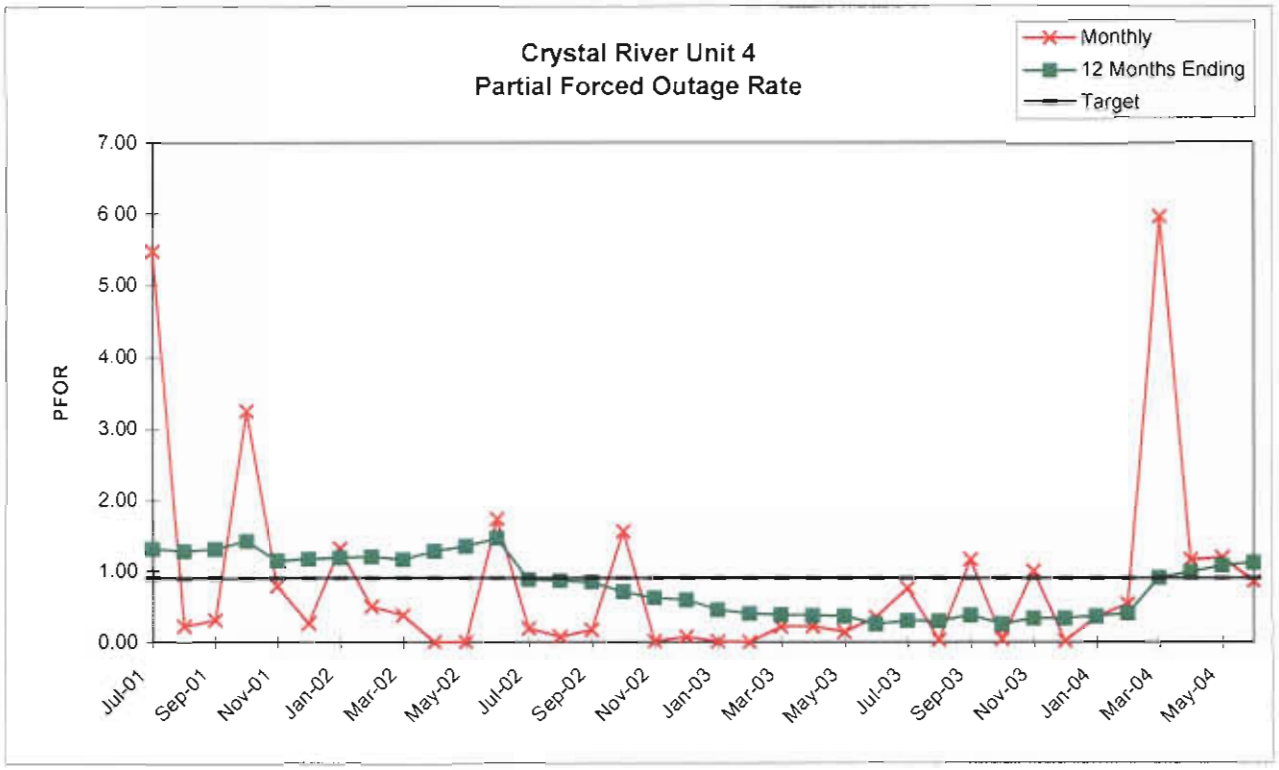
	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
PER HOURS	744 00	672.00	744 00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	696.00	744.00	719 00	744.00	720.00
SER HOURS	744 00	672.00	744.00	719.00	733.53	720.00	744.00	744 00	712.23	745.00	714.40	605.95	721 33	580.50	744.00	716.23	744.00	713.97
RSH	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0 00	0.00	0.00	0.00	0 00	0.00
UH	0.00	0.00	0.00	0.00	10 47	0.00	0.00	0.00	7 77	0.00	5.60	138.05	22.67	115.50	0.00	2.77	0.00	6 03
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.60	130.52	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	10.47	0.00	0.00	0.00	7.77	0.00	0.00	7.53	22.67	115.50	0.00	2.77	0.00	6.03
MOH	0.00	0 00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.37	0.00	16.63	19.75	13.43	16.13	49.17	1.65	13.75	2.33	17.63	1.55	5.15	7.47	321.25	116.10	17.85	16.15
LRPF	101.19	0.00	69.84	56.83	54.90	110.43	82.47	102.11	434.98	102.28	292 04	53.88	351.33	299.47	99.55	51.65	357.98	272.80
EFOH	0.05	0 00	1.61	1.56	1.02	2.47	5 63	0.23	8.31	0.33	7.15	0.12	2.51	3 11	44.42	8.33	8.88	6.12
PMOH	0.00	157.67	16.47	0.00	4.67	17.40	29.17	95.12	0.00	4.17	0.00	4.00	12.83	285.84	0.00	0.00	27.67	12.00
LRPM	0.00	73.00	176.22	0.00	386.83	553.32	101.99	161.29	0.00	101.87	0.00	102.06	101.07	112.47	0.00	0.00	414.96	43.98
EMOH	0.00	15.99	4 03	0.00	2.51	13.37	4.13	21 31	0.00	0.59	0.00	0 57	1.80	44.65	0.00	0.00	15.95	0.73
NPC	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720 00

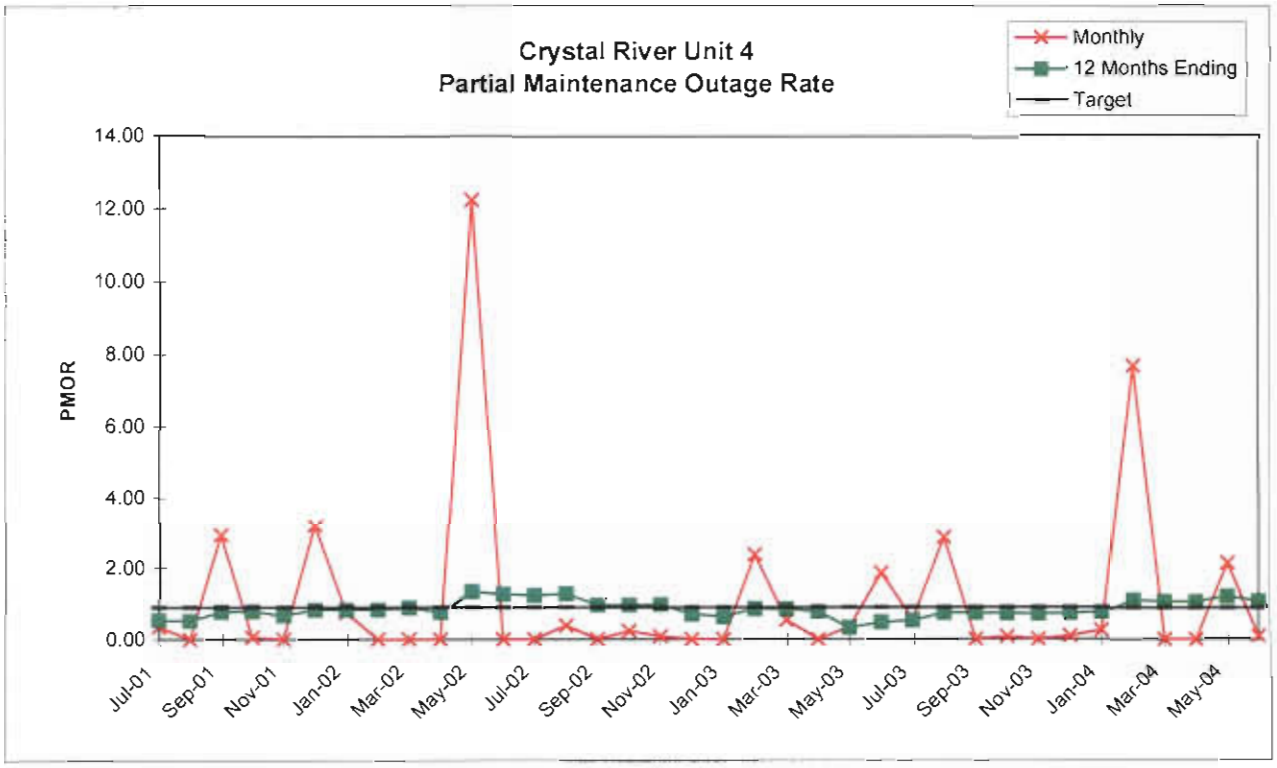
MONTHLY	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	0.00	0.00	0.00	0.00	1.41	0.00	0.00	0.00	1.08	0.00	0.00	1.23	3.05	16.59	0.00	0.39	0.00	0.84
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.01	0.00	0.22	0.22	0.14	0.34	0.76	0.03	1.17	0.04	1.00	0.02	0.35	0.54	5.97	1.16	1.19	0.86
PMOR	0.00	2.38	0.54	0.00	0.34	1.86	0.56	2.86	0.00	0.08	0.00	0.09	0.25	7.69	0.00	0.00	2.14	0.10
EUOR	0.01	2.38	0.76	0.22	1.88	2.20	1.31	2.90	2.23	0.12	1.00	1.34	3.63	23.46	5.97	1.54	3.34	1.79
EUOF	0.01	2.38	0.76	0.22	1.88	2.20	1.31	2.90	2.23	0.12	0.99	1.10	3.63	23.46	5.97	1.54	3.34	1.79
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.78	17.54	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.99	97.62	99.24	99.78	98.12	97.80	98.69	97.10	97.77	99.88	98.23	81.35	96.37	76.54	94.03	98.46	96.66	98.21

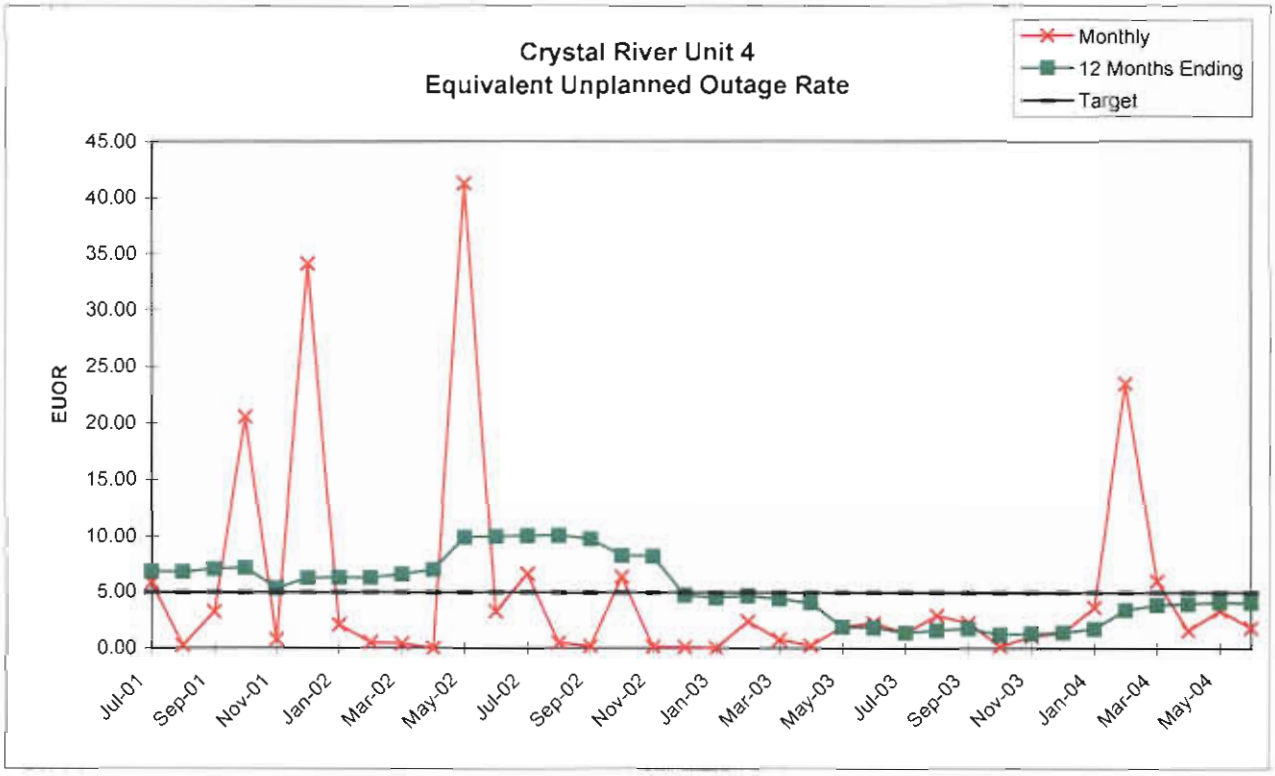
12 MONTHS	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	2.78	2.78	2.58	2.36	1.19	1.06	0.52	0.52	0.60	0.21	0.21	0.30	0.56	1.90	1.90	1.93	1.81	1.88
MOR	0.70	0.70	0.65	0.59	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.45	0.40	0.38	0.37	0.36	0.25	0.30	0.29	0.38	0.25	0.33	0.33	0.36	0.40	0.91	0.99	1.08	1.12
PMOR	0.62	0.85	0.84	0.77	0.32	0.47	0.52	0.73	0.73	0.72	0.71	0.73	0.75	1.10	1.05	1.05	1.21	1.06
EUOR	4.47	4.65	4.38	4.03	1.86	1.78	1.33	1.53	1.70	1.17	1.25	1.35	1.67	3.36	3.81	3.92	4.05	4.01
EUOF	3.68	3.83	3.88	3.90	1.86	1.78	1.33	1.53	1.70	1.17	1.25	1.33	1.64	3.31	3.75	3.86	3.99	3.95
POF	17.65	17.65	11.38	3.18	0.00	0.00	0.00	0.00	0.00	0.00	0.06	1.55	1.55	1.55	1.55	1.55	1.55	1.55
EAF	78.67	78.52	84.73	92.92	98.14	98.22	98.67	98.47	98.30	98.83	98.69	97.11	96.81	95.14	94.70	94.59	94.46	94.50

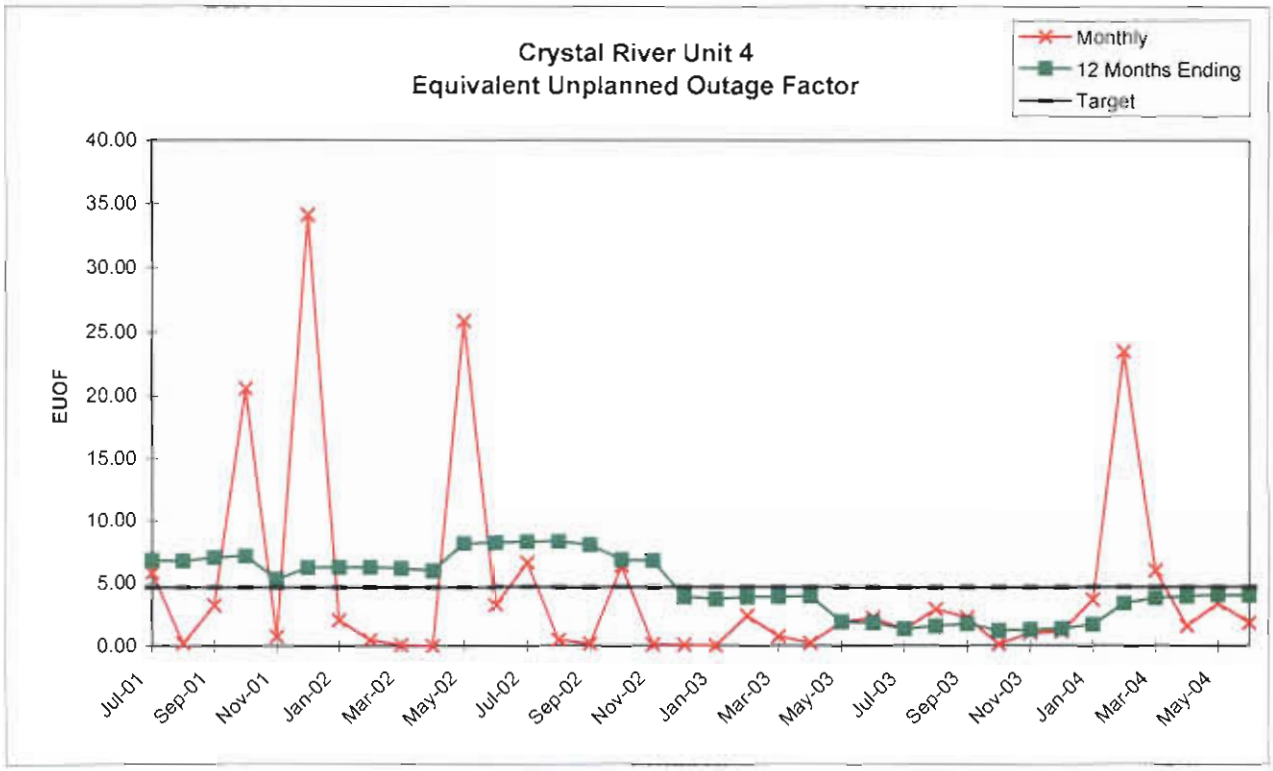

Crystal River Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04

Crystal River
Unit 5

	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	457.00	711.62	720.00	745.00	720.00	737.70	744.00	672.00	744.00	719.00	742.78	720.00	717.20	744.00	720.00	97.27	313.84	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00
UH	287.00	32.38	0.00	0.00	0.00	6.30	0.00	0.00	0.00	0 00	1.22	0.00	26 80	0.00	0.00	647.73	406.16	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	647.73	358.23	0.00
FOH	287.00	32.38	0.00	0.00	0.00	6.30	0.00	0.00	0.00	0.00	1.22	0.00	26.80	0.00	0.00	0.00	47.93	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	63.00	21.00	234.73	5.33	0.00	38.70	2.57	0.00	0.82	2.08	156.08	3.62	0.00	57.10	19.58	0.00	0.00	11.48
LRPF	202.62	296.57	54.71	64.30	0.00	232.26	411 51	0.00	420.59	166.15	87.00	431.59	0.00	76.71	30.14	0.00	0.00	88.75
EFOH	17 80	8.69	17.91	0.48	0.00	12.54	1.48	0.00	0.48	0.48	18.94	2.18	0.00	6.11	0.82	0.00	0.00	1 42
PMOH	0.00	22.75	2 67	0.00	125.33	18.25	12.05	0.00	0.00	0.00	5.83	0.00	22.35	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	103 65	54.64	0.00	72.27	67.54	70.99	0.00	0.00	0.00	336.12	0.00	120.24	0.00	0.00	0 00	0.00	0.00
EMOH	0.00	3.29	0.20	0.00	12.63	1.72	1 19	0.00	0.00	0.00	2.73	0.00	3.75	0.00	0.00	0.00	0.00	0.00
NPC	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00

MONTHLY	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	38.58	4.35	0.00	0.00	0.00	0.85	0.00	0.00	0.00	0.00	0.16	0.00	3.50	0.00	0.00	0.00	13.25	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	3.90	1.22	2.49	0.06	0.00	1.70	0.20	0.00	0.06	0.07	2.55	0.30	0.00	0.82	0.11	0.00	0.00	0.19
PMOR	0.00	0.46	0.03	0.00	1.75	0.23	0.16	0.00	0.00	0.00	0.37	0.00	0.52	0.00	0.00	0.00	0.00	0.00
EUOR	40.97	5.96	2.52	0.06	1.75	2.76	0.36	0.00	0.06	0.07	3.08	0.30	4.11	0.82	0.11	0.00	13.25	0.19
EUOF	40.97	5.96	2.52	0.06	1.75	2.76	0.36	0.00	0.06	0.07	3.08	0.30	4.11	0.82	0.11	0.00	6.66	0.19
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	86.94	49.75	0.00
EAF	59.03	94.04	97.48	99.94	98.25	97.24	99.64	100.00	99.94	99.93	96.92	99.70	95.89	99.18	99.89	13.06	43.59	99.81

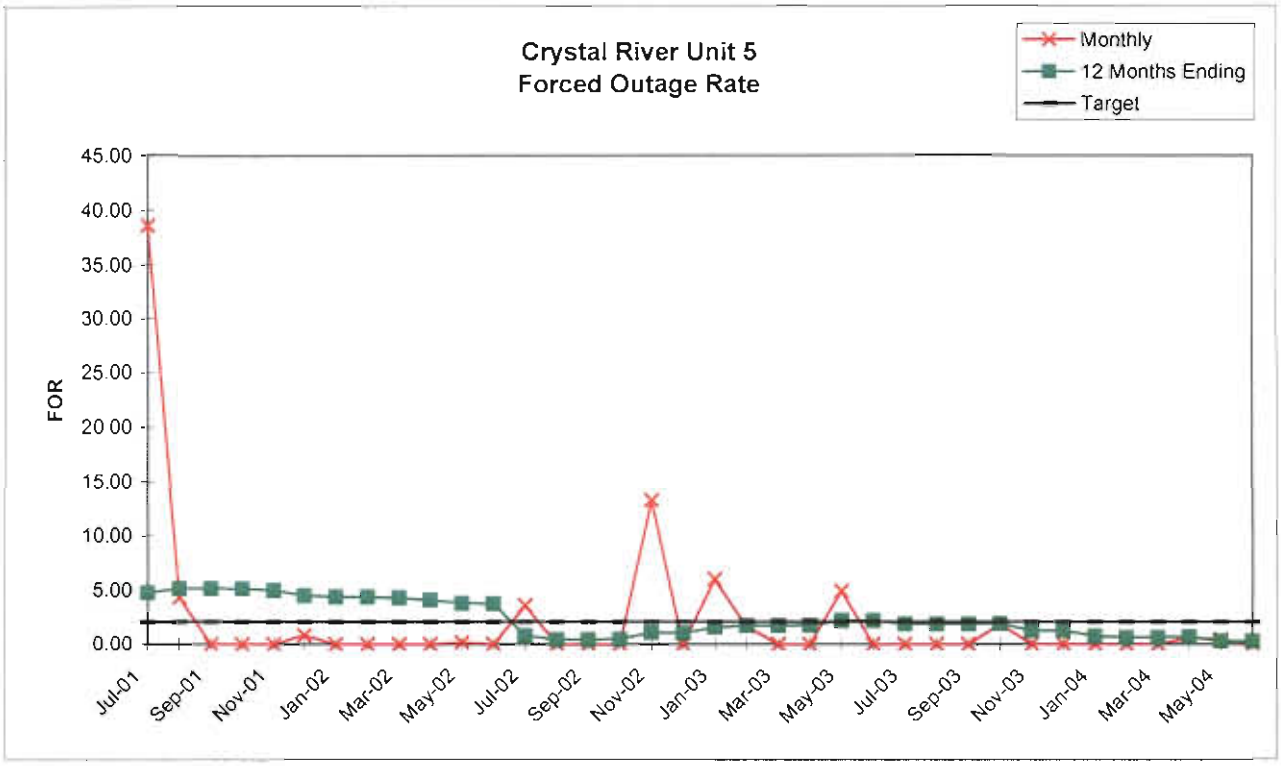
12 MONTHS	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	4.75	5.16	5.14	5.11	4.95	4.51	4.37	4.37	4.27	4.06	3.77	3.73	0.76	0.39	0.39	0.42	1.06	0.98
MOR	7.38	7.41	7.41	7.41	6.43	1.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	1.53	1.65	1.90	0.90	0.77	0.90	0.91	0.90	0.91	0.78	0.93	0.96	0.73	0.69	0.50	0.53	0.56	0.42
PMOR	0.49	0.54	0.54	0.54	0.37	0.37	0.38	0.35	0.35	0.33	0.34	0.26	0.29	0.25	0.25	0.27	0.12	0.10
EUOR	13.25	13.78	13.98	13.08	11.79	7.17	5.60	5.57	5.47	5.13	5.00	4.90	1.77	1.34	1.14	1.22	1.74	1.49
EUOF	11.90	12.37	12.55	11.74	10.58	6.43	5.03	4.99	4.91	4.84	5.00	4.90	1.77	1.34	1.14	1.13	1.54	1.32
POF	10.25	10.25	10.25	10.25	10.25	10.25	10.25	10.25	10.25	5.61	0.00	0.00	0.00	0.00	0.00	7.39	11.48	11.48
EAF	77.85	77.38	77.20	78.01	79.16	83.32	84.72	84.75	84.84	89.54	95.00	95.10	98.23	98.66	98.86	91.47	86.98	87.20

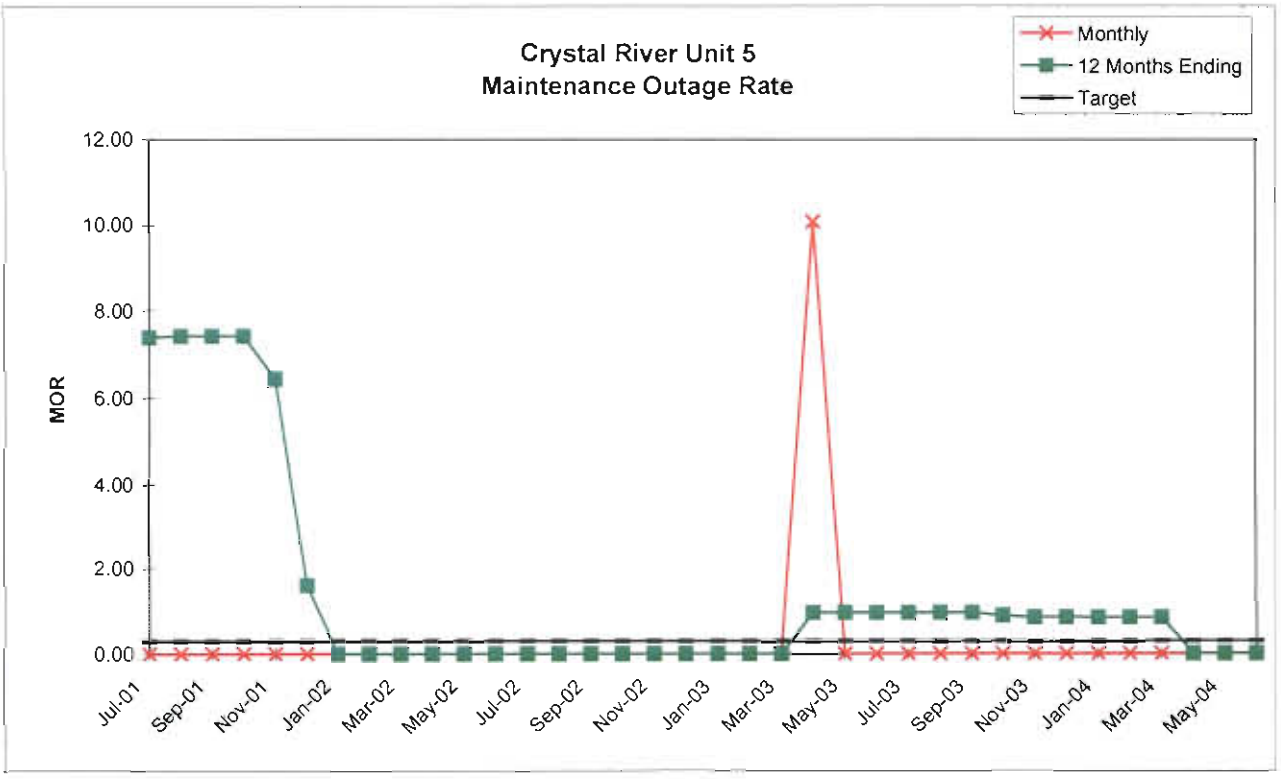
Crystal River
Unit 5

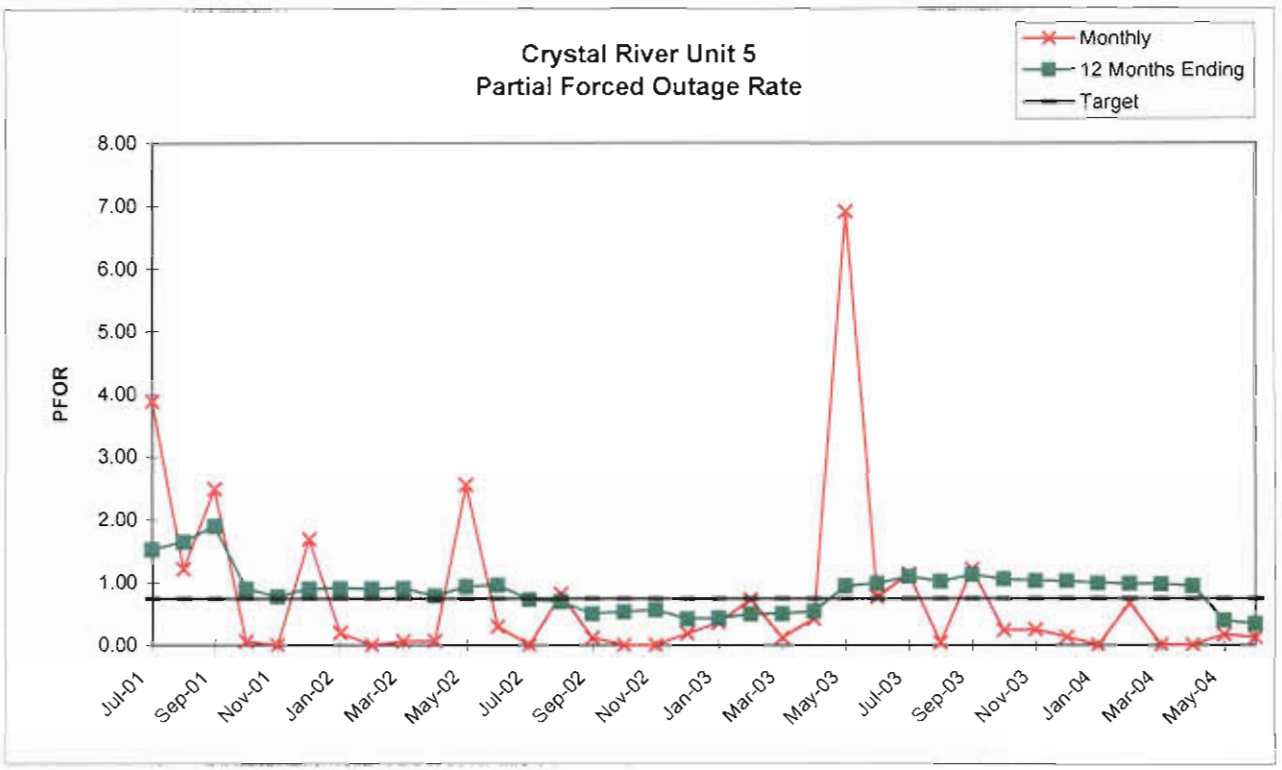
	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
PER HOURS	744.00	672 00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	696 00	744.00	719.00	744.00	720.00
SER HOURS	699.13	661.00	744.00	646.55	707.45	720.00	744.00	744.00	720.00	731.40	720.00	744.00	744.00	696 00	744 00	593.80	665.23	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	44.87	11.00	0.00	72.45	36 55	0.00	0.00	0.00	0.00	13.60	0 00	0.00	0.00	0.00	0.00	125.20	78.77	0.00
POH	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	122.00	76 20	0.00
FOH	44.87	11.00	0.00	0.00	36.55	0.00	0.00	0.00	0.00	13.60	0.00	0.00	0.00	0.00	0.00	3.20	2.57	0.00
MOH	0.00	0.00	0.00	72.45	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	8.72	49 67	3.22	19.83	304.95	20.02	14.97	2.22	27.68	12.03	7.63	6 00	0.00	10.98	0.00	0.00	8.00	5.90
LRPF	206.06	70 11	203.52	99 00	115 20	197 73	404.67	98.83	226.08	102.93	168.21	114.24	0.00	304.43	0 00	0.00	99.04	103.78
EFOH	2.51	4.86	0 91	2.74	49.00	5.52	8.45	0.31	8.73	1.73	1.79	0.96	0.00	4.66	0.00	0.00	1.11	0 85
PMOH	0.00	135.73	40.08	0.00	116.03	30.42	9.75	3 25	7.00	0.00	7.50	1.75	0.00	144.25	0.00	75.63	11.33	6.00
LRPM	0.00	183.81	223.28	0.00	384.48	104.23	575.00	337.10	99.05	0.00	545.97	99.15	0.00	103.63	0.00	99.00	202.44	40.99
EMOH	0.00	34.80	12.48	0.00	62.22	4.42	7.82	1.53	0.97	0.00	5.71	0.24	0 00	20.85	0.00	10 44	3.20	0.34
NPC	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717 00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717 00	717 00	717.00

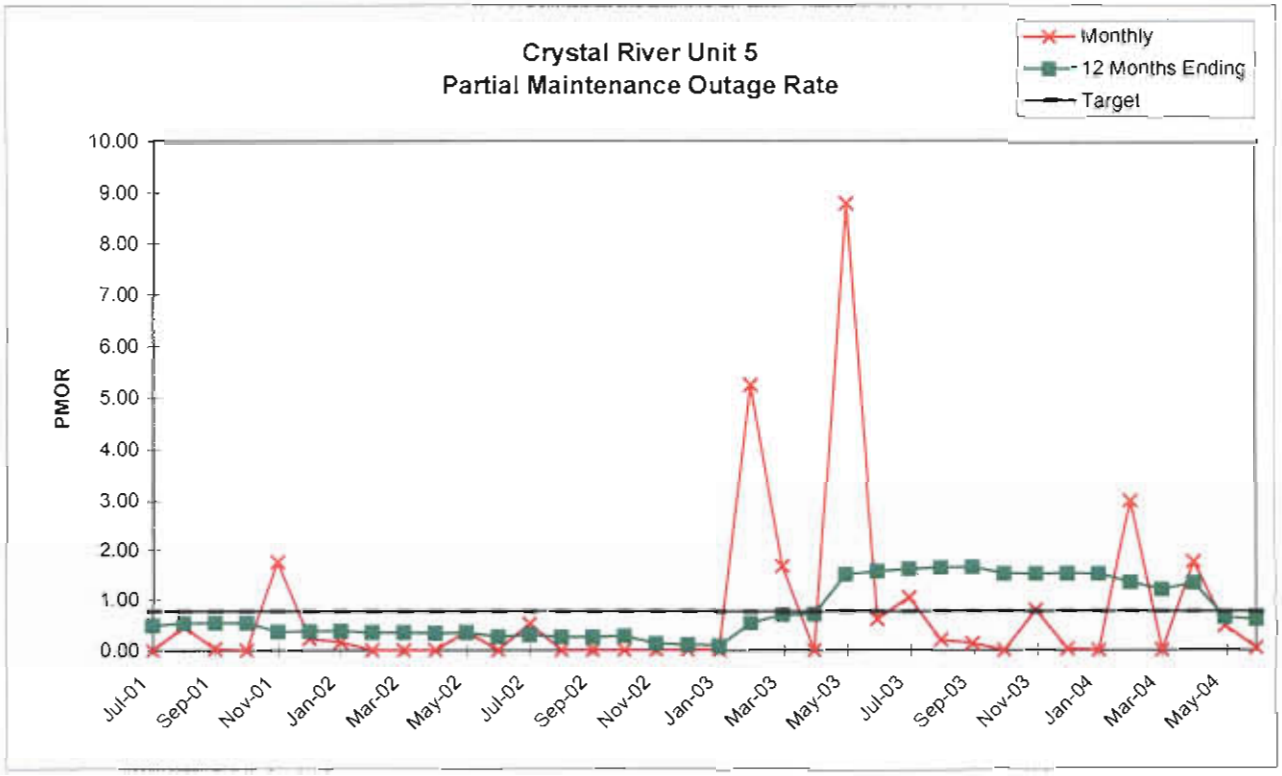
MONTHLY	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	6.03	1.64	0.00	0.00	4.91	0.00	0.00	0.00	0.00	1.83	0.00	0.00	0.00	0.00	0.00	0.54	0.38	0.00
MOR	0.00	0.00	0.00	10.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.36	0.73	0.12	0.42	6.93	0.77	1.14	0.04	1.21	0.24	0.25	0.13	0.00	0.67	0.00	0.00	0.17	0.12
PMOR	0.00	5.26	1.68	0.00	8.79	0.61	1.05	0.21	0.13	0.00	0.79	0.03	0.00	3.00	0.00	1.76	0.48	0.05
EUOR	6.37	7.54	1.80	10.46	19.86	1.38	2.19	0.25	1.35	2.06	1.04	0.16	0.00	3.67	0.00	2.29	1.03	0.17
EUOF	6.37	7.54	1.80	10.46	19.86	1.38	2.19	0.25	1.35	2.06	1.04	0.16	0.00	3.67	0.00	1.90	0.92	0.17
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.97	10.24	0.00
EAF	93.63	92.46	98.20	89.54	80.14	98.62	97.81	99.75	98.65	97.94	98.96	99.84	100.00	96.33	100.00	81.13	88.83	99.83

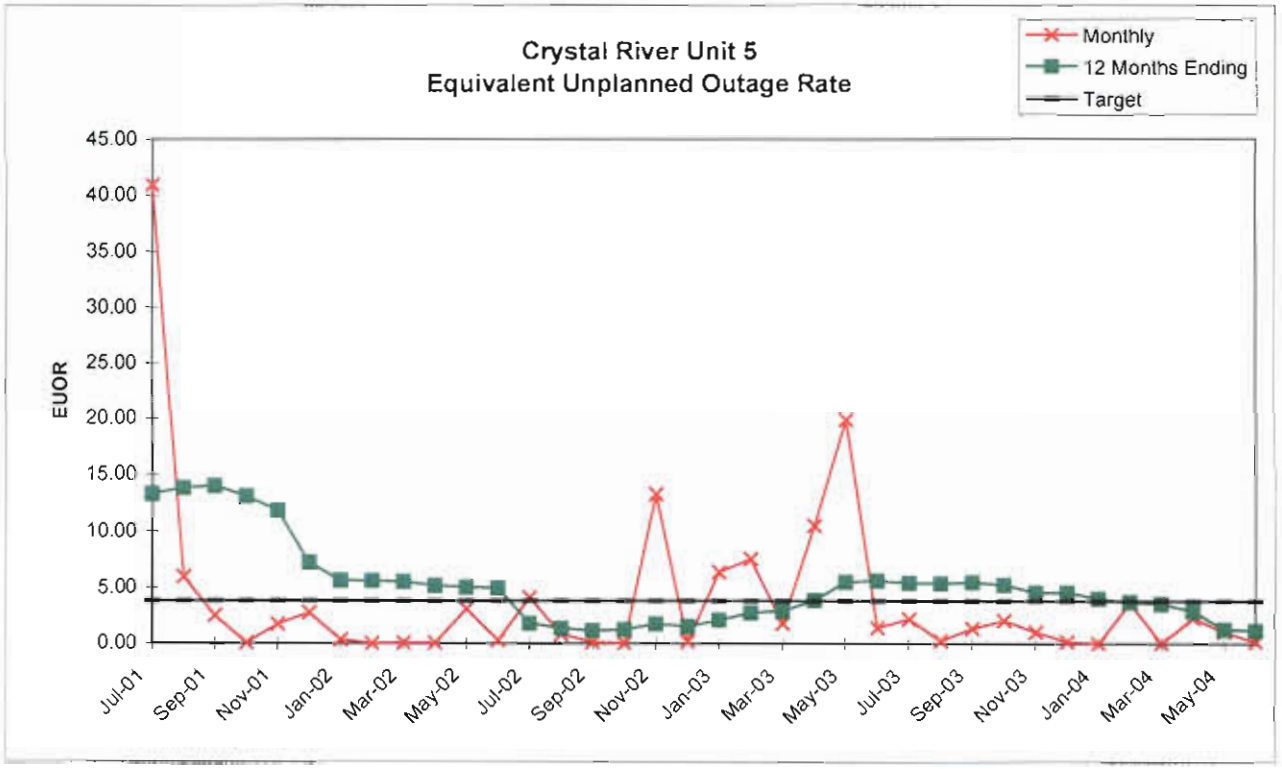
12 MONTHS	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	1.56	1.70	1.70	1.72	2.18	2.18	1.83	1.83	1.83	1.85	1.22	1.22	0.70	0.58	0.58	0.62	0.23	0.23
MOR	0.00	0.00	0.00	0.95	0.95	0.95	0.95	0.95	0.95	0.88	0.84	0.84	0.83	0.83	0.83	0.00	0.00	0.00
PFOR	0.43	0.50	0.50	0.54	0.94	0.98	1.09	1.01	1.12	1.05	1.02	1.02	0.99	0.98	0.97	0.94	0.39	0.33
PMOR	0.08	0.54	0.71	0.71	1.51	1.57	1.61	1.63	1.65	1.52	1.51	1.52	1.51	1.34	1.20	1.33	0.64	0.60
EUOR	2.07	2.72	2.89	3.85	5.46	5.56	5.38	5.32	5.44	5.20	4.52	4.52	3.98	3.68	3.53	2.87	1.26	1.15
EUOF	1.83	2.41	2.55	3.41	4.83	4.92	4.76	4.71	4.81	4.99	4.52	4.52	3.98	3.68	3.53	2.83	1.23	1.13
POF	11.48	11.48	11.48	11.48	11.48	11.48	11.48	11.48	11.48	4.09	0.00	0.00	0.00	0.00	0.00	1.39	2.26	2.26
EAF	86.69	86.11	85.96	85.11	83.68	83.59	83.76	83.81	83.71	90.92	95.48	95.48	96.02	96.32	96.47	95.78	96.52	96.62

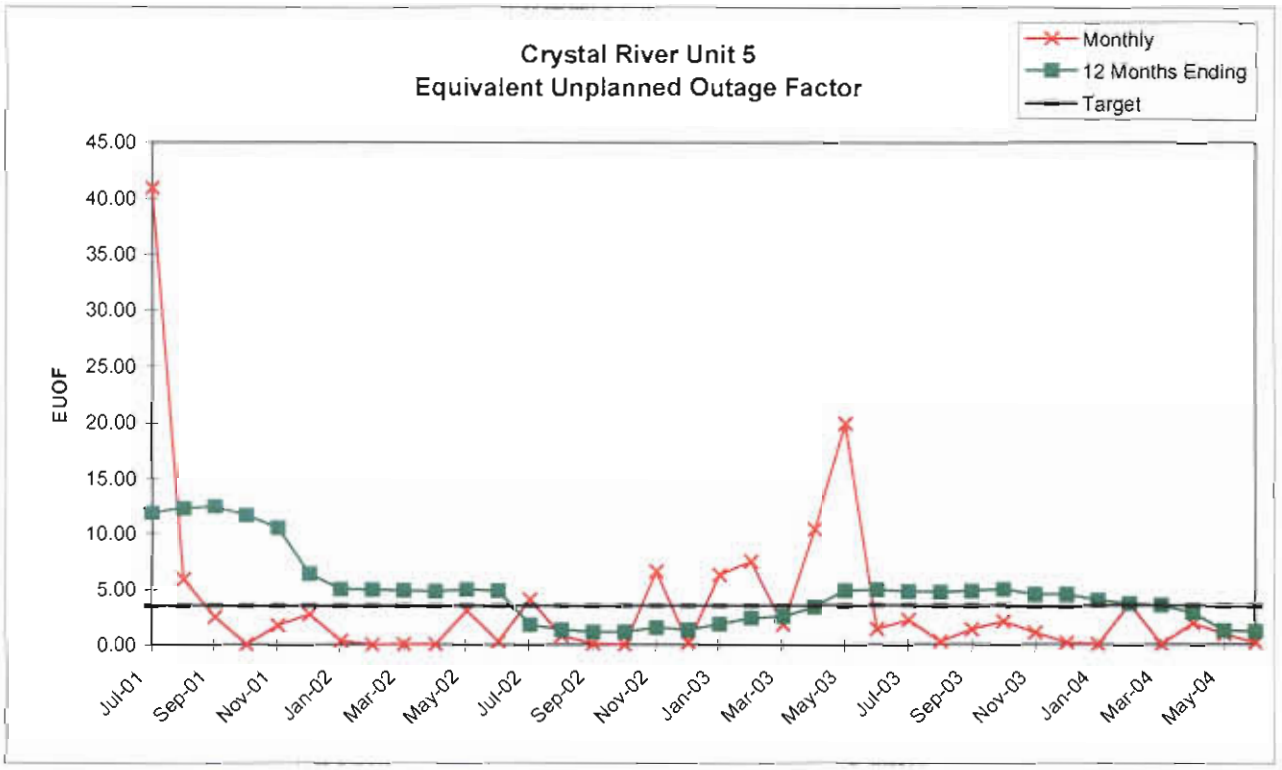

Crystal River Unit 5
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 5
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 5
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 5
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 5
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04


Crystal River Unit 5
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04

Hines
Unit 1

	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744 00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	744.00	720.00	744.37	29.87	743.20	744.00	672.00	737.17	297.68	721.00	709.07	744.00	744.00	696.35	745.00	530.83	538.02
RSH	0 00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	6.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.33
UH	0.00	0.00	0.00	0.63	690.13	0.80	0 00	0.00	0 00	421.32	23.00	10.93	0.00	0.00	23.65	0.00	189.17	201.65
POH	0.00	0.00	0.00	0.63	690.13	0.00	0.00	0.00	0.00	421 32	0.00	0.00	0.00	0.00	0 00	0.00	189.17	201.65
FOH	0 00	0.00	0.00	0.00	0.00	0.80	0.00	0.00	0.00	0.00	0.00	10.93	0.00	0.00	23.65	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	23.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50	0 00	0.00	1.40	0.00	0.00	2.30	0.00	0 00	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	381.74	0.00	0.00	248.92	0.00	0.00	234.08	0.00	0.00	0.00
EFOH	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.40	0.00	0.00	0.72	0 00	0.00	1.12	0.00	0.00	0.00
PMOH	0 00	0.00	0.00	232.77	0.00	0.00	37.37	0.00	0.00	10.05	37.47	0.00	0.00	0.00	53.82	0.00	0.00	0 00
LRPM	0.00	0.00	0.00	132.00	0.00	0.00	251 98	0.00	0.00	251.98	241.98	0.00	0.00	0.00	233.99	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	63.75	0.00	0.00	19.54	0 00	0.00	5.25	18 81	0.00	0.00	0.00	26.13	0.00	0 00	0.00
NPC	482 00	482 00	482 00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482 00	482.00	482.00	482.00	482.00

MONTHLY	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	0.00	0.00	0.00	1.52	0.00	0.00	3.28	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.00	0.10	0.00	0.00	0.16	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	8.56	0.00	0.00	2.63	0.00	0.00	1.76	2.61	0.00	0.00	0.00	3.75	0.00	0.00	0.00
EUOR	0.00	0.00	0.00	8.56	0.00	0.11	2.63	0.00	0.05	1.76	5.62	1.62	0.00	0.00	7.07	0.00	0.00	0.00
EUOF	0.00	0.00	0.00	8.56	0.00	0.11	2.63	0.00	0.05	0.73	5.62	1.62	0.00	0.00	7.07	0.00	0.00	0.00
POF	0.00	0.00	0.00	0.08	95.85	0.00	0.00	0.00	0.00	58.60	0.00	0.00	0.00	0.00	0.00	0.00	26.27	27.10
EAF	100.00	100.00	100.00	91.36	4.15	99.89	97.37	100.00	99.95	40.67	94.38	98.38	100.00	100.00	92.93	100.00	73.73	72.90

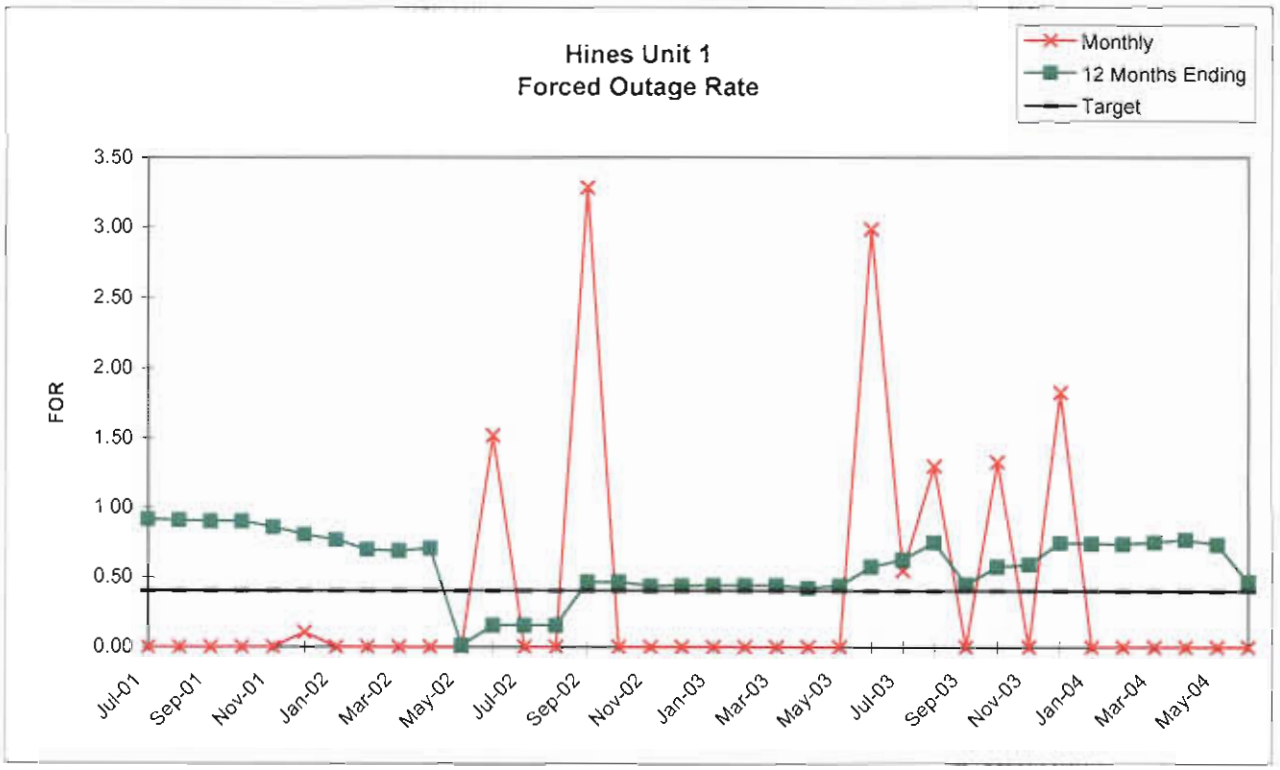
12 MONTHS	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	0.91	0.91	0.90	0.90	0.86	0.80	0.76	0.69	0.69	0.70	0.01	0.15	0.15	0.15	0.46	0.46	0.44	0.44
MOR	1.70	0.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.30	0.30	0.30	0.30	0.30	0.30	0.28	0.29
PFOR	2.19	0.90	0.90	0.87	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.03
PMOR	0.82	0.81	0.78	1.79	1.88	1.81	2.02	1.83	1.81	1.75	1.89	1.41	1.41	1.41	1.76	0.92	0.86	0.88
EUOR	5.51	3.44	2.56	3.54	2.72	2.60	2.77	2.51	2.49	2.45	2.20	1.87	1.87	1.87	2.54	1.71	1.60	1.63
EUOF	4.00	2.50	1.86	2.57	1.89	1.87	2.09	2.09	2.10	2.04	1.92	1.63	1.63	1.63	2.22	1.49	1.49	1.48
POF	12.27	12.27	12.27	12.28	15.62	15.62	15.62	15.62	15.62	17.68	12.69	12.69	12.69	12.69	12.69	12.69	6.97	9.27
EAF	83.73	85.23	85.87	85.15	82.50	82.51	82.29	82.29	82.29	80.31	85.39	85.67	85.67	85.67	85.09	85.82	91.54	89.25

Hines
Unit 1

	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
PER HOURS	744.00	672 00	744 00	719.00	744.00	720 00	744.00	744.00	720 00	745.00	720.00	744.00	744.00	696.00	744.00	719.00	744.00	720.00
SER HOURS	686.65	672 00	744.00	669.35	372.07	698.50	739.95	734.32	720.00	735.10	321.40	730 40	744.00	696.00	622.02	480.30	744.00	720.00
RSH	57.35	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	56.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0 00	49.65	371.93	21.50	4.05	9.68	0.00	9 90	342.00	13.60	0.00	0.00	121.98	238.70	0.00	0.00
POH	0.00	0.00	0.00	49.65	371.93	0.00	0.00	0.00	0.00	0.00	342.00	0.00	0.00	0.00	121.98	238.70	0.00	0 00
FOH	0.00	0.00	0.00	0.00	0.00	21.50	4.05	9.68	0.00	9.90	0.00	13.60	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	96.77	72.00	4.02	0.00	0.00	0.00	0.00	0.00	0.00	8.25	0.00	0.00	0.00	0.00	0.00	0.00	1.73	48.93
LRPF	246 99	252.00	146.88	0.00	0.00	0.00	0.00	0.00	0.00	257.01	0.00	0.00	0.00	0.00	0.00	0.00	293.94	276.02
EFOH	49.59	37.64	1 23	0.00	0.00	0.00	0.00	0.00	0.00	4.40	0.00	0.00	0.00	0.00	0.00	0.00	1.06	28.02
PMOH	51.88	0.00	0.00	113.23	23.33	0.00	0.00	0.00	0 00	0.00	169.07	0.00	0.00	0.00	0.00	480.30	262.08	0.00
LRPM	247.01	0.00	0 00	250.01	240.03	0.00	0.00	0.00	0.00	0.00	261.99	0.00	0.00	0 00	0.00	236.00	236.00	0.00
EMOH	26.59	0.00	0.00	58.73	11.62	0.00	0.00	0.00	0.00	0.00	91.90	0.00	0.00	0.00	0.00	235.17	128.32	0.00
NPC	482 00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482 00	482 00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00

MONTHLY	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	0.00	0.00	0.00	0.00	0.00	2.99	0.54	1.30	0.00	1.33	0.00	1.83	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	7.22	5.60	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.14	3.89
PMOR	3.87	0.00	0.00	8.77	3.12	0.00	0.00	0.00	0.00	0.00	28.59	0.00	0.00	0.00	0.00	48.96	17.25	0.00
EUOR	11.09	5.60	0.16	8.77	3.12	2.99	0.54	1.30	0.00	1.92	28.59	1.83	0.00	0.00	0.00	48.96	17.39	3.89
EUOF	10.24	5.60	0.16	8.17	1.56	2.99	0.54	1.30	0.00	1.92	12.76	1.83	0.00	0.00	0.00	32.71	17.39	3.89
POF	0.00	0.00	0.00	6.91	49.99	0.00	0.00	0.00	0.00	0.00	47.50	0.00	0.00	0.00	16.40	33.20	0.00	0.00
EAF	89.76	94.40	99.84	84.93	48.45	97.01	99.46	98.70	100.00	98.08	39.74	98.17	100.00	100.00	83.60	34.09	82.61	96.11

12 MONTHS	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	0.44	0.44	0.44	0.42	0.44	0.57	0.62	0.75	0.45	0.57	0.59	0.75	0.74	0.74	0.75	0.77	0.73	0.46
MOR	0.29	0.29	0.29	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.66	1.14	1.15	1.10	1.15	1.14	1.14	1.14	1.13	1.18	1.22	1.19	0.55	0.07	0.06	0.06	0.07	0.42
PMOR	0.98	0.98	0.98	1.59	1.57	1.57	1.57	1.57	1.23	1.24	2.47	2.41	2.06	2.05	2.08	4.46	5.72	5.70
EUOR	2.36	2.84	2.85	3.37	3.14	3.27	3.32	3.44	2.80	2.98	4.26	4.32	3.33	2.85	2.87	5.25	6.47	6.56
EUOF	2.13	2.56	2.56	3.18	2.83	2.94	2.99	3.10	2.52	2.68	3.73	3.89	3.02	2.58	2.57	4.57	5.91	5.99
POF	9.27	9.27	9.27	5.03	9.27	9.27	9.27	9.27	9.27	9.27	11.02	8.72	8.72	8.69	10.08	12.23	8.00	8.00
EAF	88.60	88.17	88.16	91.80	87.90	87.78	87.74	87.63	88.21	88.04	85.25	87.40	88.27	88.73	87.35	83.19	86.09	86.01


Hines Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
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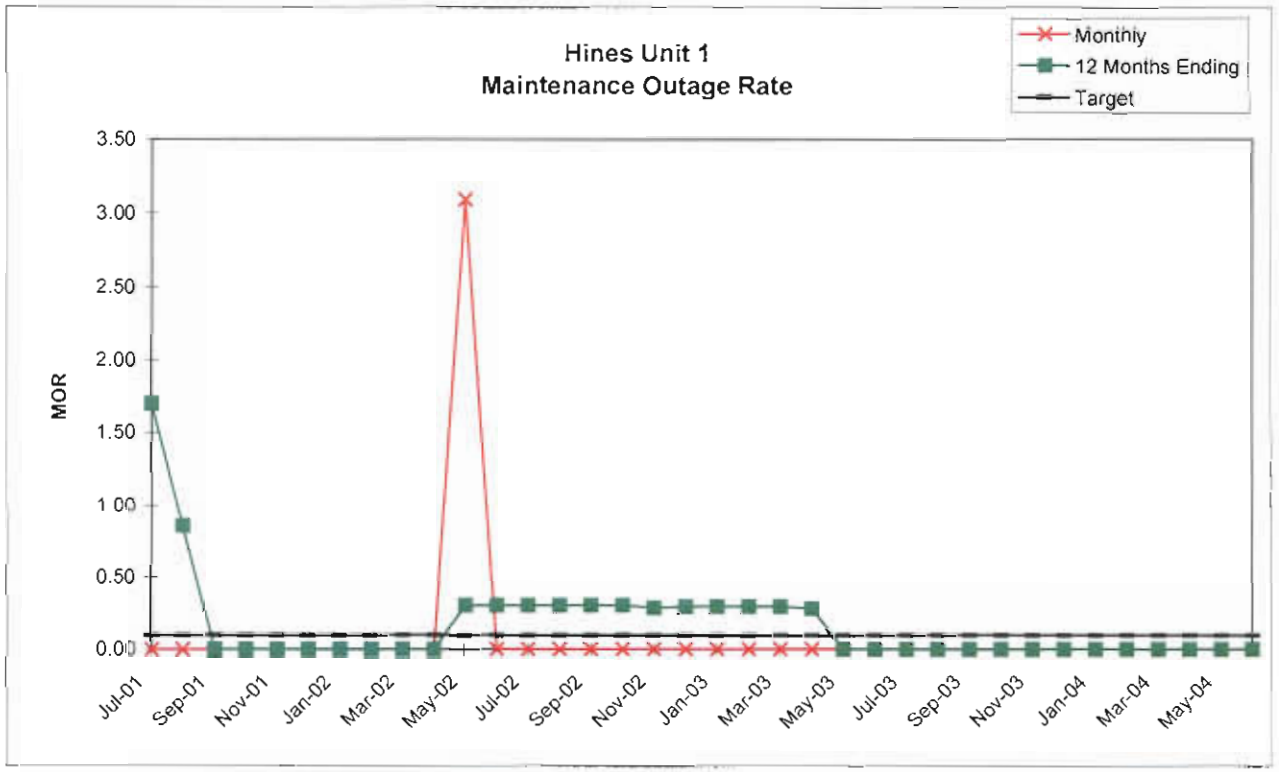
Jan-04
Mar-04
May-04


Hines Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-01
Sep-01
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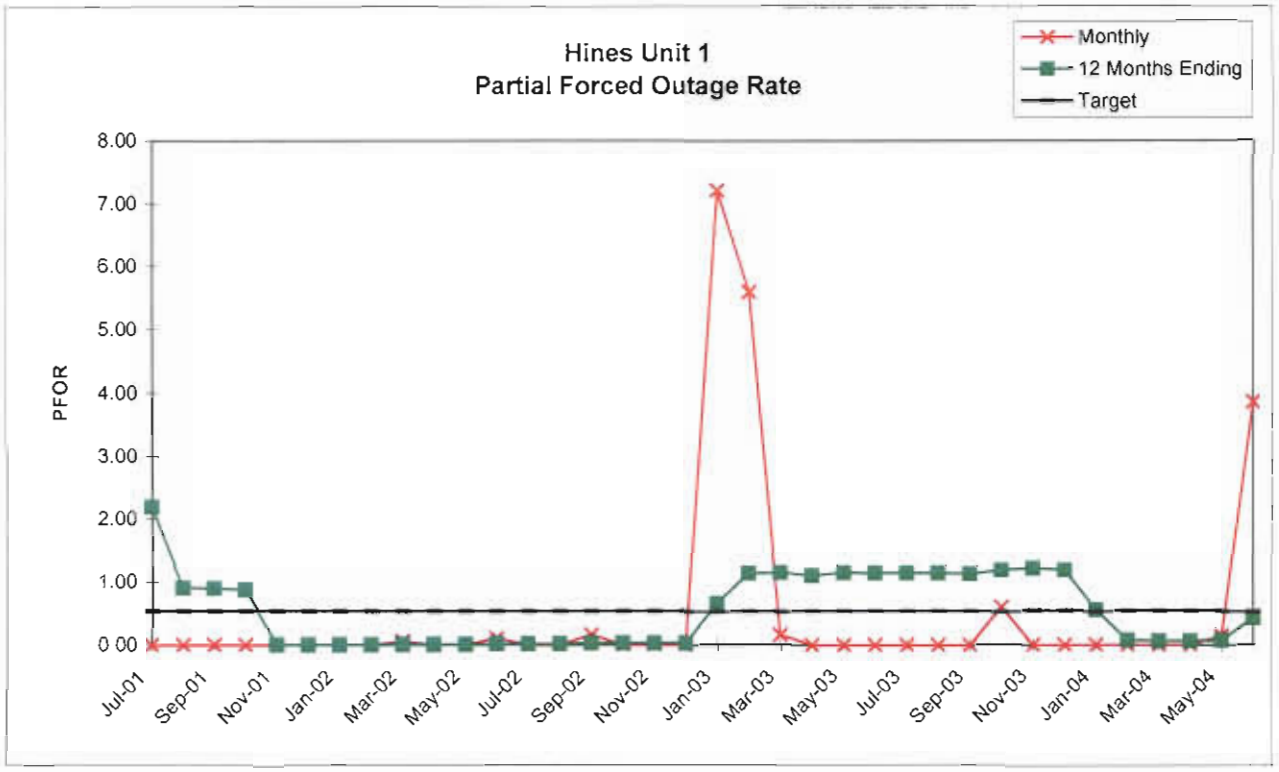
Hines Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
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7.00
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2.00
1.00
0.00
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Sep-01
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Jan-02
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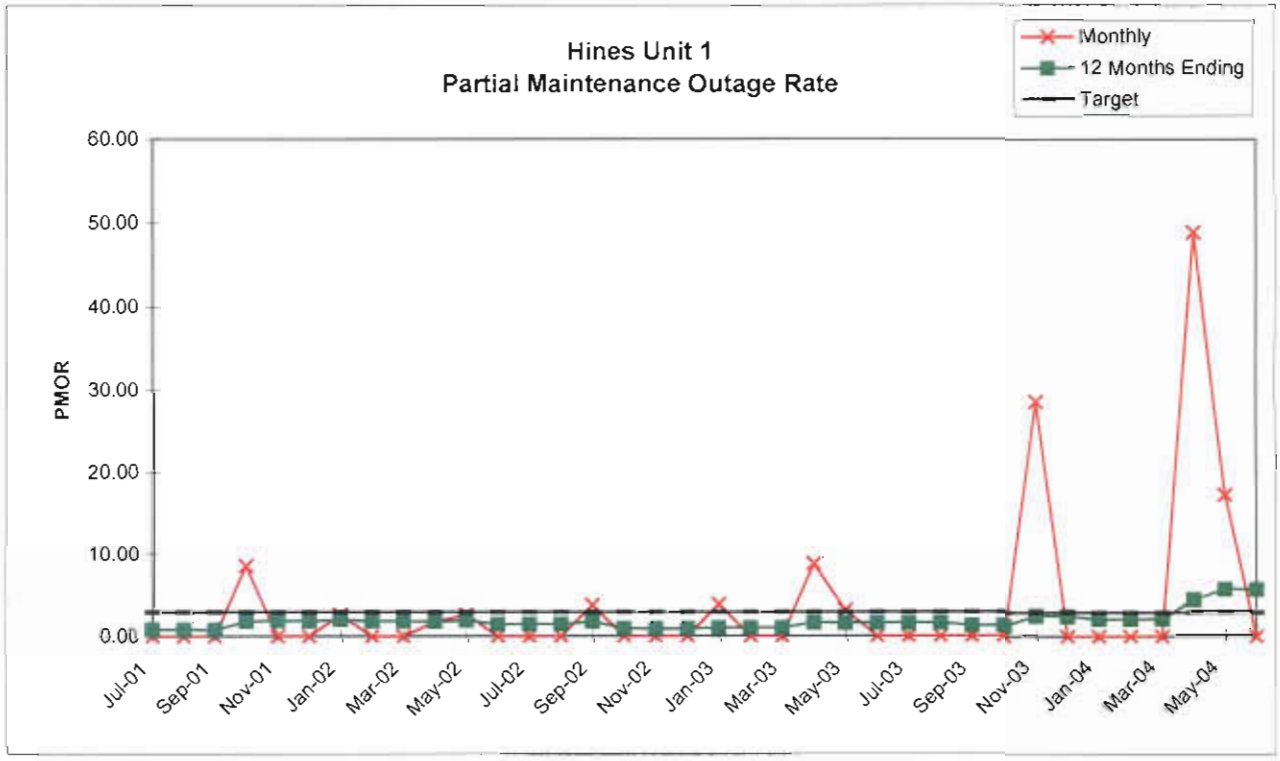
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Monthly
12 Months Ending
Target
PMOR
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50.00
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30.00
20.00
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Jul-01
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Jan-02
Mar-02
May-02
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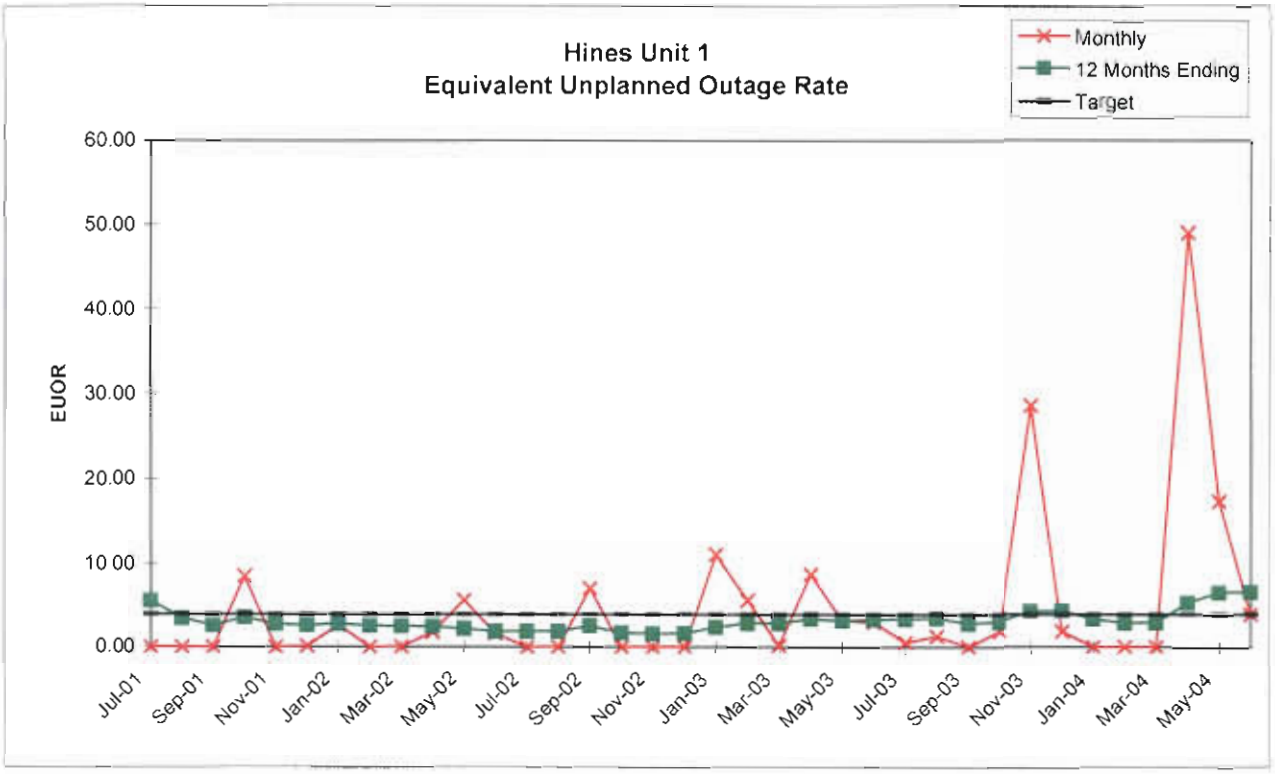
May-04


Hines Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
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50.00
40.00
30.00
20.00
10.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
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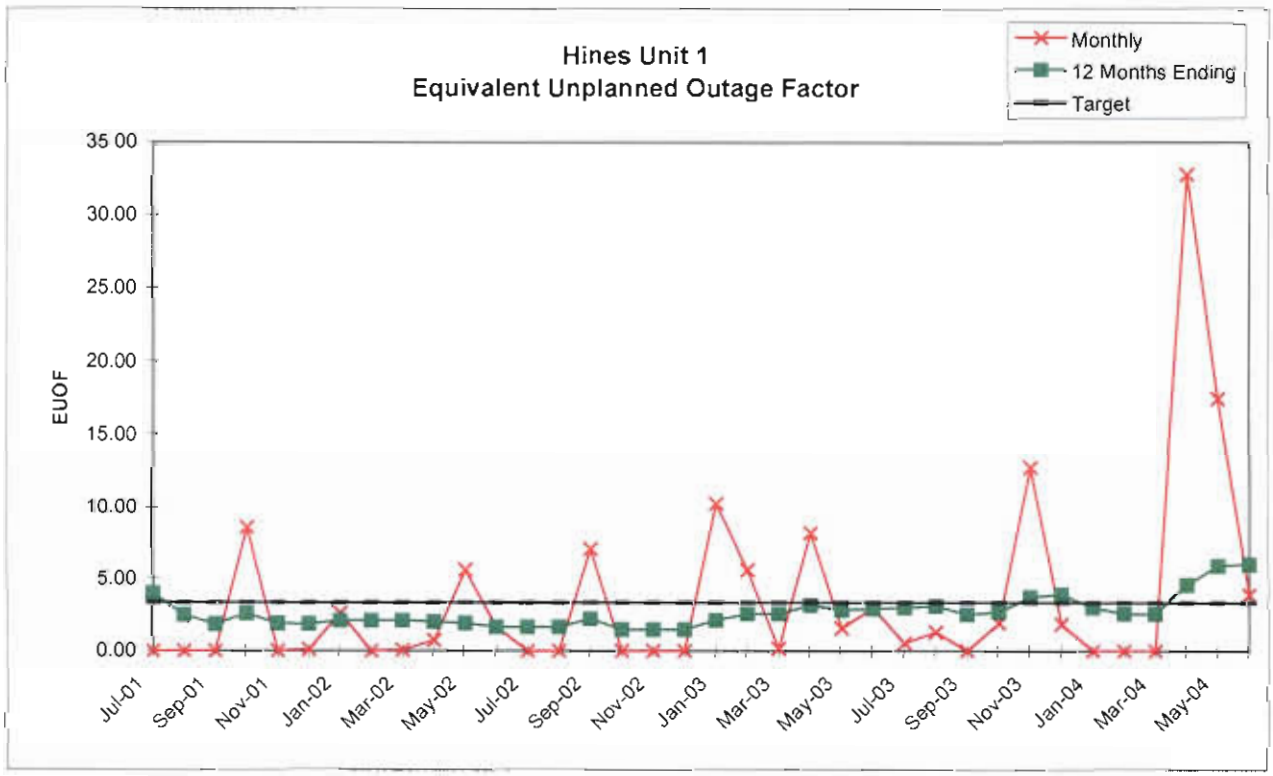
Nov-03
Jan-04
Mar-04
May-04


Hines Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
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30.00
25.00
20.00
15.00
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5.00
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Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04

Tiger Bay

	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	744.00	699 67	614.33	713 08	744.00	709.72	672.00	286.37	669.33	744.00	710.92	716.00	742.70	708.00	464.70	720.00	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	20.33	130.67	6.92	0.00	34.28	0.00	457.63	49.67	0.00	9.08	28.00	1.30	12.00	280.30	0.00	0.00
POH	0.00	0.00	0.00	130.67	0.00	0.00	0.00	0.00	457.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	20.33	0.00	6.92	0.00	34.28	0.00	0.00	4.82	0.00	9.08	28.00	1.30	12.00	2.38	0.00	0.00
MOH	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.85	0.00	0.00	0.00	0.00	0.00	277.92	0.00	0.00
PFOH	0.00	0.00	322 52	0.00	0.00	0.00	0.00	0.00	0.00	0.85	0.00	0.00	0.00	0.00	0.47	0.00	0.00	0.00
LRPF	0.00	0.00	73.01	0 00	0.00	0.00	0.00	0.00	0.00	198.96	0.00	0.00	0.00	0.00	182.34	0.00	0.00	0.00
EFOH	0.00	0.00	113.76	0.00	0 00	0.00	0.00	0.00	0.00	0.82	0.00	0.00	0.00	0.00	0.41	0.00	0 00	0.00
PMOH	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.38	0.00	9.62	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	207.26	0.00	190.95	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.38	0.00	8.87	0.00	0.00
NPC	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00

MONTHLY	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	0.00	0.00	2.82	0.00	0.96	0.00	4.61	0.00	0.00	0.71	0.00	1.26	3.76	0.17	1.67	0.51	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.28	0.00	0.00	0.00	0.00	0.00	37.42	0.00	0.00
PFOR	0.00	0.00	16.26	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.32	0.00	1.91	0.00	0.00
EUOR	0.00	0.00	18.62	0.00	0.96	0.00	4.61	0.00	0.00	7.02	0.00	1.26	3.76	0.50	1.72	38.82	0.00	0.00
EUOF	0.00	0.00	18.62	0.00	0.96	0.00	4.61	0.00	0.00	7.02	0.00	1.26	3.76	0.50	1.72	38.82	0.00	0.00
POF	0.00	0.00	0.00	17.54	0.00	0.00	0.00	0.00	61.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	100.00	81.38	82.46	99.04	100.00	95.39	100.00	38.49	92.98	100.00	98.74	96.24	99.50	98.28	61.18	100.00	100.00

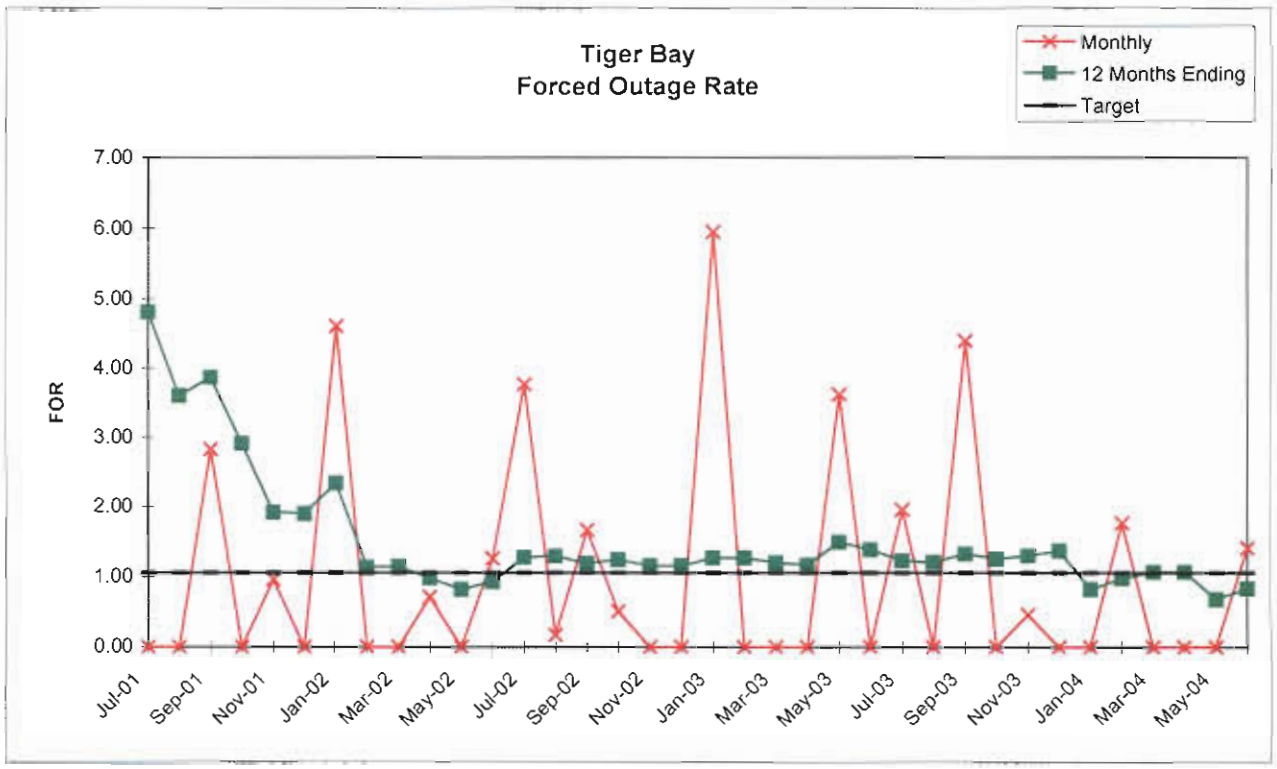
12 MONTHS	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
FOR	4.80	3.59	3.86	2.90	1.91	1.90	2.33	1.13	1.14	0.98	0.82	0.93	1.27	1.29	1.19	1.24	1.15	1.15
MOR	1.71	1.69	1.70	1.69	1.62	0.86	0.86	0.85	0.86	1.38	0.61	0.55	0.56	0.56	0.56	3.93	3.93	3.93
PFOR	0.02	0.02	1.57	1.56	1.50	1.49	1.49	1.48	1.50	1.45	1.44	1.42	1.43	1.43	0.02	0.02	0.02	0.02
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.14	0.14	0.14
EUOR	6.37	5.18	6.92	5.99	4.92	4.17	4.60	3.41	3.45	3.74	2.83	2.87	3.22	3.26	1.77	5.23	5.14	5.14
EUOF	5.62	4.57	6.10	5.26	4.46	3.78	4.17	3.09	3.09	3.49	2.64	2.68	3.00	3.04	1.65	4.95	4.88	4.88
POF	10.65	10.65	10.65	12.14	9.33	9.33	9.33	9.33	10.46	6.72	6.72	6.72	6.72	6.72	6.72	5.22	5.22	5.22
EAF	83.73	84.78	83.25	82.60	86.21	86.89	86.50	87.58	86.45	89.79	90.64	90.60	90.28	90.24	91.63	89.82	89.90	89.90

Tiger Bay

	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	696.00	744.00	719.00	744.00	720.00
SER HOURS	680.52	672.00	744.00	485.95	717.08	707.75	729.45	744.00	373.32	745.00	617 82	349.27	595.12	636.59	70.25	492 70	685.20	709.85
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	99.33	294.20	148.88	0.00	218.75	184.47	58.80	0.00
UH	63.48	0.00	0.00	233.05	26.92	12.25	14.55	0.00	346.68	0.00	2.85	100.53	0.00	59.41	455.00	41.83	0.00	10.15
POH	0.00	0.00	0.00	233.05	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	47.98	455.00	0.00	0.00	0.00
FOH	43.05	0.00	0.00	0.00	26.92	0.00	14.55	0.00	17.15	0.00	2.85	0.00	0.00	11.43	0.00	0.00	0.00	10.15
MOH	20.43	0.00	0.00	0.00	0.00	12.25	0.00	0.00	329.53	0.00	0.00	100.53	0.00	0.00	0.00	41.83	0.00	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0 00
EFOH	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0 00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	207.00	207.00	207 00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00

MONTHLY	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	5.95	0.00	0.00	0.00	3.62	0.00	1.96	0.00	4.39	0.00	0.46	0.00	0.00	1.76	0.00	0.00	0.00	1.41
MOR	2.91	0.00	0.00	0.00	0.00	1.70	0.00	0.00	46.88	0.00	0.00	22.35	0.00	0.00	0.00	7.83	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	8.53	0.00	0.00	0.00	3.62	1.70	1.96	0.00	48.15	0.00	0.46	22.35	0.00	1.76	0.00	7.83	0.00	1.41
EUOF	8.53	0.00	0.00	0.00	3.62	1.70	1.96	0.00	48.15	0.00	0.40	13.51	0.00	1.64	0.00	5.82	0.00	1.41
POF	0.00	0.00	0.00	32.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.89	61.16	0.00	0.00	0.00
EAF	91.47	100.00	100.00	67.59	96.38	98.30	98.04	100.00	51.85	100.00	99.60	86.49	100.00	91.46	38.84	94.18	100.00	98.59

12 MONTHS	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FOR	1.26	1.26	1.20	1.16	1.49	1.38	1.22	1.20	1.32	1.25	1.30	1.36	0.82	0.97	1.07	1.06	0.68	0.82
MOR	4.18	4.18	3.96	3.54	3.55	3.69	3.69	3.69	7.60	4.30	4.35	5.76	5.58	5.61	6.13	6.67	6.70	6.54
PFOR	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.11	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	5.50	5.50	5.21	4.76	5.08	5.11	4.95	4.91	8.83	5.44	5.54	6.97	6.31	6.47	7.07	7.59	7.29	7.26
EUOF	5.21	5.21	5.21	4.63	4.94	4.98	4.82	4.78	8.60	5.30	5.33	6.48	5.75	5.87	5.87	6.34	6.04	6.01
POF	5.22	5.22	0.00	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	2.66	3.20	8.38	5.73	5.73	5.73
EAF	89.57	89.57	94.79	92.71	92.40	92.36	92.52	92.56	88.74	92.04	92.01	90.86	91.59	90.94	85.76	87.93	88.24	88.26


Tiger Bay
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
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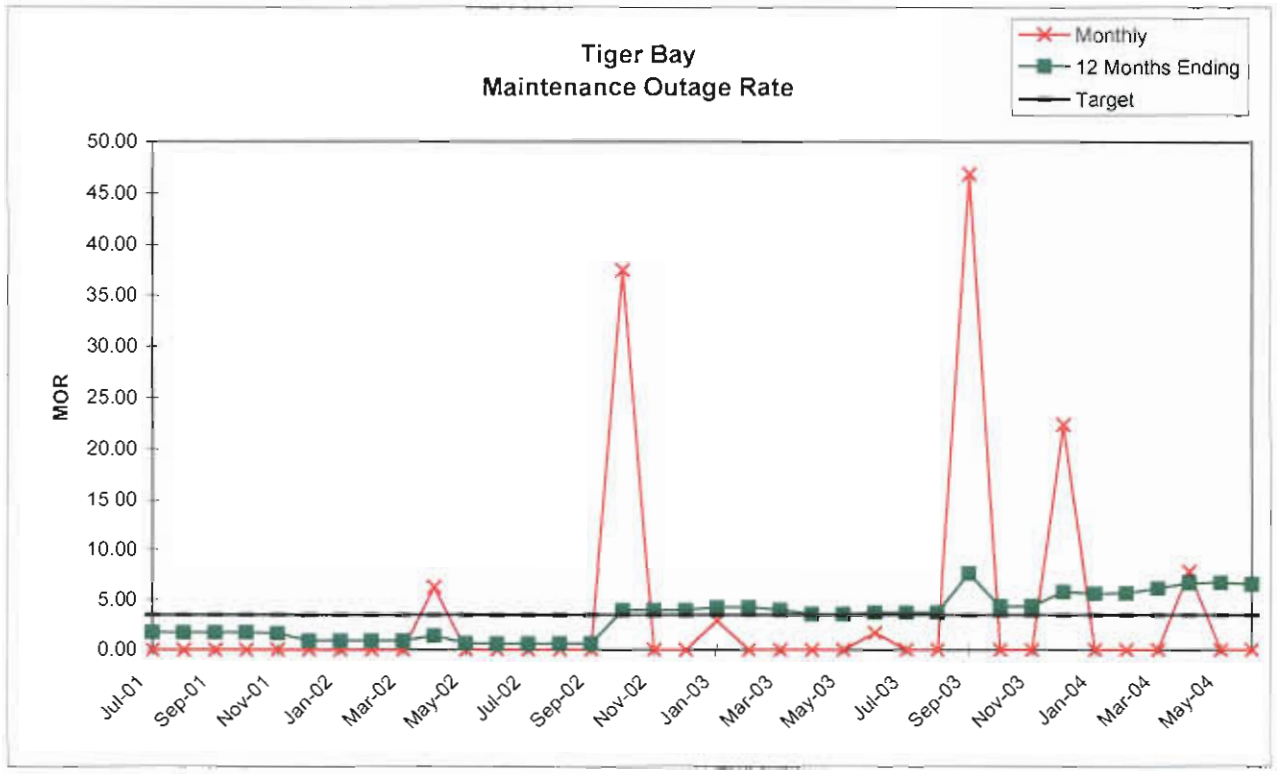
Tiger Bay
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
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45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
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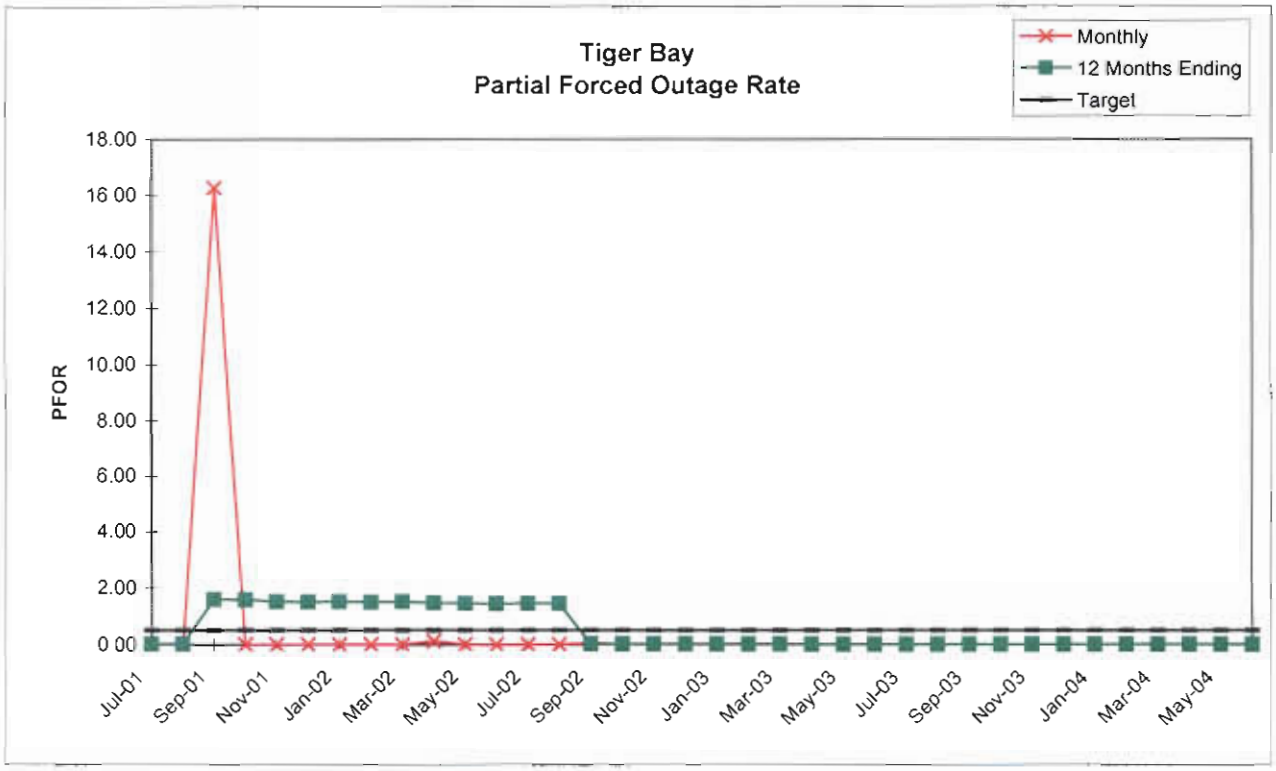
Mar-04
May-04


Tiger Bay
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
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16.00
14.00
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6.00
4.00
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0.00
Jul-01
Sep-01
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Jan-02
Mar-02
May-02
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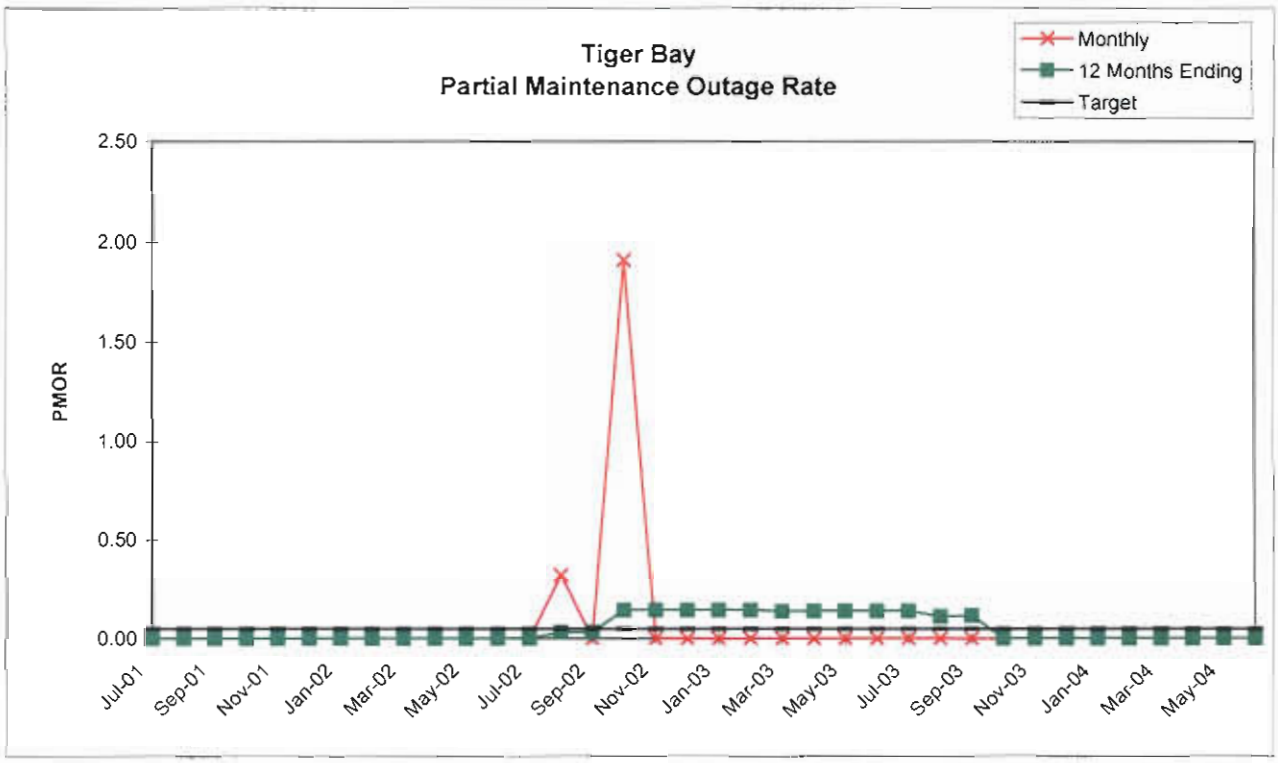
Tiger Bay
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
2.50
2.00
1.50
1.00
0.50
0.00
Jul-01
Sep-01
Nov-01
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Mar-02
May-02
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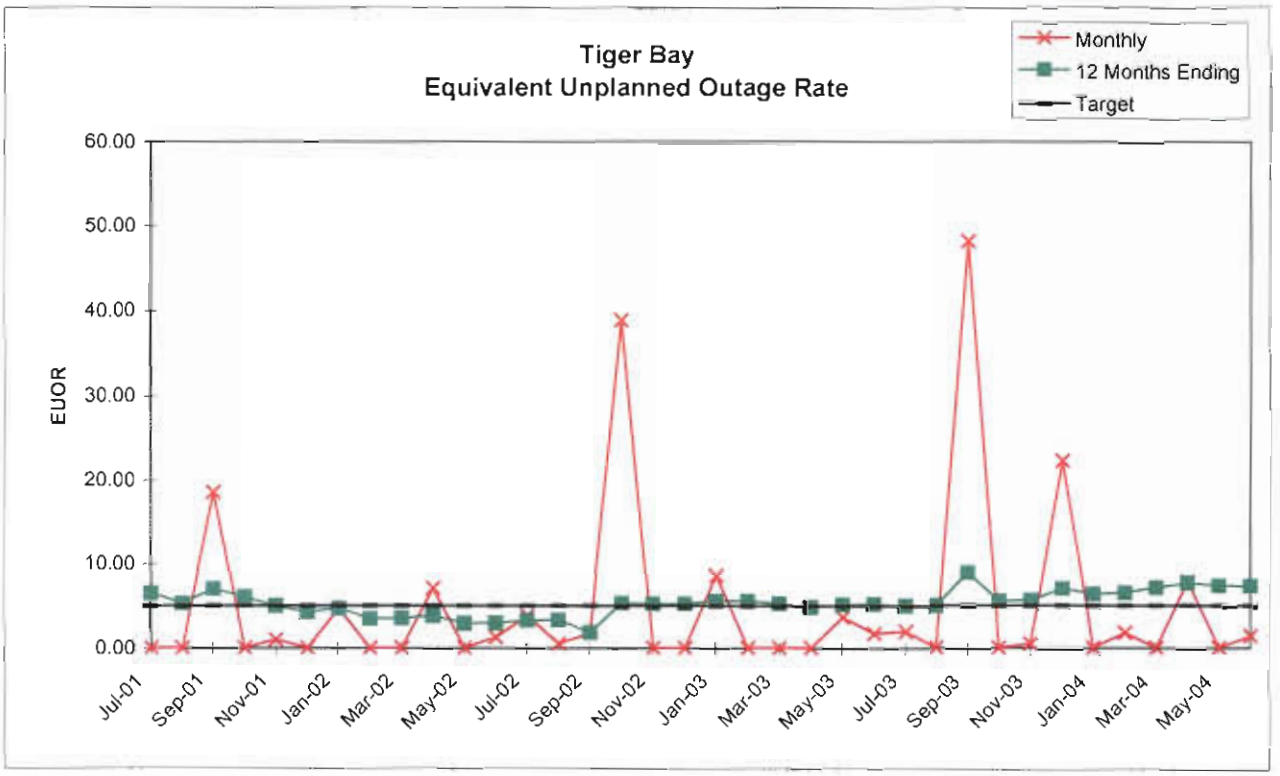
Tiger Bay
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
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0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
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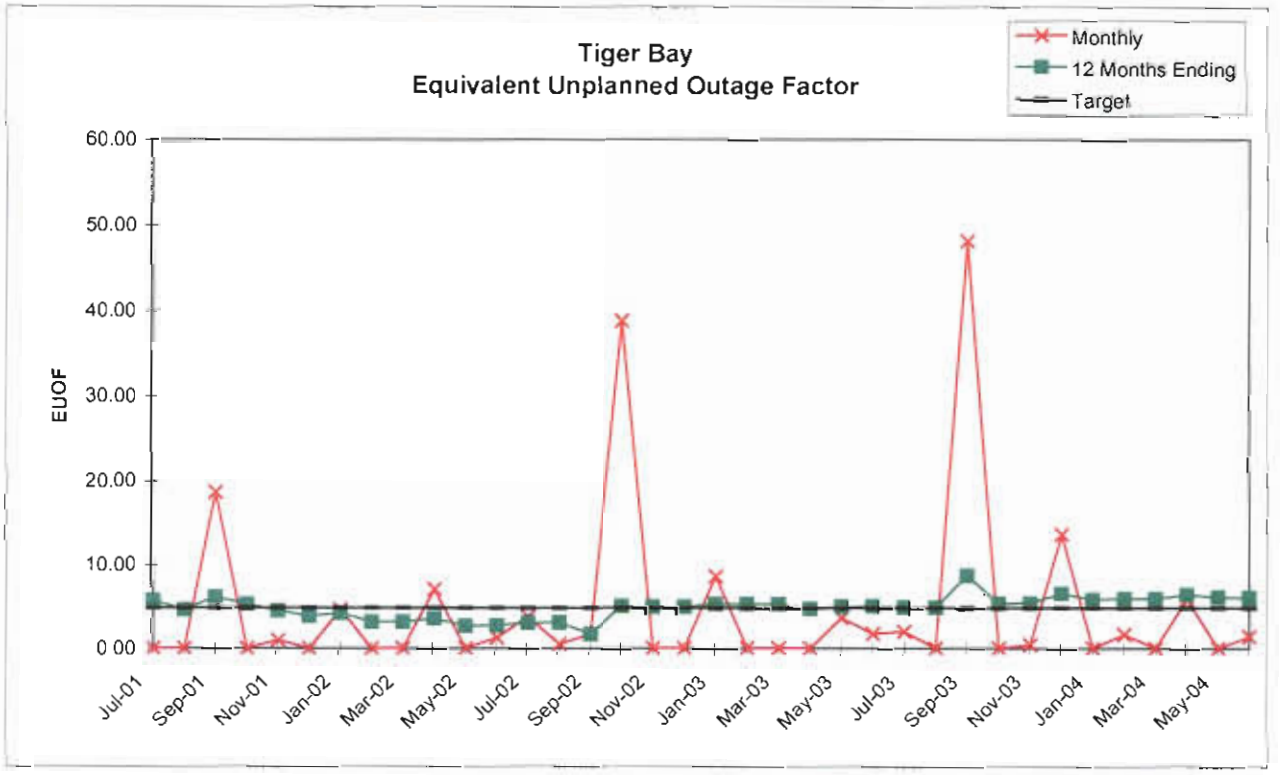
Tiger Bay
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
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Nov-02
Jan-03
Mar-03
May-03
Jul-03
Sep-03
Nov-03
Jan-04
Mar-04
May-04

Exhibit ____ (SSW-1)

Tolling Agreement between Shady Hills Power Company, L.L.C. and Florida Progress Corporation, d/b/a Progress Energy Florida, Inc.

(Filed Separately)

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TOLLING AGREEMENT

between

SHADY HILLS POWER COMPANY, L.L.C.

and

FLORIDA POWER CORPORATION,
d/b/a PROGRESS ENERGY FLORIDA, INC.

August 6, 2004

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TOLLING AGREEMENT

THIS TOLLING AGREEMENT (the "Agreement") is entered into as of the 6th Day of August, 2004, (the "Agreement Date"), by and between Shady Hills Power Company, L.L.C. ("Seller"), a Delaware limited liability company, and Florida Power Corporation, d/b/a Progress Energy Florida, Inc. ("Buyer"). Seller and Buyer may be individually referred to herein as a "Party" and, collectively, as the "Parties."

RECITALS

(A) Seller owns the Shady Hills electric generating facility located in Pasco County, Florida;

(B) Seller and Buyer desire to enter into a tolling arrangement whereby Buyer will deliver Fuel to Seller's Shady Hills electric generating facility and Seller will convert such Fuel into Energy and/or Ancillary Services when scheduled by Buyer; and

(C) The Parties desire to enter into this Agreement to set forth their respective rights and obligations in connection with this tolling arrangement.

NOW, THEREFORE, in consideration of the mutual promises and agreements set forth herein and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties hereby agree as follows:

1. DEFINITIONS

1.1 Defined Terms.

The following terms shall have the meanings set forth below.

(1) "Abandon" or "Abandonment" means the voluntary relinquishment of all possession and control of the Facility or complete cessation of work at the Facility by Seller and Seller's contractors, but only if such relinquishment or cessation is (i) in violation of Prudent Utility Practice, and (ii) not caused by a Force Majeure Event or an Event of Default by Buyer. Seller's assignment or transfer of the Facility or all or the majority of the stock or other ownership interests of Seller shall not, in and of itself, constitute Abandonment.

(2) "Acceptable Credit Rating" means, with respect to any Person, a Credit Rating by S&P and Moody's of at least BBB- by S&P and Baa3 by Moody's.

(3) "Acceptable Guarantor" means a Person that has an Acceptable Credit Rating and that is acceptable, as determined in a commercially reasonable manner, to the Party who would be protected by the Guaranty for this Agreement.

(4) "Actual Equivalent Availability" means the percentage of time the Facility is available for service, up to the Monthly Demonstrated Capacity, whether dispatched by Buyer or not, each Peak Month or Non-Peak Month during the Delivery Term, calculated in accordance with the formula in Exhibit D. The maximum Actual Equivalent Availability of the Facility is one hundred percent (100%). Any Forced Derate or Forced Outage will reduce the Actual Equivalent Availability of the Facility below one hundred percent (100%).

(5) "Affiliate" means any Person that directly or indirectly controls, is controlled by or is under common control with the Person in question.

(6) "AGC" means automatic generation control, which is the capability to make automatic adjustments to generation output in response to system changes through the use of a digital computer. This control is based on such factors as load, frequency, cost, and tie line flows.

(7) "Ancillary Services" means the ancillary services that are, or may become, available from the Facility which shall be delivered by Seller to Buyer for Buyer's sale to third parties or for Buyer to keep for its own use. Ancillary Services include, as defined by a Transmission Provider's open access transmission tariff, Reactive Supply and Voltage Control from Generation Sources Service, Regulation and Frequency Response Service, Energy Imbalance Service, Operating Reserve – Spinning Reserve Service and Operating Reserve - Supplemental Reserve Service provided within the safe operating parameters of the existing equipment at the Facility and environmental permits related to such services.

(8) "Available Capacity" is the Monthly Demonstrated Capacity of the Facility during an hour reduced by the capacity not available that hour due to a Forced Derate or Forced Outage. The Available Capacity shall be zero (0) during any periods of Forced Outage or any Force Majeure Events claimed by Seller where the Facility is forced out of service as a result of such Force Majeure Event.

(9) "Availability Notice" has the meaning set forth in Section 7.3.

(10) "Availability Rebate" has the meaning set forth in Section 6.3, 9.2(3) and Exhibit E.

(11) "Bankruptcy" means with respect to a Person that such Person (i) ceases doing business as a going concern, files a voluntary petition in bankruptcy or is adjudicated bankrupt or insolvent, or files any petition or answer seeking any reorganization, arrangement, composition, readjustment, liquidation, dissolution or similar relief under the present or any future federal bankruptcy code or any other present or future applicable federal, state or other Governmental Rule, or seeks or consents to or acquiesces in the appointment of any trustee, receiver, custodian or liquidator of said Person or of all or any substantial part of its properties, or makes an assignment for the benefit of creditors; or

(ii) a proceeding is initiated against the Person seeking any reorganization, arrangement, composition, readjustment, liquidation, dissolution or similar relief under the present or any future federal bankruptcy code or any other Governmental Rule and, such proceeding, as described in this Section 1.1(11)(ii), is not dismissed within ninety (90) Days after the commencement, or any trustee, receiver, custodian or liquidator of said Person or of all or any substantial part of its properties is appointed without the consent or acquiescence of said Person, and such appointment is not vacated or stayed on appeal or otherwise within ninety (90) Days after the appointment, or, within ninety (90) Days after the expiration of any such stay, has not been vacated.

(12) "Bankruptcy Court" has the meaning set forth in Section 11.1 (2).

(13) "Btu" means British Thermal Unit which is the standard Unit for measuring the quantity of heat energy, such as the heat content of Fuel.

(14) "Business Day" means a Day other than Saturday, Sunday, a NERC holiday or a Day that is authorized as a holiday by banks in New York, New York.

(15) "Capacity Charge" means the amount to be paid by Buyer to Seller each month during the Delivery Term for the Monthly Demonstrated Capacity, as is further set forth in Section 9.2.

(16) "Capacity Price" has the meaning set forth in Exhibit A.

(17) "Claims" means all claims or actions filed by a Person, including fines or penalties, whether groundless, false or fraudulent, that relate to the subject matter of an indemnity, and the resulting losses, damages, expenses, attorney's fees and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are filed prior to or after the expiration or termination of this Agreement.

(18) "Compressor Washes" means an offline water wash of the Facility's combustion turbine compressor(s).

(19) "Contract Term" means the term of this Agreement beginning on the Agreement Date and ending on the Termination Date.

(20) "Credit Rating" means with respect to a Party or any entity, on any date of determination, the respective ratings then assigned to such Party's or entity's unsecured, senior long-term debt (not supported by third party credit enhancement). In the event of any inconsistency in ratings by the two rating agencies (a "split rating"), the lowest assigned rating shall control.

(21) "Damages" has the meaning set forth in Section 13.1(1).

(22) "Day" means the 24-hour period beginning and ending at 12:00 midnight EPT.

(23) "Defaulting Party" has the meaning set forth in Section 11.1(1).

(24) "Delivery Point" means the high side of the Facility's step up transformer(s) at the point of interconnection with the Transmission Provider's system.

(25) "Delivery Term" means the period commencing at hour ending 0100 EPT on April 1, 2007 through and including hour ending 2400 EPT on the Termination Date.

(26) "Demonstrated Capacity" means the number of MWs (rounded to the nearest MW) of Energy and/or Ancillary Services which the Facility is capable of generating, less Energy used for Station Load, as demonstrated by the most recent performance test and corrected to sixty (60) degrees Fahrenheit and sixty percent (60%) relative humidity.

(27) "DIP Lender" means, collectively, General Electric Capital Corporation, as Agent and Lender and GECC Capital Markets Group, Inc. as Lead Arranger, with respect to the Debtor-In-Possession Agreement, dated as of November 5, 2003, among Mirant Corporation and certain of its subsidiaries.

(28) "Dispatch Notice" has the meaning set forth in Section 7.4(2).

(29) "Eastern Prevailing Time" or "EPT" means the prevailing time (*i.e.*, Standard Time or Daylight Savings Time) on any given Day in the Eastern Time Zone.

(30) "Electrical Interconnection Agreements" mean the interconnection agreement(s) between Seller and the Transmission Provider providing for the maintenance and operation of the Electrical Interconnection Facilities.

(31) "Electrical Interconnection Facilities" means the equipment necessary to connect the Units to the Transmission Provider's 230 kV transmission system.

(32) "Energy" means the electric energy in MWh to be delivered by Seller to Buyer pursuant to this Agreement as three-phase, alternating 60 Hertz current at the nominal voltage of the Delivery Point.

(33) "Energy Meters" means the Transmission Provider's revenue meters located at the Delivery Point.

(34) "Event of Default" has the meaning set forth in Section 11.1(1).

(35) "Exhibit" means any exhibit attached to this Agreement, which is hereby incorporated into this Agreement by reference.

(36) "Facility" means the dual-fueled electric generating facility consisting of Units 1, 2 and 3 owned by Seller in Pasco County, Florida, including all equipment used to produce the Demonstrated Capacity, Energy and Ancillary Services, buildings and

facilities, facility control systems, fire protection systems, potable, process, and sanitary water supply, treatment, storage, disposal, and transfer systems, the Electrical Interconnection Facilities, the Gas Interconnection Facilities and all related equipment necessary to accept Fuel at the Fuel Delivery Point including storage and transfer systems, and ingress and egress to the Facility Site.

(37) "Facility Site" means the parcel of land on which the Facility is located in Pasco County, Florida, in the Florida Power Corporation control area.

(38) "FERC" means the Federal Energy Regulatory Commission, or its successor.

(39) "Final Fuel Oil Inventory" means the amount of Fuel Oil in net gallons in Seller's Fuel Oil storage tank(s) at the Facility at the end of the Delivery Term, as measured at midnight on the date such inventory is transferred from Buyer to Seller.

(40) "Force Majeure Event" means an event or circumstance that prevents the performance by a Party of its obligations under this Agreement which is not within the reasonable control of, or the result of the negligence of, the claiming Party and which by the exercise of due diligence the claiming Party is unable to overcome or avoid. Force Majeure includes, without limitation, acts of God; strikes, lock-outs or other industrial disturbances; acts of the public enemy, terrorism, war (whether declared or not), blockades, insurrections, civil disturbances and riots, and epidemics; land slides, lightning, earthquakes, firestorms, hurricanes, tornadoes, floods, washouts, and extreme weather conditions impairing the operation of the Facility or the Transmission Provider's transmission system; bona fide events of force majeure claimed by third-party suppliers of transmission, Fuel or Fuel transportation; orders, directives, restraints, and requirements of any Governmental Authority; and any other similar causes not enumerated that are not within the reasonable control of the claiming Party and which prevent the performance by a Party of its obligations under this Agreement; provided that none of the following shall constitute a Force Majeure Event: (1) the loss of Buyer's markets or reductions in its load requirements, (2) Seller's ability to sell the Monthly Demonstrated Capacity, Energy and/or Ancillary Services at a price higher than the prices in this Agreement, (3) any Forced Outage or Forced Derate, except to the extent caused by an event that is otherwise a Force Majeure Event.

(41) "Forced Derate" means a curtailment at the Facility resulting from equipment failure or malfunction or a Force Majeure Event claimed by Seller which prevents the Facility from functioning at the Monthly Demonstrated Capacity while remaining in service, excluding hours for Planned Maintenance Outages.

(42) "Forced Derate Quantity" means the Monthly Demonstrated Capacity minus the Available Capacity during any Forced Derate (expressed in whole MWs).

(43) "Forced Derate Hours" has the meaning set forth in Exhibit D.

(44) "Forced Outage" means the Facility has been forced out of service by equipment failure or malfunction, excluding Planned Maintenance Outages and any Force Majeure Event claimed by Seller.

(45) "Forced Outage Hours" has the meaning set forth in Exhibit D.

(46) "FPSC" means the Florida Public Service Commission or any successor agency.

(47) "Fuel" means Gas and Fuel Oil.

(48) "Fuel Delivery Point" means either the Fuel Oil Delivery Point or Gas Delivery Point, as the case may be.

(49) "Fuel Oil" means number 2 Fuel Oil that meets the specifications set forth in Exhibit J or as approved by Seller.

(50) "Fuel Oil Delivery Point" means the hose connection at the unloading rack at the Facility.

(51) "GAAP" means Generally Accepted Accounting Principles.

(52) "Gas" means natural gas or any mixture of hydrocarbon gases or hydrocarbon gases and non-combustible gases consisting predominantly of methane.

(53) "Gas Delivery Point" means the point of interconnection between the Gas Transporter's pipeline and the Lateral Pipeline.

(54) "Gas Imbalance Charges" means any pipeline scheduling, imbalance, cashout, operational flow order or other similar pipeline penalties or charges resulting from failure to timely communicate to the pipeline, nominations, nomination changes or failure to timely adjust nominations.

(55) "Gas Index" or "GI" has the meaning set forth in Section 6.1(3).

(56) "Gas Interconnection Agreement" means the interconnection agreement between Seller and the Gas Transporter providing for the operation and maintenance of the Gas Interconnection Facilities.

(57) "Gas Interconnection Facilities" means the lateral pipeline and other equipment necessary to connect the Facility with the Gas Transporter's transportation system.

(58) "Gas Meter" means the Gas meter located at the Gas Delivery Point.

(59) "Gas Transporter" means Florida Gas Transmission Company or its successor.

(60) "Generator Imbalance Fees" means any imbalance fees, penalties or other similar fees, costs or penalties imposed by any Transmission Provider.

(61) "Governmental Authority" means any federal, state or local governmental body, any governmental, military, regulatory or administrative agency, commission, body or other authority exercising or entitled to exercise any administrative, executive, judicial, legislative, policy, regulatory or taxing authority, jurisdiction or power, any court or governmental tribunal, or any applicable independent system operator, regional transmission organization, regional power pool, reliability council or other regional entity performing similar functions.

(62) "Governmental Rule" means any law, rule, regulation, ordinance, order, code, permit, interpretation, judgment, decree, directive, guideline, policy or similar form of decision of any Governmental Authority having the effect and force of law.

(63) "Guaranteed Availability" means the percentage of time Seller guarantees that the Facility will be available for service, up to the Monthly Demonstrated Capacity, whether dispatched by Buyer or not, during all On-Peak Hours of each Peak Month or Non-Peak Month during the Delivery Term, as further set forth in Section 6.3.

(64) "Guaranteed Heat Rate" or "GHR" has the meaning set forth in Section 6.1(2).

(65) "Guaranty" means a guaranty from an Acceptable Guarantor substantially in the form of Exhibit K.

(66) "Heat Rate" means the measure of efficiency in converting input fuel into electricity, expressed in Btu/kWh.

(67) "Heat Rate Differential" or "HRD" has the meaning set forth in Section 6.1(2).

(68) "Heat Rate Payment" or "HRP" has the meaning set forth in Section 6.1(3).

(69) "HHV" means higher heating value in Btu/lb or Btu/Standard Cubic Foot.

(70) "Initial Fuel Oil Inventory" means the amount of Fuel Oil in net gallons in Seller's Fuel Oil storage tank(s) at the Facility at the beginning of the Delivery Term, as measured at midnight on the date such inventory is transferred from Seller to Buyer.

(71) "Interest Rate" means a per annum rate of interest equal to the Prime Rate plus two percentage points (2%); provided, the Interest Rate shall never exceed the maximum rate permitted by applicable Governmental Rules.

(72) "kW" means kilowatt.

(73) "kWh" means kilowatt-hour.

(74) "Lateral Pipeline" is the pipeline owned by Florida Gas Transmission Company which connects the Facility to the Gas Transporter's pipeline.

(75) "Letter of Credit" means an unconditional, irrevocable, non-transferable, standby letter of credit naming a Party as the sole beneficiary, issued by a United States commercial bank, a United States financial institution, or the United States branch of a foreign commercial bank, with a minimum of one billion U. S. dollars capital and surplus, in each case with a Credit Rating of at least A by S&P and A2 by Moody's, in a form reasonably acceptable to the Party who would be protected by the Letter of Credit under this Agreement. All costs relating to any Letter of Credit shall be for the account of the Pledging Party.

(76) "MMBtu" means one million British Thermal Units.

(77) "Monthly Demonstrated Capacity" means the Demonstrated Capacity multiplied by the applicable monthly adjustment factor, as specified in Exhibit L, and rounded to the nearest MW. The Monthly Demonstrated Capacity reflects the Demonstrated Capacity adjusted each month based on temperature and other conditions normally expected during such month.

(78) "Moody's" means Moody's Investor Services, Inc., or its successor.

(79) "MW" means a megawatt. One MW is equal to 1,000 kW.

(80) "MWh" means a megawatt-hour. One MWh is equal to 1,000 kWh.

(81) "Non-Defaulting Party" has the meaning set forth in Section 11.1(1)(a).

(82) "Non-Peak Month" means all hours during each of the following months: March, April, October, November and December.

(83) "On-Peak Hours" means the sixteen (16) hours during each Business Day from hour ending 0800 EPT through and including hour ending 2300 EPT.

(84) "Operational Limitations" means the physical operating parameters of the Facility as set forth in Exhibit G.

(85) "Peak Month" means all hours during each of the following months: January, February, May, June, July, August and September.

(86) "Person" means an individual, partnership, corporation, limited liability company, association, trust, joint venture, unincorporated organization, Governmental Authority, or other type of entity.

(87) "Planned Maintenance Outage" means a planned curtailment or outage at one or more Units at the Facility for the purpose of performing maintenance on the Units, as further described in Section 4.3.

(88) "Pledging Party" means the Party required to provide Security pursuant to Section 19.

(89) "Prime Rate" means the prime lending rate as may from time to time be published in *The Wall Street Journal* under "Money Rates," or if such rate is no longer published, an index specified by *The Wall Street Journal* as the replacement rate. If no replacement rate is specified, the Parties will agree on a replacement index that most accurately corresponds to such rate.

(90) "Prudent Industry Practice" means any of the spectrum of practices, methods, standards and acts engaged in or adopted by a significant portion of the electric power industry that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, could have been expected to accomplish the desired result consistent with good business practices, reliability, economy, safety and expedition, and which practices, methods, standards and acts reflect due regard for operation and maintenance standards recommended by the Facility's equipment suppliers and manufacturers, operational limits, and all applicable Governmental Rules. Prudent Industry Practice is not intended to be limited to the optimum practice, method, standard or act to the exclusion of all others but rather to be a spectrum of acceptable practices, methods, standards or acts.

(91) "Run Hour" means any increment of an hour that a Unit at the Facility is in operation including, without limitation, hours required for start up and shut down. Such hours shall begin when the control room operator at the Facility initiates a start sequence.

(92) "S&P" means the Standard & Poor's Ratings Group, a division of The McGraw-Hill Companies, or its successor.

(93) "Secured Party" means the Party entitled to demand and receive Security pursuant to Section 19.

(94) "Security" means a Guaranty, Letter of Credit or cash in the form of currency of the United States of America.

(95) "Settlement Amount" means, with respect to this Agreement and the Non-Defaulting Party, the net losses and costs, if any, expressed in U.S. dollars, which such Non-Defaulting Party incurs as a result of the termination of this Agreement including, at the Non-Defaulting Party's option, all (i) net losses and costs incurred by the Non-Defaulting Party to (a) purchase and/or sell, as applicable, capacity, energy and ancillary services equally useful as the Monthly Demonstrated Capacity, Energy and Ancillary Services purchased and sold under this Agreement and (b) maintain, terminate, obtain or

re-establish any trading positions entered into by a Party to hedge its obligations under this Agreement, and (ii) reasonable attorney's fees incurred by the Non-Defaulting Party in connection with the termination of this Agreement. If the Settlement Amount is a positive number, the Settlement Amount shall be due to the Non-Defaulting Party from the Defaulting Party. If the Non-Defaulting Party does not incur any net losses and costs as a result of the termination of this Agreement, the Settlement Amount shall be deemed to be zero (0). In calculating a Settlement Amount, the Non-Defaulting Party shall discount to present value (in a commercially reasonable manner based on the Interest Rate for the applicable period) any amount which would otherwise have been due at a later date and shall add interest at the Interest Rate to any amount due prior to the date of the calculation.

(96) "Start Charge" means the total amount to be paid by Buyer to Seller each month during the Delivery Term for all Successful Starts during such month, as is further set forth in Section 9.4.

(97) "Start Fee" has the meaning set forth in Exhibit C.

(98) "Station Load" means the power required by the auxiliary equipment necessary for the operation of the Facility including, but not limited to, pumps, fans, etc.

(99) "Successful Start" has the meaning set forth in Exhibit G, as applicable for each Unit.

(100) "Termination Date" has the meaning set forth in Section 2.1.

(101) "Tested Heat Rate" or "THR" has the meaning in Section 6.1(1).

(102) "Transmission Ancillary Services" means those ancillary services that Buyer must purchase from the Transmission Provider as necessary to support the transmission of Energy and/or Ancillary Services from the Delivery Point.

(103) "Transmission Provider" means Florida Power Corporation or any successor thereto that provides electric transmission services to support the transmission of Energy and/or Ancillary Services from the Delivery Point.

(104) "Transmission Provider's Protocols" means the documents adopted by the Transmission Provider, as amended from time to time, that contain the scheduling, operating, planning, reliability and settlement policies, rules, guidelines, procedures, standards and criteria of the control area.

(105) "Unit(s)" mean the General Electric 7FA combustion turbine (Unit 1), the General Electric 7FA combustion turbine (Unit 2) and the General Electric 7FA combustion turbine (Unit 3) in a simple cycle configuration, as applicable.

(106) "VOM Charge" means the variable amount, if any, to be paid by Buyer to Seller for the MWh of Energy and/or Ancillary Services delivered by Seller to Buyer in a month relating to the variable operation and maintenance costs of the Facility (excluding Fuel costs), as is further set forth in Section 9.3 and Exhibit B.

(107) "VOM Price" has the meaning set forth in Exhibit B.

2. TERM; CONDITIONS PRECEDENT; SURVIVAL

2.1 Term.

The Contract Term and Delivery Term shall continue through April 30, 2014, unless terminated prior to such date pursuant to this Agreement (the "Termination Date").

2.2 Conditions Precedent to the Parties' Performance.

Performance under this Agreement of any obligation to provide or pay for the tolling arrangement shall arise only upon the satisfaction of the following conditions:

(1) Notwithstanding any other provision of this Agreement, approval by the creditors' committee(s) and the Bankruptcy Court, as applicable, and receipt of any waivers from the DIP Lender, which may be required, shall be conditions precedent to Seller's performance under this Agreement. The approval of the Bankruptcy Court shall include a court order that confers rights to the Buyer under this Agreement that are acceptable to the Buyer. In the event such approval(s) has not been obtained within ninety (90) Days after the Agreement Date, either Party may terminate this Agreement upon written notice to the other Party with no obligation or liability under this Agreement to the other Party resulting from such termination.

(2) Notwithstanding any other provision of this Agreement, this Agreement and the rights and obligations of the Parties set forth herein are expressly subject to and contingent upon approval in its entirety by a final, non-appealable order of the FPSC within one hundred twenty (120) Days after the Agreement Date. In the event such approval has not been obtained within one hundred twenty (120) Days after the Agreement Date, either Party may terminate this Agreement upon written notice to the other Party with no obligation or liability under this Agreement to the other Party resulting from such termination.

2.3 Survival.

As of the Termination Date, the Parties shall no longer be bound by the terms and conditions hereof, except (i) to the extent necessary to enforce any rights and the obligations of the Parties, including, but not limited to, payment obligations, arising under this Agreement prior to such Termination Date and (ii) the obligations of the Parties hereunder with respect to confidentiality, audit and indemnification shall survive any termination of this Agreement and shall continue for a period of two (2) years following such Termination Date, provided that such obligations with respect to indemnification shall continue only with respect to Claims for

indemnification based upon events or circumstances occurring or arising on or before the Termination Date.

3. CONTRACT OPTIONS

[redacted]

4. OPERATION OF THE FACILITY

4.1 Permits.

Seller shall, at its expense, acquire and maintain in effect during the Contract Term, from any and all Governmental Authorities with jurisdiction over Seller and/or the Facility, all permits and approvals, in each case necessary for the ownership, operation and maintenance of the Facility in accordance with this Agreement, and all Governmental Rules and for the Facility to operate at the Demonstrated Capacity. Seller shall be responsible for, and bear all costs of, compliance with all of its permits, including its air permit, and all emissions laws and regulations. Notwithstanding the foregoing, Buyer shall be responsible for all costs associated with emissions credits required for the operation of the Facility as dispatched by Buyer. Seller shall transfer to Buyer any emissions credits for the Delivery Term received by Seller from any Governmental Authority related to the Facility.

4.2 Prudent Industry Practice.

Seller shall cause the Facility to be operated and maintained in accordance with Prudent Industry Practice and in accordance with the terms and conditions of this Agreement.

4.3 Maintenance Outages.

(1) Schedule of Planned Maintenance Outages.

(a) Seller shall not be obligated to deliver Energy and/or Ancillary Services pursuant to this Agreement during Planned Maintenance Outages. The Facility shall not be considered unavailable during Planned Maintenance Outages for the purpose of calculating the Actual Equivalent Availability of the Facility.

(b) Buyer agrees that Seller must perform Planned Maintenance Outages at the Facility in an effort to reduce and prevent Forced Derates and/or Forced Outages

and to maintain the efficiency of the Units. Such Planned Maintenance Outages include, but are not limited to, the Unit manufacturer's recommended and required maintenance, Compressor Washes and any preventive maintenance that maintains or improves the reliability of the Facility. The Planned Maintenance Outage schedule shall be based on (i) the Unit manufacturer's equivalent start and runtime guidelines, (ii) Prudent Industry Practice, (iii) the long-term service agreement for the Units, (iv) the actual dispatch of the Units and (v) the Unit's point in the maintenance cycle and the potential impacts to the Unit and costs if the maintenance schedule is changed. On or before October 1, 2006 and on each October 1st thereafter during the Delivery Term, Seller shall provide to Buyer, in writing, its proposed schedule of Planned Maintenance Outages for the next calendar year and the reason for such Planned Maintenance Outages. Seller shall not schedule Planned Maintenance Outages during the On-Peak Hours of the Peak Months without Buyer's prior written consent.

(c) The Parties shall have the right to make reasonable adjustments to the schedule of Planned Maintenance Outages. The Parties shall agree upon the adjustments to the Planned Maintenance Outages schedule at least forty-five (45) Days in advance of each Planned Maintenance Outage and the Parties shall use reasonable judgment when requesting and agreeing to the adjustments. In the event the Unit manufacturer issues a new technical bulletin which requires immediate maintenance to be performed, Seller shall notify Buyer of the circumstances surrounding such maintenance and Seller will work together with Buyer to schedule the maintenance outage notwithstanding the short notice involved.

(d) In addition to the schedule described above, Planned Maintenance Outages shall be deemed to include (i) maintenance performed within the minimum shut down period for a Unit as specified in the Operational Limitations and/or (ii) hours required for maintenance to the extent that Seller has obtained Buyer's prior written approval regarding the hours required to perform such maintenance.

(2) Duration of Planned Maintenance Outages. Unless otherwise agreed to by Buyer, Planned Maintenance Outages shall be limited to (i) ten (10) Days per Unit each calendar year in which there is no minor inspection, hot gas path inspection, or major inspection; (ii) thirteen (13) Days per Unit each calendar year in which a minor inspection (e.g. combustion inspection) occurs, of which a minimum of eight (8) Days are consecutive; (iii) twenty-five (25) Days per Unit each calendar year in which a hot gas path inspection occurs, of which a minimum of twenty (20) Days are consecutive; and (iv) forty-five (45) Days per Unit each calendar year in which a major inspection occurs, of which forty (40) Days are consecutive. If a minor inspection and a hot gas path inspection are to be performed on a Unit during the same calendar year, the limits in section 4.3(2)(iii) shall apply. If a minor inspection and/or a hot gas path inspection are to be performed on a Unit during the same calendar year as a major inspection, the limits in Section 4.3(2)(iv) shall apply. Seller shall use commercially reasonable efforts to complete any Planned

Maintenance Outage in a timely manner. During each Planned Maintenance Outage, Seller shall keep Buyer apprised of the status and the expected duration of the Planned Maintenance Outage.

(3) Compressor Wash. If the maintenance schedule from the Unit manufacturer requires Seller to perform a Compressor Wash during the Peak Months, Seller shall use commercially reasonable efforts to schedule such Compressor Wash to ensure that the Facility is available during the On-Peak Hours of the Peak Months.

(4) Maintenance-related Charges. If Seller is required to start and operate a Unit for maintenance purposes, Seller and Buyer shall work together such that the maintenance related start and operation can be completed when the Energy and/or Ancillary Services from the Facility is being dispatched by the Buyer. If the Seller and Buyer are unable to complete the maintenance related start and operation during a time when the Buyer has dispatched the Facility, Seller shall notify Buyer of the date of the maintenance related start and operation at least five (5) Business Days in advance. Buyer shall provide, at its expense, all Fuel required for the start and operation of the Unit and schedule the quantity of Energy and/or Ancillary Services produced during such operation in a commercially reasonable manner. Buyer shall be entitled to all revenues associated with the sale of Energy and/or Ancillary Services from the Facility during the period of time the Unit is being operated for maintenance purposes. If the Facility is not dispatched by Buyer during the maintenance related start and operation period, Seller shall reimburse Buyer an amount equal to the positive difference, if any, obtained by subtracting (i) the cost of Fuel plus the Start Charge and the VOM Charge payable by Buyer during the start and operation period from (ii) the Energy revenues received by Buyer during such period.

4.4 Station Load.

Seller shall be responsible for Station Load at all times including during all Planned Maintenance Outages, Forced Derates, and Forced Outages, and during start up and shut down of a Unit, and any periods when the Facility has not been dispatched. Seller will net Station Load from the maximum capacity of the Facility to determine the Demonstrated Capacity.

4.5 Performance Test.

(1) During the second quarter of 2007 and in January of each year of the Delivery Term thereafter or any date as mutually agreed by the Parties, Seller shall conduct a performance test of the Facility to calculate the Demonstrated Capacity and the Heat Rate of the Facility. Buyer and Seller shall work together such that the performance test can be completed while the Facility is being dispatched by the Buyer. If the Facility is dispatched by Buyer during the test period, Buyer shall pay for all required Gas, the Start Charge and VOM Charge. If the Buyer and Seller are unable to complete the test during a time when the Buyer has dispatched the Facility, Seller shall notify Buyer of the date of the performance test at least five (5) Business Days in advance of such test. Buyer shall provide, at its expense, all Gas required for the performance test and schedule the quantity of Energy produced during the test in a commercially reasonable manner. Buyer shall be entitled to all revenues associated with the sale of the test Energy from the Facility. If the Facility is not dispatched by Buyer during the test period, Seller shall

reimburse Buyer an amount equal to the positive difference, if any, obtained by subtracting (i) the cost of test Gas plus the Start Charge and the VOM Charge payable by Buyer during the test period from (ii) the test Energy revenues received by Buyer. Buyer or its designated representative shall have the option to witness any performance test.

(2) Buyer and Seller each shall have the right to perform up to two (2) additional optional performance tests of the Facility during each year. If Buyer performs an additional performance test and the Demonstrated Capacity and the Tested Heat Rate resulting from such test is within two percent (2%) of the most recent performance test, then Buyer shall pay the cost of such optional performance test. If the Demonstrated Capacity and the Tested Heat Rate resulting from such test is not within two percent (2%) of the most recent performance test, then Seller shall pay the cost of such optional performance test.

(3) The Monthly Demonstrated Capacity and the Tested Heat Rate shall be based on the results of the most recent performance test. Seller shall provide Buyer a copy of the performance test results as soon as such results become available but no later than two (2) weeks after the conclusion of the performance test.

4.6 Operating Procedures.

The Parties shall develop operating procedures no later than thirty (30) Days prior to the start of the Delivery Term that will cover the protocols under which the Parties will perform their respective obligations under this Agreement. The operating procedures shall be consistent with the Gas Interconnection Agreement, Electrical Interconnection Agreement, the Transmission Provider's tariff, the Transmission Provider's Protocols, all metering systems, any electronic communication systems and the Operational Limitations in Exhibit G. The operating procedures shall include, without limitation, the method of daily communications, the delivery of Fuel to the Facility, dispatch procedures, notices regarding the availability of the Facility, identification and contact of key personnel and operations logs.

4.7 Performance Monitoring.

During the Delivery Term, the Buyer shall have the right, at its sole expense, to install and operate Facility operations performance monitoring equipment upon written notice to Seller, provided that the installation of such equipment would not hinder Seller's performance of its obligations under this Agreement. Seller shall assist Buyer in the installation of such equipment, including without limitation, server and communications media. Seller shall have the right to utilize the monitoring equipment to obtain Facility data. In the event Buyer suggests Facility upgrades or improvements to Seller based on Facility data obtained from the monitoring equipment, Seller shall not be obligated to incur any costs to make such upgrades or improvements unless mutually agreed upon by the Parties. The performance information to be monitored is listed in Exhibit F.

4.8 Operation of the Facility by Buyer.

(1) Except when an Event of Default with respect to Buyer has occurred and is continuing, during the Delivery Term, (i) if Seller Abandons the Facility and such Abandonment continues for a period exceeding seven (7) consecutive Days, or (ii) if Seller fails for a period of seven (7) consecutive Days to provide Buyer the Monthly Demonstrated Capacity, Energy and/or Ancillary Services from the Facility in accordance with this Agreement and Seller's failure is not excused by a Force Majeure Event, Forced Outage, Forced Derate, Planned Maintenance Outage or Buyer's failure to perform any of its obligations hereunder, then Buyer may, but is not obligated to, assume operational responsibility for the Facility to continue operation, complete any necessary repairs, which are not being undertaken by Seller, or take such other steps as are reasonable in the circumstances, or may designate a third party or parties to do the same, so as to assure uninterrupted availability and deliverability of the Monthly Demonstrated Capacity, Energy and/or Ancillary Services from the Facility in accordance with this Agreement. In such an event, Seller agrees to fully cooperate with Buyer in providing access to the Facility, and permitting Buyer to operate the Facility as provided herein. Buyer's exercise of its operation rights of the Facility under this Section 4.8(1) shall not confer ownership rights of the Facility to Buyer.

(2) During any period of Buyer's operation of the Facility pursuant to Section 4.8(1), any payments to Seller shall be made only after any and all reasonable costs and expenses incurred by Buyer in exercising its rights under this Section 4.8 are deducted.

(3) Except as provided in Section 4.8(6) below, Buyer's exercise of its rights under this Section 4.8 to operate the Facility shall not be deemed an assumption by Buyer of any liability of Seller under any agreement between Seller and any other party.

(4) In the event Buyer exercises its right to assume operation of the Facility pursuant to Section 4.8(1), Buyer shall not have the right to terminate this Agreement as a result of Seller's Abandonment of the Facility, failure to deliver as described in Section 4.8(1) or for any other reason during the period the Facility is being operated by Buyer.

(5) Buyer may continue to operate the Facility until the earlier of:

(a) Seller provides written notice to Buyer that it is prepared to resume operations at the Facility and such notice describes the impediment concerning Seller's operation of the Facility and explains how the impediment has been remedied. Seller and Buyer will mutually agree to an orderly and commercially reasonable transition, including the timing of the transition, of the operation of the Facility from Buyer to Seller;

(b) the project lender, any financing party or a designee of any such party, after providing written notice to Buyer of its intent to do so, assumes operation of the Facility, provided that it has been demonstrated to Buyer's reasonable satisfaction that the project lender, financing party or a designee of any such party,

as applicable, is technically qualified to operate the Facility in accordance with this Agreement;

(c) Buyer and Seller mutually agree to terminate this Agreement; or

(d) An Event of Default with respect to Buyer occurs and is continuing related to Buyer's failure to perform any of its obligations under this Section 4.8.

(6) Buyer agrees that during any period it is in possession of the Facility under this Section 4.8, it shall operate the Facility in accordance with Prudent Utility Practice, the Unit manufacturer's recommended and required maintenance schedule and the Operational Limitations in this Agreement. Further, Buyer shall comply with applicable Governmental Rules and maintain in full force and effect all permits, licenses and consents required by any Governmental Authority related to the operation and maintenance of the Facility. Buyer shall adhere to the maintenance schedule as required by Seller's service agreement(s) with any other party. Buyer shall be liable for any damages to the Facility while operating same pursuant to Section 4.8(1). During the period while Buyer is operating the Facility, Buyer shall carry and maintain, or cause to be carried and maintained, no less than the insurance coverages listed in Exhibit I, applicable to all operations undertaken by Buyer pursuant to Section 4.8(1). Such minimum amounts may be satisfied either by primary insurance or by any combination of primary and excess/umbrella insurance. At least two (2) Business Days prior to assuming operational control of the Facility under this Section 4.8, Buyer shall provide Seller with written documentation as evidence that Buyer has obtained the insurance coverages required under this Section 4.8(6). Buyer's right to assume operational control of the Facility under this Section 4.8 shall be expressly subject to Seller's verification that Buyer has obtained such insurance coverages prior to the commencement date of Buyer's operation of the Facility. Buyer shall comply with and maintain in full force and effect any third party contract related to the Facility, unless Seller notifies Buyer that (i) the performance of the other party to any such contract was the cause of the problem which led to Buyer's assumption of operational responsibility for the Facility, or (ii) such other party is in default under any such contract and that Seller shall suspend or terminate its performance under such contract. Buyer shall not cause any default, breach, invalidation or termination of any agreements between Seller and any other party. Seller shall provide Buyer with copies of all such contracts, permits, licenses and consents within ten (10) Days of receiving notice that Buyer intends to take possession of the Facility under this Section 4.8.

5. CAPACITY; ENERGY; AND ANCILLARY SERVICES

5.1 Monthly Demonstrated Capacity.

Subject to the terms and conditions of this Agreement, Seller agrees to make available to Buyer, on an exclusive basis, during the Delivery Term, and Buyer agrees to accept, the Monthly Demonstrated Capacity at the Delivery Point. In consideration, Buyer agrees to pay the Capacity Charge. As of the Agreement Date, the Demonstrated Capacity of the Facility is 517 MW.

5.2 Energy.

Subject to the terms and conditions of this Agreement, Seller agrees to make available to Buyer, on an exclusive basis, and to deliver to Buyer during the Delivery Term, and Buyer agrees to receive, the Energy Buyer has dispatched up to the Monthly Demonstrated Capacity. In consideration, Buyer agrees to pay the Start Charge and the VOM Charge, as applicable.

5.3 Ancillary Services.

Subject to the terms and conditions of this Agreement, Seller agrees to make available to Buyer, on an exclusive basis, and to deliver to Buyer during the Deliver Term, and Buyer agrees to receive, the Ancillary Services as scheduled by Buyer. The Parties acknowledge and agree that certain of such Ancillary Services would require that a portion of the Monthly Demonstrated Capacity of the Facility be held in reserve for such Ancillary Services to be sold or provided (or as may be used by Buyer for its own account) from the Facility and that the combination of Energy and Ancillary Services to be sold from the Facility by Buyer shall not exceed the Monthly Demonstrated Capacity of the Facility. Any Ancillary Services which Seller may be required to provide to the Transmission Provider(s) under the terms of the Electrical Interconnection Agreement or under the Transmission Provider's Protocols shall be deducted from the Monthly Demonstrated Capacity made available to the Buyer under this Agreement; provided, however, such deduction shall not constitute a Forced Derate or Forced Outage.

5.4 Exclusive Rights.

So long as no Event of Default has occurred and is continuing with respect to Buyer, if Buyer does not call on all of the Monthly Demonstrated Capacity, Energy and/or Ancillary Services of the Facility, pursuant to the dispatch and scheduling provisions in this Agreement, Seller shall not have the right to sell any such remaining Monthly Demonstrated Capacity, Energy and/or Ancillary Services from the Facility to any third party during the Delivery Term without the prior written consent of Buyer except as may be required pursuant to any Electrical Interconnection Agreement between Seller and any Transmission Provider(s) or as may be required by any Governmental Authority. However, consistent with Section 24.1, if an Event of Default has occurred and is continuing with respect to Buyer, Seller shall use commercially reasonable efforts to mitigate its losses resulting from such Event of Default by selling the Monthly Demonstrated Capacity, Energy and Ancillary Services to third parties during any period of suspension of Seller's performance obligations hereunder pursuant to Section 11.2(1).

5.5 Energy Delivery Point.

All deliveries and receipts of Energy shall be made and measured at the Delivery Point.

5.6 Title, Risk of Loss and Indemnity.

(1) As between the Parties, Seller shall be deemed to be in exclusive possession and control (and responsible for any damages or injury caused thereby) of the Energy and Ancillary

Services prior to the Delivery Point, and Buyer shall be deemed to be in exclusive possession and control (and responsible for any damages or injury caused thereby) of the Energy and Ancillary Services at and from the Delivery Point. Title to the Energy and Ancillary Services and exclusive rights to the Monthly Demonstrated Capacity shall remain at all times with Buyer. Each of Seller and Buyer shall and hereby does indemnify, defend and hold harmless the other Party from any Claims arising from any act, failure to act or incident relating to Energy and Ancillary Services occurring when the Energy and Ancillary Services is under its possession and control.

(2) Seller warrants that the Energy delivered by Seller and the Ancillary Services available from the Facility shall be free and clear of all liens, Claims and encumbrances arising prior to the Delivery Point and warrants that the Monthly Demonstrated Capacity is free and clear of liens, Claims and encumbrances.

5.7 Transmission Services.

Buyer shall arrange, either directly or indirectly through a third party, for all transmission service and Transmission Ancillary Services and shall pay all costs pursuant to the Transmission Provider's tariff and the Transmission Provider's Protocols including, without limitation, all costs associated with line losses, necessary to transmit the Energy and Ancillary Services delivered under this Agreement from the Delivery Point to any point at which Buyer redelivers the Energy and Ancillary Services to its customer(s).

5.8 Electrical Interconnection Agreement.

Seller has entered into an Electrical Interconnection Agreement with the Transmission Provider and shall maintain such Electrical Interconnection Agreement in full force and effect throughout the Delivery Term.

5.9 Energy Meters.

Energy and Ancillary Services delivered by Seller shall be measured by the Energy Meters at the Delivery Point. The Transmission Provider shall own, operate, maintain and test the Energy Meters at the Delivery Point. Seller shall coordinate with the Transmission Provider and Buyer with respect to the maintenance and testing of Energy Meters consistent with the Electrical Interconnection Agreement and Prudent Industry Practice.

6. HEAT RATE AND GUARANTEED AVAILABILITY

6.1 Heat Rate.

(1) Heat Rate Test. Each year during the performance test described in Section 4.5, Seller shall conduct a Heat Rate test of the Facility. All three Units will be tested simultaneously on Gas. The Heat Rate shall be equal to the quotient, expressed in Btu/kWh, of (i) the HHV of Gas consumed by the Facility during the test period divided by (ii) the amount of Energy

generated by the Facility and delivered to the Delivery Point during such test period (the "Tested Heat Rate" or "THR"). Although the Heat Rate test shall be conducted using Gas only, the THR shall be deemed the same regardless of whether the Facility is consuming Gas or Fuel Oil.

(2) Heat Rate Differential. After each Heat Rate test, a Heat Rate Differential ("HRD"), expressed as Btu/kWh, shall be calculated using one of the formulas below depending on whether the THR is above or below the GHR.

(a) If THR > GHR, then HRD = [THR – (1.03 x GHR)]; or
(b) If THR < GHR, then HRD = [(0.97 x GHR) – THR].

Where: Guaranteed Heat Rate ("GHR") = 10,400 Btu/kWh

(3) Heat Rate Payment. Seller shall calculate a Heat Rate Payment ("HRP") on a daily basis pursuant to the formula below. If the HRD is negative or zero, the HRP will be equal to zero. Seller shall pay Buyer the HRP if the THR is greater than the GHR. Buyer shall pay Seller the HRP if the THR is less than the GHR. The HRP shall be calculated as follows:

HRP = (DE x HRD x GI) ÷ 1000

Where:

DE = total delivered Energy and/or Ancillary Services (MWh) for the applicable Day

HRD = Heat Rate Differential currently in effect for the applicable Day (Btu/kWh)

GI = the Gas Daily Midpoint (GDM) price as published in the Platts Gas Daily, Daily Price Survey for the specified "Flow Date" in $/MMBtu. The GDM location will be the "Florida Gas, Zone 2" Midpoint price for the Day of Gas flow plus the applicable Florida Gas Transmission (FGT) FTS-1 fuel and commodity cost to transport from FGT Zone 2 to the FGT Market Area for the applicable month of flow. If no "Florida Gas, Zone 2" price is published for such Day, then the GDM price shall be the average of the following: 1) the price for the first Day for which a price is published that next precedes the relevant Day; and 2) the price for the first Day for which a price is published that next follows the relevant Day.

The HRP for each Day during each month of the Delivery Term shall be included on the monthly statement sent to Buyer and paid pursuant to Section 12.1.

6.2 Availability of the Facility on April 1, 2007.

(1) Unless excused by a Force Majeure Event, if Seller fails to make the Facility available for operation on April 1, 2007 in accordance with this Agreement, then Seller shall pay Buyer [redacted] per Day for each Day that Seller fails to make the Facility available for operation on and after April 1, 2007. Seller's obligation to make such payment to Buyer due to the Facility's unavailability shall end on the Day on which Seller provides written notice to Buyer that the Facility is available for dispatch by Buyer subject to the terms of this Agreement. Buyer shall not be required to pay Seller a pro-rata portion of the Capacity Charge for each Day that Seller fails to make the Facility available for operation on and after April 1, 2007.

(2) The damages to paid by Seller to Buyer under Section 6.2(1) shall be Buyer's sole and exclusive remedy for the failure of the Delivery Term to start on April 1, 2007. If Seller is required to pay damages to Buyer under Section 6.2(1), then the terms and conditions under Section 6.3 shall not be applicable.

6.3 Guaranteed Availability during the Delivery Term.

(1) Unless excused by (i) Buyer's failure to meet its obligations under this Agreement or (ii) a Planned Maintenance Outage, Seller agrees that the Guaranteed Availability of the Facility shall be [redacted] during all On-Peak Hours of each Peak Month and [redacted] during all On-Peak Hours of each Non-Peak Month. Seller shall calculate the Actual Equivalent Availability of the Facility for each month during the Delivery Term in accordance with the formula set forth in Exhibit D. If the Actual Equivalent Availability is less than the Guaranteed Availability for the respective Peak Month or Non-Peak Month, Seller shall pay Buyer the Availability Rebate as set forth in Exhibit E.

(2) During the Delivery Term, the reduction to the Capacity Charge as described in Sections 6.3(1) and 9.2(3) shall be Buyer's sole and exclusive remedy for Seller's failure to meet the Guaranteed Availability of the Facility or to deliver Energy and/or Ancillary Services to Buyer when scheduled.

7. SCHEDULING AND DISPATCH

7.1 Dispatch.

During the Delivery Term, Buyer may dispatch the Facility, up to the Available Capacity, on a Day ahead or intra-Day basis provided that any dispatch schedules shall be consistent with the Operational Limitations, applicable Governmental Rules and the Facility's air permit and other environmental permits.

7.2 Automatic Generation Control.

Seller represents that the Facility is capable of receiving and responding to AGC commands via a digital, serial interface. Buyer, at its expense, shall have the right to furnish and install such communication equipment at the Facility as is necessary to receive Buyer's AGC commands. Seller shall provide Buyer and/or Buyer's agents access to Facility to install such equipment up to three (3) months prior to the Delivery Term. Buyer shall have the right to operate the Facility via remote AGC.

7.3 Availability Notice.

During the Delivery Term, Seller shall provide Buyer a notice regarding the availability of the Facility immediately after discovering that the Facility is unable to deliver all or part of the Energy and/or Ancillary Services whether due to a Forced Derate, Forced Outage, a Seller Force Majeure Event or a Planned Maintenance Outage (an "Availability Notice"). Seller shall notify Buyer of (i) the cause (or if not known, Seller's best estimate), (ii) the proposed action required to resume operation and (iii) Seller's best estimate of the expected duration. The content and method of transmitting such Availability Notice shall be mutually agreed to by the Parties. Seller also shall provide Buyer an Availability Notice when the Forced Derate, Forced Outage, Seller Force Majeure Event or Planned Maintenance Outage has ended. For purposes of calculating the Actual Equivalent Availability of the Facility, any period of Forced Derate or Forced Outage will be treated as ending at the end of the hour in which Seller notifies Buyer it is able to resume deliveries of Energy and/or Ancillary Services from the Facility.

7.4 Dispatch Notice.

(1) During the Delivery Term, Buyer shall provide Seller a preliminary weekly dispatch schedule, in writing, by Friday noon of each week for the upcoming week. The schedule shall include Buyer's good faith estimate of the amounts of Energy and Ancillary Services to be scheduled by Buyer each Day of the upcoming week.

(2) Buyer shall also provide Seller a notice for each Day it wishes to dispatch the Facility by no later than 9:00 a.m. EPT of the Business Day prior to the Day to which the notice shall relate (a "Dispatch Notice"). The content and method of transmitting such Dispatch Notice shall be mutually agreed to by the Parties. A Dispatch Notice shall be effective until either the delivery of a subsequent Dispatch Notice or until Buyer notifies Seller of a change in the dispatch of the Facility.

(3) Subject to the Operational Limitations, Buyer may modify a currently effective dispatch schedule. Modifications may include, but are not limited to, extending or shortening of dispatch hours and increasing or decreasing of load levels. Schedule changes shall be communicated to Seller by Buyer, with no less notice than the minimum time needed to attain the new load, based on the maximum ramp rate of the Unit(s) in service, prior to the time the new load level is required to be dispatched.

(4) To cancel a dispatch schedule and avoid a Start Charge, Buyer must notify Seller of such cancellation prior to the Facility operator initiating the start sequence. If Buyer fails to provide a Dispatch Notice to Seller to cancel dispatch of the Facility before the Facility operator initiates the start sequence, Buyer will be responsible for the Start Fee for the applicable Unit(s) and such start shall count as a Successful Start for the purpose of the Operational Limitations.

(5) By 11:00 a.m. EPT of the Business Day prior to the Day to which the notice relates, Buyer will notify Seller of Buyer's anticipated deliveries of Fuel Oil to the Fuel Oil Delivery Point.

7.5 Implementation of Scheduling Changes.

The Parties shall cooperate to ensure that all changes in the dispatch schedule are properly, appropriately and promptly (considering the particular circumstances involved) communicated to all entities requiring notification of any increase or decrease in the scheduled dispatch of the Facility. The Parties shall be further obligated to coordinate their scheduling activities and notices to one another to allow each Party sufficient time to meet deadlines and requirements of any Transmission Provider(s) and Gas transportation providers to assist the other Party in minimizing and/or eliminating Generator Imbalance Fees and Gas Imbalance Charges that may be associated with such deadlines and requirements.

7.6 Generator Imbalance Fees.

(1) Buyer acknowledges that its purchase of Energy and/or Ancillary Services are on a unit-contingent basis, and the actual amounts of Energy and/or Ancillary Services delivered in any hour depend on the mechanical and climatic conditions prevailing at the Facility at the time of production, among other factors. Buyer further acknowledges that the Transmission Provider will assess Generator Imbalance Fees when the quantity of Energy and/or Ancillary Services delivered from the Facility deviates from the quantity of Energy and/or Ancillary Services scheduled by Buyer with the Transmission Provider. Subject to the terms of this Agreement and consistent with Prudent Industry Practices and the Operational Limitations, Seller agrees to operate the Facility to promptly comply with the dispatch by Buyer and endeavor to minimize such Generator Imbalance Fees.

(2) Seller shall be responsible for Generator Imbalance Fees caused by (i) a Forced Derate, (ii) a Forced Outage, (iii) a Force Majeure Event claimed by Seller, (iv) Seller's failure to comply with Buyer's dispatch schedule for reasons other than climatic conditions at the time of any such failure, (v) Seller's failure to comply with the Operational Limitations and/or (vi) Seller's failure to comply with dispatch instructions from the Transmission Provider. Although Seller is responsible for Generator Imbalance Fees caused by a Forced Derate, a Forced Outage or a Force Majeure Event claimed by Seller, such responsibility shall end at the beginning of the first hour following the hour in which the Buyer submits a schedule change to the Transmission Provider. If Buyer fails to submit a schedule change to the Transmission Provider at the first opportunity following Buyer's receipt of an Availability Notice (whether oral or written) from Seller, Seller's responsibility for Generator Imbalance Fees shall nevertheless end at the time

such schedule change could have become effective if it had been promptly submitted to the Transmission Provider pursuant to the Transmission Provider's tariff and/or Protocols.

(3) Buyer shall be responsible for Generator Imbalance Fees other than the Generator Imbalance Fees for which Seller is responsible pursuant to Section 7.6(2). In addition, Buyer shall be solely responsible for Generator Imbalance Fees at any time Buyer requests that the Facility operate on AGC.

8. FUEL

8.1 Fuel and Fuel Metering.

(1) Fuel. During the Delivery Term, Buyer, at its sole cost and expense, shall arrange, nominate, balance, transport and deliver to the Fuel Delivery Point such quantities of Fuel as are required by Seller to generate at the Facility the quantity of Energy and/or Ancillary Services scheduled by Buyer including, without limitation, Fuel required for start up and shut down of the Units.

(2) Gas Delivery Point Operator Account. Prior to the commencement of the Delivery Term, Seller agrees to transfer the Gas Delivery Point from Seller's Delivery Point Operator Account to Buyer's Delivery Point Operator Account in accordance with the Gas Transporter's tariff, Delivery Point Operator Account Authorization Form and Operational Data Request Form.

(3) Gas Metering. Gas delivered by Buyer to the Facility shall be measured by the Gas Meter at the Gas Delivery Point. The Gas Transporter shall own, operate, maintain and test the Gas Meter. Seller shall coordinate with the Gas Transporter and Buyer with respect to maintenance and testing of the Gas Meter consistent with the Gas Interconnection Agreement and Prudent Industry Practice. The Gas Meter, located at the Facility, will measure the Gas consumed by the entire Facility rather than individual Units.

(4) Fuel Oil Delivery Measurement. The quantity of Fuel Oil in net gallons delivered by transport truck will be determined by supplier's Florida State certified truck rack meter readings upon loading. Each transport truck driver will provide Seller's personnel with a bill of lading verifying the date, Fuel type (i.e. low sulfur diesel or low sulfur #2) and the net gallons loaded. An original copy of such bill of lading will be promptly delivered to Buyer to facilitate payment for such Fuel Oil. Seller's personnel will verify (by observing sight glasses on the transport truck) that each truck was full upon delivery and empty after completion of delivery.

8.2 Gas Interconnection Agreement.

Seller has entered into the Gas Interconnection Agreement with the Gas Transporter and shall maintain such Gas Interconnection Agreement in full force and effect throughout the Delivery Term.

8.3 Transportation Service.

Buyer shall arrange and pay for all transportation service required to deliver the Fuel to the Fuel Delivery Point. Seller shall arrange and pay for all transportation service required to deliver the Fuel from the Fuel Delivery Point to the Facility.

8.4 Gas Specifications.

(1) All Gas tendered by Buyer for delivery to the Gas Delivery Point shall meet the then current natural gas quality specifications as set forth in the Gas Transporter's FERC tariff, as such specifications may change from time to time.

(2) If Gas tendered for delivery under this Agreement at the Gas Delivery Point materially fails for any reason to conform to the applicable specification set forth in Section 8.4(1), Seller will consider whether it is able to accept such non-conforming Gas and may refuse to take possession of all or any part of such Gas, giving Buyer the reasons for such refusal as soon as practicable.

(3) Buyer, as soon as it becomes aware of any delivery of Gas that materially fails to conform to any applicable specification for Gas set forth in Section 8.4(1), which deviation was not pre-approved by Seller, shall immediately cease further non-compliant deliveries and inform Seller of the cause and nature of such failure. If, and only if, Seller approves in writing the continued delivery of the non-conforming Gas on a temporary basis, Buyer may recommence deliveries of such non-conforming Gas, and shall immediately provide Seller its best estimate of the probable duration and quantity of the non-conforming Gas deliveries, and as soon as possible thereafter, shall recommence delivery of Gas conforming to Section 8.4(1). If the Facility is damaged as a direct result of the delivery of non-conforming Gas, Seller shall be entitled to the same remedies available to Buyer pursuant to the terms of the applicable Gas transportation agreements. Seller shall use commercially reasonable efforts to mitigate any damages resulting from the delivery of any non-conforming Gas at the Gas Delivery Point.

(4) Any failure by Buyer to deliver Gas meeting the specifications for Gas set forth in Section 8.4(1) to the Gas Delivery Point when needed to operate the Facility as scheduled by Buyer shall excuse Seller from its obligation to deliver scheduled Energy and/or Ancillary Services to Buyer except that Seller shall not be excused of this obligation for the period that Seller accepts the delivery of non-conforming Gas under Section 8.4(3). The unavailability of the Facility due to Buyer's delivery of non-conforming Gas that was not approved by the Seller shall not be considered a Forced Derate or Forced Outage, and the Facility shall be considered available for the purpose of calculating the Actual Equivalent Availability.

8.5 Fuel Oil Specifications.

(1) Fuel Oil supplied by Buyer to the Fuel Oil Delivery Point shall be of a quality meeting or better than the specifications for Fuel Oil set forth in Exhibit J. Seller and Buyer shall

notify each other of any material failure of Fuel Oil to comply with such specifications as soon as either Party becomes aware of such failure.

(2) Seller shall be responsible for routine tests performed prior to transferring Fuel Oil between storage tanks and prior to burning Fuel Oil.

(3) If Fuel Oil tendered for delivery under this Agreement to the Fuel Oil Delivery Point fails for any reason to materially conform to the Fuel Oil specifications set forth in Exhibit J, Seller may refuse all or any part of such Fuel Oil, giving Buyer the reasons for such refusal as soon as practical, and Buyer shall promptly (i) arrange at no cost to Seller for the removal of any such non-compliant Fuel Oil from or in the Fuel Oil storage tanks or (ii) blend any non-conforming Fuel Oil to meet the specifications set forth in Exhibit J. All costs associated with blending shall be for Buyer's account only, and Seller shall not be responsible for any such costs.

8.6 Title, Risk of Loss and Indemnity.

(1) As between the Parties, Buyer shall be deemed to be in exclusive possession and control (and responsible for any damages or injury caused thereby) of the Fuel prior to the Fuel Delivery Point, and Seller shall be deemed to be in exclusive possession and control (and responsible for any damages or injury caused thereby) of the Fuel at and from the Fuel Delivery Point. Notwithstanding delivery to the Fuel Delivery Point, title to the Fuel shall remain with Buyer or Buyer's third party supplier. Each of Seller and Buyer shall and hereby does indemnify, defend and hold harmless the other Party from any Claims arising from any act, failure to act or incident related to Fuel occurring when the indemnifying Party is in possession of such Fuel.

(2) Buyer warrants that the Fuel delivered by Buyer shall be free and clear of all liens, Claims and encumbrances arising prior to the Fuel Delivery Point.

8.7 Gas Imbalance Charges.

Buyer shall be responsible for all Gas Imbalance Charges associated with Gas deliveries under this Agreement to the extent such charges are caused by Buyer's actions or inactions. Seller shall be responsible for all Gas Imbalance Charges associated with Gas deliveries under this Agreement to the extent such charges are caused by Seller's actions or inactions. Both Parties shall use commercially reasonable efforts to avoid imbalances and to correct any imbalances which may occur.

8.8 Fuel Oil Inventory.

(1) An Independent Petroleum Inspector will measure the Initial Fuel Oil Inventory and the Final Fuel Oil Inventory, as adjusted for ambient conditions at the Facility and corrected to sixty (60) degrees Fahrenheit and sixty percent (60%) relative humidity, and report same to both Buyer and Seller. The Independent Petroleum Inspector will also sample the Seller's storage tank(s) and analyze the Fuel Oil to assure compliance with the specifications set forth in

Exhibit J. The Independent Petroleum Inspector will be selected by mutual agreement between Buyer and Seller and the cost will be equally shared between Buyer and Seller.

(2) At the beginning of the Delivery Term, Seller will sell and transfer title to the Initial Fuel Oil Inventory to Buyer. At the end of the Delivery Term, Buyer will sell and transfer title to the Final Fuel Oil Inventory to Seller. The sale price from Seller to Buyer and from Buyer to Seller will be the Initial Fuel Oil Inventory or Final Fuel Oil Inventory, as applicable, in net gallons multiplied by the cost per gallon determined by the average of the low and high daily prices averaged over the Days published in the calendar month of the respective sale and transfer dates for low sulfur diesel (.05% Sulfur) Gulf Coast pipeline as published in Platts U.S. Markets plus ten cents per gallon (to account for delivery charges and taxes). If the Platts U.S. Markets price described herein is not published, then the Parties shall mutually agree on a substitute index to represent the Gulf Coast market price for the Fuel Oil. Payment shall be due within ten (10) Business Days after the date the transfer is made by Seller and Buyer, as applicable. Buyer will make commercially reasonable efforts to provide Seller with a Final Fuel Oil Inventory approximately equal to the Initial Fuel Oil Inventory. Seller will provide Buyer with an estimate of the Initial Fuel Oil Inventory at least fifteen (15) Days prior to the start of the Delivery Term.

9. CHARGES

9.1 Monthly Charges.

For each full or partial month during the Delivery Term, Buyer shall pay to Seller the Capacity Charge, VOM Charge, and Start Charge, to the extent applicable. The charges established under this Agreement compensate Seller for all costs related to Station Load for the Facility, and no such costs shall be charged to Buyer.

9.2 Capacity Charge.

(1) Capacity Charge. In consideration for the right of Buyer to "toll" the Facility, in conformance with the terms and conditions of this Agreement, Buyer shall pay to Seller for each month during the Delivery Term a Capacity Charge equal to (i) the Monthly Demonstrated Capacity multiplied by (ii) the applicable Capacity Price for such month, *provided, however*, if the first or last month of the Delivery Term is a partial month, the Capacity Charge shall be pro-rated based upon the number of Days in such partial month falling within the Delivery Term compared to the total number of Days in such month. The Capacity Charge shall be payable each month throughout the Delivery Term whether or not Buyer actually schedules deliveries of Energy or Ancillary Services. The Monthly Demonstrated Capacity may change as a result of the performance tests or optional re-tests of the Facility's generating capability. Upon any valid performance test or optional retest of the Facility, the Monthly Demonstrated Capacity established by such test shall be used to calculate the Capacity Charge until the date of the next valid test.

(2) Payment of Capacity Charge during a Force Majeure Event. If Seller claims a Force Majeure Event and the Available Capacity of the Facility is not equal to zero (0), such

Force Majeure Event shall be deemed to be a Forced Derate for the purpose of calculating the Actual Equivalent Availability of the Facility and Buyer shall be entitled to an Availability Rebate as described in Section 9.2(3) below. If Seller claims a Force Majeure Event and the Available Capacity of the Facility is zero (0) as a result, Buyer shall be relieved of the obligation to pay Seller the portion of the Capacity Charge associated with the period of the Force Majeure Event. The remedy provided to Buyer in the preceding sentence is in lieu of the Availability Rebate described in Sections 6.3 and 9.2(3). If Buyer claims a Force Majeure Event for any reason, Buyer shall not be relieved of the obligation to pay Seller the Capacity Charge.

(3) Rebate of Capacity Charge for Actual Equivalent Availability. On a monthly basis, Seller shall calculate a rebate to the Capacity Charge, if any, resulting from any variation between the Actual Equivalent Availability of the Facility for a month and the applicable Guaranteed Availability of the Facility for such month in accordance with the formula set forth in Exhibit E (the "Availability Rebate"). The Availability Rebate, if any, payable by Seller for a month shall be netted against the Capacity Charge payable by Buyer for such month.

9.3 VOM Charge.

Buyer shall pay to Seller for each month during the Delivery Term a VOM Charge, as set forth in Exhibit B, equal to the sum of (i) the VOM Price applicable while the Facility is operating on Gas multiplied by the total quantity of Energy and/or Ancillary Services delivered to the Delivery Point during a month while the Facility is operating on Gas and (ii) the VOM Price applicable while the Facility is operating on Fuel Oil multiplied by the total quantity of Energy and/or Ancillary Services delivered to the Delivery Point during a month while the Facility is operating on Fuel Oil.

9.4 Start Charge.

For each month during the Delivery Term, Buyer shall pay to Seller a Start Charge equal to (i) the total number of Successful Starts per Unit during such month multiplied by (ii) the Start Fee for the applicable Unit. Buyer shall only pay one Start Fee for each Successful Start scheduled by Buyer. Buyer shall not be obligated to pay a Start Fee for a restart of any Unit which experiences a Forced Outage during a currently effective Dispatch Notice if the Forced Outage ends and the Unit is started during such currently effective Dispatch Notice. If the currently effective Dispatch Notice has expired, Seller shall refer to the preliminary weekly dispatch schedule provided by Buyer pursuant to Section 7.4(1) to determine whether the Facility would have been scheduled to operate at the time the Forced Outage ends. If the preliminary weekly dispatch schedule reflects that the Facility would have been scheduled to operate at the time the Forced Outage ends, Seller shall waive the Start Fee for the applicable Unit(s) in the event Buyer submits a Dispatch Notice which is consistent with the preliminary schedule.

10. REPRESENTATIONS AND WARRANTIES

10.1 Representations and Warranties.

(1) As a material inducement to entering into this Agreement, each Party with respect to itself, hereby represents and warrants to the other Party as of the Agreement Date and throughout the Contract Term as follows:

(a) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation and is qualified to conduct its business in those jurisdictions necessary for it to perform its obligations under this Agreement;

(b) it has all authorizations from any Governmental Authority necessary for it to legally perform its obligations under this Agreement or will obtain such authorizations in a timely manner prior to when any performance by it requiring such authorization becomes due;

(c) the execution, delivery and performance of this Agreement are within its powers, have been duly authorized by all necessary action and do not violate any of the terms or conditions in its governing documents or any contract to which it is a party or any Governmental Rule applicable to it;

(d) this Agreement constitutes a legal, valid and binding obligation of such Party enforceable against it in accordance with its terms, and each Party has all rights such that it can and will perform its obligations to the other Party in conformance with the terms and conditions of this Agreement, subject to bankruptcy, insolvency, reorganization and other laws affecting creditor's rights generally and general principles of equity;

(e) except as provided in Section 11.1(2), no Bankruptcy is pending against it or to its knowledge threatened against it; and

(f) the audited financial statements provided by Seller and Buyer pursuant to Section 12.3(2) are true and accurate based on the respective Party's knowledge, information and belief;

(g) it has negotiated and entered into this Agreement in the ordinary course of its respective business, in good faith, for fair consideration and on an arm's length basis.

(2) Buyer hereby represents and warrants that Buyer will use the Monthly Demonstrated Capacity, Energy and Ancillary Services of the Facility, purchased under this Agreement, exclusively for resale to Buyer's retail customers and/or wholesale customers.

(3) Seller hereby represents and warrants that the terms and conditions of this Agreement are fair and reasonable and reflect its exercise of prudent business judgment consistent with its fiduciary duties as a debtor-in-possession and are supported by fair consideration and reasonably equivalent value in money or money's worth.

(4) Each of Buyer and Seller represent and warrant to the other that it is a "forward contract merchant" within the meaning of the United States Bankruptcy Code.

10.2 No Other Representations and Warranties.

Each Party acknowledges that it has entered into this Agreement based solely upon the express representations and warranties set forth in this Agreement.

11. EVENT OF DEFAULT AND REMEDIES

11.1 Event of Default.

(1) An "Event of Default" shall mean with respect to a Party (the "Defaulting Party") any of the actions set forth below in this Section 11.1(1):

(a) the failure of the Defaulting Party to make, when due, any payment required under this Agreement if such failure is not remedied within five (5) Business Days after written notice of such failure is given to the Defaulting Party by the other Party (the "Non-Defaulting Party");

(b) except as permitted by Section 5.4, Seller sold Monthly Demonstrated Capacity, Energy and/or Ancillary Services from the Facility to a third party during the Delivery Term;

(c) any representation or warranty (including, but not limited to, the representation and warranty set forth in Section 10.1(1)(f)) made by the Defaulting Party in this Agreement shall prove to have been false or misleading in any material respect when made; provided that if such representation or warranty is capable of being corrected, no Event of Default shall have occurred if the Defaulting Party is diligently pursuing such correction and such representation or warranty is corrected within thirty (30) Days from the date upon which the Non-Defaulting Party gives written notice to the Defaulting Party of the false and misleading nature of the representation or warranty;

(d) the failure by the Defaulting Party to perform any material covenant set forth in this Agreement (other than the events that are otherwise specifically covered in this Section 11.1(1) as a separate Event of Default and other than any covenant for which an exclusive remedy is set out elsewhere in this Agreement), and such failure is not excused by a Force Majeure Event or cured within thirty (30) Days after written notice thereof to the Defaulting Party or, if such failure

cannot reasonably be cured in such period and the Defaulting Party within such period commences, and thereafter proceeds with reasonable due diligence, to cure such failure, such period shall be extended for such further period as shall be necessary for the Party to cure such failure with reasonable due diligence, provided that the total cure period shall not exceed ninety (90) Days;

(e) except as provided in Section 11.1(2), the Bankruptcy of the Defaulting Party;

(f) the failure by the Defaulting Party to meet its obligation to provide Security as required by Section 19 if such failure is not remedied within one (1) Business Day after written notice of such failure is given to the Defaulting Party by the other Non-Defaulting Party; and

(g) the failure of the Defaulting Party to assign the Agreement in accordance with Section 16.

(2) Notwithstanding anything herein to the contrary, Buyer acknowledges that Seller filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy code on July 14, 2003 (the "Filing") and such case remains pending in the United States Bankruptcy Court, Northern District of Texas (the "Bankruptcy Court"). Until such time as Seller emerges from Chapter 11 Bankruptcy through the confirmation of a plan or reorganization, the Filing shall not constitute an Event of Default under Sections 11.1(c) and/or (e) of this Agreement; provided, however, that in the event (A) Seller files a motion which contemplates the sale of substantially all of its assets; (B) Seller files a Chapter 11 plan which contemplates the sale of substantially all of its assets; (C) Seller files a motion or request to convert its Chapter 11 case to a Chapter 7 proceeding; (D) the Bankruptcy Court enters an order converting Seller's case from a Chapter 11 proceeding to a Chapter 7 proceeding; or (E) the Bankruptcy Court enters an order appointing a trustee or examiner (with expanded powers) in Seller's bankruptcy case, any such event (A) through (E) shall constitute an Event of Default under Sections 11.1(b),(c) and/or (f) of this Agreement.

11.2 Remedies Upon an Event of Default.

(1) Upon the occurrence of an Event of Default and for so long as such Event of Default is continuing, the Non-Defaulting Party may, upon written notice to the Defaulting Party, establish a date, no earlier than the Day such notice is effective and no later than twenty (20) Days after such notice is effective, on which this Agreement will terminate ("Early Termination Date"). Moreover, the Non-Defaulting Party will have the right to exercise all rights and remedies available to it under this Agreement, at law, and in equity including, but not limited to, the right: (a) to suspend performance hereunder until the Event of Default has been cured, provided, however, in no event shall any such suspension continue for longer than ten (10) Business Days unless an Early Termination Date shall have been declared and notice thereof pursuant to this Section 11.2(1) given; (b) to retain, draw on, liquidate or apply any Security in accordance with the terms of this Agreement, including Section 19; (c) to require the Defaulting Party to pay damages as set forth in Section 11.2(2); (d) to file suit to compel the Defaulting

Party to perform or obtain damages from the Defaulting Party; and/or (e) to file suit to enjoin any acts that are unlawful or violate the rights of the Non-Defaulting Party under this Agreement.

(2) Except as otherwise expressly provided herein, any Event of Default shall subject the Defaulting Party to the payment only of actual direct damages to the Non-Defaulting Party. Subject to the terms of this Agreement, the Non-Defaulting Party shall be entitled to take any actions as may be necessary or appropriate to protect, preserve or enforce its rights or to reduce any risk of loss resulting from an early termination of this Agreement. The Non-Defaulting Party shall calculate a Settlement Amount, if any, resulting from an Early Termination Date in a commercially reasonably manner. The Settlement Amount is intended to compensate the Non-Defaulting Party for the loss of bargain and the loss of protection against risks arising from the early termination of this Agreement. Upon determination of the Settlement Amount by the Non-Defaulting Party, the Non-Defaulting Party shall provide the Defaulting Party with a written statement showing the calculation of the Settlement Amount in sufficient detail to allow the Defaulting Party to compare such amount to its own estimate of the Settlement Amount. In the event the Defaulting Party disputes the Non-Defaulting Party's calculation of the Settlement Amount, the dispute shall be resolved pursuant to the terms of Article 21. Nothing in this Section 11.2(2) shall be construed to restrict or preclude the Non-Defaulting Party from realizing on any Security held by the Non-Defaulting Party at any time upon the occurrence of an Event of Default with respect to the Defaulting Party notwithstanding (and without awaiting the outcome of) any dispute as to the Settlement Amount payable. Consistent with Section 24.1, the Parties have an obligation to mitigate damages in an Event of Default in order to minimize the Settlement Amount.

(3) Any assertion by the Non-Defaulting Party of its entitlement to enforce any of the remedies described in Section 11.2(1) must be initiated by the Non-Defaulting Party, through written notice to the Defaulting Party, no later than the expiration of twelve (12) months after the termination of this Agreement. The Party who fails to act in a timely manner as provided in this Section 11.2 shall be deemed to have waived its right to enforce such remedies.

12. BILLING AND PAYMENT

12.1 Billing and Payment.

Following each month during the Delivery Term, Seller shall render to Buyer (by regular mail, facsimile or other acceptable means pursuant to Section 18) a statement setting forth the Capacity Charge, VOM Charge, and Start Charge, to the extent applicable, for such month and any other amounts due to either Party. On or before the later of (i) ten (10) Days after receipt of Seller's statement or (ii) the twentieth (20th) Day of the month in which such statement is received or if such Day is not a Business Day, the immediately following Business Day, Buyer shall render, by wire transfer, the amount set forth on such statement to the payment address provided in Exhibit H hereto. Overdue payments shall accrue interest from the due date to the date of payment at the Interest Rate. Any disputed invoiced amounts, except amounts which are manifestly inaccurate or are not reasonably supported by documentation, shall be paid in full on the applicable payment due date, subject to later return together with interest accrued at the

Interest Rate until the date paid. Inadvertent overpayments shall be returned by Seller upon request or deducted by Seller from subsequent payments.

12.2 Netting.

If Buyer and Seller are each required to pay an amount under this Agreement in the same month, then such amounts with respect to each Party may be aggregated and the Parties may discharge their obligations to pay through netting, in which case the Party, if any, owing the greater aggregate amount may pay to the other Party the difference between the amounts owed. Such netting shall not result in any waiver of, and each Party reserves to itself, any rights, counterclaims, remedies or defenses (to the extent not expressly herein waived or denied) which such Party has or may be entitled to arising from or out of this Agreement.

12.3 Audit and Financial Information.

(1) Each Party (and its representatives) has the right, on five (5) Business Days prior written notice, at its sole expense and during normal working hours, to examine the records of the other Party to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement. If requested, Seller shall provide to Buyer statements evidencing the quantities of Energy and/or Ancillary Services delivered at the Delivery Point, metering records of Fuel delivered to the Fuel Delivery Point and/or Fuel consumed at the Facility and any tests or records of any non-conforming Gas delivered at the Gas Delivery Point. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be promptly made and shall bear interest calculated at the Interest Rate from the date the overpayment or underpayment was made until such adjustment is paid or refunded; *provided, however*, that no adjustment for any statement or payment will be made unless objection to the accuracy thereof was made prior to the lapse of twenty-four (24) months from the receipt thereof.

(2) If requested by a Party ("Party A"), the other Party or its guarantor, if any, ("Party B") shall deliver (i) within 120 Days following the end of each fiscal year, a copy of Party B's annual report containing audited consolidated financial statements for such fiscal year and (ii) within 60 Days after the end of each of its first three fiscal quarters of each fiscal year, a copy of Party B's quarterly report containing unaudited consolidated financial statements for such fiscal quarter. In all cases the statements shall be for the most recent accounting period and prepared in accordance with GAAP; provided, however, that should any such statements not be available on a timely basis due to a delay in preparation or certification, such delay shall not be an Event of Default under Section 11.1 so long as Party B diligently pursues the preparation, certification and delivery of the statements. If Party B's financial statements are publicly available from the website of the Securities and Exchange Commission, Party B shall not be required to deliver copies of such statements to Party A. Notwithstanding this Section 12.3(2), with respect to Seller, all financial statements shall be for Mirant Corporation.

13. INDEMNIFICATION

13.1 Indemnification by Seller.

(1) Seller shall indemnify, defend and hold harmless Buyer and Buyer's officers, directors, agents and employees from and against any and all Claims, demands, liabilities (including reasonable attorney's fees), judgments, fines, settlements and other amounts (collectively, "Damages") arising from any and all Claims relating to or arising out of the negligence or intentional misconduct of Seller.

(2) Except to the extent caused by the acts or failures to act of Buyer in breach of this Agreement and except to the extent Buyer is obligated to indemnify Seller for such Claims elsewhere under this Agreement, Seller shall indemnify, defend and hold harmless Buyer and Buyer's officers, directors, agents and employees, from and against all Claims for (i) personal injury, (ii) property damage, and/or (iii) Claims related to environmental laws or regulations, which arise from Seller's ownership or operation of the Facility or Seller's handling, treatment, storage and disposal of hazardous waste at the Facility including, but not limited to, Title 40, Code of Federal Regulations and Chapter 17, Florida Administrative Code.

13.2 Indemnification by Buyer.

(1) Buyer shall indemnify, defend and hold harmless Seller and Seller's officers, directors, agents and employees from and against any and all Damages, as defined in Section 13.1(1), arising from any and all Claims relating to or arising out of (i) the negligence or intentional misconduct of Buyer and/or (ii) Buyer's actions or omissions taken or made in connection with Buyer's operation of the Facility pursuant to Section 4.8.

(2) Except to the extent caused by the acts or failures to act of Seller in breach of this Agreement and except to the extent Seller is obligated to indemnify Buyer for such claims elsewhere under this Agreement, Buyer shall indemnify, defend and hold harmless Seller and Seller's officers, directors, agents and employees from and against all Claims for (i) personal injury, (ii) property damage, and/or (iii) Claims related to environmental laws or regulations, which arise from Buyer's operation of the Facility pursuant to Section 4.8 or Buyer's handling, treatment, storage and disposal of hazardous waste during Buyer's operation of the Facility including, but not limited to, Title 40, Code of Federal Regulations and Chapter 17, Florida Administrative Code. For purposes of clarity, in the event Buyer exercises its right pursuant to Section 4.8(1) to operate the Facility, any act or failure to act by Seller in breach of this Agreement, which led to Buyer's operation of the Facility, shall not be used to excuse Buyer's indemnification obligations hereunder.

13.3 Settlement of Claims.

No Claims relating to or arising out of the alleged negligence or intentional misconduct of the indemnifying Party may be settled by such Party without the prior written consent of the indemnified Party, which consent shall not be unreasonably withheld or delayed. With respect to

this Section 13.3, "unreasonably withheld or delayed" shall not include the indemnified Party's withholding or delay of consent to any settlement in which there is admission of guilt or wrongdoing by the indemnified Party or, in the absence of such admission, when the Parties have been unable to agree on the amount of Damages due to the indemnified Party as a result of the applicable Claim.

14. LIMITATION OF LIABILITY

THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS HEREIN PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY SHALL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY HEREIN PROVIDED, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST OPPORTUNITY COSTS OR LOST PROFITS, BY STATUTE, IN TORT OR CONTRACT, AT LAW OR IN EQUITY, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES IS WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING, WITHOUT LIMITATION, THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE IS SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE LIQUIDATED DAMAGES CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS. THE PROVISIONS OF THIS SECTION 14 SHALL NOT LIMIT IN ANY WAY EITHER PARTY'S RIGHT TO EXERCISE THE REMEDIES SET FORTH IN ARTICLE 17 OF THIS AGREEMENT, OR TO RECOVER THE AMOUNTS PAYABLE PURSUANT TO ARTICLE 17.

15. TAXES

15.1 General.

Buyer and Seller shall each use reasonable efforts to minimize taxes applicable to the transactions to be carried out under the terms of this Agreement. Either Party, upon written request of the other, shall provide a certificate of exemption or other reasonably satisfactory evidence of exemption if such Party is exempt from taxes, and shall use reasonable efforts to obtain and cooperate with obtaining any exemption from or reduction of tax.

15.2 Applicable Taxes.

(1) Seller shall be responsible for all existing and any new sale, use, transportation, excise, business and operation, *ad valorem*, or other similar tax, imposed or levied by any Governmental Authority relating to the ownership of the Facility or operation of the Facility. Notwithstanding the foregoing, if this Agreement is deemed by any Governmental Authority to be a taxable "license to use real property," Seller shall not be responsible for any existing or new sale, use or similar tax levied thereon. Seller shall not be responsible for any existing or new sale, use, transportation, excise, *ad valorem*, or similar tax imposed or levied on the sale, use or consumption of Fuel.

(2) Buyer shall be responsible for all existing and any new sale, use, transportation, excise, *ad valorem*, or other similar tax imposed or levied by any Governmental Authority relating to the sale, use or consumption of Fuel and relating to the Monthly Demonstrated Capacity, Energy and/or Ancillary Services at and after its receipt by Buyer at the Delivery Point. If this Agreement is deemed by any Governmental Authority to be a taxable "license to use real property," Buyer shall be responsible for any existing or new sale, use or similar tax levied thereon.

(3) If Seller is required to collect or remit any tax on behalf of Buyer as a result of the transactions contemplated in this Agreement (including any sales, use, utility or gross receipts tax, or any tax of a similar nature), Buyer shall reimburse that tax to Seller, with such reimbursement to be made on an after tax basis. Neither Party is required to pay, or cause to be paid, any taxes measured by the income of the other Party.

(4) Each Party shall indemnify, release, defend and hold harmless the other Party from and against any and all liability for (i) taxes measured by the income of the indemnifying Party and (ii) taxes imposed or assessed by any Governmental Authority with respect to the transactions contemplated in this Agreement that are the responsibility of such Party pursuant to this Section 15.2.

16. ASSIGNMENT; BINDING EFFECT

16.1 Assignment.

Neither Party shall assign this Agreement or any of its rights or obligations hereunder without the prior written consent of the other Party, which consent shall not be unreasonably withheld or delayed, and any such assignee shall agree in writing to be bound by the terms and conditions hereof and shall meet the non-assigning Party's creditworthiness criteria which shall include, but shall not be limited to, providing adequate assurance to the non-assigning Party in an amount and form determined by the non-assigning Party in a commercially reasonable manner. The Parties acknowledge that the form and amount of any adequate assurance which the non-assigning Party may require from an assignee, as described in the preceding sentence, may not be the same as the form and amount of Security which Seller or Buyer, as applicable, is required to provide pursuant to Sections 19.1 or 19.2. Notwithstanding the foregoing, either Party may,

without the need for consent from the other Party, (a) transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements; (b) transfer or assign this Agreement to an Affiliate of such Party; or (c) transfer or assign this Agreement to any Person succeeding to all or substantially all of the assets of such Party; provided, that in the case of clauses (b) and (c) any such assignee shall agree in writing to be bound by the terms and conditions hereof and shall (i) meet the non-assigning Party's creditworthiness criteria which shall include, but shall not be limited to, providing adequate assurance to the non-assigning Party in an amount and form determined by the non-assigning Party in a commercially reasonable manner and (ii) demonstrate to the non-assigning Party that it has internal and/or external resources with reasonable proficiency in generation operations and that it is able to operate the Facility consistent with Prudent Industry Practice and in accordance with all the obligations under this Agreement. Upon any assignment consented to by the other Party or permitted under clauses (b) or (c) of the preceding sentence, the assigning Party shall be relieved of liability for all obligations arising hereunder after the date such assignment becomes effective. The Parties agree that it shall be a condition precedent to any proposed assignment of this Agreement that the assignor and assignee shall fulfill the obligations of this Section 16.1 before the assignment of this Agreement shall be allowed to occur.

16.2 Binding Effect.

This Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and permitted assigns.

17. CONFIDENTIALITY

Each Party shall keep confidential, and shall not disseminate to any third party (other than such Party's Affiliates) or use for any other purpose (except with written authorization), any information received from the other that is confidential or proprietary, including this Agreement, unless legally compelled (by deposition, inquiry, request for production of documents, subpoena, civil investigative demand or similar process, or by order of a court or tribunal of competent jurisdiction, or in order to comply with applicable rules or requirements of any stock exchange, government department or agency or other Governmental Authority, or by requirements of any securities law or regulation or other Governmental Rule) or as necessary to enforce the terms of this Agreement. Either Party may disclose the terms of this Agreement to (i) its Affiliates, and to its and their officers, directors, employees, attorneys and accountants, and (ii) its lenders, prospective lenders, financing participants and their respective consultants and agents who (in the case of Persons identified in clause (ii)) are bound to hold, treat and protect such information on a confidential basis. If any Party is compelled to disclose any confidential information of the other Party, such Party shall request that such disclosure be protected and maintained in confidence to the extent reasonable under the circumstances and use reasonable efforts to protect or limit disclosure with respect to commercially sensitive terms. In addition, such Party shall provide the other Party with prompt notice of the requirement to disclose confidential information in order to enable the other Party to seek an appropriate protective order or other remedy, and such Party shall consult with the other Party with respect to the other Party taking steps to resist or narrow the scope of any required disclosure.

18. NOTICES

All notices, requests, statements or payments shall be made to the addresses and persons specified in Exhibit H hereto. All notices or requests shall be made in writing except where this Agreement expressly provides that notice may be made orally. Notices required to be in writing shall be delivered by letter, facsimile or other documentary form. Notice by facsimile shall be deemed to have been received on the Day on which it was transmitted (where confirmation of successful transmission is received) (unless transmitted after 5:00 p.m. at the place of receipt or on a Day that is not a Business Day in which case it shall be deemed received on the next Business Day); provided that dispatch notifications and notifications of changes in availability of the Facility sent by facsimile shall be treated as received when confirmation of successful transmission is received. Notice by hand delivery, overnight mail, or courier shall be deemed to have been received when delivered. Notice by telephone shall be deemed to have been received at the time the call is received. A Party may change its address by providing notice of same in accordance herewith.

19. SECURITY

19.1 Security Provided by Buyer.

(1) Security Provided by Buyer. If, during the Contract Term, Buyer's Credit Rating falls below an Acceptable Credit Rating, then within five (5) Business Days, Buyer shall provide to Seller Security in a form chosen by Buyer. If the form is a Letter of Credit or cash, the amount of such Letter of Credit or cash shall equal [redacted]. If the form is a Guaranty, the amount of the Guaranty shall equal [redacted] Buyer shall be required to maintain such Security throughout the Contract Term unless otherwise provided in Section 19.1(2) or Section 19.4.

(2) Buyer Guarantor Credit Downgrade. If Buyer has provided a Guaranty to Seller pursuant to Section 19.1(1) and Buyer's guarantor fails to maintain an Acceptable Credit Rating at any time during the Contract Term, Buyer shall be required to replace such Guaranty with a Letter of Credit or cash in the amount of [redacted] Upon Seller's receipt of the Letter of Credit or cash, Seller shall return the Guaranty to Buyer.

19.2 Security Provided by Seller.

(1) Security Provided by Seller. Within five (5) Business Days of the execution of this Agreement, Seller shall provide to Buyer Security in the amount of [redacted] which, at Seller's election, shall be in the form of either a Letter of Credit or cash. Seller shall be required to maintain such Security throughout the Contract Term unless otherwise provided in Section 19.2(2) or Section 19.4.

(2) Substitution of Security. If, during the Contract Term, Mirant Corporation has an Acceptable Credit Rating and thereby becomes an Acceptable Guarantor, Seller, upon written notice to Buyer, may substitute the Security provided in accordance with Section 19.2(1) with a

Guaranty from Mirant Corporation in an amount equal to [redacted] If Seller elects to provide such substitute Security, Buyer will return to Seller the Security that Seller previously provided to Buyer pursuant to Section 19.2(1).

(3) Seller Guarantor Credit Downgrade. If Seller has provided a Guaranty to Buyer pursuant to Section 19.2(2) and Mirant Corporation fails to maintain an Acceptable Credit Rating at any time during the Contract Term, Seller shall be required to provide a Letter of Credit or cash in the amount of [redacted] and the existing Guaranty shall be reduced to [redacted] In lieu of reducing the amount of the existing Guaranty, Seller may choose to terminate the existing Guaranty and replace it with a new Guaranty from Mirant Corporation in the amount of [redacted] The Parties acknowledge and agree that Seller shall not be required to provide a Guaranty from an entity other than Mirant Corporation notwithstanding any failure of Mirant Corporation to maintain an Acceptable Credit Rating and such Guaranty shall be deemed acceptable Security to Buyer.

19.3 Letter of Credit.

If (i) the Pledging Party is required to provide a Letter of Credit under Section 19, (ii) the Pledging Party fails to cause any Letter of Credit to be renewed or replaced at least twenty (20) days before its expiration and (iii) the Pledging Party has not provided substitute Security if permitted under Section 19, then the Secured Party shall have the right to draw all or any part of the available balance of such Letter of Credit. The Pledging Party's failure to renew the Letter of Credit shall not, in and of itself, result in an Event of Default under Section 11.1(f). The cash proceeds received by the Secured Party from drawing on a Letter of Credit under this provision shall be held as Security just as though the Pledging Party had originally posted cash to support its obligations under Section 19. In the event the bank issuing the Letter of Credit shall fail to honor the Secured Party's properly documented request to draw on the outstanding Letter of Credit and the Pledging Party shall fail to provide a replacement Letter of Credit or other form of Security as permitted herein, the occurrence of such event shall be deemed an Event of Default under Section 11.1(f).

19.4 Exercise of Rights Against Security.

In the event (i) an Event of Default with respect to the Pledging Party has occurred and is continuing, and/or (ii) an Early Termination Date has occurred or been designated as the result of an Event of Default with respect to the Pledging Party, then unless the Pledging Party has paid in full all of its obligations that are due to the Secured Party under this Agreement, the Secured Party may exercise one or more of the following rights and remedies:

(1) Letter of Credit. In the event that the Security posted by the Pledging Party is a Letter of Credit, the Secured Party may draw on the entire, undrawn portion of any outstanding Letter of Credit. Unless and until such amounts are applied to the Pledging Party's payment obligations hereunder, the cash proceeds received from drawing upon the Letter of Credit shall be deemed Security for the Pledging Party's obligations to the Secured Party and the Secured Party shall have the rights and remedies set forth in Section 19.3(b) with respect to such cash

proceeds. Notwithstanding the Secured Party's receipt of cash proceeds from a drawing under a Letter of Credit, the Pledging Party shall remain liable (i) for any failure to provide any additional Security as required by Section 19 or (ii) for any amounts owing to the Secured Party and remaining unpaid after the application of the amounts so drawn by the Secured Party.

(2) Cash. In the event that the Security posted by the Pledging Party is cash, the Secured Party shall have the right to apply such cash against and in satisfaction of any amount due and payable by the Pledging Party in respect of its obligations under this Agreement.

(3) Guaranty. In the event that the Security posted by the Pledging Party is a Guaranty, the Secured Party shall have the right to demand payment from the guarantor in accordance with the terms of the Guaranty.

19.5 Return of Security.

If the Pledging Party achieves an Acceptable Credit Rating at any time during the Contract Term, the Secured Party shall, upon request, return any Security posted by the Pledging Party, provided, however, the provisions of Sections 19.1 and 19.2 shall continue to apply to any subsequent failures to maintain an Acceptable Credit Rating. Following termination of this Agreement, the Secured Party shall return any Security posted by the Pledging Party within five (5) Business Days after the date on which the Pledging Party has paid the Secured Party all amounts owed to the Secured Party under this Agreement.

20. FORCE MAJEURE

Neither Party shall be in breach or liable for any delay or failure in its performance under this Agreement to the extent such performance is prevented or delayed due to a Force Majeure Event, provided that:

(1) the non-performing Party shall give the other Party written notice as soon as practical and within three (3) Business Days of the commencement of the Force Majeure Event, with details to be supplied within ten (10) Days after the commencement of the Force Majeure Event further describing the particulars of the occurrence;

(2) the delay in performance shall be of no greater scope and of no longer duration than is directly caused by the Force Majeure Event;

(3) the Party whose performance is delayed or prevented shall proceed with due diligence to overcome the events or circumstances preventing or delaying performance and shall provide written progress reports to the other Party during the period that performance is delayed or prevented describing actions taken and to be taken to remedy the consequences of the Force Majeure Event, the schedule for such actions and the expected date by which performance shall no longer be prevented or delayed by the Force Majeure Event; and

(4) when the performance of the Party claiming the Force Majeure Event is no longer being delayed or prevented, that Party shall give the other Party written notice to that effect.

21. DISPUTE RESOLUTION

In the event of any dispute arising out of or relating to this Agreement which the Parties are unable to settle within thirty (30) Days after the dispute arose, either Party may refer the dispute to a meeting of senior management, in which case each Party shall nominate a senior officer of its management to meet at a mutually agreed time and place not later than forty-five (45) Days after the dispute arose to attempt to resolve the dispute. Should a resolution not be reached within fifteen (15) Days after the meeting of senior officers, then either Party may pursue its rights at law or in equity with respect to such dispute. Unless directed otherwise by a court or a Governmental Authority or unless otherwise provided by the express terms of this Agreement, no Party shall cease or delay performance of its obligations under this Agreement during the existence of any dispute or the pendency of any proceeding to resolve it, and the Parties shall pay to each other all amounts owing under Section 12.1. Notwithstanding the foregoing, if either Party has the right to terminate this Agreement pursuant to Section 11.2, such Party shall not be obligated to comply with this Section 21 prior to or as a condition precedent to exercising its right to terminate the Agreement.

22. INSURANCE

Seller shall carry and maintain, or cause to be carried and maintained, no less than the insurance coverages listed in Exhibit I, applicable to all operations undertaken by Seller. Such minimum amounts may be satisfied either by primary insurance or by any combination of primary and excess/umbrella insurance. Except as provided in Exhibit I, the required insurance coverages shall be maintained in effect throughout the Contract Term.

23. MATERIAL CHANGE TO AIR PERMIT

If the air permit for the Facility, as originally issued, is amended such that the maximum number of Run Hours or the minimum load, as determined by environmental restrictions contained in the air permit, materially reduces the availability of the Facility, Seller shall provide Buyer with prompt written notice of such amendment, and Buyer shall have the right to terminate this Agreement by providing written notice to Seller within ninety (90) Days of Buyer's receipt of notice of any such amendment, with any such termination to be effective ninety (90) Days after delivery of such termination notice. Seller and Buyer shall not be liable for any damages resulting from an early termination of this Agreement pursuant to this Section 23. If the Facility's air permit is amended by any Governmental Authority, Seller shall promptly notify Buyer of any modifications to the Operational Limitations as may be necessary to comply with the amended air permit.

24. MISCELLANEOUS

24.1 Duty to Mitigate.

Each Party agrees that it has a duty to mitigate damages and covenants that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this Agreement.

24.2 Entire Agreement and Amendments.

This Agreement constitutes the entire agreement between the Parties with respect to the subject matter hereof. There are no prior or contemporaneous agreements or representations affecting the subject matter of this Agreement other than those herein expressed. No amendment, modification or change to this Agreement shall be enforceable unless reduced to writing and executed by both Parties.

24.3 Governing Law.

This Agreement and the rights and duties of the Parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the State of Florida, without giving effect to principles of conflicts of laws that would require the application of the law of any other state. The Parties expressly waive the right to a jury trial for any dispute arising from this Agreement.

24.4 Waivers.

The failure of either Party hereto to enforce at any time any provision of this Agreement shall not be construed to be a waiver of such provision, nor in any way to affect the validity of this Agreement or any part hereof or the right of a Party thereafter to enforce each and every such provision. A waiver under this Agreement must be in writing and state that it is a waiver. No waiver of any breach of this Agreement shall be held to constitute a waiver of any other or subsequent breach.

24.5 Fines.

Except as otherwise provided in this Agreement, each Party shall be responsible for and shall pay the fines that are levied upon it by a Governmental Authority or regulatory body as a result of such Party's own actions or inactions except to the extent one Party is obligated to indemnify the other Party under this Agreement.

24.6 Severability.

Except as otherwise stated herein, any provision or section declared or rendered unlawful by a Governmental Authority, or deemed unlawful because of a statutory change, will not otherwise affect the lawful obligations that arise under this Agreement.

24.7 Headings; Exhibits.

The headings used for the sections and articles herein are for convenience and reference purposes only and shall in no way affect the meaning or interpretation of the provisions of this Agreement. Any and all Exhibits referred to in this Agreement are, by such reference, incorporated herein and made a part hereof for all purposes.

24.8 No Third Party Beneficiaries.

Nothing in this Agreement shall provide any benefit to any third party or entitle any third party to any claim, cause of action, remedy or right of any kind, it being the intent of the Parties that this Agreement shall not be construed as a third party beneficiary contract.

24.9 Counterparts.

This Agreement may be executed in several counterparts, each of which is an original and all of which constitute one and the same instrument.

24.10 No Partnership.

Nothing contained in this Agreement shall be construed to create a partnership, joint venture, agency or other relationship that may invoke fiduciary obligations between the Parties hereto.

24.11 Press Releases.

The Parties shall not issue a press release or make any public statement with respect to this Agreement or the tolling arrangement described herein without the prior written agreement of the other Party with respect to the form, substance and timing thereof, except either Party may make any such press release or public statement when the releasing Party is advised by its legal counsel that such a press release or public statement is required by law, regulation, stock exchange rules or in connection with the financing of the Facility, but in such event the Parties shall use their reasonably good faith efforts to agree as to the form, substance and timing of such release or statement.

24.12 Rights under the Federal Power Act.

(1) This Agreement shall not be subject to change through any unilateral application by either Party to any Governmental Authority including, but not limited to, the FERC pursuant to the provisions of Sections 205, 206 or 306 of the Federal Power Act, without the prior mutual written agreement of both Parties. Each of the Parties hereby irrevocably waives any right it may or can have to unilaterally seek any change, or to support any application, complaint, or action by any other party or Governmental Authority seeking such change.

(2) Absent agreement by the Parties to the proposed change, the standard of review for changes to any Section of this Agreement proposed by a Party, a non-party or the FERC acting sua sponte shall be the "public interest" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) (the "Mobile-Sierra" doctrine).

[Signature page follows this page]

IN WITNESS WHEREOF, each of Seller and Buyer has caused this Agreement to be executed on its behalf by its duly authorized representative to be effective as of the date first above written.

Shady Hills Power Company, L.L.C.

By: _____

Name: _____

Title _____

Date: _____

Florida Power Corporation
d/b/a Progress Energy Florida, Inc.

By: _____

Name: _____

Title: _____

Date: _____

EXHIBIT A
CAPACITY PRICE

The price to be used in calculating the Capacity Charge for a month pursuant to Section 9.2 (the "Capacity Price") shall be:

January	[redacted]
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

EXHIBIT B
VOM PRICE

The price for Energy and Ancillary Services to be used in calculating the VOM Charge for a month pursuant to Section 9.3 (the "VOM Price") is as follows:

While operating on Gas, the VOM Price shall be [redacted].

While operating on Fuel Oil, the VOM Price shall be [redacted].

The VOM Price, applicable to both Gas and Fuel Oil, [redacted]

EXHIBIT C
START FEE

The "Start Fee" for each Successful Start of a Unit to be used in calculating the Start Charge for a month pursuant to Section 9.4 shall be as follows:

Unit 1: [redacted]

Unit 2: [redacted]

Unit 3 [redacted]

The Start Fee shall increase at a rate of [redacted] per year after the first calendar year during the Delivery Term.

EXHIBIT D
CALCULATION OF ACTUAL EQUIVALENT AVAILABILITY

The Actual Equivalent Availability of the Facility shall be calculated during all On-Peak Hours for each Peak Month and Non-Peak Month during the Delivery Term using the following formula:

$$AEA\ (\%) = [(MDC*HRS)-(MDC*FOH)-\sum_{x=1}^{N}(FDQ_x*FDH_x)]/(MDC*HRS)$$

Where:

AEA	=	Actual Equivalent Availability of the Facility during a month (measured as a percentage) (%).
MDC	=	Monthly Demonstrated Capacity for the applicable month (MW).
HRS	=	all On-Peak Hours in the applicable month.
FOH	=	"Forced Outage Hours" means the total On-Peak Hours during a month in which the Facility experiences a Forced Outage.
FDQ	=	"Forced Derate Quantity" has the meaning set forth in Section 1.1(41).
FDH	=	"Forced Derate Hours" means, for each Forced Derate, the total number of On-Peak Hours, if any, during which the Forced Derate was in effect.
x	=	each Forced Derate during the applicable month.
N	=	the sum of all Forced Derates during the applicable month.

EXHIBIT E
CALCULATION OF THE AVAILABILITY REBATE

The Availability Rebate shall be calculated for each Peak Month and Non-Peak Month during the Delivery Term using the following formula:

Peak Months
When the Actual Equivalent Availability is less than [redacted] the Seller shall pay to the Buyer the Availability Rebate which shall be calculated as follows:

Availability Rebate = ([redacted] - AEA)*Capacity Charge for respective month

Non-Peak Months
When the Actual Equivalent Availability is less than [redacted], the Seller shall pay to the Buyer the Availability Rebate which shall be calculated as follows:

Availability Rebate = ([redacted] - AEA)*Capacity Charge for respective month

In the event the Actual Equivalent Availability for any month is below 50%, then the Availability Rebate shall be equal to the total Capacity Charge for the respective month. The Availability Rebates for all Peak Months and Non-Peak Months for a calendar year shall not exceed the total Capacity Charges paid by Buyer during such year. The Availability Rebate, if any, payable by Seller to Buyer shall be netted against charges payable by Buyer to Seller hereunder in the monthly invoice sent to Buyer.

EXHIBIT F
PERFORMANCE INFORMATION

Ambient conditions
Unit performance data

- MW
- MVAR
- Power Factor
- Frequency
- Breaker Position
- Temperatures
- Amps
- AGC Control Setpoints
- Heat rate
- Vibration Monitoring

Plant Switchyard data

- Voltage
- Breaker Position

Fuel data

- Temperature
- Btu content
- Specific gravity
- Pressures
- Tank Levels

Continuous Emissions Monitoring Systems (CEMS) data
Balance of Plant data

- Tank Levels
- Pressures
- Heater Temperatures

EXHIBIT G
OPERATIONAL LIMITATIONS

The Operational Limitations applicable to Units 1, 2 and 3 are as follows:

Minimum Unit Load — The minimum Unit load is 100 MW.

Start Notification — The minimum notification to start a Unit is one (1) hour.

Cancel Notification — Buyer may cancel a schedule at any time subject to the Operational Limitations. To avoid a start charge, Seller must cancel prior to initiation of the start sequence.

Minimum Run Time — Once a Unit is started, such Unit must run for a minimum of two (2) consecutive hours.

Minimum Time Off-line — The minimum time between a shut down of a Unit and a subsequent start up of such Unit is two (2) hours.

Number of Starts — Buyer may start each Unit no more than two (2) times per Day.

Ramp Rates — The ramp rate per Unit in response to a dispatch request from the minimum Unit load described above is 13 MW per minute. The ramp rates for starts are as follows:

Hot Start:	30 Minutes to full load
Warm Start:	30 Minutes to full load
Cold Start:	30 Minutes to full load

Successful Start — A Successful Start means synchronization of the Unit to the transmission grid at full dispatched load within 30 minutes of a start initiation.

Switching Fuels — Once started, the Units may switch from Gas to Fuel Oil or from Fuel Oil to Gas without the schedule being taken to zero and without incurring a Start Charge.

Permit Hours — The Units shall not operate more than an average of 3390 hours per Unit per calendar year. The Units shall not operate more than an average of 1000 hours per Unit on Fuel Oil per calendar year. No Unit shall operate more than 5000 hours in a single year.

Min./Max. AGC — The minimum AGC set point is 110 MW. The maximum AGC set point is full load at ambient conditions.

Note: In the event the air permit for the Facility is amended or modified during the Agreement Term as a result of a change in any Governmental Rule or a new Governmental Rule, Seller shall have the right to amend or modify these Operational Limitations to be consistent with such air permit. Seller shall notify Buyer of any such changes in writing.

EXHIBIT H
NOTICES

Progress Energy Florida, Inc.

NOTICES:

Progress Energy Florida, Inc.
100 Central Ave.
BT9G
St. Petersburg, FL 33701
Attention: Director – Origination
and Account Management
Phone: 727.820.4550
Facsimile: 727.820.4598

PAYMENT:
Florida Power Corporation
Wachovia Bank, N.A.
Winston Salem, N.C.
[redacted]

SCHEDULING:

24 Hour Desk:
Phone: 919.546.6747
Facsimile: 919.546.3374

Shady Hills Power Company, L.L.C

NOTICES:

Shady Hills Power Company, L.L.C.
1155 Perimeter Center
Atlanta, Georgia 30338-5416
Attention: Legal Department, Commercial
Phone: 678.579.6900
Facsimile: 678.579.5988

PAYMENT:

Bank of America, N.A.
[redacted]

SCHEDULING:

24 Hour Desk: 678.579.3008.
24 Hour Desk Fax: 678.579.5767

EXHIBIT I
INSURANCE

Seller Requirements

Seller shall at its sole expense purchase from and maintain in a company or companies lawfully authorized to conduct business in the jurisdiction where the Facility is located the insurance described in this Exhibit I. Such insurers shall maintain an A.M. Best's rating of A or better or if such insurer is not rated by A.M. Best, a comparable financial strength rating from a rating entity acceptable to Buyer.

Seller agrees to waive and shall cause its insurers to waive all rights of subrogation against Buyer. Buyer agrees to waive and shall cause its insurers to waive all rights of subrogation against Seller. Buyer shall be named as an additional insured under all coverages except All Risk Property Insurance, Workers Compensation and Business Interruption.

All Risk Property Insurance – Seller will procure and maintain all risk property insurance including coverage for physical damage, boiler and machinery and extra expense during the operation of the Facility. Coverage valuation shall be the actual repair or replacement costs subject to a policy limit no less than two (2) times the probable maximum loss for the Facility and no greater than the full replacement cost of the Facility. Coverage will also apply during inland transit (including brown water marine). Such coverage shall allow for reasonable sublimits for specific perils as consistent with Prudent Industry Practice.

Commercial General Liability – Seller will carry commercial general liability coverage to a limit of $2 million per occurrence, $4 million in aggregate. The insurance will cover Claims brought against Seller for third party bodily injury (including death), personal injury and property damage. The coverage will include provisions for broad form property damage, explosion, collapse and underground hazard coverage (XCU), cross liability, severability of interest and broad form contractual liability. In addition to this coverage, Seller will also require any contractors utilized to provide similar coverage during maintenance of the Facility covering Seller, lenders and other parties.

Excess Liability/Umbrella Coverage – Seller will carry excess liability/umbrella coverage insurance of $3 million per occurrence so that the total coverage for Commercial General Liability and Excess Liability/Umbrella Coverage shall be at least $5 million per occurrence, however, such $5 million total coverage may be made up of any combination of Commercial General Liability and Excess Liability/Umbrella Coverage at Seller's sole discretion.

Workers Compensation – Seller will carry workers compensation insurance covering statutory workers compensation obligations as required by state law. The coverage will also include $1 million in Employers Liability coverage insuring Claims brought by employees brought outside the Florida workers' compensation statute. Seller will also require the same coverage of any contractors employed for maintenance of the facility.

Business Interruption – Seller, in its sole discretion, may carry business interruption insurance to cover the actual loss sustained resulting from interruption of business as a result of physical loss or damage as insured by the all risk property insurance.

Buyer Requirements

During the period while Buyer is operating the Facility pursuant to Section 4.8 of this Agreement, Buyer shall at its sole expense purchase from and maintain in a company or companies lawfully authorized to conduct business in the jurisdiction where the Facility is located the insurance described in this Exhibit I. Such insurers shall maintain an A.M. Best's rating of A or better or if such insurer is not rated by A.M. Best, a comparable financial strength rating from a rating entity acceptable to Seller.

Seller agrees to waive and shall cause its insurers to waive all rights of subrogation against Buyer. Buyer agrees to waive and shall cause its insurers to waive all rights of subrogation against Seller. Seller shall be named as an additional insured under all coverages except All Risk Property Insurance and Workers Compensation.

All Risk Property Insurance – Buyer will procure and maintain all risk property insurance including coverage for physical damage, boiler and machinery and extra expense during the operation of the Facility. Coverage valuation shall be the actual repair or replacement costs subject to a policy limit no less than two (2) times the probable maximum loss for the Facility and no greater than the full replacement cost of the Facility. Coverage will also apply during inland transit (including brown water marine). Such coverage shall allow for reasonable sublimits for specific perils as consistent with Prudent Industry Practice.

Commercial General Liability – Buyer will carry commercial general liability coverage to a limit of $2 million per occurrence, $4 million in aggregate. The insurance will cover Claims brought against Buyer for third party bodily injury (including death), personal injury and property damage. The coverage will include provisions for broad form property damage, explosion, collapse and underground hazard coverage (XCU), cross liability, severability of interest and broad form contractual liability. In addition to this coverage, Seller will also require any contractors utilized to provide similar coverage during maintenance of the Facility covering Buyer and other parties.

Excess Liability/Umbrella Coverage – Buyer will carry excess liability/umbrella coverage insurance of $3 million per occurrence so that the total coverage for Commercial General Liability and Excess Liability/Umbrella Coverage shall be at least $5 million per occurrence, however, such $5 million total coverage may be made up of any combination of Commercial General Liability and Excess Liability/Umbrella Coverage at Buyer's sole discretion.

Workers Compensation – Buyer will carry workers compensation insurance covering statutory workers compensation obligations as required by state law. The coverage will also include $1 million in Employers Liability coverage insuring Claims brought by employees brought outside

the Florida workers' compensation statute. Buyer will also require the same coverage of any contractors employed for maintenance of the facility.

EXHIBIT J
FUEL OIL SPECIFICATIONS

METHOD		ASTM TEST
Flash Point Minimum	140° F or legal	D-93
Pour Point Maximum	20° F	D-97
Water & Sediment % Volume Maximum	0.05%	D-96/D1796
Carbon Residue on 10% Bottoms Max.	0.35%	D-189/D-4530
Distillation Points 90% Min. Max.	540° F 650° F	D-86
Viscosity @ 100° F Min. CS Max.	1.9 3.6	D-445
Ash Weight % Maximum	0.01	D-482
Gravity Minimum API	30	D-287/D-1298
Sulfur Weight % Maximum	0.05	D-1552/
BTU/Gallon Minimum	137,000	D-240
DuPont Stability Maximum	7 maximum	N/A
Oxidation Stability mg/100 ml Max.	2.5	D-2274

EXHIBIT K
FORM OF GUARANTY

GUARANTY AGREEMENT

This Guaranty Agreement (the "Guaranty"), dated effective as of _____, is made and entered into by _____, a _____corporation ("Guarantor").

WHEREAS, _____a _____ corporation (the "Company"), and_____ (the "Counterparty"), have entered into or are contemplating entering into the Tolling Agreement between Shady Hills Power Company, L.L.C. and Florida Power Corporation, d/b/a as Progress Energy Florida, Inc.") (such contract, as the same may from time to time be modified, amended and supplemented, shall be referred to herein as the "Contract");

WHEREAS, Company is a wholly owned subsidiary of Guarantor and Guarantor will directly or indirectly benefit from the transactions to be entered into between Company and Counterparty.

NOW THEREFORE, in consideration of Counterparty entering into the Contract, Guarantor hereby covenants and agrees as follows:

1. GUARANTY. Subject to the provisions hereof, (a) Guarantor hereby irrevocably and unconditionally guarantees the timely payment when due of the obligations of Company (the "Obligations") to Counterparty under the Contract, and (b) to the extent that Company shall fail or refuse to pay any Obligations, Guarantor shall promptly pay to Counterparty the amount due. This Guaranty shall constitute a guarantee of payment and not of collection. The liability of Guarantor under the Guaranty shall be subject to the following:

(a) Guarantor's obligations and liability under this Guaranty shall be limited to payment obligations only and Guarantor shall have no obligation to perform under any Contract, including without limitation, to sell, deliver, supply or transport gas, electricity or any other commodity;

(b) Guarantor's liability hereunder shall be and is specifically limited to payments expressly required to be made under the Contract (even if such payments are deemed to be damages); and

(c) the aggregate amount covered by this Guaranty shall not exceed the lesser of (i) all amounts Company owes to Counterparty pursuant to the Contract or (ii) _____ United States Dollars ($_____ U.S. Dollars).

This Guaranty shall continue to be effective or be reinstated, as the case may be, if at any time any payment of the Obligations by Company are annulled, set aside, invalidated, declared to be fraudulent or preferential, rescinded or must otherwise be returned, refunded or repaid by

Counterparty upon the insolvency, bankruptcy, dissolution, liquidation or reorganization of Company as though such payment or payments had not been made.

2. DEMANDS AND NOTICE. If (i) Company fails or refuses to pay any Obligations under the Contract or Company has an Event of Default, as defined in Section 11 of the Contract); and (ii) Counterparty elects to exercise its rights hereunder, Counterparty shall make a demand upon Guarantor (hereinafter referred to as a "Payment Demand"). A Payment Demand shall be in writing and shall reasonably and briefly specify in what manner and what amount Company has failed to pay and an explanation of why such payment is due, with a specific statement that Counterparty is calling upon Guarantor to pay under this Guaranty. A Payment Demand satisfying the foregoing requirements shall be required with respect to Obligations before Guarantor is required to pay such Obligations hereunder and shall be deemed sufficient notice to Guarantor that it must pay the Obligations within two (2) business days of Guarantor's receipt of such Payment Demand. A single written Payment Demand shall be effective as to any specific default during the continuance of such default, until Company or Guarantor has cured such default, and additional written demands concerning such default shall not be required until such default is cured.

3. REPRESENTATIONS AND WARRANTIES. Guarantor represents and warrants that:

(a) it is a corporation duly organized and validly existing under the laws of the State of _____ and has the corporate power and authority to execute, deliver and carry out the terms and provisions of the Guaranty;

(b) no authorization, approval, consent or order of, or registration or filing with, any court or other governmental body having jurisdiction over Guarantor is required on the part of Guarantor for the execution and delivery of this Guaranty; and

(c) this Guaranty, when executed and delivered, will constitute a valid and legally binding agreement of Guarantor, except as the enforceability of this Guaranty may be limited by the effect of any applicable bankruptcy, insolvency, reorganization, moratorium or similar laws affecting creditors' rights generally and by general principles of equity.

4. SETOFFS AND COUNTERCLAIMS. WITHOUT LIMITING GUARANTOR'S OWN DEFENSES AND RIGHTS HEREUNDER, GUARANTOR RESERVES TO ITSELF ALL RIGHTS, SETOFFS, COUNTERCLAIMS AND OTHER DEFENSES TO WHICH COMPANY IS OR MAY BE ENTITLED TO ARISING FROM OR OUT OF THE CONTRACT, EXCEPT FOR DEFENSES ARISING OUT OF THE BANKRUPTCY, INSOLVENCY, DISSOLUTION OR LIQUIDATION OF COMPANY.

5. AMENDMENT OF GUARANTY. Guarantor may amend this Guaranty to increase the guaranty limit set forth in Paragraph 1(c) or to extend the termination date set forth in Section 7 without the consent of Counterparty provided that any such amendment shall be in writing and signed by Guarantor. No other term or provision of this Guaranty shall be amended, modified, altered, waived or supplemented except in a writing signed by both Guarantor and

Counterparty. Any such waiver as provided in this Section 5 shall be effective only in the specific instance and for the specific purpose for which it was given.

6. SUBROGATION. Guarantor shall be subrogated to all rights of Counterparty against Company in respect of any amounts paid by Guarantor pursuant to the Guaranty, provided that Guarantor waives any rights it may acquire by way of subrogation under this Guaranty, by any payment made hereunder or otherwise (including without limitation, any statutory rights of subrogation under Section 509 of the Bankruptcy Code, 11 U.S.C. § 509, or otherwise), for reimbursement, exoneration, contribution, indemnification, or any right to participate in any claim or remedy of Counterparty against any collateral which Counterparty now has or acquires, until all of the Obligations have been irrevocably paid to Counterparty in full. If any amount shall be paid to Guarantor on account of such subrogation rights at any time when all the Obligations shall not have been paid in full, such amount shall be held in trust for the benefit of Counterparty and shall forthwith be paid to Counterparty to be applied to the Obligations. Upon payment in full of the Obligations, Guarantor shall be subrogated to the rights of Counterparty against Company and Counterparty agrees to such actions as Guarantor may reasonably require to implement such subrogation.

7. WAIVERS AND TERMINATION. Guarantor hereby waives (a) notice of acceptance of this Guaranty; (b) presentment and demand concerning the liabilities of Guarantor, except as expressly hereinabove set forth; and (c) any right to require that any action or proceeding be brought against Company or any other person, or except as expressly hereinabove set forth, to require that Counterparty seek enforcement of any performance against Company or any other person, prior to any action against Guarantor under the terms hereof.

Except as to applicable statutes of limitation, no delay of Counterparty in the exercise of, or failure to exercise, any rights hereunder shall operate as a waiver of such rights, a waiver of any other rights or a release of Guarantor from any obligations hereunder.

Guarantor consents to the renewal, compromise, extension, acceleration or other changes in the time of payment of or other changes in the terms of the Obligations, or any part thereof or any changes or modifications to the terms of the Contract.

This Guaranty shall terminate in accordance with Section 19 of the Contract. No such termination shall affect Guarantor's liability with respect to any Obligations entered into prior to the time the termination is effective, which Obligations shall remain guaranteed pursuant to the terms of this Guaranty.

8. NOTICE. Any Payment Demand, notice, request, instruction, correspondence or other document to be given hereunder by any party to another (herein collectively called "Notice") shall be in writing and delivered personally or mailed by certified mail, postage prepaid and return receipt requested, or by facsimile, as follows:

To Guarantor: To Counterparty:

_____	_____
_____	_____
_____	_____
Attn: _____	Attn: _____
Fax No.: _____	Fax No.: _____

Notice given by personal delivery or mail shall be effective upon actual receipt. Notice given by facsimile shall be effective upon actual receipt if received during the recipient's normal business hours, or at the beginning of the recipient's next business day after receipt if not received during the recipient's normal business hours. All Notices by facsimile shall be confirmed promptly after transmission in writing by certified mail or personal delivery. Any party may change any address to which Notice is to be given to it by giving notice as provided above of such change of address.

9. ASSIGNMENT. Neither Guarantor nor Counterparty shall assign this Guaranty without the express written consent of the other party, which consent shall not be unreasonably withheld or delayed.

10. MISCELLANEOUS. **THIS GUARANTY SHALL IN ALL RESPECTS BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAW OF THE STATE OF FLORIDA.** All rights, remedies and powers provided in this Guaranty may be exercised only to the extent that the exercise thereof does not violate any applicable provision of law, and all of the provisions of this Guaranty are intended to be subject to all applicable mandatory provisions of law that may be controlling and to be limited to the extent necessary so that it will not render this Guaranty invalid or unenforceable in whole or in part. This Guaranty shall be binding upon Guarantor, its successors and permitted assigns and inure to the benefit of and be enforceable by Counterparty, its successors and permitted assigns. The Guaranty embodies the entire agreement and understanding between Guarantor and Counterparty and supersedes all prior agreements and understandings relating to the subject matter hereof. The headings in this Guaranty are for purposes of reference only, and shall not affect the meaning hereof.

[Signature page follows this page]

IN WITNESS WHEREOF, the Guarantor has executed this Guaranty on _____, but it is effective as of the date first above written.

Guarantor's Name

By: _____
Name: _____
Title: _____

EXHIBIT L
DEMONSTRATED CAPACITY ADJUSTMENT FACTORS

Month	Adjustment Factor
January	[redacted]
February	
March	
April	
May	
June	
July	
August	
September	
October	
November	
December	

Exhibit ____ (SSW-3)

Summary of Benefits of the Shady Hills Tolling Agreement

NPV Costs, 2004$:

Capacity Charges for Shady Hills	[redacted]
Gas Pipeline Reservation Charges	[redacted]
Additional Equity Cost	[redacted]

NPV Benefits, 2004$:

Capacity Deferral Benefit (Advancement Cost)	**($69,872,000)**
Energy Savings, net	**$285,179,000**

Net Benefit to PEF: $55,442,000, NPV

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO 40
COMPANY/ P.E.F.
WITNESS: Samuel S. Waters (SSW-3)
DATE 11-08-04

TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
FILED: 02/17/04

TAMPA ELECTRIC COMPANY

FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 41
COMPANY/ TECO
WITNESS: J. Denise Jordan
DATE: 11-08-04

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
(JDJ-1)

FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

INDEX

DOCUMENT NO.	TITLE	PAGE
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2	Final Fuel and Purchased Power Over/ (Under) Recovery for January 2003 - December 2003	18
3	Actual Fuel and Purchased Power True-up *vs.* Mid-Course Estimates	20
4	Final Fuel and Purchased Power Recovery January 2003 - December 2003 Schedules A1 through A9	22

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
(JDJ-1)
DOCUMENT NO. 1

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 1

FINAL CAPACITY OVER/(UNDER) RECOVERY FOR

JANUARY 2003 - DECEMBER 2003

EXHIBIT NO._____
DOCKET NO. 040001-EI
TAMPA ELECTRIC COMPANY
(JDJ-1)
DOCUMENT NO. 1
PAGE 1 OF 4

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2003 THROUGH DECEMBER 2003

1.	End-of-Period True-up: Over/(Under) Recovery	($2,457,523)
2.	Less: Actual/Estimated Over/(Under) Recovery Approved at the November 2003 Fuel Hearings for the January 2003 through December 2003 period	(2,161,509)
3.	Net True-up: Over/(Under) Recovery to be carried forward to the January 2005 through December 2005 period	**($296,014)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2003 THROUGH DECEMBER 2003

	Actual Jan-03	Actual Feb-03	Actual Mar-03	Actual Apr-03	Actual May-03	Actual Jun-03	Actual Jul-03	Actual Aug-03	Actual Sep-03	Actual Oct-03	Actual Nov-03	Actual Dec-03	Total
1 UNIT POWER CAPACITY CHARGES	1,256,468	1,708,018	1,708,018	1,712,050	1,710,034	1,710,034	1,710,034	1,710,034	1,749,517	1,710,034	1,710,034	1,711,052	20,105,327
2 CAPACITY PAYMENTS TO COGENERATORS	1,537,065	1,718,645	1,480,795	1,616,695	1,612,045	1,612,045	1,612,045	1,612,045	1,612,045	1,617,005	1,617,005	1,617,005	19,264,440
3 EMERGENCY CAPACITY CHARGES	1,220,757	1,115,664	1,206,791	872,285	197,117	(6,807)	(12,691)	(12,691)	(12,691)	(12,691)	(12,691)	(162,691)	4,379,661
4 INCREMENTAL SECURITY O&M COSTS	0	0	21,476	63,157	37,397	32,030	4,387	2,031	2,003	39,196	4,456	8,589	214,722
5 (CAPACITY REVENUES)	(75,160)	(51,688)	(125,625)	(88,307)	(83,402)	(37,408)	(49,638)	(22,774)	(32,274)	(34,269)	(29,075)	(14,784)	(644,404)
6 TOTAL CAPACITY DOLLARS	3,939,129	4,490,639	4,291,456	4,175,880	3,473,192	3,309,895	3,264,137	3,288,645	3,318,600	3,319,275	3,289,728	3,159,170	43,319,746
7 JURISDICTIONAL PERCENTAGE	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	
8 JURISDICTIONAL CAPACITY DOLLARS	3,759,352	4,285,691	4,095,598	3,985,297	3,314,679	3,158,835	3,115,165	3,138,555	3,167,143	3,167,787	3,139,589	3,014,989	41,342,680
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	3,317,287	3,049,230	2,714,160	2,934,940	3,492,901	3,752,058	3,880,012	3,940,657	3,908,252	3,552,701	3,136,975	3,071,607	40,750,780
10 PRIOR PERIOD TRUE-UP PROVISION	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,336)	(1,528,054)
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	3,189,949	2,921,892	2,586,822	2,807,602	3,365,563	3,624,720	3,752,674	3,813,319	3,780,914	3,425,363	3,009,637	2,944,271	39,222,726
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	(569,403)	(1,363,799)	(1,508,776)	(1,177,695)	50,884	465,885	637,509	674,764	613,771	257,576	(129,952)	(70,718)	(2,119,954)
13 INTEREST PROVISION FOR PERIOD	(2,187)	(3,030)	(4,239)	(5,363)	(5,859)	(5,041)	(4,084)	(3,542)	(2,867)	(2,374)	(2,132)	(2,136)	(42,854)
14 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(1,822,769)	(2,267,021)	(3,506,512)	(4,892,189)	(5,947,909)	(5,775,546)	(5,187,364)	(4,426,601)	(3,628,041)	(2,889,799)	(2,507,259)	(2,512,005)	(1,822,769)
15 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	127,338	127,338	127,338	127,338	127,338	127,338	127,338	127,338	127,338	127,338	127,338	127,336	1,528,054
16 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 15)	(2,267,021)	(3,506,512)	(4,892,189)	(5,947,909)	(5,775,546)	(5,187,364)	(4,426,601)	(3,628,041)	(2,889,799)	(2,507,259)	(2,512,005)	(2,457,523)	**(2,457,523)**

EXHIBIT NO. _____
DOCKET NO. 040001-EI
TAMPA ELECTRIC COMPANY
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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2003 THROUGH DECEMBER 2003

	Actual Jan-03	Actual Feb-03	Actual Mar-03	Actual Apr-03	Actual May-03	Actual Jun-03	Actual Jul-03	Actual Aug-03	Actual Sep-03	Actual Oct-03	Actual Nov-03	Actual Dec-03	Total
1 BEGINNING TRUE-UP AMOUNT	(1,822,769)	(2,267,021)	(3,506,512)	(4,892,189)	(5,947,909)	(5,775,546)	(5,187,364)	(4,426,601)	(3,628,041)	(2,889,799)	(2,507,259)	(2,512,005)	(1,822,769)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(2,264,834)	(3,503,482)	(4,887,950)	(5,942,546)	(5,769,687)	(5,182,323)	(4,422,517)	(3,624,499)	(2,886,932)	(2,504,885)	(2,509,873)	(2,455,387)	(2,414,669)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(4,087,603)	(5,770,503)	(8,394,462)	(10,834,735)	(11,717,596)	(10,957,869)	(9,609,881)	(8,051,100)	(6,514,973)	(5,394,684)	(5,017,132)	(4,967,392)	(4,237,438)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(2,043,802)	(2,885,252)	(4,197,231)	(5,417,368)	(5,858,798)	(5,478,935)	(4,804,941)	(4,025,550)	(3,257,487)	(2,697,342)	(2,508,566)	(2,483,696)	(2,118,719)
5 INTEREST RATE % - 1ST DAY OF MONTH	1.290	1.270	1.250	1.180	1.190	1.210	1.000	1.050	1.060	1.060	1.050	1.000	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	1.270	1.250	1.180	1.190	1.210	1.000	1.050	1.060	1.060	1.050	1.000	1.060	NA
7 TOTAL (LINE 5 + LINE 6)	2.560	2.520	2.430	2.370	2.400	2.210	2.050	2.110	2.120	2.110	2.050	2.060	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	1.280	1.260	1.215	1.185	1.200	1.105	1.025	1.055	1.060	1.055	1.025	1.030	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.107	0.105	0.101	0.099	0.100	0.092	0.085	0.088	0.088	0.088	0.085	0.086	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(2,187)	(3,030)	(4,239)	(5,363)	(5,859)	(5,041)	(4,084)	(3,542)	(2,867)	(2,374)	(2,132)	(2,136)	(42,854)

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EXHIBIT NO. 040001-EI
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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2003 THROUGH DECEMBER 2003

	(1) ACTUAL	(2) ACTUAL/ ESTIMATED	(3) VARIANCE (1) - (2)	(4) % CHANGE (3)/(2)
1 UNIT POWER CAPACITY CHARGES	$20,105,327	$24,622,829	($4,517,502)	-18.35%
2 CAPACITY PAYMENTS TO COGENERATORS	19,264,440	$19,269,290	(4,850)	-0.03%
3 EMERGENCY CAPACITY CHARGES	4,379,661	0	4,379,661	0.00%
4 INCREMENTAL SECURITY O&M COSTS	214,722	187,017	27,705	15.00%
5 (CAPACITY REVENUES)	(644,404)	($825,890)	181,486	-21.97%
6 TOTAL CAPACITY DOLLARS	$43,319,746	$43,253,246	$66,500	0.15%
7 JURISDICTIONAL PERCENTAGE	95.43611%	95.43611%	0.00000%	0.00%
8 JURISDICTIONAL CAPACITY DOLLARS	$41,342,680	$41,279,217	$63,463	0.15%
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	40,750,780	41,014,914	(264,134)	-0.64%
10 PRIOR PERIOD TRUE-UP PROVISION	(1,528,054)	(1,528,054)	0	0.00%
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	$39,222,726	$39,486,860	($264,134)	-0.67%
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	($2,119,954)	($1,792,357)	($327,597)	18.28%
13 INTEREST PROVISION FOR PERIOD	(42,854)	(54,690)	11,836	-21.64%
14 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(1,822,769)	(1,842,516)	19,747	-1.07%
15 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	1,528,054	1,528,054	0	0.00%
16 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 15)	($2,457,523)	($2,161,509)	($296,014)	13.69%

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
(JDJ-1)
DOCUMENT NO. 2

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 2

FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY

FOR

JANUARY 2003 - DECEMBER 2003

TAMPA ELECTRIC COMPANY
FINAL FUEL OVER/(UNDER)-RECOVERY
FOR THE PERIOD
JANUARY 2003 THROUGH DECEMBER 2003

1 TOTAL FUEL COSTS FOR THE PERIOD		$646,244,377
2 JURISDICTIONAL FUEL COSTS (INCL. PEABODY AND ALL ADJUSTMENTS)		621,842,511
3 JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD		599,026,725
4 ACTUAL OVER/(UNDER)-RECOVERED FUEL COSTS FOR THE PERIOD (LINE 3 - LINE 2)		(22,815,786)
5 INTEREST		(490,289)
6 TRUE-UP COLLECTED		3,165,591
7 PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/02)		(31,827,918)
8 ACTUAL OVER/(UNDER)-RECOVERY FOR THE PERIOD (LINE 4 + LINE 5 + LINE 6 + LINE 7)		(51,968,402)
9 PROJECTED UNDER-RECOVERY PER PROJECTION FILED 9/21/03 (SCHEDULE E1-A LINE 3)		(91,007,445)
10 NET OVER/(UNDER)-RECOVERED FUEL COSTS (LINE 8 - LINE 9)		39,039,043
11 ADJUSTMENT FOR GANNON O&M OFFSET CREDIT PER FPSC DECISION 11/14/03	*	(8,416,800)
12 FINAL FUEL OVER/(UNDER)-RECOVERY (LINE 10 + LINE 11)		**$30,622,243**

* Tampa Electric does not believe that the $8.4 million credit is appropriate and has asked the Commission to reconsider its decision to impose it.

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
(JDJ-1)
DOCUMENT NO. 3

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 3

ACTUAL FUEL AND PURCHASED POWER TRUE-UP

VS.

MID-COURSE ESTIMATES

JANUARY 2003 - DECEMBER 2003

TAMPA ELECTRIC COMPANY
CALCULATION OF TRUE-UP AMOUNT
ACTUAL vs. MID-COURSE ESTIMATES
FOR THE PERIOD:
JANUARY 2003 THROUGH DECEMBER 2003

		ACTUAL	ESTIMATED	VARIANCE AMOUNT	%
A	1. FUEL COST OF SYSTEM NET GENERATION	$465,710,361	$488,210,888	($22,500,527)	(4.6)
	2. FUEL COST OF POWER SOLD	3,830,596	15,911,002	(12,080,406)	(75.9)
	2a. GAINS FROM MARKET BASED SALES	866,219	3,460,994	(2,594,775)	(75.0)
	3. FUEL COST OF PURCHASED POWER	172,409,043	128,416,040	43,993,003	34.3
	3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0
	3b. PAYMENT TO QUALIFIED FACILITIES	12,825,460	12,984,665	(159,205)	(1.2)
	4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0
	6a. ADJ. TO FUEL COST (FT. MEADE/WAUCHULA)	(80,527)	(72,108)	(8,419)	11.7
	6b. ADJ. TO FUEL COST	(31,891)	(2,738)	(29,153)	1,064.7
	6c. RISK MANAGEMENT O&M	108,746	415,000	(306,254)	(73.8)
	7. ADJUSTED TOTAL FUEL & NET PWR.TRANS. SUM OF LINES A1 THRU 6c	$646,244,377	$610,579,751	$35,664,626	5.8
C	1. JURISDICTIONAL FUEL REVENUE	$601,362,076	$601,738,147	($376,071)	(0.1)
	2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0
	a. TRUE-UP PROVISION	(3,165,591)	(3,165,591)	0	0.0
	b. INCENTIVE PROVISION	830,240	830,431	(191)	0.0
	3. JURIS. FUEL REVENUE APPL. TO PERIOD (Sum of Lines C1 through C2b)	599,026,725	599,402,987	(376,262)	(0.1)
	6B.JURISDICTIONAL FUEL COST	627,105,981	595,639,042	31,466,939	5.3
	6D.PEABODY CONTRACT BUY OUT AMORT. JURISD.	3,151,092	3,169,783	(18,691)	(0.6)
	6E.1999 REVENUE REFUND ADJ.	2,238	0	2,238	0.0
	6F.GANNON O&M OFFSET CREDIT PER FPSC 11/14/03	(8,416,800)	0	(8,416,800)	0.0
	6G.OTHER	0	0	0	0.0
	6H.JURISD. TOTAL FUEL & NET PWR. TRANS. (INCL. PEABODY AND ALL ADJUSTMENTS)	621,842,511	598,808,825	23,033,686	3.8
	7. TRUE-UP PROV.- THIS PER. (LINE C3-C6H)	(22,815,786)	594,162	(23,409,948)	(3,940.0)
	8. INTEREST PROVISION - THIS PERIOD	(490,289)	(368,055)	(122,234)	33.2
	9.TOTAL TRUE-UP AMOUNT FOR PERIOD	($23,306,075)	$226,107	($23,532,182)	(10,407.5)
	10.TRUE-UP & INT. PROV. BEG. OF PERIOD (Beginning January 2003)	(31,827,918)	(31,827,918)	0	0.0
	11.TRUE-UP COLLECTED (REFUNDED)	3,165,591	3,165,591	0	0.0
	12.END OF PERIOD TOTAL NET TRUE-UP (LINE C9 through C11)	($51,968,402)	($28,436,220)	($23,532,182)	82.8

Line numbers reference Schedule A-2 included in Document No. 4

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
(JDJ-1)
DOCUMENT NO. 4

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 4

FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2003 - DECEMBER 2003

SCHEDULES A1 THROUGH A9

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

JANUARY 2003

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	31,877,915	31,877,915	0	0.0%	1,344,393	1,344,393	0	0.0%	2.37118	2.37118	0.00000	0.0%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(6,108)	(6,108)	(0)	0.0%	1,344,393 (a)	1,344,393 (a)	0	0.0%	(0.00045)	(0.00045)	(0.00000)	0.0%
4b. Adjustments to Fuel Cost	(2,738)	(2,738)	0	0.0%	1,344,393 (a)	1,344,393 (a)	0	0.0%	(0.00020)	(0.00020)	0.00000	0.0%
4c. Incremental Hedging O&M Costs	0	0	0	0.0%	1,344,393 (a)	1,344,393 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**31,869,069**	**31,869,069**	**0**	**0.0%**	**1,344,393**	**1,344,393**	**0**	**0.0%**	**2.37052**	**2.37052**	**0.00000**	**0.0%**
6. Fuel Cost of Purchased Power - Firm (A7)	14,320,140	14,320,140	0	0.0%	231,762	231,762	0	0.0%	6.17881	6.17881	0.00000	0.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,258,765	1,258,765	0	0.0%	47,337	47,337	0	0.0%	2.65916	2.65916	0.00000	0.0%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**15,578,905**	**15,578,905**	**0**	**0.0%**	**279,099**	**279,099**	**0**	**0.0%**	**5.58186**	**5.58186**	**0.00000**	**0.0%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,623,492**	**1,623,492**	**0**	**0.0%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	47,807	47,807	0	0.0%	2,060	2,060	0	0.0%	2.32073	2.32073	0.00000	0.0%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	4,680	4,680	0	0.0%	46	46	0	0.0%	10.17391	10.17391	0.00000	0.0%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	108,975	108,975	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	236,640	236,640	0	0.0%	6,395	6,395	0	0.0%	3.70039	3.70039	0.00000	0.0%
19. Gains on Market Based Sales	60,294	60,294	0	0.0%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**458,396**	**458,396**	**0**	**0.0%**	**8,501**	**8,501**	**0**	**0.0%**	**5.39226**	**5.39226**	**0.00000**	**0.0%**
21. Net Inadvertant Interchange					(291)	(291)	0	0.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					652	652	0	0.0%				
23. Interchange and Wheeling Losses					196	196	0	0.0%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**46,989,578**	**46,989,578**	**0**	**0.0%**	**1,615,156**	**1,615,156**	**0**	**0.0%**	**2.90929**	**2.90929**	**0.00000**	**0.0%**
25. Net Unbilled	2,373,690 (a)	2,373,690 (a)	0	0.0%	81,590	81,590	0	0.0%	2.90929	2.90929	0.00000	0.0%
26. Company Use	119,252 (a)	119,252 (a)	0	0.0%	4,099	4,099	0	0.0%	2.90929	2.90929	0.00000	0.0%
27. T & D Losses	109,040 (a)	109,040 (a)	0	0.0%	3,748	3,748	0	0.0%	2.90928	2.90928	0.00000	0.0%
28. System KWH Sales	46,989,578	46,989,578	0	0.0%	1,525,719	1,525,719	0	0.0%	3.07983	3.07983	0.00000	0.0%
29. Wholesale KWH Sales	(1,423,808)	(1,423,808)	(0)	0.0%	(46,230)	(46,230)	0	0.0%	3.07984	3.07984	0.00000	0.0%
30. Jurisdictional KWH Sales	45,565,770	45,565,770	0	0.0%	1,479,489	1,479,489	0	0.0%	3.07983	3.07983	0.00000	0.0%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	45,617,715	45,617,715	0	0.0%	1,479,489	1,479,489	0	0.0%	3.08334	3.08334	0.00000	0.0%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	276,221	276,221	0	0.0%	1,479,489	1,479,489	0	0.0%	0.01867	0.01867	0.00000	0.0%
34. Adjustment	0	0	0	0.0%	1,479,489	1,479,489	0	0.0%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	1,479,489	1,479,489	0	0.0%	0.00000	0.00000	0.00000	0.0%
36. True-up *	263,799	263,799	0	0.0%	1,479,489	1,479,489	0	0.0%	0.01783	0.01783	0.00000	0.0%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	46,157,735	46,157,735	0	0.0%	1,479,489	1,479,489	0	0.0%	3.11984	3.11984	0.00000	0.0%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.12209	3.12209	0.00000	0.0%
40. GPIF * (Already Adjusted for Taxes)	(69,203)	(69,203)	0	0.0%	1,479,489	1,479,489	0	0.0%	(0.00468)	(0.00468)	0.00000	0.0%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**46,088,532**	**46,088,532**	**0**	**0.0%**	**1,479,489**	**1,479,489**	**0**	**0.0%**	**3.11741**	**3.11741**	**0.00000**	**0.0%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.117**	**3.117**	**0.000**	**0.0%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: JANUARY 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	31,877,915	31,877,915	0	0.0%	1,344,393	1,344,393	0	0.0%	2.37118	2.37118	0.00000	0.0%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(6,108)	(6,108)	(0)	0.0%	1,344,393 (a)	1,344,393 (a)	0	0.0%	(0.00045)	(0.00045)	(0.00000)	0.0%
4b. Adjustments to Fuel Cost	(2,738)	(2,738)	0	0.0%	1,344,393 (a)	1,344,393 (a)	0	0.0%	(0.00020)	(0.00020)	0.00000	0.0%
4c. Adjustments to Fuel Cost	0	0	0	0.0%	1,344,393 (a)	1,344,393 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**31,869,069**	**31,869,069**	**0**	**0.0%**	**1,344,393**	**1,344,393**	**0**	**0.0%**	**2.37052**	**2.37052**	**0.00000**	**0.0%**
6. Fuel Cost of Purchased Power - Firm (A7)	14,320,140	14,320,140	0	0.0%	231,762	231,762	0	0.0%	6.17881	6.17881	0.00000	0.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,258,765	1,258,765	0	0.0%	47,337	47,337	0	0.0%	2.65916	2.65916	0.00000	0.0%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**15,578,905**	**15,578,905**	**0**	**0.0%**	**279,099**	**279,099**	**0**	**0.0%**	**5.58186**	**5.58186**	**0.00000**	**0.0%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,623,492**	**1,623,492**	**0**	**0.0%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	47,807	47,807	0	0.0%	2,060	2,060	0	0.0%	2.32073	2.32073	0.00000	0.0%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	4,680	4,680	0	0.0%	46	46	0	0.0%	10.17391	10.17391	0.00000	0.0%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	108,975	108,975	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	236,640	236,640	0	0.0%	6,395	6,395	0	0.0%	3.70039	3.70039	0.00000	0.0%
19. Gains on Market Based Sales	60,294	60,294	0	0.0%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**458,396**	**458,396**	**0**	**0.0%**	**8,501**	**8,501**	**0**	**0.0%**	**5.39226**	**5.39226**	**0.00000**	**0.0%**
21. Net Inadvertant Interchange					(291)	(291)	0	0.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					652	652	0	0.0%				
23. Interchange and Wheeling Losses					196	196	0	0.0%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**46,989,578**	**46,989,578**	**0**	**0.0%**	**1,615,156**	**1,615,156**	**0**	**0.0%**	**2.90929**	**2.90929**	**0.00000**	**0.0%**
25. Net Unbilled	2,373,690 (a)	2,373,690 (a)	0	0.0%	81,590	81,590	0	0.0%	2.90929	2.90929	0.00000	0.0%
26. Company Use	119,252 (a)	119,252 (a)	0	0.0%	4,099	4,099	0	0.0%	2.90929	2.90929	0.00000	0.0%
27. T & D Losses	109,040 (a)	109,040 (a)	0	0.0%	3,748	3,748	0	0.0%	2.90928	2.90928	0.00000	0.0%
28. System KWH Sales	46,989,578	46,989,578	0	0.0%	1,525,719	1,525,719	0	0.0%	3.07983	3.07983	0.00000	0.0%
29. Wholesale KWH Sales	(1,423,808)	(1,423,808)	(0)	0.0%	(46,230)	(46,230)	0	0.0%	3.07984	3.07984	0.00000	0.0%
30. Jurisdictional KWH Sales	45,565,770	45,565,770	0	0.0%	1,479,489	1,479,489	0	0.0%	3.07983	3.07983	0.00000	0.0%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	45,617,715	45,617,715	0	0.0%	1,479,489	1,479,489	0	0.0%	3.08334	3.08334	0.00000	0.0%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	276,221	276,221	0	0.0%	1,479,489	1,479,489	0	0.0%	0.01867	0.01867	0.00000	0.0%
34. Adjustment	0	0	0	0.0%	1,479,489	1,479,489	0	0.0%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	1,479,489	1,479,489	0	0.0%	0.00000	0.00000	0.00000	0.0%
36. True-up *	263,799	263,799	0	0.0%	1,479,489	1,479,489	0	0.0%	0.01783	0.01783	0.00000	0.0%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	46,157,735	46,157,735	0	0.0%	1,479,489	1,479,489	0	0.0%	3.11984	3.11984	0.00000	0.0%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.12209	3.12209	0.00000	0.0%
40. GPIF * (Already Adjusted for Taxes)	(69,203)	(69,203)	0	0.0%	1,479,489	1,479,489	0	0.0%	(0.00468)	(0.00468)	0.00000	0.0%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**46,088,532**	**46,088,532**	**0**	**0.0%**	**1,479,489**	**1,479,489**	**0**	**0.0%**	**3.11741**	**3.11741**	**0.00000**	**0.0%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.117**	**3.117**	**0.000**	**0.0%**

SCHEDULE A2
PAGE 1 OF 3
REVISED WITH
TRUE UP FILING

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	31,877,915	31,877,915	0	0.0%	31,877,915	31,877,915	0	0.0%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	398,102	398,102	0	0.0%	398,102	398,102	0	0.0%
2a. GAINS FROM MARKET BASED SALES	60,294	60,294	0	0.0%	60,294	60,294	0	0.0%
3. FUEL COST OF PURCHASED POWER	14,320,140	14,320,140	0	0.0%	14,320,140	14,320,140	0	0.0%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,258,765	1,258,765	0	0.0%	1,258,765	1,258,765	0	0.0%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	46,998,424	46,998,424	0	0.0%	46,998,424	46,998,424	0	0.0%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(6,108)	(6,108)	(0)	0.0%	(6,108)	(6,108)	(0)	0.0%
6b. ADJ.TO FUEL COST	(2,738)	(2,738)	0	0.0%	(2,738)	(2,738)	0	0.0%
6c. INCREMENTAL HEDGING O&M COSTS	0	0	0	0.0%	0	0	0	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	46,989,578	46,989,578	0	0.0%	46,989,578	46,989,578	0	0.0%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,479,489	1,479,489	0	0.0%	1,479,489	1,479,489	0	0.0%
2. NONJURISDICTIONAL SALES	46,230	46,230	0	0.0%	46,230	46,230	0	0.0%
3. TOTAL SALES	1,525,719	1,525,719	0	0.0%	1,525,719	1,525,719	0	0.0%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9696995	0.9696995	0.0000000	0.0%	0.9696995	0.9696995	0.0000000	0.0%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	43,921,774	43,921,774	0	0.0%	43,921,774	43,921,774	0	0.0%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(263,799)	(263,799)	0	0.0%	(263,799)	(263,799)	0	0.0%
2b. INCENTIVE PROVISION	69,203	69,203	0	0.0%	69,203	69,203	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	43,727,178	43,727,178	0	0.0%	43,727,178	43,727,178	0	0.0%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE .	46,989,578	46,989,578	0	0.0%	46,989,578	46,989,578	0	0.0%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINI	0.9696995	0.9696995	0.0000000	0.0%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	45,565,770	45,565,770	0	0.0%	45,565,770	45,565,770	0	0.0%
6a. JURISDIC. LOSS MULTIPLIER	1.00114	1.00114	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	45,617,715	45,617,715	0	0.0%	45,617,715	45,617,715	0	0.0%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	284,852	284,852	0	0.0%	284,852	284,852	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	276,221	276,221	0	0.0%	276,221	276,221	0	0.0%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	45,893,936	45,893,936	0	0.0%	45,893,936	45,893,936	0	0.0%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(2,166,758)	(2,166,758)	0	0.0%	(2,166,758)	(2,166,758)	0	0.0%
8. INTEREST PROVISION FOR THE MONTH	(35,074)	(35,074)	0	0.0%	(35,074)	(35,074)	0	0.0%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(31,827,918)	(31,827,918)	0	0.0%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	263,799	263,799	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(33,765,951)	(33,765,951)	0	0.0%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(31,827,918)	(31,827,918)	0	0.0%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(33,730,877)	(33,730,877)	0	0.0%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(65,558,795)	(65,558,795)	0	0.0%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(32,779,398)	(32,779,398)	0	0.0%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.290	1.290	0	0.0%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.270	1.270	0	0.0%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	2.560	2.560	0	0.0%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.280	1.280	0	0.0%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.107	0.107	0	0.0%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(35,074)	(35,074)	0	0.0%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	471,614	471,614	0	0.0%	471,614	471,614	0	0.0%
2	LIGHT OIL	1,754,226	1,754,226	0	0.0%	1,754,226	1,754,226	0	0.0%
3	COAL	28,285,132	28,285,132	0	0.0%	28,285,132	28,285,132	0	0.0%
4	NATURAL GAS	1,366,943	1,366,943	0	0.0%	1,366,943	1,366,943	0	0.0%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	31,877,915	31,877,915	0	0.0%	31,877,915	31,877,915	0	0.0%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	8,717	8,717	0	0.0%	8,717	8,717	0	0.0%
9	LIGHT OIL	30,591	30,591	0	0.0%	30,591	30,591	0	0.0%
10	COAL	1,294,869	1,294,869	0	0.0%	1,294,869	1,294,869	0	0.0%
11	NATURAL GAS	10,216	10,216	0	0.0%	10,216	10,216	0	0.0%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,344,393	1,344,393	0	0.0%	1,344,393	1,344,393	0	0.0%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	13,252	13,252	0	0.0%	13,252	13,252	0	0.0%
16	LIGHT OIL (BBL)	47,648	47,648	0	0.0%	47,648	47,648	0	0.0%
17	COAL (TON)	615,626	615,626	0	0.0%	615,626	615,626	0	0.0%
18	NATURAL GAS (MCF	117,763	117,763	0	0.0%	117,763	117,763	0	0.0%
19	NUCLEAR (MMBTU	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	83,135	83,135	0	0.0%	83,135	83,135	0	0.0%
22	LIGHT OIL	276,950	276,950	0	0.0%	276,950	276,950	0	0.0%
23	COAL	14,465,442	14,465,442	0	0.0%	14,465,442	14,465,442	0	0.0%
24	NATURAL GAS	125,300	125,300	0	0.0%	125,300	125,300	0	0.0%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	14,950,827	14,950,827	0	0.0%	14,950,827	14,950,827	0	0.0%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.65%	0.65%	0.00	-	0.65%	0.65%	0.00	-
29	LIGHT OIL	2.28%	2.28%	0.00	-	2.28%	2.28%	0.00	-
30	COAL	96.32%	96.32%	0.00	-	96.32%	96.32%	0.00	-
31	NATURAL GAS	0.76%	0.76%	0.00	-	0.76%	0.76%	0.00	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	35.59	35.59	0.00	0.0%	35.59	35.59	0.00	0.0%
36	LIGHT OIL ($/BBL)	36.82	36.82	0.00	0.0%	36.82	36.82	0.00	0.0%
37	COAL ($/TON)	45.95	45.95	0.00	0.0%	45.95	45.95	0.00	0.0%
38	NATURAL GAS ($/M	11.61	11.61	0.00	0.0%	11.61	11.61	0.00	0.0%
39	NUCLEAR ($/MMBT	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTL	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	5.67	5.67	0.00	0.0%	5.67	5.67	0.00	0.0%
42	LIGHT OIL	6.33	6.33	0.00	0.0%	6.33	6.33	0.00	0.0%
43	COAL	1.96	1.96	0.00	0.0%	1.96	1.96	0.00	0.0%
44	NATURAL GAS	10.91	10.91	0.00	0.0%	10.91	10.91	0.00	0.0%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.13	2.13	0.00	0.0%	2.13	2.13	0.00	0.0%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,537	9,537	0	0.0%	9,537	9,537	0	0.0%
49	LIGHT OIL	9,053	9,053	0	0.0%	9,053	9,053	0	0.0%
50	COAL	11,171	11,171	0	0.0%	11,171	11,171	0	0.0%
51	NATURAL GAS	12,265	12,265	0	0.0%	12,265	12,265	0	0.0%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	11,121	11,121	0	0.0%	11,121	11,121	0	0.0%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.41	5.41	0.00	0.0%	5.41	5.41	0.00	0.0%
56	LIGHT OIL	5.73	5.73	0.00	0.0%	5.73	5.73	0.00	0.0%
57	COAL	2.18	2.18	0.00	0.0%	2.18	2.18	0.00	0.0%
58	NATURAL GAS	13.38	13.38	0.00	0.0%	13.38	13.38	0.00	0.0%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.37	2.37	0.00	0.0%	2.37	2.37	0.00	0.0%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: JANUARY 2003

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(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**2,747**	**0.00**	**0.00**
GAN.#1	114	41,855	49.3	72.0	54.8	11,939	COAL	21,187	23,586,000	499,716.6	969,287	2.32	45.75
GAN.#2	100	41,051	55.2	75.4	72.1	12,189	COAL	21,052	23,768,000	500,363.9	963,110	2.35	45.75
GAN.#3	155	55,931	48.5	70.5	61.8	12,123	COAL	28,827	23,522,000	678,068.7	1,318,810	2.36	45.75
GAN.#4	159	55,826	47.2	72.0	59.5	13,780	COAL	36,444	21,108,000	769,260.0	1,667,281	2.99	45.75
GAN.#5	217	73,740	45.7	78.4	51.6	11,425	COAL	35,990	23,408,000	842,453.9	1,646,511	2.23	45.75
GAN.#6	372	152,641	55.2	74.2	62.0	11,438	COAL	73,691	23,692,000	1,745,887.2	3,371,298	2.21	45.75
GANNON STATION	**1,117**	**421,044**	**50.7**	**74.1**	**59.8**	**11,960**	**COAL**	**217,191**	**23,185,815**	**5,035,750.3**	**9,936,297**	**2.36**	**45.75**
B.B.#1	426	194,245	61.3	71.4	69.1	10,994	COAL	89,811	23,778,960	2,135,613.6	4,174,814	2.15	46.48
B.B.#2	426	123,813	39.1	43.3	77.0	10,567	COAL	54,770	23,887,900	1,308,334.2	2,545,953	2.06	46.48
B.B.#3	433	214,627	66.6	78.6	74.8	10,735	COAL	96,662	23,835,560	2,303,996.1	4,493,279	2.09	46.48
B.B.#4	447	221,664	66.7	77.9	77.4	10,373	COAL	106,491	21,590,760	2,299,230.5	4,950,175	2.23	46.48
B.B. STATION	**1,732**	**754,349**	**58.5**	**68.0**	**74.6**	**10,668**	**COAL**	**347,734**	**23,141,730**	**8,047,174.4**	**16,164,221**	**2.14**	**46.48**
SEB-PHIL. #1(HVY OIL)	17	4,437	35.1	100.0	90.3	9,537	HVY.OIL	6,745	6,273,540	42,315.8	238,644	5.38	35.38
SEB-PHIL. #2(HVY OIL)	17	4,280	33.8	98.1	90.7	9,537	HVY.OIL	6,507	6,273,540	40,819.6	230,223	5.38	35.38
SEB-PHILLIPS TOTAL	**34**	**8,717**	**34.5**	**99.0**	**90.5**	**9,537**	**HVY.OIL**	**13,252**	**6,273,541**	**83,135.4**	**468,867**	**5.38**	**35.38**
POLK #1 GASIFIER	250	119,476	64.2	70.6	87.5	11,571	COAL	50,701	27,268,000	1,382,517.0	2,184,614	1.83	43.09
POLK #1 CT (OIL)	245	27,801	15.3	98.9	59.3	8,441	LGT.OIL	40,372	5,812,418	234,662.4	1,488,323	5.35	36.87
POLK #1 TOTAL	**250**	**147,277**	**79.2**	**95.6**	**80.3**	**10,981**	**-**	**-**	**-**	**1,617,179.4**	**3,672,937**	**2.49**	**-**
POLK #2 CT (GAS)	165	8,066	6.6	100.0	64.8	11,676	GAS	88,516	1,064,000	94,181.0	1,181,522	14.65	13.35
POLK #2 CT (OIL)	175	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**170**	**8,066**	**6.4**	**100.0**	**64.8**	**11,676**	**-**	**-**	**-**	**94,181.0**	**1,181,522**	**14.65**	**-**
POLK #3 CT (GAS)	165	1,794	1.5	100.0	59.2	15,354	GAS	25,893	1,064,000	27,550.0	185,273	10.33	7.16
POLK #3 CT (OIL)	175	2,732	2.1	100.0	59.7	15,343	LGT.OIL	7,213	5,812,418	41,924.6	265,903	9.73	36.86
POLK #3 TOTAL	**170**	**4,526**	**3.6**	**100.0**	**59.5**	**15,350**	**-**	**-**	**-**	**69,474.6**	**451,176**	**9.97**	**-**
POLK STATION TOTAL	**590**	**159,869**	**36.4**	**98.1**	**69.8**	**11,139**	**-**	**-**	**-**	**1,780,835.0**	**5,305,635**	**3.32**	**-**
B.B.C.T.#1	17	19	0.2	100.0	59.1	5,358	LGT.OIL	18	5,778,661	101.8	0	0.00	0.00
B.B.C.T.#2	80	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	39	0.1	100.0	31.7	6,710	LGT.OIL	45	5,769,180	261.7	0	0.00	0.00
C.T. TOTAL	**157**	**58**	**0.0**	**100.0**	**37.7**	**6,267**	**LGT.OIL**	**63**	**5,771,674**	**363.5**	**-**	**0.00**	**0.00**
CITY OF TAMPA	**6**	**356**	**8.0**	**0.0**	**0.0**	**10,024**	**GAS**	**3,354**	**1,064,000**	**3,568.7**	**148**	**0.04**	**0.04**
TOT. COAL (GN,BB,POLK)	**3,099**	**1,294,869**	**56.2**	**70.4**	**70.3**	**11,171**	**COAL**	**615,626**	**23,497,110**	**14,465,441.7**	**28,285,132**	**2.18**	**45.95**
SYSTEM	**3,636**	**1,344,393**	**49.7**	**78.2**	**69.3**	**11,121**	**-**	**-**	**-**	**14,950,827.3**	**31,877,915**	**2.37**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2003

SCHEDULE A5
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	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	11,973	11,973	0	0.0%	11,973	11,973	0	0.0%
3 UNIT COST ($/BBL)	34.01	34.01	0.00	0.0%	34.01	34.01	0.00	0.0%
4 AMOUNT ($)	407,180	407,180	0	0.0%	407,180	407,180	0	0.0%
5 BURNED:								
6 UNITS (BBL)	13,252	13,252	0	0.0%	13,252	13,252	0	0.0%
7 UNIT COST ($/BBL)	35.59	35.59	0.00	0.0%	35.59	35.59	0.00	0.0%
8 AMOUNT ($)	471,614	471,614	0	0.0%	471,614	471,614	0	0.0%
9 ENDING INVENTORY:								
10 UNITS (BBL)	9,463	9,463	0	0.0%	9,463	9,463	0	0.0%
11 UNIT COST ($/BBL)	36.71	36.71	0.00	0.0%	36.71	36.71	0.00	0.0%
12 AMOUNT ($)	347,419	347,419	0	0.0%	347,419	347,419	0	0.0%
13								
14 DAYS SUPPLY:	30	30	0	0.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	53,236	53,236	0	0.0%	53,236	53,236	0	0.0%
17 UNIT COST ($/BBL)	39.50	39.50	0.00	0.0%	39.50	39.50	0.00	0.0%
18 AMOUNT ($)	2,102,841	2,102,841	0	0.0%	2,102,841	2,102,841	0	0.0%
19 BURNED:								
20 UNITS (BBL)	47,648	47,648	0	0.0%	47,648	47,648	0	0.0%
21 UNIT COST ($/BBL)	36.82	36.82	0.00	0.0%	36.82	36.82	0.00	0.0%
22 AMOUNT ($)	1,754,226	1,754,226	0	0.0%	1,754,226	1,754,226	0	0.0%
23 ENDING INVENTORY:								
24 UNITS (BBL)	82,890	82,890	0	0.0%	82,890	82,890	0	0.0%
25 UNIT COST ($/BBL)	34.90	34.90	0.00	0.0%	34.90	34.90	0.00	0.0%
26 AMOUNT ($)	2,892,719	2,892,719	0	0.0%	2,892,719	2,892,719	0	0.0%
27								
28 DAYS SUPPLY: NORMAL	85	85	(0)	0.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENC	12	12	0	0.0%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	509,773	509,773	0	0.0%	509,773	509,773	0	0.0%
32 UNIT COST ($/TON)	47.25	47.25	0.00	0.0%	47.25	47.25	0.00	0.0%
33 AMOUNT ($)	24,084,451	24,084,451	0	0.0%	24,084,451	24,084,451	0	0.0%
34 BURNED:								
35 UNITS (TONS)	615,626	615,626	0	0.0%	615,626	615,626	0	0.0%
36 UNIT COST ($/TON)	45.95	45.95	0.00	0.0%	45.95	45.95	0.00	0.0%
37 AMOUNT ($)	28,285,132	28,285,132	0	0.0%	28,285,132	28,285,132	0	0.0%
38 ENDING INVENTORY:								
39 UNITS (TONS)	332,504	332,504	0	0.0%	332,504	332,504	0	0.0%
40 UNIT COST ($/TON)	45.25	45.25	0.00	0.0%	45.25	45.25	0.00	0.0%
41 AMOUNT ($)	15,047,120	15,047,120	0	0.0%	15,047,120	15,047,120	0	0.0%
42								
43 DAYS SUPPLY:	19	19	0	0.0%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	117,763	117,763	0	0.0%	117,763	117,763	0	0.0%
46 UNIT COST ($/MCF)	11.61	11.61	0.00	0.0%	11.61	11.61	0.00	0.0%
47 AMOUNT ($)	1,366,943	1,366,943	0	0.0%	1,366,943	1,366,943	0	0.0%
48 BURNED:								
49 UNITS (MCF)	117,763	117,763	0	0.0%	117,763	117,763	0	0.0%
50 UNIT COST ($/MCF)	11.61	11.61	0.00	0.0%	11.61	11.61	0.00	0.0%
51 AMOUNT ($)	1,366,943	1,366,943	0	0.0%	1,366,943	1,366,943	0	0.0%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	24,174
LUBE OIL	0
FUEL ANALYSIS	2,747
TOTAL	26,921

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(11,047)	(361,625)
OTHER USAGE	(1,191)	(40,873)
TOTAL	(12,238)	(402,498)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	35,172
IGNITION #2 OIL	337,451
IGNITION PROPANE	8,803
AERIAL SURVEY ADJ.	0
ADDITIVES	36,186
GREEN FUEL	(936)
TOTAL	416,676

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2003

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	2,064.9	5.3	2,059.6	2.321	2.321	47,806.51	47,806.51	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	108,974.85	140,485.65	
VARIOUS	JURISDIC.	SCH. - MB	6,395.0	0.0	6,395.0	3.700	4.933	236,640.44	315,445.07	60,294.33
VARIOUS		SCH.-OATT	46.0	0.0	46.0	10.174	10.174	4,679.89	4,679.89	
TOTAL			**8,505.9**	**5.3**	**8,500.6**	**4.683**	**5.981**	**398,101.69**	**508,417.12**	**60,294.33**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	1,241.3	5.3	1,236.0	2.412	2.412	29,807.12	29,807.12	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	823.6	0.0	823.6	2.185	2.185	17,999.39	17,999.39	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. - D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. CORP.		SCH. - MA	1,715.0	0.0	1,715.0	6.633	7.543	113,764.01	129,368.44	11,789.33
FLA. PWR. & LIGHT		SCH. - MA	1,235.0	0.0	1,235.0	2.430	3.475	30,012.82	42,913.47	9,022.75
CITY OF LAKELAND		SCH. - MA	100.0	0.0	100.0	1.949	3.173	1,948.63	3,173.43	910.80
CONOCO		SCH. - MA	179.0	0.0	179.0	1.969	4.509	3,524.50	8,071.87	3,985.31
SEMINOLE ELEC. CO-OP		SCH. - MA	385.0	0.0	385.0	5.348	7.100	20,588.62	27,333.96	5,536.44
THE ENERGY AUTHORITY		SCH. - MA	728.0	0.0	728.0	3.102	5.467	22,581.88	39,801.29	14,933.49
SOUTHERN COMPANY		SCH. - MA	850.0	0.0	850.0	2.713	7.697	23,061.50	65,426.36	39,695.86
REEDY CREEK		SCH. - MA	70.0	0.0	70.0	6.714	8.139	4,699.87	5,697.31	777.64
CAROLINA POWER & LIGHT		SCH. - MA	63.0	0.0	63.0	1.838	2.980	1,157.68	1,877.31	521.81
CARGILL POWER MARKETS LLC		SCH. - MA	1,070.0	0.0	1,070.0	1.844	(0.354)	19,733.87	(3,785.43)	(26,879.10)
HARDEE PWR. PART. TO THE ENGY. AUTH. *		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
AUBURNDALE POWER PARTNERS		OATT	46.0	0.0	46.0	10.174	10.174	4,679.89	4,679.89	
ADJUSTMENTS										
HARDEE PWR PART. EST.	Dec. 2002	CONTRACT	(43,765.0)	0.0	(43,765.0)	2.320	3.077	(1,015,348.00)	(1,346,649.05)	
HARDEE PWR PART. ACT.	Dec. 2002	CONTRACT	43,765.0	0.0	43,765.0	2.569	3.398	1,124,322.85	1,487,134.70	
AQUILA	Feb. 2002 **	SCH. - MA	(800.0)	0.0	(800.0)	3.037	3.080	(24,294.99)	(24,643.44)	2,163.55
AQUILA	Feb. 2002 **	SCH. - MA	800.0	0.0	800.0	2.483	2.526	19,862.05	20,210.50	(2,163.55)
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			2,064.9	5.3	2,059.6	2.321	2.321	47,806.51	47,806.51	
SUB-TOTAL HARDEE PWR. PART. CONTRACT SALES-SEI			0.0	0.0	0.0	0.000	0.000	108,974.85	140,485.65	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			6,395.0	0.0	6,395.0	3.700	4.933	236,640.44	315,445.07	60,294.33
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			46.0	0.0	46.0	10.174	10.174	4,679.89	4,679.89	
TOTAL			**8,505.9**	**5.3**	**8,500.6**	**4.683**	**5.981**	**398,101.69**	**508,417.12**	**60,294.33**
CURRENT MONTH:										
DIFFERENCE			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:										
ACTUAL			8,505.9	5.3	8,500.6	4.683	5.981	398,101.69	508,417.12	60,294.33
ESTIMATED			8,505.9	5.3	8,500.6	4.683	5.981	398,101.69	508,417.12	60,294.33
DIFFERENCE			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF JANUARY 2003.
** ORIGINALLY ADJUSTED IN SEPTEMBER 2002.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	122,296.0	0.0	508.2	121,787.8	5.040	5.040	6,138,540.85
HARDEE POWER PARTNERS		IPP	34,524.0	0.0	0.0	34,524.0	16.446	16.446	5,677,984.74
VARIOUS		OTHER	75,450.0	0.0	0.0	75,450.0	3.318	3.318	2,503,614.00
VARIOUS		MKT. BASE	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TOTAL			**232,270.0**	**0.0**	**508.2**	**231,761.8**	**6.179**	**6.179**	**14,320,139.59**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	76,870.0	0.0	0.0	76,870.0	7.325	7.325	5,630,712.43
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH. - J	21,601.0	0.0	148.8	21,452.2	4.401	4.401	944,053.82
FLA. POWER & LIGHT		SCH. - J	42,665.0	0.0	0.0	42,665.0	5.076	5.076	2,165,633.36
CITY OF LAKELAND		SCH. - J	6,160.0	0.0	52.0	6,108.0	4.906	4.906	299,662.75
ORLANDO UTIL. COMM.		SCH. - J	800.0	0.0	0.0	800.0	3.250	3.250	26,000.00
CAROLINA POWER & LIGHT		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
THE ENERGY AUTHORITY		SCH. - J	7,051.0	0.0	151.4	6,899.6	5.539	5.539	382,164.63
REEDY CREEK		SCH. - J	290.0	0.0	0.0	290.0	4.362	4.362	12,650.00
OKEELANTA		SCH. - J	4,323.0	0.0	0.0	4,323.0	4.091	4.091	176,860.96
TALLAHASSEE		SCH. - J	844.0	0.0	156.0	688.0	7.206	7.206	49,575.96
CARGILL ALLIANT		SCH. - J	14,426.0	0.0	0.0	14,426.0	4.558	4.558	657,562.00
CONOCO		SCH. - J	1,843.0	0.0	0.0	1,843.0	3.941	3.941	72,631.00
CORAL POWER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RELIANT		SCH. - J	10,590.0	0.0	0.0	10,590.0	7.519	7.519	796,252.50
SEMINOLE ELEC. CO-OP		SCH. - J	3,941.0	0.0	0.0	3,941.0	3.387	3.387	133,467.00
DUKE ENERGY		SCH. - J	1,826.0	0.0	0.0	1,826.0	6.494	6.494	118,576.00
DYNEGY POWER MARKETING		SCH. - J	5,077.0	0.0	0.0	5,077.0	4.939	4.939	250,737.41
RINGHAVER		SCH. - J	859.0	0.0	0.0	859.0	6.011	6.011	51,635.46
FLA. POWER CORP.		SCH. - D	75,450.0	0.0	0.0	75,450.0	3.879	3.879	2,926,839.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Nov. 2002	IPP	(91,254.0)	0.0	0.0	(91,254.0)	7.504	7.504	(6,847,718.74)
HARDEE PWR. PART.-NATIVE	Nov. 2002	IPP	48,998.0	0.0	0.0	48,998.0	13.976	13.976	6,847,718.74
HARDEE PWR. PART.-OTHER	Nov. 2002	IPP	(140.0)	0.0	0.0	(140.0)	1.074	1.074	(1,503.50)
HARDEE PWR. PART.-OTHER	Nov. 2002	IPP	50.0	0.0	0.0	50.0	3.007	3.007	1,503.50
HARDEE PWR. PART.-NATIVE	Dec. 2002	IPP	(43,674.0)	0.0	0.0	(43,674.0)	5.576	5.576	(2,435,159.87)
HARDEE PWR. PART.-NATIVE	Dec. 2002	IPP	43,674.0	0.0	0.0	43,674.0	5.684	5.684	2,482,432.18
FLA. POWER CORP.	Nov. 2002	SCH. - D	(59,500.0)	0.0	0.0	(59,500.0)	4.348	4.348	(2,586,915.00)
FLA. POWER CORP.	Nov. 2002	SCH. - D	59,500.0	0.0	0.0	59,500.0	3.943	3.943	2,345,940.00
FLA. POWER CORP.	Dec. 2002	SCH. - D	(45,000.0)	0.0	0.0	(45,000.0)	4.445	4.445	(2,000,100.00)
FLA. POWER CORP.	Dec. 2002	SCH. - D	45,000.0	0.0	0.0	45,000.0	4.040	4.040	1,817,850.00
TALLAHASSEE	Dec. 2002	SCH. - J	(1,149.0)	0.0	0.0	(1,149.0)	5.322	5.322	(61,147.50)
TALLAHASSEE	Dec. 2002	SCH. - J	1,149.0	0.0	0.0	1,149.0	5.265	5.265	60,497.50
CORAL POWER	Dec. 2002	SCH. - J	(352.0)	0.0	(537.3)	185.3	8.197	8.197	15,189.66
CORAL POWER	Dec. 2002	SCH. - J	352.0	0.0	537.3	(185.3)	7.265	7.265	(13,461.66)
TOTAL			**232,270.0**	**0.0**	**508.2**	**231,761.8**	**6.179**	**6.179**	**14,320,139.59**
CURRENT MONTH:									
DIFFERENCE			0.0	0.0	0.0	0.0	0.000	0.000	0.00
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:									
ACTUAL			232,270.0	0.0	508.2	231,761.8	6.179	6.179	14,320,139.59
ESTIMATED			232,270.0	0.0	508.2	231,761.8	6.179	6.179	14,320,139.59
DIFFERENCE			0.0	0.0	0.0	0.0	0.000	0.000	0.00
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	47,337.0	0.0	0.0	47,337.0	2.659	2.659	1,258,765.12
TOTAL			**47,337.0**	**0.0**	**0.0**	**47,337.0**	**2.659**	**2.659**	**1,258,765.12**
ACTUAL:									
HILLSBOROUGH COUNTY		COGEN.	17,161.0	0.0	0.0	17,161.0	2.243	2.243	384,928.46
McKAY BAY REFUSE		COGEN.	13,204.0	0.0	0.0	13,204.0	2.268	2.268	299,437.62
ORANGE COGENERATION L.P.		COGEN.	5,474.0	0.0	0.0	5,474.0	2.263	2.263	123,890.45
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	424.0	0.0	0.0	424.0	3.335	3.335	14,138.79
CARGILL MULBERRY		COGEN.	2,603.0	0.0	0.0	2,603.0	2.945	2.945	76,656.92
CARGILL MILLPOINT		COGEN.	75.0	0.0	0.0	75.0	2.330	2.330	1,747.56
CF INDUSTRIES INC.		COGEN.	890.0	0.0	0.0	890.0	3.129	3.129	27,849.69
IMC-AGRICO-NEW WALES		COGEN.	256.0	0.0	0.0	256.0	3.883	3.883	9,940.48
IMC-AGRICO-S. PIERCE		COGEN.	547.0	0.0	0.0	547.0	3.582	3.582	19,590.85
AUBURNDALE POWER PARTNERS		COGEN.	400.0	0.0	0.0	400.0	3.484	3.484	13,936.00
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR JANUARY 2003			41,034.0	0.0	0.0	41,034.0	2.369	2.369	972,116.82
ADJUSTMENTS FOR THE MONTH OF:	**NOV. AND DEC. 2002**								
McKAY BAY REFUSE	NOV. 2002	COGEN.	(12,937.0)	0.0	0.0	(12,937.0)	2.321	2.321	(300,262.85)
	NOV. 2002		12,937.0	0.0	0.0	12,937.0	2.390	2.390	309,226.39
MULBERRY PHOSPHATES INC.	NOV. 2002	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	NOV. 2002		1,489.0	0.0	0.0	1,489.0	3.512	3.512	52,291.22
CARGILL RIDGEWOOD	NOV. 2002	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	NOV. 2002		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	NOV. 2002	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	NOV. 2002		0.0	0.0	0.0	0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY	NOV. 2002	COGEN.	(18,482.0)	0.0	0.0	(18,482.0)	2.320	2.320	(428,768.10)
	NOV. 2002		18,482.0	0.0	0.0	18,482.0	2.445	2.445	451,964.27
CARGILL MILLPOINT	NOV. 2002	COGEN.	(13.0)	0.0	0.0	(13.0)	6.579	6.579	(855.21)
	NOV. 2002		13.0	0.0	0.0	13.0	24.821	24.821	3,226.69
CF INDUSTRIES INC.	NOV. 2002	COGEN.	(688.0)	0.0	0.0	(688.0)	3.772	3.772	(25,949.06)
	NOV. 2002		688.0	0.0	0.0	688.0	4.673	4.673	32,147.62
FARMLAND HYDRO LP	NOV. 2002	COGEN.	(30.0)	0.0	0.0	(30.0)	2.824	2.824	(847.18)
	NOV. 2002		30.0	0.0	0.0	30.0	(0.593)	(0.593)	(177.82)
IMC-AGRICO-S. PIERCE	NOV. 2002	COGEN.	(614.0)	0.0	0.0	(614.0)	3.805	3.805	(23,365.46)
	NOV. 2002		614.0	0.0	0.0	614.0	6.680	6.680	41,016.52
AUBURNDALE POWER PARTNERS	NOV. 2002	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	NOV. 2002		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.	NOV. 2002	COGEN.	(5,400.0)	0.0	0.0	(5,400.0)	2.179	2.179	(117,691.72)
	NOV. 2002		5,400.0	0.0	0.0	5,400.0	2.340	2.340	126,354.67
CUTRALE CITRUS	NOV. 2002	COGEN.	(8.0)	0.0	0.0	(8.0)	3.737	3.737	(298.92)
	NOV. 2002		8.0	0.0	0.0	8.0	5.807	5.807	464.56
CARGILL GREEN BAY	NOV. 2002	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	NOV. 2002		242.0	0.0	0.0	242.0	3.639	3.639	8,805.29
MULBERRY PHOSPHATES INC.	DEC. 2002	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	DEC. 2002		4,232.0	0.0	0.0	4,232.0	3.433	3.433	145,294.94
CARGILL GREEN BAY	DEC. 2002	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	DEC. 2002		340.0	0.0	0.0	340.0	4.139	4.139	14,072.45
SUB-TOTAL FOR THE MONTH OF:	**NOV. AND DEC. 2002**		6,303.0	0.0	0.0	6,303.0	4.548	4.548	286,648.30
GRAND TOTAL			**47,337.0**	**0.0**	**0.0**	**47,337.0**	**2.659**	**2.659**	**1,258,765.12**
CURRENT MONTH:									
DIFFERENCE			0.0	0.0	0.0	0.0	0.000	0.000	0.00
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:									
ACTUAL			47,337.0	0.0	0.0	47,337.0	2.659	2.659	1,258,765.12
ESTIMATED			47,337.0	0.0	0.0	47,337.0	2.659	2.659	1,258,765.12
DIFFERENCE			0.0	0.0	0.0	0.0	0.000	0.000	0.00
DIFFERENCE %			0.0%	0.0%	0.0%	0.0%	0.000	0.000	0.0%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

FEBRUARY 2003

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	24,850,700	25,335,491	(484,791)	-1.9%	1,084,910	1,142,338	(57,428)	-5.0%	2.29058	2.21786	0.07271	3.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(4,371)	(6,000)	1,629	-27.2%	1,084,910 (a)	1,142,338 (a)	(57,428)	-5.0%	(0.00040)	(0.00053)	0.00012	-23.3%
4b. Adjustments to Fuel Cost	(1,882)	0	(1,882)	0.0%	1,084,910 (a)	1,142,338 (a)	(57,428)	-5.0%	(0.00017)	0.00000	(0.00017)	0.0%
4c. Incremental Hedging O&M Costs	0	34,583	(34,583)	-100.0%	1,084,910 (a)	1,142,338 (a)	(57,428)	-5.0%	0.00000	0.00303	(0.00303)	-100.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**24,844,447**	**25,364,074**	**(519,627)**	**-2.0%**	**1,084,910**	**1,142,338**	**(57,428)**	**-5.0%**	**2.29000**	**2.22037**	**0.06964**	**3.1%**
6. Fuel Cost of Purchased Power - Firm (A7)	7,708,351	7,366,600	341,751	4.6%	153,024	154,960	(1,936)	-1.2%	5.03735	4.75387	0.28348	6.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,168,729	846,600	322,129	38.0%	50,742	34,741	16,001	46.1%	2.30328	2.43689	(0.13361)	-5.5%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**8,877,080**	**8,213,200**	**663,880**	**8.1%**	**203,766**	**189,701**	**14,065**	**7.4%**	**4.35651**	**4.32955**	**0.02696**	**0.6%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,288,676**	**1,332,039**	**(43,363)**	**-3.3%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	48,849	59,200	(10,351)	-17.5%	2,034	2,822	(788)	-27.9%	2.40162	2.09780	0.30382	14.5%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(3,300)	0	(3,300)	0.0%	6	0	6	0.0%	(55.00000)	0.00000	(55.00000)	0.0%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	12,834	0	12,834	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	270,456	248,800	21,656	8.7%	8,956	7,679	1,277	16.6%	3.01983	3.24001	(0.22017)	-6.8%
19. Gains on Market Based Sales	154,912	52,800	102,112	193.4%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**483,751**	**360,800**	**122,951**	**34.1%**	**10,996**	**10,501**	**495**	**4.7%**	**4.39934**	**3.43586**	**0.96347**	**28.0%**
21. Net Inadvertant Interchange					784	0	784	0.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					(711)	0	(711)	0.0%				
23. Interchange and Wheeling Losses					420	200	220	110.0%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**33,237,776**	**33,216,474**	**21,302**	**0.1%**	**1,277,333**	**1,321,338**	**(44,005)**	**-3.3%**	**2.60212**	**2.51385**	**0.08827**	**3.5%**
25. Net Unbilled	(3,989,133) (a)	(617,980) (a)	(3,371,153)	545.5%	(153,303)	(24,583)	(128,720)	523.6%	2.60212	2.51385	0.08827	3.5%
26. Company Use	94,769 (a)	100,554 (a)	(5,785)	-5.8%	3,642	4,000	(358)	-9.0%	2.60211	2.51385	0.08826	3.5%
27. T & D Losses	469,839 (a)	161,138 (a)	308,701	191.6%	18,056	6,410	11,646	181.7%	2.60212	2.51385	0.08827	3.5%
28. System KWH Sales	33,237,776	33,216,474	21,302	0.1%	1,408,938	1,335,511	73,427	5.5%	2.35907	2.48717	(0.12811)	-5.2%
29. Wholesale KWH Sales	(903,428)	(422,421)	(481,007)	113.9%	(38,296)	(16,984)	(21,312)	125.5%	2.35907	2.48717	(0.12810)	-5.2%
30. Jurisdictional KWH Sales	32,334,348	32,794,053	(459,705)	-1.4%	1,370,642	1,318,527	52,115	4.0%	2.35907	2.48717	(0.12811)	-5.2%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	32,371,209	32,831,438	(460,229)	-1.4%	1,370,642	1,318,527	52,115	4.0%	2.36176	2.49001	(0.12825)	-5.2%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	274,647	278,731	(4,084)	-1.5%	1,370,642	1,318,527	52,115	4.0%	0.02004	0.02114	(0.00110)	-5.2%
34. Adjustment	0	0	0	0.0%	1,370,642	1,318,527	52,115	4.0%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	1,370,642	1,318,527	52,115	4.0%	0.00000	0.00000	0.00000	0.0%
36. True-up *	263,799	263,799	0	0.0%	1,370,642	1,318,527	52,115	4.0%	0.01925	0.02001	(0.00076)	-3.8%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	32,909,655	33,373,968	(464,313)	-1.4%	1,370,642	1,318,527	52,115	4.0%	2.40104	2.53116	(0.13012)	-5.1%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.40277	2.53298	(0.13021)	-5.1%
40. GPIF * (Already Adjusted for Taxes)	(69,203)	(69,203)	0	0.0%	1,370,642	1,318,527	52,115	4.0%	(0.00505)	(0.00525)	0.00020	-3.8%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**32,840,452**	**33,304,765**	**(464,313)**	**-1.4%**	**1,370,642**	**1,318,527**	**52,115**	**4.0%**	**2.39772**	**2.52773**	**(0.13001)**	**-5.1%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**2.398**	**2.528**	**(0.130)**	**-5.1%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: FEBRUARY 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	56,728,615	57,213,406	(484,791)	-0.8%	2,429,303	2,486,731	(57,428)	-2.3%	2.33518	2.30075	0.03443	1.5%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(10,479)	(12,108)	1,629	-13.5%	2,429,303 (a)	2,486,731 (a)	(57,428)	-2.3%	(0.00043)	(0.00049)	0.00006	-11.4%
4b. Adjustments to Fuel Cost	(4,620)	(2,738)	(1,882)	68.7%	2,429,303 (a)	2,486,731 (a)	(57,428)	-2.3%	(0.00019)	(0.00011)	(0.00008)	72.7%
4c. Adjustments to Fuel Cost	0	34,583	(34,583)	-100.0%	2,429,303 (a)	2,486,731 (a)	(57,428)	-2.3%	0.00000	0.00139	(0.00139)	-100.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**56,713,516**	**57,233,143**	**(519,627)**	**-0.9%**	**2,429,303**	**2,486,731**	**(57,428)**	**-2.3%**	**2.33456**	**2.30154**	**0.03302**	**1.4%**
6. Fuel Cost of Purchased Power - Firm (A7)	22,028,491	21,686,740	341,751	1.6%	384,786	386,722	(1,936)	-0.5%	5.72487	5.60784	0.11703	2.1%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	2,427,494	2,105,365	322,129	15.3%	98,079	82,078	16,001	19.5%	2.47504	2.56508	(0.09004)	-3.5%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**24,455,985**	**23,792,105**	**663,880**	**2.8%**	**482,865**	**468,800**	**14,065**	**3.0%**	**5.06477**	**5.07511**	**(0.01034)**	**-0.2%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**2,912,168**	**2,955,531**	**(43,363)**	**-1.5%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	96,656	107,007	(10,351)	-9.7%	4,094	4,882	(788)	-16.1%	2.36092	2.19187	0.16905	7.7%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	1,380	4,680	(3,300)	-70.5%	52	46	6	13.0%	2.65385	10.17391	(7.52007)	-73.9%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	121,809	108,975	12,834	11.8%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	507,096	485,440	21,656	4.5%	15,351	14,074	1,277	9.1%	3.30334	3.44920	(0.14586)	-4.2%
19. Gains on Market Based Sales	215,206	113,094	102,112	90.3%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**942,147**	**819,196**	**122,951**	**15.0%**	**19,497**	**19,002**	**495**	**2.6%**	**4.83227**	**4.31110**	**0.52118**	**12.1%**
21. Net Inadvertant Interchange					493	(291)	784	-269.4%				
22. Wheeling Rec'd. less Wheeling Del'd.					(59)	652	(711)	-109.0%				
23. Interchange and Wheeling Losses					616	396	220	55.6%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**80,227,354**	**80,206,052**	**21,302**	**0.0%**	**2,892,489**	**2,936,494**	**(44,005)**	**-1.5%**	**2.77364**	**2.73135**	**0.04229**	**1.5%**
25. Net Unbilled	(1,615,443) (a)	1,755,710 (a)	(3,371,153)	-192.0%	(71,713)	57,007	(128,720)	-225.8%	2.25265	3.07981	(0.82716)	-26.9%
26. Company Use	214,021 (a)	219,806 (a)	(5,785)	-2.6%	7,741	8,099	(358)	-4.4%	2.76477	2.71399	0.05078	1.9%
27. T & D Losses	578,879 (a)	270,178 (a)	308,701	114.3%	21,804	10,158	11,646	114.6%	2.65492	2.65976	(0.00483)	-0.2%
28. System KWH Sales	80,227,354	80,206,052	21,302	0.0%	2,934,657	2,861,230	73,427	2.6%	2.73379	2.80320	(0.06941)	-2.5%
29. Wholesale KWH Sales	(2,327,236)	(1,846,229)	(481,007)	26.1%	(84,526)	(63,214)	(21,312)	33.7%	2.75328	2.92060	(0.16732)	-5.7%
30. Jurisdictional KWH Sales	77,900,118	78,359,823	(459,705)	-0.6%	2,850,131	2,798,016	52,115	1.9%	2.73321	2.80055	(0.06734)	-2.4%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	77,988,924	78,449,153	(460,229)	-0.6%	2,850,131	2,798,016	52,115	1.9%	2.73633	2.80374	(0.06741)	-2.4%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	550,868	554,952	(4,084)	-0.7%	2,850,131	2,798,016	52,115	1.9%	0.01933	0.01983	(0.00051)	-2.6%
34. Adjustment	0	0	0	0.0%	2,850,131	2,798,016	52,115	1.9%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	2,850,131	2,798,016	52,115	1.9%	0.00000	0.00000	0.00000	0.0%
36. True-up *	527,598	527,598	0	0.0%	2,850,131	2,798,016	52,115	1.9%	0.01851	0.01886	(0.00034)	-1.8%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	79,067,390	79,531,703	(464,313)	-0.6%	2,850,131	2,798,016	52,115	1.9%	2.77417	2.84243	(0.06827)	-2.4%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.77616	2.84448	(0.06832)	-2.4%
40. GPIF * (Already Adjusted for Taxes)	(138,406)	(138,406)	0	0.0%	2,850,131	2,798,016	52,115	1.9%	(0.00486)	(0.00495)	0.00009	-1.8%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**78,928,984**	**79,393,297**	**(464,313)**	**-0.6%**	**2,850,131**	**2,798,016**	**52,115**	**1.9%**	**2.77130**	**2.83953**	**(0.06823)**	**-2.4%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**2.771**	**2.840**	**(0.069)**	**-2.4%**

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	24,850,700	25,335,491	(484,791)	-1.9%	56,728,615	57,213,406	(484,791)	-0.8%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	328,839	308,000	20,839	6.8%	726,941	706,102	20,839	3.0%
2a. GAINS FROM MARKET BASED SALES	154,912	52,800	102,112	193.4%	215,206	113,094	102,112	90.3%
3. FUEL COST OF PURCHASED POWER	7,708,351	7,366,600	341,751	4.6%	22,028,491	21,686,740	341,751	1.6%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,168,729	846,600	322,129	38.0%	2,427,494	2,105,365	322,129	15.3%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	33,244,029	33,187,891	56,138	0.2%	80,242,453	80,186,315	56,138	0.1%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(4,371)	(6,000)	1,629	-27.2%	(10,479)	(12,108)	1,629	-13.5%
6b. ADJ.TO FUEL COST	(1,882)	0	(1,882)	0.0%	(4,620)	(2,738)	(1,882)	68.7%
6c. INCREMENTAL HEDGING O&M COSTS	0	34,583	(34,583)	-100.0%	0	34,583	(34,583)	-100.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	33,237,776	33,216,474	21,302	0.1%	80,227,354	80,206,052	21,302	0.0%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,370,642	1,318,527	52,115	4.0%	2,850,131	2,798,016	52,115	1.9%
2. NONJURISDICTIONAL SALES	38,296	16,984	21,312	125.5%	84,526	63,214	21,312	33.7%
3. TOTAL SALES	1,408,938	1,335,511	73,427	5.5%	2,934,657	2,861,230	73,427	2.6%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9728192	0.9872828	(0.0144636)	-1.5%	0.9711973	0.9779067	(0.0067094)	-0.7%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: FEBRUARY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	40,722,045	39,526,541	1,195,504	3.0%	84,643,819	83,448,315	1,195,504	1.4%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(263,799)	(263,799)	0	0.0%	(527,598)	(527,598)	0	0.0%
2b. INCENTIVE PROVISION	69,203	69,203	0	0.0%	138,406	138,406	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	40,527,449	39,331,945	1,195,504	3.0%	84,254,627	83,059,123	1,195,504	1.4%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE .	33,237,776	33,216,474	21,302	0.1%	80,227,354	80,206,052	21,302	0.0%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINI	0.9728192	0.9872828	(0.0144636)	-1.5%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	32,334,348	32,794,053	(459,705)	-1.4%	77,900,118	78,359,823	(459,705)	-0.6%
6a. JURISDIC. LOSS MULTIPLIER	1.00114	1.00114	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	32,371,209	32,831,438	(460,229)	-1.4%	77,988,924	78,449,153	(460,229)	-0.6%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	282,321	282,321	0	0.0%	567,173	567,173	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	274,647	278,731	(4,084)	-1.5%	550,868	554,952	(4,084)	-0.7%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	32,645,856	33,110,169	(464,313)	-1.4%	78,539,792	79,004,105	(464,313)	-0.6%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	7,881,593	6,221,776	1,659,817	26.7%	5,714,835	4,055,018	1,659,817	40.9%
8. INTEREST PROVISION FOR THE MONTH	(31,178)	(32,660)	1,482	-4.5%	(66,252)	(67,734)	1,482	-2.2%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(33,765,951)	(33,765,951)	0	0.0%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	263,799	263,799	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(25,651,737)	(27,313,036)	1,661,299	-6.1%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: FEBRUARY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(33,765,951)	(33,765,951)	0	0.0%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(25,620,559)	(27,280,376)	1,659,817	-6.1%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(59,386,510)	(61,046,327)	1,659,817	-2.7%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(29,693,255)	(30,523,164)	829,909	-2.7%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.270	1.270	0	0.0%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.250	1.300	(0)	-3.8%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	2.520	2.570	(0)	-1.9%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.260	1.285	(0)	-1.9%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.105	0.107	(0)	-1.9%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(31,178)	(32,660)	1,482	-4.5%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	385,066	172,759	212,307	122.9%	856,680	644,373	212,307	32.9%
2	LIGHT OIL	1,241,591	812,358	429,233	52.8%	2,995,817	2,566,584	429,233	16.7%
3	COAL	22,010,478	23,870,976	(1,860,498)	-7.8%	50,295,610	52,156,108	(1,860,498)	-3.6%
4	NATURAL GAS	1,213,565	479,398	734,167	153.1%	2,580,508	1,846,341	734,167	39.8%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	24,850,700	25,335,491	(484,791)	-1.9%	56,728,615	57,213,406	(484,791)	-0.8%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	6,485	3,076	3,409	110.8%	15,202	11,793	3,409	28.9%
9	LIGHT OIL	19,856	11,156	8,700	78.0%	50,447	41,747	8,700	20.8%
10	COAL	1,056,358	1,122,083	(65,725)	-5.9%	2,351,227	2,416,952	(65,725)	-2.7%
11	NATURAL GAS	2,211	6,023	(3,812)	-63.3%	12,427	16,239	(3,812)	-23.5%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,084,910	1,142,338	(57,428)	-5.0%	2,429,303	2,486,731	(57,428)	-2.3%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	9,874	4,631	5,243	113.2%	23,126	17,883	5,243	29.3%
16	LIGHT OIL (BBL)	30,813	19,961	10,852	54.4%	78,461	67,609	10,852	16.1%
17	COAL (TON)	478,410	507,211	(28,801)	-5.7%	1,094,036	1,122,837	(28,801)	-2.6%
18	NATURAL GAS (MCF	25,363	65,450	(40,087)	-61.2%	143,126	183,213	(40,087)	-21.9%
19	NUCLEAR (MMBTU	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	61,942	29,834	32,108	107.6%	145,077	112,969	32,108	28.4%
22	LIGHT OIL	178,915	116,252	62,663	53.9%	455,865	393,202	62,663	15.9%
23	COAL	11,464,264	12,265,077	(800,813)	-6.5%	25,929,706	26,730,519	(800,813)	-3.0%
24	NATURAL GAS	26,860	67,287	(40,427)	-60.1%	152,160	192,587	(40,427)	-21.0%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	11,731,981	12,478,450	(746,469)	-6.0%	26,682,808	27,429,277	(746,469)	-2.7%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.60%	0.27%	0.00	-	0.63%	0.47%	0.00	-
29	LIGHT OIL	1.83%	0.98%	0.01	-	2.08%	1.68%	0.00	-
30	COAL	97.37%	98.23%	(0.01)	-	96.79%	97.19%	(0.00)	-
31	NATURAL GAS	0.20%	0.53%	(0.00)	-	0.51%	0.65%	(0.00)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	39.00	37.30	1.69	4.5%	37.04	36.03	1.01	2.8%
36	LIGHT OIL ($/BBL)	40.29	40.70	(0.40)	-1.0%	38.18	37.96	0.22	0.6%
37	COAL ($/TON)	46.01	47.06	(1.06)	-2.2%	45.97	46.45	(0.48)	-1.0%
38	NATURAL GAS ($/M	47.85	7.32	40.52	553.2%	18.03	10.08	7.95	78.9%
39	NUCLEAR ($/MMBT	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTL	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	6.22	5.79	0.43	7.4%	5.91	5.70	0.20	3.5%
42	LIGHT OIL	6.94	6.99	(0.05)	-0.7%	6.57	6.53	0.04	0.7%
43	COAL	1.92	1.95	(0.03)	-1.4%	1.94	1.95	(0.01)	-0.6%
44	NATURAL GAS	45.18	7.12	38.06	534.1%	16.96	9.59	7.37	76.9%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.12	2.03	0.09	4.3%	2.13	2.09	0.04	1.9%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,552	9,699	(147)	-1.5%	9,543	9,579	(36)	-0.4%
49	LIGHT OIL	9,011	10,421	(1,410)	-13.5%	9,037	9,419	(382)	-4.1%
50	COAL	10,853	10,931	(78)	-0.7%	11,028	11,060	(32)	-0.3%
51	NATURAL GAS	12,148	11,172	976	8.7%	12,244	11,860	384	3.2%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,814	10,924	(110)	-1.0%	10,984	11,030	(46)	-0.4%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.94	5.62	0.32	5.7%	5.64	5.46	0.18	3.3%
56	LIGHT OIL	6.25	7.28	(1.03)	-14.1%	5.94	6.15	(0.21)	-3.4%
57	COAL	2.08	2.13	(0.05)	-2.3%	2.14	2.16	(0.02)	-0.9%
58	NATURAL GAS	54.89	7.96	46.93	589.6%	20.77	11.37	9.40	82.7%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.29	2.22	0.07	3.2%	2.34	2.30	0.04	1.7%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: FEBRUARY 2003

SCHEDULE A4
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(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	94	37,272	59.0	78.8	72.8	11,666	COAL	18,256	23,818,000	434,821.4	771,907	2.07	42.28
GAN.#2	100	39,294	58.5	82.7	69.3	12,750	COAL	20,839	24,042,000	501,011.2	881,122	2.24	42.28
GAN.#3	155	44,832	43.0	62.6	65.5	11,709	COAL	21,843	24,032,000	524,931.0	923,574	2.06	42.28
GAN.#4	164	10,685	9.7	14.8	58.5	12,430	COAL	5,710	23,260,000	132,814.6	241,432	2.26	42.28
GAN.#5	0	-226	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	372	128,435	51.4	68.6	69.0	11,195	COAL	60,140	23,908,000	1,437,827.1	2,542,861	1.98	42.28
GANNON STATION	**885**	**260,292**	**43.8**	**60.2**	**66.9**	**11,646**	**COAL**	**126,788**	**23,909,245**	**3,031,405.3**	**5,360,896**	**2.06**	**42.28**
B.B.#1	428	178,959	62.2	73.9	66.4	10,744	COAL	81,064	23,717,880	1,922,671.2	3,875,139	2.17	47.80
B.B.#2	433	73,719	25.3	30.6	74.0	10,133	COAL	31,100	24,018,560	746,969.8	1,486,668	2.02	47.80
B.B.#3	438	223,190	75.8	92.6	75.8	10,670	COAL	98,908	24,077,580	2,381,461.9	4,728,144	2.12	47.80
B.B.#4	460	197,136	63.8	74.1	75.4	10,593	COAL	93,138	22,421,140	2,088,252.7	4,452,318	2.26	47.80
B.B. STATION	**1,759**	**673,004**	**56.9**	**68.0**	**73.0**	**10,608**	**COAL**	**304,210**	**23,468,555**	**7,139,355.6**	**14,542,289**	**2.16**	**47.80**
SEB-PHIL. #1(HVY OIL)	17	3,214	28.1	100.0	79.4	9,552	HVY.OIL	4,894	6,273,540	30,698.8	190,856	5.94	39.00
SEB-PHIL. #2(HVY OIL)	17	3,271	28.6	100.0	90.0	9,552	HVY.OIL	4,980	6,273,540	31,243.3	194,210	5.94	39.00
SEB-PHILLIPS TOTAL	**34**	**6,485**	**28.4**	**100.0**	**84.7**	**9,552**	**HVY.OIL**	**9,874**	**6,273,545**	**61,942.1**	**385,066**	**5.94**	**39.00**
POLK #1 GASIFIER	260	123,062	70.4	77.8	84.4	10,511	COAL	47,412	27,282,000	1,293,503.5	2,107,293	1.71	44.45
POLK #1 CT (OIL)	245	18,357	11.1	98.9	68.4	8,498	LGT.OIL	26,866	5,806,525	155,996.0	1,080,766	5.89	40.23
POLK #1 TOTAL	**260**	**141,419**	**80.9**	**92.4**	**81.9**	**10,250**	**-**	**-**	**-**	**1,449,499.5**	**3,188,059**	**2.25**	**-**
POLK #2 CT (GAS)	175	1,933	1.6	72.5	72.4	12,198	GAS	22,265	1,059,000	23,579.0	1,158,954	59.96	52.05
POLK #2 CT (OIL)	180	0	0.0	72.5	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**178**	**1,933**	**1.6**	**72.5**	**72.4**	**12,198**	**-**	**-**	**-**	**23,579.0**	**1,158,954**	**59.96**	**-**
POLK #3 CT (GAS)	175	0	0.0	98.7	0.0	0	GAS	0	1,059,000	0.0	-3,890	0.00	0.00
POLK #3 CT (OIL)	180	1,499	1.2	98.7	65.7	15,291	LGT.OIL	3,947	5,806,525	22,918.8	158,786	10.59	40.23
POLK #3 TOTAL	**178**	**1,499**	**1.3**	**98.7**	**65.7**	**15,289**	**-**	**-**	**-**	**22,918.8**	**154,896**	**10.33**	**-**
POLK STATION TOTAL	**616**	**144,851**	**35.0**	**88.4**	**74.5**	**10,328**	**-**	**-**	**-**	**1,495,997.3**	**4,501,909**	**3.11**	**-**
B.B.C.T.#1	15	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	583	0.00	0.00
B.B.C.T.#2	80	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	70	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	1,456	0.00	0.00
C.T. TOTAL	**165**	**0**	**0.0**	**100.0**	**0.0**	**0**	**LGT.OIL**	**0**	**0**	**0.0**	**2,039**	**0.00**	**0.00**
CITY OF TAMPA	**6**	**278**	**6.9**	**0.0**	**0.0**	**11,801**	**GAS**	**3,098**	**1,059,000**	**3,280.8**	**58,501**	**21.04**	**18.88**
TOT. COAL (GN,BB,POLK)	**2,904**	**1,056,358**	**54.1**	**66.5**	**72.1**	**10,853**	**COAL**	**478,410**	**23,963,274**	**11,464,264.4**	**22,010,478**	**2.08**	**46.01**
SYSTEM	**3,465**	**1,084,910**	**46.6**	**73.2**	**69.9**	**10,814**	**-**	**-**	**-**	**11,731,981.1**	**24,850,700**	**2.29**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2003

SCHEDULE A5
PAGE 1 OF 2
REVISED WITH
TRUE UP FILING

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	16,247	4,631	11,616	250.8%	28,220	16,604	11,616	70.0%
3 UNIT COST ($/BBL)	39.11	35.05	4.06	11.6%	36.94	34.30	2.64	7.7%
4 AMOUNT ($)	635,371	162,317	473,054	291.4%	1,042,551	569,497	473,054	83.1%
5 BURNED:								
6 UNITS (BBL)	9,874	4,631	5,243	113.2%	23,126	17,883	5,243	29.3%
7 UNIT COST ($/BBL)	39.00	37.30	1.69	4.5%	37.04	36.03	1.01	2.8%
8 AMOUNT ($)	385,066	172,759	212,307	122.9%	856,680	644,373	212,307	32.9%
9 ENDING INVENTORY:								
10 UNITS (BBL)	15,836	9,463	6,373	67.3%	15,836	9,463	6,373	67.3%
11 UNIT COST ($/BBL)	39.00	36.17	2.83	7.8%	39.00	36.17	2.83	7.8%
12 AMOUNT ($)	617,565	342,247	275,318	80.4%	617,565	342,247	275,318	80.4%
13								
14 DAYS SUPPLY:	56	32	24	73.5%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	28,748	25,420	3,328	13.1%	81,984	78,656	3,328	4.2%
17 UNIT COST ($/BBL)	45.80	47.15	(1.35)	-2.9%	41.71	41.97	(0.26)	-0.6%
18 AMOUNT ($)	1,316,725	1,198,598	118,127	9.9%	3,419,566	3,301,439	118,127	3.6%
19 BURNED:								
20 UNITS (BBL)	30,813	19,961	10,852	54.4%	78,461	67,609	10,852	16.1%
21 UNIT COST ($/BBL)	40.29	40.70	(0.40)	-1.0%	38.18	37.96	0.22	0.6%
22 AMOUNT ($)	1,241,591	812,358	429,233	52.8%	2,995,817	2,566,584	429,233	16.7%
23 ENDING INVENTORY:								
24 UNITS (BBL)	71,537	82,746	(11,209)	-13.5%	71,537	82,746	(11,209)	-13.5%
25 UNIT COST ($/BBL)	37.12	37.29	(0.17)	-0.5%	37.12	37.29	(0.17)	-0.5%
26 AMOUNT ($)	2,655,220	3,085,498	(430,278)	-13.9%	2,655,220	3,085,498	(430,278)	-13.9%
27								
28 DAYS SUPPLY: NORMAL	84	96	(12)	-12.6%	-	-	-	-
29 DAYS SUPPLY: EMERGENC	10	12	(2)	-13.5%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	599,894	674,300	(74,406)	-11.0%	1,109,667	1,184,073	(74,406)	-6.3%
32 UNIT COST ($/TON)	47.14	47.21	(0.07)	-0.2%	47.19	47.23	(0.04)	-0.1%
33 AMOUNT ($)	28,277,069	31,833,580	(3,556,511)	-11.2%	52,361,520	55,918,031	(3,556,511)	-6.4%
34 BURNED:								
35 UNITS (TONS)	478,410	507,211	(28,801)	-5.7%	1,094,036	1,122,837	(28,801)	-2.6%
36 UNIT COST ($/TON)	46.01	47.06	(1.06)	-2.2%	45.97	46.45	(0.48)	-1.0%
37 AMOUNT ($)	22,010,478	23,870,976	(1,860,498)	-7.8%	50,295,610	52,156,108	(1,860,498)	-3.6%
38 ENDING INVENTORY:								
39 UNITS (TONS)	453,988	499,593	(45,605)	-9.1%	453,988	499,593	(45,605)	-9.1%
40 UNIT COST ($/TON)	46.67	46.58	0.09	0.2%	46.67	46.58	0.09	0.2%
41 AMOUNT ($)	21,187,290	23,270,717	(2,083,427)	-9.0%	21,187,290	23,270,717	(2,083,427)	-9.0%
42								
43 DAYS SUPPLY:	25	28	(3)	-11.9%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	25,363	65,450	(40,087)	-61.2%	143,126	183,213	(40,087)	-21.9%
46 UNIT COST ($/MCF)	47.85	7.32	40.52	553.2%	18.03	10.08	7.95	78.9%
47 AMOUNT ($)	1,213,565	479,398	734,167	153.1%	2,580,508	1,846,341	734,167	39.8%
48 BURNED:								
49 UNITS (MCF)	25,363	65,450	(40,087)	-61.2%	143,126	183,213	(40,087)	-21.9%
50 UNIT COST ($/MCF)	47.85	7.32	40.52	553.2%	18.03	10.08	7.95	78.9%
51 AMOUNT ($)	1,213,565	479,398	734,167	153.1%	2,580,508	1,846,341	734,167	39.8%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	19,841
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	19,841

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(8,715)	(294,959)
OTHER USAGE	(573)	(17,674)
TOTAL	(9,288)	(312,633)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	26,097
IGNITION #2 OIL	275,118
IGNITION PROPANE	7,242
AERIAL SURVEY ADJ.	(480,888)
ADDITIVES	46,010
GREEN FUEL	0
TOTAL	(126,421)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2003

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KW (A) FUEL COST	(6) CENTS/KW (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	2,822.0	0.0	2,822.0	2.098	2.098	59,200.00	59,200.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. - MB	7,679.0	0.0	7,679.0	3.240	4.249	248,800.00	326,300.00	52,800.00
TOTAL			**10,501.0**	**0.0**	**10,501.0**	**2.933**	**3.671**	**308,000.00**	**385,500.00**	**52,800.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	996.8	0.0	996.8	2.548	2.548	25,399.23	25,399.23	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	1,037.1	0.0	1,037.1	2.305	2.305	23,904.44	23,904.44	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. - D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. CORP.		SCH. - MA	299.0	0.0	299.0	2.836	5.478	8,479.34	16,379.92	6,961.72
FLA. PWR. & LIGHT		SCH. - MA	4,960.0	0.0	4,960.0	2.145	3.365	106,376.41	166,924.91	44,974.10
CITY OF LAKELAND		SCH. - MA	275.0	0.0	275.0	2.034	3.652	5,593.86	10,041.87	3,584.51
CONOCO		SCH. - MA	158.0	0.0	158.0	2.289	2.840	3,617.21	4,487.72	374.39
SEMINOLE ELEC. CO-OP		SCH. - MA	1,215.0	0.0	1,215.0	2.595	3.703	31,524.69	44,986.29	9,646.50
THE ENERGY AUTHORITY		SCH. - MA	169.0	0.0	169.0	3.191	4.587	5,393.31	7,752.46	1,828.49
DYNEGY POWER MARKETING		SCH. - MA	57.0	0.0	57.0	4.160	4.460	2,371.38	2,542.00	(8.36)
REEDY CREEK		SCH. - MA	90.0	0.0	90.0	2.442	2.821	2,198.11	2,539.01	58.30
TALLAHASSEE		SCH. - MA	49.0	0.0	49.0	2.150	2.708	1,053.74	1,327.13	119.53
CARGILL ALLIANT		SCH. - MA	1,684.0	0.0	1,684.0	6.167	11.669	103,848.60	196,509.16	87,372.80
HARDEE PWR. PART. TO THE ENGY. AUTH. *		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
AUBURNDALE POWER PARTNERS		SCH. - OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ADJUSTMENTS										
HARDEE PWR PART. EST.	Nov. 2002	CONTRACT	(50,091.0)	0.0	(50,091.0)	2.320	3.077	(1,162,111.20)	(1,541,300.07)	
HARDEE PWR PART. ACT.	Nov. 2002	CONTRACT	50,091.0	0.0	50,091.0	2.346	3.075	1,174,945.08	1,540,298.25	
SEMINOLE ELEC. HARDEE	Nov. 2002	SCH. - D	(1,013.0)	0.0	(1,013.0)	2.334	2.334	(23,647.34)	(23,647.34)	
SEMINOLE ELEC. HARDEE	Nov. 2002	SCH. - D	1,013.0	0.0	1,013.0	2.289	2.289	23,192.46	23,192.46	
SEMINOLE ELEC. HARDEE	Dec. 2002	SCH. - D	(1,011.2)	0.0	(1,011.2)	2.121	2.121	(21,446.83)	(21,446.83)	
SEMINOLE ELEC. HARDEE	Dec. 2002	SCH. - D	1,011.2	0.0	1,011.2	2.121	2.121	21,446.56	21,446.56	
AUBURNDALE PWR PARTNERS	Jan. 2003	SCH. - OATT	(46.0)	0.0	(46.0)	10.174	10.174	(4,679.89)	(4,679.89)	
AUBURNDALE PWR PARTNERS	Jan. 2003	SCH. - OATT	12.0	0.0	12.0	14.739	14.739	1,768.64	1,768.64	
SEMINOLE ELEC. CO-OP	Jan. 2003	SCH. - OATT	40.0	0.0	40.0	(0.973)	(0.973)	(389.24)	(389.24)	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			2,033.9	0.0	2,033.9	2.402	2.402	48,848.52	48,848.52	
SUB-TOTAL HARDEE PWR. PART. CONTRACT SALES-SEP.			0.0	0.0	0.0	0.000	0.000	12,833.88	(1,001.82)	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			8,956.0	0.0	8,956.0	3.020	5.064	270,456.65	453,490.47	154,911.98
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			6.0	0.0	6.0	(55.008)	(55.008)	(3,300.49)	(3,300.49)	
TOTAL			**10,995.9**	**0.0**	**10,995.9**	**2.991**	**4.529**	**328,838.56**	**498,036.68**	**154,911.98**
CURRENT MONTH:										
DIFFERENCE			494.9	0.0	494.9	0.058	0.858	20,838.56	112,536.68	102,111.98
DIFFERENCE %			4.7%	0.0%	4.7%	2.0%	23.4%	6.8%	29.2%	193.4%
PERIOD TO DATE:										
ACTUAL			19,501.8	5.3	19,496.5	3.729	5.162	726,940.25	1,006,453.80	215,206.31
ESTIMATED			19,006.9	5.3	19,001.6	3.716	4.704	706,101.69	893,917.12	113,094.33
DIFFERENCE			494.9	0.0	494.9	0.013	0.458	20,838.56	112,536.68	102,111.98
DIFFERENCE %			2.6%	0.0%	2.6%	0.3%	9.7%	3.0%	12.6%	90.3%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF FEBRUARY 2003.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	SCH. - J	5,127.0	0.0	2,190.0	2,937.0	5.686	5.686	167,000.00
HARDEE POWER PARTNERS	IPP	24,978.0	0.0	0.0	24,978.0	6.779	6.779	1,693,300.00
VARIOUS	OTHER	14,302.0	0.0	0.0	14,302.0	4.149	4.149	593,400.00
VARIOUS	MKT. BASE	112,743.0	0.0	0.0	112,743.0	4.358	4.358	4,912,900.00
TOTAL		**157,150.0**	**0.0**	**2,190.0**	**154,960.0**	**4.754**	**4.754**	**7,366,600.00**
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	34,665.0	0.0	0.0	34,665.0	7.665	7.665	2,657,170.62
HARDEE PWR. PART.-OTHERS	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	SCH. - J	20,625.0	0.0	0.0	20,625.0	4.345	4.345	896,238.73
FLA. POWER & LIGHT	SCH. - J	20,812.0	0.0	0.0	20,812.0	4.511	4.511	938,916.36
CITY OF LAKELAND	SCH. - J	4,594.0	0.0	0.0	4,594.0	3.996	3.996	183,585.00
ORLANDO UTIL. COMM.	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CAROLINA POWER & LIGHT	SCH. - J	435.0	0.0	0.0	435.0	3.129	3.129	13,610.00
THE ENERGY AUTHORITY	SCH. - J	5,045.0	0.0	0.0	5,045.0	4.312	4.312	217,555.00
REEDY CREEK	SCH. - J	395.0	0.0	0.0	395.0	4.292	4.292	16,955.00
OKEELANTA	SCH. - J	8,092.0	0.0	0.0	8,092.0	4.328	4.328	350,245.76
TALLAHASSEE	SCH. - J	25.0	0.0	0.0	25.0	1.938	1.938	484.50
CALPINE	SCH. - J	12.0	0.0	0.0	12.0	6.800	6.800	816.00
CARGILL ALLIANT	SCH. - J	1,327.0	0.0	0.0	1,327.0	5.386	5.386	71,476.00
CONOCO	SCH. - J	673.0	0.0	0.0	673.0	3.749	3.749	25,229.00
CORAL POWER	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RELIANT	SCH. - J	100.0	0.0	0.0	100.0	3.725	3.725	3,725.00
SEMINOLE ELEC. CO-OP	SCH. - J	8,283.0	0.0	0.0	8,283.0	3.626	3.626	300,314.00
DUKE ENERGY	SCH. - J	555.0	0.0	0.0	555.0	3.816	3.816	21,178.00
DYNEGY POWER MARKETING	SCH. - J	585.0	0.0	0.0	585.0	5.042	5.042	29,494.00
RINGHAVER	SCH. - J	1,327.0	0.0	0.0	1,327.0	4.561	4.561	60,524.98
FLA. POWER CORP.	SCH. - D	45,900.0	0.0	0.0	45,900.0	4.030	4.030	1,849,647.27

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Jan. 2003	IPP	(76,870.0)	0.0	0.0	(76,870.0)	7.325	7.325	(5,630,712.43)
HARDEE PWR. PART.-NATIVE	Jan. 2003	IPP	76,848.0	0.0	0.0	76,848.0	7.435	7.435	5,713,500.31
FLA. POWER CORP.	Dec. 2002	SCH. - D	(45,000.0)	0.0	0.0	(45,000.0)	4.040	4.040	(1,817,850.00)
FLA. POWER CORP.	Dec. 2002	SCH. - D	45,000.0	0.0	0.0	45,000.0	4.050	4.050	1,822,350.00
FLA. POWER CORP.	Jan. 2003	SCH. - D	(75,450.0)	0.0	0.0	(75,450.0)	3.879	3.879	(2,926,839.00)
FLA. POWER CORP.	Jan. 2003	SCH. - D	75,450.0	0.0	0.0	75,450.0	3.889	3.889	2,934,384.00
CALPINE	Nov. 2002	SCH. - J	(2,756.0)	0.0	(147.0)	(2,609.0)	3.741	3.741	(97,596.00)
CALPINE	Nov. 2002	SCH. - J	1,974.0	0.0	147.0	1,827.0	3.501	3.501	63,970.00
CARGILL ALLIANT	Nov. 2002	SCH. - J	(43,100.0)	0.0	(1,603.3)	(41,496.7)	4.453	4.453	(1,848,031.50)
CARGILL ALLIANT	Nov. 2002	SCH. - J	43,882.0	0.0	1,746.6	42,135.4	4.466	4.466	1,881,657.50
CARGILL ALLIANT	Dec. 2002	SCH. - J	(17,667.0)	0.0	0.0	(17,667.0)	3.998	3.998	(706,360.00)
CARGILL ALLIANT	Dec. 2002	SCH. - J	17,667.0	0.0	99.0	17,568.0	4.021	4.021	706,360.00
FLA. POWER CORP.	Nov. 2002	SCH. - J	(47,129.0)	0.0	(686.8)	(46,442.2)	4.146	4.146	(1,925,466.42)
FLA. POWER CORP.	Nov. 2002	SCH. - J	47,129.0	0.0	688.8	46,440.2	4.146	4.146	1,925,466.42
FLA. POWER CORP.	Dec. 2002	SCH. - J	(64,987.0)	0.0	(432.7)	(64,554.3)	4.067	4.067	(2,625,304.96)
FLA. POWER CORP.	Dec. 2002	SCH. - J	64,987.0	0.0	268.2	64,718.8	4.056	4.056	2,625,304.96
FLA. POWER CORP.	Jan. 2003	SCH. - J	(21,601.0)	0.0	(148.8)	(21,452.2)	4.401	4.401	(944,053.82)
FLA. POWER CORP.	Jan. 2003	SCH. - J	21,440.0	0.0	148.8	21,291.2	4.321	4.321	919,903.82
AUBURNDALE PWR PARTNERS	Nov. 2002	SCH. - J	(1,974.0)	0.0	(147.0)	(1,827.0)	3.501	3.501	(63,970.00)
AUBURNDALE PWR PARTNERS	Nov. 2002	SCH. - J	1,974.0	0.0	166.0	1,808.0	3.538	3.538	63,970.00
DUKE ENERGY	Nov. 2002	SCH. - J	(2,884.0)	0.0	(643.4)	(2,240.6)	5.137	5.137	(115,093.17)
DUKE ENERGY	Nov. 2002	SCH. - J	2,884.0	0.0	645.0	2,239.0	5.140	5.140	115,093.17
DUKE ENERGY	Dec. 2002	SCH. - J	(3,563.0)	0.0	0.0	(3,563.0)	3.983	3.983	(141,899.00)
DUKE ENERGY	Dec. 2002	SCH. - J	3,563.0	0.0	30.0	3,533.0	4.016	4.016	141,899.00
CITY OF LAKELAND	Nov. 2002	SCH. - J	(16,322.0)	0.0	(2,353.7)	(13,968.3)	4.393	4.393	(613,606.98)
CITY OF LAKELAND	Nov. 2002	SCH. - J	16,322.0	0.0	2,416.3	13,905.7	4.413	4.413	613,606.98
CITY OF LAKELAND	Dec. 2002	SCH. - J	(12,210.0)	0.0	(204.2)	(12,005.8)	4.627	4.627	(555,501.23)
CITY OF LAKELAND	Dec. 2002	SCH. - J	12,210.0	0.0	210.5	11,999.5	4.629	4.629	555,501.23
SEMINOLE ELEC. CO-OP	Nov. 2002	SCH. - J	(8,535.0)	0.0	(1,039.5)	(7,495.5)	3.838	3.838	(287,691.15)
SEMINOLE ELEC. CO-OP	Nov. 2002	SCH. - J	8,535.0	0.0	1,049.7	7,485.3	3.843	3.843	287,691.15
SEMINOLE ELEC. CO-OP	Jan. 2003	SCH. - J	(3,941.0)	0.0	0.0	(3,941.0)	3.387	3.387	(133,467.00)
SEMINOLE ELEC. CO-OP	Jan. 2003	SCH. - J	3,941.0	0.0	0.0	3,941.0	3.399	3.399	133,967.00
THE ENERGY AUTHORITY	Nov. 2002	SCH. - J	(15,662.0)	0.0	(1,576.0)	(14,086.0)	4.368	4.368	(615,297.53)
THE ENERGY AUTHORITY	Nov. 2002	SCH. - J	15,662.0	0.0	1,609.5	14,052.5	4.379	4.379	615,297.53
CONOCO	Dec. 2002	SCH. - J	(2,061.0)	0.0	(172.7)	(1,888.3)	4.092	4.092	(77,263.75)
CONOCO	Dec. 2002	SCH. - J	2,061.0	0.0	276.3	1,784.7	4.329	4.329	77,263.75
CORAL POWER	Dec. 2002	SCH. - J	(352.0)	0.0	(537.3)	185.3	7.265	7.265	13,461.66
CORAL POWER	Dec. 2002	SCH. - J	352.0	0.0	264.0	88.0	(15.297)	(15.297)	(13,461.66)
FLA. POWER & LIGHT	Dec. 2002	SCH. - J	(65,325.0)	0.0	(827.3)	(64,497.7)	4.385	4.385	(2,828,156.19)
FLA. POWER & LIGHT	Dec. 2002	SCH. - J	65,325.0	0.0	997.0	64,328.0	4.396	4.396	2,828,156.19
TALLAHASSEE	Jan. 2003	SCH. - J	(4,323.0)	0.0	0.0	(4,323.0)	4.091	4.091	(176,860.96)
TALLAHASSEE	Jan. 2003	SCH. - J	4,323.0	0.0	0.0	4,323.0	4.091	4.091	176,863.96
TOTAL			**153,267.0**	**0.0**	**243.0**	**153,024.0**	**5.037**	**5.037**	**7,708,351.10**
CURRENT MONTH:									
DIFFERENCE			(3,883.0)	0.0	(1,947.0)	(1,936.0)	0.283	0.283	341,751.10
DIFFERENCE %			-2.5%	0.0%	-88.9%	-1.2%	6.0%	6.0%	4.6%
PERIOD TO DATE:									
ACTUAL			385,537.0	0.0	751.2	384,785.8	5.725	5.725	22,028,490.69
ESTIMATED			389,420.0	0.0	2,698.2	386,721.8	5.608	5.608	21,686,739.59
DIFFERENCE			(3,883.0)	0.0	(1,947.0)	(1,936.0)	0.117	0.117	341,751.10
DIFFERENCE %			-1.0%	0.0%	-72.2%	-0.5%	2.1%	2.1%	1.6%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	34,741.0	0.0	0.0	34,741.0	2.437	2.437	846,600.00
TOTAL			34,741.0	0.0	0.0	34,741.0	2.437	2.437	846,600.00
ACTUAL:									
HILLSBOROUGH COUNTY		COGEN.	13,540.0	0.0	0.0	13,540.0	2.110	2.110	285,649.36
McKAY BAY REFUSE		COGEN.	11,929.0	0.0	0.0	11,929.0	2.101	2.101	250,678.87
ORANGE COGENERATION L.P.		COGEN.	5,152.0	0.0	0.0	5,152.0	2.005	2.005	103,305.22
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	1,423.0	0.0	0.0	1,423.0	3.212	3.212	45,713.66
CARGILL MULBERRY		COGEN.	8,016.0	0.0	0.0	8,016.0	2.977	2.977	238,632.26
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	478.0	0.0	0.0	478.0	2.962	2.962	14,158.32
IMC-AGRICO-NEW WALES		COGEN.	446.0	0.0	0.0	446.0	2.729	2.729	12,173.56
IMC-AGRICO-S. PIERCE		COGEN.	9,407.0	0.0	0.0	9,407.0	2.969	2.969	279,325.01
AUBURNDALE POWER PARTNERS		COGEN.	350.0	0.0	0.0	350.0	2.063	2.063	7,220.88
CUTRALE CITRUS		COGEN.	1.0	0.0	0.0	1.0	2.066	2.066	20.66
SUB-TOTAL FOR FEBRUARY 2003			50,742.0	0.0	0.0	50,742.0	2.438	2.438	1,236,877.80
ADJUSTMENTS FOR THE MONTH OF:	**NOV. AND DEC. 2002**								
McKAY BAY REFUSE	NOV. 2002	COGEN.	(12,937.0)	0.0	0.0	(12,937.0)	2.390	2.390	(309,226.39)
	NOV. 2002		12,937.0	0.0	0.0	12,937.0	2.252	2.252	291,298.17
MULBERRY PHOSPHATES INC.	NOV. 2002	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	NOV. 2002		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	NOV. 2002	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	NOV. 2002		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	NOV. 2002	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	NOV. 2002		0.0	0.0	0.0	0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY	NOV. 2002	COGEN.	(18,482.0)	0.0	0.0	(18,482.0)	2.445	2.445	(451,964.27)
	NOV. 2002		18,482.0	0.0	0.0	18,482.0	2.194	2.194	405,570.29
CARGILL MILLPOINT	NOV. 2002	COGEN.	(13.0)	0.0	0.0	(13.0)	24.821	24.821	(3,226.69)
	NOV. 2002		13.0	0.0	0.0	13.0	(11.664)	(11.664)	(1,516.27)
CF INDUSTRIES INC.	NOV. 2002	COGEN.	(688.0)	0.0	0.0	(688.0)	4.673	4.673	(32,147.62)
	NOV. 2002		688.0	0.0	0.0	688.0	2.873	2.873	19,764.70
FARMLAND HYDRO LP	NOV. 2002	COGEN.	(30.0)	0.0	0.0	(30.0)	(0.593)	(0.593)	177.82
	NOV. 2002		30.0	0.0	0.0	30.0	6.241	6.241	1,872.18
IMC-AGRICO-S. PIERCE	NOV. 2002	COGEN.	(614.0)	0.0	0.0	(614.0)	6.680	6.680	(41,016.52)
	NOV. 2002		614.0	0.0	0.0	614.0	0.931	0.931	5,716.68
AUBURNDALE POWER PARTNERS	NOV. 2002	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	NOV. 2002		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.	NOV. 2002	COGEN.	(5,400.0)	0.0	0.0	(5,400.0)	2.340	2.340	(126,354.67)
	NOV. 2002		5,400.0	0.0	0.0	5,400.0	1.998	1.998	107,908.31
CUTRALE CITRUS	NOV. 2002	COGEN.	(8.0)	0.0	0.0	(8.0)	5.807	5.807	(464.56)
	NOV. 2002		8.0	0.0	0.0	8.0	1.666	1.666	133.28
CARGILL GREEN BAY	NOV. 2002	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	NOV. 2002		0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	DEC. 2002	COGEN.	(12,999.0)	0.0	0.0	(12,999.0)	2.224	2.224	(289,048.82)
	DEC. 2002		12,999.0	0.0	0.0	12,999.0	2.389	2.389	310,572.23
HILLSBOROUGH COUNTY	DEC. 2002	COGEN.	(19,286.0)	0.0	0.0	(19,286.0)	2.225	2.225	(429,182.58)
	DEC. 2002		19,286.0	0.0	0.0	19,286.0	2.392	2.392	461,336.02
ORANGE COGENERATION L.P.	DEC. 2002	COGEN.	(5,652.0)	0.0	0.0	(5,652.0)	2.110	2.110	(119,263.18)
	DEC. 2002		5,652.0	0.0	0.0	5,652.0	2.316	2.316	130,912.59
SUB-TOTAL FOR THE MONTH OF:	**NOV. AND DEC. 2002**		0.0	0.0	0.0	0.0	0.000	0.000	(68,149.30)
GRAND TOTAL			**50,742.0**	**0.0**	**0.0**	**50,742.0**	**2.303**	**2.303**	**1,168,728.50**
CURRENT MONTH:									
DIFFERENCE			16,001.0	0.0	0.0	16,001.0	(0.134)	(0.134)	322,128.50
DIFFERENCE %			46.1%	0.0%	0.0%	46.1%	-5.5%	-5.5%	38.0%
PERIOD TO DATE:									
ACTUAL			98,079.0	0.0	0.0	98,079.0	2.475	2.475	2,427,493.62
ESTIMATED			82,078.0	0.0	0.0	82,078.0	2.565	2.565	2,105,365.12
DIFFERENCE			16,001.0	0.0	0.0	16,001.0	(0.090)	(0.090)	322,128.50
DIFFERENCE %			19.5%	0.0%	0.0%	19.5%	(0.035)	(0.035)	15.3%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

MARCH 2003

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	32,533,978	33,837,562	(1,303,584)	-3.9%	1,246,644	1,290,306	(43,662)	-3.4%	2.60972	2.62244	(0.01272)	-0.5%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(5,269)	(6,000)	731	-12.2%	1,246,644 (a)	1,290,306 (a)	(43,662)	-3.4%	(0.00042)	(0.00047)	0.00004	-9.1%
4b. Adjustments to Fuel Cost	(2,253)	0	(2,253)	0.0%	1,246,644 (a)	1,290,306 (a)	(43,662)	-3.4%	(0.00018)	0.00000	(0.00018)	0.0%
4c. Incremental Hedging O&M Costs	0	34,583	(34,583)	-100.0%	1,246,644 (a)	1,290,306 (a)	(43,662)	-3.4%	0.00000	0.00268	(0.00268)	-100.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**32,526,456**	**33,866,145**	**(1,339,689)**	**-4.0%**	**1,246,644**	**1,290,306**	**(43,662)**	**-3.4%**	**2.60912**	**2.62466**	**(0.01554)**	**-0.6%**
6. Fuel Cost of Purchased Power - Firm (A7)	13,922,672	5,896,100	8,026,572	136.1%	238,528	122,522	116,006	94.7%	5.83691	4.81228	1.02463	21.3%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,347,837	1,023,600	324,237	31.7%	49,744	39,467	10,277	26.0%	2.70955	2.59356	0.11599	4.5%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**15,270,509**	**6,919,700**	**8,350,809**	**120.7%**	**288,272**	**161,989**	**126,283**	**78.0%**	**5.29726**	**4.27171**	**1.02555**	**24.0%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,534,916**	**1,452,295**	**82,621**	**5.7%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	53,992	78,800	(24,808)	-31.5%	2,289	3,124	(835)	-26.7%	2.35876	2.52241	(0.16365)	-6.5%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	548	0	548	0.0%	8	0	8	0.0%	6.85000	0.00000	6.85000	0.0%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	1,182,886	1,025,700	157,186	15.3%	41,328	36,664	4,664	12.7%	2.86219	2.79757	0.06462	2.3%
19. Gains on Market Based Sales	285,858	425,800	(139,942)	-32.9%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**1,523,284**	**1,530,300**	**(7,016)**	**-0.5%**	**43,625**	**39,788**	**3,837**	**9.6%**	**3.49177**	**3.84613**	**(0.35437)**	**-9.2%**
21. Net Inadvertant Interchange					(900)	0	(900)	0.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					104	0	104	0.0%				
23. Interchange and Wheeling Losses					660	600	60	10.0%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**46,273,681**	**39,255,545**	**7,018,136**	**17.9%**	**1,489,835**	**1,411,907**	**77,928**	**5.5%**	**3.10596**	**2.78032**	**0.32564**	**11.7%**
25. Net Unbilled	3,202,059 (a)	1,176,576 (a)	2,025,483	172.2%	103,094	42,318	60,776	143.6%	3.10596	2.78032	0.32564	11.7%
26. Company Use	114,020 (a)	111,213 (a)	2,807	2.5%	3,671	4,000	(329)	-8.2%	3.10597	2.78033	0.32564	11.7%
27. T & D Losses	2,353,759 (a)	1,921,369 (a)	432,390	22.5%	75,782	69,106	6,676	9.7%	3.10596	2.78032	0.32564	11.7%
28. System KWH Sales	46,273,681	39,255,545	7,018,136	17.9%	1,307,288	1,296,483	10,805	0.8%	3.53967	3.02785	0.51182	16.9%
29. Wholesale KWH Sales	(1,917,932)	(925,010)	(992,922)	107.3%	(54,184)	(30,550)	(23,634)	77.4%	3.53967	3.02786	0.51181	16.9%
30. Jurisdictional KWH Sales	44,355,749	38,330,535	6,025,214	15.7%	1,253,104	1,265,933	(12,829)	-1.0%	3.53967	3.02785	0.51182	16.9%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	44,406,315	38,374,232	6,032,083	15.7%	1,253,104	1,265,933	(12,829)	-1.0%	3.54371	3.03130	0.51241	16.9%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	268,193	273,197	(5,004)	-1.8%	1,253,104	1,265,933	(12,829)	-1.0%	0.02140	0.02158	(0.00018)	-0.8%
34. Adjustment	0	0	0	0.0%	1,253,104	1,265,933	(12,829)	-1.0%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	1,253,104	1,265,933	(12,829)	-1.0%	0.00000	0.00000	0.00000	0.0%
36. True-up *	263,799	263,799	0	0.0%	1,253,104	1,265,933	(12,829)	-1.0%	0.02105	0.02084	0.00021	1.0%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	44,938,307	38,911,228	6,027,079	15.5%	1,253,104	1,265,933	(12,829)	-1.0%	3.58616	3.07372	0.51244	16.7%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.58874	3.07593	0.51281	16.7%
40. GPIF * (Already Adjusted for Taxes)	(68,561)	(69,203)	642	-0.9%	1,253,104	1,265,933	(12,829)	-1.0%	(0.00547)	(0.00547)	(0.00000)	0.1%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**44,869,746**	**38,842,025**	**6,027,721**	**15.5%**	**1,253,104**	**1,265,933**	**(12,829)**	**-1.0%**	**3.58327**	**3.07046**	**0.51281**	**16.7%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.583**	**3.070**	**0.513**	**16.7%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: MARCH 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	89,262,593	91,050,968	(1,788,375)	-2.0%	3,675,947	3,777,037	(101,090)	-2.7%	2.42829	2.41065	0.01764	0.7%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (FLMeade/Wauch. Wheeling Losses)	(15,748)	(18,108)	2,360	-13.0%	3,675,947 (a)	3,777,037 (a)	(101,090)	-2.7%	(0.00043)	(0.00048)	0.00005	-10.6%
4b. Adjustments to Fuel Cost	(6,873)	(2,738)	(4,135)	151.0%	3,675,947 (a)	3,777,037 (a)	(101,090)	-2.7%	(0.00019)	(0.00007)	(0.00011)	157.9%
4c. Adjustments to Fuel Cost	0	69,166	(69,166)	-100.0%	3,675,947 (a)	3,777,037 (a)	(101,090)	-2.7%	0.00000	0.00183	(0.00183)	-100.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**89,239,972**	**91,099,288**	**(1,859,316)**	**-2.0%**	**3,675,947**	**3,777,037**	**(101,090)**	**-2.7%**	**2.42767**	**2.41192**	**0.01575**	**0.7%**
6. Fuel Cost of Purchased Power - Firm (A7)	35,951,163	27,582,840	8,368,323	30.3%	623,314	509,244	114,070	22.4%	5.76775	5.41643	0.35132	6.5%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	3,775,331	3,128,965	646,366	20.7%	147,823	121,545	26,278	21.6%	2.55395	2.57433	(0.02037)	-0.8%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**39,726,494**	**30,711,805**	**9,014,689**	**29.4%**	**771,137**	**630,789**	**140,348**	**22.2%**	**5.15168**	**4.86879**	**0.28289**	**5.8%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**4,447,084**	**4,407,826**	**39,258**	**0.9%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	150,648	185,807	(35,159)	-18.9%	6,383	8,006	(1,623)	-20.3%	2.36014	2.32085	0.03930	1.7%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	1,928	4,680	(2,752)	-58.8%	60	46	14	30.4%	3.21333	10.17391	(6.96058)	-68.4%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	121,809	108,975	12,834	11.8%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	1,689,982	1,511,140	178,842	11.8%	56,679	50,738	5,941	11.7%	2.98167	2.97832	0.00335	0.1%
19. Gains on Market Based Sales	501,064	538,894	(37,830)	-7.0%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**2,465,431**	**2,349,496**	**115,935**	**4.9%**	**63,122**	**58,790**	**4,332**	**7.4%**	**3.90582**	**3.99642**	**(0.09060)**	**-2.3%**
21. Net Inadvertant Interchange					(407)	(291)	(116)	39.9%				
22. Wheeling Rec'd. less Wheeling Del'd.					45	652	(607)	-93.1%				
23. Interchange and Wheeling Losses					1,276	996	280	28.1%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**126,501,035**	**119,461,597**	**7,039,438**	**5.9%**	**4,382,324**	**4,348,401**	**33,923**	**0.8%**	**2.88662**	**2.74725**	**0.13937**	**5.1%**
25. Net Unbilled	1,586,616 (a)	2,932,286 (a)	(1,345,670)	-45.9%	31,381	99,325	(67,944)	-68.4%	5.05598	2.95221	2.10376	71.3%
26. Company Use	328,041 (a)	331,019 (a)	(2,978)	-0.9%	11,412	12,099	(687)	-5.7%	2.87453	2.73592	0.13861	5.1%
27. T & D Losses	2,932,638 (a)	2,191,547 (a)	741,091	33.8%	97,586	79,264	18,322	23.1%	3.00518	2.76487	0.24031	8.7%
28. System KWH Sales	126,501,035	119,461,597	7,039,438	5.9%	4,241,945	4,157,713	84,232	2.0%	2.98215	2.87325	0.10889	3.8%
29. Wholesale KWH Sales	(4,245,168)	(2,771,239)	(1,473,929)	53.2%	(138,710)	(93,764)	(44,946)	47.9%	3.06046	2.95555	0.10492	3.5%
30. Jurisdictional KWH Sales	122,255,867	116,690,358	5,565,509	4.8%	4,103,235	4,063,949	39,286	1.0%	2.97950	2.87135	0.10815	3.8%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	122,395,239	116,823,385	5,571,854	4.8%	4,103,235	4,063,949	39,286	1.0%	2.98290	2.87463	0.10827	3.8%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	819,061	828,149	(9,088)	-1.1%	4,103,235	4,063,949	39,286	1.0%	0.01996	0.02038	(0.00042)	-2.0%
34. Adjustment	0	0	0	0.0%	4,103,235	4,063,949	39,286	1.0%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	4,103,235	4,063,949	39,286	1.0%	0.00000	0.00000	0.00000	0.0%
36. True-up *	791,397	791,397	0	0.0%	4,103,235	4,063,949	39,286	1.0%	0.01929	0.01947	(0.00019)	-1.0%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	124,005,697	118,442,931	5,562,766	4.7%	4,103,235	4,063,949	39,286	1.0%	3.02214	2.91448	0.10767	3.7%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.02432	2.91658	0.10774	3.7%
40. GPIF * (Already Adjusted for Taxes)	(206,967)	(207,609)	642	-0.3%	4,103,235	4,063,949	39,286	1.0%	(0.00504)	(0.00511)	0.00006	-1.3%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**123,798,730**	**118,235,322**	**5,563,408**	**4.7%**	**4,103,235**	**4,063,949**	**39,286**	**1.0%**	**3.01928**	**2.91147**	**0.10780**	**3.7%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.019**	**2.911**	**0.108**	**3.7%**

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	32,533,978	33,837,562	(1,303,584)	-3.9%	89,262,593	91,050,968	(1,788,375)	-2.0%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	1,237,426	1,104,500	132,926	12.0%	1,964,367	1,810,602	153,765	8.5%
2a. GAINS FROM MARKET BASED SALES	285,858	425,800	(139,942)	-32.9%	501,064	538,894	(37,830)	-7.0%
3. FUEL COST OF PURCHASED POWER	13,922,672	5,896,100	8,026,572	136.1%	35,951,163	27,582,840	8,368,323	30.3%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,347,837	1,023,600	324,237	31.7%	3,775,331	3,128,965	646,366	20.7%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	46,281,203	39,226,962	7,054,241	18.0%	126,523,656	119,413,277	7,110,379	6.0%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(5,269)	(6,000)	731	-12.2%	(15,748)	(18,108)	2,360	-13.0%
6b. ADJ.TO FUEL COST	(2,253)	0	(2,253)	0.0%	(6,873)	(2,738)	(4,135)	151.0%
6c. INCREMENTAL HEDGING O&M COSTS	0	34,583	(34,583)	-100.0%	0	69,166	(69,166)	-100.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	46,273,681	39,255,545	7,018,136	17.9%	126,501,035	119,461,597	7,039,438	5.9%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,253,104	1,265,933	(12,829)	-1.0%	4,103,235	4,063,949	39,286	1.0%
2. NONJURISDICTIONAL SALES	54,184	30,550	23,634	77.4%	138,710	93,764	44,946	47.9%
3. TOTAL SALES	1,307,288	1,296,483	10,805	0.8%	4,241,945	4,157,713	84,232	2.0%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9585524	0.9764362	(0.0178838)	-1.8%	0.9673004	0.9774482	(0.0101478)	-1.0%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	37,106,542	37,939,683	(833,141)	-2.2%	121,750,361	121,387,998	362,363	0.3%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(263,799)	(263,799)	0	0.0%	(791,397)	(791,397)	0	0.0%
2b. INCENTIVE PROVISION No	68,561	69,203	(642)	-0.9%	206,967	207,609	(642)	-0.3%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	36,911,304	37,745,087	(833,783)	-2.2%	121,165,931	120,804,210	361,721	0.3%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE .	46,273,681	39,255,545	7,018,136	17.9%	126,501,035	119,461,597	7,039,438	5.9%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINI	0.9585524	0.9764362	(0.0178838)	-1.8%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	44,355,749	38,330,535	6,025,214	15.7%	122,255,867	116,690,358	5,565,509	4.8%
6a. JURISDIC. LOSS MULTIPLIER	1.00114	1.00114	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	44,406,315	38,374,232	6,032,083	15.7%	122,395,239	116,823,385	5,571,854	4.8%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	279,790	279,790	0	0.0%	846,963	846,963	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	268,193	273,197	(5,004)	-1.8%	819,061	828,149	(9,088)	-1.1%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	44,674,508	38,647,429	6,027,079	15.6%	123,214,300	117,651,534	5,562,766	4.7%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(7,763,204)	(902,342)	(6,860,862)	760.3%	(2,048,369)	3,152,676	(5,201,045)	-165.0%
8. INTEREST PROVISION FOR THE MONTH	(29,695)	(29,843)	148	-0.5%	(95,947)	(97,577)	1,630	-1.7%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(25,651,737)	(27,313,036)	1,661,299	-6.1%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	263,799	263,799	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(33,180,837)	(27,981,422)	(5,199,415)	18.6%	NOT APPLICABLE			

Note 1: Includes adjustment of ($789) for 2002 and $98 for January & February 2003.

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(25,651,737)	(27,313,036)	1,661,299	-6.1%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(33,151,142)	(27,951,579)	(5,199,563)	18.6%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(58,802,879)	(55,264,615)	(3,538,264)	6.4%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(29,401,440)	(27,632,308)	(1,769,132)	6.4%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.250	1.300	(0)	-3.8%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.180	1.300	(0)	-9.2%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	2.430	2.600	(0)	-6.5%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.215	1.300	(0)	-6.5%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.101	0.108	(0)	-6.5%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(29,695)	(29,843)	148	-0.5%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	627,987	260,408	367,579	141.2%	1,484,667	904,781	579,886	64.1%
2	LIGHT OIL	219,523	176,327	43,196	24.5%	3,215,340	2,742,911	472,429	17.2%
3	COAL	25,618,380	24,760,841	857,539	3.5%	75,913,990	76,916,949	(1,002,959)	-1.3%
4	NATURAL GAS	6,068,088	8,639,986	(2,571,898)	-29.8%	8,648,596	10,486,327	(1,837,731)	-17.5%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	32,533,978	33,837,562	(1,303,584)	-3.9%	89,262,593	91,050,968	(1,788,375)	-2.0%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	10,384	4,719	5,665	120.0%	25,586	16,512	9,074	55.0%
9	LIGHT OIL	2,610	2,466	144	5.8%	53,057	44,213	8,844	20.0%
10	COAL	1,176,228	1,122,785	53,443	4.8%	3,527,455	3,539,737	(12,282)	-0.3%
11	NATURAL GAS	57,422	160,336	(102,914)	-64.2%	69,849	176,575	(106,726)	-60.4%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,246,644	1,290,306	(43,662)	-3.4%	3,675,947	3,777,037	(101,090)	-2.7%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	15,877	7,107	8,770	123.4%	39,003	24,990	14,013	56.1%
16	LIGHT OIL (BBL)	6,904	4,334	2,570	59.3%	85,365	71,943	13,422	18.7%
17	COAL (TON)	548,335	510,337	37,998	7.4%	1,642,371	1,633,174	9,197	0.6%
18	NATURAL GAS (MCI	665,874	1,154,902	(489,028)	-42.3%	809,000	1,338,115	(529,115)	-39.5%
19	NUCLEAR (MMBTU	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	99,606	45,553	54,053	118.7%	244,683	158,522	86,161	54.4%
22	LIGHT OIL	39,921	25,168	14,753	58.6%	495,786	418,370	77,416	18.5%
23	COAL	13,028,693	12,306,706	721,987	5.9%	38,958,399	39,037,225	(78,826)	-0.2%
24	NATURAL GAS	705,160	1,187,185	(482,025)	-40.6%	857,320	1,379,772	(522,452)	-37.9%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	13,873,380	13,564,612	308,768	2.3%	40,556,188	40,993,889	(437,701)	-1.1%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.83%	0.37%	0.00	-	0.70%	0.44%	0.00	-
29	LIGHT OIL	0.21%	0.19%	0.00	-	1.44%	1.17%	0.00	-
30	COAL	94.35%	87.02%	0.07	-	95.96%	93.72%	0.02	-
31	NATURAL GAS	4.61%	12.43%	(0.08)	-	1.90%	4.67%	(0.03)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	39.55	36.64	2.91	7.9%	38.07	36.21	1.86	5.1%
36	LIGHT OIL ($/BBL)	31.80	40.68	(8.89)	-21.8%	37.67	38.13	(0.46)	-1.2%
37	COAL ($/TON)	46.72	48.52	(1.80)	-3.7%	46.22	47.10	(0.87)	-1.9%
38	NATURAL GAS ($/M	9.11	7.48	1.63	21.8%	10.69	7.84	2.85	36.4%
39	NUCLEAR ($/MMBT	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTL	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	6.30	5.72	0.59	10.3%	6.07	5.71	0.36	6.3%
42	LIGHT OIL	5.50	7.01	(1.51)	-21.5%	6.49	6.56	(0.07)	-1.1%
43	COAL	1.97	2.01	(0.05)	-2.3%	1.95	1.97	(0.02)	-1.1%
44	NATURAL GAS	8.61	7.28	1.33	18.2%	10.09	7.60	2.49	32.7%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.35	2.49	(0.15)	-6.0%	2.20	2.22	(0.02)	-0.9%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,592	9,653	(61)	-0.6%	9,563	9,600	(37)	-0.4%
49	LIGHT OIL	15,295	10,206	5,089	49.9%	9,344	9,463	(119)	-1.3%
50	COAL	11,077	10,961	116	1.1%	11,044	11,028	16	0.1%
51	NATURAL GAS	12,280	7,404	4,876	65.9%	12,274	7,814	4,460	57.1%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	11,129	10,513	616	5.9%	11,033	10,853	180	1.7%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	6.05	5.52	0.53	9.6%	5.80	5.48	0.32	5.8%
56	LIGHT OIL	8.41	7.15	1.26	17.6%	6.06	6.20	(0.14)	-2.3%
57	COAL	2.18	2.21	(0.03)	-1.4%	2.15	2.17	(0.02)	-0.9%
58	NATURAL GAS	10.57	5.39	5.18	96.1%	12.38	5.94	6.44	108.4%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.61	2.62	(0.01)	-0.4%	2.43	2.41	0.02	0.8%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: MARCH 2003

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(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	94	32,677	46.7	62.8	71.9	11,862	COAL	16,426	23,598,000	387,620.7	721,433	2.21	43.92
GAN.#2	100	39,755	53.4	73.5	66.3	12,341	COAL	20,647	23,762,000	490,614.0	906,820	2.28	43.92
GAN.#3	155	64,446	55.9	80.3	67.9	11,839	COAL	31,645	24,110,000	762,961.0	1,389,854	2.16	43.92
GAN.#4	164	60,159	49.3	66.1	73.5	11,387	COAL	28,771	23,810,000	685,037.5	1,263,627	2.10	43.92
GAN.#5	0	-229	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	372	116,781	42.2	57.5	66.5	11,323	COAL	54,838	24,114,000	1,322,363.5	2,408,494	2.06	43.92
GANNON STATION	**885**	**313,589**	**47.6**	**65.5**	**68.6**	**11,635**	**COAL**	**152,327**	**23,952,396**	**3,648,596.7**	**6,690,228**	**2.13**	**43.92**
B.B.#1	428	190,435	59.8	67.1	72.6	10,970	COAL	85,820	24,342,140	2,089,047.8	4,121,708	2.16	48.03
B.B.#2	433	206,163	64.0	72.7	74.4	10,756	COAL	91,862	24,139,580	2,217,504.7	4,411,889	2.14	48.03
B.B.#3	438	186,320	57.2	66.4	72.7	10,737	COAL	82,662	24,201,740	2,000,556.7	3,970,038	2.13	48.03
B.B.#4	460	245,982	71.9	82.5	74.0	10,740	COAL	119,863	22,041,060	2,641,914.4	5,756,704	2.34	48.03
B.B. STATION	**1,759**	**828,900**	**63.3**	**72.3**	**73.4**	**10,796**	**COAL**	**380,207**	**23,537,241**	**8,949,023.6**	**18,260,339**	**2.20**	**48.03**
SEB-PHIL. #1(HVY OIL)	17	4,969	39.3	95.1	92.1	9,592	HVY.OIL	7,598	6,273,540	47,664.6	300,526	6.05	39.55
SEB-PHIL. #2(HVY OIL)	17	5,415	42.8	99.8	89.8	9,592	HVY.OIL	8,279	6,273,540	51,941.1	327,461	6.05	39.55
SEB-PHILLIPS TOTAL	**34**	**10,384**	**41.0**	**97.4**	**91.0**	**9,592**	**HVY.OIL**	**15,877**	**6,273,541**	**99,605.7**	**627,987**	**6.05**	**39.55**
POLK #1 GASIFIER	260	33,739	17.4	21.8	80.0	12,777	COAL	15,801	27,282,000	431,072.5	667,813	1.98	42.26
POLK #1 CT (OIL)	245	131	0.1	22.0	17.4	25,377	LGT.OIL	602	5,794,557	3,336.4	25,324	19.33	42.09
POLK #1 TOTAL	**260**	**33,870**	**17.5**	**21.9**	**78.9**	**12,826**	**-**	**-**	**-**	**434,408.9**	**693,137**	**2.05**	**-**
POLK #2 CT (GAS)	175	16,635	12.8	64.0	67.0	10,978	GAS	172,441	1,059,000	182,615.0	1,501,665	9.03	8.71
POLK #2 CT (OIL)	180	31	0.0	65.4	15.2	35,161	LGT.OIL	188	5,794,566	1,091.9	7,932	25.59	42.19
POLK #2 TOTAL	**178**	**16,666**	**12.6**	**65.4**	**66.5**	**11,023**	**-**	**-**	**-**	**183,706.9**	**1,509,597**	**9.06**	**-**
POLK #3 CT (GAS)	175	26,208	20.1	98.3	67.5	11,757	GAS	290,956	1,059,000	308,122.0	2,620,291	10.00	9.01
POLK #3 CT (OIL)	180	1,798	1.3	98.6	62.2	14,261	LGT.OIL	4,425	5,794,558	25,640.9	186,267	10.36	42.09
POLK #3 TOTAL	**178**	**28,006**	**21.1**	**98.6**	**67.1**	**11,916**	**-**	**-**	**-**	**333,762.9**	**2,806,558**	**10.02**	**-**
POLK STATION TOTAL	**616**	**78,542**	**17.1**	**56.7**	**71.9**	**12,119**	**-**	**-**	**-**	**951,878.7**	**5,009,292**	**6.38**	**-**
B.B.C.T.#1	15	120	1.1	100.0	80.0	17,748	LGT.OIL	367	5,808,460	2,129.7	0	0.00	0.00
B.B.C.T.#2	80	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	70	530	1.0	100.0	68.8	14,570	LGT.OIL	1,322	5,839,028	7,721.9	0	0.00	0.00
C.T. TOTAL	**165**	**650**	**0.5**	**100.0**	**70.8**	**15,156**	**LGT.OIL**	**1,689**	**5,832,352**	**9,851.6**	**-**	**0.00**	**0.00**
CITY OF TAMPA	**6**	**305**	**6.8**	**0.0**	**0.0**	**11,500**	**GAS**	**3,312**	**1,059,000**	**3,507.4**	**39,989**	**13.11**	**12.07**
BAYSIDE UNIT 1	0	14,274	-	-	-	14,776	GAS	199,165	972,290	210,916.0	1,906,143	13.35	9.57
BAYSIDE UNIT 2	0	0	-	-	-	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE STATION	**0**	**14,274**	**-**	**-**	**-**	**14,776**	**GAS**	**199,165**	**972,290**	**210,916.0**	**1,906,143**	**13.35**	**9.57**
TOT. COAL (GN,BB,POLK)	**2,904**	**1,176,228**	**54.4**	**65.7**	**72.5**	**11,077**	**COAL**	**548,335**	**23,760,479**	**13,028,692.8**	**25,618,380**	**2.18**	**46.72**
SYSTEM	**3,465**	**1,246,644**	**48.4**	**71.0**	**73.7**	**11,129**	**-**	**-**	**-**	**13,873,379.7**	**32,533,978**	**2.61**	**-**

LEGEND:
H.P. = HOOKERS POINT
B.B. = BIG BEND
GAN. = GANNON
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2003

SCHEDULE A5
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	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	10,823	7,107	3,716	52.3%	39,043	23,711	15,332	64.7%
3 UNIT COST ($/BBL)	37.61	35.05	2.56	7.3%	37.13	34.52	2.61	7.5%
4 AMOUNT ($)	407,091	249,100	157,991	63.4%	1,449,642	818,597	631,045	77.1%
5 BURNED:								
6 UNITS (BBL)	15,877	7,107	8,770	123.4%	39,003	24,990	14,013	56.1%
7 UNIT COST ($/BBL)	39.55	36.64	2.91	7.9%	38.07	36.21	1.86	5.1%
8 AMOUNT ($)	627,987	260,408	367,579	141.2%	1,484,667	904,781	579,886	64.1%
9 ENDING INVENTORY:								
10 UNITS (BBL)	10,782	9,463	1,319	13.9%	10,782	9,463	1,319	13.9%
11 UNIT COST ($/BBL)	39.32	35.69	3.63	10.2%	39.32	35.69	3.63	10.2%
12 AMOUNT ($)	423,956	337,714	86,242	25.5%	423,956	337,714	86,242	25.5%
13								
14 DAYS SUPPLY:	40	33	7	20.6%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	15,202	10,425	4,777	45.8%	97,186	89,081	8,105	9.1%
17 UNIT COST ($/BBL)	49.28	47.63	1.65	3.5%	42.89	42.64	0.26	0.6%
18 AMOUNT ($)	749,214	496,557	252,657	50.9%	4,168,780	3,797,996	370,784	9.8%
19 BURNED:								
20 UNITS (BBL)	6,904	4,334	2,570	59.3%	85,365	71,943	13,422	18.7%
21 UNIT COST ($/BBL)	31.80	40.68	(8.89)	-21.8%	37.67	38.13	(0.46)	-1.2%
22 AMOUNT ($)	219,523	176,327	43,196	24.5%	3,215,340	2,742,911	472,429	17.2%
23 ENDING INVENTORY:								
24 UNITS (BBL)	68,333	82,746	(14,413)	-17.4%	68,333	82,746	(14,413)	-17.4%
25 UNIT COST ($/BBL)	40.32	38.48	1.84	4.8%	40.32	38.48	1.84	4.8%
26 AMOUNT ($)	2,754,944	3,183,745	(428,801)	-13.5%	2,754,944	3,183,745	(428,801)	-13.5%
27								
28 DAYS SUPPLY: NORMAL	91	105	(14)	-13.1%	-	-	-	-
29 DAYS SUPPLY: EMERGENC	10	12	(2)	-17.4%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	594,579	791,300	(196,721)	-24.9%	1,704,246	1,975,373	(271,127)	-13.7%
32 UNIT COST ($/TON)	47.28	48.15	(0.87)	-1.8%	47.22	47.59	(0.38)	-0.8%
33 AMOUNT ($)	28,109,310	38,098,167	(9,988,857)	-26.2%	80,470,830	94,016,198	(13,545,368)	-14.4%
34 BURNED:								
35 UNITS (TONS)	548,335	510,337	37,998	7.4%	1,642,371	1,633,174	9,197	0.6%
36 UNIT COST ($/TON)	46.72	48.52	(1.80)	-3.7%	46.22	47.10	(0.87)	-1.9%
37 AMOUNT ($)	25,618,380	24,760,841	857,539	3.5%	75,913,990	76,916,949	(1,002,959)	-1.3%
38 ENDING INVENTORY:								
39 UNITS (TONS)	500,232	780,556	(280,324)	-35.9%	500,232	780,556	(280,324)	-35.9%
40 UNIT COST ($/TON)	47.05	47.26	(0.22)	-0.5%	47.05	47.26	(0.22)	-0.5%
41 AMOUNT ($)	23,533,546	36,891,877	(13,358,331)	-36.2%	23,533,546	36,891,877	(13,358,331)	-36.2%
42								
43 DAYS SUPPLY:	27	42	(15)	-36.6%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	665,874	1,154,902	(489,028)	-42.3%	809,000	1,338,115	(529,115)	-39.5%
46 UNIT COST ($/MCF)	9.11	7.48	1.63	21.8%	10.69	7.84	2.85	36.4%
47 AMOUNT ($)	6,068,088	8,639,986	(2,571,898)	-29.8%	8,648,596	10,486,327	(1,837,731)	-17.5%
48 BURNED:								
49 UNITS (MCF)	665,874	1,154,902	(489,028)	-42.3%	809,000	1,338,115	(529,115)	-39.5%
50 UNIT COST ($/MCF)	9.11	7.48	1.63	21.8%	10.69	7.84	2.85	36.4%
51 AMOUNT ($)	6,068,088	8,639,986	(2,571,898)	-29.8%	8,648,596	10,486,327	(1,837,731)	-17.5%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	27,287
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	27,287

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(8,778)	(318,460)
OTHER USAGE	(2,724)	(111,507)
TOTAL	(11,502)	(429,967)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	25,716
IGNITION #2 OIL	291,173
IGNITION PROPANE	2,745
AERIAL SURVEY ADJ.	(523,022)
ADDITIVES	58,714
GREEN FUEL	0
TOTAL	(144,674)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2003

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	3,124.0	0.0	3,124.0	2.522	2.522	78,800.00	78,800.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. - MB	36,664.0	0.0	36,664.0	2.798	4.281	1,025,700.00	1,569,600.00	425,800.00
TOTAL			**39,788.0**	**0.0**	**39,788.0**	**2.776**	**4.143**	**1,104,500.00**	**1,648,400.00**	**425,800.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	1,317.0	54.7	1,262.3	2.539	2.539	32,043.50	32,043.50	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	1,026.3	0.0	1,026.3	2.139	2.139	21,948.15	21,948.15	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. - D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. CORP.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		SCH. - MA	1,822.0	0.0	1,822.0	2.332	4.678	42,480.87	85,229.19	35,751.84
CITY OF LAKELAND		SCH. - MA	323.0	0.0	323.0	1.978	4.714	6,389.25	15,224.76	7,595.19
CONOCO		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		SCH. - MA	37,316.0	0.0	37,316.0	2.899	3.764	1,081,874.96	1,404,753.94	179,585.54
DYNEGY POWER MARKETING		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
REEDY CREEK		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
TALLAHASSEE		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	1,794.0	0.0	1,794.0	2.420	6.326	43,406.50	113,489.58	63,194.12
DUKE ENERGY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE PWR. PART. TO FLA. PWR. & LIGHT*		SCH. - MA	100.0	0.0	100.0	5.404	5.404	5,404.00	5,404.00	
HARDEE PWR. PART. TO THE ENERGY AUTH.*		SCH. - MA	180.0	0.0	180.0	5.186	5.186	9,334.80	9,334.80	
CARGILL ALLIANT		SCH. - OATT	8.0	0.0	8.0	6.848	6.848	547.83	547.83	
ADJUSTMENTS										
FLA. PWR. CORP.	Feb. 2003	SCH. - MA	(299.0)	0.0	(299.0)	2.836	5.478	(8,479.34)	(16,379.92)	(6,961.72)
FLA. PWR. CORP.	Feb. 2003	SCH. - MA	250.0	0.0	250.0	2.437	2.827	6,092.59	13,944.78	7,067.19
CONOCO	Feb. 2003	SCH. - MA	(158.0)	0.0	(158.0)	2.289	2.840	(3,617.21)	(4,487.72)	(374.39)
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			2,343.3	54.7	2,288.6	2.359	2.359	53,991.65	53,991.65	
SUB-TOTAL HARDEE PWR. PART. CONTRACT SALES-SEP.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			41,328.0	0.0	41,328.0	2.862	3.936	1,182,886.42	1,626,513.41	285,857.77
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			8.0	0.0	8.0	6.848	6.848	547.83	547.83	
TOTAL			**43,679.3**	**54.7**	**43,624.6**	**2.837**	**3.853**	**1,237,425.90**	**1,681,052.89**	**285,857.77**
CURRENT MONTH:										
DIFFERENCE			3,891.3	54.7	3,836.6	0.061	(0.290)	132,925.90	32,652.89	(139,942.23)
DIFFERENCE %			9.8%	0.0%	9.6%	2.2%	-7.0%	12.0%	2.0%	-32.9%
PERIOD TO DATE:										
ACTUAL			63,181.1	60.0	63,121.1	3.112	4.258	1,964,366.15	2,687,506.69	501,064.08
ESTIMATED			58,794.9	5.3	58,789.6	3.080	4.324	1,810,601.69	2,542,317.12	538,894.33
DIFFERENCE			4,386.2	54.7	4,331.5	0.032	(0.066)	153,764.46	145,189.57	(37,830.25)
DIFFERENCE %			7.5%	1032.1%	7.4%	1.0%	-1.5%	8.5%	5.7%	-7.0%

* SEC 60% PROFIT OR $2,249.80 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	2,526.0	0.0	1,439.0	1,087.0	4.995	4.995	54,300.00
HARDEE POWER PARTNERS		IPP	14,377.0	0.0	0.0	14,377.0	7.179	7.179	1,032,100.00
VARIOUS		OTHER	22,541.0	0.0	0.0	22,541.0	3.540	3.540	798,000.00
VARIOUS		MKT. BASE	84,517.0	0.0	0.0	84,517.0	4.747	4.747	4,011,700.00
TOTAL			**123,961.0**	**0.0**	**1,439.0**	**122,522.0**	**4.812**	**4.812**	**5,896,100.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	47,585.0	0.0	0.0	47,585.0	7.211	7.211	3,431,126.85
HARDEE PWR. PART.-OTHERS		IPP	280.0	0.0	0.0	280.0	5.264	5.264	14,738.80
FLA. POWER CORP.		SCH. - J	19,880.0	0.0	977.3	18,902.7	4.844	4.844	915,558.44
FLA. POWER & LIGHT		SCH. - J	18,545.0	0.0	977.4	17,567.6	4.667	4.667	819,820.27
CITY OF LAKELAND		SCH. - J	6,220.0	0.0	1,927.3	4,292.7	8.682	8.682	372,690.68
ORLANDO UTIL. COMM.		SCH. - J	3,200.0	0.0	0.0	3,200.0	9.050	9.050	289,600.00
CAROLINA POWER & LIGHT		SCH. - J	49.0	0.0	0.0	49.0	5.600	5.600	2,744.00
THE ENERGY AUTHORITY		SCH. - J	6,754.0	0.0	433.0	6,321.0	6.194	6.194	391,541.50
REEDY CREEK		SCH. - J	195.0	0.0	0.0	195.0	5.210	5.210	10,160.00
OKEELANTA		SCH. - J	12,198.0	0.0	0.0	12,198.0	4.742	4.742	578,371.95
TALLAHASSEE		SCH. - J	3,082.0	0.0	0.0	3,082.0	7.980	7.980	245,958.40
CALPINE		SCH. - J	2,634.0	0.0	540.6	2,093.4	9.641	9.641	201,819.47
CARGILL ALLIANT		SCH. - J	24,838.0	0.0	2,009.5	22,828.5	7.253	7.253	1,655,853.28
CONOCO		SCH. - J	1,532.0	0.0	0.0	1,532.0	4.897	4.897	75,029.50
CORAL POWER		SCH. - J *	0.0	0.0	0.0 *	0.0 *	0.000	0.000	0.00
RELIANT		SCH. - J *	7,671.0	0.0	112.9 *	7,558.1 *	7.493 *	7.493 *	566,360.21
SEMINOLE ELEC. CO-OP		SCH. - J	5,391.0	0.0	0.0	5,391.0	5.097	5.097	274,787.00
DUKE ENERGY		SCH. - J	2,381.0	0.0	0.0	2,381.0	6.923	6.923	164,845.00
DYNEGY POWER MARKETING		SCH. - J	685.0	0.0	0.0	685.0	3.000	3.000	20,550.00
RINGHAVER		SCH. - J	3,886.0	0.0	0.0	3,886.0	8.047	8.047	312,699.93
FLA. POWER CORP.		SCH. - D	78,500.0	0.0	0.0	78,500.0	4.126	4.126	3,238,880.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Feb. 2003	IPP	(34,665.0)	0.0	0.0	(34,665.0)	7.665	7.665	(2,657,170.62)
HARDEE PWR. PART.-NATIVE	Feb. 2003	IPP	34,665.0	0.0	0.0	34,665.0	7.784	7.784	2,698,186.45
FLA. POWER CORP.	Feb. 2003	SCH. - D	(45,900.0)	0.0	0.0	(45,900.0)	4.030	4.030	(1,849,647.27)
FLA. POWER CORP.	Feb. 2003	SCH. - D	45,900.0	0.0	0.0	45,900.0	4.276	4.276	1,962,561.27
FLA. POWER CORP.	Jan. 2003	SCH. - D	(75,450.0)	0.0	0.0	(75,450.0)	3.889	3.889	(2,934,384.00)
FLA. POWER CORP.	Jan. 2003	SCH. - D	75,450.0	0.0	0.0	75,450.0	4.135	4.135	3,119,991.00
TOTAL			**245,506.0**	**0.0**	**6,978.0**	**238,528.0**	**5.837**	**5.837**	**13,922,672.11**
CURRENT MONTH:									
DIFFERENCE			121,545.0	0.0	5,539.0	116,006.0	1.025	1.025	8,026,572.11
DIFFERENCE %			98.1%	0.0%	384.9%	94.7%	21.3%	21.3%	136.1%
PERIOD TO DATE:									
ACTUAL			631,043.0	0.0	7,729.2	623,313.8	5.768	5.768	35,951,162.80
ESTIMATED			513,381.0	0.0	4,137.2	509,243.8	5.416	5.416	27,582,839.59
DIFFERENCE			117,662.0	0.0	3,592.0	114,070.0	0.352	0.352	8,368,323.21
DIFFERENCE %			22.9%	0.0%	86.8%	22.4%	6.5%	6.5%	30.3%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	39,467.0	0.0	0.0	39,467.0	2.594	2.594	1,023,600.00
TOTAL		**39,467.0**	**0.0**	**0.0**	**39,467.0**	**2.594**	**2.594**	**1,023,600.00**
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	12,154.0	0.0	0.0	12,154.0	2.087	2.087	253,628.10
McKAY BAY REFUSE	COGEN.	13,334.0	0.0	0.0	13,334.0	2.078	2.078	277,135.46
ORANGE COGENERATION L.P.	COGEN.	5,704.0	0.0	0.0	5,704.0	1.947	1.947	111,035.70
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	494.0	0.0	0.0	494.0	3.899	3.899	19,263.21
CARGILL MULBERRY	COGEN.	6,459.0	0.0	0.0	6,459.0	3.588	3.588	231,746.54
CARGILL MILLPOINT	COGEN.	57.0	0.0	0.0	57.0	2.434	2.434	1,387.33
CF INDUSTRIES INC.	COGEN.	690.0	0.0	0.0	690.0	3.789	3.789	26,144.09
IMC-AGRICO-NEW WALES	COGEN.	49.0	0.0	0.0	49.0	4.749	4.749	2,327.06
IMC-AGRICO-S. PIERCE	COGEN.	10,801.0	0.0	0.0	10,801.0	3.607	3.607	389,589.41
AUBURNDALE POWER PARTNERS	COGEN.	2.0	0.0	0.0	2.0	5.753	5.753	115.06
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR MARCH 2003		49,744.0	0.0	0.0	49,744.0	2.638	2.638	1,312,371.96
ADJUSTMENTS FOR THE MONTH OF JANUARY 2003								
HILLSBOROUGH COUNTY	COGEN.	(17,161.0)	0.0	0.0	(17,161.0)	2.243	2.243	(384,928.46)
		17,161.0	0.0	0.0	17,161.0	2.329	2.329	399,606.66
McKAY BAY REFUSE	COGEN.	(13,204.0)	0.0	0.0	(13,204.0)	2.268	2.268	(299,437.62)
		13,204.0	0.0	0.0	13,204.0	2.236	2.236	295,197.33
ORANGE COGENERATION L.P.	COGEN.	(5,474.0)	0.0	0.0	(5,474.0)	2.263	2.263	(123,890.45)
		5,474.0	0.0	0.0	5,474.0	2.710	2.710	148,358.44
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	(424.0)	0.0	0.0	(424.0)	3.335	3.335	(14,138.79)
		424.0	0.0	0.0	424.0	3.067	3.067	13,002.74
CARGILL MULBERRY	COGEN.	(2,603.0)	0.0	0.0	(2,603.0)	2.945	2.945	(76,656.92)
		2,603.0	0.0	0.0	2,603.0	2.887	2.887	75,143.32
CARGILL MILLPOINT	COGEN.	(75.0)	0.0	0.0	(75.0)	2.330	2.330	(1,747.56)
		75.0	0.0	0.0	75.0	2.402	2.402	1,801.40
CF INDUSTRIES INC.	COGEN.	(890.0)	0.0	0.0	(890.0)	3.129	3.129	(27,849.69)
		890.0	0.0	0.0	890.0	3.176	3.176	28,269.89
IMC-AGRICO-NEW WALES	COGEN.	(256.0)	0.0	0.0	(256.0)	3.883	3.883	(9,940.48)
		256.0	0.0	0.0	256.0	3.904	3.904	9,994.10
IMC-AGRICO-S. PIERCE	COGEN.	(547.0)	0.0	0.0	(547.0)	3.582	3.582	(19,590.85)
		547.0	0.0	0.0	547.0	3.618	3.618	19,790.35
AUBURNDALE POWER PARTNERS	COGEN.	(400.0)	0.0	0.0	(400.0)	3.484	3.484	(13,936.00)
		400.0	0.0	0.0	400.0	4.105	4.105	16,418.10
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF: JANUARY 2003		0.0	0.0	0.0	0.0	0.000	0.000	35,465.51
GRAND TOTAL		**49,744.0**	**0.0**	**0.0**	**49,744.0**	**2.710**	**2.710**	**1,347,837.47**
CURRENT MONTH:								
DIFFERENCE		10,277.0	0.0	0.0	10,277.0	0.116	0.116	324,237.47
DIFFERENCE %		26.0%	0.0%	0.0%	26.0%	4.5%	4.5%	31.7%
PERIOD TO DATE:								
ACTUAL		147,823.0	0.0	0.0	147,823.0	2.554	2.554	3,775,331.09
ESTIMATED		121,545.0	0.0	0.0	121,545.0	2.574	2.574	3,128,965.12
DIFFERENCE		26,278.0	0.0	0.0	26,278.0	(0.020)	(0.020)	646,365.97
DIFFERENCE %		21.6%	0.0%	0.0%	21.6%	(0.008)	(0.008)	20.7%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

APRIL 2003

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	36,891,645	41,660,745	(4,769,100)	-11.4%	1,302,771	1,413,271	(110,500)	-7.8%	2.83178	2.94782	(0.11604)	-3.9%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(6,002)	(6,000)	(2)	0.0%	1,302,771 (a)	1,413,271 (a)	(110,500)	-7.8%	(0.00046)	(0.00042)	(0.00004)	8.5%
4b. Adjustments to Fuel Cost	(1,081)	0	(1,081)	0.0%	1,302,771 (a)	1,413,271 (a)	(110,500)	-7.8%	(0.00008)	0.00000	(0.00008)	0.0%
4c. Incremental Hedging O&M Costs	0	34,583	(34,583)	-100.0%	1,302,771 (a)	1,413,271 (a)	(110,500)	-7.8%	0.00000	0.00245	(0.00245)	-100.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**36,884,562**	**41,689,328**	**(4,804,766)**	**-11.5%**	**1,302,771**	**1,413,271**	**(110,500)**	**-7.8%**	**2.83124**	**2.94985**	**(0.11861)**	**-4.0%**
6. Fuel Cost of Purchased Power - Firm (A7)	8,169,033	3,568,000	4,601,033	129.0%	155,794	62,819	92,975	148.0%	5.24348	5.67981	(0.43633)	-7.7%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,168,907	1,072,300	96,607	9.0%	50,046	40,097	9,949	24.8%	2.33567	2.67426	(0.33860)	-12.7%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**9,337,940**	**4,640,300**	**4,697,640**	**101.2%**	**205,840**	**102,916**	**102,924**	**100.0%**	**4.53650**	**4.50882**	**0.02768**	**0.6%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,508,611**	**1,516,187**	**(7,576)**	**-0.5%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	68,661	68,400	261	0.4%	2,350	2,879	(529)	-18.4%	2.92174	2.37582	0.54592	23.0%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	397,882	2,717,600	(2,319,718)	-85.4%	13,598	73,701	(60,103)	-81.5%	2.92603	3.68733	(0.76130)	-20.6%
19. Gains on Market Based Sales	67,489	913,600	(846,111)	-92.6%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**534,032**	**3,699,600**	**(3,165,568)**	**-85.6%**	**15,948**	**76,580**	**(60,632)**	**-79.2%**	**3.34858**	**4.83103**	**(1.48244)**	**-30.7%**
21. Net Inadvertant Interchange					1,661	0	1,661	0.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					520	0	520	0.0%				
23. Interchange and Wheeling Losses					1,809	1,100	709	64.5%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**45,688,470**	**42,630,028**	**3,058,442**	**7.2%**	**1,493,035**	**1,438,507**	**54,528**	**3.8%**	**3.06011**	**2.96349**	**0.09662**	**3.3%**
25. Net Unbilled	1,440,607 (a)	909,407 (a)	531,200	58.4%	47,077	30,687	16,390	53.4%	3.06011	2.96349	0.09662	3.3%
26. Company Use	121,731 (a)	118,540 (a)	3,191	2.7%	3,978	4,000	(22)	-0.6%	3.06011	2.96350	0.09661	3.3%
27. T & D Losses	1,714,119 (a)	1,044,957 (a)	669,162	64.0%	56,016	35,261	20,754	58.9%	3.06011	2.96349	0.09661	3.3%
28. System KWH Sales	45,688,470	42,630,028	3,058,442	7.2%	1,385,965	1,368,559	17,406	1.3%	3.29651	3.11496	0.18155	5.8%
29. Wholesale KWH Sales	(1,466,718)	(1,288,876)	(177,842)	13.8%	(44,493)	(41,377)	(3,116)	7.5%	3.29651	3.11496	0.18156	5.8%
30. Jurisdictional KWH Sales	44,221,752	41,341,152	2,880,600	7.0%	1,341,472	1,327,182	14,290	1.1%	3.29651	3.11496	0.18155	5.8%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	44,272,165	41,388,281	2,883,884	7.0%	1,341,472	1,327,182	14,290	1.1%	3.30027	3.11851	0.18176	5.8%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	268,358	268,876	(518)	-0.2%	1,341,472	1,327,182	14,290	1.1%	0.02000	0.02026	(0.00025)	-1.3%
34. Adjustment	0	0	0	0.0%	1,341,472	1,327,182	14,290	1.1%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	1,341,472	1,327,182	14,290	1.1%	0.00000	0.00000	0.00000	0.0%
36. True-up *	263,799	263,799	0	0.0%	1,341,472	1,327,182	14,290	1.1%	0.01966	0.01988	(0.00021)	-1.1%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	44,804,322	41,920,956	2,883,366	6.9%	1,341,472	1,327,182	14,290	1.1%	3.33994	3.15864	0.18129	5.7%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.34234	3.16092	0.18142	5.7%
40. GPIF * (Already Adjusted for Taxes)	(69,252)	(69,203)	(49)	0.1%	1,341,472	1,327,182	14,290	1.1%	(0.00516)	(0.00521)	0.00005	-1.0%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**44,735,070**	**41,851,753**	**2,883,317**	**6.9%**	**1,341,472**	**1,327,182**	**14,290**	**1.1%**	**3.33718**	**3.15571**	**0.18147**	**5.8%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.337**	**3.156**	**0.181**	**5.7%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: APRIL 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	126,154,238	132,711,713	(6,557,475)	-4.9%	4,978,718	5,190,308	(211,590)	-4.1%	2.53387	2.55691	(0.02304)	-0.9%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(21,750)	(24,108)	2,358	-9.8%	4,978,718 (a)	5,190,308 (a)	(211,590)	-4.1%	(0.00044)	(0.00046)	0.00003	-5.9%
4b. Adjustments to Fuel Cost	(7,954)	(2,738)	(5,216)	190.5%	4,978,718 (a)	5,190,308 (a)	(211,590)	-4.1%	(0.00016)	(0.00005)	(0.00011)	202.8%
4c. Adjustments to Fuel Cost	0	103,749	(103,749)	-100.0%	4,978,718 (a)	5,190,308 (a)	(211,590)	-4.1%	0.00000	0.00200	(0.00200)	-100.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**126,124,534**	**132,788,616**	**(6,664,082)**	**-5.0%**	**4,978,718**	**5,190,308**	**(211,590)**	**-4.1%**	**2.53327**	**2.55840**	**(0.02512)**	**-1.0%**
6. Fuel Cost of Purchased Power - Firm (A7)	44,120,196	31,150,840	12,969,356	41.6%	779,108	572,063	207,045	36.2%	5.66291	5.44535	0.21756	4.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	4,944,238	4,201,265	742,973	17.7%	197,869	161,642	36,227	22.4%	2.49874	2.59912	(0.10037)	-3.9%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**49,064,434**	**35,352,105**	**13,712,329**	**38.8%**	**976,977**	**733,705**	**243,272**	**33.2%**	**5.02207**	**4.81830**	**0.20377**	**4.2%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**5,955,695**	**5,924,013**	**31,682**	**0.5%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	219,309	254,207	(34,898)	-13.7%	8,733	10,885	(2,152)	-19.8%	2.51127	2.33539	0.17588	7.5%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	1,928	4,680	(2,752)	-58.8%	60	46	14	30.4%	3.21333	10.17391	(6.96058)	-68.4%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	121,809	108,975	12,834	11.8%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	2,087,864	4,228,740	(2,140,876)	-50.6%	70,277	124,439	(54,162)	-43.5%	2.97091	3.39824	(0.42734)	-12.6%
19. Gains on Market Based Sales	568,553	1,452,494	(883,941)	-60.9%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**2,999,463**	**6,049,096**	**(3,049,633)**	**-50.4%**	**79,070**	**135,370**	**(56,300)**	**-41.6%**	**3.79343**	**4.46856**	**(0.67514)**	**-15.1%**
21. Net Inadvertant Interchange					1,254	(291)	1,545	-530.9%				
22. Wheeling Rec'd. less Wheeling Del'd.					565	652	(87)	-13.3%				
23. Interchange and Wheeling Losses					3,085	2,096	989	47.2%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**172,189,505**	**162,091,625**	**10,097,880**	**6.2%**	**5,875,359**	**5,786,908**	**88,451**	**1.5%**	**2.93071**	**2.80101**	**0.12970**	**4.6%**
25. Net Unbilled	3,027,223 (a)	3,841,693 (a)	(814,470)	-21.2%	78,458	130,012	(51,554)	-39.7%	3.85840	2.95488	0.90352	30.6%
26. Company Use	449,772 (a)	449,559 (a)	213	0.0%	15,390	16,099	(709)	-4.4%	2.92250	2.79247	0.13003	4.7%
27. T & D Losses	4,646,757 (a)	3,236,504 (a)	1,410,253	43.6%	153,601	114,525	39,076	34.1%	3.02521	2.82602	0.19919	7.0%
28. System KWH Sales	172,189,505	162,091,625	10,097,880	6.2%	5,627,910	5,526,272	101,638	1.8%	3.05956	2.93311	0.12645	4.3%
29. Wholesale KWH Sales	(5,711,886)	(4,060,115)	(1,651,771)	40.7%	(183,203)	(135,141)	(48,062)	35.6%	3.11779	3.00435	0.11344	3.8%
30. Jurisdictional KWH Sales	166,477,619	158,031,510	8,446,109	5.3%	5,444,707	5,391,131	53,576	1.0%	3.05760	2.93132	0.12628	4.3%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	166,667,404	158,211,666	8,455,738	5.3%	5,444,707	5,391,131	53,576	1.0%	3.06109	2.93467	0.12642	4.3%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	1,087,419	1,097,025	(9,606)	-0.9%	5,444,707	5,391,131	53,576	1.0%	0.01997	0.02035	(0.00038)	-1.9%
34. Adjustment	0	0	0	0.0%	5,444,707	5,391,131	53,576	1.0%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	5,444,707	5,391,131	53,576	1.0%	0.00000	0.00000	0.00000	0.0%
36. True-up *	1,055,196	1,055,196	0	0.0%	5,444,707	5,391,131	53,576	1.0%	0.01938	0.01957	(0.00019)	-1.0%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	168,810,019	160,363,887	8,446,132	5.3%	5,444,707	5,391,131	53,576	1.0%	3.10044	2.97459	0.12586	4.2%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.10267	2.97673	0.12594	4.2%
40. GPIF * (Already Adjusted for Taxes)	(276,219)	(276,812)	593	-0.2%	5,444,707	5,391,131	53,576	1.0%	(0.00507)	(0.00513)	0.00006	-1.2%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**168,533,800**	**160,087,075**	**8,446,725**	**5.3%**	**5,444,707**	**5,391,131**	**53,576**	**1.0%**	**3.09760**	**2.97160**	**0.12600**	**4.2%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.098**	**2.972**	**0.126**	**4.2%**

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: APRIL 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	36,891,645	41,660,745	(4,769,100)	-11.4%	126,154,238	132,711,713	(6,557,475)	-4.9%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	466,543	2,786,000	(2,319,457)	-83.3%	2,430,910	4,596,602	(2,165,692)	-47.1%
2a. GAINS FROM MARKET BASED SALES	67,489	913,600	(846,111)	-92.6%	568,553	1,452,494	(883,941)	-60.9%
3. FUEL COST OF PURCHASED POWER	8,169,033	3,568,000	4,601,033	129.0%	44,120,196	31,150,840	12,969,356	41.6%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,168,907	1,072,300	96,607	9.0%	4,944,238	4,201,265	742,973	17.7%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	45,695,553	42,601,445	3,094,108	7.3%	172,219,209	162,014,722	10,204,487	6.3%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(6,002)	(6,000)	(2)	0.0%	(21,750)	(24,108)	2,358	-9.8%
6b. ADJ.TO FUEL COST	(1,081)	0	(1,081)	0.0%	(7,954)	(2,738)	(5,216)	190.5%
6c. INCREMENTAL HEDGING O&M COSTS	0	34,583	(34,583)	-100.0%	0	103,749	(103,749)	-100.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	45,688,470	42,630,028	3,058,442	7.2%	172,189,505	162,091,625	10,097,880	6.2%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,341,472	1,327,182	14,290	1.1%	5,444,707	5,391,131	53,576	1.0%
2. NONJURISDICTIONAL SALES	44,493	41,377	3,116	7.5%	183,203	135,141	48,062	35.6%
3. TOTAL SALES	1,385,965	1,368,559	17,406	1.3%	5,627,910	5,526,272	101,638	1.8%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9678975	0.9697660	(0.0018685)	-0.2%	0.9674474	0.9755457	(0.0080983)	-0.8%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	45,646,859	45,515,229	131,630	0.3%	167,397,220	166,903,227	493,993	0.3%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(263,799)	(263,799)	0	0.0%	(1,055,196)	(1,055,196)	0	0.0%
2b. INCENTIVE PROVISION	69,252	69,203	49	0.1%	276,219	276,812	(593)	-0.2%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	45,452,312	45,320,633	131,679	0.3%	166,618,243	166,124,843	493,400	0.3%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE	45,688,470	42,630,028	3,058,442	7.2%	172,189,505	162,091,625	10,097,880	6.2%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINI	0.9678975	0.9697660	(0.0018685)	-0.2%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	44,221,752	41,341,152	2,880,600	7.0%	166,477,619	158,031,510	8,446,109	5.3%
6a. JURISDIC. LOSS MULTIPLIER	1.00114	1.00114	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	44,272,165	41,388,281	2,883,884	7.0%	166,667,404	158,211,666	8,455,738	5.3%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	277,259	277,259	0	0.0%	1,124,222	1,124,222	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	268,358	268,876	(518)	-0.2%	1,087,419	1,097,025	(9,606)	-0.9%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	44,540,523	41,657,157	2,883,366	6.9%	167,754,823	159,308,691	8,446,132	5.3%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	911,789	3,663,476	(2,751,687)	-75.1%	(1,136,580)	6,816,152	(7,952,732)	-116.7%
8. INTEREST PROVISION FOR THE MONTH	(32,267)	(28,099)	(4,168)	14.8%	(128,214)	(125,676)	(2,538)	2.0%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(33,180,837)	(27,981,422)	(5,199,415)	18.6%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	263,799	263,799	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(32,037,516)	(24,082,246)	(7,955,270)	33.0%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(33,180,837)	(27,981,422)	(5,199,415)	18.6%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(32,005,249)	(24,054,147)	(7,951,102)	33.1%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(65,186,086)	(52,035,569)	(13,150,517)	25.3%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(32,593,043)	(26,017,785)	(6,575,258)	25.3%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.180	1.300	(0)	-9.2%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.190	1.300	(0)	-8.5%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	2.370	2.600	(0)	-8.8%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.185	1.300	(0)	-8.8%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.099	0.108	(0)	-8.3%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(32,267)	(28,099)	(4,168)	14.8%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	64,717	154,300	(89,583)	-58.1%	1,549,384	1,059,081	490,303	46.3%
2	LIGHT OIL	828,657	569,500	259,157	45.5%	4,043,997	3,312,411	731,586	22.1%
3	COAL	23,369,261	24,011,316	(642,055)	-2.7%	99,283,251	100,928,265	(1,645,014)	-1.6%
4	NATURAL GAS	12,629,010	16,925,629	(4,296,619)	-25.4%	21,277,606	27,411,956	(6,134,350)	-22.4%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	36,891,645	41,660,745	(4,769,100)	-11.4%	126,154,238	132,711,713	(6,557,475)	-4.9%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	681	2,831	(2,150)	-75.9%	26,267	19,343	6,924	35.8%
9	LIGHT OIL	6,466	7,326	(860)	-11.7%	59,523	51,539	7,984	15.5%
10	COAL	1,059,825	1,087,933	(28,108)	-2.6%	4,587,280	4,627,670	(40,390)	-0.9%
11	NATURAL GAS	235,799	315,181	(79,382)	-25.2%	305,648	491,756	(186,108)	-37.8%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,302,771	1,413,271	(110,500)	-7.8%	4,978,718	5,190,308	(211,590)	-4.1%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	1,619	4,265	(2,646)	-62.0%	40,622	29,255	11,367	38.9%
16	LIGHT OIL (BBL)	18,932	13,415	5,517	41.1%	104,297	85,358	18,939	22.2%
17	COAL (TON)	491,369	495,526	(4,157)	-0.8%	2,133,740	2,128,700	5,040	0.2%
18	NATURAL GAS (MCF)	1,743,750	2,322,849	(579,099)	-24.9%	2,552,750	3,660,964	(1,108,214)	-30.3%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	10,158	27,360	(17,202)	-62.9%	254,841	185,882	68,959	37.1%
22	LIGHT OIL	88,319	77,676	10,643	13.7%	584,105	496,046	88,059	17.8%
23	COAL	11,811,605	11,992,032	(180,427)	-1.5%	50,770,004	51,029,257	(259,253)	-0.5%
24	NATURAL GAS	1,844,887	2,387,968	(543,081)	-22.7%	2,702,207	3,767,740	(1,065,533)	-28.3%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	13,754,969	14,485,036	(730,067)	-5.0%	54,311,157	55,478,925	(1,167,768)	-2.1%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.05%	0.20%	(0.00)	-	0.53%	0.37%	0.00	-
29	LIGHT OIL	0.50%	0.52%	(0.00)	-	1.20%	0.99%	0.00	-
30	COAL	81.35%	76.98%	0.04	-	92.14%	89.16%	0.03	-
31	NATURAL GAS	18.10%	22.30%	(0.04)	-	6.14%	9.47%	(0.03)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	39.97	36.18	3.80	10.5%	38.14	36.20	1.94	5.4%
36	LIGHT OIL ($/BBL)	43.77	42.45	1.32	3.1%	38.77	38.81	(0.03)	-0.1%
37	COAL ($/TON)	47.56	48.46	(0.90)	-1.9%	46.53	47.41	(0.88)	-1.9%
38	NATURAL GAS ($/MCF)	7.24	7.29	(0.04)	-0.6%	8.34	7.49	0.85	11.3%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	6.37	5.64	0.73	13.0%	6.08	5.70	0.38	6.7%
42	LIGHT OIL	9.38	7.33	2.05	28.0%	6.92	6.68	0.25	3.7%
43	COAL	1.98	2.00	(0.02)	-1.2%	1.96	1.98	(0.02)	-1.1%
44	NATURAL GAS	6.85	7.09	(0.24)	-3.4%	7.87	7.28	0.60	8.2%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.68	2.88	(0.19)	-6.7%	2.32	2.39	(0.07)	-2.9%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	14,916	9,664	5,252	54.3%	9,702	9,610	92	1.0%
49	LIGHT OIL	13,659	10,603	3,056	28.8%	9,813	9,625	188	2.0%
50	COAL	11,145	11,023	122	1.1%	11,068	11,027	41	0.4%
51	NATURAL GAS	7,824	7,576	248	3.3%	8,841	7,662	1,179	15.4%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,558	10,249	309	3.0%	10,909	10,689	220	2.1%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	9.50	5.45	4.05	74.3%	5.90	5.48	0.42	7.7%
56	LIGHT OIL	12.82	7.77	5.05	65.0%	6.79	6.43	0.36	5.6%
57	COAL	2.21	2.21	0.00	0.0%	2.16	2.18	(0.02)	-0.9%
58	NATURAL GAS	5.36	5.37	(0.01)	-0.2%	6.96	5.57	1.39	25.0%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.83	2.95	(0.12)	-4.1%	2.53	2.56	(0.03)	-1.2%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: APRIL 2003

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(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	75	7,580	14.1	98.2	87.3	11,247	COAL	3,613	23,598,000	85,259.6	154,597	2.04	42.79
GAN.#2	100	7,082	9.8	95.6	58.9	11,811	COAL	3,520	23,762,000	83,642.2	150,617	2.13	42.79
GAN.#3	150	24,103	22.3	34.1	63.7	12,383	COAL	12,478	23,920,000	298,473.8	533,921	2.22	42.79
GAN.#4	164	53,574	45.4	65.0	69.1	12,496	COAL	27,837	24,050,000	669,479.9	1,191,117	2.22	42.79
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	353	98,704	38.9	51.6	69.3	11,713	COAL	47,942	24,116,000	1,156,169.3	2,051,389	2.08	42.79
GANNON STATION	**842**	**191,043**	**31.6**	**60.5**	**68.6**	**12,003**	**COAL**	**95,390**	**24,038,419**	**2,293,024.8**	**4,081,641**	**2.14**	**42.79**
B.B.#1	421	211,988	70.0	82.5	70.0	11,232	COAL	97,089	24,525,000	2,381,099.0	4,730,045	2.23	48.72
B.B.#2	411	227,232	76.9	88.8	80.1	10,673	COAL	99,085	24,477,320	2,425,331.6	4,827,288	2.12	48.72
B.B.#3	428	208,037	67.6	79.5	78.7	10,626	COAL	91,020	24,287,180	2,210,617.3	4,434,372	2.13	48.72
B.B.#4	452	212,390	65.4	76.7	81.3	10,634	COAL	99,782	22,634,780	2,258,550.0	4,861,245	2.29	48.72
B.B. STATION	**1,712**	**859,647**	**69.8**	**81.7**	**77.6**	**10,790**	**COAL**	**386,976**	**23,969,458**	**9,275,597.9**	**18,852,950**	**2.19**	**48.72**
SEB-PHIL. #1(HVY OIL)	17	676	5.5	44.2	58.4	14,916	HVY.OIL	1,607	6,273,540	10,081.1	64,237	9.50	39.97
SEB-PHIL. #2(HVY OIL)	17	5	0.0	1.0	34.1	14,924	HVY.OIL	12	6,273,540	76.5	480	9.60	40.00
SEB-PHILLIPS TOTAL	**34**	**681**	**2.8**	**22.6**	**46.3**	**14,916**	**HVY.OIL**	**1,619**	**6,273,570**	**10,157.6**	**64,717**	**9.50**	**39.97**
POLK #1 GASIFIER	255	9,135	5.0	13.5	35.7	26,600	COAL	9,003	26,990,000	242,982.1	434,670	4.76	48.28
POLK #1 CT (OIL)	225	6,378	3.9	37.6	28.9	13,280	LGT.OIL	18,307	5,781,808	84,703.1	743,433	11.66	40.61
POLK #1 TOTAL	**255**	**15,513**	**8.5**	**34.4**	**32.6**	**21,123**	**-**	**-**	**-**	**327,685.2**	**1,178,103**	**7.59**	**-**
POLK #2 CT (GAS)	150	11,467	10.6	98.7	78.4	10,928	GAS	118,444	1,058,000	125,314.0	696,751	6.08	5.88
POLK #2 CT (OIL)	160	32	0.0	86.0	0.9	66,677	LGT.OIL	367	5,781,815	2,122.6	14,908	46.59	40.62
POLK #2 TOTAL	**155**	**11,499**	**10.3**	**99.1**	**63.9**	**11,082**	**-**	**-**	**-**	**127,436.6**	**711,659**	**6.19**	**-**
POLK #3 CT (GAS)	150	18,227	16.9	99.0	78.7	11,874	GAS	204,566	1,058,000	216,431.0	1,201,751	6.59	5.87
POLK #3 CT (OIL)	165	53	0.0	89.4	20.8	26,546	LGT.OIL	242	5,781,811	1,398.6	9,823	18.53	40.59
POLK #3 TOTAL	**158**	**18,280**	**16.1**	**99.0**	**78.1**	**11,916**	**-**	**-**	**-**	**217,829.6**	**1,211,574**	**6.63**	**-**
POLK STATION TOTAL	**568**	**45,292**	**11.1**	**70.0**	**53.8**	**14,858**	**-**	**-**	**-**	**672,951.4**	**3,101,336**	**6.85**	**-**
B.B.C.T.#1	14	3	0.0	100.0	100.0	31,633	LGT.OIL	16	5,861,025	94.9	60,493	2016.43	3780.81
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**140**	**3**	**0.0**	**100.0**	**18.9**	**31,633**	**LGT.OIL**	**16**	**5,861,643**	**94.9**	**60,493**	**2016.43**	**3780.81**
CITY OF TAMPA	**6**	**502**	**11.6**	**0.0**	**0.0**	**10,481**	**GAS**	**4,973**	**1,058,000**	**5,261.4**	**39,864**	**7.94**	**8.02**
BAYSIDE ST 1	246	63,660	63.9	78.1	81.8	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	30,006	48.9	52.7	92.5	10,555	GAS	299,357	1,058,000	316,720.2	2,260,484	7.53	7.55
BAYSIDE CT1B	148	50,582	84.8	99.1	85.6	10,556	GAS	504,683	1,058,000	533,954.1	3,810,928	7.53	7.55
BAYSIDE CT1C	148	61,360	80.9	61.2	132.2	10,548	GAS	611,727	1,058,000	647,206.7	4,619,231	7.53	7.55
BAYSIDE UNIT 1 TOTAL	**690**	**205,608**	**68.8**	**73.5**	**95.7**	**7,285**	**GAS**	**########**	**1,058,000**	**1,497,881.0**	**10,690,644**	**5.20**	**7.55**
BAYSIDE UNIT 2 TOTAL	**0**	**-5**	**-**	**-**	**-**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE STATION TOTAL	**690**	**205,603**	**41.4**	**73.5**	**95.7**	**7,285**	**GAS**	**########**	**1,058,000**	**1,497,881.0**	**10,690,644**	**5.20**	**7.55**
TOT. COAL (GN,BB,POLK)	**2,809**	**1,059,825**	**52.5**	**69.2**	**71.1**	**11,145**	**COAL**	**491,369**	**24,038,187**	**11,811,604.8**	**23,369,261**	**2.21**	**47.56**
SYSTEM	**3,992**	**1,302,771**	**45.4**	**75.5**	**74.3**	**10,558**	**-**	**-**	**-**	**13,754,969.0**	**36,891,645**	**2.83**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2003

SCHEDULE A5
PAGE 1 OF 2
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	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	4,075	4,265	(190)	-4.5%	43,118	27,976	15,142	54.1%
3 UNIT COST ($/BBL)	43.81	34.05	9.76	28.7%	37.76	34.45	3.31	9.6%
4 AMOUNT ($)	178,540	145,223	33,317	22.9%	1,628,182	963,820	664,362	68.9%
5 BURNED:								
6 UNITS (BBL)	1,619	4,265	(2,646)	-62.0%	40,622	29,255	11,367	38.9%
7 UNIT COST ($/BBL)	39.97	36.18	3.80	10.5%	38.14	36.20	1.94	5.4%
8 AMOUNT ($)	64,717	154,300	(89,583)	-58.1%	1,549,384	1,059,081	490,303	46.3%
9 ENDING INVENTORY:								
10 UNITS (BBL)	13,238	9,463	3,775	39.9%	13,238	9,463	3,775	39.9%
11 UNIT COST ($/BBL)	40.87	35.18	5.69	16.2%	40.87	35.18	5.69	16.2%
12 AMOUNT ($)	541,052	332,899	208,153	62.5%	541,052	332,899	208,153	62.5%
13								
14 DAYS SUPPLY:	36	25	11	43.6%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	36,067	18,731	17,336	92.6%	133,253	107,812	25,441	23.6%
17 UNIT COST ($/BBL)	35.74	44.10	(8.37)	-19.0%	40.96	42.89	(1.93)	-4.5%
18 AMOUNT ($)	1,288,908	826,117	462,791	56.0%	5,457,688	4,624,113	833,575	18.0%
19 BURNED:								
20 UNITS (BBL)	18,932	13,415	5,517	41.1%	104,297	85,358	18,939	22.2%
21 UNIT COST ($/BBL)	43.77	42.45	1.32	3.1%	38.77	38.81	(0.03)	-0.1%
22 AMOUNT ($)	828,657	569,500	259,157	45.5%	4,043,997	3,312,411	731,586	22.1%
23 ENDING INVENTORY:								
24 UNITS (BBL)	77,484	82,746	(5,262)	-6.4%	77,484	82,746	(5,262)	-6.4%
25 UNIT COST ($/BBL)	37.74	39.18	(1.44)	-3.7%	37.74	39.18	(1.44)	-3.7%
26 AMOUNT ($)	2,924,372	3,241,804	(317,432)	-9.8%	2,924,372	3,241,804	(317,432)	-9.8%
27								
28 DAYS SUPPLY: NORMAL	110	119	(9)	-7.7%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	11	12	(1)	-6.4%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	663,934	596,300	67,634	11.3%	2,368,180	2,571,673	(203,493)	-7.9%
32 UNIT COST ($/TON)	48.19	48.15	0.05	0.1%	47.49	47.72	(0.23)	-0.5%
33 AMOUNT ($)	31,995,557	28,709,250	3,286,307	11.4%	112,466,387	122,725,448	(10,259,061)	-8.4%
34 BURNED:								
35 UNITS (TONS)	491,369	495,526	(4,157)	-0.8%	2,133,740	2,128,700	5,040	0.2%
36 UNIT COST ($/TON)	47.56	48.46	(0.90)	-1.9%	46.53	47.41	(0.88)	-1.9%
37 AMOUNT ($)	23,369,261	24,011,316	(642,055)	-2.7%	99,283,251	100,928,265	(1,645,014)	-1.6%
38 ENDING INVENTORY:								
39 UNITS (TONS)	672,797	881,330	(208,533)	-23.7%	672,797	881,330	(208,533)	-23.7%
40 UNIT COST ($/TON)	47.47	47.49	(0.02)	0.0%	47.47	47.49	(0.02)	0.0%
41 AMOUNT ($)	31,940,620	41,857,714	(9,917,094)	-23.7%	31,940,620	41,857,714	(9,917,094)	-23.7%
42								
43 DAYS SUPPLY:	33	44	(11)	-23.9%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	1,743,750	2,322,849	(579,099)	-24.9%	2,552,750	3,660,964	(1,108,214)	-30.3%
46 UNIT COST ($/MCF)	7.24	7.29	(0.04)	-0.6%	8.34	7.49	0.85	11.3%
47 AMOUNT ($)	12,629,010	16,925,628	(4,296,618)	-25.4%	21,277,606	27,411,955	(6,134,349)	-22.4%
48 BURNED:								
49 UNITS (MCF)	1,743,750	2,322,849	(579,099)	-24.9%	2,552,750	3,660,964	(1,108,214)	-30.3%
50 UNIT COST ($/MCF)	7.24	7.29	(0.04)	-0.6%	8.34	7.49	0.85	11.3%
51 AMOUNT ($)	12,629,010	16,925,629	(4,296,619)	-25.4%	21,277,606	27,411,956	(6,134,350)	-22.4%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	3,273
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	3,273

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(6,288)	(225,783)
OTHER USAGE	(1,696)	(65,040)
TOTAL	(7,984)	(290,823)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	51,232
IGNITION #2 OIL	222,510
IGNITION PROPANE	18,553
AERIAL SURVEY ADJ.	(523,022)
ADDITIVES	11,505
GREEN FUEL	0
TOTAL	(219,222)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2003

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	2,879.0	0.0	2,879.0	2.376	2.376	68,400.00	68,400.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. - MB	73,701.0	0.0	73,701.0	3.687	5.249	2,717,600.00	3,868,500.00	913,600.00
TOTAL			**76,580.0**	**0.0**	**76,580.0**	**3.638**	**5.141**	**2,786,000.00**	**3,936,900.00**	**913,600.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	1,242.3	1.3	1,241.0	3.123	3.123	38,756.36	38,756.36	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	1,109.0	0.0	1,109.0	2.697	2.697	29,904.39	29,904.39	
FLA. PWR. CORP.		SCH. - MA	230.0	0.0	230.0	1.994	2.240	4,586.95	5,151.57	(318.56)
FLA. PWR. & LIGHT		SCH. - MA	5,800.0	0.0	5,800.0	1.823	2.480	105,723.00	143,842.90	15,847.90
CITY OF LAKELAND		SCH. - MA	1,610.0	0.0	1,610.0	1.872	3.526	30,135.50	56,766.08	20,448.18
SEMINOLE ELEC. CO-OP		SCH. - MA	990.0	0.0	990.0	2.649	3.716	26,225.95	36,791.29	6,763.74
THE ENERGY AUTHORITY		SCH. - MA	31.0	0.0	31.0	4.469	4.899	1,385.39	1,518.75	14.32
CARGILL ALLIANT		SCH. - MA	82.0	0.0	82.0	1.585	1.798	1,299.70	1,474.63	(139.96)
NEW SMYRNA BEACH		SCH. - MA	1,800.0	0.0	1,800.0	6.557	7.580	118,020.00	136,433.37	11,501.37
ORLANDO UTILITIES		SCH. - MA	2,645.0	0.0	2,645.0	3.489	4.268	92,273.85	112,892.42	10,461.77
HARDEE PWR. PART. TO FLA. PWR. CORP.*		SCH. - MA	50.0	0.0	50.0	4.085	4.490	2,042.50	2,245.21	195.71
HARDEE PWR. PART. TO FLA. PWR. & LIGHT*		SCH. - MA	300.0	0.0	300.0	4.023	4.814	12,069.35	14,441.20	2,329.85
HARDEE PWR. PART. TO CITY OF LAKELAND.*		SCH. - MA	25.0	0.0	25.0	3.970	4.105	992.50	1,026.18	30.18
HARDEE PWR. PART. TO THE ENERGY AUTH.*		SCH. - MA	35.0	0.0	35.0	4.018	5.044	1,406.30	1,765.42	354.22
CARGILL ALLIANT		SCH. - OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ADJUSTMENTS										
HPP TO FLA. PWR. & LIGHT	MAR. 2003	SCH. - MA	(100.0)	0.0	(100.0)	5.404	0.000	(5,404.00)	(5,404.00)	
HPP TO FLA. PWR. & LIGHT**	MAR. 2003	SCH. - MA	100.0	0.0	100.0	5.549	0.000	5,549.48	5,563.48	
HPP TO THE ENERGY AUTH.	MAR. 2002	SCH. - MA	(180.0)	0.0	(180.0)	5.186	5.186	(9,334.80)	(9,334.80)	
HPP TO THE ENERGY AUTH.**	MAR. 2003	SCH. - MA	180.0	0.0	180.0	6.062	6.076	10,910.72	10,935.92	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			2,351.3	1.3	2,350.0	2.922	2.922	68,660.75	68,660.75	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			13,598.0	0.0	13,598.0	2.926	3.795	397,882.39	516,109.62	67,488.70
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL			**15,949.3**	**1.3**	**15,948.0**	**2.925**	**3.667**	**466,543.14**	**584,770.37**	**67,488.70**
CURRENT MONTH:										
DIFFERENCE			(60,630.7)	1.3	(60,632.0)	(0.713)	(1.474)	(2,319,456.86)	(3,352,129.63)	(846,111.30)
DIFFERENCE %			-79.2%	0.0%	-79.2%	-19.6%	-28.7%	-83.3%	-85.1%	-92.6%
PERIOD TO DATE:										
ACTUAL			79,130.4	61.3	79,069.1	3.074	4.139	2,430,909.29	3,272,277.06	568,552.78
ESTIMATED			135,374.9	5.3	135,369.6	3.396	4.786	4,596,601.69	6,479,217.12	1,452,494.33
DIFFERENCE			(56,244.5)	56.0	(56,300.5)	(0.322)	(0.647)	(2,165,692.40)	(3,206,940.06)	(883,941.55)
DIFFERENCE %			-41.5%	1056.6%	-41.6%	-9.5%	-13.5%	-47.1%	-49.5%	-60.9%

* SEC 60% PROFIT OR $4,364.95 HAS BEEN EXCLUDED.
** SALES TO HARDEE POWER PARTNERS FOR OTHERS INCLUDES TEC 40% PROFIT. SEC 60% PROFIT OR $2,363.88 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	1,322.0	0.0	800.0	522.0	6.3	6.3	32,900.00
HARDEE POWER PARTNERS		IPP	24,660.0	0.0	0.0	24,660.0	6.835	6.835	1,685,500.00
VARIOUS		OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
VARIOUS		MKT. BASE	37,637.0	0.0	0.0	37,637.0	4.914	4.914	1,849,600.00
TOTAL			**63,619.0**	**0.0**	**800.0**	**62,819.0**	**5.680**	**5.680**	**3,568,000.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	42,579.0	0.0	0.0	42,579.0	6.361	6.361	2,708,651.81
HARDEE PWR. PART.-OTHERS		IPP	410.0	0.0	0.0	410.0	4.041	4.041	16,568.05
FLA. POWER CORP.		SCH. - J	12,215.0	0.0	218.0	11,997.0	5.391	5.391	646,760.00
FLA. POWER & LIGHT		SCH. - J	9,773.0	0.0	288.8	9,484.2	4.597	4.597	435,986.98
CITY OF LAKELAND		SCH. - J	1,396.0	0.0	0.0	1,396.0	6.938	6.938	96,849.50
ORLANDO UTIL. COMM.		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CAROLINA POWER & LIGHT		SCH. - J	2,935.0	0.0	0.0	2,935.0	5.721	5.721	167,917.00
THE ENERGY AUTHORITY		SCH. - J	8,399.0	0.0	0.0	8,399.0	5.514	5.514	463,117.00
REEDY CREEK		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
OKEELANTA		SCH. - J	13,160.0	0.0	0.0	13,160.0	4.562	4.562	600,393.60
TALLAHASSEE		SCH. - J	204.0	0.0	0.0	204.0	6.192	6.192	12,632.28
CALPINE		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL ALLIANT		SCH. - J	5,143.0	0.0	0.0	5,143.0	5.798	5.798	298,177.00
CONOCO		SCH. - J	243.0	0.0	0.0	243.0	5.033	5.033	12,230.00
CORAL POWER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RELIANT		SCH. - J	1,593.0	0.0	0.0	1,593.0	9.200	9.200	146,556.00
SEMINOLE ELEC. CO-OP		SCH. - J	3,763.0	0.0	0.0	3,763.0	4.436	4.436	166,928.72
DUKE ENERGY		SCH. - J	1,027.0	0.0	0.0	1,027.0	6.600	6.600	67,782.00
DYNEGY POWER MARKETING		SCH. - J	211.0	0.0	0.0	211.0	6.500	6.500	13,715.00
RINGHAVER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	154,255.33
FLA. POWER CORP.		SCH. - D	53,250.0	0.0	0.0	53,250.0	4.323	4.323	2,302,027.50
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Mar. 2003	IPP	(47,585.0)	0.0	0.0	(47,585.0)	7.211	7.211	(3,431,126.85)
HARDEE PWR. PART.-NATIVE	Mar. 2003	IPP	47,585.0	0.0	0.0	47,585.0	6.609	6.609	3,144,820.86
HARDEE PWR. OTHER	Mar. 2003	IPP	(280.0)	0.0	0.0	(280.0)	5.264	5.264	(14,738.80)
HARDEE PWR. OTHER	Mar. 2003	IPP	280.0	0.0	0.0	280.0	5.278	5.278	14,778.00
FLA. POWER CORP.	Mar. 2003	SCH. - D	(78,500.0)	0.0	0.0	(78,500.0)	2.500	2.500	(3,238,880.00)
FLA. POWER CORP.	Mar. 2003	SCH. - D	78,500.0	0.0	0.0	78,500.0	2.552	2.552	3,308,745.00
FLA. POWER CORP.	Feb. 2003	SCH. - D	(45,900.0)	0.0	0.0	(45,900.0)	(17.797)	(17.797)	(1,962,561.27)
FLA. POWER CORP.	Feb. 2003	SCH. - D	45,900.0	0.0	0.0	45,900.0	0.000	0.000	2,003,412.27
OKEELANTA	Mar. 2003	SCH. - J	(12,198.0)	0.0	0.0	(12,198.0)	0.000	0.000	(578,371.95)
OKEELANTA	Mar. 2003	SCH. - J	12,198.0	0.0	0.0	12,198.0	37.720	37.720	612,408.11
TOTAL			**156,301.0**	**0.0**	**506.8**	**155,794.2**	**5.243**	**5.243**	**8,169,033.14**
CURRENT MONTH:									
DIFFERENCE			92,682.0	0.0	(293.2)	92,975.2	(0.437)	(0.437)	4,601,033.14
DIFFERENCE %			145.7%	0.0%	-36.7%	148.0%	-7.7%	-7.7%	129.0%
PERIOD TO DATE:									
ACTUAL			787,344.0	0.0	8,236.0	779,108.0	5.663	5.663	44,120,195.94
ESTIMATED			577,000.0	0.0	4,937.2	572,062.8	5.445	5.445	31,150,839.59
DIFFERENCE			210,344.0	0.0	3,298.8	207,045.2	0.218	0.218	12,969,356.35
DIFFERENCE %			36.5%	0.0%	66.8%	36.2%	4.0%	4.0%	41.6%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	40,097.0	0.0	0.0	40,097.0	2.674	2.674	1,072,300.00
TOTAL		**40,097.0**	**0.0**	**0.0**	**40,097.0**	**2.674**	**2.674**	**1,072,300.00**
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	18,355.0	0.0	0.0	18,355.0	1.891	1.891	347,106.43
McKAY BAY REFUSE	COGEN.	12,852.0	0.0	0.0	12,852.0	1.891	1.891	243,038.70
ORANGE COGENERATION L.P.	COGEN.	7,590.0	0.0	0.0	7,590.0	1.782	1.782	135,233.28
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	565.0	0.0	0.0	565.0	4.353	4.353	24,596.99
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	163.0	0.0	0.0	163.0	3.565	3.565	5,810.50
IMC-AGRICO-NEW WALES	COGEN.	392.0	0.0	0.0	392.0	3.814	3.814	14,951.44
IMC-AGRICO-S. PIERCE	COGEN.	10,114.0	0.0	0.0	10,114.0	3.734	3.734	377,686.12
AUBURNDALE POWER PARTNERS	COGEN.	15.0	0.0	0.0	15.0	4.276	4.276	641.39
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR APRIL 2003		50,046.0	0.0	0.0	50,046.0	2.296	2.296	1,149,064.85
ADJUSTMENTS FOR THE MONTH OF:	**FEBRUARY 2003**							
HILLSBOROUGH COUNTY	COGEN.	(13,540.0)	0.0	0.0	(13,540.0)	2.110	2.110	(285,649.36)
		13,540.0	0.0	0.0	13,540.0	2.106	2.106	285,149.53
McKAY BAY REFUSE	COGEN.	(11,929.0)	0.0	0.0	(11,929.0)	2.101	2.101	(250,678.87)
		11,929.0	0.0	0.0	11,929.0	2.098	2.098	250,248.07
ORANGE COGENERATION L.P.	COGEN.	(5,152.0)	0.0	0.0	(5,152.0)	2.005	2.005	(103,305.22)
		5,152.0	0.0	0.0	5,152.0	2.000	2.000	103,052.42
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	(1,423.0)	0.0	0.0	(1,423.0)	3.212	3.212	(45,713.66)
		1,423.0	0.0	0.0	1,423.0	3.284	3.284	46,735.06
CARGILL MULBERRY	COGEN.	(8,016.0)	0.0	0.0	(8,016.0)	2.977	2.977	(238,632.26)
		8,016.0	0.0	0.0	8,016.0	3.049	3.049	244,385.99
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	(478.0)	0.0	0.0	(478.0)	2.962	2.962	(14,158.32)
		478.0	0.0	0.0	478.0	3.034	3.034	14,501.42
IMC-AGRICO-NEW WALES	COGEN.	(446.0)	0.0	0.0	(446.0)	2.729	2.729	(12,173.56)
		446.0	0.0	0.0	446.0	2.801	2.801	12,493.69
IMC-AGRICO-S. PIERCE	COGEN.	(9,407.0)	0.0	0.0	(9,407.0)	2.969	2.969	(279,325.01)
		9,407.0	0.0	0.0	9,407.0	3.041	3.041	286,077.17
AUBURNDALE POWER PARTNERS	COGEN.	(350.0)	0.0	0.0	(350.0)	2.063	2.063	(7,220.88)
		350.0	0.0	0.0	350.0	2.135	2.135	7,472.11
CUTRALE CITRUS	COGEN.	(1.0)	0.0	0.0	(1.0)	2.066	2.066	(20.66)
		1.0	0.0	0.0	1.0	1.992	1.992	19.92
SUB-TOTAL FOR THE MONTH OF:	**FEBRUARY 2003**	0.0	0.0	0.0	0.0	0.000	0.000	13,257.58

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ADJUSTMENTS FOR THE MONTH OF:	**MARCH 2003**							
HILLSBOROUGH COUNTY	COGEN.	(12,154.0)	0.0	0.0	(12,154.0)	2.087	2.087	(253,628.10)
		12,154.0	0.0	0.0	12,154.0	2.109	2.109	256,268.24
McKAY BAY REFUSE	COGEN.	(13,334.0)	0.0	0.0	(13,334.0)	2.078	2.078	(277,135.46)
		13,334.0	0.0	0.0	13,334.0	2.099	2.099	279,904.38
ORANGE COGENERATION L.P.	COGEN.	(5,704.0)	0.0	0.0	(5,704.0)	1.947	1.947	(111,035.70)
		5,704.0	0.0	0.0	5,704.0	1.967	1.967	112,211.47
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**MARCH 2003**	0.0	0.0	0.0	0.0	0.000	0.000	6,584.83
GRAND TOTAL		**50,046.0**	**0.0**	**0.0**	**50,046.0**	**2.336**	**2.336**	**1,168,907.26**
CURRENT MONTH:								
DIFFERENCE		9,949.0	0.0	0.0	9,949.0	(0.339)	(0.339)	96,607.26
DIFFERENCE %		24.8%	0.0%	0.0%	24.8%	-12.7%	-12.7%	9.0%
PERIOD TO DATE:								
ACTUAL		197,869.0	0.0	0.0	197,869.0	2.499	2.499	4,944,238.35
ESTIMATED		161,642.0	0.0	0.0	161,642.0	2.599	2.599	4,201,265.12
DIFFERENCE		36,227.0	0.0	0.0	36,227.0	(0.100)	(0.100)	742,973.23
DIFFERENCE %		22.4%	0.0%	0.0%	22.4%	(0.039)	(0.039)	17.7%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

MAY 2003

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	47,178,688	41,847,866	5,330,822	12.7%	1,634,644	1,457,900	176,744	12.1%	2.88618	2.87042	0.01575	0.5%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(8,114)	(6,000)	(2,114)	35.2%	1,634,644 (a)	1,457,900 (a)	176,744	12.1%	(0.00050)	(0.00041)	(0.00008)	20.6%
4b. Adjustments to Fuel Cost	(4,817)	0	(4,817)	0.0%	1,634,644 (a)	1,457,900 (a)	176,744	12.1%	(0.00029)	0.00000	(0.00029)	0.0%
4c. Incremental Hedging O&M Costs	0	34,583	(34,583)	-100.0%	1,634,644 (a)	1,457,900 (a)	176,744	12.1%	0.00000	0.00237	(0.00237)	-100.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**47,165,757**	**41,876,449**	**5,289,308**	**12.6%**	**1,634,644**	**1,457,900**	**176,744**	**12.1%**	**2.88538**	**2.87238**	**0.01300**	**0.5%**
6. Fuel Cost of Purchased Power - Firm (A7)	14,643,590	10,705,300	3,938,290	36.8%	207,734	217,189	(9,455)	-4.4%	7.04920	4.92902	2.12018	43.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	726,725	1,128,300	(401,575)	-35.6%	40,368	41,439	(1,071)	-2.6%	1.80025	2.72280	(0.92255)	-33.9%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**15,370,315**	**11,833,600**	**3,536,715**	**29.9%**	**248,102**	**258,628**	**(10,526)**	**-4.1%**	**6.19516**	**4.57553**	**1.61963**	**35.4%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,882,746**	**1,716,528**	**166,218**	**9.7%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	72,220	72,500	(280)	-0.4%	2,405	2,976	(571)	-19.2%	3.00291	2.43616	0.56675	23.3%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	930	0	930	0.0%	8	0	8	0.0%	11.62500	0.00000	11.62500	0.0%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	529,517	499,100	30,417	6.1%	11,891	8,737	3,154	36.1%	4.45309	5.71249	(1.25940)	-22.0%
19. Gains on Market Based Sales	242,953	94,500	148,453	157.1%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**845,620**	**666,100**	**179,520**	**27.0%**	**14,304**	**11,713**	**2,591**	**22.1%**	**5.91177**	**5.68684**	**0.22493**	**4.0%**
21. Net Inadvertant Interchange					(1,374)	0	(1,374)	0.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					21	0	21	0.0%				
23. Interchange and Wheeling Losses					1,010	200	810	405.0%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**61,690,452**	**53,043,949**	**8,646,503**	**16.3%**	**1,866,079**	**1,704,615**	**161,464**	**9.5%**	**3.30589**	**3.11178**	**0.19410**	**6.2%**
25. Net Unbilled	5,468,829 (a)	4,278,206 (a)	1,190,623	27.8%	165,427	137,484	27,943	20.3%	3.30589	3.11178	0.19410	6.2%
26. Company Use	146,054 (a)	124,471 (a)	21,583	17.3%	4,418	4,000	418	10.5%	3.30589	3.11178	0.19411	6.2%
27. T & D Losses	2,268,202 (a)	3,467,648 (a)	(1,199,446)	-34.6%	68,611	111,436	(42,825)	-38.4%	3.30589	3.11178	0.19410	6.2%
28. System KWH Sales	61,690,452	53,043,949	8,646,503	16.3%	1,627,623	1,451,695	175,928	12.1%	3.79022	3.65393	0.13629	3.7%
29. Wholesale KWH Sales	(2,050,091)	(1,685,010)	(365,081)	21.7%	(54,089)	(46,115)	(7,974)	17.3%	3.79022	3.65393	0.13629	3.7%
30. Jurisdictional KWH Sales	59,640,361	51,358,939	8,281,422	16.1%	1,573,534	1,405,580	167,954	11.9%	3.79022	3.65393	0.13629	3.7%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	59,708,351	51,417,488	8,290,863	16.1%	1,573,534	1,405,580	167,954	11.9%	3.79454	3.65810	0.13644	3.7%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	265,598	266,001	(403)	-0.2%	1,573,534	1,405,580	167,954	11.9%	0.01688	0.01892	(0.00205)	-10.8%
34. Adjustment	0	0	0	0.0%	1,573,534	1,405,580	167,954	11.9%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	1,573,534	1,405,580	167,954	11.9%	0.00000	0.00000	0.00000	0.0%
36. True-up *	263,799	263,799	0	0.0%	1,573,534	1,405,580	167,954	11.9%	0.01676	0.01877	(0.00200)	-10.7%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	60,237,748	51,947,288	8,290,460	16.0%	1,573,534	1,405,580	167,954	11.9%	3.82818	3.69579	0.13239	3.6%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.83094	3.69845	0.13249	3.6%
40. GPIF * (Already Adjusted for Taxes)	(69,252)	(69,203)	(49)	0.1%	1,573,534	1,405,580	167,954	11.9%	(0.00440)	(0.00492)	0.00052	-10.6%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**60,168,496**	**51,878,085**	**8,290,411**	**16.0%**	**1,573,534**	**1,405,580**	**167,954**	**11.9%**	**3.82654**	**3.69353**	**0.13301**	**3.6%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.827**	**3.694**	**0.133**	**3.6%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: MAY 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	173,332,926	174,559,579	(1,226,653)	-0.7%	6,613,362	6,648,208	(34,846)	-0.5%	2.62095	2.62566	(0.00471)	-0.2%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(29,864)	(30,108)	244	-0.8%	6,613,362 (a)	6,648,208 (a)	(34,846)	-0.5%	(0.00045)	(0.00045)	0.00000	-0.3%
4b. Adjustments to Fuel Cost	(12,771)	(2,738)	(10,033)	366.4%	6,613,362 (a)	6,648,208 (a)	(34,846)	-0.5%	(0.00019)	(0.00004)	(0.00015)	368.9%
4c. Adjustments to Fuel Cost	0	138,332	(138,332)	-100.0%	6,613,362 (a)	6,648,208 (a)	(34,846)	-0.5%	0.00000	0.00208	(0.00208)	-100.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**173,290,291**	**174,665,065**	**(1,374,774)**	**-0.8%**	**6,613,362**	**6,648,208**	**(34,846)**	**-0.5%**	**2.62031**	**2.62725**	**(0.00694)**	**-0.3%**
6. Fuel Cost of Purchased Power - Firm (A7)	58,763,786	41,856,140	16,907,646	40.4%	986,842	789,252	197,590	25.0%	5.95473	5.30327	0.65146	12.3%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	5,670,963	5,329,565	341,398	6.4%	238,237	203,081	35,156	17.3%	2.38039	2.62435	(0.24397)	-9.3%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**64,434,749**	**47,185,705**	**17,249,044**	**36.6%**	**1,225,079**	**992,333**	**232,746**	**23.5%**	**5.25964**	**4.75503**	**0.50461**	**10.6%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**7,838,441**	**7,640,541**	**197,900**	**2.6%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	291,529	326,707	(35,178)	-10.8%	11,138	13,861	(2,723)	-19.6%	2.61743	2.35702	0.26040	11.0%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	2,858	4,680	(1,822)	-38.9%	68	46	22	47.8%	4.20294	10.17391	(5.97097)	-58.7%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	121,809	108,975	12,834	11.8%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	2,617,381	4,727,840	(2,110,459)	-44.6%	82,168	133,176	(51,008)	-38.3%	3.18540	3.55007	(0.36467)	-10.3%
19. Gains on Market Based Sales	811,506	1,546,994	(735,488)	-47.5%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**3,845,083**	**6,715,196**	**(2,870,113)**	**-42.7%**	**93,374**	**147,083**	**(53,709)**	**-36.5%**	**4.11794**	**4.56558**	**(0.44765)**	**-9.8%**
21. Net Inadvertant Interchange					(120)	(291)	171	-58.8%				
22. Wheeling Rec'd. less Wheeling Del'd.					586	652	(66)	-10.1%				
23. Interchange and Wheeling Losses					4,095	2,296	1,799	78.4%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**233,879,957**	**215,135,574**	**18,744,383**	**8.7%**	**7,741,439**	**7,491,523**	**249,915**	**3.3%**	**3.02114**	**2.87172**	**0.14942**	**5.2%**
25. Net Unbilled	8,496,052 (a)	8,119,899 (a)	376,153	4.6%	243,885	267,496	(23,611)	-8.8%	3.48363	3.03552	0.44811	14.8%
26. Company Use	595,826 (a)	574,030 (a)	21,796	3.8%	19,808	20,099	(291)	-1.4%	3.00801	2.85601	0.15199	5.3%
27. T & D Losses	6,914,959 (a)	6,704,152 (a)	210,807	3.1%	222,212	225,961	(3,749)	-1.7%	3.11187	2.96695	0.14492	4.9%
28. System KWH Sales	233,879,957	215,135,574	18,744,383	8.7%	7,255,533	6,977,967	277,566	4.0%	3.22347	3.08307	0.14040	4.6%
29. Wholesale KWH Sales	(7,761,977)	(5,745,125)	(2,016,852)	35.1%	(237,292)	(181,256)	(56,036)	30.9%	3.27107	3.16962	0.10145	3.2%
30. Jurisdictional KWH Sales	226,117,980	209,390,449	16,727,531	8.0%	7,018,241	6,796,711	221,530	3.3%	3.22186	3.08076	0.14110	4.6%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	226,375,755	209,629,154	16,746,601	8.0%	7,018,241	6,796,711	221,530	3.3%	3.22553	3.08427	0.14126	4.6%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	1,353,017	1,363,026	(10,009)	-0.7%	7,018,241	6,796,711	221,530	3.3%	0.01928	0.02005	(0.00078)	-3.9%
34. Adjustment	0	0	0	0.0%	7,018,241	6,796,711	221,530	3.3%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	7,018,241	6,796,711	221,530	3.3%	0.00000	0.00000	0.00000	0.0%
36. True-up *	1,318,995	1,318,995	0	0.0%	7,018,241	6,796,711	221,530	3.3%	0.01879	0.01941	(0.00061)	-3.2%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	229,047,767	212,311,175	16,736,592	7.9%	7,018,241	6,796,711	221,530	3.3%	3.26361	3.12373	0.13987	4.5%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.26596	3.12598	0.13998	4.5%
40. GPIF * (Already Adjusted for Taxes)	(345,471)	(346,015)	544	-0.2%	7,018,241	6,796,711	221,530	3.3%	(0.00492)	(0.00509)	0.00017	-3.3%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**228,702,296**	**211,965,160**	**16,737,136**	**7.9%**	**7,018,241**	**6,796,711**	**221,530**	**3.3%**	**3.26104**	**3.12089**	**0.14015**	**4.5%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.261**	**3.121**	**0.140**	**4.5%**

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REVISED WITH
TRUE UP FILING

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	47,178,688	41,847,866	5,330,822	12.7%	173,332,926	174,559,579	(1,226,653)	-0.7%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	602,667	571,600	31,067	5.4%	3,033,577	5,168,202	(2,134,625)	-41.3%
2a. GAINS FROM MARKET BASED SALES	242,953	94,500	148,453	157.1%	811,506	1,546,994	(735,488)	-47.5%
3. FUEL COST OF PURCHASED POWER	14,643,590	10,705,300	3,938,290	36.8%	58,763,786	41,856,140	16,907,646	40.4%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	726,725	1,128,300	(401,575)	-35.6%	5,670,963	5,329,565	341,398	6.4%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	61,703,383	53,015,366	8,688,017	16.4%	233,922,592	215,030,088	18,892,504	8.8%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(8,114)	(6,000)	(2,114)	35.2%	(29,864)	(30,108)	244	-0.8%
6b. ADJ.TO FUEL COST	(4,817)	0	(4,817)	0.0%	(12,771)	(2,738)	(10,033)	366.4%
6c. INCREMENTAL HEDGING O&M COSTS	0	34,583	(34,583)	-100.0%	0	138,332	(138,332)	-100.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	61,690,452	53,043,949	8,646,503	16.3%	233,879,957	215,135,574	18,744,383	8.7%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,573,534	1,405,580	167,954	11.9%	7,018,241	6,796,711	221,530	3.3%
2. NONJURISDICTIONAL SALES	54,089	46,115	7,974	17.3%	237,292	181,256	56,036	30.9%
3. TOTAL SALES	1,627,623	1,451,695	175,928	12.1%	7,255,533	6,977,967	277,566	4.0%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9667681	0.9682337	(0.0014656)	-0.2%	0.9672950	0.9740245	(0.0067295)	-0.7%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	53,592,145	48,220,281	5,371,864	11.1%	220,989,365	215,123,508	5,865,857	2.7%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(263,799)	(263,799)	0	0.0%	(1,318,995)	(1,318,995)	0	0.0%
2b. INCENTIVE PROVISION	69,252	69,203	49	0.1%	345,471	346,015	(544)	-0.2%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	53,397,598	48,025,685	5,371,913	11.2%	220,015,841	214,150,528	5,865,313	2.7%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE	61,690,452	53,043,949	8,646,503	16.3%	233,879,957	215,135,574	18,744,383	8.7%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINI	0.9667681	0.9682337	(0.0014656)	-0.2%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	59,640,361	51,358,939	8,281,422	16.1%	226,117,980	209,390,449	16,727,531	8.0%
6a. JURISDIC. LOSS MULTIPLIER	1.00114	1.00114	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	59,708,351	51,417,488	8,290,863	16.1%	226,375,755	209,629,154	16,746,601	8.0%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	274,728	274,728	0	0.0%	1,398,950	1,398,950	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	265,598	266,001	(403)	-0.2%	1,353,017	1,363,026	(10,009)	-0.7%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	59,973,949	51,683,489	8,290,460	16.0%	227,728,772	210,992,180	16,736,592	7.9%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(6,576,351)	(3,657,804)	(2,918,547)	79.8%	(7,712,931)	3,158,348	(10,871,279)	-344.2%
8. INTEREST PROVISION FOR THE MONTH	(35,194)	(27,842)	(7,352)	26.4%	(163,408)	(153,518)	(9,890)	6.4%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(32,037,516)	(24,082,246)	(7,955,270)	33.0%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	263,799	263,799	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(38,385,262)	(27,504,093)	(10,881,169)	39.6%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(32,037,516)	(24,082,246)	(7,955,270)	33.0%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(38,350,068)	(27,476,251)	(10,873,817)	39.6%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(70,387,584)	(51,558,497)	(18,829,087)	36.5%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(35,193,792)	(25,779,249)	(9,414,543)	36.5%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.190	1.300	(0)	-8.5%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.210	1.300	(0)	-6.9%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	2.400	2.600	(0)	-7.7%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.200	1.300	(0)	-7.7%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.100	0.108	(0)	-7.4%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(35,194)	(27,842)	(7,352)	26.4%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	521,104	252,041	269,063	106.8%	2,070,488	1,311,122	759,366	57.9%
2	LIGHT OIL	589,896	1,259,667	(669,771)	-53.2%	4,633,893	4,572,078	61,815	1.4%
3	COAL	27,066,002	24,964,420	2,101,582	8.4%	126,349,253	125,892,685	456,568	0.4%
4	NATURAL GAS	19,001,686	15,371,738	3,629,948	23.6%	40,279,292	42,783,694	(2,504,402)	-5.9%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	47,178,688	41,847,866	5,330,822	12.7%	173,332,926	174,559,579	(1,226,653)	-0.7%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	8,284	4,714	3,570	75.7%	34,551	24,057	10,494	43.6%
9	LIGHT OIL	8,633	16,799	(8,166)	-48.6%	68,156	68,338	(182)	-0.3%
10	COAL	1,220,021	1,151,946	68,075	5.9%	5,807,301	5,779,616	27,685	0.5%
11	NATURAL GAS	397,706	284,441	113,265	39.8%	703,354	776,197	(72,843)	-9.4%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,634,644	1,457,900	176,744	12.1%	6,613,362	6,648,208	(34,846)	-0.5%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	12,850	7,104	5,746	80.9%	53,472	36,359	17,113	47.1%
16	LIGHT OIL (BBL)	15,547	30,842	(15,295)	-49.6%	119,844	116,200	3,644	3.1%
17	COAL (TON)	561,996	516,114	45,882	8.9%	2,695,736	2,644,814	50,922	1.9%
18	NATURAL GAS (MCF)	2,957,416	2,166,178	791,238	36.5%	5,510,166	5,827,142	(316,976)	-5.4%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	80,613	45,330	35,283	77.8%	335,454	231,212	104,242	45.1%
22	LIGHT OIL	90,225	178,441	(88,216)	-49.4%	674,330	674,487	(157)	0.0%
23	COAL	13,511,738	12,519,690	992,048	7.9%	64,281,742	63,548,947	732,795	1.2%
24	NATURAL GAS	3,125,988	2,226,893	899,095	40.4%	5,828,195	5,994,633	(166,438)	-2.8%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	16,808,564	14,970,354	1,838,210	12.3%	71,119,721	70,449,279	670,442	1.0%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.51%	0.32%	0.00	-	0.52%	0.36%	0.00	-
29	LIGHT OIL	0.53%	1.15%	(0.01)	-	1.03%	1.03%	0.00	-
30	COAL	74.64%	79.01%	(0.04)	-	87.81%	86.93%	0.01	-
31	NATURAL GAS	24.33%	19.51%	0.05	-	10.64%	11.68%	(0.01)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	40.55	35.48	5.07	14.3%	38.72	36.06	2.66	7.4%
36	LIGHT OIL ($/BBL)	37.94	40.84	(2.90)	-7.1%	38.67	39.35	(0.68)	-1.7%
37	COAL ($/TON)	48.16	48.37	(0.21)	-0.4%	46.87	47.60	(0.73)	-1.5%
38	NATURAL GAS ($/MCF)	6.43	7.10	(0.67)	-9.5%	7.31	7.34	(0.03)	-0.4%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	6.46	5.56	0.90	16.3%	6.17	5.67	0.50	8.8%
42	LIGHT OIL	6.54	7.06	(0.52)	-7.4%	6.87	6.78	0.09	1.4%
43	COAL	2.00	1.99	0.01	0.5%	1.97	1.98	(0.02)	-0.8%
44	NATURAL GAS	6.08	6.90	(0.82)	-11.9%	6.91	7.14	(0.23)	-3.2%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.81	2.80	0.01	0.4%	2.44	2.48	(0.04)	-1.6%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,731	9,616	115	1.2%	9,709	9,611	98	1.0%
49	LIGHT OIL	10,451	10,622	(171)	-1.6%	9,894	9,870	24	0.2%
50	COAL	11,075	10,868	207	1.9%	11,069	10,995	74	0.7%
51	NATURAL GAS	7,860	7,829	31	0.4%	8,286	7,723	563	7.3%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,283	10,268	15	0.1%	10,754	10,597	157	1.5%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	6.29	5.35	0.94	17.6%	5.99	5.45	0.54	9.9%
56	LIGHT OIL	6.83	7.50	(0.67)	-8.9%	6.80	6.69	0.11	1.6%
57	COAL	2.22	2.17	0.05	2.3%	2.18	2.18	0.00	0.0%
58	NATURAL GAS	4.78	5.40	(0.62)	-11.5%	5.73	5.51	0.22	4.0%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.89	2.87	0.02	0.7%	2.62	2.63	(0.01)	-0.4%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: MAY 2003

SCHEDULE A4
PAGE 1 OF 1
REVISED WITH
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(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	75	2,742	4.9	90.9	60.3	14,536	COAL	1,689	23,598,000	39,857.0	82,208	3.00	48.67
GAN.#2	100	4,946	6.6	99.7	9.6	13,399	COAL	2,789	23,762,000	66,272.2	135,748	2.74	48.67
GAN.#3	150	51,015	45.7	66.4	65.5	12,213	COAL	26,299	23,690,000	623,023.3	1,280,045	2.51	48.67
GAN.#4	164	52,778	43.3	63.3	64.6	12,331	COAL	26,945	24,152,000	650,775.6	1,311,487	2.48	48.67
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	353	162,321	61.8	78.9	66.9	11,843	COAL	81,168	23,684,000	1,922,382.9	3,950,670	2.43	48.67
GANNON STATION	**842**	**273,802**	**43.7**	**77.2**	**58.8**	**12,061**	**COAL**	**138,890**	**23,776,449**	**3,302,311.0**	**6,760,158**	**2.47**	**48.67**
B.B.#1	421	145,612	46.5	54.9	67.7	11,272	COAL	68,372	24,006,940	1,641,408.5	3,341,670	2.29	48.87
B.B.#2	411	220,950	72.3	84.6	72.6	10,930	COAL	99,708	24,221,460	2,415,076.5	4,873,211	2.21	48.87
B.B.#3	428	159,606	50.1	58.1	62.0	11,171	COAL	72,715	24,520,400	1,782,983.0	3,553,933	2.23	48.87
B.B.#4	452	258,678	76.9	88.1	78.5	10,536	COAL	120,634	22,592,260	2,725,399.2	5,895,966	2.28	48.87
B.B. STATION	**1,712**	**784,846**	**61.6**	**71.6**	**70.3**	**10,913**	**COAL**	**361,429**	**23,697,243**	**8,564,867.2**	**17,664,780**	**2.25**	**48.87**
SEB-PHIL. #1(HVY OIL)	17	3,578	28.3	71.3	87.1	9,731	HVY.OIL	5,550	6,273,540	34,817.5	225,068	6.29	40.55
SEB-PHIL. #2(HVY OIL)	17	4,706	37.2	94.0	89.5	9,731	HVY.OIL	7,300	6,273,540	45,795.8	296,036	6.29	40.55
SEB-PHILLIPS TOTAL	**34**	**8,284**	**32.7**	**82.7**	**88.3**	**9,731**	**HVY.OIL**	**12,850**	**6,273,535**	**80,613.3**	**521,104**	**6.29**	**40.55**
POLK #1 GASIFIER	255	161,373	85.1	90.0	89.3	10,191	COAL	61,677	26,664,000	1,644,559.5	2,641,064	1.64	42.82
POLK #1 CT (OIL)	225	4,697	2.8	98.6	65.2	7,599	LGT.OIL	6,157	5,796,707	35,691.3	239,823	5.11	38.95
POLK #1 TOTAL	**255**	**166,070**	**87.5**	**92.9**	**88.4**	**10,118**	**-**	**-**	**-**	**1,680,250.8**	**2,880,887**	**1.73**	**-**
POLK #2 CT (GAS)	150	22,161	19.9	99.6	79.4	10,844	GAS	227,345	1,057,000	240,304.0	1,548,774	6.99	6.81
POLK #2 CT (OIL)	160	1,513	1.3	97.1	73.4	13,026	LGT.OIL	3,401	5,796,707	19,713.2	132,460	8.75	38.95
POLK #2 TOTAL	**155**	**23,674**	**20.5**	**99.6**	**79.0**	**10,983**	**-**	**-**	**-**	**260,017.2**	**1,681,234**	**7.10**	**-**
POLK #3 CT (GAS)	150	26,788	24.0	99.9	78.4	11,733	GAS	297,348	1,057,000	314,296.0	1,969,569	7.35	6.62
POLK #3 CT (OIL)	165	1,257	1.0	99.9	74.4	13,824	LGT.OIL	2,997	5,796,707	17,373.0	116,736	9.29	38.95
POLK #3 TOTAL	**158**	**28,045**	**23.9**	**99.9**	**78.2**	**11,826**	**-**	**-**	**-**	**331,669.0**	**2,086,305**	**7.44**	**-**
POLK STATION TOTAL	**568**	**217,789**	**51.5**	**96.7**	**83.0**	**10,432**	**-**	**-**	**-**	**2,271,937.0**	**6,648,426**	**3.05**	**-**
B.B.C.T.#1	14	412	4.0	100.0	86.6	18,152	LGT.OIL	1,274	5,868,967	7,478.6	42,954	10.43	33.72
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	754	1.7	100.0	71.4	13,222	LGT.OIL	1,718	5,804,077	9,969.1	57,923	7.68	33.72
C.T. TOTAL	**140**	**1,166**	**1.1**	**100.0**	**74.3**	**14,964**	**LGT.OIL**	**2,992**	**5,831,704**	**17,447.7**	**100,877**	**8.65**	**33.72**
CITY OF TAMPA	**6**	**968**	**21.7**	**0.0**	**0.0**	**10,367**	**GAS**	**9,494**	**1,057,000**	**10,035.2**	**80,277**	**8.29**	**8.46**
BAYSIDE ST 1	246	116,706	63.8	93.9	63.8	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	88,462	80.3	94.1	92.2	11,084	GAS	927,650	1,057,000	980,526.4	5,896,535	6.67	6.36
BAYSIDE CT1B	148	61,665	56.0	72.1	88.1	11,084	GAS	646,641	1,057,000	683,499.3	4,110,323	6.67	6.36
BAYSIDE CT1C	148	80,956	73.5	90.5	93.2	11,084	GAS	848,938	1,057,000	897,327.3	5,396,208	6.67	6.36
BAYSIDE UNIT 1 TOTAL	**690**	**347,789**	**67.7**	**88.5**	**81.4**	**7,365**	**GAS**	**2,423,229**	**1,057,000**	**2,561,353.0**	**15,403,066**	**4.43**	**6.36**
BAYSIDE UNIT 2 TOTAL	**0**	**0**	**-**	**-**	**-**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE STATION TOTAL	**690**	**347,789**	**67.7**	**88.5**	**81.4**	**7,365**	**GAS**	**2,423,229**	**1,057,000**	**2,561,353.0**	**15,403,066**	**4.43**	**6.36**
TOT. COAL (GN,BB,POLK)	**2,809**	**1,220,021**	**58.4**	**74.9**	**68.6**	**11,075**	**COAL**	**561,996**	**24,042,409**	**13,511,737.7**	**27,066,002**	**2.22**	**48.16**
SYSTEM	**3,992**	**1,634,644**	**55.0**	**81.7**	**73.1**	**10,283**	**-**	**-**	**-**	**16,808,564.4**	**47,178,686**	**2.89**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2003

SCHEDULE A5
PAGE 1 OF 2
REVISED WITH
TRUE UP FILING

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	12,003	7,104	4,899	69.0%	55,121	35,080	20,041	57.1%
3 UNIT COST ($/BBL)	37.21	34.05	3.16	9.3%	37.64	34.37	3.27	9.5%
4 AMOUNT ($)	446,624	241,891	204,733	84.6%	2,074,806	1,205,711	869,095	72.1%
5 BURNED:								
6 UNITS (BBL)	12,850	7,104	5,746	80.9%	53,472	36,359	17,113	47.1%
7 UNIT COST ($/BBL)	40.55	35.48	5.07	14.3%	38.72	36.06	2.66	7.4%
8 AMOUNT ($)	521,104	252,041	269,063	106.8%	2,070,488	1,311,122	759,366	57.9%
9 ENDING INVENTORY:								
10 UNITS (BBL)	12,391	9,463	2,928	30.9%	12,391	9,463	2,928	30.9%
11 UNIT COST ($/BBL)	39.74	34.69	5.05	14.6%	39.74	34.69	5.05	14.6%
12 AMOUNT ($)	492,475	328,318	164,157	50.0%	492,475	328,318	164,157	50.0%
13								
14 DAYS SUPPLY:	27	21	6	29.3%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	31,955	35,756	(3,801)	-10.6%	165,208	143,568	21,640	15.1%
17 UNIT COST ($/BBL)	33.79	40.98	(7.19)	-17.5%	39.57	42.41	(2.84)	-6.7%
18 AMOUNT ($)	1,079,852	1,465,232	(385,380)	-26.3%	6,537,540	6,089,345	448,195	7.4%
19 BURNED:								
20 UNITS (BBL)	15,547	30,842	(15,295)	-49.6%	119,844	116,200	3,644	3.1%
21 UNIT COST ($/BBL)	37.94	40.84	(2.90)	-7.1%	38.67	39.35	(0.68)	-1.7%
22 AMOUNT ($)	589,896	1,259,667	(669,771)	-53.2%	4,633,893	4,572,078	61,815	1.4%
23 ENDING INVENTORY:								
24 UNITS (BBL)	82,925	82,746	179	0.2%	82,925	82,746	179	0.2%
25 UNIT COST ($/BBL)	36.62	39.42	(2.80)	-7.1%	36.62	39.42	(2.80)	-7.1%
26 AMOUNT ($)	3,036,606	3,261,611	(225,005)	-6.9%	3,036,606	3,261,611	(225,005)	-6.9%
27								
28 DAYS SUPPLY: NORMAL	119	120	(1)	-0.9%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	12	12	0	0.2%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	576,928	661,300	(84,372)	-12.8%	2,945,108	3,232,973	(287,865)	-8.9%
32 UNIT COST ($/TON)	48.22	48.44	(0.22)	-0.5%	47.63	47.87	(0.24)	-0.5%
33 AMOUNT ($)	27,820,080	32,035,333	(4,215,253)	-13.2%	140,286,467	154,760,781	(14,474,314)	-9.4%
34 BURNED:								
35 UNITS (TONS)	561,996	516,114	45,882	8.9%	2,695,736	2,644,814	50,922	1.9%
36 UNIT COST ($/TON)	48.16	48.37	(0.21)	-0.4%	46.87	47.60	(0.73)	-1.5%
37 AMOUNT ($)	27,066,002	24,964,420	2,101,582	8.4%	126,349,253	125,892,685	456,568	0.4%
38 ENDING INVENTORY:								
39 UNITS (TONS)	687,729	1,026,516	(338,787)	-33.0%	687,729	1,026,516	(338,787)	-33.0%
40 UNIT COST ($/TON)	48.10	47.92	0.18	0.4%	48.10	47.92	0.18	0.4%
41 AMOUNT ($)	33,076,382	49,189,951	(16,113,569)	-32.8%	33,076,382	49,189,951	(16,113,569)	-32.8%
42								
43 DAYS SUPPLY:	33	50	(17)	-33.0%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	2,957,416	2,166,178	791,238	36.5%	5,510,166	5,827,142	(316,976)	-5.4%
46 UNIT COST ($/MCF)	6.43	7.10	(0.67)	-9.5%	7.31	7.34	(0.03)	-0.4%
47 AMOUNT ($)	19,001,686	15,371,739	3,629,947	23.6%	40,279,292	42,783,694	(2,504,402)	-5.9%
48 BURNED:								
49 UNITS (MCF)	2,957,416	2,166,178	791,238	36.5%	5,510,166	5,827,142	(316,976)	-5.4%
50 UNIT COST ($/MCF)	6.43	7.10	(0.67)	-9.5%	7.31	7.34	(0.03)	-0.4%
51 AMOUNT ($)	19,001,686	15,371,738	3,629,948	23.6%	40,279,292	42,783,694	(2,504,402)	-5.9%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	25,903
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	25,903

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(10,572)	(363,901)
OTHER USAGE	(395)	(13,821)
TOTAL	(10,967)	(377,722)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	6,289
IGNITION #2 OIL	337,998
IGNITION PROPANE	767
AERIAL SURVEY ADJ.	0
ADDITIVES	36,630
GREEN FUEL	0
TOTAL	381,684

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2003

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	2,976.0	0.0	2,976.0	2.436	2.436	72,500.00	72,500.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. - MB	8,737.0	0.0	8,737.0	5.712	7.116	499,100.00	621,700.00	94,500.00
TOTAL			**11,713.0**	**0.0**	**11,713.0**	**4.880**	**5.927**	**571,600.00**	**694,200.00**	**94,500.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	1,416.9	50.6	1,366.3	3.378	3.378	46,152.36	46,152.36	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	1,038.7	0.0	1,038.7	2.510	2.510	26,067.83	26,067.83	
FLA. PWR. CORP.		SCH. - MA	2,564.0	0.0	2,564.0	5.304	8.251	136,004.10	211,544.68	65,694.82
FLA. PWR. & LIGHT		SCH. - MA	1,808.0	0.0	1,808.0	3.462	5.256	62,595.49	95,023.62	25,485.41
CITY OF LAKELAND		SCH. - MA	1,066.0	0.0	1,066.0	3.523	4.627	37,551.99	49,320.70	7,675.27
SEMINOLE ELEC. CO-OP		SCH. - MA	711.0	0.0	711.0	4.750	6.356	33,768.95	45,190.56	8,691.37
THE ENERGY AUTHORITY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	4,511.0	0.0	4,511.0	4.423	7.539	199,502.01	340,081.19	123,256.94
ORLANDO UTILITIES		SCH. - MA	370.0	0.0	370.0	5.127	7.770	18,970.58	28,748.62	8,357.24
RELIANT ENERGY		SCH. - MA	35.0	0.0	35.0	5.073	6.596	1,775.48	2,308.59	398.71
HARDEE PWR. PART. TO FLA. PWR. CORP.*		SCH. - MA	295.0	0.0	295.0	4.682	5.342	13,812.84	15,758.27	1,904.13
HARDEE PWR. PART. TO FLA. PWR. & LIGHT*		SCH. - MA	147.0	0.0	147.0	3.912	5.962	5,750.42	8,764.58	2,993.58
HARDEE PWR. PART. TO NEW SMYRNA BEACH*		SCH. - MA	17.0	0.0	17.0	4.259	4.605	724.03	782.84	56.43
HARDEE PWR. PART. TO CITY OF LAKELAND*		SCH. - MA	184.0	0.0	184.0	4.454	5.158	8,195.03	9,490.19	1,269.40
HARDEE PWR. PART. TO CITY OF SEMINOLE ELEC. CO-OP*		SCH. - MA	183.0	0.0	183.0	5.938	6.831	10,866.30	12,500.44	1,608.52
AUBURNDALE POWER PARTNERS		SCH. - OATT	11.0	0.0	11.0	7.959	7.959	875.49	875.49	
CARGILL ALLIANT		SCH. - OATT	1.0	0.0	1.0	8.500	8.500	85.00	85.00	
ADJUSTMENTS										
CARGILL ALLIANT	APR. 2003	SCH. - MA	(82.0)	0.0	(82.0)	1.585	(0.171)	(1,299.70)	(1,474.63)	139.96
CARGILL ALLIANT	APR. 2003	SCH. - MA	82.0	0.0	82.0	1.585	(0.181)	1,299.70	1,465.96	(148.63)
FLA. PWR. CORP.	APR. 2003	SCH. - MA	(230.0)	0.0	(230.0)	1.994	2.240	(4,586.95)	(5,151.57)	318.58
FLA. PWR. CORP.	APR. 2003	SCH. - MA	230.0	0.0	230.0	1.994	2.200	4,586.95	5,060.20	(409.95)
FLA. PWR. & LIGHT	APR. 2003	SCH. - MA	(5,800.0)	0.0	(5,800.0)	1.823	2.480	(105,723.00)	(143,842.90)	(15,847.90)
FLA. PWR. & LIGHT	APR. 2003	SCH. - MA	5,800.0	0.0	5,800.0	1.823	2.435	105,723.00	141,207.39	13,212.39
NEW SMYRNA BEACH	APR. 2003	SCH. - MA	(1,800.0)	0.0	(1,800.0)	6.557	7.580	(118,020.00)	(136,433.37)	(11,501.37)
NEW SMYRNA BEACH	APR. 2003	SCH. - MA	1,800.0	0.0	1,800.0	6.557	7.563	118,020.00	136,130.86	11,198.86
CITY OF LAKELAND	APR. 2003	SCH. - MA	(1,610.0)	0.0	(1,610.0)	1.872	3.526	(30,135.50)	(56,766.08)	(20,448.18)
CITY OF LAKELAND	APR. 2003	SCH. - MA	1,610.0	0.0	1,610.0	1.872	3.465	30,135.50	55,780.59	19,462.69
ORLANDO UTILITIES	APR. 2003	SCH. - MA	(2,645.0)	0.0	(2,645.0)	3.489	4.268	(92,273.85)	(112,892.42)	(10,461.77)
ORLANDO UTILITIES	APR. 2003	SCH. - MA	2,645.0	0.0	2,645.0	3.489	4.252	92,273.85	112,476.71	10,046.06
AUBURNDALE POWER PARTNERS	APR. 2003	SCH. - OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
AUBURNDALE POWER PARTNERS	APR. 2003	SCH. - OATT	(4.0)	0.0	(4.0)	0.760	0.760	(30.41)	(30.41)	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			2,455.6	50.6	2,405.0	3.003	3.003	72,220.19	72,220.19	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			11,891.0	0.0	11,891.0	4.453	6.855	529,517.22	815,075.02	242,952.56
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			8.0	0.0	8.0	11.626	11.626	930.08	930.08	
TOTAL			**14,354.6**	**50.6**	**14,304.0**	**4.213**	**6.210**	**602,667.49**	**888,225.29**	**242,952.56**
CURRENT MONTH:										
DIFFERENCE			2,641.6	50.6	2,591.0	(0.667)	0.283	31,067.49	194,025.29	148,452.56
DIFFERENCE %			22.6%	0.0%	22.1%	-13.7%	4.8%	5.4%	27.9%	157.1%
PERIOD TO DATE:										
ACTUAL			93,485.0	111.9	93,373.1	3.249	4.456	3,033,576.78	4,160,502.35	811,505.34
ESTIMATED			147,087.9	5.3	147,082.6	3.514	4.877	5,168,201.69	7,173,417.12	1,546,994.33
DIFFERENCE			(53,602.9)	106.6	(53,709.5)	(0.265)	(0.421)	(2,134,624.91)	(3,012,914.77)	(735,488.99)
DIFFERENCE %			-36.4%	2011.3%	-36.5%	-7.5%	-8.6%	-41.3%	-42.0%	-47.5%

* SEC 60% PROFIT OR $11,748.08 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	9,682.0	0.0	5,194.0	4,488.0	7.244	7.244	325,100.00
HARDEE POWER PARTNERS		IPP	49,810.0	0.0	0.0	49,810.0	6.380	6.380	3,177,800.00
VARIOUS		OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
VARIOUS		MKT. BASE	162,891.0	0.0	0.0	162,891.0	4.422	4.422	7,202,400.00
TOTAL			**222,383.0**	**0.0**	**5,194.0**	**217,189.0**	**4.929**	**4.929**	**10,705,300.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	81,525.0	0.0	0.0	81,525.0	6.416	6.416	5,230,270.73
HARDEE PWR. PART.-OTHERS		IPP	826.0	0.0	0.0	826.0	4.778	4.778	39,464.26
FLA. POWER CORP.		SCH. - J	4,987.0	0.0	20.0	4,967.0	4.856	4.856	241,213.00
FLA. POWER & LIGHT		SCH. - J	9,968.0	0.0	0.0	9,968.0	4.987	4.987	497,124.00
CITY OF LAKELAND		SCH. - J	7,910.0	0.0	804.5	7,105.5	6.436	6.436	457,318.64
ORLANDO UTIL. COMM.		SCH. - J	22,150.0	0.0	1,361.1	20,788.9	10.011	10.011	2,081,231.04
CAROLINA POWER & LIGHT		SCH. - J	2,960.0	0.0	59.0	2,901.0	6.776	6.776	196,562.00
THE ENERGY AUTHORITY		SCH. - J	10,291.0	0.0	1,483.3	8,807.7	8.391	8.391	739,035.60
REEDY CREEK		SCH. - J	85.0	0.0	0.0	85.0	5.353	5.353	4,550.00
OKEELANTA		SCH. - J	16,433.0	0.0	0	16,433.0	5.040	5.040	828,181.41
TALLAHASSEE		SCH. - J	350.0	0.0	0.0	350.0	6.470	6.470	22,645.00
CALPINE		SCH. - J	168.0	0.0	0.0	168.0	5.924	5.924	9,953.00
CARGILL ALLIANT		SCH. - J	42,382.0	0.0	347.0	42,035.0	7.026	7.026	2,953,338.00
CONOCO		SCH. - J	1,901.0	0.0	0.0	1,901.0	2.719	2.719	51,696.50
CORAL POWER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RELIANT		SCH. - J	10,207.0	0.0	1,594.7	8,612.3	9.593	9.593	826,173.36
SEMINOLE ELEC. CO-OP		SCH. - J	682.0	0.0	0.0	682.0	2.803	2.803	19,117.00
DUKE ENERGY		SCH. - J	579.0	0.0	0.0	579.0	8.213	8.213	47,553.00
DYNEGY POWER MARKETING		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RINGHAVER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Apr. 2003	IPP	(42,579.0)	0.0	0.0	(42,579.0)	6.361	6.361	(2,708,651.81)
HARDEE PWR. PART.-NATIVE	Apr. 2003	IPP	42,579.0	0.0	0.0	42,579.0	6.179	6.179	2,630,871.78
FLA. POWER CORP.	Mar. 2003	SCH. - D	(78,500.0)	0.0	0.0	(78,500.0)	4.215	4.215	(3,308,745.00)
FLA. POWER CORP.	Mar. 2003	SCH. - D	78,500.0	0.0	0.0	78,500.0	4.587	4.587	3,600,765.00
FLA. POWER CORP.	Apr. 2003	SCH. - D	(53,250.0)	0.0	0.0	(53,250.0)	4.323	4.323	(2,302,027.50)
FLA. POWER CORP.	Apr. 2003	SCH. - D	53,250.0	0.0	0.0	53,250.0	4.695	4.695	2,500,117.50
RINGHAVER	Apr. 2003	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	(154,255.33)
RINGHAVER	Apr. 2003	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	140,599.46
THE ENERGY AUTHORITY	Apr. 2003	SCH. - J	(8,399.0)	0.0	0.0	(8,399.0)	5.514	5.514	(463,117.00)
THE ENERGY AUTHORITY	Apr. 2003	SCH. - J	8,399.0	0.0	0.0	8,399.0	5.508	5.508	462,606.00
TOTAL			**213,404.0**	**0.0**	**5,669.6**	**207,734.4**	**7.049**	**7.049**	**14,643,589.64**
CURRENT MONTH:									
DIFFERENCE			(8,979.0)	0.0	475.6	(9,454.6)	2.120	2.120	3,938,289.64
DIFFERENCE %			-4.0%	0.0%	9.2%	-4.4%	43.0%	43.0%	36.8%
PERIOD TO DATE:									
ACTUAL			1,000,748.0	0.0	13,905.6	986,842.4	5.955	5.955	58,763,785.58
ESTIMATED			799,383.0	0.0	10,131.2	789,251.8	5.303	5.303	41,856,139.59
DIFFERENCE			201,365.0	0.0	3,774.4	197,590.6	0.652	0.652	16,907,645.99
DIFFERENCE %			25.2%	0.0%	37.3%	25.0%	12.3%	12.3%	40.4%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	41,439.0	0.0	0.0	41,439.0	2.723	2.723	1,128,300.00
TOTAL			**41,439.0**	**0.0**	**0.0**	**41,439.0**	**2.723**	**2.723**	**1,128,300.00**
ACTUAL:									
HILLSBOROUGH COUNTY		COGEN.	18,401.0	0.0	0.0	18,401.0	1.746	1.746	321,232.46
McKAY BAY REFUSE		COGEN.	13,222.0	0.0	0.0	13,222.0	1.746	1.746	230,848.39
ORANGE COGENERATION L.P.		COGEN.	7,843.0	0.0	0.0	7,843.0	1.714	1.714	134,417.69
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	575.0	0.0	0.0	575.0	4.992	4.992	28,706.14
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	58.0	0.0	0.0	58.0	5.461	5.461	3,167.24
CF INDUSTRIES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	107.0	0.0	0.0	107.0	4.305	4.305	4,606.07
IMC-AGRICO-S. PIERCE		COGEN.	160.0	0.0	0.0	160.0	6.619	6.619	10,590.13
AUBURNDALE POWER PARTNERS		COGEN.	2.0	0.0	0.0	2.0	7.583	7.583	151.66
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR MAY 2003			40,368.0	0.0	0.0	40,368.0	1.818	1.818	733,719.78
ADJUSTMENTS FOR THE MONTH OF:	**APRIL 2003**								
HILLSBOROUGH COUNTY		COGEN.	(18,355.0)	0.0	0.0	(18,355.0)	1.891	1.891	(347,106.43)
			18,355.0	0.0	0.0	18,355.0	1.875	1.875	344,223.12
McKAY BAY REFUSE		COGEN.	(12,852.0)	0.0	0.0	(12,852.0)	1.891	1.891	(243,038.70)
			12,852.0	0.0	0.0	12,852.0	1.875	1.875	241,020.48
ORANGE COGENERATION L.P.		COGEN.	(7,590.0)	0.0	0.0	(7,590.0)	1.782	1.782	(135,233.28)
			7,590.0	0.0	0.0	7,590.0	1.757	1.757	133,369.13
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	(565.0)	0.0	0.0	(565.0)	4.353	4.353	(24,596.99)
			565.0	0.0	0.0	565.0	4.367	4.367	24,673.07
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE		COGEN.	(10,114.0)	0.0	0.0	(10,114.0)	3.734	3.734	(377,686.12)
			10,114.0	0.0	0.0	10,114.0	3.731	3.731	377,381.16
AUBURNDALE POWER PARTNERS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**APRIL 2003**		0.0	0.0	0.0	0.0	0.000	0.000	(6,994.56)
GRAND TOTAL			**40,368.0**	**0.0**	**0.0**	**40,368.0**	**1.800**	**1.800**	**726,725.22**
CURRENT MONTH:									
DIFFERENCE			(1,071.0)	0.0	0.0	(1,071.0)	(0.923)	(0.923)	(401,574.78)
DIFFERENCE %			-2.6%	0.0%	0.0%	-2.6%	-33.9%	-33.9%	-35.6%
PERIOD TO DATE:									
ACTUAL			238,237.0	0.0	0.0	238,237.0	2.380	2.380	5,670,963.57
ESTIMATED			203,081.0	0.0	0.0	203,081.0	2.624	2.624	5,329,565.12
DIFFERENCE			35,156.0	0.0	0.0	35,156.0	(0.244)	(0.244)	341,398.45
DIFFERENCE %			17.3%	0.0%	0.0%	17.3%	(0.093)	(0.093)	6.4%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

JUNE 2003

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	52,099,093	45,045,564	7,053,529	15.7%	1,528,226	1,562,765	(34,539)	-2.2%	3.40912	2.88243	0.52670	18.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(7,310)	(6,000)	(1,310)	21.8%	1,528,226 (a)	1,562,765 (a)	(34,539)	-2.2%	(0.00048)	(0.00038)	(0.00009)	24.6%
4b. Adjustments to Fuel Cost	(4,554)	0	(4,554)	0.0%	1,528,226 (a)	1,562,765 (a)	(34,539)	-2.2%	(0.00030)	0.00000	(0.00030)	0.0%
4c. Incremental Hedging O&M Costs	0	34,583	(34,583)	-100.0%	1,528,226 (a)	1,562,765 (a)	(34,539)	-2.2%	0.00000	0.00221	(0.00221)	-100.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**52,087,229**	**45,074,147**	**7,013,082**	**15.6%**	**1,528,226**	**1,562,765**	**(34,539)**	**-2.2%**	**3.40835**	**2.88426**	**0.52409**	**18.2%**
6. Fuel Cost of Purchased Power - Firm (A7)	13,218,541	10,668,300	2,550,241	23.9%	225,048	205,062	19,986	9.7%	5.87365	5.20248	0.67118	12.9%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	736,351	1,085,200	(348,849)	-32.1%	38,612	40,097	(1,485)	-3.7%	1.90705	2.70644	(0.79938)	-29.5%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**13,954,892**	**11,753,500**	**2,201,392**	**18.7%**	**263,660**	**245,159**	**18,501**	**7.5%**	**5.29276**	**4.79424**	**0.49852**	**10.4%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,791,886**	**1,807,924**	**(16,038)**	**-0.9%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	67,994	62,900	5,094	8.1%	2,697	2,591	106	4.1%	2.52110	2.42763	0.09346	3.8%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	61	0	61	0.0%	1	0	1	0.0%	6.10000	0.00000	6.10000	0.0%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	46,433	1,114,400	(1,067,967)	-95.8%	1,128	18,305	(17,177)	-93.8%	4.11640	6.08795	(1.97155)	-32.4%
19. Gains on Market Based Sales	4,145	212,300	(208,155)	-98.0%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**118,633**	**1,389,600**	**(1,270,967)**	**-91.5%**	**3,826**	**20,896**	**(17,070)**	**-81.7%**	**3.10071**	**6.65008**	**(3.54937)**	**-53.4%**
21. Net Inadvertant Interchange					(87)	0	(87)	0.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					170	0	170	0.0%				
23. Interchange and Wheeling Losses					129	300	(171)	-57.0%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**65,923,488**	**55,438,047**	**10,485,441**	**18.9%**	**1,788,014**	**1,786,728**	**1,286**	**0.1%**	**3.68697**	**3.10277**	**0.58420**	**18.8%**
25. Net Unbilled	(1,479,506) (a)	1,070,704 (a)	(2,550,210)	-238.2%	(40,128)	34,508	(74,636)	-216.3%	3.68697	3.10277	0.58420	18.8%
26. Company Use	160,899 (a)	124,111 (a)	36,788	29.6%	4,364	4,000	364	9.1%	3.68696	3.10278	0.58419	18.8%
27. T & D Losses	4,499,833 (a)	1,574,811 (a)	2,925,022	185.7%	122,047	50,755	71,292	140.5%	3.68697	3.10277	0.58420	18.8%
28. System KWH Sales	65,923,488	55,438,047	10,485,441	18.9%	1,701,731	1,697,465	4,266	0.3%	3.87391	3.26593	0.60798	18.6%
29. Wholesale KWH Sales	(2,002,345)	(1,780,781)	(221,564)	12.4%	(51,688)	(54,526)	2,838	-5.2%	3.87391	3.26593	0.60798	18.6%
30. Jurisdictional KWH Sales	63,921,143	53,657,266	10,263,877	19.1%	1,650,043	1,642,939	7,104	0.4%	3.87391	3.26593	0.60798	18.6%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	63,994,013	53,718,435	10,275,578	19.1%	1,650,043	1,642,939	7,104	0.4%	3.87832	3.26965	0.60867	18.6%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	263,929	263,453	476	0.2%	1,650,043	1,642,939	7,104	0.4%	0.01600	0.01604	(0.00004)	-0.3%
34. Adjustment	0	0	0	0.0%	1,650,043	1,642,939	7,104	0.4%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	1,650,043	1,642,939	7,104	0.4%	0.00000	0.00000	0.00000	0.0%
36. True-up *	263,799	263,799	0	0.0%	1,650,043	1,642,939	7,104	0.4%	0.01599	0.01606	(0.00007)	-0.4%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	64,521,741	54,245,687	10,276,054	18.9%	1,650,043	1,642,939	7,104	0.4%	3.91031	3.30175	0.60856	18.4%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.91312	3.30412	0.60900	18.4%
40. GPIF * (Already Adjusted for Taxes)	(69,252)	(69,203)	(49)	0.1%	1,650,043	1,642,939	7,104	0.4%	(0.00420)	(0.00421)	0.00002	-0.4%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**64,452,489**	**54,176,484**	**10,276,005**	**19.0%**	**1,650,043**	**1,642,939**	**7,104**	**0.4%**	**3.90892**	**3.29991**	**0.60902**	**18.5%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.909**	**3.300**	**0.609**	**18.5%**

* Based on Jurisdictional Sales (a) Included for Informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: JUNE 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	225,432,019	219,605,143	5,826,876	2.7%	8,141,588	8,210,973	(69,385)	-0.8%	2.76889	2.67453	0.09436	3.5%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(37,174)	(36,108)	(1,066)	3.0%	8,141,588 (a)	8,210,973 (a)	(69,385)	-0.8%	(0.00046)	(0.00044)	(0.00002)	3.8%
4b. Adjustments to Fuel Cost	(17,325)	(2,738)	(14,587)	532.7%	8,141,588 (a)	8,210,973 (a)	(69,385)	-0.8%	(0.00021)	(0.00003)	(0.00018)	538.1%
4c. Adjustments to Fuel Cost	0	172,915	(172,915)	-100.0%	8,141,588 (a)	8,210,973 (a)	(69,385)	-0.8%	0.00000	0.00211	(0.00211)	-100.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**225,377,520**	**219,739,212**	**5,638,308**	**2.6%**	**8,141,588**	**8,210,973**	**(69,385)**	**-0.8%**	**2.76823**	**2.67617**	**0.09206**	**3.4%**
6. Fuel Cost of Purchased Power - Firm (A7)	71,982,327	52,524,440	19,457,887	37.0%	1,211,890	994,314	217,576	21.9%	5.93967	5.28248	0.65719	12.4%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	6,407,314	6,414,765	(7,451)	-0.1%	276,849	243,178	33,671	13.8%	2.31437	2.63789	(0.32352)	-12.3%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**78,389,641**	**58,939,205**	**19,450,436**	**33.0%**	**1,488,739**	**1,237,492**	**251,247**	**20.3%**	**5.26551**	**4.76279**	**0.50271**	**10.6%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**9,630,327**	**9,448,465**	**181,862**	**1.9%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	359,523	389,607	(30,084)	-7.7%	13,835	16,452	(2,617)	-15.9%	2.59865	2.36814	0.23050	9.7%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	2,919	4,680	(1,761)	-37.6%	69	46	23	50.0%	4.23043	10.17391	(5.94348)	-58.4%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	121,809	108,975	12,834	11.8%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	2,663,814	5,842,240	(3,178,426)	-54.4%	83,296	151,481	(68,185)	-45.0%	3.19801	3.85675	(0.65874)	-17.1%
19. Gains on Market Based Sales	815,651	1,759,294	(943,643)	-53.6%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**3,963,716**	**8,104,796**	**(4,141,080)**	**-51.1%**	**97,200**	**167,979**	**(70,779)**	**-42.1%**	**4.07790**	**4.82489**	**(0.74699)**	**-15.5%**
21. Net Inadvertant Interchange					(207)	(291)	84	-28.9%				
22. Wheeling Rec'd. less Wheeling Del'd.					756	652	104	16.0%				
23. Interchange and Wheeling Losses					4,224	2,596	1,628	62.7%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**299,803,445**	**270,573,621**	**29,229,824**	**10.8%**	**9,529,452**	**9,278,251**	**251,201**	**2.7%**	**3.14607**	**2.91621**	**0.22986**	**7.9%**
25. Net Unbilled	7,016,546 (a)	9,190,603 (a)	(2,174,057)	-23.7%	203,757	302,004	(98,247)	-32.5%	3.44359	3.04321	0.40038	13.2%
26. Company Use	756,725 (a)	698,141 (a)	58,584	8.4%	24,172	24,099	73	0.3%	3.13058	2.89697	0.23361	8.1%
27. T & D Losses	11,414,792 (a)	8,278,963 (a)	3,135,829	37.9%	344,259	276,716	67,543	24.4%	3.31576	2.99186	0.32389	10.8%
28. System KWH Sales	299,803,445	270,573,621	29,229,824	10.8%	8,957,264	8,675,432	281,832	3.2%	3.34704	3.11885	0.22819	7.3%
29. Wholesale KWH Sales	(9,764,322)	(7,525,906)	(2,238,416)	29.7%	(288,980)	(235,782)	(53,198)	22.6%	3.37889	3.19189	0.18700	5.9%
30. Jurisdictional KWH Sales	290,039,123	263,047,715	26,991,408	10.3%	8,668,284	8,439,650	228,634	2.7%	3.34598	3.11681	0.22917	7.4%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	290,369,768	263,347,589	27,022,179	10.3%	8,668,284	8,439,650	228,634	2.7%	3.34980	3.12036	0.22943	7.4%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	1,616,946	1,626,479	(9,533)	-0.6%	8,668,284	8,439,650	228,634	2.7%	0.01865	0.01927	(0.00062)	-3.2%
34. Adjustment	0	0	0	0.0%	8,668,284	8,439,650	228,634	2.7%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	8,668,284	8,439,650	228,634	2.7%	0.00000	0.00000	0.00000	0.0%
36. True-up *	1,582,794	1,582,794	0	0.0%	8,668,284	8,439,650	228,634	2.7%	0.01826	0.01875	(0.00049)	-2.6%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	293,569,508	266,556,862	27,012,646	10.1%	8,668,284	8,439,650	228,634	2.7%	3.38671	3.15839	0.22832	7.2%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.38915	3.16066	0.22849	7.2%
40. GPIF * (Already Adjusted for Taxes)	(414,723)	(415,218)	495	-0.1%	8,668,284	8,439,650	228,634	2.7%	(0.00478)	(0.00492)	0.00014	-2.8%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**293,154,785**	**288,141,844**	**27,013,141**	**10.1%**	**8,668,284**	**8,439,650**	**228,634**	**2.7%**	**3.38437**	**3.15574**	**0.22863**	**7.2%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.384**	**3.156**	**0.228**	**7.2%**

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	52,099,093	45,045,564	7,053,529	15.7%	225,432,019	219,605,143	5,826,876	2.7%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	114,488	1,177,300	(1,062,812)	-90.3%	3,148,065	6,345,502	(3,197,437)	-50.4%
2a. GAINS FROM MARKET BASED SALES	4,145	212,300	(208,155)	-98.0%	815,651	1,759,294	(943,643)	-53.6%
3. FUEL COST OF PURCHASED POWER	13,218,541	10,668,300	2,550,241	23.9%	71,982,327	52,524,440	19,457,887	37.0%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	736,351	1,085,200	(348,849)	-32.1%	6,407,314	6,414,765	(7,451)	-0.1%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	65,935,352	55,409,464	10,525,888	19.0%	299,857,944	270,439,552	29,418,392	10.9%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(7,310)	(6,000)	(1,310)	21.8%	(37,174)	(36,108)	(1,066)	3.0%
6b. ADJ.TO FUEL COST	(4,554)	0	(4,554)	0.0%	(17,325)	(2,738)	(14,587)	532.7%
6c. INCREMENTAL HEDGING O&M COSTS	0	34,583	(34,583)	-100.0%	0	172,915	(172,915)	-100.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	65,923,488	55,438,047	10,485,441	18.9%	299,803,445	270,573,621	29,229,824	10.8%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,650,043	1,642,939	7,104	0.4%	8,668,284	8,439,650	228,634	2.7%
2. NONJURISDICTIONAL SALES	51,688	54,526	(2,838)	-5.2%	288,980	235,782	53,198	22.6%
3. TOTAL SALES	1,701,731	1,697,465	4,266	0.3%	8,957,264	8,675,432	281,832	3.2%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9696262	0.9678780	0.0017482	0.2%	0.9677379	0.9728219	(0.0050840)	-0.5%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	56,277,645	56,396,395	(118,750)	-0.2%	277,267,010	271,519,903	5,747,107	2.1%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(263,799)	(263,799)	0	0.0%	(1,582,794)	(1,582,794)	0	0.0%
2b. INCENTIVE PROVISION	69,252	69,203	49	0.1%	414,723	415,218	(495)	-0.1%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	56,083,098	56,201,799	(118,701)	-0.2%	276,098,939	270,352,327	5,746,612	2.1%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE	65,923,488	55,438,047	10,485,441	18.9%	299,803,445	270,573,621	29,229,824	10.8%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINI	0.9696262	0.9678780	0.0017482	0.2%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	63,921,143	53,657,266	10,263,877	19.1%	290,039,123	263,047,715	26,991,408	10.3%
6a. JURISDIC. LOSS MULTIPLIER	1.00114	1.00114	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	63,994,013	53,718,435	10,275,578	19.1%	290,369,768	263,347,589	27,022,179	10.3%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	272,197	272,197	0	0.0%	1,671,147	1,671,147	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	263,929	263,453	476	0.2%	1,616,946	1,626,479	(9,533)	-0.6%
6e. OTHER		0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	64,257,942	53,981,888	10,276,054	19.0%	291,986,714	264,974,068	27,012,646	10.2%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(8,174,844)	2,219,911	(10,394,755)	-468.3%	(15,887,775)	5,378,259	(21,266,034)	-395.4%
8. INTEREST PROVISION FOR THE MONTH	(38,954)	(28,363)	(10,591)	37.3%	(202,362)	(181,881)	(20,481)	11.3%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(38,385,262)	(27,504,093)	(10,881,169)	39.6%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	263,799	263,799	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(46,335,261)	(25,048,746)	(21,286,515)	85.0%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(38,385,262)	(27,504,093)	(10,881,169)	39.6%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(46,296,307)	(25,020,383)	(21,275,924)	85.0%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(84,681,569)	(52,524,476)	(32,157,093)	61.2%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(42,340,785)	(26,262,238)	(16,078,547)	61.2%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.210	1.300	(0)	-6.9%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.000	1.300	(0)	-23.1%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	2.210	2.600	(0)	-15.0%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.105	1.300	(0)	-15.0%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.092	0.108	(0)	-14.8%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(38,954)	(28,363)	(10,591)	37.3%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	528,186	408,390	119,796	29.3%	2,598,674	1,719,512	879,162	51.1%
2	LIGHT OIL	782,597	1,351,475	(568,878)	-42.1%	5,416,490	5,923,553	(507,063)	-8.6%
3	COAL	24,796,476	27,870,603	(3,074,127)	-11.0%	151,145,729	153,763,288	(2,617,559)	-1.7%
4	NATURAL GAS	25,991,834	15,415,096	10,576,738	68.6%	66,271,126	58,198,790	8,072,336	13.9%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	52,099,093	45,045,564	7,053,529	15.7%	225,432,019	219,605,143	5,826,876	2.7%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	9,638	7,745	1,893	24.4%	44,189	31,802	12,387	39.0%
9	LIGHT OIL	11,444	18,575	(7,131)	-38.4%	79,600	86,913	(7,313)	-8.4%
10	COAL	1,089,409	1,250,753	(161,344)	-12.9%	6,896,710	7,030,369	(133,659)	-1.9%
11	NATURAL GAS	417,735	285,692	132,043	46.2%	1,121,089	1,061,889	59,200	5.6%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,528,226	1,562,765	(34,539)	-2.2%	8,141,588	8,210,973	(69,385)	-0.8%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	14,967	11,670	3,297	28.3%	68,439	48,029	20,410	42.5%
16	LIGHT OIL (BBL)	20,486	34,240	(13,754)	-40.2%	140,330	150,440	(10,110)	-6.7%
17	COAL (TON)	505,207	573,048	(67,841)	-11.8%	3,200,943	3,217,862	(16,919)	-0.5%
18	NATURAL GAS (MCF)	3,018,929	2,197,566	821,363	37.4%	8,529,095	8,024,708	504,387	6.3%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	93,900	74,360	19,540	26.3%	429,354	305,572	123,782	40.5%
22	LIGHT OIL	115,957	198,586	(82,629)	-41.6%	790,267	873,073	(82,786)	-9.5%
23	COAL	12,101,895	13,787,271	(1,685,376)	-12.2%	76,383,637	77,336,218	(952,581)	-1.2%
24	NATURAL GAS	3,212,139	2,259,177	952,962	42.2%	9,040,334	8,253,810	786,524	9.5%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	15,523,891	16,319,394	(795,503)	-4.9%	86,643,612	86,768,673	(125,061)	-0.1%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.63%	0.50%	0.00	-	0.54%	0.39%	0.00	-
29	LIGHT OIL	0.75%	1.19%	(0.00)	-	0.98%	1.06%	(0.00)	-
30	COAL	71.29%	80.03%	(0.09)	-	84.71%	85.62%	(0.01)	-
31	NATURAL GAS	27.33%	18.28%	0.09	-	13.77%	12.93%	0.01	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	35.29	34.99	0.30	0.8%	37.97	35.80	2.17	6.1%
36	LIGHT OIL ($/BBL)	38.20	39.47	(1.27)	-3.2%	38.60	39.37	(0.78)	-2.0%
37	COAL ($/TON)	49.08	48.64	0.45	0.9%	47.22	47.78	(0.57)	-1.2%
38	NATURAL GAS ($/MCF)	8.61	7.01	1.59	22.7%	7.77	7.25	0.52	7.1%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	5.62	5.49	0.13	2.4%	6.05	5.63	0.43	7.6%
42	LIGHT OIL	6.75	6.81	(0.06)	-0.8%	6.85	6.78	0.07	1.0%
43	COAL	2.05	2.02	0.03	1.4%	1.98	1.99	(0.01)	-0.5%
44	NATURAL GAS	8.09	6.82	1.27	18.6%	7.33	7.05	0.28	4.0%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	3.36	2.76	0.60	21.6%	2.60	2.53	0.07	2.8%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,743	9,601	142	1.5%	9,716	9,609	107	1.1%
49	LIGHT OIL	10,133	10,691	(558)	-5.2%	9,928	10,045	(117)	-1.2%
50	COAL	11,109	11,023	86	0.8%	11,075	11,000	75	0.7%
51	NATURAL GAS	7,689	7,908	(219)	-2.8%	8,064	7,773	291	3.7%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,158	10,443	(285)	-2.7%	10,642	10,567	75	0.7%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.48	5.27	0.21	4.0%	5.88	5.41	0.47	8.7%
56	LIGHT OIL	6.84	7.28	(0.44)	-6.0%	6.80	6.82	(0.02)	-0.3%
57	COAL	2.28	2.23	0.05	2.2%	2.19	2.19	0.00	0.0%
58	NATURAL GAS	6.22	5.40	0.82	15.2%	5.91	5.48	0.43	7.8%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	3.41	2.88	0.53	18.4%	2.77	2.67	0.10	3.7%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: JUNE 2003

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(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	75	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#2	100	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	150	70,309	65.1	86.9	69.4	12,100	COAL	36,249	23,470,000	850,764.0	1,764,312	2.51	48.67
GAN.#4	164	53,909	45.7	60.5	67.8	12,481	COAL	28,715	23,432,000	672,849.9	1,397,617	2.59	48.67
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	353	70,031	27.6	34.7	57.6	11,738	COAL	34,665	23,714,000	822,045.8	1,687,216	2.41	48.67
GANNON STATION	**842**	**194,249**	**32.0**	**62.6**	**49.7**	**12,076**	**COAL**	**99,629**	**23,543,945**	**2,345,659.7**	**4,849,145**	**2.50**	**48.67**
B.B.#1	421	157,833	52.1	59.1	62.6	11,324	COAL	74,759	23,907,000	1,787,263.4	3,753,959	2.38	50.21
B.B.#2	411	193,418	65.4	75.9	68.0	10,994	COAL	87,730	24,238,380	2,126,433.1	4,405,286	2.28	50.21
B.B.#3	428	189,726	61.6	71.1	67.4	11,023	COAL	85,348	24,502,840	2,091,273.8	4,285,676	2.26	50.21
B.B.#4	452	232,398	71.4	79.6	72.4	10,641	COAL	109,842	22,513,740	2,472,946.3	5,515,622	2.37	50.21
B.B. STATION	**1,712**	**773,375**	**62.7**	**71.5**	**67.7**	**10,962**	**COAL**	**357,679**	**23,702,593**	**8,477,916.6**	**17,960,543**	**2.32**	**50.21**
SEB-PHIL. #1(HVY OIL)	17	4,934	40.3	100.0	90.0	9,742	HVY.OIL	7,662	6,273,540	48,068.0	270,392	5.48	35.29
SEB-PHIL. #2(HVY OIL)	17	4,704	38.4	92.7	90.7	9,742	HVY.OIL	7,305	6,273,540	45,832.0	257,794	5.48	35.29
SEB-PHILLIPS TOTAL	**34**	**9,638**	**39.4**	**96.4**	**90.3**	**9,743**	**HVY.OIL**	**14,967**	**6,273,538**	**93,900.0**	**528,186**	**5.48**	**35.29**
POLK #1 GASIFIER	255	121,785	66.3	70.6	88.4	10,496	COAL	47,899	26,688,000	1,278,318.6	1,986,788	1.63	41.48
POLK #1 CT (OIL)	225	8,909	5.5	90.8	50.6	9,399	LGT.OIL	14,927	5,796,495	83,734.9	570,579	6.40	38.22
POLK #1 TOTAL	**255**	**130,694**	**71.2**	**84.5**	**84.1**	**10,422**	**-**	**-**	**-**	**1,362,053.5**	**2,557,367**	**1.96**	**-**
POLK #2 CT (GAS)	150	17,686	16.4	96.1	79.0	10,597	GAS	176,148	1,064,000	187,421.0	1,696,302	9.59	9.63
POLK #2 CT (OIL)	160	1,756	1.5	96.5	75.0	13,129	LGT.OIL	3,976	5,796,494	23,049.5	151,999	8.66	38.23
POLK #2 TOTAL	**155**	**19,442**	**17.4**	**96.5**	**78.6**	**10,826**	**-**	**-**	**-**	**210,470.5**	**1,848,301**	**9.51**	**-**
POLK #3 CT (GAS)	150	20,462	18.9	96.5	81.2	11,885	GAS	228,557	1,064,000	243,185.0	2,202,877	10.77	9.64
POLK #3 CT (OIL)	165	744	0.6	98.3	95.0	11,515	LGT.OIL	1,479	5,796,495	8,570.1	56,515	7.60	38.21
POLK #3 TOTAL	**158**	**21,206**	**18.6**	**98.5**	**81.7**	**11,872**	**-**	**-**	**-**	**251,755.1**	**2,259,392**	**10.65**	**-**
POLK STATION TOTAL	**568**	**171,342**	**41.9**	**91.7**	**81.9**	**10,647**	**-**	**-**	**-**	**1,824,279.1**	**6,665,060**	**3.89**	**-**
B.B.C.T.#1	14	14	0.1	100.0	100.0	19,507	LGT.OIL	48	5,734,355	273.1	1,617	11.55	33.69
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	21	0.0	100.0	35.0	15,667	LGT.OIL	56	5,828,521	329.0	1,887	8.99	33.70
C.T. TOTAL	**140**	**35**	**0.0**	**100.0**	**47.3**	**17,203**	**LGT.OIL**	**104**	**5,785,529**	**602.1**	**3,504**	**10.01**	**33.69**
CITY OF TAMPA	**6**	**821**	**19.0**	**0.0**	**0.0**	**10,426**	**GAS**	**8,045**	**1,064,000**	**8,559.9**	**95,891**	**11.68**	**11.92**
BAYSIDE ST 1	246	130,606	73.7	90.6	76.5	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	87,098	81.7	95.7	85.4	11,161	GAS	913,602	1,064,000	972,072.6	7,711,016	8.85	8.44
BAYSIDE CT1B	148	85,140	79.9	97.2	86.2	11,161	GAS	893,065	1,064,000	950,220.7	7,537,679	8.85	8.44
BAYSIDE CT1C	148	76,221	71.5	93.3	85.1	11,161	GAS	799,512	1,064,000	850,680.6	6,748,069	8.85	8.44
BAYSIDE UNIT 1 TOTAL	**690**	**379,065**	**76.3**	**93.7**	**82.3**	**7,315**	**GAS**	**2,606,179**	**1,064,000**	**2,772,974.0**	**21,996,764**	**5.80**	**8.44**
BAYSIDE UNIT 2 TOTAL	**0**	**(299)**	**-**	**-**	**-**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE STATION TOTAL	**690**	**378,766**	**76.2**	**93.7**	**82.3**	**7,321**	**GAS**	**2,606,179**	**1,064,000**	**2,772,974.0**	**21,996,764**	**5.81**	**8.44**
TOT. COAL (GN,BB,POLK)	**2,809**	**1,089,409**	**53.9**	**68.8**	**64.2**	**11,109**	**COAL**	**505,207**	**23,954,353**	**12,101,894.9**	**24,796,476**	**2.28**	**49.08**
SYSTEM	**3,992**	**1,528,226**	**53.2**	**78.9**	**69.1**	**10,158**	**-**	**-**	**-**	**15,523,891.4**	**52,099,093**	**3.41**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2003

SCHEDULE A5
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	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	17,459	11,670	5,789	49.6%	72,580	46,750	25,830	55.3%
3 UNIT COST ($/BBL)	30.97	34.05	(3.08)	-9.0%	36.04	34.29	1.75	5.1%
4 AMOUNT ($)	540,788	397,364	143,424	36.1%	2,615,594	1,603,075	1,012,519	63.2%
5 BURNED:								
6 UNITS (BBL)	14,967	11,670	3,297	28.3%	68,439	48,029	20,410	42.5%
7 UNIT COST ($/BBL)	35.29	34.99	0.30	0.8%	37.97	35.80	2.17	6.1%
8 AMOUNT ($)	528,186	408,390	119,796	29.3%	2,598,674	1,719,512	879,162	51.1%
9 ENDING INVENTORY:								
10 UNITS (BBL)	14,883	9,463	5,420	57.3%	14,883	9,463	5,420	57.3%
11 UNIT COST ($/BBL)	35.12	34.34	0.79	2.3%	35.12	34.34	0.79	2.3%
12 AMOUNT ($)	522,758	324,948	197,810	60.9%	522,758	324,948	197,810	60.9%
13								
14 DAYS SUPPLY:	32	20	12	61.6%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	25,407	39,625	(14,218)	-35.9%	190,615	183,193	7,422	4.1%
17 UNIT COST ($/BBL)	35.85	38.81	(2.97)	-7.6%	39.07	41.64	(2.56)	-6.2%
18 AMOUNT ($)	910,728	1,538,020	(627,292)	-40.8%	7,448,268	7,627,365	(179,097)	-2.3%
19 BURNED:								
20 UNITS (BBL)	20,486	34,240	(13,754)	-40.2%	140,330	150,440	(10,110)	-6.7%
21 UNIT COST ($/BBL)	38.20	39.47	(1.27)	-3.2%	38.60	39.37	(0.78)	-2.0%
22 AMOUNT ($)	782,597	1,351,475	(568,878)	-42.1%	5,416,490	5,923,553	(507,063)	-8.6%
23 ENDING INVENTORY:								
24 UNITS (BBL)	77,076	82,746	(5,670)	-6.9%	77,076	82,746	(5,670)	-6.9%
25 UNIT COST ($/BBL)	36.31	39.20	(2.89)	-7.4%	36.31	39.20	(2.89)	-7.4%
26 AMOUNT ($)	2,798,710	3,243,797	(445,087)	-13.7%	2,798,710	3,243,797	(445,087)	-13.7%
27								
28 DAYS SUPPLY: NORMAL	111	119	(8)	-6.7%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	11	12	(1)	-6.9%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	520,798	610,300	(89,502)	-14.7%	3,465,906	3,843,273	(377,367)	-9.8%
32 UNIT COST ($/TON)	48.89	48.71	0.18	0.4%	47.82	48.00	(0.18)	-0.4%
33 AMOUNT ($)	25,463,316	29,728,382	(4,265,066)	-14.3%	165,749,783	184,489,163	(18,739,380)	-10.2%
34 BURNED:								
35 UNITS (TONS)	505,207	573,048	(67,841)	-11.8%	3,200,943	3,217,862	(16,919)	-0.5%
36 UNIT COST ($/TON)	49.08	48.64	0.45	0.9%	47.22	47.78	(0.57)	-1.2%
37 AMOUNT ($)	24,796,476	27,870,603	(3,074,127)	-11.0%	151,145,729	153,763,288	(2,617,559)	-1.7%
38 ENDING INVENTORY:								
39 UNITS (TONS)	703,320	1,063,768	(360,448)	-33.9%	703,320	1,063,768	(360,448)	-33.9%
40 UNIT COST ($/TON)	48.60	48.25	0.35	0.7%	48.60	48.25	0.35	0.7%
41 AMOUNT ($)	34,181,444	51,324,458	(17,143,014)	-33.4%	34,181,444	51,324,458	(17,143,014)	-33.4%
42								
43 DAYS SUPPLY:	35	54	(19)	-34.8%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	3,018,929	2,197,566	821,363	37.4%	8,529,095	8,024,708	504,387	6.3%
46 UNIT COST ($/MCF)	8.61	7.01	1.59	22.7%	7.77	7.25	0.52	7.1%
47 AMOUNT ($)	25,991,834	15,415,095	10,576,739	68.6%	66,271,126	58,198,789	8,072,337	13.9%
48 BURNED:								
49 UNITS (MCF)	3,018,929	2,197,566	821,363	37.4%	8,529,095	8,024,708	504,387	6.3%
50 UNIT COST ($/MCF)	8.61	7.01	1.59	22.7%	7.77	7.25	0.52	7.1%
51 AMOUNT ($)	25,991,834	15,415,096	10,576,738	68.6%	66,271,126	58,198,790	8,072,336	13.9%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	17,681
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	17,681

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(9,267)	(311,347)
OTHER USAGE	(1,503)	(54,680)
TOTAL	(10,770)	(366,027)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	11,907
IGNITION #2 OIL	293,639
IGNITION PROPANE	11,965
AERIAL SURVEY ADJ.	0
ADDITIVES	120,711
GREEN FUEL	0
TOTAL	438,222

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2003

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KW (A) FUEL COST	(6) CENTS/KW (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	2,591.0	0.0	2,591.0	2.428	2.428	62,900.00	62,900.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. - MB	18,305.0	0.0	18,305.0	6.088	7.570	1,114,400.00	1,385,600.00	212,300.00
TOTAL			**20,896.0**	**0.0**	**20,896.0**	**5.634**	**6.932**	**1,177,300.00**	**1,448,500.00**	**212,300.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	1,696.1	57.8	1,638.3	2.680	2.680	43,900.12	43,900.12	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	1,058.5	0.0	1,058.5	2.276	2.276	24,093.93	24,093.93	
FLA. PWR. CORP.		SCH. - MA	125.0	0.0	125.0	4.935	5.846	6,168.71	7,307.12	658.41
FLA. PWR. & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.0
CITY OF LAKELAND		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.0
SEMINOLE ELEC. CO-OP		SCH. - MA	950.0	0.0	950.0	3.872	4.657	36,781.38	44,237.32	3,807.94
THE ENERGY AUTHORITY		SCH. - MA	53.0	0.0	53.0	4.684	5.217	2,482.39	2,765.07	79.16
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.0
NEW SMYRNA BEACH		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.0
ORLANDO UTILITIES		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.0
RELIANT ENERGY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.0
HARDEE PWR. PART. TO FLA. PWR. CORP.*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO FLA. PWR. & LIGHT*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO NEW SMYRNA BEACH*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO CITY OF LAKELAND*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO SEMINOLE ELEC. CO-OP*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
AUBURNDALE POWER PARTNERS		SCH. - OATT	1.0	0.0	1.0	6.100	6.100	61.00	61.00	
CARGILL ALLIANT		SCH. - OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ADJUSTMENTS										
HARDEE PWR. PART. TO FLA. PWR. & LIGHT**	MAY. 2003	SCH. - MA	(147.0)	0.0	(147.0)	3.912	5.962	(5,750.40)	(8,764.58)	(2,993.60)
HARDEE PWR. PART. TO FLA. PWR. & LIGHT**	MAY. 2003	SCH. - MA	147.0	0.0	147.0	4.592	6.370	6,750.40	9,364.58	2,593.60
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			2,754.6	57.8	2,696.8	2.521	2.521	67,994.05	67,994.05	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			1,128.0	0.0	1,128.0	4.116	4.868	46,432.48	54,909.51	4,145.51
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			1.0	0.0	1.0	6.100	6.100	61.00	61.00	
TOTAL			**3,883.6**	**57.8**	**3,825.8**	**2.993**	**3.214**	**114,487.53**	**122,964.56**	**4,145.51**
CURRENT MONTH:										
DIFFERENCE			(17,012.4)	57.8	(17,070.2)	(2.641)	(3.718)	(1,062,812.47)	(1,325,535.44)	(208,154.49)
DIFFERENCE %			-81.4%	0.0%	-81.7%	-46.9%	-53.6%	-90.3%	-91.5%	-98.0%
PERIOD TO DATE:										
ACTUAL			97,368.6	169.7	97,198.9	3.239	4.407	3,148,064.31	4,283,466.91	815,650.85
ESTIMATED			167,983.9	5.3	167,978.6	3.778	5.133	6,345,501.69	8,621,917.12	1,759,294.33
DIFFERENCE			(70,615.3)	164.4	(70,779.7)	(0.539)	(0.726)	(3,197,437.38)	(4,338,450.21)	(943,643.48)
DIFFERENCE %			-42.0%	3101.9%	-42.1%	-14.3%	-14.1%	-50.4%	-50.3%	-53.6%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF JUNE 2003.
** SEC 60% PROFIT OR $11,148.08 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	10,617.0	0.0	5,658.0	4,959.0	7.352	7.352	364,600.00
HARDEE POWER PARTNERS		IPP	55,649.0	0.0	0.0	55,649.0	6.530	6.530	3,633,700.00
VARIOUS		OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
VARIOUS		MKT. BASE	144,454.0	0.0	0.0	144,454.0	4.617	4.617	6,670,000.00
TOTAL			**210,720.0**	**0.0**	**5,658.0**	**205,062.0**	**5.202**	**5.202**	**10,668,300.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	77,302.0	0.0	0.0	77,302.0	6.329	6.329	4,892,577.88
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH. - J	33,182.0	0.0	105.0	33,077.0	6.103	6.103	2,018,655.55
FLA. POWER & LIGHT		SCH. - J	2,410.0	0.0	1,444.2	965.8	(2.027)	(2.027)	(19,578.94)
CITY OF LAKELAND		SCH. - J	16,617.0	0.0	154.0	16,463.0	5.611	5.611	923,739.50
ORLANDO UTIL. COMM.		SCH. - J	18,325.0	0.0	309.2	18,015.8	6.575	6.575	1,184,549.95
CAROLINA POWER & LIGHT		SCH. - J	1,525.0	0.0	0.0	1,525.0	4.378	4.378	66,763.00
THE ENERGY AUTHORITY		SCH. - J	27,267.0	0.0	316.0	26,951.0	5.394	5.394	1,453,733.76
REEDY CREEK		SCH. - J	140.0	0.0	0.0	140.0	4.861	4.861	6,805.00
OKEELANTA		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TALLAHASSEE		SCH. - J	1,533.0	0.0	0.0	1,533.0	4.759	4.759	72,948.80
CALPINE		SCH. - J	30.0	0.0	0.0	30.0	6.350	6.350	1,905.00
CARGILL ALLIANT		SCH. - J	32,930.0	0.0	50.0	32,880.0	5.624	5.624	1,849,058.50
CONOCO		SCH. - J	3,724.0	0.0	49.0	3,675.0	2.892	2.892	106,285.46
CORAL POWER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RELIANT		SCH. - J	4,543.0	0.0	1,303.4	3,239.6	9.062	9.062	293,558.42
SEMINOLE ELEC. CO-OP		SCH. - J	7,198.0	0.0	768.0	6,430.0	4.955	4.955	318,632.00
DUKE ENERGY		SCH. - J	2,996.0	0.0	175.0	2,821.0	6.677	6.677	188,367.94
DYNEGY POWER MARKETING		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RINGHAVER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	May 2003	IPP	(81,525.0)	0.0	0.0	(81,525.0)	6.416	6.416	(5,230,270.73)
HARDEE PWR. PART.-NATIVE	May 2003	IPP	81,525.0	0.0	0.0	81,525.0	6.243	6.243	5,089,592.32
HARDEE PWR. PART.-OTHERS	May 2003	IPP	(826.0)	0.0	0.0	(826.0)	4.778	4.778	(39,464.26)
HARDEE PWR. PART.-OTHERS	May 2003	IPP	826.0	0.0	0.0	826.0	4.899	4.899	40,464.26
OKEELANTA	May 2003	SCH. - J	(16,433.0)	0.0	0.0	(16,433.0)	5.040	5.040	(828,181.41)
OKEELANTA	May 2003	SCH. - J	16,433.0	0.0	0.0	16,433.0	5.041	5.041	828,366.03
THE ENERGY AUTHORITY	May 2003	SCH. - J	(10,291.0)	0.0	(1,483.3)	(8,807.7)	8.391	8.391	(739,035.60)
THE ENERGY AUTHORITY	May 2003	SCH. - J	10,291.0	0.0	1,483.3	8,807.7	8.391	8.391	739,068.93
TOTAL			**229,722.0**	**0.0**	**4,673.8**	**225,048.2**	**5.874**	**5.874**	**13,218,541.36**
CURRENT MONTH:									
DIFFERENCE			19,002.0	0.0	(984.2)	19,986.2	0.672	0.672	2,550,241.36
DIFFERENCE %			9.0%	0.0%	-17.4%	9.7%	12.9%	12.9%	23.9%
PERIOD TO DATE:									
ACTUAL			1,230,470.0	0.0	18,579.4	1,211,890.6	5.940	5.940	71,982,326.94
ESTIMATED			1,010,103.0	0.0	15,789.2	994,313.8	5.282	5.282	52,524,439.59
DIFFERENCE			220,367.0	0.0	2,790.2	217,576.8	0.658	0.658	19,457,887.35
DIFFERENCE %			21.8%	0.0%	17.7%	21.9%	12.5%	12.5%	37.0%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	40,097.0	0.0	0.0	40,097.0	2.706	2.706	1,085,200.00
TOTAL			**40,097.0**	**0.0**	**0.0**	**40,097.0**	**2.706**	**2.706**	**1,085,200.00**
ACTUAL:									
HILLSBOROUGH COUNTY		COGEN.	17,172.0	0.0	0.0	17,172.0	1.733	1.733	297,628.17
McKAY BAY REFUSE		COGEN.	11,840.0	0.0	0.0	11,840.0	1.731	1.731	204,895.18
ORANGE COGENERATION L.P.		COGEN.	7,590.0	0.0	0.0	7,590.0	1.717	1.717	130,335.38
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	516.0	0.0	0.0	516.0	4.395	4.395	22,678.31
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	252.0	0.0	0.0	252.0	8.574	8.574	21,605.38
CF INDUSTRIES INC.		COGEN.	1,014.0	0.0	0.0	1,014.0	4.579	4.579	46,432.45
IMC-AGRICO-NEW WALES		COGEN.	150.0	0.0	0.0	150.0	4.216	4.216	6,323.88
IMC-AGRICO-S. PIERCE		COGEN.	71.0	0.0	0.0	71.0	5.548	5.548	3,939.18
AUBURNDALE POWER PARTNERS		COGEN.	1.0	0.0	0.0	1.0	1.713	1.713	17.13
CUTRALE CITRUS		COGEN.	6.0	0.0	0.0	6.0	4.450	4.450	266.98
SUB-TOTAL FOR JUNE 2003			38,612.0	0.0	0.0	38,612.0	1.901	1.901	734,122.04
ADJUSTMENTS FOR THE MONTH OF:	**MAY 2003**								
HILLSBOROUGH COUNTY		COGEN.	(18,401.0)	0.0	0.0	(18,401.0)	1.746	1.746	(321,232.46)
			18,401.0	0.0	0.0	18,401.0	1.751	1.751	322,179.34
McKAY BAY REFUSE		COGEN.	(13,222.0)	0.0	0.0	(13,222.0)	1.746	1.746	(230,848.39)
			13,222.0	0.0	0.0	13,222.0	1.751	1.751	231,528.08
ORANGE COGENERATION L.P.		COGEN.	(7,843.0)	0.0	0.0	(7,843.0)	1.714	1.714	(134,417.69)
			7,843.0	0.0	0.0	7,843.0	1.722	1.722	135,020.40
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**MAY 2003**		0.0	0.0	0.0	0.0	0.000	0.000	2,229.28
GRAND TOTAL			**38,612.0**	**0.0**	**0.0**	**38,612.0**	**1.907**	**1.907**	**736,351.32**
CURRENT MONTH:									
DIFFERENCE			(1,485.0)	0.0	0.0	(1,485.0)	(0.799)	(0.799)	(348,848.68)
DIFFERENCE %			-3.7%	0.0%	0.0%	-3.7%	-29.5%	-29.5%	-32.1%
PERIOD TO DATE:									
ACTUAL			276,849.0	0.0	0.0	276,849.0	2.314	2.314	6,407,314.89
ESTIMATED			243,178.0	0.0	0.0	243,178.0	2.638	2.638	6,414,765.12
DIFFERENCE			33,671.0	0.0	0.0	33,671.0	(0.324)	(0.324)	(7,450.23)
DIFFERENCE %			13.8%	0.0%	0.0%	13.8%	(0.123)	(0.123)	-0.1%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

JULY 2003

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	47,997,843	51,707,470	(3,709,627)	-7.2%	1,550,100	1,715,723	(165,623)	-9.7%	3.09644	3.01374	0.08269	2.7%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wsuch. Wheeling Losses)	(6,114)	(6,000)	(2,114)	35.2%	1,550,100 (a)	1,715,723 (a)	(165,623)	-9.7%	(0.00052)	(0.00035)	(0.00017)	49.7%
4b. Adjustments to Fuel Cost	(3,997)	0	(3,997)	0.0%	1,550,100 (a)	1,715,723 (a)	(165,623)	-9.7%	(0.00026)	0.00000	(0.00026)	0.0%
4c. Incremental Hedging O&M Costs	0	34,583	(34,583)	-100.0%	1,550,100 (a)	1,715,723 (a)	(165,623)	-9.7%	0.00000	0.00202	(0.00202)	-100.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**47,985,732**	**51,736,053**	**(3,750,321)**	**-7.2%**	**1,550,100**	**1,715,723**	**(165,623)**	**-9.7%**	**3.09565**	**3.01541**	**0.08025**	**2.7%**
6. Fuel Cost of Purchased Power - Firm (A7)	19,176,912	12,332,100	6,844,812	55.5%	328,140	198,738	129,402	65.1%	5.84413	6.20520	(0.36108)	-5.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	930,621	1,151,800	(221,179)	-19.2%	40,910	41,439	(529)	-1.3%	2.27480	2.77951	(0.50471)	-18.2%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**20,107,533**	**13,483,900**	**6,623,633**	**49.1%**	**369,050**	**240,177**	**128,873**	**53.7%**	**5.44846**	**5.61415**	**(0.16569)**	**-3.0%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,919,150**	**1,955,900**	**(36,750)**	**-1.9%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	95,998	41,700	54,298	130.2%	2,850	1,934	916	47.4%	3.36835	2.15615	1.21220	56.2%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	3,166	0	3,166	0.0%	51	0	51	0.0%	6.20784	0.00000	6.20784	0.0%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	66,715	1,835,100	(1,768,385)	-96.4%	1,696	28,420	(26,724)	-94.0%	3.93367	6.45707	(2.52341)	-39.1%
19. Gains on Market Based Sales	26,162	393,100	(366,938)	-93.3%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**192,041**	**2,269,900**	**(2,077,859)**	**-91.5%**	**4,597**	**30,354**	**(25,757)**	**-84.9%**	**4.17753**	**7.47809**	**(3.30056)**	**-44.1%**
21. Net Inadvertant Interchange					(424)	0	(424)	0.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					(339)	0	(339)	0.0%				
23. Interchange and Wheeling Losses					372	400	(28)	-7.0%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**67,901,224**	**62,950,053**	**4,951,171**	**7.9%**	**1,913,418**	**1,925,146**	**(11,728)**	**-0.6%**	**3.54869**	**3.26988**	**0.27880**	**8.5%**
25. Net Unbilled	1,850,995 (a)	1,749,486 (a)	101,509	5.8%	52,160	53,503	(1,343)	-2.5%	3.54869	3.26988	0.27880	8.5%
26. Company Use	167,214 (a)	130,795 (a)	36,419	27.8%	4,712	4,000	712	17.8%	3.54868	3.26988	0.27881	8.5%
27. T & D Losses	3,794,505 (a)	2,898,458 (a)	896,047	30.9%	106,927	88,641	18,286	20.6%	3.54869	3.26988	0.27880	8.5%
28. System KWH Sales	67,901,224	62,950,053	4,951,171	7.9%	1,749,619	1,779,002	(29,383)	-1.7%	3.88091	3.53850	0.34241	9.7%
29. Wholesale KWH Sales	(2,049,239)	(1,929,973)	(119,266)	6.2%	(52,803)	(54,542)	1,739	-3.2%	3.88091	3.53851	0.34241	9.7%
30. Jurisdictional KWH Sales	65,851,985	61,020,080	4,831,905	7.9%	1,696,816	1,724,460	(27,644)	-1.6%	3.88091	3.53850	0.34241	9.7%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	65,927,056	61,089,643	4,837,413	7.9%	1,696,816	1,724,460	(27,644)	-1.6%	3.88534	3.54254	0.34280	9.7%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	261,528	261,398	130	0.0%	1,696,816	1,724,460	(27,644)	-1.6%	0.01541	0.01516	0.00025	1.7%
34. Adjustment	0	0	0	0.0%	1,696,816	1,724,460	(27,644)	-1.6%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	1,696,816	1,724,460	(27,644)	-1.6%	0.00000	0.00000	0.00000	0.0%
36. True-up *	263,799	263,799	0	0.0%	1,696,816	1,724,460	(27,644)	-1.6%	0.01555	0.01530	0.00025	1.6%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	66,452,383	61,614,840	4,837,543	7.9%	1,696,816	1,724,460	(27,644)	-1.6%	3.91630	3.57299	0.34331	9.6%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.91912	3.57557	0.34355	9.6%
40. GPIF * (Already Adjusted for Taxes)	(69,252)	(69,203)	(49)	0.1%	1,696,816	1,724,460	(27,644)	-1.6%	(0.00408)	(0.00401)	(0.00007)	1.7%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**66,383,131**	**61,545,637**	**4,837,494**	**7.9%**	**1,696,816**	**1,724,460**	**(27,644)**	**-1.6%**	**3.91504**	**3.57156**	**0.34348**	**9.6%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.915**	**3.572**	**0.343**	**9.6%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: JULY 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	273,429,862	271,312,613	2,117,249	0.8%	9,691,688	9,926,696	(235,008)	-2.4%	2.82128	2.73316	0.08812	3.2%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(45,288)	(42,108)	(3,180)	7.6%	9,691,688 (a)	9,926,696 (a)	(235,008)	-2.4%	(0.00047)	(0.00042)	(0.00004)	10.2%
4b. Adjustments to Fuel Cost	(21,322)	(2,738)	(18,584)	678.7%	9,691,688 (a)	9,926,696 (a)	(235,008)	-2.4%	(0.00022)	(0.00003)	(0.00019)	697.6%
4c. Adjustments to Fuel Cost	0	207,498	(207,498)	-100.0%	9,691,688 (a)	9,926,696 (a)	(235,008)	-2.4%	0.00000	0.00209	(0.00209)	-100.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**273,363,252**	**271,475,265**	**1,887,987**	**0.7%**	**9,691,688**	**9,926,696**	**(235,008)**	**-2.4%**	**2.82059**	**2.73480**	**0.08580**	**3.1%**
6. Fuel Cost of Purchased Power - Firm (A7)	91,159,239	64,856,540	26,302,699	40.6%	1,540,030	1,193,052	346,978	29.1%	5.91932	5.43619	0.48313	8.9%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	7,337,935	7,566,565	(228,630)	-3.0%	317,759	284,617	33,142	11.6%	2.30928	2.65851	(0.34923)	-13.1%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**98,497,174**	**72,423,105**	**26,074,069**	**36.0%**	**1,857,789**	**1,477,669**	**380,120**	**25.7%**	**5.30185**	**4.90117**	**0.40068**	**8.2%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**11,549,477**	**11,404,365**	**145,112**	**1.3%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	455,521	431,307	24,214	5.6%	16,685	18,386	(1,701)	-9.3%	2.73012	2.34584	0.38428	16.4%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	6,085	4,680	1,405	30.0%	120	46	74	160.9%	5.07083	10.17391	(5.10308)	-50.2%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	121,809	108,975	12,834	11.8%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	2,730,529	7,677,340	(4,946,811)	-64.4%	84,992	179,901	(94,909)	-52.8%	3.21269	4.26754	(1.05485)	-24.7%
19. Gains on Market Based Sales	841,813	2,152,394	(1,310,581)	-60.9%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**4,155,757**	**10,374,696**	**(6,218,939)**	**-59.9%**	**101,797**	**198,333**	**(96,536)**	**-48.7%**	**4.08240**	**5.23095**	**(1.14855)**	**-22.0%**
21. Net Inadvertant Interchange					(631)	(291)	(340)	116.8%				
22. Wheeling Rec'd. less Wheeling Del'd.					417	652	(235)	-36.0%				
23. Interchange and Wheeling Losses					4,596	2,996	1,600	53.4%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**367,704,669**	**333,523,674**	**34,180,995**	**10.2%**	**11,442,870**	**11,203,397**	**239,473**	**2.1%**	**3.21340**	**2.97699**	**0.23641**	**7.9%**
25. Net Unbilled	8,867,541 (a)	10,940,089 (a)	(2,072,548)	-18.9%	255,917	356,507	(99,590)	-28.0%	3.46501	3.07732	0.38769	12.6%
26. Company Use	923,939 (a)	828,936 (a)	95,003	11.5%	28,884	28,099	785	2.8%	3.19879	2.95006	0.24874	8.4%
27. T & D Losses	15,209,297 (a)	11,177,421 (a)	4,031,876	36.1%	451,186	365,357	85,829	23.5%	3.37096	3.05931	0.31164	10.2%
28. System KWH Sales	367,704,669	333,523,674	34,180,995	10.2%	10,706,883	10,454,434	252,449	2.4%	3.43428	3.19026	0.24402	7.6%
29. Wholesale KWH Sales	(11,813,561)	(9,455,879)	(2,357,682)	24.9%	(341,783)	(290,324)	(51,459)	17.7%	3.45645	3.25701	0.19944	6.1%
30. Jurisdictional KWH Sales	355,891,108	324,067,795	31,823,313	9.8%	10,365,100	10,164,110	200,990	2.0%	3.43355	3.18835	0.24520	7.7%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	356,296,824	324,437,232	31,859,592	9.8%	10,365,100	10,164,110	200,990	2.0%	3.43747	3.19199	0.24548	7.7%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	1,878,474	1,887,877	(9,403)	-0.5%	10,365,100	10,164,110	200,990	2.0%	0.01812	0.01857	(0.00045)	-2.4%
34. Adjustment	0	0	0	0.0%	10,365,100	10,164,110	200,990	2.0%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	10,365,100	10,164,110	200,990	2.0%	0.00000	0.00000	0.00000	0.0%
36. True-up *	1,846,593	1,846,593	0	0.0%	10,365,100	10,164,110	200,990	2.0%	0.01782	0.01817	(0.00035)	-1.9%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	360,021,891	328,171,702	31,850,189	9.7%	10,365,100	10,164,110	200,990	2.0%	3.47340	3.22873	0.24467	7.6%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.47591	3.23106	0.24485	7.6%
40. GPIF * (Already Adjusted for Taxes)	(483,975)	(484,421)	446	-0.1%	10,365,100	10,164,110	200,990	2.0%	(0.00467)	(0.00477)	0.00010	-2.0%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**359,537,916**	**327,687,281**	**31,850,635**	**9.7%**	**10,365,100**	**10,164,110**	**200,990**	**2.0%**	**3.47124**	**3.22629**	**0.24495**	**7.6%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.471**	**3.226**	**0.245**	**7.6%**

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	47,997,843	51,707,470	(3,709,627)	-7.2%	273,429,862	271,312,613	2,117,249	0.8%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	165,879	1,876,800	(1,710,921)	-91.2%	3,313,944	8,222,302	(4,908,358)	-59.7%
2a. GAINS FROM MARKET BASED SALES	26,162	393,100	(366,938)	-93.3%	841,813	2,152,394	(1,310,581)	-60.9%
3. FUEL COST OF PURCHASED POWER	19,176,912	12,332,100	6,844,812	55.5%	91,159,239	64,856,540	26,302,699	40.6%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	930,621	1,151,800	(221,179)	-19.2%	7,337,935	7,566,565	(228,630)	-3.0%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	67,913,335	62,921,470	4,991,865	7.9%	367,771,279	333,361,022	34,410,257	10.3%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(8,114)	(6,000)	(2,114)	35.2%	(45,288)	(42,108)	(3,180)	7.6%
6b. ADJ.TO FUEL COST	(3,997)	0	(3,997)	0.0%	(21,322)	(2,738)	(18,584)	678.7%
6c. INCREMENTAL HEDGING O&M COSTS	0	34,583	(34,583)	-100.0%	0	207,498	(207,498)	-100.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	67,901,224	62,950,053	4,951,171	7.9%	367,704,669	333,523,674	34,180,995	10.2%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,696,816	1,724,460	(27,644)	-1.6%	10,365,100	10,164,110	200,990	2.0%
2. NONJURISDICTIONAL SALES	52,803	54,542	(1,739)	-3.2%	341,783	290,324	51,459	17.7%
3. TOTAL SALES	1,749,619	1,779,002	(29,383)	-1.7%	10,706,883	10,454,434	252,449	2.4%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9698203	0.9693412	0.0004791	0.0%	0.9680782	0.9722296	(0.0041514)	-0.4%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	57,927,664	59,207,371	(1,279,707)	-2.2%	335,194,674	330,727,274	4,467,400	1.4%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(263,799)	(263,799)	0	0.0%	(1,846,593)	(1,846,593)	0	0.0%
2b. INCENTIVE PROVISION	69,252	69,203	49	0.1%	483,975	484,421	(446)	-0.1%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	57,733,117	59,012,775	(1,279,658)	-2.2%	333,832,056	329,365,102	4,466,954	1.4%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE	67,901,224	62,950,053	4,951,171	7.9%	367,704,669	333,523,674	34,180,995	10.2%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINI	0.9698203	0.9693412	0.0004791	0.0%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	65,851,985	61,020,080	4,831,905	7.9%	355,891,108	324,067,795	31,823,313	9.8%
6a. JURISDIC. LOSS MULTIPLIER	1.00114	1.00114	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	65,927,055	61,089,643	4,837,412	7.9%	356,296,823	324,437,232	31,859,591	9.8%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	269,666	269,666	0	0.0%	1,940,813	1,940,813	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	261,528	261,398	130	0.0%	1,878,474	1,887,877	(9,403)	-0.5%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	66,188,583	61,351,041	4,837,542	7.9%	358,175,297	326,325,109	31,850,188	9.8%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(8,455,466)	(2,338,266)	(6,117,200)	261.6%	(24,343,241)	3,039,993	(27,383,234)	-900.8%
8. INTEREST PROVISION FOR THE MONTH	(42,866)	(28,173)	(14,693)	52.2%	(245,228)	(210,054)	(35,174)	16.7%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(46,335,261)	(25,048,746)	(21,286,515)	85.0%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	263,799	263,799	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(54,569,794)	(27,151,386)	(27,418,408)	101.0%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(46,335,261)	(25,048,746)	(21,286,515)	85.0%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(54,526,928)	(27,123,213)	(27,403,715)	101.0%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(100,862,189)	(52,171,959)	(48,690,230)	93.3%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(50,431,095)	(26,085,980)	(24,345,115)	93.3%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.000	1.300	(0)	-23.1%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.050	1.300	(0)	-19.2%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	2.050	2.600	(1)	-21.2%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.025	1.300	(0)	-21.2%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.085	0.108	(0)	-21.3%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(42,866)	(28,173)	(14,693)	52.2%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	608,525	525,056	83,469	15.9%	3,207,199	2,244,568	962,631	42.9%
2	LIGHT OIL	333,582	1,876,173	(1,542,591)	-82.2%	5,750,072	7,799,726	(2,049,654)	-26.3%
3	COAL	25,995,254	29,712,386	(3,717,132)	-12.5%	177,140,983	183,475,674	(6,334,691)	-3.5%
4	NATURAL GAS	21,060,482	19,593,855	1,466,627	7.5%	87,331,608	77,792,645	9,538,963	12.3%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	47,997,843	51,707,470	(3,709,627)	-7.2%	273,429,862	271,312,613	2,117,249	0.8%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	11,847	10,414	1,433	13.8%	56,036	42,216	13,820	32.7%
9	LIGHT OIL	4,537	26,098	(21,561)	-82.6%	84,137	113,011	(28,874)	-25.5%
10	COAL	1,156,214	1,322,028	(165,814)	-12.5%	8,052,924	8,352,397	(299,473)	-3.6%
11	NATURAL GAS	377,502	357,183	20,319	5.7%	1,498,591	1,419,072	79,519	5.6%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,550,100	1,715,723	(165,623)	-9.7%	9,691,688	9,926,696	(235,008)	-2.4%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	18,486	15,690	2,796	17.8%	86,925	63,719	23,206	36.4%
16	LIGHT OIL (BBL)	9,344	48,841	(39,497)	-80.9%	149,674	199,281	(49,607)	-24.9%
17	COAL (TON)	543,825	608,192	(64,367)	-10.6%	3,744,768	3,826,054	(81,286)	-2.1%
18	NATURAL GAS (MCF)	2,867,977	2,795,531	72,446	2.6%	11,397,072	10,820,239	576,833	5.3%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	115,973	99,770	16,203	16.2%	545,327	405,342	139,985	34.5%
22	LIGHT OIL	54,013	282,652	(228,639)	-80.9%	844,300	1,155,725	(311,425)	-26.9%
23	COAL	13,154,642	14,618,402	(1,463,760)	-10.0%	89,538,279	91,954,620	(2,416,341)	-2.6%
24	NATURAL GAS	3,057,264	2,873,767	183,497	6.4%	12,097,598	11,127,577	970,021	8.7%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	16,381,892	17,874,591	(1,492,699)	-8.4%	103,025,504	104,643,264	(1,617,760)	-1.5%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.76%	0.61%	0.00	-	0.58%	0.43%	0.00	-
29	LIGHT OIL	0.29%	1.52%	(0.01)	-	0.87%	1.14%	(0.00)	-
30	COAL	74.59%	77.05%	(0.02)	-	83.09%	84.14%	(0.01)	-
31	NATURAL GAS	24.35%	20.82%	0.04	-	15.46%	14.30%	0.01	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	32.92	33.46	(0.55)	-1.6%	36.90	35.23	1.67	4.7%
36	LIGHT OIL ($/BBL)	35.70	38.41	(2.71)	-7.1%	38.42	39.14	(0.72)	-1.8%
37	COAL ($/TON)	47.80	48.85	(1.05)	-2.2%	47.30	47.95	(0.65)	-1.4%
38	NATURAL GAS ($/MCF)	7.34	7.01	0.33	4.8%	7.66	7.19	0.47	6.6%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	5.25	5.26	(0.02)	-0.3%	5.88	5.54	0.34	6.2%
42	LIGHT OIL	6.18	6.64	(0.46)	-7.0%	6.81	6.75	0.06	0.9%
43	COAL	1.98	2.03	(0.06)	-2.8%	1.98	2.00	(0.02)	-0.8%
44	NATURAL GAS	6.89	6.82	0.07	1.0%	7.22	6.99	0.23	3.3%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.93	2.89	0.04	1.3%	2.65	2.59	0.06	2.4%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,789	9,580	209	2.2%	9,732	9,602	130	1.4%
49	LIGHT OIL	11,905	10,830	1,075	9.9%	10,035	10,227	(192)	-1.9%
50	COAL	11,377	11,058	319	2.9%	11,119	11,009	110	1.0%
51	NATURAL GAS	8,099	8,046	53	0.7%	8,073	7,841	232	3.0%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,568	10,418	150	1.4%	10,630	10,542	88	0.8%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.14	5.04	0.10	2.0%	5.72	5.32	0.40	7.5%
56	LIGHT OIL	7.35	7.19	0.16	2.2%	6.83	6.90	(0.07)	-1.0%
57	COAL	2.25	2.25	0.00	0.0%	2.20	2.20	0.00	0.0%
58	NATURAL GAS	5.58	5.49	0.09	1.6%	5.83	5.48	0.35	6.4%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	3.10	3.01	0.09	3.0%	2.82	2.73	0.09	3.3%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: JULY 2003

SCHEDULE A4
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(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	75	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#2	100	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	150	72,440	64.9	85.5	73.3	12,308	COAL	38,444	23,192,000	891,593.2	1,834,213	2.53	47.71
GAN.#4	164	42,359	34.7	51.7	62.0	13,230	COAL	24,292	23,070,000	560,416.4	1,159,003	2.74	47.71
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	353	133,883	51.0	63.7	64.3	11,985	COAL	67,663	23,714,000	1,604,560.4	3,228,290	2.41	47.71
GANNON STATION	**842**	**248,682**	**39.7**	**72.8**	**52.1**	**12,291**	**COAL**	**130,399**	**23,440,134**	**3,056,570.0**	**6,221,506**	**2.50**	**47.71**
B.B.#1	421	169,176	54.0	58.9	68.4	11,198	COAL	77,772	24,358,120	1,894,379.7	3,818,851	2.26	49.10
B.B.#2	411	213,042	69.7	78.0	69.7	10,873	COAL	94,584	24,489,580	2,316,336.9	4,644,373	2.18	49.10
B.B.#3	428	178,586	56.1	68.5	56.2	11,665	COAL	84,993	24,511,300	2,083,280.8	4,173,425	2.34	49.10
B.B.#4	452	191,005	56.8	66.9	75.7	11,074	COAL	89,739	23,571,140	2,115,252.9	4,406,469	2.31	49.10
B.B. STATION	**1,712**	**751,809**	**59.0**	**68.0**	**67.6**	**11,185**	**COAL**	**347,088**	**24,227,981**	**8,409,250.3**	**17,043,118**	**2.27**	**49.10**
SEB-PHIL. #1(HVY OIL)	17	5,891	46.6	100.0	98.5	9,789	HVY.OIL	9,192	6,273,540	57,668.6	302,584	5.14	32.92
SEB-PHIL. #2(HVY OIL)	17	5,956	47.1	100.0	99.3	9,789	HVY.OIL	9,294	6,273,540	58,304.7	305,941	5.14	32.92
SEB-PHILLIPS TOTAL	**34**	**11,847**	**46.8**	**100.0**	**98.9**	**9,789**	**HVY.OIL**	**18,486**	**6,273,537**	**115,973.3**	**608,525**	**5.14**	**32.92**
POLK #1 GASIFIER	255	155,723	82.1	87.4	83.7	10,845	COAL	66,338	25,458,000	1,688,821.6	2,730,630	1.75	41.16
POLK #1 CT (OIL)	225	2,564	1.5	99.5	77.3	7,342	LGT.OIL	3,283	5,801,350	18,823.1	124,871	4.87	38.03
POLK #1 TOTAL	**255**	**158,287**	**83.4**	**88.7**	**83.6**	**10,788**	**-**	**-**	**-**	**1,707,644.7**	**2,855,501**	**1.80**	**-**
POLK #2 CT (GAS)	150	22,359	20.0	99.2	78.5	10,809	GAS	226,730	1,066,000	241,694.0	1,764,561	7.89	7.78
POLK #2 CT (OIL)	160	79	0.1	96.9	23.6	65,162	LGT.OIL	882	5,801,347	5,115.6	33,547	42.46	38.04
POLK #2 TOTAL	**155**	**22,438**	**19.5**	**99.4**	**77.8**	**11,000**	**-**	**-**	**-**	**246,809.6**	**1,798,108**	**8.01**	**-**
POLK #3 CT (GAS)	150	31,352	28.1	98.7	79.8	11,900	GAS	349,990	1,066,000	373,089.0	2,723,674	8.69	7.78
POLK #3 CT (OIL)	165	38	0.0	96.6	13.8	20,239	LGT.OIL	132	5,801,318	765.9	5,023	13.22	38.05
POLK #3 TOTAL	**158**	**31,390**	**26.7**	**99.4**	**79.3**	**11,910**	**-**	**-**	**-**	**373,854.9**	**2,728,697**	**8.69**	**-**
POLK STATION TOTAL	**568**	**212,115**	**50.2**	**94.6**	**80.8**	**10,977**	**-**	**-**	**-**	**2,328,309.2**	**7,382,306**	**3.48**	**-**
B.B.C.T.#1	14	357	3.4	100.0	79.7	18,739	LGT.OIL	1,167	5,734,425	6,690.0	39,341	11.02	33.71
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	1,499	3.4	100.0	75.7	15,089	LGT.OIL	3,880	5,828,504	22,618.2	130,800	8.73	33.71
C.T. TOTAL	**140**	**1,856**	**1.8**	**100.0**	**76.5**	**15,791**	**LGT.OIL**	**5,047**	**5,806,766**	**29,308.2**	**170,141**	**9.17**	**33.71**
CITY OF TAMPA	**6**	**1,432**	**32.1**	**0.0**	**0.0**	**10,134**	**GAS**	**13,613**	**1,066,000**	**14,511.5**	**128,884**	**9.00**	**9.47**
BAYSIDE ST 1	246	110,399	60.3	83.8	67.6	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	72,180	65.6	95.5	80.0	11,447	GAS	775,094	1,066,000	826,249.9	5,595,761	7.75	7.22
BAYSIDE CT1B	148	72,497	65.8	95.3	77.9	11,447	GAS	778,497	1,066,000	829,878.7	5,620,329	7.75	7.22
BAYSIDE CT1C	148	67,427	61.2	94.9	79.7	11,447	GAS	724,053	1,066,000	771,840.5	5,227,273	7.75	7.22
BAYSIDE UNIT 1 TOTAL	**690**	**322,503**	**62.8**	**91.1**	**75.1**	**7,529**	**GAS**	**2,277,644**	**1,066,000**	**2,427,969.0**	**16,443,363**	**5.10**	**7.22**
BAYSIDE UNIT 2 TOTAL	**0**	**(144)**	**-**	**-**	**-**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE STATION TOTAL	**690**	**322,359**	**62.8**	**91.1**	**75.1**	**7,532**	**GAS**	**2,277,644**	**1,066,000**	**2,427,969.0**	**16,443,363**	**5.10**	**7.22**
TOT. COAL (GN,BB,POLK)	**2,809**	**1,156,214**	**55.3**	**71.2**	**64.4**	**11,377**	**COAL**	**543,825**	**24,189,112**	**13,154,641.9**	**25,995,254**	**2.25**	**47.80**
SYSTEM	**3,992**	**1,550,100**	**52.2**	**79.5**	**69.2**	**10,568**	**-**	**-**	**-**	**16,381,891.5**	**47,997,843**	**3.10**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2003

SCHEDULE A5
PAGE 1 OF 2
REVISED WITH
TRUE UP FILING

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	16,833	15,690	1,143	7.3%	89,413	62,440	26,973	43.2%
3 UNIT COST ($/BBL)	29.84	32.05	(2.21)	-6.9%	34.87	33.73	1.14	3.4%
4 AMOUNT ($)	502,245	502,865	(620)	-0.1%	3,117,839	2,105,940	1,011,899	48.0%
5 BURNED:								
6 UNITS (BBL)	18,486	15,690	2,796	17.8%	86,925	63,719	23,206	36.4%
7 UNIT COST ($/BBL)	32.92	33.46	(0.55)	-1.6%	36.90	35.23	1.67	4.7%
8 AMOUNT ($)	608,525	525,056	83,469	15.9%	3,207,199	2,244,568	962,631	42.9%
9 ENDING INVENTORY:								
10 UNITS (BBL)	13,230	9,463	3,767	39.8%	13,230	9,463	3,767	39.8%
11 UNIT COST ($/BBL)	33.11	32.91	0.20	0.6%	33.11	32.91	0.20	0.6%
12 AMOUNT ($)	438,034	311,438	126,596	40.6%	438,034	311,438	126,596	40.6%
13								
14 DAYS SUPPLY:	32	21	11	54.2%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	15,497	54,257	(38,760)	-71.4%	206,112	237,450	(31,338)	-13.2%
17 UNIT COST ($/BBL)	34.41	37.82	(3.41)	-9.0%	38.72	40.76	(2.04)	-5.0%
18 AMOUNT ($)	533,235	2,051,826	(1,518,591)	-74.0%	7,981,503	9,679,191	(1,697,688)	-17.5%
19 BURNED:								
20 UNITS (BBL)	9,344	48,841	(39,497)	-80.9%	149,674	199,281	(49,607)	-24.9%
21 UNIT COST ($/BBL)	35.70	38.41	(2.71)	-7.1%	38.42	39.14	(0.72)	-1.8%
22 AMOUNT ($)	333,582	1,876,173	(1,542,591)	-82.2%	5,750,072	7,799,726	(2,049,654)	-26.3%
23 ENDING INVENTORY:								
24 UNITS (BBL)	73,688	82,746	(9,058)	-10.9%	73,688	82,746	(9,058)	-10.9%
25 UNIT COST ($/BBL)	36.32	38.84	(2.53)	-6.5%	36.32	38.84	(2.53)	-6.5%
26 AMOUNT ($)	2,676,145	3,214,228	(538,083)	-16.7%	2,676,145	3,214,228	(538,083)	-16.7%
27								
28 DAYS SUPPLY: NORMAL	94	119	(25)	-21.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	11	12	(1)	-10.9%	-	-	-	-
COAL (3)								
30 PURCHASES:								
31 UNITS (TONS)	403,393	518,300	(114,907)	-22.2%	3,869,299	4,361,573	(492,274)	-11.3%
32 UNIT COST ($/TON)	46.18	48.89	(2.71)	-5.5%	47.65	48.11	(0.46)	-0.9%
33 AMOUNT ($)	18,629,147	25,338,431	(6,709,284)	-26.5%	184,378,930	209,827,594	(25,448,664)	-12.1%
34 BURNED:								
35 UNITS (TONS)	543,825	608,192	(64,367)	-10.6%	3,744,768	3,826,054	(81,286)	-2.1%
36 UNIT COST ($/TON)	47.80	48.85	(1.05)	-2.2%	47.30	47.95	(0.65)	-1.4%
37 AMOUNT ($)	25,995,254	29,712,386	(3,717,132)	-12.5%	177,140,983	183,475,674	(6,334,691)	-3.5%
38 ENDING INVENTORY:								
39 UNITS (TONS)	562,888	973,876	(410,988)	-42.2%	562,888	973,876	(410,988)	-42.2%
40 UNIT COST ($/TON)	48.28	48.50	(0.21)	-0.4%	48.28	48.50	(0.21)	-0.4%
41 AMOUNT ($)	27,178,178	47,228,140	(20,049,962)	-42.5%	27,178,178	47,228,140	(20,049,962)	-42.5%
42								
43 DAYS SUPPLY:	36	53	(17)	-32.0%	-	-	-	-
NATURAL GAS(4)								
44 PURCHASES:								
45 UNITS (MCF)	2,867,977	2,795,531	72,446	2.6%	11,397,072	10,820,239	576,833	5.3%
46 UNIT COST ($/MCF)	7.34	7.01	0.33	4.8%	7.66	7.19	0.47	6.6%
47 AMOUNT ($)	21,060,482	19,593,855	1,466,627	7.5%	87,331,608	77,792,644	9,538,964	12.3%
48 BURNED:								
49 UNITS (MCF)	2,867,977	2,795,531	72,446	2.6%	11,397,072	10,820,239	576,833	5.3%
50 UNIT COST ($/MCF)	7.34	7.01	0.33	4.8%	7.66	7.19	0.47	6.6%
51 AMOUNT ($)	21,060,482	19,593,855	1,466,627	7.5%	87,331,608	77,792,645	9,538,963	12.3%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	21,556
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	21,556

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(8,581)	(289,805)
OTHER USAGE	(960)	(32,413)
TOTAL	(9,541)	(322,218)

(3) RECONCILIATION - COALS

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	58,646
IGNITION #2 OIL	268,249
IGNITION PROPANE	1,311
AERIAL SURVEY ADJ.	0
ADDITIVES	34,635
GREEN FUEL	0
TOTAL	362,841

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2003

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KW (A) FUEL COST	(6) CENTS/KW (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	1,934.0	0.0	1,934.0	2.156	2.156	41,700.00	41,700.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. - MB	28,420.0	0.0	28,420.0	6.457	8.162	1,835,100.00	2,319,700.00	393,100.00
TOTAL			**30,354.0**	**0.0**	**30,354.0**	**6.183**	**7.780**	**1,876,800.00**	**2,361,400.00**	**393,100.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	2,078.4	180.6	1,897.8	3.796	3.796	72,032.48	72,032.48	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	952.0	0.0	952.0	2.517	2.517	23,965.46	23,965.46	
FLA. PWR. CORP.		SCH. - MA	600.0	0.0	600.0	4.223	5.372	25,338.50	32,230.15	4,587.65
FLA. PWR. & LIGHT		SCH. - MA	851.0	0.0	851.0	3.935	6.706	33,485.89	57,067.57	20,313.84
CITY OF LAKELAND		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELEC. CO-OP		SCH. - MA	175.0	0.0	175.0	3.180	4.132	5,565.44	7,231.57	994.13
THE ENERGY AUTHORITY		SCH. - MA	70.0	0.0	70.0	3.321	4.086	2,324.85	2,860.42	266.77
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
NEW SMYRNA BEACH		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ORLANDO UTILITIES		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
RELIANT ENERGY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO FLA. PWR. CORP.*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO FLA. PWR. & LIGHT*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO NEW SMYRNA BEACH*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO CITY OF LAKELAND*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO SEMINOLE ELEC. CO-OP*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
AUBURNDALE POWER PARTNERS		SCH. - OATT	40.0	0.0	40.0	5.985	5.985	2,394.09	2,394.09	
CARGILL ALLIANT		SCH. - OATT	11.0	0.0	11.0	7.018	7.018	772.00	772.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			3,030.4	180.6	2,849.8	3.369	3.369	95,997.94	95,997.94	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			1,696.0	0.0	1,696.0	3.934	5.860	66,714.68	99,389.71	26,162.39
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			51.0	0.0	51.0	6.208	6.208	3,166.09	3,166.09	
TOTAL			**4,777.4**	**180.6**	**4,596.8**	**3.609**	**4.319**	**165,878.71**	**198,553.74**	**26,162.39**
CURRENT MONTH:										
DIFFERENCE			(25,576.6)	180.6	(25,757.2)	(2.574)	(3.461)	(1,710,921.29)	(2,162,846.26)	(366,937.61)
DIFFERENCE %			-84.3%	0.0%	-84.9%	-41.6%	-44.5%	-91.2%	-91.6%	-93.3%
PERIOD TO DATE:										
ACTUAL			102,146.0	350.3	101,795.7	3.255	4.403	3,313,943.02	4,482,020.65	841,813.24
ESTIMATED			198,337.9	5.3	198,332.6	4.146	5.538	8,222,301.69	10,983,317.12	2,152,394.33
DIFFERENCE			(96,191.9)	345.0	(96,536.9)	(0.891)	(1.135)	(4,908,358.67)	(6,501,296.47)	(1,310,581.09)
DIFFERENCE %			-48.5%	6509.4%	-48.7%	-21.5%	-20.5%	-59.7%	-59.2%	-60.9%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF JULY 2003.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	17,418.0	0.0	8,210.0	9,208.0	7.969	7.969	733,800.00
HARDEE POWER PARTNERS		IPP	83,150.0	0.0	0.0	83,150.0	6.743	6.743	5,606,400.00
VARIOUS		OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
VARIOUS		MKT. BASE	106,380.0	0.0	0.0	106,380.0	5.633	5.633	5,991,900.00
TOTAL			**206,948.0**	**0.0**	**8,210.0**	**198,738.0**	**6.205**	**6.205**	**12,332,100.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	96,910.0	0.0	0.0	96,910.0	5.994	5.994	5,809,064.56
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH. - J	15,170.0	0.0	480.3	14,689.7	5.037	5.037	739,934.85
FLA. POWER & LIGHT		SCH. - J	16,904.0	0.0	1,112.8	15,791.2	6.793	6.793	1,072,623.95
CITY OF LAKELAND		SCH. - J	26,714.0	0.0	1,642.8	25,071.2	6.683	6.683	1,675,625.43
ORLANDO UTIL. COMM.		SCH. - J	41,580.0	0.0	2,773.3	38,806.7	7.802	7.802	3,027,573.69
CAROLINA POWER & LIGHT		SCH. - J	4,320.0	0.0	0.0	4,320.0	4.606	4.606	198,995.00
THE ENERGY AUTHORITY		SCH. - J	59,050.0	0.0	0.0	59,050.0	5.008	5.008	2,957,305.53
REEDY CREEK		SCH. - J	300.0	0.0	0.0	300.0	6.513	6.513	19,540.00
OKEELANTA		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TALLAHASSEE		SCH. - J	1,820.0	0.0	3,735.9	(1,915.9)	(5.757)	-5.757	110,303.50
CALPINE		SCH. - J	96.0	0.0	0.0	96.0	7.391	7.391	7,095.00
CARGILL ALLIANT		SCH. - J	41,942.0	0.0	263.3	41,678.7	4.361	4.361	1,817,709.96
CONOCO		SCH. - J	1,488.0	0.0	0.0	1,488.0	2.762	2.762	41,097.50
CORAL POWER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RELIANT		SCH. - J	6,105.0	0.0	1,897.0	4,208.0	11.564	11.564	486,624.77
SEMINOLE ELEC. CO-OP		SCH. - J	27,330.0	0.0	597.7	26,732.3	4.972	4.972	1,329,172.14
DUKE ENERGY		SCH. - J	1,037.0	0.0	123.4	913.6	7.776	7.776	71,043.80
DYNEGY POWER MARKETING		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RINGHAVER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	June 2003	IPP	(77,302.0)	0.0	0.0	(77,302.0)	6.329	6.329	(4,892,577.88)
HARDEE PWR. PART.-NATIVE	June 2003	IPP	77,302.0	0.0	0.0	77,302.0	6.087	6.087	4,705,740.87
CARGILL ALLIANT	June 2003	SCH. - J	(32,930.0)	0.0	(50.0)	(32,880.0)	5.624	5.624	(1,849,058.50)
CARGILL ALLIANT	June 2003	SCH. - J	32,930.0	0.0	50.0	32,880.0	5.624	5.624	1,849,231.50
CONOCO	June 2003	SCH. - J	(3,724.0)	0.0	(49.0)	(3,675.0)	2.892	2.892	(106,285.46)
CONOCO	June 2003	SCH. - J	3,724.0	0.0	49.0	3,675.0	2.897	2.897	106,455.00
ORLANDO UTIL. COMM.	June 2003	SCH. - J	(18,325.0)	0.0	(309.2)	(18,015.8)	6.575	6.575	(1,184,549.95)
ORLANDO UTIL. COMM.	June 2003	SCH. - J	18,325.0	0.0	309.2	18,015.8	6.577	6.577	1,184,896.68
SEMINOLE ELEC. CO-OP	June 2003	SCH. - J	(7,198.0)	0.0	(768.0)	(6,430.0)	4.955	4.955	(318,632.00)
SEMINOLE ELEC. CO-OP	June 2003	SCH. - J	7,198.0	0.0	768.0	6,430.0	4.942	4.942	317,772.00
THE ENERGY AUTHORITY	June 2003	SCH. - J	(27,267.0)	0.0	(316.0)	(26,951.0)	5.394	5.394	(1,453,733.76)
THE ENERGY AUTHORITY	June 2003	SCH. - J	27,267.0	0.0	316.0	26,951.0	5.395	5.395	1,453,944.00
TOTAL			**340,766.0**	**0.0**	**12,626.5**	**328,139.5**	**5.844**	**5.844**	**19,176,912.18**
CURRENT MONTH:									
DIFFERENCE			133,818.0	0.0	4,416.5	129,401.5	(0.361)	(0.361)	6,844,812.18
DIFFERENCE %			64.7%	0.0%	53.8%	65.1%	-5.8%	-5.8%	55.5%
PERIOD TO DATE:									
ACTUAL			1,571,236.0	0.0	31,205.9	1,540,030.1	5.919	5.919	91,159,239.12
ESTIMATED			1,217,051.0	0.0	23,999.2	1,193,051.8	5.436	5.436	64,856,539.59
DIFFERENCE			354,185.0	0.0	7,206.7	346,978.3	0.483	0.483	26,302,699.53
DIFFERENCE %			29.1%	0.0%	30.0%	29.1%	8.9%	8.9%	40.6%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	41,439.0	0.0	0.0	41,439.0	2.780	2.780	1,151,800.00
TOTAL			**41,439.0**	**0.0**	**0.0**	**41,439.0**	**2.780**	**2.780**	**1,151,800.00**
ACTUAL:									
HILLSBOROUGH COUNTY		COGEN.	18,015.0	0.0	0.0	18,015.0	1.838	1.838	331,113.54
McKAY BAY REFUSE		COGEN.	10,996.0	0.0	0.0	10,996.0	1.813	1.813	199,306.59
ORANGE COGENERATION L.P.		COGEN.	7,521.0	0.0	0.0	7,521.0	1.774	1.774	133,452.39
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	2,167.0	0.0	0.0	2,167.0	5.011	5.011	108,592.31
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	19.0	0.0	0.0	19.0	11.780	11.780	2,238.24
CF INDUSTRIES INC.		COGEN.	1,197.0	0.0	0.0	1,197.0	4.624	4.624	55,347.93
IMC-AGRICO-NEW WALES		COGEN.	808.0	0.0	0.0	808.0	4.882	4.882	39,448.12
IMC-AGRICO-S. PIERCE		COGEN.	182.0	0.0	0.0	182.0	2.826	2.826	5,143.20
AUBURNDALE POWER PARTNERS		COGEN.	5.0	0.0	0.0	5.0	3.561	3.561	178.04
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR JULY 2003			40,910.0	0.0	0.0	40,910.0	2.138	2.138	874,820.36
ADJUSTMENTS FOR THE MONTH OF:	**JUNE 2003**								
HILLSBOROUGH COUNTY		COGEN.	(17,172.0)	0.0	0.0	(17,172.0)	1.733	1.733	(297,628.17)
			17,172.0	0.0	0.0	17,172.0	1.882	1.882	323,115.77
McKAY BAY REFUSE		COGEN.	(11,840.0)	0.0	0.0	(11,840.0)	1.731	1.731	(204,895.18)
			11,840.0	0.0	0.0	11,840.0	1.880	1.880	222,608.78
ORANGE COGENERATION L.P.		COGEN.	(7,590.0)	0.0	0.0	(7,590.0)	1.717	1.717	(130,335.38)
			7,590.0	0.0	0.0	7,590.0	1.819	1.819	138,065.32
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	(516.0)	0.0	0.0	(516.0)	4.395	4.395	(22,678.31)
			516.0	0.0	0.0	516.0	4.879	4.879	25,173.63
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	(252.0)	0.0	0.0	(252.0)	8.574	8.574	(21,605.38)
			252.0	0.0	0.0	252.0	8.883	8.883	22,385.82
CF INDUSTRIES INC.		COGEN.	(1,014.0)	0.0	0.0	(1,014.0)	4.579	4.579	(46,432.45)
			1,014.0	0.0	0.0	1,014.0	4.924	4.924	49,926.40
IMC-AGRICO-NEW WALES		COGEN.	(150.0)	0.0	0.0	(150.0)	4.216	4.216	(6,323.88)
			150.0	0.0	0.0	150.0	4.571	4.571	6,855.76
IMC-AGRICO-S. PIERCE		COGEN.	(71.0)	0.0	0.0	(71.0)	5.548	5.548	(3,939.18)
			71.0	0.0	0.0	71.0	5.783	5.783	4,106.22
AUBURNDALE POWER PARTNERS		COGEN.	(1.0)	0.0	0.0	(1.0)	1.713	1.713	(17.13)
			1.0	0.0	0.0	1.0	3.139	3.139	31.39
CUTRALE CITRUS		COGEN.	(6.0)	0.0	0.0	(6.0)	4.450	4.450	(266.98)
			6.0	0.0	0.0	6.0	4.784	4.784	287.04
SUB-TOTAL FOR THE MONTH OF:	**JUNE 2003**		0.0	0.0	0.0	0.0	0.000	0.000	58,434.09
ADJUSTMENTS FOR THE MONTH OF:	**MAY 2003**								
HILLSBOROUGH COUNTY		COGEN.	(18,401.0)	0.0	0.0	(18,401.0)	1.751	1.751	(322,179.34)
			18,401.0	0.0	0.0	18,401.0	1.745	1.745	321,028.09
McKAY BAY REFUSE		COGEN.	(13,222.0)	0.0	0.0	(13,222.0)	1.751	1.751	(231,528.08)
			13,222.0	0.0	0.0	13,222.0	1.745	1.745	230,701.64
ORANGE COGENERATION L.P.		COGEN.	(7,843.0)	0.0	0.0	(7,843.0)	1.722	1.722	(135,020.40)
			7,843.0	0.0	0.0	7,843.0	1.713	1.713	134,364.47
SUB-TOTAL FOR THE MONTH OF:	**MAY 2003**		0.0	0.0	0.0	0.0	0.000	0.000	(2,633.62)
GRAND TOTAL			**40,910.0**	**0.0**	**0.0**	**40,910.0**	**2.275**	**2.275**	**930,620.83**
CURRENT MONTH:									
DIFFERENCE			(529.0)	0.0	0.0	(529.0)	(0.505)	(0.505)	(221,179.17)
DIFFERENCE %			-1.3%	0.0%	0.0%	-1.3%	-18.2%	-18.2%	-19.2%
PERIOD TO DATE:									
ACTUAL			317,759.0	0.0	0.0	317,759.0	2.309	2.309	7,337,935.72
ESTIMATED			284,617.0	0.0	0.0	284,617.0	2.659	2.659	7,566,565.12
DIFFERENCE			33,142.0	0.0	0.0	33,142.0	(0.349)	(0.349)	(228,629.40)
DIFFERENCE %			11.6%	0.0%	0.0%	11.6%	(0.131)	(0.131)	-3.0%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

AUGUST 2003

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	46,229,283	52,106,110	(5,876,827)	-11.3%	1,570,552	1,731,111	(160,559)	-9.3%	2.94351	3.00998	(0.06648)	-2.2%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(7,812)	(6,000)	(1,812)	30.2%	1,570,552 (a)	1,731,111 (a)	(160,559)	-9.3%	(0.00050)	(0.00035)	(0.00015)	43.5%
4b. Adjustments to Fuel Cost	(3,239)	0	(3,239)	0.0%	1,570,552 (a)	1,731,111 (a)	(160,559)	-9.3%	(0.00021)	0.00000	(0.00021)	0.0%
4c. Incremental Hedging O&M Costs	13,645	34,583	(20,938)	-60.5%	1,570,552 (a)	1,731,111 (a)	(160,559)	-9.3%	0.00087	0.00200	(0.00113)	-56.5%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**46,231,877**	**52,134,693**	**(5,902,816)**	**-11.3%**	**1,570,552**	**1,731,111**	**(160,559)**	**-9.3%**	**2.94367**	**3.01163**	**(0.06796)**	**-2.3%**
6. Fuel Cost of Purchased Power - Firm (A7)	13,627,735	11,915,800	1,711,935	14.4%	247,523	193,051	54,472	28.2%	5.50564	6.17236	(0.66671)	-10.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,465,275	1,158,700	306,575	26.5%	41,132	41,439	(307)	-0.7%	3.56237	2.79616	0.76621	27.4%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**15,093,010**	**13,074,500**	**2,018,510**	**15.4%**	**288,655**	**234,490**	**54,165**	**23.1%**	**5.22874**	**5.57572**	**(0.34698)**	**-6.2%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,859,207**	**1,965,601**	**(106,394)**	**-5.4%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	89,711	59,800	29,911	50.0%	2,687	2,678	9	0.3%	3.33870	2.23301	1.10570	49.5%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	963	0	963	0.0%	16	0	16	0.0%	6.01875	0.00000	6.01875	0.0%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	62,590	2,005,500	(1,942,910)	-96.9%	1,102	31,348	(30,246)	-96.5%	5.67967	6.39754	(0.71786)	-11.2%
19. Gains on Market Based Sales	9,257	476,500	(467,243)	-98.1%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**162,521**	**2,541,800**	**(2,379,279)**	**-93.6%**	**3,805**	**34,026**	**(30,221)**	**-88.8%**	**4.27125**	**7.47017**	**(3.19892)**	**-42.8%**
21. Net Inadvertant Interchange					1,837	0	1,837	0.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					536	0	536	0.0%				
23. Interchange and Wheeling Losses					354	500	(146)	-29.2%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**61,162,366**	**62,667,393**	**(1,505,027)**	**-2.4%**	**1,857,421**	**1,931,075**	**(73,654)**	**-3.8%**	**3.29286**	**3.24521**	**0.04766**	**1.5%**
25. Net Unbilled	26,145 (a)	555,742 (a)	(529,597)	-95.3%	794	17,125	(16,331)	-95.4%	3.29282	3.24521	0.04761	1.5%
26. Company Use	154,666 (a)	129,808 (a)	24,858	19.1%	4,697	4,000	697	17.4%	3.29287	3.24520	0.04767	1.5%
27. T & D Losses	3,133,457 (a)	4,873,458 (a)	(1,740,001)	-35.7%	95,159	150,174	(55,015)	-36.6%	3.29286	3.24521	0.04766	1.5%
28. System KWH Sales	61,162,366	62,667,393	(1,505,027)	-2.4%	1,756,771	1,759,776	(3,005)	-0.2%	3.48152	3.56110	(0.07958)	-2.2%
29. Wholesale KWH Sales	(1,798,138)	(1,954,721)	156,583	-8.0%	(51,648)	(54,891)	3,243	-5.9%	3.48152	3.56110	(0.07957)	-2.2%
30. Jurisdictional KWH Sales	59,364,228	60,712,672	(1,348,444)	-2.2%	1,705,123	1,704,885	238	0.0%	3.48152	3.56110	(0.07958)	-2.2%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	59,431,903	60,781,884	(1,349,981)	-2.2%	1,705,123	1,704,885	238	0.0%	3.48549	3.56516	(0.07967)	-2.2%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	259,281	258,803	478	0.2%	1,705,123	1,704,885	238	0.0%	0.01521	0.01518	0.00003	0.2%
34. Adjustment	0	0	0	0.0%	1,705,123	1,704,885	238	0.0%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	1,705,123	1,704,885	238	0.0%	0.00000	0.00000	0.00000	0.0%
36. True-up *	263,799	263,799	0	0.0%	1,705,123	1,704,885	238	0.0%	0.01547	0.01547	(0.00000)	0.0%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	59,954,983	61,304,486	(1,349,503)	-2.2%	1,705,123	1,704,885	238	0.0%	3.51617	3.59581	(0.07965)	-2.2%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.51870	3.59840	(0.07970)	-2.2%
40. GPIF * (Already Adjusted for Taxes)	(69,252)	(69,203)	(49)	0.1%	1,705,123	1,704,885	238	0.0%	(0.00406)	(0.00406)	(0.00000)	0.1%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**59,885,731**	**61,235,283**	**(1,349,552)**	**-2.2%**	**1,705,123**	**1,704,885**	**238**	**0.0%**	**3.51464**	**3.59434**	**(0.07970)**	**-2.2%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.515**	**3.594**	**(0.079)**	**-2.2%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: AUGUST 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	319,659,145	323,418,723	(3,759,578)	-1.2%	11,262,240	11,657,807	(395,567)	-3.4%	2.83833	2.77427	0.06406	2.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(53,100)	(48,108)	(4,992)	10.4%	11,262,240 (a)	11,657,807 (a)	(395,567)	-3.4%	(0.00047)	(0.00041)	(0.00006)	14.3%
4b. Adjustments to Fuel Cost	(24,561)	(2,738)	(21,823)	797.0%	11,262,240 (a)	11,657,807 (a)	(395,567)	-3.4%	(0.00022)	(0.00002)	(0.00019)	828.5%
4c. Adjustments to Fuel Cost	13,645	242,081	(228,436)	-94.4%	11,262,240 (a)	11,657,807 (a)	(395,567)	-3.4%	0.00012	0.00208	(0.00196)	-94.2%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**319,595,129**	**323,609,958**	**(4,014,829)**	**-1.2%**	**11,262,240**	**11,657,807**	**(395,567)**	**-3.4%**	**2.83776**	**2.77591**	**0.06185**	**2.2%**
6. Fuel Cost of Purchased Power - Firm (A7)	104,786,974	76,772,340	28,014,634	36.5%	1,787,553	1,386,103	401,450	29.0%	5.86203	5.53872	0.32332	5.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	8,803,210	8,725,265	77,945	0.9%	358,891	326,056	32,835	10.1%	2.45289	2.67600	(0.22311)	-8.3%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**113,590,184**	**85,497,605**	**28,092,579**	**32.9%**	**2,146,444**	**1,712,159**	**434,285**	**25.4%**	**5.29202**	**4.99356**	**0.29846**	**6.0%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**13,408,684**	**13,369,966**	**38,718**	**0.3%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	545,232	491,107	54,125	11.0%	19,372	21,064	(1,692)	-8.0%	2.81454	2.33150	0.48304	20.7%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	7,048	4,680	2,368	50.6%	136	46	90	195.7%	5.18235	10.17391	(4.99156)	-49.1%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	121,809	108,975	12,834	11.8%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	2,793,119	9,682,840	(6,889,721)	-71.2%	86,094	211,249	(125,155)	-59.2%	3.24427	4.58361	(1.33935)	-29.2%
19. Gains on Market Based Sales	851,070	2,628,894	(1,777,824)	-67.6%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**4,318,278**	**12,916,496**	**(8,598,218)**	**-66.6%**	**105,602**	**232,359**	**(126,757)**	**-54.8%**	**4.08920**	**5.55885**	**(1.46965)**	**-26.4%**
21. Net Inadvertant Interchange					1,206	(291)	1,497	-514.4%				
22. Wheeling Rec'd. less Wheeling Del'd.					953	652	301	46.2%				
23. Interchange and Wheeling Losses					4,950	3,496	1,454	41.6%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**428,867,035**	**396,191,067**	**32,675,968**	**8.2%**	**13,300,291**	**13,134,472**	**165,819**	**1.3%**	**3.22449**	**3.01642**	**0.20807**	**6.9%**
25. Net Unbilled	8,893,686 (a)	11,495,831 (a)	(2,602,145)	-22.6%	256,711	372,632	(115,921)	-31.1%	3.46447	3.08504	0.37944	12.3%
26. Company Use	1,078,605 (a)	958,744 (a)	119,861	12.5%	33,581	32,099	1,482	4.6%	3.21195	2.98683	0.22512	7.5%
27. T & D Losses	18,342,754 (a)	16,050,879 (a)	2,291,875	14.3%	546,345	515,531	30,814	6.0%	3.35736	3.11347	0.24389	7.8%
28. System KWH Sales	428,867,035	396,191,067	32,675,968	8.2%	12,463,654	12,214,210	249,444	2.0%	3.44094	3.24369	0.19725	6.1%
29. Wholesale KWH Sales	(13,611,699)	(11,410,600)	(2,201,099)	19.3%	(393,431)	(345,215)	(48,216)	14.0%	3.45974	3.30536	0.15438	4.7%
30. Jurisdictional KWH Sales	415,255,336	384,780,467	30,474,869	7.9%	12,070,223	11,868,995	201,228	1.7%	3.44033	3.24190	0.19843	6.1%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	415,728,727	385,219,116	30,509,611	7.9%	12,070,223	11,868,995	201,228	1.7%	3.44425	3.24559	0.19866	6.1%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	2,137,755	2,146,680	(8,925)	-0.4%	12,070,223	11,868,995	201,228	1.7%	0.01771	0.01809	(0.00038)	-2.1%
34. Adjustment	0	0	0	0.0%	12,070,223	11,868,995	201,228	1.7%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	12,070,223	11,868,995	201,228	1.7%	0.00000	0.00000	0.00000	0.0%
36. True-up *	2,110,392	2,110,392	0	0.0%	12,070,223	11,868,995	201,228	1.7%	0.01748	0.01778	(0.00030)	-1.7%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	419,976,874	389,476,188	30,500,686	7.8%	12,070,223	11,868,995	201,228	1.7%	3.47945	3.28146	0.19799	6.0%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.48195	3.28382	0.19813	6.0%
40. GPIF * (Already Adjusted for Taxes)	(553,227)	(553,624)	397	-0.1%	12,070,223	11,868,995	201,228	1.7%	(0.00458)	(0.00466)	0.00008	-1.7%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**419,423,647**	**388,922,564**	**30,501,083**	**7.8%**	**12,070,223**	**11,868,995**	**201,228**	**1.7%**	**3.47737**	**3.27916**	**0.19821**	**6.0%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.477**	**3.279**	**0.198**	**6.0%**

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	46,229,283	52,106,110	(5,876,827)	-11.3%	319,659,145	323,418,723	(3,759,578)	-1.2%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	153,264	2,065,300	(1,912,036)	-92.6%	3,467,208	10,287,602	(6,820,394)	-66.3%
2a. GAINS FROM MARKET BASED SALES	9,257	476,500	(467,243)	-98.1%	851,070	2,628,894	(1,777,824)	-67.6%
3. FUEL COST OF PURCHASED POWER	13,627,735	11,915,800	1,711,935	14.4%	104,786,974	76,772,340	28,014,634	36.5%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,465,275	1,158,700	306,575	26.5%	8,803,210	8,725,265	77,945	0.9%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	61,159,772	62,638,810	(1,479,038)	-2.4%	428,931,051	395,999,832	32,931,219	8.3%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(7,812)	(6,000)	(1,812)	30.2%	(53,100)	(48,108)	(4,992)	10.4%
6b. ADJ.TO FUEL COST	(3,239)	0	(3,239)	0.0%	(24,561)	(2,738)	(21,823)	797.0%
6c. INCREMENTAL HEDGING O&M COSTS	13,645	34,583	(20,938)	-60.5%	13,645	242,081	(228,436)	-94.4%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	61,162,366	62,667,393	(1,505,027)	-2.4%	428,867,035	396,191,067	32,675,968	8.2%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,705,123	1,704,885	238	0.0%	12,070,223	11,868,995	201,228	1.7%
2. NONJURISDICTIONAL SALES	51,648	54,891	(3,243)	-5.9%	393,431	345,215	48,216	14.0%
3. TOTAL SALES	1,756,771	1,759,776	(3,005)	-0.2%	12,463,654	12,214,210	249,444	2.0%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9706006	0.9688080	0.0017926	0.2%	0.9684337	0.9717366	(0.0033029)	-0.3%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	58,657,101	58,529,859	127,242	0.2%	393,851,775	389,257,133	4,594,642	1.2%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(263,799)	(263,799)	0	0.0%	(2,110,392)	(2,110,392)	0	0.0%
2b. INCENTIVE PROVISION	69,252	69,203	49	0.1%	553,227	553,624	(397)	-0.1%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	58,462,554	58,335,263	127,291	0.2%	392,294,610	387,700,365	4,594,245	1.2%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	61,162,366	62,667,393	(1,505,027)	-2.4%	428,867,035	396,191,067	32,675,968	8.2%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9706006	0.9688080	0.0017926	0.2%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	59,364,228	60,712,672	(1,348,444)	-2.2%	415,255,336	384,780,467	30,474,869	7.9%
6a. JURISDIC. LOSS MULTIPLIER	1.00114	1.00114	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	59,431,903	60,781,884	(1,349,981)	-2.2%	415,728,726	385,219,116	30,509,610	7.9%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	267,135	267,135	0	0.0%	2,207,948	2,207,948	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	259,281	258,803	478	0.2%	2,137,755	2,146,680	(8,925)	-0.4%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	59,691,184	61,040,687	(1,349,503)	-2.2%	417,866,481	387,365,796	30,500,685	7.9%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(1,228,630)	(2,705,424)	1,476,794	-54.6%	(25,571,871)	334,569	(25,906,440)	-7743.2%
8. INTEREST PROVISION FOR THE MONTH	(48,446)	(30,642)	(17,804)	58.1%	(293,674)	(240,696)	(52,978)	22.0%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(54,569,794)	(27,151,386)	(27,418,408)	101.0%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	263,799	263,799	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(55,583,071)	(29,623,653)	(25,959,418)	87.6%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(54,569,794)	(27,151,386)	(27,418,408)	101.0%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(55,534,625)	(29,593,011)	(25,941,614)	87.7%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(110,104,419)	(56,744,397)	(53,360,022)	94.0%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(55,052,210)	(28,372,199)	(26,680,011)	94.0%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.050	1.300	(0)	-19.2%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.060	1.300	(0)	-18.5%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	2.110	2.600	(0)	-18.8%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.055	1.300	(0)	-18.8%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.088	0.108	(0)	-18.5%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(48,446)	(30,642)	(17,804)	58.1%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	565,066	519,664	45,402	8.7%	3,772,265	2,764,232	1,008,033	36.5%
2	LIGHT OIL	454,005	1,861,821	(1,407,816)	-75.6%	6,204,077	9,661,547	(3,457,470)	-35.8%
3	COAL	25,735,927	30,070,233	(4,334,306)	-14.4%	202,876,910	213,545,907	(10,668,997)	-5.0%
4	NATURAL GAS	19,474,285	19,654,392	(180,107)	-0.9%	106,805,893	97,447,037	9,358,856	9.6%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	46,229,283	52,106,110	(5,876,827)	-11.3%	319,659,145	323,418,723	(3,759,578)	-1.2%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	10,640	10,479	161	1.5%	66,676	52,695	13,981	26.5%
9	LIGHT OIL	6,949	26,237	(19,288)	-73.5%	91,086	139,248	(48,162)	-34.6%
10	COAL	1,172,446	1,334,644	(162,198)	-12.2%	9,225,370	9,687,041	(461,671)	-4.8%
11	NATURAL GAS	380,517	359,751	20,766	5.8%	1,879,108	1,778,823	100,285	5.6%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,570,552	1,731,111	(160,559)	-9.3%	11,262,240	11,657,807	(395,567)	-3.4%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	16,408	15,789	619	3.9%	103,333	79,508	23,825	30.0%
16	LIGHT OIL (BBL)	11,887	49,182	(37,295)	-75.8%	161,561	248,463	(86,902)	-35.0%
17	COAL (TON)	567,450	613,765	(46,315)	-7.5%	4,312,218	4,439,819	(127,601)	-2.9%
18	NATURAL GAS (MCF)	2,836,997	2,814,779	22,218	0.8%	14,234,069	13,635,018	599,051	4.4%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	102,938	100,376	2,562	2.6%	648,265	505,718	142,547	28.2%
22	LIGHT OIL	66,724	283,914	(217,190)	-76.5%	911,024	1,439,639	(528,615)	-36.7%
23	COAL	13,500,195	14,752,017	(1,251,822)	-8.5%	103,038,474	106,706,637	(3,668,163)	-3.4%
24	NATURAL GAS	3,027,075	2,893,577	133,498	4.6%	15,124,674	14,021,154	1,103,520	7.9%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	16,696,932	18,029,884	(1,332,952)	-7.4%	119,722,437	122,673,148	(2,950,711)	-2.4%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.68%	0.61%	0.00	-	0.59%	0.45%	0.00	-
29	LIGHT OIL	0.44%	1.52%	(0.01)	-	0.81%	1.19%	(0.00)	-
30	COAL	74.65%	77.10%	(0.02)	-	81.91%	83.09%	(0.01)	-
31	NATURAL GAS	24.23%	20.78%	0.03	-	16.69%	15.26%	0.01	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	34.44	32.91	1.53	4.6%	36.51	34.77	1.74	5.0%
36	LIGHT OIL ($/BBL)	38.19	37.86	0.34	0.9%	38.40	38.89	(0.48)	-1.2%
37	COAL ($/TON)	45.35	48.99	(3.64)	-7.4%	47.05	48.10	(1.05)	-2.2%
38	NATURAL GAS ($/MCF)	6.86	6.98	(0.12)	-1.7%	7.50	7.15	0.36	5.0%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	5.49	5.18	0.31	6.0%	5.82	5.47	0.35	6.5%
42	LIGHT OIL	6.80	6.56	0.25	3.8%	6.81	6.71	0.10	1.5%
43	COAL	1.91	2.04	(0.13)	-6.5%	1.97	2.00	(0.03)	-1.6%
44	NATURAL GAS	6.43	6.79	(0.36)	-5.3%	7.06	6.95	0.11	1.6%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.77	2.89	(0.12)	-4.2%	2.67	2.64	0.03	1.3%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,675	9,579	96	1.0%	9,723	9,597	126	1.3%
49	LIGHT OIL	9,602	10,821	(1,219)	-11.3%	10,002	10,339	(337)	-3.3%
50	COAL	11,515	11,053	462	4.2%	11,169	11,015	154	1.4%
51	NATURAL GAS	7,955	8,043	(88)	-1.1%	8,049	7,882	167	2.1%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,631	10,415	216	2.1%	10,630	10,523	107	1.0%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.31	4.96	0.35	7.1%	5.66	5.25	0.41	7.8%
56	LIGHT OIL	6.53	7.10	(0.57)	-8.0%	6.81	6.94	(0.13)	-1.9%
57	COAL	2.20	2.25	(0.05)	-2.2%	2.20	2.20	0.00	0.0%
58	NATURAL GAS	5.12	5.46	(0.34)	-6.2%	5.68	5.48	0.20	3.6%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.94	3.01	(0.07)	-2.3%	2.84	2.77	0.07	2.5%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: AUGUST 2003

SCHEDULE A4
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(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	75	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#2	100	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	150	73,428	65.8	87.8	72.3	12,728	COAL	39,690	23,548,000	934,620.1	1,713,520	2.33	43.17
GAN.#4	164	52,344	42.9	85.0	47.2	14,247	COAL	33,023	22,582,000	745,725.4	1,425,689	2.72	43.17
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	353	139,688	53.2	61.1	67.0	11,916	COAL	70,043	23,764,000	1,664,501.9	3,023,938	2.16	43.17
GANNON STATION	**842**	**265,460**	**42.4**	**78.6**	**50.2**	**12,600**	**COAL**	**142,756**	**23,430,521**	**3,344,847.4**	**6,163,147**	**2.32**	**43.17**
B.B.#1	421	162,277	51.8	60.0	62.3	11,436	COAL	76,741	24,183,560	1,855,874.9	3,695,776	2.28	48.16
B.B.#2	411	139,794	45.7	50.6	72.4	11,095	COAL	64,637	23,995,940	1,551,026.3	3,112,859	2.23	48.16
B.B.#3	428	188,794	59.3	68.5	62.9	11,566	COAL	89,154	24,493,260	2,183,670.4	4,293,575	2.27	48.16
B.B.#4	452	275,957	82.1	92.1	82.1	10,872	COAL	133,240	22,517,140	3,000,180.6	6,416,717	2.33	48.16
B.B. STATION	**1,712**	**766,822**	**60.2**	**68.4**	**70.1**	**11,203**	**COAL**	**363,772**	**23,615,760**	**8,590,752.2**	**17,518,927**	**2.28**	**48.16**
SEB-PHIL. #1(HVY OIL)	17	5,705	45.1	100.0	92.2	9,675	HVY.OIL	8,798	6,273,540	55,193.1	302,989	5.31	34.44
SEB-PHIL. #2(HVY OIL)	17	4,935	39.0	87.5	90.4	9,675	HVY.OIL	7,610	6,273,540	47,744.9	262,077	5.31	34.44
SEB-PHILLIPS TOTAL	**34**	**10,640**	**42.1**	**93.8**	**91.3**	**9,675**	**HVY.OIL**	**16,408**	**6,273,540**	**102,938.0**	**565,066**	**5.31**	**34.44**
POLK #1 GASIFIER	255	140,164	73.9	82.7	83.4	11,163	COAL	60,922	25,682,000	1,564,595.7	2,053,853	1.47	33.71
POLK #1 CT (OIL)	225	6,096	3.6	100.0	68.6	8,756	LGT.OIL	9,585	5,795,766	53,377.7	366,389	6.01	38.23
POLK #1 TOTAL	**255**	**146,260**	**77.1**	**92.8**	**82.6**	**11,062**	**-**	**-**	**-**	**1,617,973.4**	**2,420,242**	**1.65**	**-**
POLK #2 CT (GAS)	150	22,175	19.9	97.9	83.2	10,995	GAS	228,505	1,067,000	243,815.0	1,614,089	7.28	7.06
POLK #2 CT (OIL)	160	342	0.3	98.7	47.3	20,535	LGT.OIL	1,211	5,795,768	7,017.7	46,285	13.53	38.22
POLK #2 TOTAL	**155**	**22,517**	**19.5**	**98.7**	**82.3**	**11,140**	**-**	**-**	**-**	**250,832.7**	**1,660,374**	**7.37**	**-**
POLK #3 CT (GAS)	150	24,346	21.8	97.9	79.8	12,619	GAS	287,926	1,067,000	307,217.0	2,037,727	8.37	7.08
POLK #3 CT (OIL)	165	469	0.4	77.8	69.8	11,704	LGT.OIL	946	5,795,767	5,485.5	36,180	7.71	38.25
POLK #3 TOTAL	**158**	**24,815**	**21.1**	**97.9**	**79.5**	**12,601**	**-**	**-**	**-**	**312,702.5**	**2,073,907**	**8.36**	**-**
POLK STATION TOTAL	**568**	**193,592**	**45.8**	**95.8**	**81.7**	**11,269**	**-**	**-**	**-**	**2,181,508.6**	**6,154,523**	**3.18**	**-**
B.B.C.T.#1	14	42	0.4	100.0	75.0	20,062	LGT.OIL	145	5,820,669	842.6	5,151	12.26	35.52
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**140**	**42**	**0.0**	**100.0**	**14.2**	**20,062**	**LGT.OIL**	**145**	**5,820,669**	**842.6**	**5,151**	**12.26**	**35.52**
CITY OF TAMPA	**6**	**1,199**	**26.9**	**0.0**	**0.0**	**10,236**	**GAS**	**11,502**	**1,067,000**	**12,272.6**	**103,761**	**8.65**	**9.02**
BAYSIDE ST 1	246	116,265	63.5	93.1	64.1	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	73,034	66.3	99.0	82.8	11,368	GAS	778,083	1,067,000	830,215.0	5,296,721	7.25	6.81
BAYSIDE CT1B	148	72,700	66.0	91.3	82.7	11,368	GAS	774,526	1,067,000	826,418.9	5,272,502	7.25	6.81
BAYSIDE CT1C	148	71,004	64.5	95.6	82.3	11,368	GAS	756,455	1,067,000	807,137.1	5,149,485	7.25	6.81
BAYSIDE UNIT 1 TOTAL	**690**	**333,003**	**64.9**	**94.5**	**76.0**	**7,399**	**GAS**	**2,309,064**	**1,067,000**	**2,463,771.0**	**15,718,708**	**4.72**	**6.81**
BAYSIDE UNIT 2 TOTAL	**0**	**(206)**	**-**	**-**	**-**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE STATION TOTAL	**690**	**332,797**	**64.8**	**94.5**	**76.0**	**7,403**	**GAS**	**2,309,064**	**1,067,000**	**2,463,771.0**	**15,718,708**	**4.72**	**6.81**
TOT. COAL (GN,BB,POLK)	**2,809**	**1,172,446**	**56.1**	**72.7**	**65.3**	**11,515**	**COAL**	**567,450**	**23,790,992**	**13,500,195.3**	**25,735,927**	**2.20**	**45.35**
SYSTEM	**3,992**	**1,570,552**	**52.9**	**81.6**	**67.9**	**10,631**	**-**	**-**	**-**	**16,696,932.4**	**46,229,283**	**2.94**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

SCHEDULE A5
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	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	17,667	15,789	1,878	11.9%	107,080	78,229	28,851	36.9%
3 UNIT COST ($/BBL)	34.31	32.05	2.26	7.1%	34.78	33.39	1.39	4.2%
4 AMOUNT ($)	606,204	506,037	100,167	19.8%	3,724,043	2,611,977	1,112,066	42.6%
5 BURNED:								
6 UNITS (BBL)	16,408	15,789	619	3.9%	103,333	79,508	23,825	30.0%
7 UNIT COST ($/BBL)	34.44	32.91	1.53	4.6%	36.51	34.77	1.74	5.0%
8 AMOUNT ($)	565,066	519,664	45,402	8.7%	3,772,265	2,764,232	1,008,033	36.5%
9 ENDING INVENTORY:								
10 UNITS (BBL)	14,489	9,463	5,026	53.1%	14,489	9,463	5,026	53.1%
11 UNIT COST ($/BBL)	34.47	32.37	2.10	6.5%	34.47	32.37	2.10	6.5%
12 AMOUNT ($)	499,409	306,343	193,066	63.0%	499,409	306,343	193,066	63.0%
13								
14 DAYS SUPPLY:	53	28	25	90.9%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	28,507	54,593	(26,086)	-47.8%	234,619	292,043	(57,424)	-19.7%
17 UNIT COST ($/BBL)	38.82	37.30	1.52	4.1%	38.74	40.12	(1.38)	-3.4%
18 AMOUNT ($)	1,106,640	2,036,394	(929,754)	-45.7%	9,088,143	11,715,585	(2,627,442)	-22.4%
19 BURNED:								
20 UNITS (BBL)	11,887	49,182	(37,295)	-75.8%	161,561	248,463	(86,902)	-35.0%
21 UNIT COST ($/BBL)	38.19	37.86	0.34	0.9%	38.40	38.89	(0.48)	-1.2%
22 AMOUNT ($)	454,005	1,861,821	(1,407,816)	-75.6%	6,204,077	9,661,547	(3,457,470)	-35.8%
23 ENDING INVENTORY:								
24 UNITS (BBL)	82,014	82,746	(732)	-0.9%	82,014	82,746	(732)	-0.9%
25 UNIT COST ($/BBL)	36.99	38.48	(1.49)	-3.9%	36.99	38.48	(1.49)	-3.9%
26 AMOUNT ($)	3,033,344	3,184,040	(150,696)	-4.7%	3,033,344	3,184,040	(150,696)	-4.7%
27								
28 DAYS SUPPLY: NORMAL	106	115	(9)	-7.5%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	12	12	(0)	-0.9%	-	-	-	-
COAL (3)								
30 PURCHASES:								
31 UNITS (TONS)	496,196	544,300	(48,104)	-8.8%	4,365,495	4,905,873	(540,378)	-11.0%
32 UNIT COST ($/TON)	47.89	49.02	(1.13)	-2.3%	47.68	48.21	(0.53)	-1.1%
33 AMOUNT ($)	23,760,565	26,681,784	(2,921,219)	-10.9%	208,139,495	236,509,378	(28,369,883)	-12.0%
34 BURNED:								
35 UNITS (TONS)	567,450	613,765	(46,315)	-7.5%	4,312,218	4,439,819	(127,601)	-2.9%
36 UNIT COST ($/TON)	45.35	48.99	(3.64)	-7.4%	47.05	48.10	(1.05)	-2.2%
37 AMOUNT ($)	25,735,927	30,070,233	(4,334,306)	-14.4%	202,876,910	213,545,907	(10,668,997)	-5.0%
38 ENDING INVENTORY:								
39 UNITS (TONS)	491,634	904,411	(412,777)	-45.6%	491,634	904,411	(412,777)	-45.6%
40 UNIT COST ($/TON)	48.58	48.78	(0.19)	-0.4%	48.58	48.78	(0.19)	-0.4%
41 AMOUNT ($)	23,884,802	44,114,847	(20,230,045)	-45.9%	23,884,802	44,114,847	(20,230,045)	-45.9%
42								
43 DAYS SUPPLY:	37	55	(18)	-32.8%	-	-	-	-
NATURAL GAS(4)								
44 PURCHASES:								
45 UNITS (MCF)	2,836,997	2,814,779	22,218	0.8%	14,234,069	13,635,018	599,051	4.4%
46 UNIT COST ($/MCF)	6.86	6.98	(0.12)	-1.7%	7.50	7.15	0.36	5.0%
47 AMOUNT ($)	19,474,285	19,654,393	(180,108)	-0.9%	106,805,893	97,447,037	9,358,856	9.6%
48 BURNED:								
49 UNITS (MCF)	2,836,997	2,814,779	22,218	0.8%	14,234,069	13,635,018	599,051	4.4%
50 UNIT COST ($/MCF)	6.86	6.98	(0.12)	-1.7%	7.50	7.15	0.36	5.0%
51 AMOUNT ($)	19,474,285	19,654,392	(180,107)	-0.9%	106,805,893	97,447,037	9,358,856	9.6%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	20,237
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	20,237

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(7,698)	(274,200)
OTHER USAGE	(596)	(21,236)
TOTAL	(8,294)	(295,436)

(3) RECONCILIATION - COALS

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	24,551
IGNITION #2 OIL	253,963
IGNITION PROPANE	4,505
AERIAL SURVEY ADJ.	(1,632,199)
ADDITIVES	31,166
GREEN FUEL	0
TOTAL	(1,318,014)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KW (A) FUEL COST	(6) CENTS/KW (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	2,678.0	0.0	2,678.0	2.233	2.233	59,800.00	59,800.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. - MB	31,348.0	0.0	31,348.0	6.398	8.239	2,005,500.00	2,582,900.00	476,500.00
TOTAL			**34,026.0**	**0.0**	**34,026.0**	**6.070**	**7.767**	**2,065,300.00**	**2,642,700.00**	**476,500.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	1,816.6	74.7	1,741.9	3.651	3.651	63,596.39	63,596.39	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	967.0	0.0	967.0	2.701	2.701	26,114.85	26,114.85	
FLA. PWR. CORP.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT		SCH. - MA	50.0	0.0	50.0	2.327	3.117	1,163.45	1,558.63	203.18
CITY OF LAKELAND		SCH. - MA	50.0	0.0	50.0	4.523	5.303	2,261.45	2,651.63	198.18
SEMINOLE ELEC. CO-OP		SCH. - MA	125.0	0.0	125.0	3.358	4.672	4,197.64	5,840.61	1,162.97
THE ENERGY AUTHORITY		SCH. - MA	338.0	0.0	338.0	3.794	5.109	12,825.24	17,267.99	3,144.83
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
NEW SMYRNA BEACH		SCH. - MA	234.0	0.0	234.0	4.287	6.185	10,030.52	14,473.61	3,544.53
ORLANDO UTILITIES		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
RELIANT ENERGY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO FLA. PWR. CORP.*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO FLA. PWR. & LIGHT*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO ORLANDO UTILITIES*		SCH. - MA	50.0	0.0	50.0	4.081	4.303	2,040.50	2,151.67	104.17
HARDEE PWR. PART. TO NEW SMYRNA BEACH*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO CITY OF LAKELAND*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO SEMINOLE ELEC. CO-OP*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO THE ENERGY AUTHORITY*		SCH. - MA	255.0	0.0	255.0	4.122	4.489	10,511.20	11,446.48	899.58
AUBURNDALE POWER PARTNERS		SCH. - OATT	16.0	0.0	16.0	8.325	8.325	1,331.97	1,331.97	
CARGILL ALLIANT		SCH. - OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ADJUSTMENTS										
AUBURNDALE POWER PARTNERS	MAY 2003	SCH. - OATT	(11.0)	0.0	(11.0)	7.959	7.959	(875.49)	(875.49)	
AUBURNDALE POWER PARTNERS	MAY 2003	SCH. - OATT	11.0	0.0	11.0	8.258	8.258	908.42	908.42	
AUBURNDALE POWER PARTNERS	APR 2003	SCH. - OATT	4.0	0.0	4.0	0.760	0.760	30.41	30.41	
AUBURNDALE POWER PARTNERS	APR 2003	SCH. - OATT	(4.0)	0.0	(4.0)	0.183	0.183	(7.33)	(7.33)	
AUBURNDALE POWER PARTNERS	JAN 2003	SCH. - OATT	(12.0)	0.0	(12.0)	14.739	14.739	(1,768.64)	(1,768.64)	
AUBURNDALE POWER PARTNERS	JAN 2003	SCH. - OATT	12.0	0.0	12.0	10.258	10.258	1,230.96	1,230.96	
CARGILL ALLIANT	MAR 2003	SCH. - OATT	(8.0)	0.0	(8.0)	6.848	6.848	(547.83)	(547.83)	
CARGILL ALLIANT	MAR 2003	SCH. - OATT	8.0	0.0	8.0	7.051	7.051	564.04	564.04	
SEMINOLE ELEC. CO-OP	JAN 2003	SCH. - OATT	(40.0)	0.0	(40.0)	(0.973)	(0.973)	389.24	389.24	
SEMINOLE ELEC. CO-OP	JAN 2003	SCH. - OATT	40.0	0.0	40.0	(0.733)	(0.733)	(293.19)	(293.19)	
SEMINOLE ELEC. PRECO-1	JUL 2003	SCH. - D	(2,078.4)	(180.6)	(1,897.8)	3.796	3.796	(72,032.48)	(72,032.48)	
SEMINOLE ELEC. PRECO-1	JUL 2003	SCH. - D	2,078.4	202.3	1,876.1	3.839	3.839	72,032.48	72,032.48	
TEC WHOLESALE MARKETING **	JAN-JUL 2003	SCH. - OATT	0.0	0.0	0.0	0.000	0.000	19,559.85	19,559.85	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			2,783.6	96.4	2,687.2	3.338	3.338	89,711.24	89,711.24	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			1,102.0	0.0	1,102.0	5.680	6.801	62,589.85	74,950.47	9,257.44
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			16.0	0.0	16.0	6.016	6.016	962.56	962.56	
TOTAL			**3,901.6**	**96.4**	**3,805.2**	**4.028**	**4.353**	**153,263.65**	**165,624.27**	**9,257.44**
CURRENT MONTH:										
DIFFERENCE			(30,124.4)	96.4	(30,220.8)	(2.042)	(3.414)	(1,912,036.35)	(2,477,075.73)	(467,242.56)
DIFFERENCE %			-88.5%	0.0%	-88.8%	-33.6%	-44.0%	-92.6%	-93.7%	-98.1%
PERIOD TO DATE:										
ACTUAL			106,047.6	446.7	105,600.9	3.283	4.401	3,467,206.67	4,647,644.92	851,070.68
ESTIMATED			232,363.9	5.3	232,358.6	4.427	5.864	10,287,601.69	13,626,017.12	2,628,894.33
DIFFERENCE			(126,316.3)	441.4	(126,757.7)	(1.144)	(1.463)	(6,820,395.02)	(8,978,372.20)	(1,777,823.65)
DIFFERENCE %			-54.4%	8328.3%	-54.6%	-25.8%	-24.9%	-66.3%	-65.9%	-67.6%

* SEC 60% PROFIT OR $1,505.62 HAS BEEN EXCLUDED.

**REFUND DUE TO SETTLEMENT OF TEC OPEN ACCESS TRANSMISSION RATE CASE FILED WITH FERC ON 12/16/02.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	15,645.0	0.0	7,535.0	8,110.0	7.866	7.866	637,900.00
HARDEE POWER PARTNERS		IPP	84,133.0	0.0	0.0	84,133.0	6.699	6.699	5,636,000.00
VARIOUS		OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
VARIOUS		MKT. BASE	100,808.0	0.0	0.0	100,808.0	5.597	5.597	5,641,900.00
TOTAL			**200,586.0**	**0.0**	**7,535.0**	**193,051.0**	**6.172**	**6.172**	**11,915,800.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	73,746.0	0.0	0.0	73,746.0	6.713	6.713	4,950,823.98
HARDEE PWR. PART.-OTHERS		IPP	305.0	0.0	0.0	305.0	4.129	4.129	12,594.40
FLA. POWER CORP.		SCH. - J	32,142.0	0.0	0.0	32,142.0	5.931	5.931	1,906,419.00
FLA. POWER & LIGHT		SCH. - J	5,240.0	0.0	524.0	4,716.0	3.363	3.363	158,579.40
CITY OF LAKELAND		SCH. - J	27,870.0	0.0	493.1	27,376.9	5.517	5.517	1,510,347.75
ORLANDO UTIL. COMM.		SCH. - J	30,750.0	0.0	1,169.8	29,580.2	4.488	4.488	1,327,488.27
CAROLINA POWER & LIGHT		SCH. - J	2,483.0	0.0	236.6	2,246.4	5.974	5.974	134,189.15
THE ENERGY AUTHORITY		SCH. - J	36,427.0	0.0	574.5	35,852.5	5.214	5.214	1,869,401.19
REEDY CREEK		SCH. - J	835.0	0.0	0.0	835.0	5.553	5.553	46,370.00
OKEELANTA		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TALLAHASSEE		SCH. - J	3,299.0	0.0	0.0	3,299.0	6.413	6.413	211,570.60
CALPINE		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL ALLIANT		SCH. - J	20,191.0	0.0	0.0	20,191.0	3.572	3.572	721,153.50
CONOCO		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CORAL POWER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RELIANT		SCH. - J	5,717.0	0.0	263.5	5,453.5	8.562	8.562	466,937.27
SEMINOLE ELEC. CO-OP		SCH. - J	14,035.0	0.0	1,170.4	12,864.6	5.378	5.378	691,852.33
DUKE ENERGY		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
DYNEGY POWER MARKETING		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RINGHAVER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	July 2003	IPP	(96,910.0)	0.0	0.0	(96,910.0)	5.994	5.994	(5,809,064.56)
HARDEE PWR. PART.-NATIVE	July 2003	IPP	96,910.0	0.0	0.0	96,910.0	6.273	6.273	6,078,924.08
CARGILL ALLIANT	July 2003	SCH. - J	(41,942.0)	0.0	(263.3)	(41,678.7)	4.361	4.361	(1,817,709.96)
CARGILL ALLIANT	July 2003	SCH. - J	41,942.0	0.0	286.0	41,656.0	4.339	4.339	1,807,567.50
CITY OF LAKELAND	July 2003	SCH. - J	(26,714.0)	0.0	(1,642.8)	(25,071.2)	6.683	6.683	(1,675,625.43)
CITY OF LAKELAND	July 2003	SCH. - J	26,714.0	0.0	1,783.9	24,930.1	6.326	6.326	1,577,056.92
TALLAHASSEE	July 2003	SCH. - J	(1,820.0)	0.0	(3,735.9)	1,915.9	(5.757)	-5.757	(110,303.50)
TALLAHASSEE	July 2003	SCH. - J	1,820.0	0.0	0.0	1,820.0	6.061	6.061	110,313.00
DUKE ENERGY	July 2003	SCH. - J	(1,037.0)	0.0	(123.4)	(913.6)	7.776	7.776	(71,043.80)
DUKE ENERGY	July 2003	SCH. - J	1,037.0	0.0	134.0	903.0	7.358	7.358	66,443.00
FLA. POWER CORP.	July 2003	SCH. - J	(15,170.0)	0.0	(480.3)	(14,689.7)	5.037	5.037	(739,934.85)
FLA. POWER CORP.	July 2003	SCH. - J	15,170.0	0.0	521.6	14,648.4	4.910	4.910	719,297.76
FLA. POWER & LIGHT	July 2003	SCH. - J	(16,904.0)	0.0	(1,112.8)	(15,791.2)	6.793	6.793	(1,072,623.95)
FLA. POWER & LIGHT	July 2003	SCH. - J	16,904.0	0.0	1,208.4	15,695.6	6.322	6.322	992,285.22
ORLANDO UTIL. COMM.	July 2003	SCH. - J	(41,580.0)	0.0	(2,773.3)	(38,806.7)	7.802	7.802	(3,027,573.69)
ORLANDO UTIL. COMM.	July 2003	SCH. - J	41,580.0	0.0	3,011.5	38,568.5	7.523	7.523	2,901,627.26
RELIANT	July 2003	SCH. - J	(6,105.0)	0.0	(1,897.0)	(4,208.0)	11.564	11.564	(486,624.77)
RELIANT	July 2003	SCH. - J	6,105.0	0.0	2,060.0	4,045.0	9.644	9.644	390,118.05
SEMINOLE ELEC. CO-OP	July 2003	SCH. - J	(27,330.0)	0.0	(597.7)	(26,732.3)	4.972	4.972	(1,329,172.14)
SEMINOLE ELEC. CO-OP	July 2003	SCH. - J	27,330.0	0.0	649.0	26,681.0	4.885	4.885	1,303,331.45
THE ENERGY AUTHORITY	July 2003	SCH. - J	(59,050.0)	0.0	0.0	(59,050.0)	5.008	5.008	(2,957,305.53)
THE ENERGY AUTHORITY	July 2003	SCH. - J	59,050.0	0.0	4,056.8	54,993.2	5.037	5.037	2,770,026.24
TOTAL			**253,040.0**	**0.0**	**5,516.6**	**247,523.4**	**5.506**	**5.506**	**13,627,735.14**

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
CURRENT MONTH:								
DIFFERENCE		52,454.0	0.0	(2,018.4)	54,472.4	(0.666)	(0.666)	1,711,935.14
DIFFERENCE %		26.2%	0.0%	-26.8%	28.2%	-10.8%	-10.8%	14.4%
PERIOD TO DATE:								
ACTUAL		1,824,276.0	0.0	36,722.5	1,787,553.5	5.862	5.862	104,786,974.26
ESTIMATED		1,417,637.0	0.0	31,534.2	1,386,102.8	5.539	5.539	76,772,339.59
DIFFERENCE		406,639.0	0.0	5,188.3	401,450.7	0.323	0.323	28,014,634.67
DIFFERENCE %		28.7%	0.0%	16.5%	29.0%	5.8%	5.8%	36.5%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	41,439.0	0.0	0.0	41,439.0	2.796	2.796	1,158,700.00
TOTAL			**41,439.0**	**0.0**	**0.0**	**41,439.0**	**2.796**	**2.796**	**1,158,700.00**
ACTUAL:									
HILLSBOROUGH COUNTY		COGEN.	15,977.0	0.0	0.0	15,977.0	2.132	2.132	340,604.99
McKAY BAY REFUSE		COGEN.	13,301.0	0.0	0.0	13,301.0	2.123	2.123	282,380.03
ORANGE COGENERATION L.P.		COGEN.	7,843.0	0.0	0.0	7,843.0	2.033	2.033	159,475.28
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	1,409.0	0.0	0.0	1,409.0	4.367	4.367	61,532.92
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	630.0	0.0	0.0	630.0	3.343	3.343	21,060.36
CF INDUSTRIES INC.		COGEN.	1,153.0	0.0	0.0	1,153.0	4.971	4.971	57,309.96
IMC-AGRICO-NEW WALES		COGEN.	378.0	0.0	0.0	378.0	3.684	3.684	13,924.00
IMC-AGRICO-S. PIERCE		COGEN.	333.0	0.0	0.0	333.0	5.045	5.045	16,800.53
AUBURNDALE POWER PARTNERS		COGEN.	60.0	0.0	0.0	60.0	3.008	3.008	1,804.93
CUTRALE CITRUS		COGEN.	48.0	0.0	0.0	48.0	4.424	4.424	2,123.50
SUB-TOTAL FOR AUGUST 2003			41,132.0	0.0	0.0	41,132.0	2.327	2.327	957,016.50
ADJUSTMENTS FOR THE MONTH OF:	**JULY 2003**								
HILLSBOROUGH COUNTY		COGEN.	(18,015.0)	0.0	0.0	(18,015.0)	1.838	1.838	(331,113.54)
			18,015.0	0.0	0.0	18,015.0	2.136	2.136	384,724.39
McKAY BAY REFUSE		COGEN.	(10,996.0)	0.0	0.0	(10,996.0)	1.813	1.813	(199,306.59)
			10,996.0	0.0	0.0	10,996.0	2.115	2.115	232,519.61
ORANGE COGENERATION L.P.		COGEN.	(7,521.0)	0.0	0.0	(7,521.0)	1.774	1.774	(133,452.39)
			7,521.0	0.0	0.0	7,521.0	2.034	2.034	153,002.60
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	(2,167.0)	0.0	0.0	(2,167.0)	5.011	5.011	(108,592.31)
			2,167.0	0.0	0.0	2,167.0	5.014	5.014	108,650.25
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	(19.0)	0.0	0.0	(19.0)	11.780	11.780	(2,238.24)
			19.0	0.0	0.0	19.0	179.196	179.196	34,047.28
CF INDUSTRIES INC.		COGEN.	(1,197.0)	0.0	0.0	(1,197.0)	4.624	4.624	(55,347.93)
			1,197.0	0.0	0.0	1,197.0	4.625	4.625	55,358.80
IMC-AGRICO-NEW WALES		COGEN.	(808.0)	0.0	0.0	(808.0)	4.882	4.882	(39,448.12)
			808.0	0.0	0.0	808.0	4.890	4.890	39,509.44
IMC-AGRICO-S. PIERCE		COGEN.	(182.0)	0.0	0.0	(182.0)	2.826	2.826	(5,143.20)
			182.0	0.0	0.0	182.0	2.828	2.828	5,146.07
AUBURNDALE POWER PARTNERS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**JULY 2003**		0.0	0.0	0.0	0.0	0.000	0.000	138,316.12

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ADJUSTMENTS FOR THE MONTH OF:	**JUNE 2003**								
HILLSBOROUGH COUNTY		COGEN.	(17,172.0)	0.0	0.0	(17,172.0)	1.733	1.733	(297,628.17)
			17,172.0	0.0	0.0	17,172.0	2.139	2.139	367,350.45
McKAY BAY REFUSE		COGEN.	(11,840.0)	0.0	0.0	(11,840.0)	1.731	1.731	(204,895.18)
			11,840.0	0.0	0.0	11,840.0	2.137	2.137	252,968.06
ORANGE COGENERATION L.P.		COGEN.	(7,590.0)	0.0	0.0	(7,590.0)	1.717	1.717	(130,335.38)
			7,590.0	0.0	0.0	7,590.0	2.107	2.107	159,915.25
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	(516.0)	0.0	0.0	(516.0)	4.395	4.395	(22,678.31)
			516.0	0.0	0.0	516.0	4.395	4.395	22,678.41
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT		COGEN.	(252.0)	0.0	0.0	(252.0)	8.574	8.574	(21,605.38)
			252.0	0.0	0.0	252.0	17.089	17.089	43,064.74
CF INDUSTRIES INC.		COGEN.	(1,014.0)	0.0	0.0	(1,014.0)	4.579	4.579	(46,432.45)
			1,014.0	0.0	0.0	1,014.0	4.581	4.581	46,455.93
IMC-AGRICO-NEW WALES		COGEN.	(150.0)	0.0	0.0	(150.0)	4.216	4.216	(6,323.88)
			150.0	0.0	0.0	150.0	4.246	4.246	6,369.30
IMC-AGRICO-S. PIERCE		COGEN.	(71.0)	0.0	0.0	(71.0)	5.548	5.548	(3,939.18)
			71.0	0.0	0.0	71.0	5.548	5.548	3,939.18
AUBURNDALE POWER PARTNERS		COGEN.	(1.0)	0.0	0.0	(1.0)	1.713	1.713	(17.13)
			1.0	0.0	0.0	1.0	1.713	1.713	17.13
CUTRALE CITRUS		COGEN.	(6.0)	0.0	0.0	(6.0)	4.450	4.450	(266.98)
			6.0	0.0	0.0	6.0	4.450	4.450	266.98
SUB-TOTAL FOR THE MONTH OF:	**JUNE 2003**		0.0	0.0	0.0	0.0	0.000	0.000	168,903.39
ADJUSTMENTS FOR THE MONTH OF:	**MAY 2003**								
HILLSBOROUGH COUNTY		COGEN.	(18,401.0)	0.0	0.0	(18,401.0)	1.745	1.745	(321,028.09)
			18,401.0	0.0	0.0	18,401.0	2.190	2.190	403,010.64
McKAY BAY REFUSE		COGEN.	(13,222.0)	0.0	0.0	(13,222.0)	1.745	1.745	(230,701.64)
			13,222.0	0.0	0.0	13,222.0	2.191	2.191	289,642.56
ORANGE COGENERATION L.P.		COGEN.	(7,843.0)	0.0	0.0	(7,843.0)	1.713	1.713	(134,364.47)
			7,843.0	0.0	0.0	7,843.0	2.111	2.111	165,577.86
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY		COGEN.	(575.0)	0.0	0.0	(575.0)	4.992	4.992	(28,706.14)
			575.0	0.0	0.0	575.0	5.064	5.064	29,119.68
CARGILL MULBERRY		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	1,025.00
CARGILL MILLPOINT		COGEN.	(58.0)	0.0	0.0	(58.0)	5.461	5.461	(3,167.24)
			58.0	0.0	0.0	58.0	42.473	42.473	24,634.50
CF INDUSTRIES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	(107.0)	0.0	0.0	(107.0)	4.305	4.305	(4,606.07)
			107.0	0.0	0.0	107.0	4.447	4.447	4,758.44
IMC-AGRICO-S. PIERCE		COGEN.	(160.0)	0.0	0.0	(160.0)	6.619	6.619	(10,590.13)
			160.0	0.0	0.0	160.0	6.704	6.704	10,726.71
AUBURNDALE POWER PARTNERS		COGEN.	(2.0)	0.0	0.0	(2.0)	7.583	7.583	(151.66)
			2.0	0.0	0.0	2.0	7.583	7.583	151.66
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**MAY 2003**		0.0	0.0	0.0	0.0	0.000	0.000	195,331.61

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ADJUSTMENTS FOR THE MONTH OF:	**APRIL 2003**							
HILLSBOROUGH COUNTY	COGEN.	(18,355.0)	0.0	0.0	(18,355.0)	1.891	1.891	(347,106.43)
		18,355.0	0.0	0.0	18,355.0	1.751	1.751	321,387.50
McKAY BAY REFUSE	COGEN.	(12,852.0)	0.0	0.0	(12,852.0)	1.891	1.891	(243,038.70)
		12,852.0	0.0	0.0	12,852.0	2.157	2.157	277,214.20
ORANGE COGENERATION L.P.	COGEN.	(7,590.0)	0.0	0.0	(7,590.0)	1.782	1.782	(135,233.28)
		7,590.0	0.0	0.0	7,590.0	2.132	2.132	161,818.75
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	(565.0)	0.0	0.0	(565.0)	4.353	4.353	(24,596.99)
		565.0	0.0	0.0	565.0	4.286	4.286	24,218.21
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	1,025.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	(163.0)	0.0	0.0	(163.0)	3.565	3.565	(5,810.50)
		163.0	0.0	0.0	163.0	3.557	3.557	5,798.09
IMC-AGRICO-NEW WALES	COGEN.	(392.0)	0.0	0.0	(392.0)	3.814	3.814	(14,951.44)
		392.0	0.0	0.0	392.0	3.664	3.664	14,364.60
IMC-AGRICO-S. PIERCE	COGEN.	(10,114.0)	0.0	0.0	(10,114.0)	3.734	3.734	(377,686.12)
		10,114.0	0.0	0.0	10,114.0	3.620	3.620	366,079.56
AUBURNDALE POWER PARTNERS	COGEN.	(15.0)	0.0	0.0	(15.0)	4.276	4.276	(641.39)
		15.0	0.0	0.0	15.0	4.348	4.348	652.16
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**APRIL 2003**	0.0	0.0	0.0	0.0	0.000	0.000	23,493.22
ADJUSTMENTS FOR THE MONTH OF:	**MARCH 2003**							
HILLSBOROUGH COUNTY	COGEN.	(12,154.0)	0.0	0.0	(12,154.0)	2.087	2.087	(253,628.10)
		12,154.0	0.0	0.0	12,154.0	2.136	2.136	259,650.02
McKAY BAY REFUSE	COGEN.	(13,334.0)	0.0	0.0	(13,334.0)	2.078	2.078	(277,135.46)
		13,334.0	0.0	0.0	13,334.0	2.130	2.130	283,993.78
ORANGE COGENERATION L.P.	COGEN.	(5,704.0)	0.0	0.0	(5,704.0)	1.947	1.947	(111,035.70)
		5,704.0	0.0	0.0	5,704.0	2.003	2.003	114,237.85
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	(494.0)	0.0	0.0	(494.0)	3.899	3.899	(19,263.21)
		494.0	0.0	0.0	494.0	4.123	4.123	20,369.96
CARGILL MULBERRY	COGEN.	(6,459.0)	0.0	0.0	(6,459.0)	3.588	3.588	(231,746.54)
		6,459.0	0.0	0.0	6,459.0	3.793	3.793	244,996.41
CARGILL MILLPOINT	COGEN.	(57.0)	0.0	0.0	(57.0)	2.434	2.434	(1,387.33)
		57.0	0.0	0.0	57.0	2.695	2.695	1,535.94
CF INDUSTRIES INC.	COGEN.	(690.0)	0.0	0.0	(690.0)	3.789	3.789	(26,144.09)
		690.0	0.0	0.0	690.0	4.151	4.151	28,642.12
IMC-AGRICO-NEW WALES	COGEN.	(49.0)	0.0	0.0	(49.0)	4.749	4.749	(2,327.06)
		49.0	0.0	0.0	49.0	4.680	4.680	2,293.01
IMC-AGRICO-S. PIERCE	COGEN.	(10,801.0)	0.0	0.0	(10,801.0)	3.607	3.607	(389,589.41)
		10,801.0	0.0	0.0	10,801.0	3.814	3.814	411,913.95
AUBURNDALE POWER PARTNERS	COGEN.	(2.0)	0.0	0.0	(2.0)	5.753	5.753	(115.06)
		2.0	0.0	0.0	2.0	5.753	5.753	115.06
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**MARCH 2003**	0.0	0.0	0.0	0.0	0.000	0.000	55,376.14

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ADJUSTMENTS FOR THE MONTH OF:	FEBRUARY 2003							
HILLSBOROUGH COUNTY	COGEN.	(13,540.0)	0.0	0.0	(13,540.0)	2.110	2.110	(285,649.36)
		13,540.0	0.0	0.0	13,540.0	1.771	1.771	239,790.50
McKAY BAY REFUSE	COGEN.	(11,929.0)	0.0	0.0	(11,929.0)	2.101	2.101	(250,678.87)
		11,929.0	0.0	0.0	11,929.0	1.924	1.924	229,512.25
ORANGE COGENERATION L.P.	COGEN.	(5,152.0)	0.0	0.0	(5,152.0)	2.005	2.005	(103,305.22)
		5,152.0	0.0	0.0	5,152.0	1.973	1.973	101,634.81
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	(1,423.0)	0.0	0.0	(1,423.0)	3.212	3.212	(45,713.86)
		1,423.0	0.0	0.0	1,423.0	3.193	3.193	45,438.77
CARGILL MULBERRY	COGEN.	(8,016.0)	0.0	0.0	(8,016.0)	2.977	2.977	(238,632.26)
		8,016.0	0.0	0.0	8,016.0	2.927	2.927	234,609.55
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	(478.0)	0.0	0.0	(478.0)	2.962	2.962	(14,158.32)
		478.0	0.0	0.0	478.0	2.856	2.856	13,651.03
IMC-AGRICO-NEW WALES	COGEN.	(446.0)	0.0	0.0	(446.0)	2.729	2.729	(12,173.56)
		446.0	0.0	0.0	446.0	2.645	2.645	11,797.36
IMC-AGRICO-S. PIERCE	COGEN.	(9,407.0)	0.0	0.0	(9,407.0)	2.969	2.969	(279,325.01)
		9,407.0	0.0	0.0	9,407.0	2.921	2.921	274,757.10
AUBURNDALE POWER PARTNERS	COGEN.	(350.0)	0.0	0.0	(350.0)	2.063	2.063	(7,220.88)
		350.0	0.0	0.0	350.0	2.145	2.145	7,509.02
CUTRALE CITRUS	COGEN.	(1.0)	0.0	0.0	(1.0)	2.066	2.066	(20.66)
		1.0	0.0	0.0	1.0	4.386	4.386	43.86
SUB-TOTAL FOR THE MONTH OF:	FEBRUARY 2003	0.0	0.0	0.0	0.0	0.000	0.000	(78,133.55)
ADJUSTMENTS FOR THE MONTH OF:	JANUARY 2003							
HILLSBOROUGH COUNTY	COGEN.	(17,161.0)	0.0	0.0	(17,161.0)	2.243	2.243	(384,928.46)
		17,161.0	0.0	0.0	17,161.0	2.397	2.397	411,335.95
McKAY BAY REFUSE	COGEN.	(13,204.0)	0.0	0.0	(13,204.0)	2.268	2.268	(299,437.62)
		13,204.0	0.0	0.0	13,204.0	2.148	2.148	283,637.19
ORANGE COGENERATION L.P.	COGEN.	(5,474.0)	0.0	0.0	(5,474.0)	2.263	2.263	(123,890.45)
		5,474.0	0.0	0.0	5,474.0	2.219	2.219	121,468.18
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	(424.0)	0.0	0.0	(424.0)	3.335	3.335	(14,138.79)
		424.0	0.0	0.0	424.0	3.258	3.258	13,812.60
CARGILL MULBERRY	COGEN.	(2,603.0)	0.0	0.0	(2,603.0)	2.945	2.945	(76,656.92)
		2,603.0	0.0	0.0	2,603.0	2.880	2.880	74,971.49
CARGILL MILLPOINT	COGEN.	(75.0)	0.0	0.0	(75.0)	2.330	2.330	(1,747.56)
		75.0	0.0	0.0	75.0	2.196	2.196	1,647.09
CF INDUSTRIES INC.	COGEN.	(890.0)	0.0	0.0	(890.0)	3.129	3.129	(27,849.69)
		890.0	0.0	0.0	890.0	3.018	3.018	26,859.53
IMC-AGRICO-NEW WALES	COGEN.	(256.0)	0.0	0.0	(256.0)	3.883	3.883	(9,940.48)
		256.0	0.0	0.0	256.0	3.836	3.836	9,819.96
IMC-AGRICO-S. PIERCE	COGEN.	(547.0)	0.0	0.0	(547.0)	3.582	3.582	(19,590.85)
		547.0	0.0	0.0	547.0	3.490	3.490	19,089.69
AUBURNDALE POWER PARTNERS	COGEN.	(400.0)	0.0	0.0	(400.0)	3.484	3.484	(13,936.00)
		400.0	0.0	0.0	400.0	3.612	3.612	14,446.29
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	JANUARY 2003	0.0	0.0	0.0	0.0	0.000	0.000	4,971.15
SUB-TOTAL JANUARY - JULY 2003 ADJUSTMENTS		0.0	0.0	0.0	0.0	0.000	0.000	508,258.08
GRAND TOTAL		41,132.0	0.0	0.0	41,132.0	3.562	3.562	1,465,274.58
CURRENT MONTH:								
DIFFERENCE		(307.0)	0.0	0.0	(307.0)	0.766	0.766	306,574.58
DIFFERENCE %		-0.7%	0.0%	0.0%	-0.7%	27.4%	27.4%	26.5%
PERIOD TO DATE:								
ACTUAL		358,891.0	0.0	0.0	358,891.0	2.453	2.453	8,803,210.30
ESTIMATED		326,056.0	0.0	0.0	326,056.0	2.676	2.676	8,725,265.12
DIFFERENCE		32,835.0	0.0	0.0	32,835.0	(0.223)	(0.223)	77,945.18
DIFFERENCE %		10.1%	0.0%	0.0%	10.1%	(0.083)	(0.083)	0.9%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

SEPTEMBER 2003

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	44,625,731	36,134,831	8,490,900	23.5%	1,420,748	1,172,753	247,995	21.1%	3.14100	3.08120	0.05981	1.9%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(7,712)	(5,000)	(1,712)	28.5%	1,420,748 (a)	1,172,753 (a)	247,995	21.1%	(0.00054)	(0.00051)	(0.00003)	6.1%
4b. Adjustments to Fuel Cost	(2,601)	0	(2,601)	0.0%	1,420,748 (a)	1,172,753 (a)	247,995	21.1%	(0.00018)	0.00000	(0.00018)	0.0%
4c. Incremental Hedging O&M Costs	22,245	34,583	(12,338)	-35.7%	1,420,748 (a)	1,172,753 (a)	247,995	21.1%	0.00157	0.00295	(0.00138)	-46.9%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**44,637,663**	**36,163,414**	**8,474,249**	**23.4%**	**1,420,748**	**1,172,753**	**247,995**	**21.1%**	**3.14184**	**3.08363**	**0.05821**	**1.9%**
6. Fuel Cost of Purchased Power - Firm (A7)	15,485,189	26,278,100	(10,792,911)	-41.1%	324,845	551,169	(226,324)	-41.1%	4.76695	4.76770	(0.00076)	0.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	886,271	1,092,700	(206,429)	-18.9%	34,721	40,097	(5,376)	-13.4%	2.55255	2.72514	(0.17259)	-6.3%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**16,371,460**	**27,370,800**	**(10,999,340)**	**-40.2%**	**359,566**	**591,266**	**(231,700)**	**-39.2%**	**4.55312**	**4.62919**	**(0.07607)**	**-1.6%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,780,314**	**1,764,019**	**16,295**	**0.9%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	87,402	61,400	26,002	42.3%	2,285	2,556	(271)	-10.6%	3.82503	2.40219	1.42284	59.2%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	1,130	0	1,130	0.0%	(64)	0	(64)	0.0%	(1.76563)	0.00000	(1.76563)	0.0%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	5,925	123,600	(117,675)	-95.2%	160	2,692	(2,532)	-94.1%	3.70313	4.59138	(0.88826)	-19.3%
19. Gains on Market Based Sales	789	15,200	(14,411)	-94.8%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**95,246**	**200,200**	**(104,954)**	**-52.4%**	**2,381**	**5,248**	**(2,867)**	**-54.6%**	**4.00025**	**3.81479**	**0.18547**	**4.9%**
21. Net Inadvertant Interchange					(1,702)	0	(1,702)	0.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					(865)	0	(865)	0.0%				
23. Interchange and Wheeling Losses					469	100	369	369.0%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**60,813,877**	**63,334,014**	**(2,420,137)**	**-3.8%**	**1,774,897**	**1,758,671**	**16,226**	**0.9%**	**3.43197**	**3.60124**	**(0.16928)**	**-4.7%**
25. Net Unbilled	(1,745,945) (a)	(3,252,462) (a)	1,506,517	-46.3%	(50,873)	(90,315)	39,442	-43.7%	3.43197	3.60124	(0.16927)	-4.7%
26. Company Use	124,134 (a)	144,050 (a)	(19,916)	-13.8%	3,617	4,000	(383)	-9.6%	3.43196	3.60125	(0.16929)	-4.7%
27. T & D Losses	2,780,683 (a)	1,945,067 (a)	835,616	43.0%	81,023	54,011	27,012	50.0%	3.43197	3.60124	(0.16927)	-4.7%
28. System KWH Sales	60,913,877	63,334,014	(2,420,137)	-3.8%	1,741,130	1,790,975	(49,845)	-2.8%	3.49853	3.53629	(0.03776)	-1.1%
29. Wholesale KWH Sales	(1,841,975)	(1,455,359)	(386,616)	26.6%	(52,650)	(41,155)	(11,495)	27.9%	3.49853	3.53629	(0.03776)	-1.1%
30. Jurisdictional KWH Sales	59,071,902	61,878,655	(2,806,753)	-4.5%	1,688,480	1,749,820	(61,340)	-3.5%	3.49853	3.53629	(0.03776)	-1.1%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	59,139,244	61,949,197	(2,809,953)	-4.5%	1,688,480	1,749,820	(61,340)	-3.5%	3.50251	3.54032	(0.03780)	-1.1%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	256,603	258,524	(1,921)	-0.7%	1,688,480	1,749,820	(61,340)	-3.5%	0.01520	0.01477	0.00042	2.9%
34. Adjustment	0	0	0	0.0%	1,688,480	1,749,820	(61,340)	-3.5%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	1,688,480	1,749,820	(61,340)	-3.5%	0.00000	0.00000	0.00000	0.0%
36. True-up *	263,799	263,799	0	0.0%	1,688,480	1,749,820	(61,340)	-3.5%	0.01562	0.01508	0.00055	3.6%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	59,659,646	62,471,520	(2,811,874)	-4.5%	1,688,480	1,749,820	(61,340)	-3.5%	3.53333	3.57017	(0.03683)	-1.0%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.53588	3.57274	(0.03686)	-1.0%
40. GPIF * (Already Adjusted for Taxes)	(69,252)	(69,203)	(49)	0.1%	1,688,480	1,749,820	(61,340)	-3.5%	(0.00410)	(0.00395)	(0.00015)	3.7%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**59,590,394**	**62,402,317**	**(2,811,923)**	**-4.5%**	**1,688,480**	**1,749,820**	**(61,340)**	**-3.5%**	**3.53178**	**3.56879**	**(0.03701)**	**-1.0%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.532**	**3.569**	**(0.037)**	**-1.0%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: SEPTEMBER 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	364,284,876	359,553,554	4,731,322	1.3%	12,682,988	12,830,560	(147,572)	-1.2%	2.87223	2.80232	0.06991	2.5%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(60,812)	(54,108)	(6,704)	12.4%	12,682,988 (a)	12,830,560 (a)	(147,572)	-1.2%	(0.00048)	(0.00042)	(0.00006)	13.7%
4b. Adjustments to Fuel Cost	(27,162)	(2,738)	(24,424)	892.0%	12,682,988 (a)	12,830,560 (a)	(147,572)	-1.2%	(0.00021)	(0.00002)	(0.00019)	903.6%
4c. Adjustments to Fuel Cost	35,890	276,664	(240,774)	-87.0%	12,682,988 (a)	12,830,560 (a)	(147,572)	-1.2%	0.00028	0.00216	(0.00187)	-86.9%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**364,232,792**	**359,773,372**	**4,459,420**	**1.2%**	**12,682,988**	**12,830,560**	**(147,572)**	**-1.2%**	**2.87182**	**2.80403**	**0.06779**	**2.4%**
6. Fuel Cost of Purchased Power - Firm (A7)	120,272,163	103,050,440	17,221,723	16.7%	2,112,398	1,937,272	175,126	9.0%	5.69363	5.31936	0.37427	7.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	9,689,481	9,817,965	(128,484)	-1.3%	393,612	366,153	27,459	7.5%	2.46168	2.68138	(0.21970)	-8.2%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**129,961,644**	**112,868,405**	**17,093,239**	**15.1%**	**2,506,010**	**2,303,425**	**202,585**	**8.8%**	**5.18600**	**4.90003**	**0.28597**	**5.8%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**15,188,998**	**15,133,985**	**55,013**	**0.4%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	632,634	552,507	80,127	14.5%	21,657	23,620	(1,963)	-8.3%	2.92115	2.33915	0.58200	24.9%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	8,178	4,680	3,498	74.7%	72	46	26	56.5%	11.35833	10.17391	1.18442	11.6%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	121,809	108,975	12,834	11.8%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	2,799,044	9,806,440	(7,007,396)	-71.5%	86,254	213,941	(127,687)	-59.7%	3.24512	4.58371	(1.33859)	-29.2%
19. Gains on Market Based Sales	851,859	2,644,094	(1,792,235)	-67.8%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**4,413,524**	**13,116,696**	**(8,703,172)**	**-66.4%**	**107,983**	**237,607**	**(129,624)**	**-54.6%**	**4.08724**	**5.52033**	**(1.43309)**	**-26.0%**
21. Net Inadvertant Interchange					(496)	(291)	(205)	70.4%				
22. Wheeling Rec'd. less Wheeling Del'd.					88	652	(564)	-86.5%				
23. Interchange and Wheeling Losses					5,419	3,596	1,823	50.7%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**489,780,912**	**459,525,081**	**30,255,831**	**6.6%**	**15,075,188**	**14,893,143**	**182,045**	**1.2%**	**3.24892**	**3.08548**	**0.16344**	**5.3%**
25. Net Unbilled	7,147,741 (a)	8,243,369 (a)	(1,095,628)	-13.3%	205,838	282,317	(76,479)	-27.1%	3.47251	2.91990	0.55261	18.9%
26. Company Use	1,202,739 (a)	1,102,794 (a)	99,945	9.1%	37,198	36,099	1,099	3.0%	3.23334	3.05492	0.17843	5.8%
27. T & D Losses	21,123,437 (a)	17,995,946 (a)	3,127,491	17.4%	627,368	569,542	57,826	10.2%	3.36699	3.15972	0.20727	6.6%
28. System KWH Sales	489,780,912	459,525,081	30,255,831	6.6%	14,204,784	14,005,185	199,599	1.4%	3.44800	3.28111	0.16689	5.1%
29. Wholesale KWH Sales	(15,453,674)	(12,865,959)	(2,587,715)	20.1%	(446,081)	(386,370)	(59,711)	15.5%	3.46432	3.32996	0.13436	4.0%
30. Jurisdictional KWH Sales	474,327,238	446,659,122	27,668,116	6.2%	13,758,703	13,618,815	139,888	1.0%	3.44747	3.27972	0.16775	5.1%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	474,867,971	447,168,313	27,699,658	6.2%	13,758,703	13,618,815	139,888	1.0%	3.45140	3.28346	0.16794	5.1%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	2,394,358	2,405,204	(10,846)	-0.5%	13,758,703	13,618,815	139,888	1.0%	0.01740	0.01766	(0.00026)	-1.5%
34. Adjustment	0	0	0	0.0%	13,758,703	13,618,815	139,888	1.0%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	13,758,703	13,618,815	139,888	1.0%	0.00000	0.00000	0.00000	0.0%
36. True-up *	2,374,191	2,374,191	0	0.0%	13,758,703	13,618,815	139,888	1.0%	0.01726	0.01743	(0.00018)	-1.0%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	479,636,520	451,947,708	27,688,812	6.1%	13,758,703	13,618,815	139,888	1.0%	3.48606	3.31855	0.16751	5.0%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.48857	3.32094	0.16763	5.0%
40. GPIF * (Already Adjusted for Taxes)	(622,479)	(622,827)	348	-0.1%	13,758,703	13,618,815	139,888	1.0%	(0.00452)	(0.00457)	0.00005	-1.1%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**479,014,041**	**451,324,881**	**27,689,160**	**6.1%**	**13,758,703**	**13,618,815**	**139,888**	**1.0%**	**3.48405**	**3.31637**	**0.16768**	**5.1%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.484**	**3.316**	**0.168**	**5.1%**

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	44,625,731	36,134,831	8,490,900	23.5%	364,284,876	359,553,554	4,731,322	1.3%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	94,457	185,000	(90,543)	-48.9%	3,561,665	10,472,602	(6,910,937)	-66.0%
2a. GAINS FROM MARKET BASED SALES	789	15,200	(14,411)	-94.8%	851,859	2,644,094	(1,792,235)	-67.8%
3. FUEL COST OF PURCHASED POWER	15,485,189	26,278,100	(10,792,911)	-41.1%	120,272,163	103,050,440	17,221,723	16.7%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	886,271	1,092,700	(206,429)	-18.9%	9,689,481	9,817,965	(128,484)	-1.3%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	60,901,945	63,305,431	(2,403,486)	-3.8%	489,832,996	459,305,263	30,527,733	6.6%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(7,712)	(6,000)	(1,712)	28.5%	(60,812)	(54,108)	(6,704)	12.4%
6b. ADJ.TO FUEL COST	(2,601)	0	(2,601)	0.0%	(27,162)	(2,738)	(24,424)	892.0%
6c. INCREMENTAL HEDGING O&M COSTS	22,245	34,583	(12,338)	-35.7%	35,890	276,664	(240,774)	-87.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	60,913,877	63,334,014	(2,420,137)	-3.8%	489,780,912	459,525,081	30,255,831	6.6%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,688,480	1,749,820	(61,340)	-3.5%	13,758,703	13,618,815	139,888	1.0%
2. NONJURISDICTIONAL SALES	52,650	41,155	11,495	27.9%	446,081	386,370	59,711	15.5%
3. TOTAL SALES	1,741,130	1,790,975	(49,845)	-2.8%	14,204,784	14,005,185	199,599	1.4%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9697610	0.9770209	(0.0072599)	-0.7%	0.9685964	0.9724124	(0.0038160)	-0.4%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	57,590,390	60,076,745	(2,486,355)	-4.1%	451,442,165	449,333,878	2,108,287	0.5%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(263,799)	(263,799)	0	0.0%	(2,374,191)	(2,374,191)	0	0.0%
2b. INCENTIVE PROVISION	69,252	69,203	49	0.1%	622,479	622,827	(348)	-0.1%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	57,395,843	59,882,149	(2,486,306)	-4.2%	449,690,453	447,582,514	2,107,939	0.5%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	60,913,877	63,334,014	(2,420,137)	-3.8%	489,780,912	459,525,081	30,255,831	6.6%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9697610	0.9770209	(0.0072599)	-0.7%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	59,071,902	61,878,655	(2,806,753)	-4.5%	474,327,238	446,659,122	27,668,116	6.2%
6a. JURISDIC. LOSS MULTIPLIER	1.00114	1.00114	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	59,139,244	61,949,197	(2,809,953)	-4.5%	474,867,970	447,168,313	27,699,657	6.2%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	264,604	264,604	0	0.0%	2,472,552	2,472,552	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	256,603	258,524	(1,921)	-0.7%	2,394,358	2,405,204	(10,846)	-0.5%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	59,395,847	62,207,721	(2,811,874)	-4.5%	477,262,328	449,573,517	27,688,811	6.2%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(2,000,004)	(2,325,572)	325,568	-14.0%	(27,571,875)	(1,991,003)	(25,580,872)	1284.8%
8. INTEREST PROVISION FOR THE MONTH	(49,677)	(33,107)	(16,570)	50.0%	(343,351)	(273,803)	(69,548)	25.4%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(55,583,071)	(29,623,653)	(25,959,418)	87.6%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	263,799	263,799	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(57,368,953)	(31,718,533)	(25,650,420)	80.9%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(55,583,071)	(29,623,653)	(25,959,418)	87.6%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(57,319,276)	(31,685,426)	(25,633,850)	80.9%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(112,902,347)	(61,309,079)	(51,593,268)	84.2%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(56,451,174)	(30,654,540)	(25,796,634)	84.2%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.060	1.300	(0)	-18.5%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.060	1.300	(0)	-18.5%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	2.120	2.600	(0)	-18.5%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.060	1.300	(0)	-18.5%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.088	0.108	(0)	-18.5%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(49,677)	(33,107)	(16,570)	50.0%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	604,951	533,675	71,276	13.4%	4,377,216	3,297,907	1,079,309	32.7%
2	LIGHT OIL	252,946	703,632	(450,686)	-64.1%	6,457,023	10,365,179	(3,908,156)	-37.7%
3	COAL	23,206,032	17,554,090	5,651,942	32.2%	226,082,942	231,099,997	(5,017,055)	-2.2%
4	NATURAL GAS	20,561,802	17,343,434	3,218,368	18.6%	127,367,695	114,790,471	12,577,224	11.0%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	44,625,731	36,134,831	8,490,900	23.5%	364,284,876	359,553,554	4,731,322	1.3%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	11,697	10,842	855	7.9%	78,373	63,537	14,836	23.4%
9	LIGHT OIL	4,112	10,317	(6,205)	-60.1%	95,198	149,565	(54,367)	-36.4%
10	COAL	1,009,409	812,935	196,474	24.2%	10,234,779	10,499,976	(265,197)	-2.5%
11	NATURAL GAS	395,530	338,659	56,871	16.8%	2,274,638	2,117,482	157,156	7.4%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,420,748	1,172,753	247,995	21.1%	12,682,988	12,830,560	(147,572)	-1.2%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	18,079	16,337	1,742	10.7%	121,412	95,845	25,567	26.7%
16	LIGHT OIL (BBL)	6,763	18,338	(11,575)	-63.1%	168,324	266,801	(98,477)	-36.9%
17	COAL (TON)	486,241	359,095	127,146	35.4%	4,798,459	4,798,914	(455)	0.0%
18	NATURAL GAS (MCF)	3,078,900	2,493,219	585,681	23.5%	17,312,969	16,128,237	1,184,732	7.3%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	113,418	103,810	9,608	9.3%	761,683	609,528	152,155	25.0%
22	LIGHT OIL	39,259	106,519	(67,260)	-63.1%	950,283	1,546,158	(595,875)	-38.5%
23	COAL	11,487,517	8,730,372	2,757,145	31.6%	114,525,991	115,437,009	(911,018)	-0.8%
24	NATURAL GAS	3,202,056	2,562,903	639,153	24.9%	18,326,730	16,584,057	1,742,673	10.5%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	14,842,250	11,503,604	3,338,646	29.0%	134,564,687	134,176,752	387,935	0.3%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.82%	0.92%	(0.00)	-	0.62%	0.50%	0.00	-
29	LIGHT OIL	0.29%	0.88%	(0.01)	-	0.75%	1.17%	(0.00)	-
30	COAL	71.05%	69.32%	0.02	-	80.70%	81.84%	(0.01)	-
31	NATURAL GAS	27.84%	28.88%	(0.01)	-	17.93%	16.50%	0.01	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	33.46	32.67	0.79	2.4%	36.05	34.41	1.64	4.8%
36	LIGHT OIL ($/BBL)	37.40	38.37	(0.97)	-2.5%	38.36	38.85	(0.49)	-1.3%
37	COAL ($/TON)	47.73	48.88	(1.16)	-2.4%	47.12	48.16	(1.04)	-2.2%
38	NATURAL GAS ($/MCF)	6.68	6.96	(0.28)	-4.0%	7.36	7.12	0.24	3.4%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	5.33	5.14	0.19	3.8%	5.75	5.41	0.34	6.2%
42	LIGHT OIL	6.44	6.61	(0.16)	-2.5%	6.79	6.70	0.09	1.4%
43	COAL	2.02	2.01	0.01	0.5%	1.97	2.00	(0.03)	-1.4%
44	NATURAL GAS	6.42	6.77	(0.35)	-5.1%	6.95	6.92	0.03	0.4%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	3.01	3.14	(0.13)	-4.3%	2.71	2.68	0.03	1.0%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,696	9,575	121	1.3%	9,719	9,593	126	1.3%
49	LIGHT OIL	9,547	10,325	(778)	-7.5%	9,982	10,338	(356)	-3.4%
50	COAL	11,380	10,739	641	6.0%	11,190	10,994	196	1.8%
51	NATURAL GAS	8,096	7,568	528	7.0%	8,057	7,832	225	2.9%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,447	9,809	638	6.5%	10,610	10,458	152	1.5%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.17	4.92	0.25	5.1%	5.59	5.19	0.40	7.7%
56	LIGHT OIL	6.15	6.82	(0.67)	-9.8%	6.78	6.93	(0.15)	-2.2%
57	COAL	2.30	2.16	0.14	6.5%	2.21	2.20	0.01	0.5%
58	NATURAL GAS	5.20	5.12	0.08	1.6%	5.60	5.42	0.18	3.3%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	3.14	3.08	0.06	1.9%	2.87	2.80	0.07	2.5%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: SEPTEMBER 2003

SCHEDULE A4
PAGE 1 OF 1
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(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAP-ABILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	NET AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE BTU/KWH	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	94	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#2	100	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	150	69,015	63.9	78.0	76.2	11,655	COAL	33,101	24,300,000	804,354.3	1,421,797	2.06	42.95
GAN.#4	164	47,735	40.4	80.5	47.7	13,432	COAL	26,524	24,174,000	641,191.2	1,139,294	2.39	42.95
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	353	163,359	64.3	77.8	65.3	11,523	COAL	78,116	24,098,000	1,882,439.4	3,355,340	2.05	42.95
GANNON STATION	**861**	**280,109**	**45.2**	**83.4**	**49.1**	**11,881**	**COAL**	**137,741**	**24,161,179**	**3,327,984.9**	**5,916,431**	**2.11**	**42.95**
B.B.#1	421	183,306	60.5	66.5	62.6	11,478	COAL	89,245	23,574,920	2,103,949.6	4,457,852	2.43	49.95
B.B.#2	411	138,368	46.8	51.4	65.4	10,960	COAL	63,202	23,995,140	1,516,540.8	3,156,986	2.28	49.95
B.B.#3	428	115,134	37.4	41.6	48.9	11,574	COAL	55,445	24,033,960	1,332,559.5	2,769,518	2.41	49.95
B.B.#4	452	262,409	80.6	86.9	81.1	10,842	COAL	126,870	22,425,800	2,845,164.2	6,337,249	2.42	49.95
B.B. STATION	**1,712**	**699,217**	**56.7**	**62.0**	**64.7**	**11,153**	**COAL**	**334,762**	**23,294,784**	**7,798,214.1**	**16,721,605**	**2.39**	**49.95**
SEB-PHIL. #1(HVY OIL)	17	5,922	48.4	100.0	92.8	9,696	HVY.OIL	9,152	6,273,540	57,417.7	306,240	5.17	33.46
SEB-PHIL. #2(HVY OIL)	17	5,775	47.2	98.5	92.8	9,696	HVY.OIL	8,927	6,273,540	56,000.7	298,711	5.17	33.46
SEB-PHILLIPS TOTAL	**34**	**11,697**	**47.8**	**99.3**	**92.8**	**9,696**	**HVY.OIL**	**18,079**	**6,273,541**	**113,418.4**	**604,951**	**5.17**	**33.46**
POLK #1 GASIFIER	255	30,083	16.4	19.7	78.1	12,011	COAL	13,738	26,300,000	361,317.6	567,996	1.89	41.34
POLK #1 CT (OIL)	225	3,612	2.2	23.2	82.8	8,117	LGT.OIL	5,050	5,805,737	29,317.3	190,691	5.28	37.76
POLK #1 TOTAL	**255**	**33,695**	**18.4**	**21.7**	**78.6**	**11,593**	**-**	**-**	**-**	**390,634.9**	**758,687**	**2.25**	**-**
POLK #2 CT (GAS)	150	30,180	27.9	91.6	82.6	11,006	GAS	319,391	1,040,000	332,166.6	2,120,540	7.03	6.64
POLK #2 CT (OIL)	160	78	0.1	82.9	28.9	36,218	LGT.OIL	486	5,805,741	2,819.5	18,339	23.51	37.73
POLK #2 TOTAL	**155**	**30,258**	**27.1**	**91.6**	**82.2**	**11,071**	**-**	**-**	**-**	**334,986.1**	**2,138,879**	**7.07**	**-**
POLK #3 CT (GAS)	150	29,231	27.1	94.5	79.4	12,466	GAS	350,396	1,040,000	364,411.4	2,327,003	7.96	6.64
POLK #3 CT (OIL)	165	32	0.0	94.5	14.7	16,944	LGT.OIL	92	5,805,748	535.3	3,482	10.88	37.85
POLK #3 TOTAL	**158**	**29,263**	**25.7**	**94.5**	**79.0**	**12,471**	**-**	**-**	**-**	**364,946.7**	**2,330,485**	**7.96**	**-**
POLK STATION TOTAL	**568**	**93,216**	**22.8**	**61.0**	**79.7**	**11,699**	**-**	**-**	**-**	**1,090,567.7**	**5,228,051**	**5.61**	**-**
B.B.C.T.#1	14	136	1.3	100.0	81.0	18,913	LGT.OIL	442	5,820,706	2,572.2	15,746	11.58	35.62
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	254	0.6	100.0	60.5	15,806	LGT.OIL	693	5,793,985	4,014.7	24,688	9.72	35.62
C.T. TOTAL	**140**	**390**	**0.4**	**100.0**	**64.4**	**16,889**	**LGT.OIL**	**1,135**	**5,804,408**	**6,586.9**	**40,434**	**10.37**	**35.62**
CITY OF TAMPA	**6**	**1,543**	**35.7**	**0.0**	**0.0**	**10,203**	**GAS**	**15,138**	**1,040,000**	**15,743.5**	**120,597**	**7.82**	**7.97**
BAYSIDE ST 1	246	115,771	65.4	93.9	65.4	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	74,864	70.3	97.4	86.0	11,348	GAS	816,897	1,040,000	849,572.7	5,457,522	7.29	6.68
BAYSIDE CT1B	148	69,237	65.0	96.0	85.7	11,348	GAS	755,496	1,040,000	785,715.9	5,047,317	7.29	6.68
BAYSIDE CT1C	148	75,293	70.7	98.3	85.4	11,348	GAS	821,582	1,040,000	854,445.3	5,488,823	7.29	6.68
BAYSIDE UNIT 1 TOTAL	**690**	**335,165**	**67.5**	**96.1**	**78.4**	**7,428**	**GAS**	**2,393,975**	**1,040,000**	**2,489,734.0**	**15,993,662**	**4.77**	**6.68**
BAYSIDE UNIT 2 TOTAL	**0**	**(589)**	**-**	**-**	**-**	**0**	**GAS**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
BAYSIDE STATION TOTAL	**690**	**334,576**	**67.3**	**96.1**	**78.4**	**7,441**	**GAS**	**2,393,975**	**1,040,000**	**2,489,734.0**	**15,993,662**	**4.78**	**6.68**
TOT. COAL (GN,BB,POLK)	**2,828**	**1,009,409**	**49.6**	**64.7**	**61.2**	**11,380**	**COAL**	**486,241**	**23,625,123**	**11,487,516.6**	**23,206,032**	**2.30**	**47.73**
SYSTEM	**4,011**	**1,420,748**	**49.2**	**75.2**	**67.2**	**10,447**	**-**	**-**	**-**	**14,842,249.5**	**44,625,731**	**3.14**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2003

SCHEDULE A5
PAGE 1 OF 2
REVISED WITH
TRUE UP FILING

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	22,976	16,337	6,639	40.6%	130,056	94,566	35,490	37.5%
3 UNIT COST ($/BBL)	31.33	32.05	(0.72)	-2.2%	34.17	33.16	1.01	3.1%
4 AMOUNT ($)	719,832	523,601	196,231	37.5%	4,443,875	3,135,578	1,308,297	41.7%
5 BURNED:								
6 UNITS (BBL)	18,079	16,337	1,742	10.7%	121,412	95,845	25,567	26.7%
7 UNIT COST ($/BBL)	33.46	32.67	0.79	2.4%	36.05	34.41	1.64	4.8%
8 AMOUNT ($)	604,951	533,675	71,276	13.4%	4,377,216	3,297,907	1,079,309	32.7%
9 ENDING INVENTORY:								
10 UNITS (BBL)	19,386	9,463	9,923	104.9%	19,386	9,463	9,923	104.9%
11 UNIT COST ($/BBL)	32.82	32.17	0.65	2.0%	32.82	32.17	0.65	2.0%
12 AMOUNT ($)	636,183	304,410	331,773	109.0%	636,183	304,410	331,773	109.0%
13								
14 DAYS SUPPLY:	142	47	95	202.3%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	13,966	22,060	(8,094)	-36.7%	248,585	314,103	(65,518)	-20.9%
17 UNIT COST ($/BBL)	35.69	37.27	(1.58)	-4.2%	38.56	39.92	(1.35)	-3.4%
18 AMOUNT ($)	498,425	822,083	(323,658)	-39.4%	9,586,568	12,537,668	(2,951,100)	-23.5%
19 BURNED:								
20 UNITS (BBL)	6,763	18,338	(11,575)	-63.1%	168,324	266,801	(98,477)	-36.9%
21 UNIT COST ($/BBL)	37.40	38.37	(0.97)	-2.5%	38.36	38.85	(0.49)	-1.3%
22 AMOUNT ($)	252,946	703,632	(450,686)	-64.1%	6,457,023	10,365,179	(3,908,156)	-37.7%
23 ENDING INVENTORY:								
24 UNITS (BBL)	82,995	82,746	249	0.3%	82,995	82,746	249	0.3%
25 UNIT COST ($/BBL)	36.82	38.21	(1.39)	-3.6%	36.82	38.21	(1.39)	-3.6%
26 AMOUNT ($)	3,055,987	3,161,846	(105,859)	-3.3%	3,055,987	3,161,846	(105,859)	-3.3%
27								
28 DAYS SUPPLY: NORMAL	104	110	(6)	-5.7%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	12	12	0	0.3%	-	-	-	-
COAL (3)								
30 PURCHASES:								
31 UNITS (TONS)	421,070	375,300	45,770	12.2%	4,786,565	5,281,173	(494,608)	-9.4%
32 UNIT COST ($/TON)	47.75	46.89	0.86	1.8%	47.68	48.12	(0.43)	-0.9%
33 AMOUNT ($)	20,105,610	17,598,774	2,506,836	14.2%	228,245,105	254,108,152	(25,863,047)	-10.2%
34 BURNED:								
35 UNITS (TONS)	486,241	359,095	127,146	35.4%	4,798,459	4,798,914	(455)	0.0%
36 UNIT COST ($/TON)	47.73	48.88	(1.16)	-2.4%	47.12	48.16	(1.04)	-2.2%
37 AMOUNT ($)	23,206,032	17,554,090	5,651,942	32.2%	226,082,942	231,099,997	(5,017,055)	-2.2%
38 ENDING INVENTORY:								
39 UNITS (TONS)	426,463	920,616	(494,153)	-53.7%	426,463	920,616	(494,153)	-53.7%
40 UNIT COST ($/TON)	48.06	48.20	(0.13)	-0.3%	48.06	48.20	(0.13)	-0.3%
41 AMOUNT ($)	20,497,671	44,370,584	(23,872,913)	-53.8%	20,497,671	44,370,584	(23,872,913)	-53.8%
42								
43 DAYS SUPPLY:	36	56	(20)	-35.2%	-	-	-	-
NATURAL GAS(4)								
44 PURCHASES:								
45 UNITS (MCF)	3,078,900	2,493,219	585,681	23.5%	17,312,969	16,128,237	1,184,732	7.3%
46 UNIT COST ($/MCF)	6.68	6.96	(0.28)	-4.0%	7.36	7.12	0.24	3.4%
47 AMOUNT ($)	20,561,802	17,343,433	3,218,369	18.6%	127,367,695	114,790,470	12,577,225	11.0%
48 BURNED:								
49 UNITS (MCF)	3,078,900	2,493,219	585,681	23.5%	17,312,969	16,128,237	1,184,732	7.3%
50 UNIT COST ($/MCF)	6.68	6.96	(0.28)	-4.0%	7.36	7.12	0.24	3.4%
51 AMOUNT ($)	20,561,802	17,343,434	3,218,368	18.6%	127,367,695	114,790,471	12,577,224	11.0%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	21,893
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	21,893

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(5,626)	(201,265)
OTHER USAGE	(596)	(21,571)
TOTAL	(6,222)	(222,836)

(3) RECONCILIATION - COALS

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	19,267
IGNITION #2 OIL	179,372
IGNITION PROPANE	3,639
AERIAL SURVEY ADJ.	(577,814)
ADDITIVES	88,827
GREEN FUEL	0
TOTAL	(286,709)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2003

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	2,556.0	0.0	2,556.0	2.402	2.402	61,400.00	61,400.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. - MB	2,692.0	0.0	2,692.0	4.591	5.479	123,600.00	147,500.00	15,200.00
TOTAL			**5,248.0**	**0.0**	**5,248.0**	**3.525**	**3.981**	**185,000.00**	**208,900.00**	**15,200.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	1,639.4	209.2	1,430.2	4.201	4.201	60,088.63	60,088.63	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	854.8	0.0	854.8	2.950	2.950	25,220.13	25,220.13	
FLA. PWR. CORP.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		SCH. - MA	60.0	0.0	60.0	3.615	4.591	2,169.29	2,754.36	354.67
SEMINOLE ELEC. CO-OP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTILITIES		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
RELIANT ENERGY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE PWR. PART. TO CITY OF LAKELAND*		SCH. - MA	100.0	0.0	100.0	3.756	4.204	3,756.00	4,204.35	434.35
AUBURNDALE POWER PARTNERS		SCH. - OATT	(113.0)	0.0	(113.0)	2.338	2.338	(2,642.50)	(2,642.50)	
CARGILL ALLIANT		SCH. - OATT	49.0	0.0	49.0	7.699	7.699	3,772.49	3,772.49	
ADJUSTMENTS										
SEMINOLE ELEC. TO HARDEE	SEPT 2002	SCH. - D	(590.7)	0.0	(590.7)	2.237	2.237	(13,212.28)	(13,212.28)	
SEMINOLE ELEC. TO HARDEE	SEPT 2002	SCH. - D	590.7	0.0	590.7	2.591	2.591	15,305.52	15,305.52	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			2,494.2	209.2	2,285.0	3.825	3.825	87,402.00	87,402.00	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			160.0	0.0	160.0	3.703	4.349	5,925.29	6,958.71	789.02
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			(64.0)	0.0	(64.0)	(1.766)	(1.766)	1,129.99	1,129.99	
TOTAL			**2,590.2**	**209.2**	**2,381.0**	**3.967**	**4.011**	**94,457.28**	**95,490.70**	**789.02**
CURRENT MONTH:										
DIFFERENCE			(2,657.8)	209.2	(2,867.0)	0.442	0.030	(90,542.72)	(113,409.30)	(14,410.98)
DIFFERENCE %			-50.6%	0.0%	-54.6%	12.5%	0.8%	-48.9%	-54.3%	-94.8%
PERIOD TO DATE:										
ACTUAL			108,637.8	655.9	107,981.9	3.298	4.393	3,561,663.95	4,743,135.62	851,859.70
ESTIMATED			237,611.9	5.3	237,606.6	4.408	5.823	10,472,601.69	13,834,917.12	2,644,094.33
DIFFERENCE			(128,974.1)	650.6	(129,624.7)	(1.110)	(1.430)	(6,910,937.74)	(9,091,781.50)	(1,792,234.63)
DIFFERENCE %			-54.3%	12275.5%	-54.6%	-25.2%	-24.6%	-66.0%	-65.7%	-67.8%

* SEC 60% PROFIT OR $651.52 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	13,073.0	0.0	7,115.0	5,958.0	4.841	4.841	288,400.00
HARDEE POWER PARTNERS		IPP	66,819.0	0.0	0.0	66,819.0	6.075	6.075	4,059,300.00
VARIOUS		OTHER	294,431.0	0.0	0.0	294,431.0	4.100	4.100	12,071,700.00
VARIOUS		MKT. BASE	183,961.0	0.0	0.0	183,961.0	5.359	5.359	9,858,700.00
TOTAL			**558,284.0**	**0.0**	**7,115.0**	**551,169.0**	**4.768**	**4.768**	**26,278,100.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	81,503.0	0.0	0.0	81,503.0	5.125	5.125	4,176,712.79
HARDEE PWR. PART.-OTHERS		IPP	100.0	0.0	0.0	100.0	3.770	3.770	3,770.00
FLA. POWER CORP.		SCH. - J	33,885.0	0.0	1,181.5	32,703.5	5.828	5.828	1,906,099.29
FLA. POWER & LIGHT		SCH. - J	16,300.0	0.0	1,678.3	14,621.7	3.875	3.875	566,562.80
CITY OF LAKELAND		SCH. - J	14,218.0	0.0	2,309.1	11,908.9	5.730	5.730	682,400.74
ORLANDO UTIL. COMM.		SCH. - J	30,100.0	0.0	3,360.4	26,739.6	7.224	7.224	1,931,791.27
CAROLINA POWER & LIGHT		SCH. - J	11,882.0	0.0	503.9	11,378.1	5.052	5.052	574,786.56
THE ENERGY AUTHORITY		SCH. - J	56,452.0	0.0	6,002.2	50,449.8	5.018	5.018	2,531,382.18
REEDY CREEK		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
OKEELANTA		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TALLAHASSEE		SCH. - J	859.0	0.0	15.0	844.0	4.939	4.939	41,682.98
CALPINE		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL ALLIANT		SCH. - J	49,463.0	0.0	0.0	49,463.0	3.203	3.203	1,584,519.00
CONOCO		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CORAL POWER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RELIANT		SCH. - J	8,652.0	0.0	678.6	7,973.4	7.507	7.507	598,561.93
SEMINOLE ELEC. CO-OP		SCH. - J	38,998.0	0.0	1,587.4	37,410.6	4.752	4.752	1,777,592.75
DUKE ENERGY		SCH. - J	441.0	0.0	42.0	399.0	6.663	6.663	26,586.00
DYNEGY POWER MARKETING		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RINGHAVER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	August 2003	IPP	(73,746.0)	0.0	0.0	(73,746.0)	6.713	6.713	(4,950,823.98)
HARDEE PWR. PART.-NATIVE	August 2003	IPP	73,746.0	0.0	0.0	73,746.0	5.528	5.528	4,076,924.28
ORLANDO UTIL. COMM.	August 2003	SCH. - J	(30,750.0)	0.0	(1,169.8)	(29,580.2)	4.488	4.488	(1,327,488.27)
ORLANDO UTIL. COMM.	August 2003	SCH. - J	30,750.0	0.0	1,169.8	29,580.2	4.490	4.490	1,328,129.99
THE ENERGY AUTHORITY	August 2003	SCH. - J	(36,427.0)	0.0	(574.5)	(35,852.5)	5.214	5.214	(1,869,401.19)
THE ENERGY AUTHORITY	August 2003	SCH. - J	36,427.0	0.0	574.5	35,852.5	5.217	5.217	1,870,486.52
FLA. POWER CORP.	April 2003	SCH. - D	(53,250.0)	0.0	0.0	(53,250.0)	4.695	4.695	(2,500,117.50)
FLA. POWER CORP.	April 2003	SCH. - D	52,600.0	0.0	0.0	52,600.0	4.667	4.667	2,455,030.92
TOTAL			**342,203.0**	**0.0**	**17,358.4**	**324,844.6**	**4.767**	**4.767**	**15,485,189.06**
CURRENT MONTH:									
DIFFERENCE			(216,081.0)	0.0	10,243.4	(226,324.4)	(0.001)	(0.001)	(10,792,910.94)
DIFFERENCE %			-38.7%	0.0%	144.0%	-41.1%	0.0%	0.0%	-41.1%
PERIOD TO DATE:									
ACTUAL			2,166,479.0	0.0	54,080.9	2,112,398.1	5.694	5.694	120,272,163.32
ESTIMATED			1,975,921.0	0.0	38,649.2	1,937,271.8	5.319	5.319	103,050,439.59
DIFFERENCE			190,558.0	0.0	15,431.7	175,126.3	0.375	0.375	17,221,723.73
DIFFERENCE %			9.6%	0.0%	39.9%	9.0%	7.1%	7.1%	16.7%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	40,097.0	0.0	0.0	40,097.0	2.725	2.725	1,092,700.00
TOTAL		40,097.0	0.0	0.0	40,097.0	2.725	2.725	1,092,700.00
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	12,902.0	0.0	0.0	12,902.0	2.349	2.349	303,111.98
McKAY BAY REFUSE	COGEN.	12,970.0	0.0	0.0	12,970.0	2.347	2.347	304,456.10
ORANGE COGENERATION L.P.	COGEN.	5,313.0	0.0	0.0	5,313.0	2.129	2.129	113,127.59
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	1,644.0	0.0	0.0	1,644.0	4.870	4.870	80,068.84
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	74.0	0.0	0.0	74.0	6.115	6.115	4,525.09
CF INDUSTRIES INC.	COGEN.	722.0	0.0	0.0	722.0	5.054	5.054	36,491.40
IMC-AGRICO-NEW WALES	COGEN.	234.0	0.0	0.0	234.0	4.599	4.599	10,761.89
IMC-AGRICO-S. PIERCE	COGEN.	286.0	0.0	0.0	286.0	5.732	5.732	16,394.51
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS	COGEN.	1.0	0.0	0.0	1.0	2.801	2.801	28.01
SUB-TOTAL FOR SEPTEMBER 2003		34,146.0	0.0	0.0	34,146.0	2.545	2.545	868,965.41
ADJUSTMENTS FOR THE MONTH OF:	**AUGUST 2003**							
HILLSBOROUGH COUNTY	COGEN.	(15,977.0)	0.0	0.0	(15,977.0)	2.132	2.132	(340,604.99)
		15,977.0	0.0	0.0	15,977.0	2.177	2.177	347,809.43
McKAY BAY REFUSE	COGEN.	(13,301.0)	0.0	0.0	(13,301.0)	2.123	2.123	(282,380.03)
		13,301.0	0.0	0.0	13,301.0	2.167	2.167	288,271.23
ORANGE COGENERATION L.P.	COGEN.	(7,843.0)	0.0	0.0	(7,843.0)	2.033	2.033	(159,475.28)
		7,843.0	0.0	0.0	7,843.0	2.087	2.087	163,685.37
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**AUGUST 2003**	0.0	0.0	0.0	0.0	0.000	0.000	17,305.73

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ADJUSTMENTS FOR THE MONTH OF:	JUNE 2003								
CARGILL MILLPOINT		COGEN.	(252.0)	0.0	0.0	(252.0)	17.089	17.089	(43,064.74)
			695.0	0.0	0.0	695.0	6.196	6.196	43,064.74
SUB-TOTAL FOR THE MONTH OF:	JUNE 2003		443.0	0.0	0.0	443.0	0.000	0.000	0.00
ADJUSTMENTS FOR THE MONTH OF:	MAY 2003								
CARGILL MILLPOINT		COGEN.	(58.0)	0.0	0.0	(58.0)	42.473	42.473	(24,634.50)
			187.0	0.0	0.0	187.0	13.174	13.174	24,634.50
SUB-TOTAL FOR THE MONTH OF:	MAY 2003		129.0	0.0	0.0	129.0	0.000	0.000	0.00
ADJUSTMENTS FOR THE MONTH OF:	FEBRUARY 2003								
CARGILL GREEN BAY		COGEN.	(1,423.0)	0.0	0.0	(1,423.0)	3.193	3.193	(45,438.77)
			1,424.0	0.0	0.0	1,424.0	3.191	3.191	45,438.77
IMC-AGRICO-S. PIERCE		COGEN.	(9,407.0)	0.0	0.0	(9,407.0)	2.921	2.921	(274,757.10)
			9,408.0	0.0	0.0	9,408.0	2.920	2.920	274,757.10
CUTRALE CITRUS		COGEN.	(1.0)	0.0	0.0	(1.0)	4.386	4.386	(43.86)
			2.0	0.0	0.0	2.0	2.193	2.193	43.86
SUB-TOTAL FOR THE MONTH OF:	FEBRUARY 2003		3.0	0.0	0.0	3.0	0.000	0.000	0.00
SUB-TOTAL PROIR MONTHS ADJUSTMENTS			575.0	0.0	0.0	575.0	3.010	3.010	17,305.73
GRAND TOTAL			34,721.0	0.0	0.0	34,721.0	2.553	2.553	886,271.14
CURRENT MONTH:									
DIFFERENCE			(5,376.0)	0.0	0.0	(5,376.0)	(0.173)	(0.173)	(206,428.86)
DIFFERENCE %			-13.4%	0.0%	0.0%	-13.4%	-6.3%	-6.3%	-18.9%
PERIOD TO DATE:									
ACTUAL			393,612.0	0.0	0.0	393,612.0	2.462	2.462	9,689,481.44
ESTIMATED			366,153.0	0.0	0.0	366,153.0	2.681	2.681	9,817,965.12
DIFFERENCE			27,459.0	0.0	0.0	27,459.0	(0.220)	(0.220)	(128,483.68)
DIFFERENCE %			7.5%	0.0%	0.0%	7.5%	(0.082)	(0.082)	-1.3%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

OCTOBER 2003

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	35,855,298	37,844,885	(1,989,587)	-5.3%	1,188,523	1,277,413	(88,890)	-7.0%	3.01679	2.96262	0.05418	1.8%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(7,075)	(6,000)	(1,075)	17.9%	1,188,523 (a)	1,277,413 (a)	(88,890)	-7.0%	(0.00060)	(0.00047)	(0.00013)	26.7%
4b. Adjustments to Fuel Cost	(1,867)	0	(1,867)	0.0%	1,188,523 (a)	1,277,413 (a)	(88,890)	-7.0%	(0.00016)	0.00000	(0.00016)	0.0%
4c. Incremental Hedging O&M Costs	22,652	34,583	(11,931)	-34.5%	1,188,523 (a)	1,277,413 (a)	(88,890)	-7.0%	0.00191	0.00271	(0.00080)	-29.6%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**35,869,008**	**37,873,468**	**(2,004,460)**	**-5.3%**	**1,188,523**	**1,277,413**	**(88,890)**	**-7.0%**	**3.01795**	**2.96486**	**0.05309**	**1.8%**
6. Fuel Cost of Purchased Power - Firm (A7)	19,381,862	17,102,800	2,279,062	13.3%	418,462	365,036	53,426	14.6%	4.63169	4.68524	(0.05355)	-1.1%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,080,151	1,122,400	(42,249)	-3.8%	41,367	41,439	(72)	-0.2%	2.61114	2.70856	(0.09742)	-3.6%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**20,462,013**	**18,225,200**	**2,236,813**	**12.3%**	**459,829**	**406,475**	**53,354**	**13.1%**	**4.44992**	**4.48372**	**(0.03380)**	**-0.8%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,648,352**	**1,683,888**	**(35,536)**	**-2.1%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	85,065	85,100	(35)	0.0%	2,495	3,274	(779)	-23.8%	3.40942	2.59927	0.81015	31.2%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	0	194,400	(194,400)	-100.0%	0	4,469	(4,469)	-100.0%	0.00000	4.34997	(4.34997)	-100.0%
19. Gains on Market Based Sales	0	16,700	(16,700)	-100.0%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**85,065**	**296,200**	**(211,135)**	**-71.3%**	**2,495**	**7,743**	**(5,248)**	**-67.8%**	**3.40942**	**3.82539**	**(0.41597)**	**-10.9%**
21. Net Inadvertant Interchange					(283)	0	(283)	0.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					1,604	0	1,604	0.0%				
23. Interchange and Wheeling Losses					179	100	79	79.0%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**56,245,956**	**55,802,468**	**443,488**	**0.8%**	**1,646,999**	**1,676,045**	**(29,046)**	**-1.7%**	**3.41506**	**3.32941**	**0.08564**	**2.6%**
25. Net Unbilled	(1,446,106) (a)	166,337 (a)	(1,612,443)	-969.4%	(42,345)	4,996	(47,341)	-947.6%	3.41506	3.32940	0.08565	2.6%
26. Company Use	200,020 (a)	133,177 (a)	66,843	50.2%	5,857	4,000	1,857	46.4%	3.41506	3.32943	0.08563	2.6%
27. T & D Losses	1,477,968 (a)	192,773 (a)	1,285,195	666.7%	43,278	5,790	37,488	647.5%	3.41506	3.32941	0.08564	2.6%
28. System KWH Sales	56,245,956	55,802,468	443,488	0.8%	1,640,209	1,661,259	(21,050)	-1.3%	3.42919	3.35905	0.07015	2.1%
29. Wholesale KWH Sales	(1,604,967)	(1,220,880)	(384,087)	31.5%	(46,803)	(36,346)	(10,457)	28.8%	3.42920	3.35905	0.07015	2.1%
30. Jurisdictional KWH Sales	54,640,989	54,581,588	59,401	0.1%	1,593,406	1,624,913	(31,507)	-1.9%	3.42919	3.35905	0.07015	2.1%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	54,703,280	54,643,811	59,469	0.1%	1,593,406	1,624,913	(31,507)	-1.9%	3.43310	3.36288	0.07023	2.1%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	254,595	256,339	(1,744)	-0.7%	1,593,406	1,624,913	(31,507)	-1.9%	0.01598	0.01578	0.00020	1.3%
34. Adjustment	0	0	0	0.0%	1,593,406	1,624,913	(31,507)	-1.9%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	1,593,406	1,624,913	(31,507)	-1.9%	0.00000	0.00000	0.00000	0.0%
36. True-up *	263,799	263,799	0	0.0%	1,593,406	1,624,913	(31,507)	-1.9%	0.01656	0.01623	0.00032	2.0%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	55,221,674	55,163,949	57,725	0.1%	1,593,406	1,624,913	(31,507)	-1.9%	3.46564	3.39489	0.07075	2.1%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.46813	3.39733	0.07080	2.1%
40. GPIF * (Already Adjusted for Taxes)	(69,252)	(69,203)	(49)	0.1%	1,593,406	1,624,913	(31,507)	-1.9%	(0.00435)	(0.00426)	(0.00009)	2.0%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**55,152,422**	**55,094,746**	**57,676**	**0.1%**	**1,593,406**	**1,624,913**	**(31,507)**	**-1.9%**	**3.46378**	**3.39307**	**0.07071**	**2.1%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.464**	**3.393**	**0.071**	**2.1%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: OCTOBER 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	400,140,174	397,398,439	2,741,735	0.7%	13,871,511	14,107,973	(236,462)	-1.7%	2.88462	2.81684	0.06778	2.4%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(67,887)	(60,108)	(7,779)	12.9%	13,871,511 (a)	14,107,973 (a)	(236,462)	-1.7%	(0.00049)	(0.00043)	(0.00006)	14.9%
4b. Adjustments to Fuel Cost	(29,029)	(2,738)	(26,291)	960.2%	13,871,511 (a)	14,107,973 (a)	(236,462)	-1.7%	(0.00021)	(0.00002)	(0.00019)	978.3%
4c. Adjustments to Fuel Cost	58,542	311,247	(252,705)	-81.2%	13,871,511 (a)	14,107,973 (a)	(236,462)	-1.7%	0.00042	0.00221	(0.00178)	-80.9%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**400,101,800**	**397,646,840**	**2,454,960**	**0.6%**	**13,871,511**	**14,107,973**	**(236,462)**	**-1.7%**	**2.88434**	**2.81860**	**0.06575**	**2.3%**
6. Fuel Cost of Purchased Power - Firm (A7)	139,654,025	120,153,240	19,500,785	16.2%	2,530,860	2,302,308	228,552	9.9%	5.51805	5.21882	0.29923	5.7%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	10,769,632	10,940,365	(170,733)	-1.6%	434,979	407,592	27,387	6.7%	2.47590	2.68415	(0.20825)	-7.8%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**150,423,657**	**131,093,605**	**19,330,052**	**14.7%**	**2,965,839**	**2,709,900**	**255,939**	**9.4%**	**5.07188**	**4.83758**	**0.23429**	**4.8%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**16,837,350**	**16,817,873**	**19,477**	**0.1%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	717,699	637,607	80,092	12.6%	24,152	26,894	(2,742)	-10.2%	2.97159	2.37082	0.60078	25.3%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	8,178	4,680	3,498	74.7%	72	46	26	56.5%	11.35833	10.17391	1.18442	11.6%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	121,809	108,975	12,834	11.8%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	2,799,044	10,000,840	(7,201,796)	-72.0%	86,254	218,410	(132,156)	-60.5%	3.24512	4.57893	(1.33381)	-29.1%
19. Gains on Market Based Sales	851,859	2,660,794	(1,808,935)	-68.0%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**4,498,589**	**13,412,696**	**(8,914,307)**	**-66.5%**	**110,478**	**245,350**	**(134,872)**	**-55.0%**	**4.07193**	**5.46684**	**(1.39491)**	**-25.5%**
21. Net Inadvertant Interchange					(779)	(291)	(488)	167.7%				
22. Wheeling Rec'd. less Wheeling Del'd.					1,692	652	1,040	159.5%				
23. Interchange and Wheeling Losses					5,598	3,696	1,902	51.5%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**546,026,868**	**515,327,549**	**30,699,319**	**6.0%**	**16,722,187**	**16,569,188**	**152,999**	**0.9%**	**3.26528**	**3.11016**	**0.15513**	**5.0%**
25. Net Unbilled	5,701,635 (a)	8,409,706 (a)	(2,708,071)	-32.2%	163,493	287,313	(123,820)	-43.1%	3.48739	2.92702	0.56037	19.1%
26. Company Use	1,402,759 (a)	1,235,971 (a)	166,788	13.5%	43,055	40,099	2,956	7.4%	3.25806	3.08230	0.17576	5.7%
27. T & D Losses	22,601,405 (a)	18,188,719 (a)	4,412,686	24.3%	670,646	575,332	95,314	16.6%	3.37009	3.16143	0.20866	6.6%
28. System KWH Sales	546,026,868	515,327,549	30,699,319	6.0%	15,844,993	15,666,444	178,549	1.1%	3.44605	3.28937	0.15668	4.8%
29. Wholesale KWH Sales	(17,058,641)	(14,086,839)	(2,971,802)	21.1%	(492,884)	(422,716)	(70,168)	16.6%	3.46098	3.33246	0.12853	3.9%
30. Jurisdictional KWH Sales	528,968,227	501,240,710	27,727,517	5.5%	15,352,109	15,243,728	108,381	0.7%	3.44557	3.28818	0.15740	4.8%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	529,571,251	501,812,124	27,759,127	5.5%	15,352,109	15,243,728	108,381	0.7%	3.44950	3.29193	0.15758	4.8%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	2,648,953	2,661,543	(12,590)	-0.5%	15,352,109	15,243,728	108,381	0.7%	0.01725	0.01746	(0.00021)	-1.2%
34. Adjustment	0	0	0	0.0%	15,352,109	15,243,728	108,381	0.7%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	15,352,109	15,243,728	108,381	0.7%	0.00000	0.00000	0.00000	0.0%
36. True-up *	2,637,990	2,637,990	0	0.0%	15,352,109	15,243,728	108,381	0.7%	0.01718	0.01731	(0.00012)	-0.7%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	534,858,194	507,111,657	27,746,537	5.5%	15,352,109	15,243,728	108,381	0.7%	3.48394	3.32669	0.15725	4.7%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.48645	3.32909	0.15736	4.7%
40. GPIF * (Already Adjusted for Taxes)	(691,731)	(692,030)	299	0.0%	15,352,109	15,243,728	108,381	0.7%	(0.00451)	(0.00454)	0.00003	-0.7%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**534,166,463**	**506,419,627**	**27,746,836**	**5.5%**	**15,352,109**	**15,243,728**	**108,381**	**0.7%**	**3.48194**	**3.32455**	**0.15739**	**4.7%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.482**	**3.325**	**0.157**	**4.7%**

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: OCTOBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	35,855,298	37,844,885	(1,989,587)	-5.3%	400,140,174	397,398,439	2,741,735	0.7%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	85,065	279,500	(194,435)	-69.6%	3,646,730	10,752,102	(7,105,372)	-66.1%
2a. GAINS FROM MARKET BASED SALES	0	16,700	(16,700)	-100.0%	851,859	2,660,794	(1,808,935)	-68.0%
3. FUEL COST OF PURCHASED POWER	19,381,862	17,102,800	2,279,062	13.3%	139,654,025	120,153,240	19,500,785	16.2%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,080,151	1,122,400	(42,249)	-3.8%	10,769,632	10,940,365	(170,733)	-1.6%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	56,232,246	55,773,885	458,361	0.8%	546,065,242	515,079,148	30,986,094	6.0%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(7,075)	(6,000)	(1,075)	17.9%	(67,887)	(60,108)	(7,779)	12.9%
6b. ADJ.TO FUEL COST	(1,867)	0	(1,867)	0.0%	(29,029)	(2,738)	(26,291)	960.2%
6c. INCREMENTAL HEDGING O&M COSTS	22,652	34,583	(11,931)	-34.5%	58,542	311,247	(252,705)	-81.2%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	56,245,956	55,802,468	443,488	0.8%	546,026,868	515,327,549	30,699,319	6.0%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,593,406	1,624,913	(31,507)	-1.9%	15,352,109	15,243,728	108,381	0.7%
2. NONJURISDICTIONAL SALES	46,803	36,346	10,457	28.8%	492,884	422,716	70,168	16.6%
3. TOTAL SALES	1,640,209	1,661,259	(21,050)	-1.3%	15,844,993	15,666,444	178,549	1.1%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9714652	0.9781214	(0.0066562)	-0.7%	0.9688934	0.9730177	(0.0041243)	-0.4%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	53,760,484	55,771,844	(2,011,360)	-3.6%	505,202,649	505,105,722	96,927	0.0%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(263,799)	(263,799)	0	0.0%	(2,637,990)	(2,637,990)	0	0.0%
2b. INCENTIVE PROVISION	69,252	69,203	49	0.1%	691,731	692,030	(299)	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	53,565,937	55,577,248	(2,011,311)	-3.6%	503,256,390	503,159,762	96,628	0.0%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	56,245,956	55,802,468	443,488	0.8%	546,026,868	515,327,549	30,699,319	6.0%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9714652	0.9781214	(0.0066562)	-0.7%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	54,640,989	54,581,588	59,401	0.1%	528,968,227	501,240,710	27,727,517	5.5%
6a. JURISDIC. LOSS MULTIPLIER	1.00114	1.00114	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	54,703,280	54,643,811	59,469	0.1%	529,571,250	501,812,124	27,759,126	5.5%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	262,073	262,073	0	0.0%	2,734,625	2,734,625	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	254,595	256,339	(1,744)	-0.7%	2,648,953	2,661,543	(12,590)	-0.5%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	54,957,875	54,900,150	57,725	0.1%	532,220,203	504,473,667	27,746,536	5.5%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(1,391,938)	677,098	(2,069,036)	-305.6%	(28,963,813)	(1,313,905)	(27,649,908)	2104.4%
8. INTEREST PROVISION FOR THE MONTH	(50,981)	(33,748)	(17,233)	51.1%	(394,332)	(307,551)	(86,781)	28.2%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(57,368,953)	(31,718,533)	(25,650,420)	80.9%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	263,799	263,799	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(58,548,073)	(30,811,384)	(27,736,689)	90.0%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(57,368,953)	(31,718,533)	(25,650,420)	80.9%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(58,497,092)	(30,777,636)	(27,719,456)	90.1%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(115,866,045)	(62,496,169)	(53,369,876)	85.4%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(57,933,023)	(31,248,085)	(26,684,938)	85.4%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.060	1.300	(0)	-18.5%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.050	1.300	(0)	-19.2%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	2.110	2.600	(0)	-18.8%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.055	1.300	(0)	-18.8%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.088	0.108	(0)	-18.5%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(50,981)	(33,748)	(17,233)	51.1%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	575,323	721,018	(145,695)	-20.2%	4,952,539	4,018,925	933,614	23.2%
2	LIGHT OIL	150,421	696,538	(546,117)	-78.4%	6,607,444	11,061,717	(4,454,273)	-40.3%
3	COAL	17,180,937	20,530,032	(3,349,095)	-16.3%	243,263,879	251,630,029	(8,366,150)	-3.3%
4	NATURAL GAS	17,948,617	15,897,297	2,051,320	12.9%	145,316,312	130,687,768	14,628,544	11.2%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	35,855,298	37,844,885	(1,989,587)	-5.3%	400,140,174	397,398,439	2,741,735	0.7%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	11,147	15,312	(4,165)	-27.2%	89,520	78,849	10,671	13.5%
9	LIGHT OIL	1,210	10,451	(9,241)	-88.4%	96,408	160,016	(63,608)	-39.8%
10	COAL	798,729	939,115	(140,386)	-14.9%	11,033,508	11,439,091	(405,583)	-3.5%
11	NATURAL GAS	377,437	312,535	64,902	20.8%	2,652,075	2,430,017	222,058	9.1%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,188,523	1,277,413	(88,890)	-7.0%	13,871,511	14,107,973	(236,462)	-1.7%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	17,441	22,967	(5,526)	-24.1%	138,853	118,812	20,041	16.9%
16	LIGHT OIL (BBL)	3,995	18,261	(14,266)	-78.1%	172,319	285,062	(112,743)	-39.6%
17	COAL (TON)	378,677	424,395	(45,718)	-10.8%	5,177,136	5,223,309	(46,173)	-0.9%
18	NATURAL GAS (MCF)	3,016,976	2,275,978	740,998	32.6%	20,329,945	18,404,215	1,925,730	10.5%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	109,418	145,521	(36,103)	-24.8%	871,101	755,049	116,052	15.4%
22	LIGHT OIL	15,656	105,802	(90,146)	-85.2%	965,939	1,651,960	(686,021)	-41.5%
23	COAL	8,876,094	9,994,961	(1,118,867)	-11.2%	123,402,085	125,431,970	(2,029,885)	-1.6%
24	NATURAL GAS	3,134,637	2,339,655	794,982	34.0%	21,461,366	18,923,712	2,537,654	13.4%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	12,135,805	12,585,939	(450,134)	-3.6%	146,700,491	146,762,691	(62,200)	0.0%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.94%	1.20%	(0.00)	-	0.65%	0.56%	0.00	-
29	LIGHT OIL	0.10%	0.82%	(0.01)	-	0.70%	1.13%	(0.00)	-
30	COAL	67.20%	73.52%	(0.06)	-	79.54%	81.08%	(0.02)	-
31	NATURAL GAS	31.76%	24.47%	0.07	-	19.12%	17.22%	0.02	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	32.99	31.39	1.59	5.1%	35.67	33.83	1.84	5.4%
36	LIGHT OIL ($/BBL)	37.65	38.14	(0.49)	-1.3%	38.34	38.80	(0.46)	-1.2%
37	COAL ($/TON)	45.37	48.37	(3.00)	-6.2%	46.99	48.17	(1.19)	-2.5%
38	NATURAL GAS ($/MCF)	5.95	6.98	(1.04)	-14.8%	7.15	7.10	0.05	0.7%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	5.26	4.95	0.30	6.1%	5.69	5.32	0.36	6.8%
42	LIGHT OIL	9.61	6.58	3.02	45.9%	6.84	6.70	0.14	2.2%
43	COAL	1.94	2.05	(0.12)	-5.8%	1.97	2.01	(0.03)	-1.7%
44	NATURAL GAS	5.73	6.79	(1.07)	-15.7%	6.77	6.91	(0.13)	-2.0%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.95	3.01	(0.05)	-1.7%	2.73	2.71	0.02	0.7%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,816	9,504	312	3.3%	9,731	9,576	155	1.6%
49	LIGHT OIL	12,939	10,124	2,815	27.8%	10,019	10,324	(305)	-3.0%
50	COAL	11,113	10,643	470	4.4%	11,184	10,965	219	2.0%
51	NATURAL GAS	8,305	7,486	819	10.9%	8,092	7,787	305	3.9%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,211	9,853	358	3.6%	10,576	10,403	173	1.7%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.16	4.71	0.45	9.6%	5.53	5.10	0.43	8.4%
56	LIGHT OIL	12.43	6.66	5.77	86.6%	6.85	6.91	(0.06)	-0.9%
57	COAL	2.15	2.19	(0.04)	-1.8%	2.20	2.20	0.00	0.0%
58	NATURAL GAS	4.76	5.09	(0.33)	-6.5%	5.48	5.38	0.10	1.9%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	3.02	2.96	0.06	2.0%	2.88	2.82	0.06	2.1%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: OCTOBER 2003

SCHEDULE A4
PAGE 1 OF 1
REVISED WITH
TRUE UP FILING

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	94	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#2	100	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	150	29,484	26.4	34.3	64.7	14,079	COAL	17,082	24,300,000	415,092.6	(59,746)	(0.20)	(3.50)
GAN.#4	164	16,525	13.5	51.3	14.7	12,279	COAL	8,394	24,174,000	202,916.6	(29,359)	(0.18)	(3.50)
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GANNON STATION	**508**	**46,009**	**12.2**	**64.9**	**23.9**	**13,432**	**COAL**	**25,476**	**24,258,486**	**618,009.2**	**(89,105)**	**(0.19)**	**(3.50)**
B.B.#1	421	141,655	45.2	49.3	69.1	11,154	COAL	65,391	24,161,900	1,579,970.8	3,195,962	2.26	48.87
B.B.#2	411	224,289	73.3	60.1	75.9	10,771	COAL	99,910	24,180,900	2,413,328.2 *	4,883,066	2.18	48.87
B.B.#3	428	154,680	48.5	58.3	69.8	11,260	COAL	71,713	24,287,140	1,741,715.6	3,504,947	2.27	48.87
B.B.#4	452	237,353	70.5	74.7	74.7	10,501	COAL	115,022	21,669,200	2,492,430.2	5,621,659	2.37	48.87
B.B. STATION	**1,712**	**757,977**	**59.4**	**60.8**	**72.4**	**10,858**	**COAL**	**352,036**	**23,378,358**	**8,227,444.8**	**17,205,634**	**2.27**	**48.87**
SEB-PHIL. #1(HVY OIL)	17	5,577	44.0	100.0	94.3	9,816	HVY.OIL	8,726	6,273,540	54,745.8	287,843	5.16	32.99
SEB-PHIL. #2(HVY OIL)	17	5,570	44.0	100.0	94.4	9,816	HVY.OIL	8,715	6,273,540	54,672.0	287,480	5.16	32.99
SEB-PHILLIPS TOTAL	**34**	**11,147**	**44.0**	**100.0**	**94.4**	**9,816**	**HVY.OIL**	**17,441**	**6,273,539**	**109,417.8**	**575,323**	**5.16**	**32.99**
POLK #1 GASIFIER	255	(5,257)	0.0	3.0	0.0	17,316	COAL	1,165	26,300,000	30,639.5	64,408	(1.23)	55.29
POLK #1 CT (OIL)	225	1,125	0.7	2.8	95.0	12,536	LGT.OIL	3,729	5,830,484	14,107.0	140,601	12.50	37.70
POLK #1 TOTAL	**255**	**(4,132)**	**0.0**	**2.8**	**0.0**	**15,460**	**-**	**-**	**-**	**44,746.5**	**205,009**	**(4.96)**	**-**
POLK #2 CT (GAS)	150	24,684	22.1	99.9	78.9	11,589	GAS	275,317	1,039,000	286,054.0	1,660,579	6.73	6.03
POLK #2 CT (OIL)	160	31	0.0	100.0	13.0	15,528	LGT.OIL	84	5,830,527	488.2	3,157	10.18	37.58
POLK #2 TOTAL	**155**	**24,715**	**21.4**	**99.9**	**78.4**	**11,594**	**-**	**-**	**-**	**286,542.2**	**1,663,736**	**6.73**	**-**
POLK #3 CT (GAS)	150	17,241	15.4	100.0	79.9	13,076	GAS	216,984	1,039,000	225,446.4	1,316,202	7.63	6.07
POLK #3 CT (OIL)	165	24	0.0	97.0	22.7	21,217	LGT.OIL	86	5,830,518	504.0	3,259	13.58	37.90
POLK #3 TOTAL	**158**	**17,265**	**14.7**	**97.0**	**79.7**	**13,087**	**-**	**-**	**-**	**225,950.4**	**1,319,461**	**7.64**	**-**
POLK STATION TOTAL	**568**	**37,848**	**8.9**	**55.5**	**43.6**	**14,723**	**-**	**-**	**-**	**557,239.1**	**3,188,206**	**8.42**	**-**
B.B.C.T.#1	14	30	0.3	100.0	71.4	18,553	LGT.OIL	96	5,786,880	556.6	3,404	11.35	35.46
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**140**	**30**	**0.0**	**100.0**	**13.5**	**18,553**	**LGT.OIL**	**96**	**5,786,464**	**556.6**	**3,404**	**11.35**	**35.46**
CITY OF TAMPA	**6**	**902**	**20.2**	**0.0**	**0.0**	**10,317**	**GAS**	**8,957**	**1,039,000**	**9,306.3**	**73,644**	**8.16**	**8.22**
BAYSIDE ST 1	246	111,440	60.8	93.6	61.0	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	65,769	59.6	84.7	79.1	11,764	GAS	744,687	1,039,000	773,730.0	4,427,516	6.73	5.95
BAYSIDE CT1B	148	67,010	60.8	97.5	81.9	11,764	GAS	758,731	1,039,000	788,321.4	4,511,013	6.73	5.95
BAYSIDE CT1C	148	75,589	68.6	97.9	83.5	11,764	GAS	855,872	1,039,000	889,250.6	5,088,560	6.73	5.95
BAYSIDE UNIT 1 TOTAL	**690**	**319,808**	**62.2**	**93.4**	**74.2**	**7,665**	**GAS**	**2,359,290**	**1,039,000**	**2,451,302.0**	**14,027,089**	**4.39**	**5.95**
BAYSIDE ST 2	0	0	0.0	0.0	0.0	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	148	9,748	8.8	0.0	0.0	10,980	GAS	103,014	1,039,000	107,031.8	573,656	5.89	5.57
BAYSIDE CT2B	148	5,054	4.6	0.0	0.0	10,980	GAS	53,414	1,039,000	55,497.2	297,447	5.89	5.57
BAYSIDE CT2C	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE CT2D	0	0	0.0	0.0	0.0	0	GAS	0	0	0.0	0	0.00	0.00
BAYSIDE UNIT 2 TOTAL	**296**	**14,802**	**6.7**	**0.0**	**0.0**	**10,980**	**GAS**	**156,428**	**1,039,000**	**162,529.0**	**871,103**	**5.89**	**5.57**
BAYSIDE STATION TOTAL	**986**	**334,610**	**45.6**	**93.4**	**74.2**	**7,812**	**GAS**	**2,515,718**	**1,039,000**	**2,613,831.0**	**14,898,192**	**4.45**	**5.92**
TOT. COAL (GN,BB,POLK)	**2,475**	**798,729**	**43.3**	**55.7**	**55.0**	**11,116**	**COAL**	**378,677**	**23,446,559**	**8,876,093.5**	**17,180,937**	**2.15**	**45.37**
SYSTEM	**3,954**	**1,188,523**	**40.3**	**69.8**	**60.5**	**10,213**	**-**	**-**	**-**	**12,135,804.8**	**35,855,298**	**3.02**	**-**

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

* includes adjustment of (2,585.5) MMBTU for August 2003.

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2003

SCHEDULE A5
PAGE 1 OF 2
REVISED WITH
TRUE UP FILING

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	19,067	22,967	(3,900)	-17.0%	149,123	117,533	31,590	26.9%
3 UNIT COST ($/BBL)	31.44	30.55	0.89	2.9%	33.82	32.65	1.17	3.6%
4 AMOUNT ($)	599,532	701,642	(102,110)	-14.6%	5,043,407	3,837,220	1,206,187	31.4%
5 BURNED:								
6 UNITS (BBL)	17,441	22,967	(5,526)	-24.1%	138,853	118,812	20,041	16.9%
7 UNIT COST ($/BBL)	32.99	31.39	1.59	5.1%	35.67	33.83	1.84	5.4%
8 AMOUNT ($)	575,323	721,018	(145,695)	-20.2%	4,952,539	4,018,925	933,614	23.2%
9 ENDING INVENTORY:								
10 UNITS (BBL)	21,012	9,463	11,549	122.0%	21,012	9,463	11,549	122.0%
11 UNIT COST ($/BBL)	32.37	31.02	1.35	4.4%	32.37	31.02	1.35	4.4%
12 AMOUNT ($)	680,259	293,564	386,695	131.7%	680,259	293,564	386,695	131.7%
13								
14 DAYS SUPPLY:	126	144	(18)	-12.6%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	2,555	22,378	(19,823)	-88.6%	251,140	336,481	(85,341)	-25.4%
17 UNIT COST ($/BBL)	30.84	37.26	(6.43)	-17.2%	38.49	39.74	(1.25)	-3.2%
18 AMOUNT ($)	78,789	833,896	(755,107)	-90.6%	9,665,357	13,371,564	(3,706,207)	-27.7%
19 BURNED:								
20 UNITS (BBL)	3,995	18,261	(14,266)	-78.1%	172,319	285,062	(112,743)	-39.6%
21 UNIT COST ($/BBL)	37.65	38.14	(0.49)	-1.3%	38.34	38.80	(0.46)	-1.2%
22 AMOUNT ($)	150,421	696,538	(546,117)	-78.4%	6,607,444	11,061,717	(4,454,273)	-40.3%
23 ENDING INVENTORY:								
24 UNITS (BBL)	76,056	82,746	(6,690)	-8.1%	76,056	82,746	(6,690)	-8.1%
25 UNIT COST ($/BBL)	36.70	37.99	(1.29)	-3.4%	36.70	37.99	(1.29)	-3.4%
26 AMOUNT ($)	2,791,288	3,143,809	(352,521)	-11.2%	2,791,288	3,143,809	(352,521)	-11.2%
27								
28 DAYS SUPPLY: NORMAL	95	108	(13)	-12.3%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	11	12	(1)	-8.1%	-	-	-	-
COAL (3)								
30 PURCHASES:								
31 UNITS (TONS)	435,588	388,300	47,288	12.2%	5,222,153	5,669,473	(447,320)	-7.9%
32 UNIT COST ($/TON)	45.80	47.20	(1.40)	-3.0%	47.53	48.05	(0.53)	-1.1%
33 AMOUNT ($)	19,949,350	18,326,085	1,623,265	8.9%	248,194,455	272,434,237	(24,239,782)	-8.9%
34 BURNED:								
35 UNITS (TONS)	378,677	424,395	(45,718)	-10.8%	5,177,136	5,223,309	(46,173)	-0.9%
36 UNIT COST ($/TON)	45.37	48.37	(3.00)	-6.2%	46.99	48.17	(1.19)	-2.5%
37 AMOUNT ($)	17,180,937	20,530,032	(3,349,095)	-16.3%	243,263,879	251,630,029	(8,366,150)	-3.3%
38 ENDING INVENTORY:								
39 UNITS (TONS)	483,374	884,521	(401,147)	-45.4%	483,374	884,521	(401,147)	-45.4%
40 UNIT COST ($/TON)	47.39	47.89	(0.50)	-1.0%	47.39	47.89	(0.50)	-1.0%
41 AMOUNT ($)	22,905,870	42,358,448	(19,452,578)	-45.9%	22,905,870	42,358,448	(19,452,578)	-45.9%
42								
43 DAYS SUPPLY:	38	54	(16)	-28.9%	-	-	-	-
NATURAL GAS(4)								
44 PURCHASES:								
45 UNITS (MCF)	3,016,976	2,275,978	740,998	32.6%	20,329,945	18,404,215	1,925,730	10.5%
46 UNIT COST ($/MCF)	5.95	6.98	(1.04)	-14.8%	7.15	7.10	0.05	0.7%
47 AMOUNT ($)	17,948,617	15,897,297	2,051,320	12.9%	145,316,312	130,687,767	14,628,545	11.2%
48 BURNED:								
49 UNITS (MCF)	3,016,976	2,275,978	740,998	32.6%	20,329,945	18,404,215	1,925,730	10.5%
50 UNIT COST ($/MCF)	5.95	6.98	(1.04)	-14.8%	7.15	7.10	0.05	0.7%
51 AMOUNT ($)	17,948,617	15,897,297	2,051,320	12.9%	145,316,312	130,687,768	14,628,544	11.2%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	19,867
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	19,867

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(5,147)	(180,714)
OTHER USAGE	(352)	(12,353)
TOTAL	(5,499)	(193,067)

(3) RECONCILIATION - COALS

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	28,276
IGNITION #2 OIL	160,847
IGNITION PROPANE	11,966
AERIAL SURVEY ADJ.	(577,814)
ADDITIVES	16,511
GREEN FUEL	0
TOTAL	(360,214)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2003

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	3,274.0	0.0	3,274.0	2.599	2.599	85,100.00	85,100.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. - MB	4,469.0	0.0	4,469.0	4.350	5.046	194,400.00	225,500.00	16,700.00
TOTAL			7,743.0	0.0	7,743.0	3.610	4.011	279,500.00	310,600.00	16,700.00
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	1,502.8	48.1	1,454.7	3.664	3.664	53,299.63	53,299.63	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	1,039.8	0.0	1,039.8	3.055	3.055	31,765.73	31,765.73	
FLA. PWR. CORP.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTILITIES		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
RELIANT ENERGY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE PWR. PART. TO CITY OF LAKELAND*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
AUBURNDALE POWER PARTNERS		SCH. - OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CARGILL ALLIANT		SCH. - OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ADJUSTMENTS										
NONE										
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			2,542.6	48.1	2,494.5	3.410	3.410	85,065.36	85,065.36	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL			2,542.6	48.1	2,494.5	3.410	3.410	85,065.36	85,065.36	0.00
CURRENT MONTH:										
DIFFERENCE			(5,200.4)	48.1	(5,248.5)	(0.200)	(0.601)	(194,434.64)	(225,534.64)	(16,700.00)
DIFFERENCE %			-67.2%	0.0%	-67.8%	-5.5%	-15.0%	-69.6%	-72.6%	-100.0%
PERIOD TO DATE:										
ACTUAL			111,180.4	704.0	110,476.4	3.301	4.370	3,646,729.31	4,828,200.98	851,859.70
ESTIMATED			245,354.9	5.3	245,349.6	4.382	5.765	10,752,101.69	14,145,517.12	2,660,794.33
DIFFERENCE			(134,174.5)	698.7	(134,873.2)	(1.081)	(1.395)	(7,105,372.38)	(9,317,316.14)	(1,808,934.63)
DIFFERENCE %			-54.7%	13183.0%	-55.0%	-24.7%	-24.2%	-66.1%	-65.9%	-68.0%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF OCTOBER 2003.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	6,607.0	0.0	3,965.0	2,642.0	4.939	4.939	130,500.00
HARDEE POWER PARTNERS		IPP	41,683.0	0.0	0.0	41,683.0	6.158	6.158	2,566,800.00
VARIOUS		OTHER	141,740.0	0.0	0.0	141,740.0	4.100	4.100	5,811,300.00
VARIOUS		MKT. BASE	178,971.0	0.0	0.0	178,971.0	4.802	4.802	8,594,200.00
TOTAL			**369,001.0**	**0.0**	**3,965.0**	**365,036.0**	**4.685**	**4.685**	**17,102,800.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	71,297.0	0.0	0.0	71,297.0	4.982	4.982	3,552,230.71
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH. - J	27,513.0	0.0	110.0	27,403.0	5.795	5.795	1,588,075.00
FLA. POWER & LIGHT		SCH. - J	3,161.0	0.0	1,007.7	2,153.3	2.522	2.522	54,301.36
CITY OF LAKELAND		SCH. - J	73,465.0	0.0	438.0	73,027.0	5.253	5.253	3,836,000.50
ORLANDO UTIL. COMM.		SCH. - J	40,125.0	0.0	378.0	39,747.0	4.663	4.663	1,853,228.00
CAROLINA POWER & LIGHT		SCH. - J	3,767.0	0.0	216.0	3,551.0	4.472	4.472	158,792.00
THE ENERGY AUTHORITY		SCH. - J	53,303.0	0.0	1,942.2	51,360.8	4.514	4.514	2,318,487.13
REEDY CREEK		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
OKEELANTA		SCH. - J	4,650.0	0.0	0.0	4,650.0	4.832	4.832	224,703.80
TALLAHASSEE		SCH. - J	1,531.0	0.0	0.0	1,531.0	5.423	5.423	83,023.72
CALPINE		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL ALLIANT		SCH. - J	111,541.0	0.0	49.0	111,492.0	4.674	4.674	5,211,442.00
CONOCO		SCH. - J	343.0	0.0	0.0	343.0	2.500	2.500	8,575.00
CORAL POWER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RELIANT		SCH. - J	1,236.0	0.0	0.0	1,236.0	8.800	8.800	108,768.00
SEMINOLE ELEC. CO-OP		SCH. - J	29,225.0	0.0	290.2	28,934.8	3.212	3.212	929,325.91
DUKE ENERGY		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
DYNEGY POWER MARKETING		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RINGHAVER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Sept. 2003	IPP	(81,503.0)	0.0	0.0	(81,503.0)	5.125	5.125	(4,176,712.79)
HARDEE PWR. PART.-NATIVE	Sept. 2003	IPP	81,503.0	0.0	0.0	81,503.0	5.201	5.201	4,239,075.91
CALPINE	Sept. 2003	SCH. - J (1)	607.0	0.0	0.0	607.0	0.000	0.000	0.00
CALPINE	August 2003	SCH. - J (1)	171.0	0.0	0.0	171.0	0.000	0.000	0.00
CALPINE	July 2003	SCH. - J	(96.0)	0.0	0.0	(96.0)	7.391	7.391	(7,095.00)
CALPINE	July 2003	SCH. - J	236.0	0.0	0.0	236.0	3.006	3.006	7,095.00
CALPINE	May 2003	SCH. - J	(168.0)	0.0	0.0	(168.0)	5.924	5.924	(9,953.00)
CALPINE	May 2003	SCH. - J	490.0	0.0	0.0	490.0	2.031	2.031	9,953.00
CALPINE	April 2003	SCH. - J (1)	93.0	0.0	0.0	93.0	0.000	0.000	0.00
CALPINE	March 2003	SCH. - J	(2,634.0)	0.0	(540.6)	(2,093.4)	9.641	9.641	(201,819.47)
CALPINE	March 2003	SCH. - J	2,831.0	0.0	540.6	2,290.4	8.812	8.812	201,819.47
CALPINE	Jan. 2003	SCH. - J (1)	206.0	0.0	0.0	206.0	0.000	0.000	0.00
FLA. POWER CORP.	7/02-4/03	SCH. - J (2)	0.0	0.0	0.0	0.0	0.000	0.000	(607,454.55)
TOTAL			**422,893.0**	**0.0**	**4,431.1**	**418,461.9**	**4.632**	**4.632**	**19,381,861.70**
CURRENT MONTH:									
DIFFERENCE			53,892.0	0.0	466.1	53,425.9	(0.053)	(0.053)	2,279,061.70
DIFFERENCE %			14.6%	0.0%	11.8%	14.6%	-1.1%	-1.1%	13.3%
PERIOD TO DATE:									
ACTUAL			2,589,372.0	0.0	58,512.0	2,530,860.0	5.518	5.518	139,654,025.02
ESTIMATED			2,344,922.0	0.0	42,614.2	2,302,307.8	5.219	5.219	120,153,239.59
DIFFERENCE			244,450.0	0.0	15,897.8	228,552.2	0.299	0.299	19,500,785.43
DIFFERENCE %			10.4%	0.0%	37.3%	9.9%	5.7%	5.7%	16.2%

(1) Due to excess generation by IPP provider, TEC's system benefits at no cost to rate payers.
(2) FPC refund to correct charges for Schedule J purchases for July 2002 - April 2003.

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (8)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	41,439.0	0.0	0.0	41,439.0	2.709	2.709	1,122,400.00
TOTAL		41,439.0	0.0	0.0	41,439.0	2.709	2.709	1,122,400.00
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	18,217.0	0.0	0.0	18,217.0	2.418	2.418	440,414.28
McKAY BAY REFUSE	COGEN.	13,583.0	0.0	0.0	13,583.0	2.418	2.418	328,414.20
ORANGE COGENERATION L.P.	COGEN.	6,532.0	0.0	0.0	6,532.0	2.217	2.217	144,820.45
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	1,192.0	0.0	0.0	1,192.0	4.581	4.581	54,611.22
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	1,265.0	0.0	0.0	1,265.0	4.682	4.682	59,230.77
IMC-AGRICO-NEW WALES	COGEN.	124.0	0.0	0.0	124.0	4.742	4.742	5,880.52
IMC-AGRICO-S. PIERCE	COGEN.	123.0	0.0	0.0	123.0	5.014	5.014	6,167.06
AUBURNDALE POWER PARTNERS	COGEN.	322.0	0.0	0.0	322.0	3.588	3.588	11,553.65
CUTRALE CITRUS	COGEN.	9.0	0.0	0.0	9.0	4.077	4.077	366.89
SUB-TOTAL FOR OCTOBER 2003		41,367.0	0.0	0.0	41,367.0	2.542	2.542	1,051,459.04
ADJUSTMENTS FOR THE MONTH OF:	**SEPTEMBER 2003**							
HILLSBOROUGH COUNTY	COGEN.	(12,902.0)	0.0	0.0	(12,902.0)	2.349	2.349	(303,111.98)
		12,902.0	0.0	0.0	12,902.0	2.441	2.441	314,989.83
McKAY BAY REFUSE	COGEN.	(12,970.0)	0.0	0.0	(12,970.0)	2.347	2.347	(304,456.10)
		12,970.0	0.0	0.0	12,970.0	2.439	2.439	316,363.75
ORANGE COGENERATION L.P.	COGEN.	(5,313.0)	0.0	0.0	(5,313.0)	2.129	2.129	(113,127.59)
		5,313.0	0.0	0.0	5,313.0	2.222	2.222	118,034.46
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**SEPTEMBER 2003**	0.0	0.0	0.0	0.0	0.000	0.000	28,692.37
GRAND TOTAL		**41,367.0**	**0.0**	**0.0**	**41,367.0**	**2.611**	**2.611**	**1,080,151.41**
CURRENT MONTH:								
DIFFERENCE		(72.0)	0.0	0.0	(72.0)	(0.097)	(0.097)	(42,248.59)
DIFFERENCE %		-0.2%	0.0%	0.0%	-0.2%	-3.6%	-3.6%	-3.8%
PERIOD TO DATE:								
ACTUAL		434,979.0	0.0	0.0	434,979.0	2.476	2.476	10,769,632.85
ESTIMATED		407,592.0	0.0	0.0	407,592.0	2.684	2.684	10,940,365.12
DIFFERENCE		27,387.0	0.0	0.0	27,387.0	(0.208)	(0.208)	(170,732.27)
DIFFERENCE %		6.7%	0.0%	0.0%	6.7%	(0.078)	(0.078)	-1.6%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

NOVEMBER 2003

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	32,259,001	42,140,517	(9,881,516)	-23.4%	1,099,479	1,358,076	(258,597)	-19.0%	2.93403	3.10296	(0.16893)	-5.4%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(6,102)	(6,000)	(102)	1.7%	1,099,479 (a)	1,358,076 (a)	(258,597)	-19.0%	(0.00055)	(0.00044)	(0.00011)	25.6%
4b. Adjustments to Fuel Cost	(1,664)	0	(1,664)	0.0%	1,099,479 (a)	1,358,076 (a)	(258,597)	-19.0%	(0.00015)	0.00000	(0.00015)	0.0%
4c. Incremental Hedging O&M Costs	23,514	34,583	(11,069)	-32.0%	1,099,479 (a)	1,358,076 (a)	(258,597)	-19.0%	0.00214	0.00255	(0.00041)	-16.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**32,274,749**	**42,169,100**	**(9,894,351)**	**-23.5%**	**1,099,479**	**1,358,076**	**(258,597)**	**-19.0%**	**2.93546**	**3.10506**	**(0.16960)**	**-5.5%**
6. Fuel Cost of Purchased Power - Firm (A7)	14,972,252	3,383,500	11,588,752	342.5%	329,749	76,534	253,215	330.9%	4.54050	4.42091	0.11959	2.7%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,026,470	1,009,100	17,370	1.7%	39,851	38,189	1,662	4.4%	2.57577	2.64238	(0.06661)	-2.5%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**15,998,722**	**4,392,600**	**11,606,122**	**264.2%**	**369,600**	**114,723**	**254,877**	**222.2%**	**4.32866**	**3.82887**	**0.49978**	**13.1%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,469,079**	**1,472,799**	**(3,720)**	**-0.3%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	70,659	51,500	19,159	37.2%	2,137	2,642	(505)	-19.1%	3.30646	1.94928	1.35718	69.6%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(260)	0	(260)	0.0%	(26)	0	(26)	0.0%	1.00000	0.00000	1.00000	0.0%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	0	2,267,700	(2,267,700)	-100.0%	0	52,684	(52,684)	-100.0%	0.00000	4.30434	(4.30434)	-100.0%
19. Gains on Market Based Sales	0	357,000	(357,000)	-100.0%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**70,399**	**2,676,200**	**(2,605,801)**	**-97.4%**	**2,111**	**55,326**	**(53,215)**	**-96.2%**	**3.33486**	**4.83715**	**(1.50228)**	**-31.1%**
21. Net Inadvertant Interchange					189	0	189	0.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					(681)	0	(681)	0.0%				
23. Interchange and Wheeling Losses					266	800	(534)	-66.8%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**48,203,072**	**43,885,500**	**4,317,572**	**9.8%**	**1,466,210**	**1,416,673**	**49,537**	**3.5%**	**3.28760**	**3.09779**	**0.18981**	**6.1%**
25. Net Unbilled	(1,900,987) (a)	(3,804,546) (a)	1,903,559	-50.0%	(57,823)	(122,815)	64,992	-52.9%	3.28760	3.09779	0.18981	6.1%
26. Company Use	106,321 (a)	123,911 (a)	(17,590)	-14.2%	3,234	4,000	(766)	-19.2%	3.28760	3.09778	0.18983	6.1%
27. T & D Losses	1,582,977 (a)	3,665,270 (a)	(2,082,293)	-56.8%	48,150	118,319	(70,169)	-59.3%	3.28760	3.09779	0.18981	6.1%
28. System KWH Sales	48,203,072	43,885,500	4,317,572	9.8%	1,472,649	1,417,169	55,480	3.9%	3.27322	3.09670	0.17652	5.7%
29. Wholesale KWH Sales	(1,375,703)	(711,033)	(664,670)	93.5%	(42,029)	(22,961)	(19,068)	83.0%	3.27322	3.09670	0.17652	5.7%
30. Jurisdictional KWH Sales	46,827,369	43,174,467	3,652,902	8.5%	1,430,620	1,394,208	36,412	2.6%	3.27322	3.09670	0.17652	5.7%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	46,880,752	43,223,686	3,657,066	8.5%	1,430,620	1,394,208	36,412	2.6%	3.27695	3.10023	0.17672	5.7%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	252,135	255,337	(3,202)	-1.3%	1,430,620	1,394,208	36,412	2.6%	0.01762	0.01831	(0.00069)	-3.8%
34. Adjustment	0	0	0	0.0%	1,430,620	1,394,208	36,412	2.6%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	1,430,620	1,394,208	36,412	2.6%	0.00000	0.00000	0.00000	0.0%
36. True-up *	263,799	263,799	0	0.0%	1,430,620	1,394,208	36,412	2.6%	0.01844	0.01892	(0.00048)	-2.5%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	47,396,686	43,742,822	3,653,864	8.4%	1,430,620	1,394,208	36,412	2.6%	3.31302	3.13747	0.17555	5.6%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.31540	3.13973	0.17567	5.6%
40. GPIF * (Already Adjusted for Taxes)	(69,252)	(69,203)	(49)	0.1%	1,430,620	1,394,208	36,412	2.6%	(0.00484)	(0.00496)	0.00012	-2.5%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**47,327,434**	**43,673,619**	**3,653,815**	**8.4%**	**1,430,620**	**1,394,208**	**36,412**	**2.6%**	**3.31056**	**3.13477**	**0.17579**	**5.6%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.311**	**3.135**	**0.176**	**5.6%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: NOVEMBER 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	432,399,175	439,538,956	(7,139,781)	-1.6%	14,970,990	15,466,049	(495,059)	-3.2%	2.88825	2.84196	0.04629	1.6%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(73,989)	(66,108)	(7,881)	11.9%	14,970,990 (a)	15,466,049 (a)	(495,059)	-3.2%	(0.00049)	(0.00043)	(0.00007)	15.6%
4b. Adjustments to Fuel Cost	(30,693)	(2,738)	(27,955)	1021.0%	14,970,990 (a)	15,466,049 (a)	(495,059)	-3.2%	(0.00021)	(0.00002)	(0.00019)	1058.1%
4c. Adjustments to Fuel Cost	82,056	345,830	(263,774)	-76.3%	14,970,990 (a)	15,466,049 (a)	(495,059)	-3.2%	0.00055	0.00224	(0.00169)	-75.5%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**432,376,549**	**439,815,940**	**(7,439,391)**	**-1.7%**	**14,970,990**	**15,466,049**	**(495,059)**	**-3.2%**	**2.88810**	**2.84375**	**0.04434**	**1.6%**
6. Fuel Cost of Purchased Power - Firm (A7)	154,626,277	123,536,740	31,089,537	25.2%	2,860,609	2,378,842	481,767	20.3%	5.40536	5.19315	0.21222	4.1%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	11,796,102	11,949,465	(153,363)	-1.3%	474,830	445,781	29,049	6.5%	2.48428	2.68057	(0.19629)	-7.3%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**166,422,379**	**135,486,205**	**30,936,174**	**22.8%**	**3,335,439**	**2,824,623**	**510,816**	**18.1%**	**4.98952**	**4.79661**	**0.19291**	**4.0%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**18,306,429**	**18,290,672**	**15,757**	**0.1%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	788,358	689,107	99,251	14.4%	26,289	29,536	(3,247)	-11.0%	2.99881	2.33311	0.66570	28.5%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	7,918	4,680	3,238	69.2%	46	46	0	0.0%	17.21304	10.17391	7.03913	69.2%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	121,809	108,975	12,834	11.8%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	2,799,044	12,268,540	(9,469,496)	-77.2%	86,254	271,094	(184,840)	-68.2%	3.24512	4.52557	(1.28045)	-28.3%
19. Gains on Market Based Sales	851,859	3,017,794	(2,165,935)	-71.8%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**4,568,988**	**16,089,096**	**(11,520,108)**	**-71.6%**	**112,589**	**300,676**	**(188,087)**	**-62.6%**	**4.05811**	**5.35097**	**(1.29286)**	**-24.2%**
21. Net Inadvertant Interchange					(590)	(291)	(299)	102.7%				
22. Wheeling Rec'd. less Wheeling Del'd.					1,011	652	359	55.1%				
23. Interchange and Wheeling Losses					5,864	4,496	1,368	30.4%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**594,229,940**	**559,213,049**	**35,016,891**	**6.3%**	**18,188,397**	**17,985,861**	**202,536**	**1.1%**	**3.26708**	**3.10918**	**0.15790**	**5.1%**
25. Net Unbilled	3,800,648 (a)	4,605,160 (a)	(804,512)	-17.5%	105,670	164,498	(58,828)	-35.8%	3.59671	2.79952	0.79719	28.5%
26. Company Use	1,509,080 (a)	1,359,882 (a)	149,198	11.0%	46,289	44,099	2,190	5.0%	3.26013	3.08370	0.17642	5.7%
27. T & D Losses	24,184,382 (a)	21,853,989 (a)	2,330,393	10.7%	718,796	693,651	25,145	3.6%	3.36457	3.15057	0.21399	6.8%
28. System KWH Sales	594,229,940	559,213,049	35,016,891	6.3%	17,317,642	17,083,613	234,029	1.4%	3.43136	3.27339	0.15797	4.8%
29. Wholesale KWH Sales	(18,434,344)	(14,797,872)	(3,636,472)	24.6%	(534,913)	(445,677)	(89,236)	20.0%	3.44623	3.32031	0.12592	3.8%
30. Jurisdictional KWH Sales	575,795,596	544,415,177	31,380,419	5.8%	16,782,729	16,637,936	144,793	0.9%	3.43088	3.27213	0.15875	4.9%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	576,452,003	545,035,810	31,416,193	5.8%	16,782,729	16,637,936	144,793	0.9%	3.43479	3.27586	0.15893	4.9%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	2,901,088	2,916,880	(15,792)	-0.5%	16,782,729	16,637,936	144,793	0.9%	0.01729	0.01753	(0.00025)	-1.4%
34. Adjustment	0	0	0	0.0%	16,782,729	16,637,936	144,793	0.9%	0.00000	0.00000	0.00000	0.0%
35. Adjustment	0	0	0	0.0%	16,782,729	16,637,936	144,793	0.9%	0.00000	0.00000	0.00000	0.0%
36. True-up *	2,901,789	2,901,789	0	0.0%	16,782,729	16,637,936	144,793	0.9%	0.01729	0.01744	(0.00015)	-0.9%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	582,254,880	550,854,479	31,400,401	5.7%	16,782,729	16,637,936	144,793	0.9%	3.46937	3.31083	0.15854	4.8%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.47187	3.31322	0.15865	4.8%
40. GPIF * (Already Adjusted for Taxes)	(760,983)	(761,233)	250	0.0%	16,782,729	16,637,936	144,793	0.9%	(0.00453)	(0.00458)	0.00004	-0.9%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**581,493,897**	**550,093,246**	**31,400,651**	**5.7%**	**16,782,729**	**16,637,936**	**144,793**	**0.9%**	**3.46734**	**3.30864**	**0.15869**	**4.8%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.467**	**3.309**	**0.158**	**4.8%**

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	32,259,001	42,140,517	(9,881,516)	-23.4%	432,399,175	439,538,956	(7,139,781)	-1.6%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	70,399	2,319,200	(2,248,801)	-97.0%	3,717,129	13,071,302	(9,354,173)	-71.6%
2a. GAINS FROM MARKET BASED SALES	0	357,000	(357,000)	-100.0%	851,859	3,017,794	(2,165,935)	-71.8%
3. FUEL COST OF PURCHASED POWER	14,972,252	3,383,500	11,588,752	342.5%	154,626,277	123,536,740	31,089,537	25.2%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,026,470	1,009,100	17,370	1.7%	11,796,102	11,949,465	(153,363)	-1.3%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	48,187,324	43,856,917	4,330,407	9.9%	594,252,566	558,936,065	35,316,501	6.3%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(6,102)	(6,000)	(102)	1.7%	(73,989)	(66,108)	(7,881)	11.9%
6b. ADJ.TO FUEL COST	(1,664)	0	(1,664)	0.0%	(30,693)	(2,738)	(27,955)	1021.0%
6c. INCREMENTAL HEDGING O&M COSTS	23,514	34,583	(11,069)	-32.0%	82,056	345,830	(263,774)	-76.3%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	48,203,072	43,885,500	4,317,572	9.8%	594,229,940	559,213,049	35,016,891	6.3%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,430,620	1,394,208	36,412	2.6%	16,782,729	16,637,936	144,793	0.9%
2. NONJURISDICTIONAL SALES	42,029	22,961	19,068	83.0%	534,913	445,677	89,236	20.0%
3. TOTAL SALES	1,472,649	1,417,169	55,480	3.9%	17,317,642	17,083,613	234,029	1.4%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9714603	0.9837980	(0.0123377)	-1.3%	0.9691117	0.9739120	(0.0048003)	-0.5%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	48,622,131	47,823,567	798,564	1.7%	553,824,780	552,929,289	895,491	0.2%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(263,799)	(263,799)	0	0.0%	(2,901,789)	(2,901,789)	0	0.0%
2b. INCENTIVE PROVISION	69,252	69,203	49	0.1%	760,983	761,233	(250)	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	48,427,584	47,628,971	798,613	1.7%	551,683,974	550,788,733	895,241	0.2%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	48,203,072	43,885,500	4,317,572	9.8%	594,229,940	559,213,049	35,016,891	6.3%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9714603	0.9837980	(0.0123377)	-1.3%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	46,827,369	43,174,467	3,652,902	8.5%	575,795,596	544,415,177	31,380,419	5.8%
6a. JURISDIC. LOSS MULTIPLIER	1.00114	1.00114	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	46,880,752	43,223,686	3,657,066	8.5%	576,452,002	545,035,810	31,416,192	5.8%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	259,542	259,542	0	0.0%	2,994,167	2,994,167	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	252,135	255,337	(3,202)	-1.3%	2,901,088	2,916,880	(15,792)	-0.5%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	47,132,887	43,479,023	3,653,864	8.4%	579,353,090	547,952,690	31,400,400	5.7%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	1,294,697	4,149,948	(2,855,251)	-68.8%	(27,669,116)	2,836,043	(30,505,159)	-1075.6%
8. INTEREST PROVISION FOR THE MONTH	(49,104)	(30,893)	(18,211)	58.9%	(443,436)	(338,444)	(104,992)	31.0%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(58,548,073)	(30,811,384)	(27,736,689)	90.0%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	263,799	263,799	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(57,038,681)	(26,428,530)	(30,610,151)	115.8%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(58,548,073)	(30,811,384)	(27,736,689)	90.0%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(56,989,577)	(26,397,637)	(30,591,940)	115.9%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(115,537,650)	(57,209,021)	(58,328,629)	102.0%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(57,768,825)	(28,604,511)	(29,164,314)	102.0%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.050	1.300	(0)	-19.2%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.000	1.300	(0)	-23.1%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	2.050	2.600	(1)	-21.2%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.025	1.300	(0)	-21.2%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.085	0.108	(0)	-21.3%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(49,104)	(30,893)	(18,211)	58.9%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
FUEL COST OF SYSTEM NET GENERATION ($)								
1 HEAVY OIL	420,203	440,919	(20,716)	-4.7%	5,372,742	4,459,844	912,898	20.5%
2 LIGHT OIL	174,670	736,991	(562,321)	-76.3%	6,782,114	11,798,708	(5,016,594)	-42.5%
3 COAL	12,103,767	20,707,264	(8,603,497)	-41.5%	255,367,646	272,337,293	(16,969,647)	-6.2%
4 NATURAL GAS	19,560,361	20,255,343	(694,982)	-3.4%	164,876,673	150,943,111	13,933,562	9.2%
5 NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6 OTHER	0	0	0	0.0%	0	0	0	0.0%
7 TOTAL ($)	32,259,001	42,140,517	(9,881,516)	-23.4%	432,399,175	439,538,956	(7,139,781)	-1.6%
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	8,010	9,407	(1,397)	-14.9%	97,530	88,256	9,274	10.5%
9 LIGHT OIL	2,757	11,048	(8,291)	-75.0%	99,165	171,064	(71,899)	-42.0%
10 COAL	618,733	948,435	(329,702)	-34.8%	11,652,241	12,387,526	(735,285)	-5.9%
11 NATURAL GAS	469,979	389,186	80,793	20.8%	3,122,054	2,819,203	302,851	10.7%
12 NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13 OTHER	0	0	0	0.0%	0	0	0	0.0%
14 TOTAL (MWH)	1,099,479	1,358,076	(258,597)	-19.0%	14,970,990	15,466,049	(495,059)	-3.2%
UNITS OF FUEL BURNED								
15 HEAVY OIL (BBL)	12,224	14,105	(1,881)	-13.3%	151,077	132,917	18,160	13.7%
16 LIGHT OIL (BBL)	4,777	19,485	(14,708)	-75.5%	177,096	304,547	(127,451)	-41.8%
17 COAL (TON)	263,026	421,672	(158,646)	-37.6%	5,440,162	5,644,981	(204,819)	-3.6%
18 NATURAL GAS (MCF)	3,567,436	2,832,570	734,866	25.9%	23,897,381	21,236,785	2,660,596	12.5%
19 NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20 OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
BTUS BURNED (MMBTU)								
21 HEAVY OIL	76,686	89,693	(13,007)	-14.5%	947,787	844,742	103,045	12.2%
22 LIGHT OIL	27,686	113,017	(85,331)	-75.5%	993,625	1,764,977	(771,352)	-43.7%
23 COAL	6,539,525	10,109,530	(3,570,005)	-35.3%	129,941,610	135,541,500	(5,599,890)	-4.1%
24 NATURAL GAS	3,685,161	2,911,761	773,400	26.6%	25,146,527	21,835,473	3,311,054	15.2%
25 NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26 OTHER	0	0	0	0.0%	0	0	0	0.0%
27 TOTAL (MMBTU)	10,329,058	13,224,001	(2,894,943)	-21.9%	157,029,549	159,986,692	(2,957,143)	-1.8%
GENERATION MIX (% MWH)								
28 HEAVY OIL	0.73%	0.69%	0.00	-	0.65%	0.57%	0.00	-
29 LIGHT OIL	0.25%	0.81%	(0.01)	-	0.66%	1.11%	(0.00)	-
30 COAL	56.28%	69.84%	(0.14)	-	77.83%	80.09%	(0.02)	-
31 NATURAL GAS	42.75%	28.66%	0.14	-	20.85%	18.23%	0.03	-
32 NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33 OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34 TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
FUEL COST PER UNIT								
35 HEAVY OIL ($/BBL)	34.38	31.26	3.12	10.0%	35.56	33.55	2.01	6.0%
36 LIGHT OIL ($/BBL)	36.56	37.82	(1.26)	-3.3%	38.30	38.74	(0.45)	-1.2%
37 COAL ($/TON)	46.02	49.11	(3.09)	-6.3%	46.94	48.24	(1.30)	-2.7%
38 NATURAL GAS ($/MCF)	5.48	7.15	(1.67)	-23.3%	6.90	7.11	(0.21)	-2.9%
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40 OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
FUEL COST PER MMBTU ($/MMBTU)								
41 HEAVY OIL	5.48	4.92	0.56	11.5%	5.67	5.28	0.39	7.4%
42 LIGHT OIL	6.31	6.52	(0.21)	-3.3%	6.83	6.68	0.14	2.1%
43 COAL	1.85	2.05	(0.20)	-9.6%	1.97	2.01	(0.04)	-2.2%
44 NATURAL GAS	5.31	6.96	(1.65)	-23.7%	6.56	6.91	(0.36)	-5.2%
45 NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46 OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47 TOTAL ($/MMBTU)	3.12	3.19	(0.06)	-2.0%	2.75	2.75	0.01	0.2%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
BTU BURNED PER KWH (BTU/KWH)								
4 HEAVY OIL	9,574	9,535	39	0.4%	9,718	9,571	147	1.5%
4 LIGHT OIL	10,042	10,230	(188)	-1.8%	10,020	10,318	(298)	-2.9%
5 COAL	10,569	10,659	(90)	-0.8%	11,152	10,942	210	1.9%
51 NATURAL GAS	7,841	7,482	359	4.8%	8,054	7,745	309	4.0%
5 NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
5 OTHER	0	0	0	0.0%	0	0	0	0.0%
5 TOTAL (BTU/KWH)	9,394	9,737	(343)	-3.5%	10,489	10,344	145	1.4%
GENERATED FUEL COST PER KWH (cents/KWH)								
5 HEAVY OIL	5.25	4.69	0.56	11.9%	5.51	5.05	0.46	9.1%
5 LIGHT OIL	6.34	6.67	(0.33)	-4.9%	6.84	6.90	(0.06)	-0.9%
5 COAL	1.96	2.18	(0.22)	-10.1%	2.19	2.20	(0.01)	-0.5%
5 NATURAL GAS	4.16	5.20	(1.04)	-20.0%	5.28	5.35	(0.07)	-1.3%
5 NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
6 OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 TOTAL (cents/KWH)	2.93	3.10	(0.17)	-5.5%	2.89	2.84	0.05	1.8%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: NOVEMBER 2003

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(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	94	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#2	100	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	150	0	0.0	100.0	0.0	0	COAL	0	0	0.0	8,404	0.00	0.00
GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	4,130	0.00	0.00
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GANNON STATION	**344**	**0**	**0.0**	**100.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**12,534**	**0.00**	**0.00**
B.B.#1	421	200,071	66.0	72.7	66.0	11,128	COAL	91,962	24,210,040	2,226,403.7	4,414,373	2.21	48.00
B.B.#2	411	136,885	46.3	39.0	75.0	10,725	COAL	60,829	24,135,380	1,468,131.0	2,919,922	2.13	48.00
B.B.#3	428	111,433	36.2	41.6	74.2	10,779	COAL	48,924	24,550,720	1,201,131.2	2,348,457	2.11	48.00
B.B.#4 (1)	452	191	0.1	0.3	15.3	0	COAL	0	0	0.0	0	0.00	0.00
B.B. STATION	**1,712**	**448,580**	**36.4**	**37.7**	**56.8**	**10,914**	**COAL**	**201,715**	**24,270,155**	**4,895,665.9**	**9,682,752**	**2.16**	**48.00**
SEB-PHIL. #1(HVY OIL)	17	4,005	32.7	99.9	94.1	9,574	HVY.OIL	6,111	6,273,540	38,338.7	210,067	5.25	34.38
SEB-PHIL. #2(HVY OIL)	17	4,005	32.7	100.0	91.7	9,574	HVY.OIL	6,113	6,273,540	38,347.7	210,136	5.25	34.38
SEB-PHILLIPS TOTAL	**34**	**8,010**	**32.7**	**99.9**	**92.9**	**9,574**	**HVY.OIL**	**12,224**	**6,273,542**	**76,686.4**	**420,203**	**5.25**	**34.38**
POLK #1 GASIFIER	255	170,153	92.7	95.8	93.7	9,661	COAL	61,311	26,812,000	1,643,859.0	2,408,481	1.42	39.28
POLK #1 CT (OIL)	225	1,969	1.2	100.0	102.3	8,025	LGT.OIL	2,728	5,792,870	15,801.6	102,565	5.21	37.60
POLK #1 TOTAL	**255**	**172,122**	**93.7**	**96.7**	**93.8**	**9,642**	**-**	**-**	**-**	**1,659,660.6**	**2,511,046**	**1.46**	**-**
POLK #2 CT (GAS)	150	21,393	19.8	100.0	80.6	10,786	GAS	223,372	1,033,000	230,743.0	1,378,248	6.44	6.17
POLK #2 CT (OIL)	160	28	0.0	99.4	41.7	12,100	LGT.OIL	58	5,792,866	336.2	2,182	7.79	37.62
POLK #2 TOTAL	**155**	**21,421**	**19.2**	**100.0**	**80.5**	**10,788**	**-**	**-**	**-**	**231,079.2**	**1,380,430**	**6.44**	**-**
POLK #3 CT (GAS)	150	14,899	13.8	100.0	78.2	11,641	GAS	167,899	1,033,000	173,440.0	1,039,190	6.97	6.19
POLK #3 CT (OIL)	165	32	0.0	99.2	38.3	18,719	LGT.OIL	102	5,792,833	591.7	3,841	12.00	37.66
POLK #3 TOTAL	**158**	**14,931**	**13.1**	**100.0**	**78.0**	**11,656**	**-**	**-**	**-**	**174,031.7**	**1,043,031**	**6.99**	**-**
POLK STATION TOTAL	**568**	**208,474**	**51.0**	**98.5**	**85.6**	**9,904**	**-**	**-**	**-**	**2,064,771.5**	**4,934,507**	**2.37**	**-**
B.B.C.T.#1	14	165	1.6	100.0	89.6	17,970	LGT.OIL	512	5,786,834	2,965.0	17,911	10.86	34.98
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	60	563	1.3	100.0	87.5	14,194	LGT.OIL	1,377	5,801,716	7,991.4	48,171	8.56	34.98
C.T. TOTAL	**140**	**728**	**0.7**	**100.0**	**87.9**	**15,050**	**LGT.OIL**	**1,889**	**5,797,681**	**10,956.4**	**66,082**	**9.08**	**34.98**
CITY OF TAMPA	**6**	**962**	**22.3**	**0.0**	**0.0**	**10,312**	**GAS**	**9,603**	**1,033,000**	**9,919.9**	**63,899**	**6.64**	**6.65**
BAYSIDE ST 1	246	101,657	57.4	83.2	64.8	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	148	62,838	59.0	89.7	84.8	11,737	GAS	713,943	1,033,000	737,502.9	3,929,184	6.25	5.50
BAYSIDE CT1B	148	72,976	68.5	97.1	84.9	11,737	GAS	829,125	1,033,000	856,486.0	4,563,088	6.25	5.50
BAYSIDE CT1C	148	64,235	60.3	95.8	85.1	11,737	GAS	729,820	1,033,000	753,904.1	4,016,564	6.25	5.50
BAYSIDE UNIT 1 TOTAL	**690**	**301,706**	**60.7**	**90.3**	**77.7**	**7,782**	**GAS**	**2,272,886**	**1,033,000**	**2,347,893.0**	**12,508,836**	**4.15**	**5.50**
BAYSIDE ST 2	316	41,003	18.0	0.0	0.0	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	148	50,167	47.1	0.0	0.0	10,256	GAS	498,055	1,033,000	514,491.3	2,547,022	5.08	5.11
BAYSIDE CT2B	148	37,195	34.9	0.0	0.0	10,256	GAS	369,263	1,033,000	381,449.1	1,888,388	5.08	5.11
BAYSIDE CT2C	148	346	0.3	0.0	0.0	10,256	GAS	3,440	1,033,000	3,553.2	17,590	5.08	5.11
BAYSIDE CT2D	148	2,308	2.2	0.0	0.0	10,256	GAS	22,915	1,033,000	23,671.4	117,188	5.08	5.11
BAYSIDE UNIT 2 TOTAL	**908**	**131,019**	**20.0**	**0.0**	**0.0**	**7,046**	**GAS**	**893,674**	**1,033,000**	**923,165.0**	**4,570,188**	**3.49**	**5.11**
BAYSIDE STATION TOTAL	**1,598**	**432,725**	**37.6**	**90.3**	**77.7**	**7,559**	**GAS**	**3,166,561**	**1,033,000**	**3,271,058.0**	**17,079,024**	**3.95**	**5.39**
TOT. COAL (GN,BB,POLK)	**2,311**	**618,733**	**37.2**	**53.4**	**52.4**	**10,569**	**COAL**	**263,026**	**24,862,651**	**6,539,524.9**	**12,103,767**	**1.96**	**46.02**
SYSTEM	**4,402**	**1,099,479**	**34.7**	**68.6**	**62.8**	**9,394**	**-**	**-**	**-**	**10,329,058.1**	**32,259,001**	**2.93**	**-**

(1) Tons consumed and associated fuel expense were included in October 2003.

LEGEND:
H.P. = HOOKERS POINT
B.B. = BIG BEND
GAN. = GANNON
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2003

SCHEDULE A5
PAGE 1 OF 2
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	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	10,157	14,105	(3,948)	-28.0%	159,280	131,638	27,642	21.0%
3 UNIT COST ($/BBL)	36.18	30.55	5.63	18.4%	33.97	32.42	1.55	4.8%
4 AMOUNT ($)	367,482	430,908	(63,426)	-14.7%	5,410,889	4,268,128	1,142,761	26.8%
5 BURNED:								
6 UNITS (BBL)	12,224	14,105	(1,881)	-13.3%	151,077	132,917	18,160	13.7%
7 UNIT COST ($/BBL)	34.38	31.26	3.12	10.0%	35.56	33.55	2.01	6.0%
8 AMOUNT ($)	420,203	440,919	(20,716)	-4.7%	5,372,742	4,459,844	912,898	20.5%
9 ENDING INVENTORY:								
10 UNITS (BBL)	18,945	9,463	9,482	100.2%	18,945	9,463	9,482	100.2%
11 UNIT COST ($/BBL)	34.07	30.74	3.33	10.8%	34.07	30.74	3.33	10.8%
12 AMOUNT ($)	645,407	290,890	354,517	121.9%	645,407	290,890	354,517	121.9%
13								
14 DAYS SUPPLY:	64	328	(264)	-80.5%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	18,148	23,771	(5,623)	-23.7%	269,288	360,252	(90,964)	-25.3%
17 UNIT COST ($/BBL)	35.15	37.28	(2.13)	-5.7%	38.26	39.58	(1.32)	-3.3%
18 AMOUNT ($)	637,949	886,275	(248,326)	-28.0%	10,303,306	14,257,839	(3,954,533)	-27.7%
19 BURNED:								
20 UNITS (BBL)	4,777	19,485	(14,708)	-75.5%	177,096	304,547	(127,451)	-41.8%
21 UNIT COST ($/BBL)	36.56	37.82	(1.26)	-3.3%	38.30	38.74	(0.45)	-1.2%
22 AMOUNT ($)	174,670	736,991	(562,321)	-76.3%	6,782,114	11,798,708	(5,016,594)	-42.5%
23 ENDING INVENTORY:								
24 UNITS (BBL)	85,194	82,746	2,448	3.0%	85,194	82,746	2,448	3.0%
25 UNIT COST ($/BBL)	36.44	37.84	(1.40)	-3.7%	36.44	37.84	(1.40)	-3.7%
26 AMOUNT ($)	3,104,461	3,131,411	(26,950)	-0.9%	3,104,461	3,131,411	(26,950)	-0.9%
27								
28 DAYS SUPPLY: NORMAL	110	78	32	41.4%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	12	12	0	3.0%	-	-	-	-
COAL (3)								
30 PURCHASES:								
31 UNITS (TONS)	270,347	579,300	(308,953)	-53.3%	5,492,500	6,248,773	(756,273)	-12.1%
32 UNIT COST ($/TON)	43.97	49.58	(5.61)	-11.3%	47.35	48.19	(0.84)	-1.7%
33 AMOUNT ($)	11,887,122	28,722,952	(16,835,830)	-58.6%	260,081,577	301,157,189	(41,075,612)	-13.6%
34 BURNED:								
35 UNITS (TONS)	263,026	421,672	(158,646)	-37.6%	5,440,162	5,644,981	(204,819)	-3.6%
36 UNIT COST ($/TON)	46.02	49.11	(3.09)	-6.3%	46.94	48.24	(1.30)	-2.7%
37 AMOUNT ($)	12,103,767	20,707,264	(8,603,497)	-41.5%	255,367,646	272,337,293	(16,969,647)	-6.2%
38 ENDING INVENTORY:								
39 UNITS (TONS)	490,695	1,042,149	(551,454)	-52.9%	490,695	1,042,149	(551,454)	-52.9%
40 UNIT COST ($/TON)	46.53	48.53	(2.00)	-4.1%	46.53	48.53	(2.00)	-4.1%
41 AMOUNT ($)	22,833,469	50,574,582	(27,741,113)	-54.9%	22,833,469	50,574,582	(27,741,113)	-54.9%
42								
43 DAYS SUPPLY:	37	42	(5)	-10.8%	-	-	-	-
NATURAL GAS(4)								
44 PURCHASES:								
45 UNITS (MCF)	3,567,436	2,832,570	734,866	25.9%	23,897,381	21,236,785	2,660,596	12.5%
46 UNIT COST ($/MCF)	5.48	7.15	(1.67)	-23.3%	6.90	7.11	(0.21)	-2.9%
47 AMOUNT ($)	19,560,361	20,255,343	(694,982)	-3.4%	164,876,673	150,943,110	13,933,563	9.2%
48 BURNED:								
49 UNITS (MCF)	3,567,436	2,832,570	734,866	25.9%	23,897,381	21,236,785	2,660,596	12.5%
50 UNIT COST ($/MCF)	5.48	7.15	(1.67)	-23.3%	6.90	7.11	(0.21)	-2.9%
51 AMOUNT ($)	19,560,361	20,255,343	(694,982)	-3.4%	164,876,673	150,943,111	13,933,562	9.2%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	17,869
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	17,869

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(3,590)	(127,496)
OTHER USAGE	(643)	(22,610)
TOTAL	(4,233)	(150,106)

(3) RECONCILIATION - COALS

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	14,440
IGNITION #2 OIL	109,627
IGNITION PROPANE	5,180
AERIAL SURVEY ADJ.	0
ADDITIVES	14,997
GREEN FUEL	0
TOTAL	144,244

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2003

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	2,642.0	0.0	2,642.0	1.949	1.949	51,500.00	51,500.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. - MB	52,684.0	0.0	52,684.0	4.304	5.304	2,267,700.00	2,794,300.00	357,000.00
TOTAL			**55,326.0**	**0.0**	**55,326.0**	**4.192**	**5.144**	**2,319,200.00**	**2,845,800.00**	**357,000.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	1,297.1	23.6	1,273.5	3.560	3.560	45,333.89	45,333.89	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	847.0	0.0	847.0	2.990	2.990	25,325.39	25,325.39	
FLA. PWR. CORP.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CITY OF LAKELAND		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SEMINOLE ELEC. CO-OP		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
THE ENERGY AUTHORITY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTILITIES		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
RELIANT ENERGY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE PWR. PART. TO CITY OF LAKELAND*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
AUBURNDALE POWER PARTNERS		SCH. - OATT	(26.0)	0.0	(26.0)	1.001	1.001	(260.31)	(260.31)	
CARGILL ALLIANT		SCH. - OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ADJUSTMENTS										
SEMINOLE ELEC. PRECO-1	Oct. 2003	SCH. - D	(1,502.8)	(48.1)	(1,454.7)	3.664	3.664	(53,299.63)	(53,299.63)	
SEMINOLE ELEC. PRECO-1	Oct. 2003	SCH. - D	1,502.8	31.9	1,470.9	3.624	3.624	53,299.63	53,299.63	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			2,144.1	7.4	2,136.7	3.307	3.307	70,659.28	70,659.28	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			(26.0)	0.0	(26.0)	1.001	1.001	(260.31)	(260.31)	
TOTAL			**2,118.1**	**7.4**	**2,110.7**	**3.335**	**3.335**	**70,398.97**	**70,398.97**	**0.00**
CURRENT MONTH:										
DIFFERENCE			(53,207.9)	7.4	(53,215.3)	(0.857)	(1.809)	(2,248,801.03)	(2,775,401.03)	(357,000.00)
DIFFERENCE %			-96.2%	0.0%	-96.2%	-20.4%	-35.2%	-97.0%	-97.5%	-100.0%
PERIOD TO DATE:										
ACTUAL			113,298.5	711.4	112,587.1	3.302	4.351	3,717,128.28	4,898,599.95	851,859.70
ESTIMATED			300,680.9	5.3	300,675.6	4.347	5.651	13,071,301.69	16,991,317.12	3,017,794.33
DIFFERENCE			(187,382.4)	706.1	(188,088.5)	(1.045)	(1.300)	(9,354,173.41)	(12,092,717.17)	(2,165,934.63)
DIFFERENCE %			-62.3%	13322.6%	-62.6%	-24.0%	-23.0%	-71.6%	-71.2%	-71.8%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF NOVEMBER 2003.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	SCH. - J	1,189.0	0.0	613.0	576.0	4.792	4.792	27,600.00
HARDEE POWER PARTNERS	IPP	7,810.0	0.0	0.0	7,810.0	7.471	7.471	583,500.00
VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
VARIOUS	MKT. BASE	68,148.0	0.0	0.0	68,148.0	4.068	4.068	2,772,400.00
TOTAL		**77,147.0**	**0.0**	**613.0**	**76,534.0**	**4.421**	**4.421**	**3,383,500.00**
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	40,196.0	0.0	0.0	40,196.0	5.111	5.111	2,054,515.41
HARDEE PWR. PART.-OTHERS	IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	SCH. - J	97,120.0	0.0	1,336.0	95,784.0	4.269	4.269	4,089,194.30
FLA. POWER & LIGHT	SCH. - J	48,980.0	0.0	809.3	48,170.7	3.945	3.945	1,900,521.10
CITY OF LAKELAND	SCH. - J	40,911.0	0.0	414.0	40,497.0	5.216	5.216	2,112,307.50
ORLANDO UTIL. COMM.	SCH. - J	3,200.0	0.0	0.0	3,200.0	6.250	6.250	200,000.00
CAROLINA POWER & LIGHT	SCH. - J	2,860.0	0.0	0.0	2,860.0	5.273	5.273	150,810.00
THE ENERGY AUTHORITY	SCH. - J	51,584.0	0.0	0.0	51,584.0	4.543	4.543	2,343,392.00
REEDY CREEK	SCH. - J	285.0	0.0	0.0	285.0	3.554	3.554	10,130.00
OKEELANTA	SCH. - J	6,837.0	0.0	0.0	6,837.0	4.826	4.826	329,984.45
TALLAHASSEE	SCH. - J	675.0	0.0	0.0	675.0	4.442	4.442	29,981.00
CALPINE	SCH. - J (1)	90.0	0.0	0.0	90.0	0.000	0.000	0.00
CARGILL ALLIANT	SCH. - J	13,841.0	0.0	0.0	13,841.0	3.604	3.604	498,796.50
CONOCO	SCH. - J	440.0	0.0	0.0	440.0	4.000	4.000	17,600.00
CORAL POWER	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RELIANT	SCH. - J	1,291.0	0.0	0.0	1,291.0	4.257	4.257	54,959.00
SEMINOLE ELEC. CO-OP	SCH. - J	21,828.0	0.0	0.0	21,828.0	4.327	4.327	944,573.00
DUKE ENERGY	SCH. - J	782.0	0.0	0.0	782.0	5.497	5.497	42,989.50
DYNEGY POWER MARKETING	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RINGHAVER	SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:								
HARDEE PWR. PART.-NATIVI	Oct. 2003 IPP	(71,297.0)	0.0	0.0	(71,297.0)	4.982	4.982	(3,552,230.71)
HARDEE PWR. PART.-NATIVI	Oct. 2003 IPP	71,297.0	0.0	0.0	71,297.0	5.090	5.090	3,629,166.46
FLA. POWER & LIGHT	Oct. 2003 SCH. - J	(3,161.0)	0.0	(1,007.7)	(2,153.3)	2.522	2.522	(54,301.36)
FLA. POWER & LIGHT	Oct. 2003 SCH. - J	3,161.0	0.0	375.8	2,785.2	4.123	4.123	114,823.51
ORLANDO UTIL. COMM.	Oct. 2003 SCH. - J	(40,125.0)	0.0	(378.0)	(39,747.0)	4.663	4.663	(1,853,228.00)
ORLANDO UTIL. COMM.	Oct. 2003 SCH. - J	40,125.0	0.0	127.0	39,998.0	4.682	4.682	1,872,806.00
SEMINOLE ELEC. CO-OP	Oct. 2003 SCH. - J	(29,225.0)	0.0	(290.2)	(28,934.8)	3.212	3.212	(929,325.91)
SEMINOLE ELEC. CO-OP	Oct. 2003 SCH. - J	29,225.0	0.0	288.2	28,936.8	3.212	3.212	929,459.91
THE ENERGY AUTHORITY	Oct. 2003 SCH. - J	(53,303.0)	0.0	(1,942.2)	(51,360.8)	4.514	4.514	(2,318,487.13)
THE ENERGY AUTHORITY	Oct. 2003 SCH. - J	53,303.0	0.0	1,439.3	51,863.7	4.538	4.538	2,353,815.13
TOTAL		**330,920.0**	**0.0**	**1,171.5**	**329,748.5**	**4.541**	**4.541**	**14,972,251.66**
CURRENT MONTH:								
DIFFERENCE		253,773.0	0.0	558.5	253,214.5	0.120	0.120	11,588,751.66
DIFFERENCE %		328.9%	0.0%	91.1%	330.9%	2.7%	2.7%	342.5%
PERIOD TO DATE:								
ACTUAL		2,920,292.0	0.0	59,683.5	2,860,608.5	5.405	5.405	154,626,276.68
ESTIMATED		2,422,069.0	0.0	43,227.2	2,378,841.8	5.193	5.193	123,536,739.59
DIFFERENCE		498,223.0	0.0	16,456.3	481,766.7	0.212	0.212	31,089,537.09
DIFFERENCE %		20.6%	0.0%	38.1%	20.3%	4.1%	4.1%	25.2%

(1) Due to excess generation by IPP provider, TEC's system benefits at no cost to rate payers.

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	38,189.0	0.0	0.0	38,189.0	2.642	2.642	1,009,100.00
TOTAL		**38,189.0**	**0.0**	**0.0**	**38,189.0**	**2.642**	**2.642**	**1,009,100.00**
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	18,052.0	0.0	0.0	18,052.0	2.409	2.409	434,831.01
McKAY BAY REFUSE	COGEN.	13,370.0	0.0	0.0	13,370.0	2.403	2.403	321,223.89
ORANGE COGENERATION L.P.	COGEN.	5,520.0	0.0	0.0	5,520.0	2.234	2.234	123,309.91
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	328.0	0.0	0.0	328.0	4.708	4.708	15,442.90
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	797.0	0.0	0.0	797.0	5.244	5.244	41,793.97
CF INDUSTRIES INC.	COGEN.	1,154.0	0.0	0.0	1,154.0	4.339	4.339	50,070.47
IMC-AGRICO-NEW WALES	COGEN.	6.0	0.0	0.0	6.0	4.398	4.398	263.85
IMC-AGRICO-S. PIERCE	COGEN.	343.0	0.0	0.0	343.0	5.154	5.154	17,677.18
AUBURNDALE POWER PARTNERS	COGEN.	276.0	0.0	0.0	276.0	4.428	4.428	12,220.31
CUTRALE CITRUS	COGEN.	5.0	0.0	0.0	5.0	3.254	3.254	162.70
SUB-TOTAL FOR NOVEMBER 2003		39,851.0	0.0	0.0	39,851.0	2.552	2.552	1,016,996.19
ADJUSTMENTS FOR THE MONTH OF:	**OCTOBER 2003**							
HILLSBOROUGH COUNTY	COGEN.	(18,217.0)	0.0	0.0	(18,217.0)	2.418	2.418	(440,414.28)
		18,217.0	0.0	0.0	18,217.0	2.442	2.442	444,782.44
McKAY BAY REFUSE	COGEN.	(13,583.0)	0.0	0.0	(13,583.0)	2.418	2.418	(328,414.20)
		13,583.0	0.0	0.0	13,583.0	2.442	2.442	331,680.03
ORANGE COGENERATION L.P.	COGEN.	(6,532.0)	0.0	0.0	(6,532.0)	2.217	2.217	(144,820.45)
		6,532.0	0.0	0.0	6,532.0	2.245	2.245	146,660.09
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**OCTOBER 2003**	0.0	0.0	0.0	0.0	0.000	0.000	9,473.63
GRAND TOTAL		**39,851.0**	**0.0**	**0.0**	**39,851.0**	**2.576**	**2.576**	**1,026,469.82**
CURRENT MONTH:								
DIFFERENCE		1,662.0	0.0	0.0	1,662.0	(0.067)	(0.067)	17,389.82
DIFFERENCE %		4.4%	0.0%	0.0%	4.4%	-2.5%	-2.5%	1.7%
PERIOD TO DATE:								
ACTUAL		474,830.0	0.0	0.0	474,830.0	2.484	2.484	11,796,102.67
ESTIMATED		445,781.0	0.0	0.0	445,781.0	2.681	2.681	11,949,465.12
DIFFERENCE		29,049.0	0.0	0.0	29,049.0	(0.196)	(0.196)	(153,362.45)
DIFFERENCE %		6.5%	0.0%	0.0%	6.5%	(0.073)	(0.073)	-1.3%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

DECEMBER 2003

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	33,311,186	48,671,932	(15,360,746)	-31.6%	1,118,389	1,443,591	(325,202)	-22.5%	2.97850	3.37159	(0.39309)	-11.7%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(6,538)	(6,000)	(538)	9.0%	1,118,389 (a)	1,443,591 (a)	(325,202)	-22.5%	(0.00058)	(0.00042)	(0.00017)	40.7%
4b. Adjustments to Fuel Cost	(1,198)	0	(1,198)	0.0%	1,118,389 (a)	1,443,591 (a)	(325,202)	-22.5%	(0.00011)	0.00000	(0.00011)	0.0%
4c. Incremental Hedging O&M Costs	26,690	69,170	(42,480)	-61.4%	1,118,389 (a)	1,443,591 (a)	(325,202)	-22.5%	0.00239	0.00479	(0.00241)	-50.2%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**33,330,140**	**48,735,102**	**(15,404,962)**	**-31.6%**	**1,118,389**	**1,443,591**	**(325,202)**	**-22.5%**	**2.98019**	**3.37596**	**(0.39577)**	**-11.7%**
6. Fuel Cost of Purchased Power - Firm (A7)	17,782,766	4,879,300	12,903,466	264.5%	353,382	126,565	226,817	179.2%	5.03217	3.85517	1.17699	30.5%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,029,358	1,035,200	(5,842)	-0.6%	41,574	39,467	2,107	5.3%	2.47597	2.62295	(0.14699)	-5.6%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**18,812,124**	**5,914,500**	**12,897,624**	**218.1%**	**394,956**	**166,032**	**228,924**	**137.9%**	**4.76309**	**3.56227**	**1.20083**	**33.7%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,513,345**	**1,609,623**	**(96,278)**	**-6.0%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	78,040	38,200	39,840	104.3%	1,811	2,171	(360)	-16.6%	4.30922	1.75956	2.54966	144.9%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	35,427	2,801,500	(2,766,073)	-98.7%	1,805	58,016	(56,211)	-96.9%	1.96271	4.82884	(2.86613)	-59.4%
19. Gains on Market Based Sales	14,360	443,200	(428,840)	-96.8%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**127,827**	**3,282,900**	**(3,155,073)**	**-96.1%**	**3,616**	**60,187**	**(56,571)**	**-94.0%**	**3.53504**	**5.45450**	**(1.91946)**	**-35.2%**
21. Net Inadvertant Interchange					(184)	0	(184)	0.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					1,225	0	1,225	0.0%				
23. Interchange and Wheeling Losses					180	900	(720)	-80.0%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**52,014,437**	**51,366,702**	**647,735**	**1.3%**	**1,510,580**	**1,548,536**	**(37,946)**	**-2.5%**	**3.44332**	**3.31711**	**0.12621**	**3.8%**
25. Net Unbilled	72,482 (a)	262,351 (a)	(189,869)	-72.4%	2,105	7,909	(5,804)	-73.4%	3.44333	3.31712	0.12621	3.8%
26. Company Use	108,740 (a)	132,685 (a)	(23,945)	-18.0%	3,158	4,000	(842)	-21.1%	3.44332	3.31713	0.12619	3.8%
27. T & D Losses	2,253,928 (a)	3,006,433 (a)	(752,505)	-25.0%	65,458	90,634	(25,176)	-27.8%	3.44332	3.31711	0.12621	3.8%
28. System KWH Sales	52,014,437	51,366,702	647,735	1.3%	1,439,869	1,445,993	(6,124)	-0.4%	3.61244	3.55235	0.06010	1.7%
29. Wholesale KWH Sales	(1,418,138)	(821,092)	(597,046)	72.7%	(39,257)	(23,114)	(16,143)	69.8%	3.61245	3.55236	0.06009	1.7%
30. Jurisdictional KWH Sales	50,596,299	50,545,610	50,689	0.1%	1,400,612	1,422,879	(22,267)	-1.6%	3.61244	3.55235	0.06010	1.7%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	50,653,979	50,603,232	50,747	0.1%	1,400,612	1,422,879	(22,267)	-1.6%	3.61656	3.55640	0.06016	1.7%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	250,004	252,903	(2,899)	-1.1%	1,400,612	1,422,879	(22,267)	-1.6%	0.01785	0.01777	0.00008	0.4%
34. Balance of 1999 Revenue Refund true-up adjustment	2,238	0	2,238	0.0%	1,400,612	1,422,879	(22,267)	-1.6%	0.00016	0.00000	0.00016	0.0%
35. Gannon O&M offset credit per FPSC decision 11/14/03	(8,416,800)	0	(8,416,800)	0.0%	1,400,612	1,422,879	(22,267)	-1.6%	(0.60094)	0.00000	(0.60094)	0.0%
36. True-up *	263,802	263,802	0	0.0%	1,400,612	1,422,879	(22,267)	-1.6%	0.01883	0.01854	0.00029	1.6%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	42,753,223	51,119,937	(8,366,714)	-16.4%	1,400,612	1,422,879	(22,267)	-1.6%	3.05247	3.59271	(0.54024)	-15.0%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.05467	3.59530	(0.54063)	-15.0%
40. GPIF * (Already Adjusted for Taxes)	(69,257)	(69,198)	(59)	0.1%	1,400,612	1,422,879	(22,267)	-1.6%	(0.00494)	(0.00486)	(0.00008)	1.7%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**42,683,966**	**51,050,739**	**(8,366,773)**	**-16.4%**	**1,400,612**	**1,422,879**	**(22,267)**	**-1.6%**	**3.04973**	**3.59044**	**(0.54071)**	**-15.1%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.050**	**3.590**	**(0.540)**	**-15.0%**

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: DECEMBER 2003

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	465,710,361	488,210,888	(22,500,527)	-4.6%	16,089,379	16,909,640	(820,261)	-4.9%	2.89452	2.88717	0.00735	0.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(80,527)	(72,108)	(8,419)	11.7%	16,089,379 (a)	16,909,640 (a)	(820,261)	-4.9%	(0.00050)	(0.00043)	(0.00007)	17.4%
4b. Adjustments to Fuel Cost	(31,891)	(2,738)	(29,153)	1064.7%	16,089,379 (a)	16,909,640 (a)	(820,261)	-4.9%	(0.00020)	(0.00002)	(0.00018)	1124.1%
4c. Adjustments to Fuel Cost	108,746	415,000	(306,254)	-73.8%	16,089,379 (a)	16,909,640 (a)	(820,261)	-4.9%	0.00068	0.00245	(0.00178)	-72.5%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**465,706,689**	**488,551,042**	**(22,844,353)**	**-4.7%**	**16,089,379**	**16,909,640**	**(820,261)**	**-4.9%**	**2.89450**	**2.88919**	**0.00531**	**0.2%**
6. Fuel Cost of Purchased Power - Firm (A7)	172,409,043	128,416,040	43,993,003	34.3%	3,213,991	2,505,407	708,584	28.3%	5.36433	5.12556	0.23877	4.7%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	12,825,460	12,984,665	(159,205)	-1.2%	516,404	485,248	31,156	6.4%	2.48361	2.67588	(0.19227)	-7.2%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**185,234,503**	**141,400,705**	**43,833,798**	**31.0%**	**3,730,395**	**2,990,655**	**739,740**	**24.7%**	**4.96555**	**4.72808**	**0.23746**	**5.0%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**19,819,774**	**19,900,295**	**(80,521)**	**-0.4%**				
14. Fuel Cost of Sch. D Jurisd. Sales (A6)	866,398	727,307	139,091	19.1%	28,100	31,707	(3,607)	-11.4%	3.08327	2.29384	0.78943	34.4%
15. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	7,918	4,680	3,238	69.2%	46	46	0	0.0%	17.21304	10.17391	7.03913	69.2%
16. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of HPP Sch. D Separ. Sales (A6)	121,809	108,975	12,834	11.8%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
18. Fuel Cost of Market Base Sales (A6)	2,834,471	15,070,040	(12,235,569)	-81.2%	88,059	329,110	(241,051)	-73.2%	3.21883	4.57903	(1.36020)	-29.7%
19. Gains on Market Based Sales	866,219	3,460,994	(2,594,775)	-75.0%								
20. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19)	**4,696,815**	**19,371,996**	**(14,675,181)**	**-75.8%**	**116,205**	**360,863**	**(244,658)**	**-67.8%**	**4.04184**	**5.36824**	**(1.32641)**	**-24.7%**
21. Net Inadvertant Interchange					(774)	(291)	(483)	166.0%				
22. Wheeling Rec'd. less Wheeling Del'd.					2,236	652	1,584	242.9%				
23. Interchange and Wheeling Losses					6,044	5,396	648	12.0%				
24. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 20 + 21 + 22 - 23)	**646,244,377**	**610,579,751**	**35,664,626**	**5.8%**	**19,698,987**	**19,534,397**	**164,590**	**0.8%**	**3.28060**	**3.12566**	**0.15493**	**5.0%**
25. Net Unbilled	3,873,130 (a)	4,867,511 (a)	(994,381)	-20.4%	107,775	172,407	(64,632)	-37.5%	3.59372	2.82327	0.77045	27.3%
26. Company Use	1,617,820 (a)	1,492,567 (a)	125,253	8.4%	49,447	48,099	1,348	2.8%	3.27183	3.10311	0.16871	5.4%
27. T & D Losses	26,438,310 (a)	24,860,422 (a)	1,577,888	6.3%	784,254	784,285	(31)	0.0%	3.37114	3.16982	0.20132	6.4%
28. System KWH Sales	646,244,377	610,579,751	35,664,626	5.8%	18,757,511	18,529,606	227,905	1.2%	3.44526	3.29516	0.15010	4.6%
29. Wholesale KWH Sales	(19,852,482)	(15,618,964)	(4,233,518)	27.1%	(574,170)	(468,791)	(105,379)	22.5%	3.45760	3.33175	0.12584	3.8%
30. Jurisdictional KWH Sales	626,391,895	594,960,787	31,431,108	5.3%	18,183,341	18,060,815	122,526	0.7%	3.44487	3.29421	0.15066	4.6%
31. Jurisdictional Loss Multiplier - 1.00114									1.00114	1.00114	0.00000	0.0%
32. Jurisdictional KWH Sales Adjusted for Line Losses	627,105,982	595,639,042	31,466,940	5.3%	18,183,341	18,060,815	122,526	0.7%	3.44879	3.29796	0.15083	4.6%
33. Peabody Coal Contract Buy-Out Amort. Jurisd.	3,151,092	3,169,783	(18,691)	-0.6%	18,183,341	18,060,815	122,526	0.7%	0.01733	0.01755	(0.00022)	-1.3%
34. Balance of 1999 Revenue Refund true-up adjustment	2,238	0	2,238	0.0%	18,183,341	18,060,815	122,526	0.7%	0.00001	0.00000	0.00001	0.0%
35. Gannon O&M offset credit per FPSC decision 11/14/03	(8,416,800)	0	(8,416,800)	0.0%	18,183,341	18,060,815	122,526	0.7%	(0.04629)	0.00000	(0.04629)	0.0%
36. True-up *	3,165,591	3,165,591	0	0.0%	18,183,341	18,060,815	122,526	0.7%	0.01741	0.01753	(0.00012)	-0.7%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	625,008,103	601,974,416	23,033,687	3.8%	18,183,341	18,060,815	122,526	0.7%	3.43726	3.33304	0.10422	3.1%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.43973	3.33544	0.10429	3.1%
40. GPIF * (Already Adjusted for Taxes)	(830,240)	(830,431)	191	0.0%	18,183,341	18,060,815	122,526	0.7%	(0.00457)	(0.00460)	0.00003	-0.7%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**624,177,863**	**601,143,985**	**23,033,878**	**3.8%**	**18,183,341**	**18,060,815**	**122,526**	**0.7%**	**3.43516**	**3.33084**	**0.10432**	**3.1%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.435**	**3.331**	**0.104**	**3.1%**

SCHEDULE A2
PAGE 1 OF 3
REVISED WITH
TRUE UP FILING

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	33,311,186	48,671,932	(15,360,746)	-31.6%	465,710,361	488,210,888	(22,500,527)	-4.6%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	113,467	2,839,700	(2,726,233)	-96.0%	3,830,596	15,911,002	(12,080,406)	-75.9%
2a. GAINS FROM MARKET BASED SALES	14,360	443,200	(428,840)	-96.8%	866,219	3,460,994	(2,594,775)	-75.0%
3. FUEL COST OF PURCHASED POWER	17,782,766	4,879,300	12,903,466	264.5%	172,409,043	128,416,040	43,993,003	34.3%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,029,358	1,035,200	(5,842)	-0.6%	12,825,460	12,984,665	(159,205)	-1.2%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	51,995,483	51,303,532	691,951	1.3%	646,248,049	610,239,597	36,008,452	5.9%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(6,538)	(6,000)	(538)	9.0%	(80,527)	(72,108)	(8,419)	11.7%
6b. ADJ.TO FUEL COST	(1,198)	0	(1,198)	0.0%	(31,891)	(2,738)	(29,153)	1064.7%
6c. INCREMENTAL HEDGING O&M COSTS	26,690	69,170	(42,480)	-61.4%	108,746	415,000	(306,254)	-73.8%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	52,014,437	51,366,702	647,735	1.3%	646,244,377	610,579,751	35,664,626	5.8%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,400,612	1,422,879	(22,267)	-1.6%	18,183,341	18,060,815	122,526	0.7%
2. NONJURISDICTIONAL SALES	39,257	23,114	16,143	69.8%	574,170	468,791	105,379	22.5%
3. TOTAL SALES	1,439,869	1,445,993	(6,124)	-0.4%	18,757,511	18,529,606	227,905	1.2%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9727357	0.9840151	(0.0112794)	-1.1%	0.9693899	0.9747004	(0.0053105)	-0.5%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	47,537,296	48,808,858	(1,271,562)	-2.6%	601,362,076	601,738,147	(376,071)	-0.1%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(263,802)	(263,802)	0	0.0%	(3,165,591)	(3,165,591)	0	0.0%
2b. INCENTIVE PROVISION	69,257	69,198	59	0.1%	830,240	830,431	(191)	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	47,342,751	48,614,254	(1,271,503)	-2.6%	599,026,725	599,402,987	(376,262)	-0.1%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	52,014,437	51,366,702	647,735	1.3%	646,244,377	610,579,751	35,664,626	5.8%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9727357	0.9840151	(0.0112794)	-1.1%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	50,596,299	50,545,610	50,689	0.1%	626,391,895	594,960,787	31,431,108	5.3%
6a. JURISDIC. LOSS MULTIPLIER	1.00114	1.00114	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	50,653,979	50,603,232	50,747	0.1%	627,105,981	595,639,042	31,466,939	5.3%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	257,011	257,011	0	0.0%	3,251,178	3,251,178	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	250,004	252,903	(2,899)	-1.1%	3,151,092	3,169,783	(18,691)	-0.6%
6e. Balance of 1999 Revenue Refund true-up adjustment	2,238	0	2,238	0.0%	2,238	0	2,238	0.0%
6f. Gannon O&M offset credit per FPSC decision 11/14/03	(8,416,800)	0	(8,416,800)	0.0%	(8,416,800)	0	(8,416,800)	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	42,489,421	50,856,135	(8,366,714)	-16.5%	621,842,511	598,808,825	23,033,686	3.8%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	4,853,330	(2,241,881)	7,095,211	-316.5%	(22,815,786)	594,162	(23,409,948)	-3940.0%
8. INTEREST PROVISION FOR THE MONTH	(46,853)	(29,611)	(17,242)	58.2%	(490,289)	(368,055)	(122,234)	33.2%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(57,038,681)	(26,428,530)	(30,610,151)	115.8%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	263,802	263,802	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(51,968,402)	(28,436,220)	(23,532,182)	82.8%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(57,038,681)	(26,428,530)	(30,610,151)	115.8%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(51,921,549)	(28,406,609)	(23,514,940)	82.8%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(108,960,230)	(54,835,139)	(54,125,091)	98.7%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(54,480,115)	(27,417,570)	(27,062,545)	98.7%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.000	1.300	(0)	-23.1%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.060	1.300	(0)	-18.5%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	2.060	2.600	(1)	-20.8%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.030	1.300	(0)	-20.8%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.086	0.108	(0)	-20.4%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(46,853)	(29,611)	(17,242)	58.2%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	308,050	477,113	(169,063)	-35.4%	5,680,792	4,936,957	743,835	15.1%
2	LIGHT OIL	286,365	746,423	(460,058)	-61.6%	7,068,479	12,545,131	(5,476,652)	-43.7%
3	COAL	14,252,294	19,737,978	(5,485,684)	-27.8%	269,619,940	292,075,271	(22,455,331)	-7.7%
4	NATURAL GAS	18,464,477	27,710,418	(9,245,941)	-33.4%	183,341,150	178,653,529	4,687,621	2.6%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	33,311,186	48,671,932	(15,360,746)	-31.6%	465,710,361	488,210,888	(22,500,527)	-4.6%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	5,708	10,240	(4,532)	-44.3%	103,238	98,496	4,742	4.8%
9	LIGHT OIL	3,938	11,283	(7,345)	-65.1%	103,103	182,347	(79,244)	-43.5%
10	COAL	669,630	900,809	(231,179)	-25.7%	12,321,871	13,288,335	(966,464)	-7.3%
11	NATURAL GAS	439,113	521,259	(82,146)	-15.8%	3,561,167	3,340,462	220,705	6.6%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,118,389	1,443,591	(325,202)	-22.5%	16,089,379	16,909,640	(820,261)	-4.9%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	8,868	15,363	(6,495)	-42.3%	159,945	148,280	11,665	7.9%
16	LIGHT OIL (BBL)	7,622	19,820	(12,198)	-61.5%	184,718	324,367	(139,649)	-43.1%
17	COAL (TON)	296,662	400,470	(103,808)	-25.9%	5,736,824	6,045,451	(308,627)	-5.1%
18	NATURAL GAS (MCF)	3,186,879	3,785,711	(598,832)	-15.8%	27,084,260	25,022,496	2,061,764	8.2%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	55,635	97,486	(41,851)	-42.9%	1,003,422	942,228	61,194	6.5%
22	LIGHT OIL	43,133	114,698	(71,565)	-62.4%	1,036,758	1,879,675	(842,917)	-44.8%
23	COAL	7,077,081	9,551,576	(2,474,495)	-25.9%	137,018,691	145,093,076	(8,074,385)	-5.6%
24	NATURAL GAS	3,317,540	3,891,740	(574,200)	-14.8%	28,464,067	25,727,213	2,736,854	10.6%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	10,493,389	13,655,500	(3,162,111)	-23.2%	167,522,938	173,642,192	(6,119,254)	-3.5%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.51%	0.71%	(0.00)	-	0.64%	0.58%	0.00	-
29	LIGHT OIL	0.35%	0.78%	(0.00)	-	0.64%	1.08%	(0.00)	-
30	COAL	59.87%	62.40%	(0.03)	-	76.58%	78.58%	(0.02)	-
31	NATURAL GAS	39.26%	36.11%	0.03	-	22.13%	19.75%	0.02	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	34.74	31.06	3.68	11.9%	35.52	33.29	2.22	6.7%
36	LIGHT OIL ($/BBL)	37.57	37.66	(0.09)	-0.2%	38.27	38.68	(0.41)	-1.1%
37	COAL ($/TON)	48.04	49.29	(1.24)	-2.5%	47.00	48.31	(1.32)	-2.7%
38	NATURAL GAS ($/MCF)	5.79	7.32	(1.53)	-20.8%	6.77	7.14	(0.37)	-5.2%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	5.54	4.89	0.64	13.1%	5.66	5.24	0.42	8.0%
42	LIGHT OIL	6.64	6.51	0.13	2.0%	6.82	6.67	0.14	2.2%
43	COAL	2.01	2.07	(0.05)	-2.5%	1.97	2.01	(0.05)	-2.2%
44	NATURAL GAS	5.57	7.12	(1.55)	-21.8%	6.44	6.94	(0.50)	-7.2%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	3.17	3.56	(0.39)	-10.9%	2.78	2.81	(0.03)	-1.1%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,747	9,520	227	2.4%	9,720	9,566	154	1.6%
49	LIGHT OIL	10,953	10,166	787	7.7%	10,056	10,308	(252)	-2.4%
50	COAL	10,569	10,603	(34)	-0.3%	11,120	10,919	201	1.8%
51	NATURAL GAS	7,555	7,466	89	1.2%	7,993	7,702	291	3.8%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	9,383	9,459	(76)	-0.8%	10,412	10,269	143	1.4%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.40	4.66	0.74	15.9%	5.50	5.01	0.49	9.8%
56	LIGHT OIL	7.27	6.62	0.65	9.8%	6.86	6.88	(0.02)	-0.3%
57	COAL	2.13	2.19	(0.06)	-2.7%	2.19	2.20	(0.01)	-0.5%
58	NATURAL GAS	4.20	5.32	(1.12)	-21.1%	5.15	5.35	(0.20)	-3.7%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.98	3.37	(0.39)	-11.6%	2.89	2.89	0.00	0.0%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: DECEMBER 2003

SCHEDULE A4
PAGE 1 OF 1
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(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#2	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#3	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#4	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P.#5	0	0	0.0	0.0	0.0	0	HVY.OIL	0	0	0.0	0	0.00	0.00
H.P. STATION	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	94	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#2	100	0	0.0	100.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#3	155	0	0.0	100.0	0.0	0	COAL	0	0	0.0	609	0.00	0.00
GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	299	0.00	0.00
GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GANNON STATION (1)	**349**	**0**	**0.0**	**100.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**908**	**0.00**	**0.00**
B.B.#1	428	181,978	57.1	61.7	60.4	11,147	COAL	84,997	23,866,540	2,028,586.2	4,258,182	2.34	50.10
B.B.#2	433	120,784	37.5	44.6	55.3	10,772	COAL	54,663	23,802,000	1,301,094.2	2,738,509	2.27	50.10
B.B.#3	438	56,579	17.4	26.4	65.9	10,605	COAL	25,194	23,816,000	600,013.4	1,262,170	2.23	50.10
B.B.#4	460	147,521	43.1	54.4	72.9	10,386	COAL	71,523	21,421,160	1,532,095.6	3,583,161	2.43	50.10
B.B. STATION	**1,759**	**506,862**	**38.7**	**46.8**	**63.8**	**10,776**	**COAL**	**236,377**	**23,106,308**	**5,461,789.4**	**11,842,022**	**2.34**	**50.10**
SEB-PHIL. #1(HVY OIL)	17	2,876	22.7	98.5	86.6	9,747	HVY.OIL	4,468	6,273,540	28,033.4	155,206	5.40	34.74
SEB-PHIL. #2(HVY OIL)	17	2,832	22.4	100.0	82.8	9,747	HVY.OIL	4,400	6,273,540	27,601.7	152,844	5.40	34.74
SEB-PHILLIPS TOTAL	**34**	**5,708**	**22.6**	**99.3**	**84.7**	**9,747**	**HVY.OIL**	**8,868**	**6,273,529**	**55,635.1**	**308,050**	**5.40**	**34.74**
POLK #1 GASIFIER	260	162,768	84.1	90.6	92.7	9,924	COAL	60,285	26,794,180	1,615,291.4	2,409,364	1.48	39.97
POLK #1 CT (OIL)	245	3,024	1.7	97.5	48.2	10,326	LGT.OIL	5,570	5,812,588	31,222.5	210,312	6.95	37.76
POLK #1 TOTAL	**260**	**165,792**	**85.7**	**97.0**	**91.2**	**9,931**	**-**	**-**	**-**	**1,646,513.9**	**2,619,676**	**1.58**	**-**
POLK #2 CT (GAS)	175	9,246	7.1	98.0	63.0	11,035	GAS	98,013	1,041,000	102,032.0	496,816	5.37	5.07
POLK #2 CT (OIL)	180	16	0.0	98.0	13.0	10,770	LGT.OIL	29	5,812,457	168.0	1,091	6.82	37.62
POLK #2 TOTAL	**178**	**9,262**	**7.0**	**98.0**	**62.6**	**11,034**	**-**	**-**	**-**	**102,200.0**	**497,907**	**5.38**	**-**
POLK #3 CT (GAS)	175	5,117	3.9	100.0	63.7	11,486	GAS	56,461	1,041,000	58,775.4	286,855	5.61	5.08
POLK #3 CT (OIL)	180	582	0.4	100.0	53.0	12,509	LGT.OIL	1,252	5,812,585	7,278.8	47,287	8.12	37.77
POLK #3 TOTAL	**178**	**5,699**	**4.3**	**100.0**	**62.4**	**11,590**	**-**	**-**	**-**	**66,054.2**	**334,142**	**5.86**	**-**
POLK STATION TOTAL	**616**	**180,753**	**39.4**	**98.1**	**74.6**	**10,040**	**-**	**-**	**-**	**1,814,768.1**	**3,451,725**	**1.91**	**-**
B.B.C.T.#1	15	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	80	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	70	316	0.6	100.0	67.6	14,124	LGT.OIL	771	5,788,362	4,463.3	27,675	8.76	35.89
C.T. TOTAL	**165**	**316**	**0.3**	**100.0**	**55.7**	**14,124**	**LGT.OIL**	**771**	**5,788,375**	**4,463.3**	**27,675**	**8.76**	**35.89**
CITY OF TAMPA	**6**	**245**	**5.5**	**0.0**	**0.0**	**11,132**	**GAS**	**2,620**	**1,041,000**	**2,727.4**	**26,529**	**10.83**	**10.13**
BAYSIDE ST 1	260	85,993	44.5	71.5	59.4	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT1A	173	59,369	46.1	71.7	74.9	11,079	GAS	631,816	1,041,000	657,720.9	4,759,804	8.02	7.53
BAYSIDE CT1B	173	37,950	29.5	58.0	74.0	11,079	GAS	403,872	1,041,000	420,430.4	3,042,577	8.02	7.53
BAYSIDE CT1C	173	65,878	51.2	80.4	73.4	11,079	GAS	701,094	1,041,000	729,838.8	5,281,709	8.02	7.53
BAYSIDE UNIT 1 TOTAL	**779**	**249,190**	**43.0**	**70.5**	**69.2**	**7,255**	**GAS**	**1,736,782**	**1,041,000**	**1,807,990.1**	**13,084,090**	**5.25**	**7.53**
BAYSIDE ST 2	330	53,647	21.9	0.0	0.0	0		0	0	0.0	0	0.00	0.00
BAYSIDE CT2A	173	24,424	19.0	0.0	0.0	11,063	GAS	259,562	1,041,000	270,204.0	917,436	3.76	3.53
BAYSIDE CT2B	173	28,329	22.0	0.0	0.0	11,063	GAS	301,067	1,041,000	313,410.4	1,064,136	3.76	3.53
BAYSIDE CT2C	173	35,296	27.4	0.0	0.0	11,063	GAS	375,103	1,041,000	390,482.4	1,325,822	3.76	3.53
BAYSIDE CT2D	173	33,618	26.1	0.0	0.0	11,063	GAS	357,271	1,041,000	371,919.3	1,262,793	3.76	3.53
BAYSIDE UNIT 2 TOTAL	**1,022**	**175,315**	**23.1**	**0.0**	**0.0**	**7,678**	**GAS**	**1,293,003**	**1,041,000**	**1,346,016.1**	**4,570,187**	**2.61**	**3.53**
BAYSIDE STATION TOTAL	**1,801**	**424,505**	**31.7**	**70.5**	**69.2**	**7,430**	**GAS**	**3,029,785**	**1,041,000**	**3,154,006.2**	**17,654,277**	**4.16**	**5.83**
TOT. COAL (GN,BB,POLK)	**2,368**	**669,830**	**38.0**	**59.4**	**57.6**	**10,569**	**COAL**	**296,662**	**23,855,727**	**7,077,080.8**	**14,252,294**	**2.13**	**48.04**
SYSTEM	**4,730**	**1,118,389**	**31.8**	**69.7**	**61.9**	**9,383**	**-**	**-**	**-**	**10,493,389.5**	**33,311,186**	**2.98**	**-**

(1) Dollars shown are for October 2003 fuel analysis.

LEGEND:
H.P. = HOOKERS POINT
B.B. = BIG BEND
GAN. = GANNON
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

SCHEDULE A5
PAGE 1 OF 2
REVISED WITH
TRUE UP FILING

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	2,193	15,363	(13,170)	-85.7%	161,473	147,001	14,472	9.8%
3 UNIT COST ($/BBL)	32.38	30.55	1.83	6.0%	33.95	32.23	1.72	5.3%
4 AMOUNT ($)	71,019	469,340	(398,321)	-84.9%	5,481,908	4,737,468	744,440	15.7%
5 BURNED:								
6 UNITS (BBL)	8,866	15,363	(6,495)	-42.3%	159,945	148,280	11,665	7.9%
7 UNIT COST ($/BBL)	34.74	31.06	3.68	11.9%	35.52	33.29	2.22	6.7%
8 AMOUNT ($)	308,050	477,113	(169,063)	-35.4%	5,680,792	4,936,957	743,835	15.1%
9 ENDING INVENTORY:								
10 UNITS (BBL)	12,270	9,463	2,807	29.7%	12,270	9,463	2,807	29.7%
11 UNIT COST ($/BBL)	34.67	30.62	4.05	13.2%	34.67	30.62	4.05	13.2%
12 AMOUNT ($)	425,454	289,779	135,675	46.8%	425,454	289,779	135,675	46.8%
13								
14 DAYS SUPPLY:	34	261	(227)	-87.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	7,527	23,770	(16,243)	-68.3%	276,815	384,022	(107,207)	-27.9%
17 UNIT COST ($/BBL)	43.50	37.29	6.21	16.7%	38.40	39.44	(1.03)	-2.6%
18 AMOUNT ($)	327,447	886,345	(558,898)	-63.1%	10,630,753	15,144,184	(4,513,431)	-29.8%
19 BURNED:								
20 UNITS (BBL)	7,622	19,820	(12,198)	-61.5%	184,718	324,367	(139,649)	-43.1%
21 UNIT COST ($/BBL)	37.57	37.66	(0.09)	-0.2%	38.27	38.68	(0.41)	-1.1%
22 AMOUNT ($)	286,365	746,423	(460,058)	-61.6%	7,068,479	12,545,131	(5,476,652)	-43.7%
23 ENDING INVENTORY:								
24 UNITS (BBL)	76,706	82,746	(6,040)	-7.3%	76,706	82,746	(6,040)	-7.3%
25 UNIT COST ($/BBL)	37.06	37.73	(0.68)	-1.8%	37.06	37.73	(0.68)	-1.8%
26 AMOUNT ($)	2,842,484	3,122,367	(279,883)	-9.0%	2,842,484	3,122,367	(279,883)	-9.0%
27								
28 DAYS SUPPLY: NORMAL	100	41	59	143.9%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	11	12	(1)	-7.3%	-	-	-	-
COAL (3)								
30 PURCHASES:								
31 UNITS (TONS)	445,241	349,300	95,941	27.5%	5,937,741	6,598,073	(660,332)	-10.0%
32 UNIT COST ($/TON)	49.02	49.37	(0.35)	-0.7%	47.48	48.26	(0.78)	-1.6%
33 AMOUNT ($)	21,827,551	17,245,718	4,581,833	26.6%	281,909,128	318,402,907	(36,493,779)	-11.5%
34 BURNED:								
35 UNITS (TONS)	296,662	400,470	(103,808)	-25.9%	5,736,824	6,045,451	(308,627)	-5.1%
36 UNIT COST ($/TON)	48.04	49.29	(1.24)	-2.5%	47.00	48.31	(1.32)	-2.7%
37 AMOUNT ($)	14,252,294	19,737,978	(5,485,684)	-27.8%	269,619,940	292,075,271	(22,455,331)	-7.7%
38 ENDING INVENTORY:								
39 UNITS (TONS)	639,274	990,979	(351,705)	-35.5%	639,274	990,979	(351,705)	-35.5%
40 UNIT COST ($/TON)	48.10	48.71	(0.61)	-1.3%	48.10	48.71	(0.61)	-1.3%
41 AMOUNT ($)	30,747,121	48,269,813	(17,522,692)	-36.3%	30,747,121	48,269,813	(17,522,692)	-36.3%
42								
43 DAYS SUPPLY:	47	21	26	125.7%	-	-	-	-
NATURAL GAS(4)								
44 PURCHASES:								
45 UNITS (MCF)	3,186,879	3,785,711	(598,832)	-15.8%	27,084,260	25,022,496	2,061,764	8.2%
46 UNIT COST ($/MCF)	5.79	7.32	(1.53)	-20.8%	6.77	7.14	(0.37)	-5.2%
47 AMOUNT ($)	18,464,477	27,710,417	(9,245,940)	-33.4%	183,341,150	178,653,527	4,687,623	2.6%
48 BURNED:								
49 UNITS (MCF)	3,186,879	3,785,711	(598,832)	-15.8%	27,084,260	25,022,496	2,061,764	8.2%
50 UNIT COST ($/MCF)	5.79	7.32	(1.53)	-20.8%	6.77	7.14	(0.37)	-5.2%
51 AMOUNT ($)	18,464,477	27,710,418	(9,245,941)	-33.4%	183,341,150	178,653,529	4,687,621	2.6%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	17,078
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	17,078

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(7,769)	(280,135)
OTHER USAGE	(624)	(22,924)
TOTAL	(8,393)	(303,059)

(3) RECONCILIATION - COALS

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	27,261
IGNITION #2 OIL	263,057
IGNITION PROPANE	8,091
AERIAL SURVEY ADJ.	0
ADDITIVES	39,986
GREEN FUEL	0
TOTAL	338,395

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	2,171.0	0.0	2,171.0	1.760	1.760	38,200.00	38,200.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. - MB	58,016.0	0.0	58,016.0	4.829	5.915	2,801,500.00	3,431,500.00	443,200.00
TOTAL			**60,187.0**	**0.0**	**60,187.0**	**4.718**	**5.765**	**2,839,700.00**	**3,469,700.00**	**443,200.00**
ACTUAL:										
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	818.4	0.0	818.4	4.306	4.306	35,243.14	35,243.14	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	992.8	0.0	992.8	4.311	4.311	42,796.37	42,796.37	
FLA. PWR. CORP.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
FLA. PWR. & LIGHT		SCH. - MA	1,225.0	0.0	1,225.0	1.934	2.677	23,696.35	35,238.28	6,837.93
CITY OF LAKELAND		SCH. - MA	180.0	0.0	180.0	1.913	3.898	3,443.10	7,017.03	2,882.73
SEMINOLE ELEC. CO-OP		SCH. - MA	400.0	0.0	400.0	2.072	3.616	8,288.00	14,463.41	4,639.41
THE ENERGY AUTHORITY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
CARGILL ALLIANT		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
NEW SMYRNA BEACH		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
ORLANDO UTILITIES		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
RELIANT ENERGY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
HARDEE PWR. PART. TO CITY OF LAKELAND*		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
AUBURNDALE POWER PARTNERS		SCH. - OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CARGILL ALLIANT		SCH. - OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ADJUSTMENTS										
NONE										
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			1,811.2	0.0	1,811.2	4.309	4.309	78,039.51	78,039.51	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			1,805.0	0.0	1,805.0	1.963	3.142	35,427.45	56,718.72	14,360.07
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL			**3,616.2**	**0.0**	**3,616.2**	**3.138**	**3.727**	**113,466.96**	**134,758.23**	**14,360.07**
CURRENT MONTH:										
DIFFERENCE			(56,570.8)	0.0	(56,570.8)	(1.580)	(2.038)	(2,726,233.04)	(3,334,941.77)	(428,839.93)
DIFFERENCE %			-94.0%	0.0%	-94.0%	-33.5%	-35.4%	-96.0%	-96.1%	-96.8%
PERIOD TO DATE:										
ACTUAL			116,914.7	711.4	116,203.3	3.296	4.332	3,830,595.24	5,033,358.18	866,219.77
ESTIMATED			360,867.9	5.3	360,862.6	4.409	5.670	15,911,001.69	20,461,017.12	3,460,994.33
DIFFERENCE			(243,953.2)	706.1	(244,659.3)	(1.113)	(1.338)	(12,080,406.45)	(15,427,658.94)	(2,594,774.56)
DIFFERENCE %			-67.6%	13322.6%	-67.8%	-25.2%	-23.6%	-75.9%	-75.4%	-75.0%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF DECEMBER 2003.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	79.0	0.0	45.0	34.0	4.412	4.412	1,500.00
HARDEE POWER PARTNERS		IPP	13,859.0	0.0	0.0	13,859.0	7.063	7.063	978,900.00
VARIOUS		OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
VARIOUS		MKT. BASE	112,672.0	0.0	0.0	112,672.0	3.460	3.460	3,898,900.00
TOTAL			**126,610.0**	**0.0**	**45.0**	**126,565.0**	**3.855**	**3.855**	**4,879,300.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	43,733.0	0.0	0.0	43,733.0	8.075	8.075	3,531,293.73
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH. - J	117,353.0	0.0	0.0	117,353.0	4.506	4.506	5,287,886.24
FLA. POWER & LIGHT		SCH. - J	40,638.0	0.0	0.0	40,638.0	4.610	4.610	1,873,495.00
CITY OF LAKELAND		SCH. - J	8,232.0	0.0	0.0	8,232.0	5.554	5.554	457,190.00
ORLANDO UTIL. COMM.		SCH. - J	1,600.0	0.0	0.0	1,600.0	7.469	7.469	119,500.00
CAROLINA POWER & LIGHT		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
THE ENERGY AUTHORITY		SCH. - J	34,378.0	0.0	0.0	34,378.0	4.673	4.673	1,606,359.50
REEDY CREEK		SCH. - J	30.0	0.0	0.0	30.0	4.500	4.500	1,350.00
OKEELANTA		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
TALLAHASSEE		SCH. - J	895.0	0.0	0.0	895.0	4.792	4.792	42,886.10
CALPINE		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL ALLIANT		SCH. - J	86,116.0	0.0	0.0	86,116.0	4.612	4.612	3,971,542.00
CONOCO		SCH. - J	2,028.0	0.0	0.0	2,028.0	4.395	4.395	89,134.00
CORAL POWER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RELIANT		SCH. - J	1,143.0	0.0	0.0	1,143.0	7.357	7.357	84,096.00
SEMINOLE ELEC. CO-OP		SCH. - J	17,087.0	0.0	0.0	17,087.0	4.516	4.516	771,612.00
DUKE ENERGY		SCH. - J	149.0	0.0	0.0	149.0	7.000	7.000	10,430.00
DYNEGY POWER MARKETING		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
RINGHAVER		SCH. - J	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH. - D	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Nov. 2003	IPP	(40,196.0)	0.0	0.0	(40,196.0)	5.111	5.111	(2,054,515.41)
HARDEE PWR. PART.-NATIVE	Nov. 2003	IPP	40,196.0	0.0	0.0	40,196.0	5.088	5.088	2,045,032.06
FLA. POWER CORP.	Apr. 2003	SCH. - D	(52,600.0)	0.0	0.0	(52,600.0)	4.667	4.667	(2,455,030.92)
FLA. POWER CORP.	Apr. 2003	SCH. - D	52,600.0	0.0	0.0	52,600.0	4.613	4.613	2,426,697.35
FLA. POWER CORP.	Feb. 2003	SCH. - D	(45,900.0)	0.0	0.0	(45,900.0)	4.365	4.365	(2,003,412.27)
FLA. POWER CORP.	Feb. 2003	SCH. - D	45,900.0	0.0	0.0	45,900.0	4.308	4.308	1,977,220.26
TOTAL			**353,382.0**	**0.0**	**0.0**	**353,382.0**	**5.032**	**5.032**	**17,782,765.64**
CURRENT MONTH:									
DIFFERENCE			226,772.0	0.0	(45.0)	226,817.0	1.177	1.177	12,903,465.64
DIFFERENCE %			179.1%	0.0%	-100.0%	179.2%	30.5%	30.5%	264.5%
PERIOD TO DATE:									
ACTUAL			3,273,674.0	0.0	59,683.5	3,213,990.5	5.364	5.364	172,409,042.32
ESTIMATED			2,548,679.0	0.0	43,272.2	2,505,406.8	5.126	5.126	128,416,039.59
DIFFERENCE			724,995.0	0.0	16,411.3	708,583.7	0.238	0.238	43,993,002.73
DIFFERENCE %			28.4%	0.0%	37.9%	28.3%	4.6%	4.6%	34.3%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	39,467.0	0.0	0.0	39,467.0	2.623	2.623	1,035,200.00
TOTAL		**39,467.0**	**0.0**	**0.0**	**39,467.0**	**2.623**	**2.623**	**1,035,200.00**
ACTUAL:								
HILLSBOROUGH COUNTY	COGEN.	18,891.0	0.0	0.0	18,891.0	2.379	2.379	449,471.02
McKAY BAY REFUSE	COGEN.	14,434.0	0.0	0.0	14,434.0	2.375	2.375	342,791.43
ORANGE COGENERATION L.P.	COGEN.	5,704.0	0.0	0.0	5,704.0	2.144	2.144	122,321.35
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	163.0	0.0	0.0	163.0	5.406	5.406	8,812.22
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	1,466.0	0.0	0.0	1,466.0	4.822	4.822	70,697.83
IMC-AGRICO-NEW WALES	COGEN.	78.0	0.0	0.0	78.0	4.242	4.242	3,308.47
IMC-AGRICO-S. PIERCE	COGEN.	217.0	0.0	0.0	217.0	4.750	4.750	10,306.46
AUBURNDALE POWER PARTNERS	COGEN.	619.0	0.0	0.0	619.0	3.489	3.489	21,599.76
CUTRALE CITRUS	COGEN.	2.0	0.0	0.0	2.0	3.257	3.257	65.14
SUB-TOTAL FOR DECEMBER 2003		41,574.0	0.0	0.0	41,574.0	2.476	2.476	1,029,373.68
ADJUSTMENTS FOR THE MONTH OF:	**NOVEMBER 2003**							
HILLSBOROUGH COUNTY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL GREEN BAY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MULBERRY	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	(1,154.0)	0.0	0.0	(1,154.0)	4.339	4.339	(50,070.47)
		1,154.0	0.0	0.0	1,154.0	4.338	4.338	50,055.09
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**NOVEMBER 2003**	0.0	0.0	0.0	0.0	0.000	0.000	(15.38)
GRAND TOTAL		**41,574.0**	**0.0**	**0.0**	**41,574.0**	**2.476**	**2.476**	**1,029,358.30**
CURRENT MONTH:								
DIFFERENCE		2,107.0	0.0	0.0	2,107.0	(0.147)	(0.147)	(5,841.70)
DIFFERENCE %		5.3%	0.0%	0.0%	5.3%	-5.6%	-5.6%	-0.6%
PERIOD TO DATE:								
ACTUAL		516,404.0	0.0	0.0	516,404.0	2.484	2.484	12,825,460.97
ESTIMATED		485,248.0	0.0	0.0	485,248.0	2.676	2.676	12,984,665.12
DIFFERENCE		31,156.0	0.0	0.0	31,156.0	(0.192)	(0.192)	(159,204.15)
DIFFERENCE %		6.4%	0.0%	0.0%	6.4%	(0.072)	(0.072)	-1.2%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A6

JANUARY 2003 - DECEMBER 2003

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2003 THROUGH DECEMBER 2003

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS	JURISDIC.	SCH. - D	31,711.9	5.3	31,706.6	2.294	2.294	727,306.51	727,306.51	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	108,974.85	140,485.65	
VARIOUS	JURISDIC.	SCH. - MB	329,156.0	0.0	329,156.0	4.580	5.953	15,074,720.33	19,593,224.96	3,460,994.33
TOTAL			**360,867.9**	**5.3**	**360,862.6**	**4.409**	**5.670**	**15,911,001.69**	**20,461,017.12**	**3,460,994.33**
ACTUAL:										
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. - D	0.0	0.0	0.0	0.000	0.000	121,808.73	139,483.83	
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	17,063.1	711.4	16,351.7	3.337	3.337	545,652.85	545,652.85	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	11,746.6	0.0	11,746.6	2.731	2.731	320,744.15	320,744.15	
AQUILA		SCH. -MA	0.0	0.0	0.0	0.000	0.000	(4,432.94)	(4,432.94)	0.00
CARGILL ALLIANT		SCH. -MA	3,560.0	0.0	3,560.0	4.173	8.749	148,554.80	311,464.70	150,418.29
CARGILL POWER MARKETS LLC		SCH. -MA	1,070.0	0.0	1,070.0	1.844	(0.354)	19,733.87	(3,785.43)	(26,879.10)
CAROLINA POWER & LIGHT		SCH. -MA	63.0	0.0	63.0	1.838	2.980	1,157.68	1,877.31	521.81
CITY OF LAKELAND		SCH. -MA	3,664.0	0.0	3,664.0	2.442	3.984	89,493.07	145,964.37	42,664.04
CONOCO		SCH. -MA	179.0	0.0	179.0	1.969	4.509	3,524.50	8,071.87	3,985.31
DYNEGY POWER MARKETING		SCH. -MA	57.0	0.0	57.0	4.160	4.460	2,371.38	2,542.00	(8.36)
FLA. PWR. & LIGHT		SCH. -MA	17,751.0	0.0	17,751.0	2.285	3.522	405,534.28	625,163.06	155,801.44
FLA. PWR. CORP.		SCH. -MA	5,484.0	0.0	5,484.0	5.324	7.284	291,954.86	399,455.37	89,387.45
NEW SMYRNA BEACH		SCH. -MA	6,545.0	0.0	6,545.0	5.005	7.497	327,552.53	490,685.66	138,000.33
ORLANDO UTIL. COMM.		SCH. -MA	3,015.0	0.0	3,015.0	3.690	4.684	111,244.43	141,225.33	18,403.30
REEDY CREEK		SCH. -MA	160.0	0.0	160.0	4.311	5.148	6,897.98	8,236.32	835.94
RELIANT ENERGY		SCH. -MA	35.0	0.0	35.0	5.073	6.596	1,775.48	2,308.59	398.71
SEMINOLE ELEC. CO-OP		SCH. -MA	4,951.0	0.0	4,951.0	3.372	4.566	166,940.67	226,075.01	41,242.50
SOUTHERN COMPANY		SCH. -MA	850.0	0.0	850.0	2.713	7.697	23,061.50	65,426.36	39,695.86
TALLAHASSEE		SCH. -MA	49.0	0.0	49.0	2.150	2.708	1,053.74	1,327.13	119.53
THE ENERGY AUTHORITY		SCH. -MA	38,705.0	0.0	38,705.0	2.917	3.815	1,128,868.02	1,476,719.82	199,852.60
HARDEE PWR. PART. TO CITY OF LAKELAND*		SCH. -MA	309.0	0.0	309.0	4.189	4.764	12,943.53	14,720.72	1,733.93
HARDEE PWR. PART. TO FLA. PWR. & LIGHT*		SCH. -MA	547.0	0.0	547.0	4.455	5.369	24,369.25	29,369.26	4,923.43
HARDEE PWR. PART. TO FLA. PWR. CORP.*		SCH. -MA	345.0	0.0	345.0	4.596	5.218	15,855.34	18,003.48	2,099.84
HARDEE PWR. PART. TO NEW SMYRNA BEACH*		SCH. -MA	17.0	0.0	17.0	4.259	4.605	724.03	782.84	56.43
HARDEE PWR. PART. TO ORLANDO*		SCH. -MA	50.0	0.0	50.0	4.081	4.303	2,040.50	2,151.67	104.17
HARDEE PWR. PART. TO SEM ELEC. CO-OP*		SCH. -MA	183.0	0.0	183.0	5.938	6.831	10,866.30	12,500.44	1,608.52
HARDEE PWR. PART. TO THE ENERGY AUTH.*		SCH. -MA	470.0	0.0	470.0	4.857	5.138	22,828.22	24,147.82	1,253.80
TEC WHOLESALE MARKETING **		SCH. -OATT	0.0	0.0	0.0	0.000	0.000	19,559.85	19,559.85	
AUBURNDALE POWER PARTNERS		SCH. -OATT	(63.0)	0.0	(63.0)	(4.788)	(4.788)	3,016.30	3,016.30	
CARGILL ALLIANT		SCH. -OATT	69.0	0.0	69.0	7.527	7.527	5,193.53	5,193.53	
SEMINOLE ELEC. CO-OP		SCH. -OATT	40.0	0.0	40.0	(0.733)	(0.733)	(293.19)	(293.19)	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			28,809.7	711.4	28,098.3	3.083	3.083	866,397.00	866,397.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			0.0	0.0	0.0	0.000	0.000	121,808.73	139,483.83	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			88,059.0	0.0	88,059.0	3.197	4.542	2,814,913.02	4,000,000.86	866,219.77
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			46.0	0.0	46.0	59.732	59.732	27,476.49	27,476.49	
TOTAL			**116,914.7**	**711.4**	**116,203.3**	**3.296**	**4.332**	**3,830,595.24**	**5,033,358.18**	**866,219.77**
DIFFERENCE			(243,953.2)	706.1	(244,659.3)	(1.113)	(1.338)	(12,080,406.45)	(15,427,658.94)	(2,594,774.56)
DIFFERENCE %			-67.6%	13322.6%	-67.8%	-25.2%	-23.6%	-75.9%	-75.4%	-75.0%

* SEC 60% PROFIT OR $20,519.97 HAS BEEN EXCLUDED.
**REFUND DUE TO SETTLEMENT OF TEC OPEN ACCESS TRANSMISSION RATE CASE FILED WITH FERC ON 12/16/02.

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A7

JANUARY 2003 - DECEMBER 2003

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2003 THROUGH DECEMBER 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	SCH. - J	205,581.0	0.0	43,272.2	162,308.8	5.485	5.485	8,902,140.84
HARDEE POWER PARTNERS	IPP	501,452.0	0.0	0.0	501,452.0	7.245	7.245	36,331,284.74
VARIOUS	OTHER	548,464.0	0.0	0.0	548,464.0	3.971	3.971	21,778,014.00
VARIOUS	MKT. BASE	1,293,182.0	0.0	0.0	1,293,182.0	4.748	4.748	61,404,600.00
TOTAL		**2,548,679.0**	**0.0**	**43,272.2**	**2,505,406.8**	**5.126**	**5.126**	**128,416,039.58**
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	725,633.0	0.0	0.0	725,633.0	6.564	6.564	47,630,401.42
HARDEE PWR. PART.-OTHERS	IPP	1,831.0	0.0	0.0	1,831.0	4.816	4.816	88,174.71
FLA. POWER CORP.	SCH.-D	252,450.0	0.0	0.0	252,450.0	4.241	4.241	10,705,948.61
AUBURNDALE POWER PARTNERS	SCH.-J	0.0	0.0	19.0	(19.0)	0.000	0.000	0.00
CALPINE	SCH.-J	3,984.0	0.0	540.6	3,443.4	5.459	5.459	187,962.47
CARGILL ALLIANT	SCH.-J	444,922.0	0.0	2,983.8	441,938.2	4.823	4.823	21,314,284.28
CAROLINA POWER & LIGHT	SCH.-J	33,216.0	0.0	1,015.5	32,200.5	5.171	5.171	1,665,168.71
CITY OF LAKELAND	SCH.-J	234,307.0	0.0	8,444.8	225,862.2	5.538	5.538	12,509,149.48
CONOCO	SCH.-J	14,215.0	0.0	152.6	14,062.4	3.553	3.553	499,677.50
CORAL POWER	SCH.-J	0.0	0.0	(273.3)	273.3	0.632	0.632	1,728.00
DUKE ENERGY	SCH.-J	11,773.0	0.0	382.6	11,390.4	6.626	6.626	754,750.44
DYNEGY POWER MARKETING	SCH.-J	6,558.0	0.0	0.0	6,558.0	4.796	4.796	314,496.41
FLA. POWER & LIGHT	SCH.-J	235,396.0	0.0	7,475.9	227,920.1	4.582	4.582	10,444,169.06
FLA. POWER CORP.	SCH.-J	435,512.0	0.0	4,455.7	431,056.3	4.762	4.762	20,527,846.58
OKEELANTA	SCH.-J	65,693.0	0.0	0.0	65,693.0	4.754	4.754	3,122,962.71
ORLANDO UTIL. COMM.	SCH.-J	191,830.0	0.0	9,339.0	182,491.0	6.540	6.540	11,935,582.24
REEDY CREEK	SCH.-J	2,555.0	0.0	0.0	2,555.0	5.030	5.030	128,510.00
RELIANT	SCH.-J	58,848.0	0.0	6,013.1	52,834.9	8.207	8.207	4,336,065.74
RINGHAVER	SCH.-J	6,072.0	0.0	0.0	6,072.0	9.313	9.313	565,459.83
SEMINOLE ELECTRIC CO-OP	SCH.-J	177,761.0	0.0	4,473.2	173,287.8	4.404	4.404	7,631,307.16
TALLAHASSEE	SCH.-J	15,117.0	0.0	171.0	14,946.0	6.176	6.176	923,055.34
THE ENERGY AUTHORITY	SCH.-J	356,001.0	0.0	14,490.0	341,511.0	5.014	5.014	17,122,341.63
TOTAL		**3,273,674.0**	**0.0**	**59,683.5**	**3,213,990.5**	**5.364**	**5.364**	**172,409,042.32**
DIFFERENCE		724,995.0	0.0	16,411.3	708,583.7	0.238	0.238	43,993,002.74
DIFFERENCE %		28.4%	0.0%	37.9%	28.3%	4.7%	4.7%	34.3%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A8

JANUARY 2003 - DECEMBER 2003

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2003 THROUGH DECEMBER 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	485,248.0	0.0	0.0	485,248.0	2.676	2.676	12,984,665.12
TOTAL		**485,248.0**	**0.0**	**0.0**	**485,248.0**	**2.676**	**2.676**	**12,984,665.12**
ACTUAL:								
AUBURNDALE POWER PARTNERS	COGEN.	2,052.0	0.0	0.0	2,052.0	3.557	3.557	72,995.60
CARGILL GREENBAY	COGEN.	11,483.0	0.0	0.0	11,483.0	4.442	4.442	510,090.47
CARGILL MILLPOINT	COGEN.	2,534.0	0.0	0.0	2,534.0	6.739	6.739	170,771.77
CARGILL MULBERRY	COGEN.	22,799.0	0.0	0.0	22,799.0	3.327	3.327	758,453.74
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	10,192.0	0.0	0.0	10,192.0	4.402	4.402	448,623.44
CUTRALE CITRUS	COGEN.	73.0	0.0	0.0	73.0	3.987	3.987	2,910.76
FARMLAND HYDRO LP	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	1,025.00
HILLSBOROUGH COUNTY	COGEN.	198,837.0	0.0	0.0	198,837.0	2.227	2.227	4,427,511.61
IMC-AGRICO-NEW WALES	COGEN.	3,028.0	0.0	0.0	3,028.0	4.094	4.094	123,956.47
IMC-AGRICO-S. PIERCE	COGEN.	32,585.0	0.0	0.0	32,585.0	3.524	3.524	1,148,162.96
McKAY BAY REFUSE	COGEN.	155,035.0	0.0	0.0	155,035.0	2.242	2.242	3,476,169.92
ORANGE COGENERATION L.P.	COGEN.	77,786.0	0.0	0.0	77,786.0	2.166	2.166	1,684,789.23
TOTAL		**516,404.0**	**0.0**	**0.0**	**516,404.0**	**2.484**	**2.484**	**12,825,460.97**
DIFFERENCE		31,156.0	0.0	0.0	31,156.0	(0.192)	(0.192)	(159,204.15)
DIFFERENCE %		6.4%	0.0%	0.0%	6.4%	-7.2%	-7.2%	-1.2%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A9

JANUARY 2003 - DECEMBER 2003

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2003 THROUGH DECEMBER 2003

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

EXHIBIT NO._____
DOCKET NO. 040001-EI
TAMPA ELECTRIC COMPANY
(JDJ-2)
DOCUMENT NO. 1
FILED 08/10/04

TAMPA ELECTRIC COMPANY

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 42
COMPANY/ TECO
WITNESS. J. Denise Jordan (JDJ-2)
DATE: 11-08-04

CALCULATION OF ESTIMATED TRUE-UP
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

SCHEDULE E1-B

		ACTUAL						ESTIMATED						
		Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	TOTAL
A. 1.	Fuel Cost of System Net Generation	50,636,344	37,162,056	36,088,409	40,596,858	47,334,927	59,914,790	64,433,479	67,625,761	62,291,996	57,998,752	48,792,818	49,794,891	622,671,081
2.	Fuel Cost of Power Sold [1]	103,576	152,919	1,627,662	116,824	57,068	135,036	2,081,200	1,236,600	1,742,000	506,900	347,700	872,200	8,979,685
3.	Fuel Cost of Purchased Power	8,493,123	3,883,842	3,831,050	4,864,976	13,591,180	19,326,958	11,419,400	7,243,000	8,480,100	5,768,300	3,741,500	4,114,800	94,758,229
3a.	Demand and Non-Fuel Cost of Purchased Pwr	0	0	0	0	0	0	0	0	0	0	0	0	0
3b.	Payments to Qualifying Facilities	1,103,020	674,075	1,064,077	1,144,555	1,438,689	1,116,748	1,221,200	1,262,500	1,276,600	1,257,200	1,182,400	1,188,700	13,929,764
4.	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
5.	Adjustment to Fuel Cost (Ft. Meade/Wau. Wheeling)	(6,652)	(5,702)	(5,872)	(5,940)	(7,331)	(7,874)	(7,000)	(7,000)	(7,000)	(7,000)	(7,000)	(7,000)	(81,371)
5a.	Adjustment to Fuel Cost	(1,655)	0	0	0	0	0	0	0	0	0	0	0	(1,655)
5b.	Incremental O&M Hedging Costs	0	0	0	0	0	0	13,346	26,404	26,404	26,404	26,404	26,404	145,368
6.	**TOTAL FUEL & NET POWER TRANS.**	**60,120,604**	**41,561,352**	**39,350,002**	**46,483,625**	**62,300,397**	**80,215,586**	**74,999,225**	**74,914,065**	**70,326,100**	**64,536,756**	**53,388,422**	**54,245,595**	**722,441,731**
[1]	Includes Gains													
B. 1.	Jurisdictional MWH Sales	1,485,840	1,328,745	1,342,548	1,303,290	1,486,764	1,753,188	1,776,207	1,763,787	1,808,701	1,665,003	1,454,025	1,445,757	18,613,855
2.	Non-Jurisdictional MWH Sales	31,433	26,332	43,124	49,717	51,938	53,097	50,222	51,127	44,856	47,316	28,975	28,362	506,499
3.	**TOTAL SALES (LINE B1+B2)**	**1,517,273**	**1,355,077**	**1,385,672**	**1,353,007**	**1,538,702**	**1,806,285**	**1,826,429**	**1,814,914**	**1,853,557**	**1,712,319**	**1,483,000**	**1,474,119**	**19,120,354**
4.	**Jurisdictional % of Total Sales**	**0.9792832**	**0.9805679**	**0.9688786**	**0.9632544**	**0.9662456**	**0.9706043**	**0.9725026**	**0.9718295**	**0.9758000**	**0.9723673**	**0.9804619**	**0.9807600**	**-**
C. 1.	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	57,667,262	51,534,769	52,046,259	50,658,272	57,179,102	68,363,735	69,621,872	69,129,227	70,895,955	65,245,024	56,945,999	56,625,230	725,912,706
1a.	Adjustment to Fuel Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
2.	True-up Provision	(7,583,954)	(7,583,954)	(7,583,954)	(7,583,954)	(7,583,954)	(7,583,954)	(7,583,954)	(7,583,954)	(7,583,954)	(7,583,954)	(7,583,954)	(7,583,951)	(91,007,445)
2a.	Incentive Provision	208,002	208,002	208,002	208,002	208,002	208,002	208,002	208,002	208,002	208,002	208,002	207,999	2,496,021
2b.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	**FUEL REVENUE APPLICABLE TO PERIOD**	**50,291,310**	**44,158,817**	**44,670,307**	**43,282,320**	**49,803,150**	**60,987,783**	**62,245,920**	**61,753,275**	**63,520,003**	**57,869,072**	**49,570,047**	**49,249,278**	**637,401,282**
4.	Total Fuel and Net Power Transactions (Line A6)	60,120,604	41,561,352	39,350,002	46,483,625	62,300,397	80,215,586	74,999,225	74,914,065	70,326,100	64,536,756	53,388,422	54,245,595	722,441,731
5.	Jurisd. Total Fuel and Net Power Transactions (Line A6*Line B4)	58,875,097	40,753,729	38,125,375	44,775,556	60,197,485	77,857,592	72,936,942	72,803,699	68,624,209	62,753,432	52,345,314	53,201,910	703,250,340
5a.	Jurisdictional Loss Multiplier	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	-
5b.	Jurisdictional Sales Adjusted for Line Losses	58,942,215	40,800,188	38,168,838	44,826,600	60,266,110	77,946,350	73,020,090	72,886,695	68,702,441	62,824,971	52,404,988	53,262,560	704,052,046
5c.	Peabody Coal Contract Buyout Amortization	254,480	251,949	249,418	246,887	244,356	241,825	239,294	236,764	234,233	231,702	229,171	226,607	2,886,686
5d.	Peabody Jurisdictionalized (Line 5c*Line B4)	249,208	247,053	241,656	237,815	236,108	234,716	232,714	230,094	228,565	225,299	224,693	222,247	2,810,168
6.	**JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS INCLUDING PEABODY**	**59,191,423**	**41,047,241**	**38,410,494**	**45,064,415**	**60,502,218**	**78,181,066**	**73,252,804**	**73,116,789**	**68,931,006**	**63,050,270**	**52,629,681**	**53,484,807**	**706,862,214**
7.	Over/(Under) Recovery	(8,900,113)	3,111,576	6,259,813	(1,782,095)	(10,699,068)	(17,193,283)	(11,006,884)	(11,363,514)	(5,411,003)	(5,181,198)	(3,059,634)	(4,235,529)	(69,460,932)
8.	Interest Provision	(45,785)	(40,305)	(29,318)	(21,806)	(21,189)	(30,711)	(52,220)	(68,841)	(70,297)	(66,594)	(60,921)	(54,449)	(562,436)
9.	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD**													**(70,023,368)**

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FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

SCHEDULE E2

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	TOTAL
		ACTUAL						ESTIMATED						
		Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	PERIOD
1.	Fuel Cost of System Net Generation	50,636,344	37,162,056	36,088,409	40,596,858	47,334,927	59,914,790	64,433,479	67,625,761	62,291,996	57,998,752	48,792,818	49,794,891	622,671,081
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold (1)	103,576	152,919	1,627,662	116,824	57,068	135,036	2,081,200	1,236,600	1,742,000	506,900	347,700	872,200	8,979,685
4.	Fuel Cost of Purchased Power	8,493,123	3,883,842	3,831,050	4,864,976	13,591,180	19,326,958	11,419,400	7,243,000	8,480,100	5,768,300	3,741,500	4,114,800	94,758,229
5.	Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	Payments to Qualifying Facilities	1,103,020	674,075	1,064,077	1,144,555	1,438,689	1,116,748	1,221,200	1,262,500	1,276,600	1,257,200	1,182,400	1,188,700	13,929,764
7.	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Adjustment to Fuel Cost (Ft. Meade/Wau. Wheeling)	(6,652)	(5,702)	(5,872)	(5,940)	(7,331)	(7,874)	(7,000)	(7,000)	(7,000)	(7,000)	(7,000)	(7,000)	(81,371)
8a.	Adjustment to Fuel Cost	(1,655)	0	0	0	0	0	0	0	0	0	0	0	(1,655)
8b.	Incremental O&M Hedging Costs	0	0	0	0	0	0	13,346	26,404	26,404	26,404	26,404	26,404	145,368
9.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**60,120,604**	**41,561,352**	**39,350,002**	**46,483,625**	**62,300,397**	**80,215,586**	**74,999,225**	**74,914,065**	**70,326,100**	**64,536,756**	**53,388,422**	**54,245,595**	**722,441,731**
10.	Jurisdictional MWH Sold	1,485,840	1,328,745	1,342,548	1,303,290	1,486,764	1,753,188	1,776,207	1,763,787	1,808,701	1,665,003	1,454,025	1,445,757	18,613,855
11.	Jurisdictional % of Total Sales	0.9792832	0.9805679	0.9688786	0.9632544	0.9662456	0.9706043	0.9725026	0.9718295	0.9758000	0.9723673	0.9804619	0.9807600	-
12.	Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	58,875,097	40,753,729	38,125,375	44,775,556	60,197,485	77,857,592	72,936,942	72,603,699	68,624,209	62,753,432	52,345,314	53,201,910	703,250,340
13.	Jurisdictional Loss Multiplier	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	-
14.	Jurisdictional Sales Adjusted for Line Losses (Line 12 * Line 13)	58,942,215	40,800,188	38,168,838	44,826,600	60,266,110	77,946,350	73,020,090	72,666,695	68,702,441	62,824,971	52,404,988	53,262,560	704,052,046
15.	Peabody Coal Contract Buyout Amortization	254,480	251,949	249,418	246,887	244,356	241,825	239,294	236,764	234,233	231,702	229,171	226,607	2,886,686
16.	Peabody Jurisdictionalized (Line 15 * Line 11)	249,208	247,053	241,656	237,815	236,108	234,716	232,714	230,094	228,565	225,299	224,693	222,247	2,810,168
17.	**JURISD. TOTAL FUEL & NET PWR. TRANS. INCL. PEABODY (LINE 14+16)**	**59,191,423**	**41,047,241**	**38,410,494**	**45,064,415**	**60,502,218**	**78,181,066**	**73,252,804**	**73,116,789**	**68,931,006**	**63,050,270**	**52,629,681**	**53,484,807**	**706,862,214**
18.	Cost Per kWh Sold (Cents/kWh)	3.9837	3.0892	2.8610	3.4577	4.0694	4.4594	4.1241	4.1454	3.8111	3.7868	3.6196	3.6994	3.7975
19.	True-up (Cents/kWh) (2)	0.5104	0.5708	0.5649	0.5619	0.5101	0.4326	0.4270	0.4300	0.4193	0.4555	0.5216	0.5246	0.4957
20.	Total (Cents/kWh) (Line 18+19)	4.4941	3.6600	3.4259	4.0396	4.5795	4.8920	4.5511	4.5754	4.2304	4.2423	4.1412	4.2240	4.2932
21.	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
22.	Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	4.4973	3.6626	3.4284	4.0425	4.5828	4.8955	4.5544	4.5787	4.2334	4.2454	4.1442	4.2270	4.2963
23.	GPIF Adjusted for Taxes (Cents/kWh) (2)	(0.0140)	(0.0157)	(0.0155)	(0.0160)	(0.0140)	(0.0119)	(0.0117)	(0.0118)	(0.0115)	(0.0125)	(0.0143)	(0.0144)	(0.0136)
24.	**TOTAL RECOVERY FACTOR (LINE 22+23)**	**4.4833**	**3.6469**	**3.4129**	**4.0265**	**4.5688**	**4.8836**	**4.5427**	**4.5669**	**4.2219**	**4.2329**	**4.1299**	**4.2126**	**4.2827**
25.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**4.483**	**3.647**	**3.413**	**4.027**	**4.569**	**4.884**	**4.543**	**4.567**	**4.222**	**4.233**	**4.130**	**4.213**	**4.283**

(1) Includes Gains
(2) Based on Jurisdictional Sales Only

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2004 THROUGH JUNE 2004

	ACTUAL					
	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	314,212	309,160	272,640	95,971	321,327	414,955
2. LIGHT OIL	795,113	316,709	509,573	587,321	237,112	993,778
3. COAL	17,340,304	15,115,870	20,477,390	18,598,631	20,024,083	21,845,401
4. NATURAL GAS	32,186,715	21,420,317	14,828,806	21,314,935	26,752,405	36,660,656
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**50,636,344**	**37,162,056**	**36,088,409**	**40,596,858**	**47,334,927**	**59,914,790**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	6,254	5,872	5,110	1,657	6,113	7,918
9. LIGHT OIL	11,788	4,876	7,858	9,416	3,485	14,415
10. COAL	821,494	737,502	986,611	881,922	947,000	939,027
11. NATURAL GAS	494,999	506,849	382,942	430,856	535,542	613,029
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,334,535**	**1,255,099**	**1,382,521**	**1,323,851**	**1,492,140**	**1,574,389**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	9,426	9,301	8,039	2,800	9,640	12,294
16. LIGHT OIL (BBL)	20,066	7,947	12,470	14,213	5,622	22,943
17. COAL (TON)	363,000	336,182	436,231	391,496	418,868	435,181
18. NATURAL GAS (MCF)	3,489,529	3,645,755	2,727,385	3,140,728	3,900,343	4,521,648
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	59,131	58,347	50,433	17,567	60,475	77,128
22. LIGHT OIL	115,704	46,040	72,419	81,741	31,679	132,202
23. COAL	8,571,351	7,882,191	10,243,531	9,380,231	9,908,131	10,147,127
24. NATURAL GAS	3,632,600	3,769,711	2,836,531	3,260,076	4,045,046	4,693,471
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**12,378,786**	**11,756,289**	**13,202,914**	**12,739,615**	**14,045,331**	**15,049,928**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.47	0.47	0.37	0.13	0.41	0.50
29. LIGHT OIL	0.88	0.39	0.57	0.71	0.23	0.92
30. COAL	61.56	58.76	71.36	66.61	63.47	59.64
31. NATURAL GAS	37.09	40.38	27.70	32.55	35.89	38.94
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	33.33	33.24	33.91	34.28	33.33	33.75
36. LIGHT OIL ($/BBL)	39.62	39.85	40.86	41.32	42.18	43.32
37. COAL ($/TON)	47.77	44.96	46.94	47.51	47.81	50.20
38. NATURAL GAS ($/MCF)	9.22	5.88	5.44	6.79	6.86	8.11
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	5.31	5.30	5.41	5.46	5.31	5.38
42. LIGHT OIL	6.87	6.88	7.04	7.19	7.48	7.52
43. COAL	2.02	1.92	2.00	1.98	2.02	2.15
44. NATURAL GAS	8.86	5.68	5.23	6.54	6.61	7.81
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**4.09**	**3.16**	**2.73**	**3.19**	**3.37**	**3.98**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	9,455	9,936	9,869	10,602	9,893	9,741
49. LIGHT OIL	9,815	9,442	9,216	8,681	9,090	9,171
50. COAL	10,434	10,688	10,383	10,636	10,463	10,806
51. NATURAL GAS	7,339	7,438	7,407	7,567	7,553	7,656
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,276**	**9,367**	**9,550**	**9,623**	**9,413**	**9,559**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	5.02	5.26	5.34	5.79	5.26	5.24
56. LIGHT OIL	6.75	6.50	6.48	6.24	6.80	6.89
57. COAL	2.11	2.05	2.08	2.11	2.11	2.33
58. NATURAL GAS	6.50	4.23	3.87	4.95	5.00	5.98
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.79**	**2.96**	**2.61**	**3.07**	**3.17**	**3.81**

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2004 THROUGH DECEMBER 2004

	ESTIMATED						
	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)							
1. HEAVY OIL	74,999	168,861	100,849	29,384	3,997	205	2,106,560
2. LIGHT OIL	900,818	1,450,757	758,740	655,436	665,955	691,361	8,562,673
3. COAL	21,188,751	23,286,879	20,648,049	21,009,766	19,246,762	22,728,980	241,510,866
4. NATURAL GAS	42,268,911	42,719,264	40,784,358	36,304,166	28,876,104	26,374,345	370,490,982
5. NUCLEAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL ($)	**64,433,479**	**67,625,761**	**62,291,996**	**57,998,752**	**48,792,818**	**49,794,891**	**622,671,081**
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	1,300	2,689	1,550	442	54	3	38,962
9. LIGHT OIL	10,255	15,183	8,749	8,062	6,168	8,369	110,644
10. COAL	951,419	1,005,400	892,521	875,716	792,781	960,687	10,792,080
11. NATURAL GAS	796,505	785,060	758,572	683,707	531,629	466,466	6,986,158
12. NUCLEAR	0	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	**1,759,479**	**1,808,332**	**1,661,392**	**1,567,927**	**1,332,632**	**1,435,547**	**17,927,844**
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	2,022	4,183	2,412	687	84	5	60,893
16. LIGHT OIL (BBL)	20,174	31,894	16,722	14,404	14,503	14,910	195,868
17. COAL (TON)	426,730	454,849	398,435	397,487	359,408	427,518	4,845,385
18. NATURAL GAS (MCF)	5,838,828	5,848,553	5,540,068	4,947,462	3,827,308	3,366,306	50,793,913
19. NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)							
21. HEAVY OIL	12,694	26,261	15,143	4,311	530	31	382,051
22. LIGHT OIL	148,416	213,541	128,012	101,752	110,086	119,348	1,300,940
23. COAL	10,177,480	10,759,480	9,492,610	9,219,751	8,347,860	10,122,760	114,252,503
24. NATURAL GAS	6,002,291	6,012,238	5,695,162	5,086,032	3,934,463	3,460,407	52,428,028
25. NUCLEAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	**16,340,881**	**17,011,520**	**15,330,927**	**14,411,846**	**12,392,939**	**13,702,546**	**168,363,522**
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.07	0.15	0.09	0.03	0.00	0.00	0.22
29. LIGHT OIL	0.58	0.84	0.53	0.51	0.51	0.58	0.62
30. COAL	54.08	55.60	53.72	55.85	59.50	66.93	60.19
31. NATURAL GAS	45.27	43.41	45.66	43.61	39.89	32.49	38.97
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT							
35. HEAVY OIL ($/BBL)	37.09	40.37	41.81	42.77	47.58	41.00	34.59
36. LIGHT OIL ($/BBL)	44.65	45.49	45.37	45.50	45.92	46.37	43.72
37. COAL ($/TON)	49.65	51.20	51.82	52.86	53.55	53.16	49.84
38. NATURAL GAS ($/MCF)	7.24	7.30	7.36	7.34	7.54	7.83	7.29
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)							
41. HEAVY OIL	5.91	6.43	6.66	6.82	7.54	6.61	5.51
42. LIGHT OIL	6.07	6.79	5.93	6.44	6.05	5.79	6.58
43. COAL	2.08	2.16	2.18	2.28	2.31	2.25	2.11
44. NATURAL GAS	7.04	7.11	7.16	7.14	7.34	7.62	7.07
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**3.94**	**3.98**	**4.06**	**4.02**	**3.94**	**3.63**	**3.70**
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	9,765	9,766	9,770	9,753	9,815	10,333	9,806
49. LIGHT OIL	14,473	14,064	14,632	12,621	13,478	14,227	11,758
50. COAL	10,697	10,702	10,636	10,528	10,530	10,537	10,587
51. NATURAL GAS	7,536	7,658	7,508	7,439	7,401	7,418	7,505
52. NUCLEAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,287**	**9,407**	**9,228**	**9,192**	**9,300**	**9,545**	**9,391**
GENERATED FUEL COST PER KWH (CENTS/KWH)							
55. HEAVY OIL	5.77	6.28	6.51	6.65	7.40	6.83	5.41
56. LIGHT OIL	8.78	9.56	8.67	8.13	8.15	8.24	7.74
57. COAL	2.23	2.32	2.31	2.40	2.43	2.37	2.24
58. NATURAL GAS	5.31	5.44	5.38	5.31	5.43	5.65	5.30
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.66**	**3.74**	**3.75**	**3.70**	**3.66**	**3.47**	**3.47**

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2004 THROUGH JUNE 2004

	ACTUAL					
	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	9,994	11,483	10,570	0	0	18,788
3. UNIT COST ($/BBL)	26.62	30.41	33.23	0.00	0.00	33.33
4. AMOUNT ($)	266,045	349,192	351,243	(4,336)	0	626,216
5. BURNED:						
6. UNITS (BBL)	9,426	9,301	8,039	2,800	9,640	12,294
7. UNIT COST ($/BBL)	33.33	33.24	33.91	34.28	33.33	33.75
8. AMOUNT ($)	314,212	309,160	272,640	95,971	321,327	414,955
9. ENDING INVENTORY:						
10. UNITS (BBL)	12,838	15,020	17,551	14,751	5,111	11,605
11. UNIT COST ($/BBL)	31.23	30.58	31.70	31.43	31.20	33.90
12. AMOUNT ($)	400,888	459,339	556,312	463,575	159,480	393,465
13. DAYS SUPPLY:	52	112	83	47	13	30
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	17,265	8,615	17,835	17,685	18,701	45,748
16. UNIT COST ($/BBL)	44.70	41.01	42.33	40.07	44.11	45.47
17. AMOUNT ($)	771,670	353,339	754,988	708,562	824,930	2,080,387
18. BURNED:						
19. UNITS (BBL)	20,066	7,947	12,470	14,213	5,622	22,943
20. UNIT COST ($/BBL)	39.62	39.85	40.86	41.32	42.18	43.32
21. AMOUNT ($)	795,113	316,709	509,573	587,321	237,112	993,778
22. ENDING INVENTORY:						
23. UNITS (BBL)	69,964	65,680	65,594	64,258	70,768	85,068
24. UNIT COST ($/BBL)	38.22	38.53	39.24	39.22	40.41	42.26
25. AMOUNT ($)	2,674,146	2,530,404	2,573,770	2,520,497	2,859,688	3,595,165
26. DAYS SUPPLY: NORMAL	102	85	90	73	78	94
27. DAYS SUPPLY: EMERGENCY	10	9	9	9	10	12
COAL						
28. PURCHASES:						
29. UNITS (TONS)	324,270	301,366	422,302	361,268	397,798	520,021
30. UNIT COST ($/TON)	46.76	46.35	46.12	47.50	46.82	50.79
31. AMOUNT ($)	15,162,290	13,969,636	19,477,195	17,160,745	18,623,340	26,414,237
32. BURNED:						
33. UNITS (TONS)	363,000	336,182	436,231	391,496	418,868	435,181
34. UNIT COST ($/TON)	47.77	44.96	46.94	47.51	47.81	50.20
35. AMOUNT ($)	17,340,304	15,115,870	20,477,390	18,598,631	20,024,083	21,845,401
36. ENDING INVENTORY:						
37. UNITS (TONS)	600,544	565,728	551,799	521,571	500,501	585,341
38. UNIT COST ($/TON)	47.78	48.02	47.19	47.66	47.52	49.18
39. AMOUNT ($)	28,694,674	27,167,176	26,041,757	24,855,793	23,781,374	28,785,703
40. DAYS SUPPLY:	47	41	40	37	35	41
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	3,489,529	3,645,755	2,727,385	3,140,728	3,900,343	4,521,648
43. UNIT COST ($/MCF)	9.22	5.88	5.44	6.79	6.86	8.11
44. AMOUNT ($)	32,186,715	21,420,317	14,828,806	21,314,935	26,752,405	36,660,656
45. BURNED:						
46. UNITS (MCF)	3,489,529	3,645,755	2,727,385	3,140,728	3,900,343	4,521,648
47. UNIT COST ($/MCF)	9.22	5.88	5.44	6.79	6.86	8.11
48. AMOUNT ($)	32,186,715	21,420,317	14,828,806	21,314,935	26,752,405	36,660,656
49. ENDING INVENTORY:						
50. UNITS (MCF)	0	0	0	0	0	0
51. UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
52. AMOUNT ($)	0	0	0	0	0	0
53. DAYS SUPPLY:	0	0	0	0	0	0
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2004 THROUGH DECEMBER 2004

	ESTIMATED						
	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	TOTAL
HEAVY OIL							
1. PURCHASES:							
2. UNITS (BBL)	2,022	4,183	2,412	687	84	5	60,228
3. UNIT COST ($/BBL)	47.28	47.57	48.06	48.52	48.69	49.20	33.81
4. AMOUNT ($)	95,592	198,971	115,927	33,332	4,090	246	2,036,518
5. BURNED:							
6. UNITS (BBL)	2,022	4,183	2,412	687	84	5	60,893
7. UNIT COST ($/BBL)	37.09	40.37	41.81	42.77	47.58	41.00	34.59
8. AMOUNT ($)	74,999	168,861	100,849	29,384	3,997	205	2,106,560
9. ENDING INVENTORY:							
10. UNITS (BBL)	11,605	11,605	11,605	11,605	11,605	11,605	11,605
11. UNIT COST ($/BBL)	35.89	38.98	40.55	40.99	41.05	41.05	41.05
12. AMOUNT ($)	416,491	452,398	470,530	475,702	476,344	476,385	476,385
13. DAYS SUPPLY:	147	335	1,361	1,308	1,231	852	-
LIGHT OIL							
14. PURCHASES:							
15. UNITS (BBL)	25,551	36,759	22,112	17,634	18,966	20,617	267,488
16. UNIT COST ($/BBL)	46.26	46.43	47.03	47.38	47.59	48.16	45.43
17. AMOUNT ($)	1,181,951	1,706,671	1,039,891	835,449	902,500	992,883	12,153,221
18. BURNED:							
19. UNITS (BBL)	20,174	31,694	16,722	14,404	14,503	14,910	195,868
20. UNIT COST ($/BBL)	44.65	45.49	45.37	45.50	45.92	46.37	43.72
21. AMOUNT ($)	900,818	1,450,757	758,740	655,436	665,955	691,361	8,562,673
22. ENDING INVENTORY:							
23. UNITS (BBL)	85,068	85,068	85,068	85,068	85,068	85,068	85,068
24. UNIT COST ($/BBL)	42.93	43.51	44.09	44.56	45.03	45.58	45.58
25. AMOUNT ($)	3,652,033	3,701,624	3,750,692	3,790,426	3,830,706	3,877,512	3,877,512
26. DAYS SUPPLY: NORMAL	102	133	135	125	124	122	-
27. DAYS SUPPLY: EMERGENCY	12	12	12	12	12	12	
COAL							
28. PURCHASES:							
29. UNITS (TONS)	564,800	429,000	414,000	444,000	424,000	364,000	4,966,825
30. UNIT COST ($/TON)	49.16	52.42	52.72	53.06	52.98	53.19	49.99
31. AMOUNT ($)	27,765,982	22,486,475	21,827,696	23,557,544	22,465,088	19,361,739	248,271,967
32. BURNED:							
33. UNITS (TONS)	426,730	454,849	398,435	397,487	359,408	427,518	4,845,385
34. UNIT COST ($/TON)	49.65	51.20	51.82	52.86	53.55	53.16	49.84
35. AMOUNT ($)	21,188,751	23,286,879	20,648,049	21,009,766	19,246,762	22,728,980	241,510,866
36. ENDING INVENTORY:							
37. UNITS (TONS)	723,411	697,562	713,127	759,640	824,232	760,714	760,714
38. UNIT COST ($/TON)	49.30	50.38	51.37	51.87	52.04	52.40	52.40
39. AMOUNT ($)	35,664,336	35,143,344	36,631,708	39,401,863	42,895,797	39,862,146	39,862,146
40. DAYS SUPPLY:	53	56	55	58	62	58	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	5,838,828	5,848,553	5,540,068	4,947,462	3,827,308	3,366,306	50,793,913
43. UNIT COST ($/MCF)	7.24	7.30	7.36	7.34	7.54	7.83	7.29
44. AMOUNT ($)	42,268,912	42,719,264	40,784,358	36,304,166	28,876,103	26,374,346	370,490,983
45. BURNED:							
46. UNITS (MCF)	5,838,828	5,848,553	5,540,068	4,947,462	3,827,308	3,366,306	50,793,913
47. UNIT COST ($/MCF)	7.24	7.30	7.36	7.34	7.54	7.83	7.29
48. AMOUNT ($)	42,268,911	42,719,264	40,784,358	36,304,166	28,876,104	26,374,345	370,490,982
49. ENDING INVENTORY:							
50. UNITS (MCF)	0	0	0	0	0	0	0
51. UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52. AMOUNT ($)	0	0	0	0	0	0	0
53. DAYS SUPPLY:	0	0	0	0	0	0	-
NUCLEAR							
54. BURNED:							
55. UNITS (MMBTU)	0	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0	0
OTHER							
58. PURCHASES:							
59. UNITS (MMBTU)	0	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0	0
62. BURNED:							
63. UNITS (MMBTU)	0	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0	0
66. ENDING INVENTORY:							
67. UNITS (MMBTU)	0	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0	

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

POWER SOLD
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2004 THROUGH JUNE 2004

(1)	(2)		(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
					MWH		CENTS/KWH				
			TYPE	TOTAL	WHEELED		(A)	(B)	TOTAL $		GAINS ON
			&	MWH	FROM	MWH FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL	MARKET
MONTH	SOLD TO		SCHEDULE	SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	COST	BASED SALES
ACTUAL Jan-04											
	VARIOUS	JURISD.	SCH. -D	1,400.0	0.0	1,400.0	3.316	3.316	46,430.74	46,430.74	
	VARIOUS	JURISD.	MKT. BASE	1,074.0	0.0	1,074.0	4.006	5.705	43,022.20	61,268.98	14,122.62
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			2,474.0	0.0	2,474.0	3.616	4.353	89,452.94	107,699.72	14,122.62
ACTUAL Feb-04											
	VARIOUS	JURISD.	SCH. -D	1,375.9	0.0	1,375.9	3.461	3.461	47,622.16	47,622.16	
	VARIOUS	JURISD.	MKT. BASE	2,429.0	0.0	2,429.0	3.228	4.719	78,408.31	114,623.84	26,888.17
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			3,804.9	0.0	3,804.9	3.312	4.264	126,030.47	162,246.00	26,888.17
ACTUAL Mar-04											
	VARIOUS	JURISD.	SCH. -D	2,116.8	0.0	2,116.8	3.195	3.195	67,628.22	67,628.22	
	VARIOUS	JURISD.	MKT. BASE	39,448.0	0.0	39,448.0	3.292	4.338	1,298,512.60	1,711,321.88	261,328.96
	VARIOUS	JURISD.	SCH. -OATT	4.0	0.0	4.0	4.810	4.810	192.40	192.40	
	TOTAL			41,568.8	0.0	41,568.8	3.287	4.280	1,366,333.22	1,779,142.50	261,328.96
ACTUAL Apr-04											
	VARIOUS	JURISD.	SCH. -D	1,916.8	0.0	1,916.8	3.120	3.120	59,796.65	59,796.65	
	VARIOUS	JURISD.	MKT. BASE	2,024.0	0.0	2,024.0	3.479	4.498	70,413.99	91,042.18	12,856.03
	VARIOUS	JURISD.	SCH. -OATT	(1,421.0)	0.0	(1,421.0)	1.847	1.847	(26,242.33)	(26,242.33)	
	TOTAL			2,519.8	0.0	2,519.8	4.126	4.945	103,968.31	124,596.50	12,856.03
ACTUAL May-04											
	VARIOUS	JURISD.	SCH. -D	1,843.7	0.5	1,843.2	4.112	4.112	75,788.53	75,788.53	
	VARIOUS	JURISD.	MKT. BASE	222.0	0.0	222.0	5.100	6.903	11,322.90	15,325.61	3,150.23
	VARIOUS	JURISD.	SCH. -OATT	(1,473.0)	0.0	(1,473.0)	2.253	2.253	(33,193.72)	(33,193.72)	
	TOTAL			592.7	0.5	592.2	9.105	9.781	53,917.71	57,920.42	3,150.23
ACTUAL Jun-04											
	VARIOUS	JURISD.	SCH. -D	2,216.7	4.2	2,212.5	3.864	3.864	85,486.90	85,486.90	
	VARIOUS	JURISD.	MKT. BASE	968.0	0.0	968.0	4.380	5.536	42,394.01	53,592.45	8,073.32
	VARIOUS	JURISD.	SCH. -OATT	(517.0)	0.0	(517.0)	0.178	0.178	(918.28)	(918.28)	
	TOTAL			2,667.7	4.2	2,663.5	4.767	5.187	126,962.63	138,161.07	8,073.32

POWER SOLD
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2004 THROUGH DECEMBER 2004

(1)	(2)		(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
					MWH		CENTS/KWH				
			TYPE	TOTAL	WHEELED	MWH	(A)	(B)	TOTAL $		GAINS ON
			&	MWH	FROM	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL	MARKET
MONTH	SOLD TO		SCHEDULE	SOLD	OTHER SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	COST	BASED SALES
ESTIMATED											
Jul-04											
	VARIOUS	JURISD.	SCH. -D	1,785.0	0.0	1,785.0	2.728	2.728	48,700.00	48,700.00	
	VARIOUS	JURISD.	MKT. BASE	27,271.0	0.0	27,271.0	4.309	7.782	1,175,000.00	2,122,200.00	857,500.00
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			29,056.0	0.0	29,056.0	4.212	7.471	1,223,700.00	2,170,900.00	857,500.00
ESTIMATED											
Aug-04											
	VARIOUS	JURISD.	SCH. -D	1,785.0	0.0	1,785.0	2.728	2.728	48,700.00	48,700.00	
	VARIOUS	JURISD.	MKT. BASE	14,059.0	0.0	14,059.0	5.280	8.779	742,300.00	1,234,200.00	445,600.00
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			15,844.0	0.0	15,844.0	4.992	8.097	791,000.00	1,282,900.00	445,600.00
ESTIMATED											
Sep-04											
	VARIOUS	JURISD.	SCH. -D	1,584.0	0.0	1,584.0	2.443	2.443	38,700.00	38,700.00	
	VARIOUS	JURISD.	MKT. BASE	23,353.0	0.0	23,353.0	4.155	7.623	970,400.00	1,780,100.00	732,900.00
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			24,937.0	0.0	24,937.0	4.047	7.294	1,009,100.00	1,818,800.00	732,900.00
ESTIMATED											
Oct-04											
	VARIOUS	JURISD.	SCH. -D	1,636.0	0.0	1,636.0	2.524	2.524	41,300.00	41,300.00	
	VARIOUS	JURISD.	MKT. BASE	6,731.0	0.0	6,731.0	4.301	7.246	289,500.00	487,700.00	176,100.00
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			8,367.0	0.0	8,367.0	3.954	6.322	330,800.00	529,000.00	176,100.00
ESTIMATED											
Nov-04											
	VARIOUS	JURISD.	SCH. -D	1,296.0	0.0	1,296.0	1.875	1.875	24,300.00	24,300.00	
	VARIOUS	JURISD.	MKT. BASE	4,081.0	0.0	4,081.0	4.935	8.253	201,400.00	336,800.00	122,000.00
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			5,377.0	0.0	5,377.0	4.198	6.716	225,700.00	361,100.00	122,000.00
ESTIMATED											
Dec-04											
	VARIOUS	JURISD.	SCH. -D	1,339.0	0.0	1,339.0	1.972	1.972	26,400.00	26,400.00	
	VARIOUS	JURISD.	MKT. BASE	15,939.0	0.0	15,939.0	3.096	5.635	493,500.00	898,200.00	352,300.00
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			17,278.0	0.0	17,278.0	3.009	5.351	519,900.00	924,600.00	352,300.00
Jan-04											
THRU	VARIOUS	JURISD.	SCH. -D	20,294.9	4.7	20,290.2	3.011	3.011	610,853.20	610,853.20	
Dec-04	VARIOUS	JURISD.	MKT. BASE	137,599.0	0.0	137,599.0	3.936	6.473	5,416,174.01	8,906,374.94	3,012,819.33
	VARIOUS	JURISD.	SCH. -OATT	-3,407.0	0.0	-3,407.0	1.766	1.766	(60,161.93)	(60,161.93)	
	TOTAL			154,486.9	4.7	154,482.2	3.862	6.122	5,966,865.28	9,457,066.21	3,012,819.33

PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2004 THROUGH JUNE 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ACTUAL Jan-04									
	VARIOUS	SCH. J	150,367.0	0.0	0.0	150,367.0	4.560	4.560	6,856,417.92
	HPP	IPP	16,784.0	0.0	0.0	16,784.0	9.752	9.752	1,636,705.41
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**167,151.0**	**0.0**	**0.0**	**167,151.0**	**5.081**	**5.081**	**8,493,123.33**
ACTUAL Feb-04									
	VARIOUS	SCH. J	77,492.0	0.0	0.0	77,492.0	4.351	4.351	3,371,683.81
	HPP	IPP	948.0	0.0	0.0	948.0	54.025	54.025	512,158.61
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**78,440.0**	**0.0**	**0.0**	**78,440.0**	**4.951**	**4.951**	**3,883,842.42**
ACTUAL Mar-04									
	VARIOUS	SCH. J	59,298.0	0.0	0.0	59,298.0	4.551	4.551	2,698,819.50
	HPP	IPP	5,957.0	0.0	0.0	5,957.0	19.007	19.007	1,132,230.70
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**65,255.0**	**0.0**	**0.0**	**65,255.0**	**5.871**	**5.871**	**3,831,050.20**
ACTUAL Apr-04									
	VARIOUS	SCH. J	61,712.0	0.0	0.0	61,712.0	5.217	5.217	3,219,245.10
	HPP	IPP	19,117.0	0.0	0.0	19,117.0	8.609	8.609	1,645,731.02
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**80,829.0**	**0.0**	**0.0**	**80,829.0**	**6.019**	**6.019**	**4,864,976.12**
ACTUAL May-04									
	VARIOUS	SCH. J	208,200.0	0.0	68.0	208,132.0	6.070	6.070	12,634,077.07
	HPP	IPP	49,884.0	0.0	0.0	49,884.0	1.919	1.919	957,102.99
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**258,084.0**	**0.0**	**68.0**	**258,016.0**	**5.268**	**5.268**	**13,591,180.06**
ACTUAL Jun-04									
	VARIOUS	SCH. J	190,479.0	0.0	496.9	189,982.1	5.564	5.564	10,571,443.02
	HPP	IPP	43,341.0	0.0	0.0	43,341.0	12.156	12.156	5,268,543.81
	VARIOUS	OTHER	89,165.0	0.0	0.0	89,165.0	3.911	3.911	3,486,971.50
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**322,985.0**	**0.0**	**496.9**	**322,488.1**	**5.993**	**5.993**	**19,326,958.33**

PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2004 THROUGH DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
ESTIMATED Jul-04									
	VARIOUS	SCH. J	326.0	0.0	226.0	100.0	10.800	10.800	10,800.00
	HPP	IPP	19,856.0	0.0	0.0	19,856.0	7.169	7.169	1,423,400.00
	VARIOUS	OTHER	157,493.0	0.0	0.0	157,493.0	4.517	4.517	7,114,000.00
	VARIOUS	MKT BASED	41,185.0	0.0	0.0	41,185.0	6.971	6.971	2,871,200.00
	TOTAL		**218,860.0**	**0.0**	**226.0**	**218,634.0**	**5.223**	**5.223**	**11,419,400.00**
ESTIMATED Aug-04									
	VARIOUS	SCH. J	1,219.0	0.0	747.0	472.0	11.631	11.631	54,900.00
	HPP	IPP	25,342.0	0.0	0.0	25,342.0	7.166	7.166	1,816,000.00
	VARIOUS	OTHER	92,034.0	0.0	0.0	92,034.0	3.833	3.833	3,527,700.00
	VARIOUS	MKT BASED	25,728.0	0.0	0.0	25,728.0	7.169	7.169	1,844,400.00
	TOTAL		**144,323.0**	**0.0**	**747.0**	**143,576.0**	**5.045**	**5.045**	**7,243,000.00**
ESTIMATED Sep-04									
	VARIOUS	SCH. J	637.0	0.0	443.0	194.0	9.794	9.794	19,000.00
	HPP	IPP	19,057.0	0.0	0.0	19,057.0	7.277	7.277	1,386,700.00
	VARIOUS	OTHER	90,363.0	0.0	0.0	90,363.0	3.697	3.697	3,340,700.00
	VARIOUS	MKT BASED	52,442.0	0.0	0.0	52,442.0	7.120	7.120	3,733,700.00
	TOTAL		**162,499.0**	**0.0**	**443.0**	**162,056.0**	**5.233**	**5.233**	**8,480,100.00**
ESTIMATED Oct-04									
	VARIOUS	SCH. J	123.0	0.0	95.0	28.0	8.929	8.929	2,500.00
	HPP	IPP	3,858.0	0.0	0.0	3,858.0	9.616	9.616	371,000.00
	VARIOUS	OTHER	99,880.0	0.0	0.0	99,880.0	3.599	3.599	3,594,700.00
	VARIOUS	MKT BASED	28,430.0	0.0	0.0	28,430.0	6.332	6.332	1,800,100.00
	TOTAL		**132,291.0**	**0.0**	**95.0**	**132,196.0**	**4.363**	**4.363**	**5,768,300.00**
ESTIMATED Nov-04									
	VARIOUS	SCH. J	16.0	0.0	13.0	3.0	10.000	10.000	300.00
	HPP	IPP	160.0	0.0	0.0	160.0	76.625	76.625	122,600.00
	VARIOUS	OTHER	92,419.0	0.0	0.0	92,419.0	3.383	3.383	3,126,500.00
	VARIOUS	MKT BASED	12,295.0	0.0	0.0	12,295.0	4.002	4.002	492,100.00
	TOTAL		**104,890.0**	**0.0**	**13.0**	**104,877.0**	**3.568**	**3.568**	**3,741,500.00**
ESTIMATED Dec-04									
	VARIOUS	SCH. J	6.0	0.0	5.0	1.0	10.000	10.000	100.00
	HPP	IPP	61.0	0.0	0.0	61.0	190.328	190.328	116,100.00
	VARIOUS	OTHER	89,530.0	0.0	0.0	89,530.0	3.296	3.296	2,950,900.00
	VARIOUS	MKT BASED	31,760.0	0.0	0.0	31,760.0	3.299	3.299	1,047,700.00
	TOTAL		**121,357.0**	**0.0**	**5.0**	**121,352.0**	**3.391**	**3.391**	**4,114,800.00**
Jan-04 THRU Dec-04	VARIOUS	SCH. J	749,875.0	0.0	2,093.9	747,781.1	5.274	5.274	39,439,286.42
	HPP	IPP	204,365.0	0.0	0.0	204,365.0	8.019	8.019	16,388,272.54
	VARIOUS	OTHER	710,884.0	0.0	0.0	710,884.0	3.818	3.818	27,141,471.50
	VARIOUS	MKT BASED	191,840.0	0.0	0.0	191,840.0	6.145	6.145	11,789,200.00
	TOTAL		**1,856,964.0**	**0.0**	**2,093.9**	**1,854,870.1**	**5.109**	**5.109**	**94,758,230.46**

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

SCHEDULE E8

(1) MONTH		(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUPTIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUSTMENT
ACTUAL	Jan-04	VARIOUS	CO-GEN.	41,268.0	0.0	0.0	41,268.0	2.673	2.673	1,103,019.54
ACTUAL	Feb-04	VARIOUS	CO-GEN.	27,540.0	0.0	0.0	27,540.0	2.448	2.448	674,075.18
ACTUAL	Mar-04	VARIOUS	CO-GEN.	38,339.0	0.0	0.0	38,339.0	2.775	2.775	1,064,077.38
ACTUAL	Apr-04	VARIOUS	CO-GEN.	44,850.0	0.0	0.0	44,850.0	2.552	2.552	1,144,554.74
ACTUAL	May-04	VARIOUS	CO-GEN.	49,880.0	0.0	0.0	49,880.0	2.884	2.884	1,438,689.45
ACTUAL	Jun-04	VARIOUS	CO-GEN.	43,663.0	0.0	0.0	43,663.0	2.558	2.558	1,116,748.03
ESTIMATED	Jul-04	VARIOUS	CO-GEN.	38,899.0	0.0	0.0	38,899.0	3.139	3.139	1,221,200.00
ESTIMATED	Aug-04	VARIOUS	CO-GEN.	38,899.0	0.0	0.0	38,899.0	3.246	3.246	1,262,500.00
ESTIMATED	Sep-04	VARIOUS	CO-GEN.	38,666.0	0.0	0.0	38,666.0	3.302	3.302	1,276,600.00
ESTIMATED	Oct-04	VARIOUS	CO-GEN.	38,899.0	0.0	0.0	38,899.0	3.232	3.232	1,257,200.00
ESTIMATED	Nov-04	VARIOUS	CO-GEN.	36,758.0	0.0	0.0	36,758.0	3.217	3.217	1,182,400.00
ESTIMATED	Dec-04	VARIOUS	CO-GEN.	36,928.0	0.0	0.0	36,928.0	3.219	3.219	1,188,700.00
	TOTAL			**474,589.0**	**0.0**	**0.0**	**474,589.0**	**2.935**	**2.935**	**13,929,764.32**

SCHEDULE E9

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

(1) MONTH		(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) TRANSACT. COST CENTS/KWH	(6) TOTAL $ FOR FUEL ADJUSTMENT	(7) COST IF GENERATED (A) CENTS PER KWH	(7) COST IF GENERATED (B) ($000)	(8) FUEL SAVINGS (7B)-(6)
ACTUAL	Jan-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	Feb-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	Mar-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	Apr-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	May-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	Jun-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Jul-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Aug-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Sep-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Oct-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Nov-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Dec-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
	TOTAL			**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
ACTUAL / ESTIMATED
JANUARY 2004 THROUGH DECEMBER 2004

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
CALCULATION OF THE CURRENT (ACTUAL/ESTIMATED) PERIOD TRUE-UP
JANUARY 2004 THROUGH DECEMBER 2004

1.	FINAL OVER/(UNDER) RECOVERY FOR JANUARY 2003 THROUGH DECEMBER 2003	($296,014)
2.	ACTUAL/ESTIMATED OVER/(UNDER) RECOVERY FOR THE CURRENT PERIOD JANUARY 2004 THROUGH DECEMBER 2004	($7,372,965)
3.	CURRENT PERIOD TRUE-UP AMOUNT TO BE REFUNDED/(RECOVERED) IN THE PROJECTION PERIOD JANUARY 2005 THROUGH DECEMBER 2005	($7,668,979)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT

	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Actual Jun-04	Estimated Jul-04	Estimated Aug-04	Estimated Sep-04	Estimated Oct-04	Estimated Nov-04	Estimated Dec-04	Total
1 UNIT POWER CAPACITY CHARGES	1,698,361	1,698,361	1,698,361	1,698,361	1,711,052	2,832,952	3,099,000	2,582,500	2,582,500	2,582,500	2,582,500	2,582,500	27,348,948
2 CAPACITY PAYMENTS TO COGENERATORS	1,660,145	1,655,185	1,655,185	1,696,355	1,696,355	1,696,355	1,717,200	1,717,200	1,723,000	1,723,000	1,723,000	1,723,000	20,385,980
3 SECURITY COSTS	18,660	22,959	153,814	63,384	218,390	112,441	0	18,401	(30,812)	(30,812)	17,258	(30,810)	532,873
4 (UNIT POWER CAPACITY REVENUES)	(28,984)	(28,966)	(115,836)	(45,542)	(20,817)	(29,542)	(86,500)	(66,600)	(80,600)	(55,600)	(51,700)	(69,500)	(680,187)
5 TOTAL CAPACITY DOLLARS	3,348,182	3,347,539	3,391,524	3,412,558	3,604,980	4,612,206	4,729,700	4,251,501	4,194,088	4,219,088	4,271,058	4,205,190	47,587,614
6 SEPARATION FACTOR	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	
7 JURISDICTIONAL CAPACITY DOLLARS	3,195,374	3,194,762	3,236,739	3,256,813	3,440,452	4,401,710	4,513,842	4,057,467	4,002,674	4,026,533	4,076,132	4,013,270	45,415,768
8 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	3,192,064	2,811,042	2,783,473	2,745,079	3,135,915	3,851,763	3,943,161	3,908,186	4,017,108	3,654,369	3,123,751	3,112,759	40,278,670
9 PRIOR PERIOD TRUE-UP PROVISION	(180,126)	(180,126)	(180,126)	(180,126)	(180,126)	(180,126)	(180,126)	(180,126)	(180,126)	(180,126)	(180,126)	(180,123)	(2,161,509)
10 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	3,011,938	2,630,916	2,603,347	2,564,953	2,955,789	3,671,637	3,763,035	3,728,060	3,836,982	3,474,243	2,943,625	2,932,636	38,117,161
11 TRUE-UP PROVISION FOR MONTH OVER/(UNDER) RECOVERY (Line 10 - Line 7)	(183,436)	(563,846)	(633,392)	(691,860)	(484,663)	(730,073)	(750,807)	(329,407)	(165,692)	(552,290)	(1,132,507)	(1,080,634)	(7,298,607)
12 INTEREST PROVISION FOR MONTH	(2,139)	(2,230)	(2,522)	(2,991)	(3,416)	(4,358)	(6,904)	(8,908)	(9,035)	(9,349)	(10,471)	(12,035)	(74,358)
13 TRUE-UP AND INT. PROVISION BEGINNING OF MONTH - OVER/(UNDER) RECOVERY	(2,457,523)	(2,462,972)	(2,848,922)	(3,304,710)	(3,819,435)	(4,127,388)	(4,681,693)	(5,259,278)	(5,417,467)	(5,412,068)	(5,793,581)	(6,756,433)	(2,457,523)
14 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS MONTH	180,126	180,126	180,126	180,126	180,126	180,126	180,126	180,126	180,126	180,126	180,126	180,123	2,161,509
15 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 11 - 14)	(2,462,972)	(2,848,922)	(3,304,710)	(3,819,435)	(4,127,388)	(4,681,693)	(5,259,278)	(5,417,467)	(5,412,068)	(5,793,581)	(6,756,433)	(7,668,979)	**(7,668,979)**

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT

	Actual Jan-04	Actual Feb-04	Actual Mar-04	Actual Apr-04	Actual May-04	Actual Jun-04	Estimated Jul-04	Estimated Aug-04	Estimated Sep-04	Estimated Oct-04	Estimated Nov-04	Estimated Dec-04	Total
1 BEGINNING TRUE-UP AMOUNT	(2,457,523)	(2,462,972)	(2,848,922)	(3,304,710)	(3,819,435)	(4,127,388)	(4,681,693)	(5,259,278)	(5,417,467)	(5,412,068)	(5,793,581)	(6,756,433)	(2,457,523)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(2,460,833)	(2,846,692)	(3,302,188)	(3,816,444)	(4,123,972)	(4,677,335)	(5,252,374)	(5,408,559)	(5,403,033)	(5,784,232)	(6,745,962)	(7,656,944)	(7,594,621)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(4,918,356)	(5,309,664)	(6,151,110)	(7,121,154)	(7,943,407)	(8,804,723)	(9,934,067)	(10,667,837)	(10,820,500)	(11,196,300)	(12,539,543)	(14,413,377)	(10,052,144)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(2,459,178)	(2,654,832)	(3,075,555)	(3,560,577)	(3,971,704)	(4,402,362)	(4,967,034)	(5,333,919)	(5,410,250)	(5,598,150)	(6,269,772)	(7,206,689)	(5,026,072)
5 INTEREST RATE % - 1ST DAY OF MONTH	1.060	1.030	0.980	0.980	1.030	1.040	1.330	2.000	2.000	2.000	2.000	2.000	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	1.030	0.980	0.980	1.030	1.040	1.330	2.000	2.000	2.000	2.000	2.000	2.000	NA
7 TOTAL (LINE 5 + LINE 6)	2.090	2.010	1.960	2.010	2.070	2.370	3.330	4.000	4.000	4.000	4.000	4.000	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	1.045	1.005	0.980	1.005	1.035	1.185	1.665	2.000	2.000	2.000	2.000	2.000	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.087	0.084	0.082	0.084	0.086	0.099	0.139	0.167	0.167	0.167	0.167	0.167	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(2,139)	(2,230)	(2,522)	(2,991)	(3,416)	(4,358)	(6,904)	(8,908)	(9,035)	(9,349)	(10,471)	(12,035)	(74,358)

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2004 Incremental Security O&M Expense

Calculation of Baseline to Determine 2004 Incremental Expenses

Grossing up Pre-Attack Expenses to Reflect Energy Sales Growth:

	2000	2001	2002	2003	2004
Base Security O&M Expense	$ 1,927,720				
Energy Sales Growth		2.72%	5.03%	2.66%	
Adjusted Baseline					$2,135,077

Calculation of 2004 Incremental Security O&M Expense:

2004 Actual/Estimated Total Security O&M Expense	$ 3,209,852
Less Baseline Adjusted for Energy Sales Growth	(2,135,077)
	1,074,775
Less O&M Savings Associated with Critical Intervention Incremental Expense and Operational Changes	(470,334)
Less Savings Due to Reduction in Capital Spending	(71,568)
Incremental Security O&M Expense	$ 532,873
Retail Jurisdictional Separation Factor	0.9543611
2004 Retail Actual/Estimated Incremental Security O&M Expense	$ 508,553

TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
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EXHIBIT TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2005 - DECEMBER 2005

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 43
COMPANY/ TECO
WITNESS: J. Denise Jordan (JDJ-3)
DATE 11-09-04

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2005 THROUGH DECEMBER 2005
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER %	(2) PROJECTED SALES AT METER MWH	(3) PROJECTED AVG 12 CP AT METER MWH	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION MWH	(7) PROJECTED AVG 12 CP AT GENERATION MWH	(8) PERCENTAGE OF SALES AT GENERATION %	(9) PERCENTAGE OF DEMAND AT GENERATION %
RS	55.19%	8,803,380	1,821	1.05763	1.04724	9,219,229	1,926	46.08%	58.28%
GS, TS	61.70%	1,066,948	197	1.05763	1.04724	1,117,347	208	5.58%	6.29%
GSD, EV-X	76.55%	5,324,964	794	1.05652	1.04663	5,573,283	839	27.85%	25.39%
GSLD, SBF	83.61%	2,303,504	315	1.04440	1.03589	2,386,172	329	11.93%	9.95%
IS-1&3, SBI-1&3	NA	1,471,473	NA	NA	1.01733	1,496,966	NA	7.48%	NA
SL/OL	781.26%	205,941	3	1.05763	1.04724	215,669	3	1.08%	0.09%
TOTAL		19,176,209	3,130			20,008,666	3,305	100.00%	100.00%

(1) AVG 12 CP load factor based on actual 2003 calendar data.
(2) Projected MWH sales for the period Jan. 2005 thru Dec. 2005.
(3) Calculated: Col (2) / (8760*Col (1)).
(4) Based on 2003 demand losses.
(5) Based on 2003 energy losses.
(6) Col (2) * Col (5).
(7) Col (3) * Col (4).
(8) Col (6) / total for Col (6).
(9) Col (7) / total for Col (7).

NOTE: Interruptible rates not included in demand allocation of capacity payments.

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2005 THROUGH DECEMBER 2005
PROJECTED

	Projected JANUARY	Projected FEBRUARY	Projected MARCH	Projected APRIL	Projected MAY	Projected JUNE	Projected JULY	Projected AUGUST	Projected SEPTEMBER	Projected OCTOBER	Projected NOVEMBER	Projected DECEMBER	Total
1 UNIT POWER CAPACITY CHARGES	2,582,500	2,582,500	2,582,500	2,582,500	2,582,500	2,645,000	2,645,000	2,645,000	2,582,500	2,582,500	2,582,500	2,582,500	31,177,500
2 CAPACITY PAYMENTS TO COGENERATORS	1,742,600	1,742,600	1,742,600	1,789,700	1,789,700	1,789,700	1,789,700	1,789,700	1,795,500	1,795,500	1,795,500	1,795,500	21,358,300
3 SECURITY COSTS	31,424	31,424	31,424	31,424	31,424	31,424	31,424	31,424	31,424	31,424	31,424	31,425	377,089
4 (UNIT POWER CAPACITY REVENUES)	(83,200)	(116,700)	(58,400)	(61,900)	(88,600)	(85,100)	(81,200)	(77,700)	(82,200)	(45,700)	(48,600)	(60,300)	(889,600)
5 TOTAL CAPACITY DOLLARS	$4,273,324	$4,239,824	$4,298,124	$4,341,724	$4,315,024	$4,381,024	$4,384,924	$4,388,424	$4,327,224	$4,363,724	$4,360,824	$4,349,125	$52,023,289
6 SEPARATION FACTOR	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	0.9641722	
7 JURISDICTIONAL CAPACITY DOLLARS	$4,120,220	$4,087,920	$4,144,132	$4,186,170	$4,160,426	$4,224,062	$4,227,822	$4,231,196	$4,172,189	$4,207,381	$4,204,585	$4,193,305	$50,159,408
8 ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2004 - DEC. 2004 OVER/(UNDER) RECOVERY													7,668,979
9 TOTAL													$57,828,387
10 REVENUE TAX FACTOR													1.00072
11 TOTAL RECOVERABLE CAPACITY DOLLARS													$57,870,023

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TAMPA ELECTRIC COMPANY
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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2005 THROUGH DECEMBER 2005
PROJECTED

RATE CLASS	(1) PERCENTAGE OF SALES AT GENERATION %	(2) PERCENTAGE OF DEMAND AT GENERATION %	(3) ENERGY RELATED COSTS ($)	(4) DEMAND RELATED COSTS ($)	(5) TOTAL CAPACITY COSTS ($)	(6) PROJECTED SALES AT METER MWH	(7) CAPACITY RECOVERY FACTOR $/MWH
RS	46.08%	58.28%	2,050,656	31,133,069	33,183,725	8,803,380	3.77
GS, TS	5.58%	6.29%	248,321	3,360,107	3,608,428	1,066,948	3.38
GSD, EV-X	27.85%	25.39%	1,239,382	13,563,292	14,802,674	5,324,964	2.78
GSLD, SBF	11.93%	9.95%	530,909	5,315,272	5,846,181	2,303,504	2.54
IS-1&3, SBI-1&3	7.48%	NA	332,875	0	332,875	1,471,473	0.23
SL/OL	1.08%	0.09%	48,062	48,078	96,140	205,941	0.47
TOTAL	100.00%	100.00%	4,450,205	53,419,818	57,870,023	19,176,209	3.02
			7.69%	92.31%			

NOTE: Using the 12 CP and 1/13th allocation method requires 1/13th or 7.69% of capacity costs to be allocated on the basis of energy, and 12/13th or 92.31% to be allocated on the basis of demand.

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2005 Incremental Security O&M Expense

Calculation of Baseline to Determine 2005 Incremental Expenses

Grossing up Pre-Attack Expenses to Reflect Energy Sales Growth:

2004 Baseline Total Security O&M Expense	$ 2,135,077
2004 Actual/Estimated Energy Sales Growth	2.37%
2005 Adjusted Baseline Expense	$ 2,185,678

Note: The 2005 adjusted baseline will be trued up for 2004 actual energy sales growth in the 2005 actual/estimated schedules that will be filed in August 2005.

Calculation of 2005 Incremental Security O&M Expense:

2005 Projected Security O&M Expense	$ 3,104,669
Less Baseline Adj. For Energy Sales Growth	(2,185,678)
	918,991
Less O&M Savings Associated with Critical Intervention Incremental Expense and Operational Changes	(470,334)
Less Savings Due to Reduction in Capital Spending	(71,568)
Incremental Security O&M Expense	$ 377,089
Retail Jurisdictional Separation Factor	0.9641722
2005 Retail Projected Incremental Security O&M Expense	$ 363,579

TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
FILED: 9/9/04

EXHIBIT TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY
JANUARY 2005 - DECEMBER 2005

SCHEDULES E1 THROUGH E10
SCHEDULE H-1

EXHIBIT NO._____
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TAMPA ELECTRIC COMPANY

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24	Schedule E1-D Fuel Adjustment Factor for TOD	(")
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48	Schedule E-9 Economy Energy Purchases	(")
49	Schedule E-10 Residential Bill Comparison	(")
50	Schedule H-1 Generating System Comparative Data	(JAN. - DEC. 2002-2005)

SCHEDULE E1

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	650,189,288	18,364,165	3.54053
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Adjustments to Fuel Cost (Ft. Meade / Wauchula Wheeling)	(84,000)	18,364,165 (1)	(0.00046)
4b.	Adjustments to Fuel Cost	0	18,364,165 (1)	0.00000
4bc.	Adjustments to Fuel Cost (Incremental Hedging O&M)	111,116	18,364,165 (1)	0.00061
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)**	**650,216,404**	**18,364,165**	**3.54068**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	97,606,600	2,093,658	4.66201
7.	Energy Cost of Economy Purchases (E9)	0	0	0.00000
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	11,451,300	455,547	2.51375
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**109,057,900**	**2,549,205**	**4.27811**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		20,913,370	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	470,800	18,997	2.47829
13.	Fuel Cost of Market Based Sales - Jurisd. (E6)	12,857,900	228,695	5.62229
14.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**13,328,700**	**247,692**	**5.38116**
15.	Net Inadvertant Interchange		0	
16.	Wheeling Received Less Wheeling Delivered		0	
17.	Interchange and Wheeling Losses		5,500	
18.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-14+15+16-17)**	**745,945,604**	**20,660,178**	**3.61055**
19.	Net Unbilled	NA (1)(a)	NA (a)	NA
20.	Company Use	1,559,758 (1)	43,200	0.00792
21.	T & D Losses	33,490,732 (1)	927,580	0.17010
22.	System MWH Sales	745,945,604	19,689,398	3.78856
23.	Wholesale MWH Sales	(19,608,072)	(513,189)	3.82083
24.	Jurisdictional MWH Sales	726,337,532	19,176,209	3.78770
25.	Jurisdictional Loss Multiplier			1.00086
26.	Jurisdictional MWH Sales Adjusted for Line Loss	726,958,929	19,176,209	3.79094
27.	True-up (2)	30,984,325	19,176,209	0.16158
28.	Total Jurisdictional Fuel Cost (Excl. GPIF)	757,943,254	19,176,209	3.95252
29.	Revenue Tax Factor			1.00072
30.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	758,488,973	19,176,209	3.95537
31.	GPIF Adjusted for Taxes (2)	(3,678,414)	19,176,209	(0.01918)
32.	**Fuel Factor Adjusted for Taxes Including GPIF**	754,810,559	19,176,209	3.93619
33.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.936**

(a) Data not available at this time.
(1) Included For Informational Purposes Only
(2) Calculation Based on Jurisdictional KWH Sales

CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2004 - December 2004 (6 months actual, 6 months estimated)	($70,023,368)
2.	FINAL TRUE-UP (January 2003 - December 2003) (Per True-Up filed February 23, 2004 and Revised August 4, 2004)	39,039,043
3.	TOTAL OVER/(UNDER) RECOVERY (Lines 1 + 4) To be included in the 12-month projected period January 2005 through December 2005 (Schedule E1, line 28)	($30,984,325)
4.	JURISDICTIONAL MWH SALES (Projected January 2005 thru December 2005)	19,176,209
5.	TRUE-UP FACTOR - cents/kwh (Lines 3/4) * (100 cents/1000 KWH)	**0.1616**

SCHEDULE E1-C

INCENTIVE FACTOR AND TRUE-UP FACTOR
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY) (January 2005 Through December 2005)	($3,678,414)	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2004 Through December 2004)	($30,984,325)	
2.	TOTAL SALES (January 2005 Through December 2005)	19,176,209	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**(0.0192)**	Cents/kWh
	B. TRUE-UP FACTOR	**0.1616**	Cents/kWh

SCHEDULE E1-D

FUEL ADJUSTMENT FACTOR FOR
OPTIONAL TIME-OF-DAY RATES
TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

1. COST RATIO
   ON-PEAK COST / OFF-PEAK COST = $\frac{5.636}{3.990}$ = 1.4125

2. SALES/GENERATION

   34.10 % ON-PEAK

   65.90 % OFF-PEAK

3. FORMULA
   FUEL ADJUSTMENT FACTOR ADJUSTED FOR TAX AND GPIF = (% ON-PEAK GENERATION * COST RATIO * OFF-PEAK FACTOR) + (% OFF-PEAK GENERATION * OFF-PEAK FACTOR)

3.9362	=	0.3410	*	1.4125	Y +	0.6590	Y
3.9362	=	1.1407	*	Y			
3.4507	=	Y					

   where Y = OFF-PEAK FACTOR and

X	=	1.4125	Y	
X	=	1.4125	*	3.4507
X	=	4.8741		

   where X = ON-PEAK FACTOR

		ON-PEAK	OFF-PEAK
4.	**FUEL COST (CENTS/KWH)**	**4.8741**	**3.4507**
5.	**FUEL FACTOR (CENTS/KWH, NEAREST 0.001)**	**4.874**	**3.451**

SCHEDULE E1-E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

GROUP	RATE SCHEDULE	AVERAGE FACTOR	FUEL RECOVERY LOSS MULTIPLIER	FUEL RECOVERY FACTOR
A	RS,GS,TS	3.936	1.0041	**3.952**
A1*	SL-2, OL-1&3	3.936	N/A	**3.679**
B	GSD,GSLD,SBF	3.936	1.0004	**3.938**
C	IS-1&3,SBI-1&3	3.936	0.9754	**3.839**
A	RST,GST			
	ON-PEAK	4.874	1.0041	**4.894**
	OFF-PEAK	3.451	1.0041	**3.465**
A1	SL-2, OL-1&3			
	ON-PEAK	N/A	N/A	**N/A**
	OFF-PEAK	N/A	N/A	**N/A**
B	GSDT, EV-X, GSLDT, SBFT			
	ON-PEAK	4.874	1.0004	**4.876**
	OFF-PEAK	3.451	1.0004	**3.452**
C	IST-1&3, SBIT-1&3			
	ON-PEAK	4.874	0.9754	**4.754**
	OFF-PEAK	3.451	0.9754	**3.366**

* GROUP A1 IS BASED ON GROUP A, 15% ON-PEAK AND 85% OFF-PEAK

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

SCHEDULE E2

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
							ESTIMATED							TOTAL
		Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	PERIOD
1.	Fuel Cost of System Net Generation	49,366,170	44,573,551	42,479,946	43,979,341	59,235,207	59,897,531	66,684,526	66,969,894	60,797,496	56,380,896	51,235,114	48,589,616	650,189,288
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold (1)	1,403,900	2,811,500	427,700	571,800	1,629,200	1,578,800	1,399,500	1,340,300	1,487,500	47,100	157,700	473,700	13,328,700
4.	Fuel Cost of Purchased Power	4,354,900	3,373,800	8,277,600	3,921,500	7,199,500	11,170,200	13,088,300	13,071,000	11,412,600	11,737,900	5,345,900	4,653,400	97,606,600
5.	Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	Payments to Qualifying Facilities	933,100	920,500	924,600	961,300	971,400	970,400	984,000	984,300	972,300	978,700	927,900	922,800	11,451,300
7.	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
8a.	Adj. to Fuel Cost (Ft. Meade/Wauchula Wheeling)	(7,000)	(7,000)	(7,000)	(7,000)	(7,000)	(7,000)	(7,000)	(7,000)	(7,000)	(7,000)	(7,000)	(7,000)	(84,000)
8b.	Adj. To Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
8c.	Adj. To Fuel Cost (Incremental Hedging O&M)	0	0	0	0	0	9,232	16,981	16,981	16,981	16,981	16,981	16,981	111,116
9.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**53,243,270**	**46,049,351**	**51,247,446**	**48,283,341**	**65,769,907**	**70,461,563**	**79,367,307**	**79,694,875**	**71,704,877**	**69,060,377**	**57,361,195**	**53,702,097**	**745,945,604**
10.	Jurisdictional MWH Sold	1,497,204	1,367,020	1,346,315	1,367,782	1,532,228	1,760,662	1,841,893	1,847,559	1,881,336	1,724,794	1,512,124	1,497,292	19,176,209
11.	Jurisdictional % of Total Sales	0.9818356	0.9809229	0.9695073	0.9718295	0.9678167	0.9717804	0.9720999	0.9719386	0.9731714	0.9717357	0.9771121	0.9796050	
12.	Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	52,276,138	45,170,863	49,684,773	46,923,175	63,653,214	68,473,166	77,152,951	77,458,525	69,781,135	67,108,433	56,048,317	52,606,842	726,337,532
13.	Jurisdictional Loss Multiplier	1.00086	1.00086	1.00086	1.00086	1.00086	1.00086	1.00086	1.00086	1.00086	1.00086	1.00086	1.00086	
14.	**JURISD. TOTAL FUEL & NET PWR. TRANS. Adjusted for Line Losses (Line 12 * Line 13)**	**52,321,095**	**45,209,710**	**49,727,502**	**46,963,529**	**63,707,956**	**68,532,053**	**77,219,303**	**77,525,139**	**69,841,147**	**67,166,146**	**56,096,519**	**52,652,084**	**726,962,183**
15.	Cost Per kWh Sold (Cents/kWh)	3.4946	3.3072	3.6936	3.4336	4.1579	3.8924	4.1924	4.1961	3.7123	3.8942	3.7098	3.5165	3.7910
16.	True-up (Cents/kWh) (2)	0.1616	0.1616	0.1616	0.1616	0.1616	0.1616	0.1616	0.1616	0.1616	0.1616	0.1616	0.1616	0.1616
17.	Total (Cents/kWh) (Line 15+16)	3.6562	3.4688	3.8552	3.5952	4.3195	4.0540	4.3540	4.3577	3.8739	4.0558	3.8714	3.6781	3.9526
18.	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
19.	Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.6588	3.4713	3.8580	3.5978	4.3226	4.0569	4.3571	4.3608	3.8767	4.0587	3.8742	3.6807	3.9554
20.	GPIF Adjusted for Taxes (Cents/kWh) (2)	(0.0192)	(0.0192)	(0.0192)	(0.0192)	(0.0192)	(0.0192)	(0.0192)	(0.0192)	(0.0192)	(0.0192)	(0.0192)	(0.0192)	(0.0192)
21.	**TOTAL RECOVERY FACTOR (LINE 19+20)**	**3.6396**	**3.4521**	**3.8388**	**3.5786**	**4.3034**	**4.0377**	**4.3379**	**4.3416**	**3.8575**	**4.0395**	**3.8550**	**3.6615**	**3.9362**
22.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**3.640**	**3.452**	**3.839**	**3.579**	**4.303**	**4.038**	**4.338**	**4.342**	**3.858**	**4.040**	**3.855**	**3.662**	**3.936**

(1) Includes Gains
(2) Based on Jurisdictional Sales Only

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	31,469	6,169	15,876	14,599	254,453	306,452
2. LIGHT OIL	776,823	623,159	700,873	421,978	643,077	723,917
3. COAL	21,671,751	19,448,843	20,546,723	20,985,895	21,178,278	20,460,979
4. NATURAL GAS	26,886,127	24,495,380	21,216,474	22,556,869	37,159,399	38,406,183
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**49,366,170**	**44,573,551**	**42,479,946**	**43,979,341**	**59,235,207**	**59,897,531**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	468	86	234	212	3,702	4,442
9. LIGHT OIL	9,072	7,524	8,410	5,105	7,731	8,575
10. COAL	954,683	855,281	917,101	921,560	939,672	909,849
11. NATURAL GAS	459,113	423,956	371,240	430,631	721,534	753,150
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,423,336**	**1,286,847**	**1,296,985**	**1,357,508**	**1,672,639**	**1,676,016**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	728	135	365	329	5,760	6,912
16. LIGHT OIL (BBL)	16,639	13,306	15,019	9,107	14,127	16,311
17. COAL (TON)	414,921	371,240	396,780	403,042	411,195	398,425
18. NATURAL GAS (MCF)	3,322,810	3,059,237	2,702,017	3,127,103	5,250,779	5,502,338
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	4,566	847	2,288	2,066	36,169	43,401
22. LIGHT OIL	96,099	77,118	86,514	52,468	81,725	94,697
23. COAL	10,063,050	9,011,290	9,675,380	9,745,078	9,963,530	9,683,390
24. NATURAL GAS	3,415,991	3,145,024	2,777,715	3,214,605	5,397,689	5,656,373
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**13,579,706**	**12,234,279**	**12,541,897**	**13,014,217**	**15,479,113**	**15,477,861**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.03	0.01	0.02	0.02	0.22	0.27
29. LIGHT OIL	0.64	0.58	0.65	0.38	0.46	0.51
30. COAL	67.07	66.46	70.71	67.88	56.18	54.28
31. NATURAL GAS	32.26	32.95	28.62	31.72	43.14	44.94
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	43.23	45.70	43.50	44.37	44.18	44.34
36. LIGHT OIL ($/BBL)	46.69	46.83	46.67	46.34	45.52	44.38
37. COAL ($/TON)	52.23	52.39	51.78	52.07	51.50	51.35
38. NATURAL GAS ($/MCF)	8.09	8.01	7.85	7.21	7.08	6.98
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	6.89	7.28	6.94	7.07	7.04	7.06
42. LIGHT OIL	8.08	8.08	8.10	8.04	7.87	7.64
43. COAL	2.15	2.16	2.12	2.15	2.13	2.11
44. NATURAL GAS	7.87	7.79	7.64	7.02	6.88	6.79
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**3.64**	**3.64**	**3.39**	**3.38**	**3.83**	**3.87**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	9,756	9,849	9,778	9,745	9,770	9,771
49. LIGHT OIL	10,593	10,250	10,287	10,278	10,571	11,043
50. COAL	10,541	10,536	10,550	10,575	10,603	10,643
51. NATURAL GAS	7,440	7,418	7,482	7,465	7,481	7,510
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,541**	**9,507**	**9,670**	**9,587**	**9,254**	**9,235**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	6.72	7.17	6.78	6.89	6.87	6.90
56. LIGHT OIL	8.56	8.28	8.33	8.27	8.32	8.44
57. COAL	2.27	2.27	2.24	2.28	2.25	2.25
58. NATURAL GAS	5.86	5.78	5.72	5.24	5.15	5.10
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.47**	**3.46**	**3.28**	**3.24**	**3.54**	**3.57**

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)							
1. HEAVY OIL	453,316	428,358	351,946	197,596	278,586	106,229	2,445,049
2. LIGHT OIL	1,232,532	1,262,069	685,641	577,694	229,647	627,198	8,504,608
3. COAL	21,429,837	21,537,220	20,282,458	15,643,994	14,357,448	20,902,084	238,445,510
4. NATURAL GAS	43,568,841	43,742,247	39,477,451	39,961,612	36,369,433	26,954,105	400,794,121
5. NUCLEAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL ($)	**66,684,526**	**66,969,894**	**60,797,496**	**56,380,896**	**51,235,114**	**48,589,616**	**650,189,288**
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	6,592	6,196	5,047	2,821	4,070	1,552	35,422
9. LIGHT OIL	13,512	13,909	8,353	7,194	2,993	8,365	100,743
10. COAL	948,000	956,754	911,281	709,121	640,526	958,447	10,622,275
11. NATURAL GAS	832,991	834,790	762,102	793,375	716,566	506,277	7,605,725
12. NUCLEAR	0	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	**1,801,095**	**1,811,649**	**1,686,783**	**1,512,511**	**1,364,155**	**1,474,641**	**18,364,165**
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	10,258	9,642	7,853	4,390	6,327	2,415	55,114
16. LIGHT OIL (BBL)	28,559	29,315	15,835	13,530	5,419	14,816	191,983
17. COAL (TON)	417,516	421,350	399,082	309,860	281,797	414,015	4,639,223
18. NATURAL GAS (MCF)	6,157,918	6,176,374	5,563,134	5,761,445	5,179,928	3,648,131	55,451,214
19. NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)							
21. HEAVY OIL	64,410	60,539	49,310	27,562	39,730	15,163	346,051
22. LIGHT OIL	165,834	170,545	91,668	78,818	31,696	85,963	1,113,145
23. COAL	10,141,960	10,234,090	9,699,040	7,483,070	6,781,641	10,092,680	112,574,199
24. NATURAL GAS	6,330,411	6,349,292	5,718,862	5,922,773	5,325,003	3,750,228	57,003,966
25. NUCLEAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	**16,702,615**	**16,814,466**	**15,559,880**	**13,512,223**	**12,178,070**	**13,944,034**	**171,037,361**
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.37	0.34	0.30	0.19	0.30	0.11	0.19
29. LIGHT OIL	0.75	0.77	0.50	0.48	0.22	0.57	0.55
30. COAL	52.63	52.81	54.02	46.88	46.95	64.99	57.84
31. NATURAL GAS	46.25	46.08	45.18	52.45	52.53	34.33	41.42
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT							
35. HEAVY OIL ($/BBL)	44.19	44.43	44.82	45.01	44.03	43.99	44.36
36. LIGHT OIL ($/BBL)	43.16	43.05	43.30	42.70	42.38	42.33	44.30
37. COAL ($/TON)	51.33	51.11	50.82	50.49	50.95	50.49	51.40
38. NATURAL GAS ($/MCF)	7.08	7.08	7.10	6.94	7.02	7.39	7.23
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)							
41. HEAVY OIL	7.04	7.08	7.14	7.17	7.01	7.01	7.07
42. LIGHT OIL	7.43	7.40	7.48	7.33	7.25	7.30	7.64
43. COAL	2.11	2.10	2.09	2.09	2.12	2.07	2.12
44. NATURAL GAS	6.88	6.89	6.90	6.75	6.83	7.19	7.03
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**3.99**	**3.98**	**3.91**	**4.17**	**4.21**	**3.48**	**3.80**
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	9,771	9,771	9,770	9,770	9,762	9,770	9,769
49. LIGHT OIL	12,273	12,261	10,974	10,956	10,590	10,277	11,049
50. COAL	10,698	10,697	10,643	10,553	10,588	10,530	10,598
51. NATURAL GAS	7,600	7,606	7,504	7,465	7,431	7,407	7,495
52. NUCLEAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,274**	**9,281**	**9,224**	**8,934**	**8,927**	**9,456**	**9,314**
GENERATED FUEL COST PER KWH (CENTS/KWH)							
55. HEAVY OIL	6.88	6.91	6.97	7.00	6.84	6.84	6.90
56. LIGHT OIL	9.12	9.07	8.21	8.03	7.67	7.50	8.44
57. COAL	2.26	2.25	2.23	2.21	2.24	2.18	2.24
58. NATURAL GAS	5.23	5.24	5.18	5.04	5.08	5.32	5.27
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.70**	**3.70**	**3.60**	**3.73**	**3.76**	**3.30**	**3.54**

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: JANUARY 2005

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	428	201,048	63.1	76.0	78.6	10,466	COAL	86,374	24,360,108	2,104,080.0	4,592,323	2.28	53.17
2. B.B.#2	433	149,859	46.5	66.1	73.5	10,708	COAL	65,872	24,360,123	1,604,650.0	3,502,275	2.34	53.17
3. B.B.#3	438	203,696	62.5	73.1	75.6	10,657	COAL	89,327	24,302,171	2,170,840.0	4,749,327	2.33	53.17
4. B.B.#4	460	242,178	70.8	80.1	82.8	10,594	COAL	110,348	23,249,900	2,565,580.0	5,866,969	2.42	53.17
5. B.B. STA.	**1,759**	**796,781**	**60.9**	**73.9**	**19.5**	**10,599**	**COAL**	**351,921**	**23,997,289**	**8,445,150.0**	**18,710,894**	**2.35**	**53.17**
6. PHILLIPS #1 (HVY OIL)	17	236	1.9	92.9	99.2	9,674	HVY OIL	367	6,220,708	2,283.0	15,864	6.72	43.23
7. PHILLIPS #2 (HVY OIL)	17	232	1.8	92.6	97.5	9,841	HVY OIL	361	6,324,100	2,283.0	15,605	6.73	43.23
8. SEB-PHILLIPS TOTAL	**34**	**468**	**1.9**	**92.7**	**49.2**	**9,756**	**HVY OIL**	**728**	**6,271,978**	**4,566.0**	**31,469**	**6.72**	**43.23**
9. POLK #1 GASIFIER	260	157,902	81.6	-	-	10,246	COAL	63,000	25,680,952	1,617,900.0	2,960,857	1.88	47.00
10. POLK #1 CT OIL	260	8,311	4.3	-	-	10,243	LGT OIL	14,700	5,790,884	85,126.0	686,657	8.26	46.71
11. POLK #1 TOTAL	**260**	**166,213**	**85.9**	**84.6**	**93.7**	**10,246**		**-**	**-**	**1,703,026.0**	**3,647,514**	**2.19**	**-**
12. POLK #2 CT GAS	180	547	0.4	-	-	12,260	GAS	6,500	1,031,692	6,706.0	52,592	9.61	8.09
13. POLK #2 CT OIL	180	182	0.1	-	-	12,280	LGT OIL	400	5,587,500	2,235.0	19,151	10.52	47.88
14. POLK #2 TOTAL	**180**	**729**	**0.5**	**95.8**	**81.0**	**12,265**		**-**	**-**	**8,941.0**	**71,743**	**9.84**	**-**
15. POLK #3 CT GAS	180	525	0.4	0.0	-	12,192	GAS	6,200	1,032,419	6,401.0	50,165	9.56	8.09
16. POLK #3 CT OIL	180	175	0.1	0.0	-	12,194	LGT OIL	400	5,335,000	2,134.0	19,151	10.94	47.88
17. POLK #3 TOTAL	**180**	**700**	**0.5**	**95.8**	**77.8**	**12,193**		**-**	**-**	**8,535.0**	**69,316**	**9.90**	**-**
18. CITY OF TAMPA GAS	**6**	**50**	**1.1**	**100.0**	**95.9**	**10,480**	GAS	**510**	1,027,451	**524.0**	**5,065**	**10.13**	**9.93**
19. BAYSIDE #1	787	200,677	34.3	93.9	61.2	7,413	GAS	1,447,000	1,028,017	1,487,540.0	11,707,822	5.83	8.09
20. BAYSIDE #2	1,040	257,314	33.3	93.7	82.0	7,442	GAS	1,862,600	1,028,036	1,914,820.0	15,070,483	5.86	8.09
21. BAYSIDE TOTAL	**1,827**	**457,991**	**33.7**	**93.8**	**34.9**	**7,429**	**GAS**	**3,309,600**	**1,028,028**	**3,402,360.0**	**26,778,305**	**5.85**	**8.09**
22. B.B.C.T.#1	15	41	0.4	71.8	136.7	17,854	LGT OIL	126	5,809,524	732.0	5,737	13.99	45.53
23. B.B.C.T.#2	80	199	0.3	71.1	82.9	15,779	LGT OIL	542	5,793,358	3,140.0	24,680	12.40	45.54
24. B.B.C.T.#3	70	164	0.3	70.7	78.1	16,659	LGT OIL	471	5,800,425	2,732.0	21,447	13.08	45.54
25. C.T. TOTAL (OIL)	**165**	**404**	**0.3**	**71.0**	**30.6**	**16,347**	**LGT OIL**	**1,139**	**5,798,068**	**6,604.0**	**51,864**	**12.84**	**45.53**
26. TOT COAL (BB,POLK)	**2,019**	**954,683**	**63.6**	**64.4**	**20.4**	**10,541**	**COAL**	**414,921**	**24,252,930**	**10,063,050.0**	**21,671,751**	**2.27**	**52.23**
27. SYSTEM	**4,411**	**1,423,336**	**43.4**	**84.6**	**10.5**	**9,541**	**-**	**-**	**-**	**13,579,706.0**	**49,366,170**	**3.47**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: FEBRUARY 2005

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	428	182,932	63.6	76.0	79.2	10,460	COAL	78,551	24,359,970	1,913,500.0	4,187,066	2.29	53.30
2. B.B.#2	433	139,834	48.1	66.1	74.6	10,691	COAL	61,372	24,359,969	1,495,020.0	3,271,360	2.34	53.30
3. B.B.#3	438	185,069	62.9	73.1	76.0	10,655	COAL	81,144	24,302,105	1,971,970.0	4,325,283	2.34	53.30
4. B.B.#4	460	204,738	66.2	74.3	83.5	10,592	COAL	93,273	23,249,922	2,168,590.0	4,971,804	2.43	53.30
5. B.B. STA.	**1,759**	**712,573**	**60.3**	**72.4**	**19.6**	**10,594**	**COAL**	**314,340**	**24,015,652**	**7,549,080.0**	**16,755,513**	**2.35**	**53.30**
6. PHILLIPS #1 (HVY OIL)	17	36	0.3	59.8	105.9	11,764	HVY OIL	57	7,429,825	423.5	2,605	7.24	45.70
7. PHILLIPS #2 (HVY OIL)	17	50	0.4	92.6	98.0	8,470	HVY OIL	78	5,429,487	423.5	3,564	7.13	45.69
8. SEB-PHILLIPS TOTAL	**34**	**86**	**0.4**	**76.2**	**50.6**	**9,849**	**HVY OIL**	**135**	**6,274,074**	**847.0**	**6,169**	**7.17**	**45.70**
9. POLK #1 GASIFIER	260	142,708	81.7	-	-	10,246	COAL	56,900	25,697,891	1,462,210.0	2,693,330	1.89	47.33
10. POLK #1 CT OIL	260	7,511	4.3	-	-	10,243	LGT OIL	13,300	5,784,361	76,932.0	622,685	8.29	46.82
11. POLK #1 TOTAL	**260**	**150,219**	**86.0**	**84.6**	**93.8**	**10,246**		**-**	**-**	**1,539,142.0**	**3,316,015**	**2.21**	**-**
12. POLK #2 CT GAS	180	23	0.0	-	-	14,391	GAS	300	1,103,333	331.0	2,402	10.44	8.01
13. POLK #2 CT OIL	180	8	0.0	-	-	13,750	LGT OIL	0	0	110.0	0	0.00	0.00
14. POLK #2 TOTAL	**180**	**31**	**0.0**	**95.8**	**0.0**	**14,226**		**-**	**-**	**441.0**	**2,402**	**7.75**	**-**
15. POLK #3 CT GAS	180	10	0.0	0.0	-	13,500	GAS	100	1,350,000	135.0	801	8.01	8.01
16. POLK #3 CT OIL	180	3	0.0	0.0	-	15,000	LGT OIL	0	0	45.0	0	0.00	0.00
17. POLK #3 TOTAL	**180**	**13**	**0.0**	**95.8**	**0.0**	**13,846**		**-**	**-**	**180.0**	**801**	**6.16**	**-**
18. CITY OF TAMPA GAS	**6**	**4**	**0.1**	**100.0**	**105.8**	**9,500**	GAS	**37**	1,027,027	**38.0**	**365**	**9.13**	**9.86**
19. BAYSIDE #1	787	275,227	52.0	93.9	70.8	7,363	GAS	1,971,100	1,028,045	2,026,380.0	15,782,598	5.73	8.01
20. BAYSIDE #2	1,040	148,692	21.3	93.7	59.4	7,520	GAS	1,087,700	1,027,986	1,118,140.0	8,709,214	5.86	8.01
21. BAYSIDE TOTAL	**1,827**	**423,919**	**34.5**	**93.8**	**31.6**	**7,418**	**GAS**	**3,058,800**	**1,028,024**	**3,144,520.0**	**24,491,812**	**5.78**	**8.01**
22. B.B.C.T.#1	15	0	0.0	71.7	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
23. B.B.C.T.#2	80	1	0.0	71.1	0.0	22,000	LGT OIL	4	5,500,000	22.0	316	31.60	79.00
24. B.B.C.T.#3	70	1	0.0	70.7	0.0	9,000	LGT OIL	2	4,500,000	9.0	158	15.80	79.00
25. C.T. TOTAL (OIL)	**165**	**2**	**0.0**	**71.0**	**0.0**	**15,500**	**LGT OIL**	**6**	**5,166,667**	**31.0**	**474**	**23.70**	**79.00**
26. TOT COAL (BB,POLK)	**2,019**	**855,281**	**63.0**	**63.1**	**20.5**	**10,536**	**COAL**	**371,240**	**24,273,489**	**9,011,290.0**	**19,448,843**	**2.27**	**52.39**
27. SYSTEM	**4,411**	**1,286,847**	**43.4**	**83.9**	**10.4**	**9,507**	**-**	**-**	**-**	**12,234,279.0**	**44,573,551**	**3.46**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: MARCH 2005

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	428	203,005	63.8	76.0	79.3	10,518	COAL	87,652	24,360,083	2,135,210.0	4,612,026	2.27	52.62
2. B.B.#2	433	208,811	64.8	66.1	78.9	10,648	COAL	91,278	24,359,868	2,223,520.0	4,802,817	2.30	52.62
3. B.B.#3	438	194,544	59.7	73.1	72.3	10,696	COAL	85,310	24,391,748	2,080,860.0	4,488,796	2.31	52.62
4. B.B.#4	460	152,726	44.6	49.1	85.1	10,586	COAL	69,540	23,249,928	1,616,800.0	3,659,018	2.40	52.62
5. B.B. STA.	**1,759**	**759,086**	**58.0**	**65.8**	**19.5**	**10,613**	**COAL**	**333,780**	**24,136,827**	**8,056,390.0**	**17,562,657**	**2.31**	**52.62**
6. PHILLIPS #1 (HVY OIL)	17	34	0.3	21.0	100.0	33,647	HVY OIL	54	21,185,185	1,144.0	2,349	6.91	43.50
7. PHILLIPS #2 (HVY OIL)	17	200	1.6	74.6	98.0	5,720	HVY OIL	311	3,678,457	1,144.0	13,527	6.76	43.50
8. SEB-PHILLIPS TOTAL	**34**	**234**	**0.9**	**47.8**	**49.2**	**9,778**	**HVY OIL**	**365**	**6,268,493**	**2,288.0**	**15,876**	**6.78**	**43.50**
9. POLK #1 GASIFIER	260	158,015	81.7	-	-	10,246	COAL	63,000	25,698,254	1,618,990.0	2,984,066	1.89	47.37
10. POLK #1 CT OIL	260	8,317	4.3	-	-	10,242	LGT OIL	14,700	5,794,830	85,184.0	685,938	8.25	46.66
11. POLK #1 TOTAL	**260**	**166,332**	**86.0**	**84.6**	**93.8**	**10,246**		**-**	**-**	**1,704,174.0**	**3,670,004**	**2.21**	**-**
12. POLK #2 CT GAS	180	192	0.1	-	-	13,984	GAS	2,600	1,032,692	2,685.0	20,415	10.63	7.85
13. POLK #2 CT OIL	180	64	0.0	-	-	13,984	LGT OIL	200	4,475,000	895.0	9,241	14.44	46.21
14. POLK #2 TOTAL	**180**	**256**	**0.2**	**95.8**	**47.4**	**13,984**		**-**	**-**	**3,580.0**	**29,656**	**11.58**	**-**
15. POLK #3 CT GAS	180	69	0.1	0.0	-	13,942	GAS	900	1,068,889	962.0	7,067	10.24	7.85
16. POLK #3 CT OIL	180	23	0.0	0.0	-	13,957	LGT OIL	100	3,210,000	321.0	4,621	20.09	46.21
17. POLK #3 TOTAL	**180**	**92**	**0.1**	**95.8**	**51.1**	**13,946**		**-**	**-**	**1,283.0**	**11,688**	**12.70**	**-**
18. CITY OF TAMPA GAS	**6**	**41**	**0.9**	**100.0**	**96.1**	**10,439**	GAS	**417**	1,026,379	**428.0**	**4,050**	**9.88**	**9.71**
19. BAYSIDE #1	787	143,154	24.4	93.9	70.3	7,472	GAS	1,040,500	1,028,006	1,069,640.0	8,169,798	5.71	7.85
20. BAYSIDE #2	1,040	227,784	29.4	63.5	80.7	7,481	GAS	1,657,600	1,027,992	1,704,000.0	13,015,144	5.71	7.85
21. BAYSIDE TOTAL	**1,827**	**370,938**	**27.3**	**76.6**	**38.3**	**7,477**	**GAS**	**2,698,100**	**1,027,997**	**2,773,640.0**	**21,184,942**	**5.71**	**7.85**
22. B.B.C.T.#1	15	0	0.0	71.8	0.0	0	LGT OIL	1	8,000,000	8.0	56	0.00	56.00
23. B.B.C.T.#2	80	4	0.0	71.1	0.0	18,000	LGT OIL	12	6,000,000	72.0	678	16.95	56.50
24. B.B.C.T.#3	70	2	0.0	70.7	0.0	17,000	LGT OIL	6	5,666,667	34.0	339	16.95	56.50
25. C.T. TOTAL (OIL)	**165**	**6**	**0.0**	**71.0**	**0.0**	**19,000**	**LGT OIL**	**19**	**6,000,000**	**114.0**	**1,073**	**17.88**	**56.47**
26. TOT COAL (BB,POLK)	**2,019**	**917,101**	**61.1**	**57.3**	**20.5**	**10,550**	**COAL**	**396,780**	**24,384,747**	**9,675,380.0**	**20,546,723**	**2.24**	**51.78**
27. SYSTEM	**4,411**	**1,296,985**	**39.5**	**73.9**	**10.6**	**9,670**	**-**	**-**	**-**	**12,541,897.0**	**42,479,946**	**3.28**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: APRIL 2005

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	421	196,125	64.7	76.0	80.6	10,519	COAL	84,688	24,360,122	2,063,010.0	4,448,130	2.27	52.52
2. B.B.#2	411	194,237	65.6	66.1	80.8	10,657	COAL	84,975	24,359,988	2,069,990.0	4,463,204	2.30	52.52
3. B.B.#3	428	197,111	64.0	73.1	77.4	10,683	COAL	86,651	24,302,085	2,105,800.0	4,551,234	2.31	52.52
4. B.B.#4	452	237,793	73.1	80.1	85.5	10,592	COAL	108,328	23,249,945	2,518,620.0	5,689,791	2.39	52.52
5. B.B. STA.	**1,712**	**825,266**	**67.0**	**74.0**	**20.3**	**10,612**	**COAL**	**364,642**	**24,016,487**	**8,757,420.0**	**19,152,359**	**2.32**	**52.52**
6. PHILLIPS #1 (HVY OIL)	17	124	1.0	93.1	91.2	8,331	HVY OIL	192	5,380,208	1,033.0	8,520	6.87	44.37
7. PHILLIPS #2 (HVY OIL)	17	88	0.7	67.8	103.5	11,739	HVY OIL	137	7,540,146	1,033.0	6,079	6.91	44.37
8. SEB-PHILLIPS TOTAL	**34**	**212**	**0.9**	**80.4**	**48.0**	**9,745**	**HVY OIL**	**329**	**6,279,635**	**2,066.0**	**14,599**	**6.89**	**44.37**
9. POLK #1 GASIFIER	255	96,294	52.4	-	-	10,257	COAL	38,400	25,720,260	987,658.0	1,833,536	1.90	47.75
10. POLK #1 CT OIL	255	5,068	2.8	-	-	10,246	LGT OIL	9,000	5,769,889	51,929.0	416,992	8.23	46.33
11. POLK #1 TOTAL	**255**	**101,362**	**55.2**	**56.4**	**90.3**	**10,256**		**-**	**-**	**1,039,587.0**	**2,250,528**	**2.22**	**-**
12. POLK #2 CT GAS	160	75	0.1	-	-	14,533	GAS	1,100	990,909	1,090.0	7,935	10.58	7.21
13. POLK #2 CT OIL	160	25	0.0	-	-	14,520	LGT OIL	100	3,630,000	363.0	4,465	17.86	44.65
14. POLK #2 TOTAL	**160**	**100**	**0.1**	**95.8**	**62.5**	**14,530**		**-**	**-**	**1,453.0**	**12,400**	**12.40**	**-**
15. POLK #3 CT GAS	165	28	0.0	0.0	-	14,500	GAS	400	1,015,000	406.0	2,885	10.30	7.21
16. POLK #3 CT OIL	165	9	0.0	0.0	-	15,000	LGT OIL	0	0	135.0	0	0.00	0.00
17. POLK #3 TOTAL	**165**	**37**	**0.0**	**95.8**	**0.0**	**14,622**		**-**	**-**	**541.0**	**2,885**	**7.80**	**-**
18. CITY OF TAMPA GAS	**6**	**20**	**0.5**	**100.0**	**95.8**	**10,450**	**GAS**	**203**	**1,029,557**	**209.0**	**1,914**	**9.57**	**9.43**
19. BAYSIDE #1	702	171,658	34.0	72.0	83.0	7,451	GAS	1,244,200	1,028,018	1,279,060.0	8,974,663	5.23	7.21
20. BAYSIDE #2	930	258,850	38.7	93.7	73.5	7,471	GAS	1,881,200	1,027,982	1,933,840.0	13,569,472	5.24	7.21
21. BAYSIDE TOTAL	**1,632**	**430,508**	**36.6**	**84.4**	**39.2**	**7,463**	**GAS**	**3,125,400**	**1,027,996**	**3,212,900.0**	**22,544,135**	**5.24**	**7.21**
22. B.B.C.T.#1	14	0	0.0	71.7	0.0	0	LGT OIL	0	0	1.0	0	0.00	0.00
23. B.B.C.T.#2	66	2	0.0	71.1	0.0	13,000	LGT OIL	5	5,200,000	26.0	372	18.60	74.40
24. B.B.C.T.#3	60	1	0.0	70.7	0.0	14,000	LGT OIL	2	7,000,000	14.0	149	14.90	74.50
25. C.T. TOTAL (OIL)	**140**	**3**	**0.0**	**71.0**	**0.0**	**13,667**	**LGT OIL**	**7**	**5,857,143**	**41.0**	**521**	**17.37**	**74.43**
26. TOT COAL (BB,POLK)	**1,967**	**921,560**	**65.1**	**64.4**	**19.7**	**10,575**	**COAL**	**403,042**	**24,178,815**	**9,745,078.0**	**20,985,895**	**2.28**	**52.07**
27. SYSTEM	**4,104**	**1,357,508**	**45.9**	**78.7**	**10.8**	**9,587**	**-**	**-**	**-**	**13,014,217.0**	**43,979,341**	**3.24**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: MAY 2005

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	421	202,436	64.6	76.0	80.4	10,583	COAL	87,950	24,359,977	2,142,460.0	4,588,304	2.27	52.17
2. B.B.#2	411	153,580	50.2	66.1	79.2	10,691	COAL	67,403	24,360,043	1,641,940.0	3,516,378	2.29	52.17
3. B.B.#3	428	203,938	64.0	73.1	77.5	10,671	COAL	89,547	24,302,098	2,176,180.0	4,671,619	2.29	52.17
4. B.B.#4	452	240,028	71.4	80.1	83.5	10,645	COAL	109,895	23,249,829	2,555,040.0	5,733,163	2.39	52.17
5. B.B. STA.	**1,712**	**799,982**	**62.8**	**74.0**	**20.1**	**10,645**	**COAL**	**354,795**	**24,001,522**	**8,515,620.0**	**18,509,464**	**2.31**	**52.17**
6. PHILLIPS #1 (HVY OIL)	17	1,861	14.7	92.9	97.7	9,718	HVY OIL	2,895	6,246,805	18,084.5	127,889	6.87	44.18
7. PHILLIPS #2 (HVY OIL)	17	1,841	14.6	92.6	98.4	9,823	HVY OIL	2,865	6,312,216	18,084.5	126,564	6.87	44.18
8. SEB-PHILLIPS TOTAL	**34**	**3,702**	**14.6**	**92.7**	**49.0**	**9,770**	**HVY OIL**	**5,760**	**6,279,340**	**36,169.0**	**254,453**	**6.87**	**44.18**
9. POLK #1 GASIFIER	255	139,690	73.6	-	-	10,365	COAL	56,400	25,672,163	1,447,910.0	2,668,814	1.91	47.32
10. POLK #1 CT OIL	255	7,352	3.9	-	-	10,362	LGT OIL	13,100	5,815,267	76,180.0	598,291	8.14	45.67
11. POLK #1 TOTAL	**255**	**147,042**	**77.5**	**84.6**	**84.6**	**10,365**		**-**	**-**	**1,524,090.0**	**3,267,105**	**2.22**	**-**
12. POLK #2 CT GAS	160	697	0.6	-	-	14,356	GAS	9,800	1,021,020	10,006.0	69,331	9.95	7.07
13. POLK #2 CT OIL	160	232	0.2	-	-	14,375	LGT OIL	600	5,558,333	3,335.0	25,989	11.20	43.32
14. POLK #2 TOTAL	**160**	**929**	**0.8**	**95.8**	**52.8**	**14,361**		**-**	**-**	**13,341.0**	**95,320**	**10.26**	**-**
15. POLK #3 CT GAS	165	311	0.3	0.0	-	14,206	GAS	4,300	1,027,442	4,418.0	30,421	9.78	7.07
16. POLK #3 CT OIL	165	104	0.1	0.0	-	14,163	LGT OIL	300	4,910,000	1,473.0	12,994	12.49	43.31
17. POLK #3 TOTAL	**165**	**415**	**0.3**	**95.8**	**50.3**	**14,195**		**-**	**-**	**5,891.0**	**43,415**	**10.46**	**-**
18. CITY OF TAMPA GAS	**6**	**548**	**12.3**	**100.0**	**96.1**	**10,465**	GAS	**5,579**	1,027,962	**5,735.0**	**51,707**	**9.44**	**9.27**
19. BAYSIDE #1	702	274,688	52.6	93.9	87.6	7,499	GAS	2,003,900	1,027,995	2,060,000.0	14,176,791	5.16	7.07
20. BAYSIDE #2	930	445,290	64.4	93.7	90.1	7,450	GAS	3,227,200	1,027,990	3,317,530.0	22,831,149	5.13	7.07
21. BAYSIDE TOTAL	**1,632**	**719,978**	**59.3**	**93.8**	**45.1**	**7,469**	**GAS**	**5,231,100**	**1,027,992**	**5,377,530.0**	**37,007,940**	**5.14**	**7.07**
22. B.B.C.T.#1	14	3	0.0	71.8	0.0	19,333	LGT OIL	10	5,800,000	58.0	457	15.23	45.70
23. B.B.C.T.#2	66	25	0.1	71.1	0.0	16,520	LGT OIL	71	5,816,901	413.0	3,244	12.98	45.69
24. B.B.C.T.#3	60	15	0.0	70.7	0.0	17,733	LGT OIL	46	5,782,609	266.0	2,102	14.01	45.70
25. C.T. TOTAL (OIL)	**140**	**43**	**0.0**	**71.0**	**0.0**	**17,140**	**LGT OIL**	**127**	**5,803,150**	**737.0**	**5,803**	**13.50**	**45.69**
26. TOT COAL (BB,POLK)	**1,967**	**939,672**	**64.2**	**64.4**	**20.6**	**10,603**	**COAL**	**411,195**	**24,230,669**	**9,963,530.0**	**21,178,278**	**2.25**	**51.50**
27. SYSTEM	**4,104**	**1,672,639**	**54.8**	**84.3**	**11.3**	**9,254**	**-**	**-**	**-**	**15,479,113.0**	**59,235,207**	**3.54**	**-**

LEGEND:
B.B. = BIG BEND
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: JUNE 2005

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	421	196,012	64.7	76.0	80.6	10,609	COAL	85,368	24,360,065	2,079,570.0	4,439,302	2.26	52.00
2. B.B.#2	411	200,927	67.9	66.1	82.6	10,708	COAL	88,319	24,359,990	2,151,450.0	4,592,760	2.29	52.00
3. B.B.#3	428	200,766	65.1	73.1	78.8	10,713	COAL	88,501	24,302,211	2,150,770.0	4,602,224	2.29	52.00
4. B.B.#4	452	176,960	54.4	80.1	81.1	10,739	COAL	81,737	23,249,936	1,900,380.0	4,250,483	2.40	52.00
5. B.B. STA.	**1,712**	**774,665**	**62.8**	**74.0**	**20.1**	**10,691**	**COAL**	**343,925**	**24,081,326**	**8,282,170.0**	**17,884,769**	**2.31**	**52.00**
6. PHILLIPS #1 (HVY OIL)	17	2,224	18.2	93.1	99.1	9,757	HVY OIL	3,461	6,270,009	21,700.5	153,448	6.90	44.34
7. PHILLIPS #2 (HVY OIL)	17	2,218	18.1	92.5	98.8	9,784	HVY OIL	3,451	6,288,177	21,700.5	153,004	6.90	44.34
8. SEB-PHILLIPS TOTAL	**34**	**4,442**	**18.1**	**92.8**	**49.5**	**9,771**	**HVY OIL**	**6,912**	**6,279,080**	**43,401.0**	**306,452**	**6.90**	**44.34**
9. POLK #1 GASIFIER	255	135,184	73.6	-	-	10,365	COAL	54,500	25,710,459	1,401,220.0	2,576,210	1.91	47.27
10. POLK #1 CT OIL	255	7,115	3.9	-	-	10,361	LGT OIL	12,700	5,804,882	73,722.0	570,497	8.02	44.92
11. POLK #1 TOTAL	**255**	**142,299**	**77.5**	**84.6**	**84.6**	**10,365**		**-**	**-**	**1,474,942.0**	**3,146,707**	**2.21**	**-**
12. POLK #2 CT GAS	160	2,659	2.3	-	-	14,269	GAS	36,900	1,028,238	37,942.0	257,473	9.68	6.98
13. POLK #2 CT OIL	160	886	0.8	-	-	14,274	LGT OIL	2,200	5,748,636	12,647.0	92,947	10.49	42.25
14. POLK #2 TOTAL	**160**	**3,545**	**3.1**	**95.8**	**55.4**	**14,271**		**-**	**-**	**50,589.0**	**350,420**	**9.88**	**-**
15. POLK #3 CT GAS	165	1,506	1.3	0.0	-	14,148	GAS	20,700	1,029,324	21,307.0	144,436	9.59	6.98
16. POLK #3 CT OIL	165	502	0.4	0.0	-	14,147	LGT OIL	1,200	5,918,333	7,102.0	50,698	10.10	42.25
17. POLK #3 TOTAL	**165**	**2,008**	**1.7**	**95.8**	**55.3**	**14,148**		**-**	**-**	**28,409.0**	**195,134**	**9.72**	**-**
18. CITY OF TAMPA GAS	**6**	**584**	**13.5**	**100.0**	**96.3**	**10,452**	GAS	**5,938**	1,027,956	**6,104.0**	**54,503**	**9.33**	**9.18**
19. BAYSIDE #1	702	295,551	58.5	93.9	88.0	7,497	GAS	2,155,300	1,028,001	2,215,650.0	15,038,821	5.09	6.98
20. BAYSIDE #2	930	452,850	67.6	93.7	89.0	7,454	GAS	3,283,500	1,027,979	3,375,370.0	22,910,950	5.06	6.98
21. BAYSIDE TOTAL	**1,632**	**748,401**	**63.7**	**93.8**	**44.7**	**7,471**	**GAS**	**5,438,800**	**1,027,988**	**5,591,020.0**	**37,949,771**	**5.07**	**6.98**
22. B.B.C.T.#1	14	6	0.1	71.7	42.9	18,833	LGT OIL	19	5,947,368	113.0	880	14.67	46.32
23. B.B.C.T.#2	66	41	0.1	71.1	62.1	16,366	LGT OIL	116	5,784,483	671.0	5,374	13.11	46.33
24. B.B.C.T.#3	60	25	0.1	70.7	41.7	17,680	LGT OIL	76	5,815,789	442.0	3,521	14.08	46.33
25. C.T. TOTAL (OIL)	**140**	**72**	**0.1**	**71.0**	**17.1**	**17,028**	**LGT OIL**	**211**	**5,810,427**	**1,226.0**	**9,775**	**13.58**	**46.33**
26. TOT COAL (BB,POLK)	**1,967**	**909,849**	**64.2**	**64.4**	**20.6**	**10,643**	**COAL**	**398,425**	**24,304,173**	**9,683,390.0**	**20,460,979**	**2.25**	**51.35**
27. SYSTEM	**4,104**	**1,676,016**	**56.7**	**84.3**	**11.2**	**9,235**	**-**	**-**	**-**	**15,477,861.0**	**59,897,531**	**3.57**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: JULY 2005

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	421	200,594	64.0	76.0	80.5	10,698	COAL	88,095	24,360,066	2,146,000.0	4,579,388	2.28	51.98
2. B.B.#2	411	207,676	67.9	66.1	83.5	10,754	COAL	91,678	24,360,043	2,233,280.0	4,765,641	2.29	51.98
3. B.B.#3	428	210,897	66.2	73.1	80.1	10,793	COAL	93,666	24,301,988	2,276,270.0	4,868,982	2.31	51.98
4. B.B.#4	452	189,143	56.2	80.1	82.7	10,778	COAL	87,677	23,250,111	2,038,500.0	4,557,659	2.41	51.98
5. B.B. STA.	**1,712**	**808,310**	**63.5**	**74.0**	**20.4**	**10,756**	**COAL**	**361,116**	**24,075,505**	**8,694,050.0**	**18,771,670**	**2.32**	**51.98**
6. PHILLIPS #1 (HVY OIL)	17	3,300	26.1	92.9	99.0	9,759	HVY OIL	5,136	6,270,444	32,205.0	226,967	6.88	44.19
7. PHILLIPS #2 (HVY OIL)	17	3,292	26.0	92.6	99.3	9,783	HVY OIL	5,122	6,287,583	32,205.0	226,349	6.88	44.19
8. SEB-PHILLIPS TOTAL	**34**	**6,592**	**26.1**	**92.7**	**49.6**	**9,771**	**HVY OIL**	**10,258**	**6,279,002**	**64,410.0**	**453,316**	**6.88**	**44.19**
9. POLK #1 GASIFIER	255	139,690	73.6	-	-	10,365	COAL	56,400	25,672,163	1,447,910.0	2,658,167	1.90	47.13
10. POLK #1 CT OIL	255	7,352	3.9	-	-	10,362	LGT OIL	13,100	5,815,267	76,180.0	579,203	7.88	44.21
11. POLK #1 TOTAL	**255**	**147,042**	**77.5**	**84.6**	**84.6**	**10,365**		**-**	**-**	**1,524,090.0**	**3,237,370**	**2.20**	**-**
12. POLK #2 CT GAS	160	9,647	8.1	-	-	14,209	GAS	133,300	1,028,327	137,076.0	942,724	9.77	7.07
13. POLK #2 CT OIL	160	3,216	2.7	-	-	14,208	LGT OIL	7,900	5,783,797	45,692.0	329,747	10.25	41.74
14. POLK #2 TOTAL	**160**	**12,863**	**10.8**	**95.8**	**57.0**	**14,209**		**-**	**-**	**182,768.0**	**1,272,471**	**9.89**	**-**
15. POLK #3 CT GAS	165	6,322	5.1	0.0	-	14,099	GAS	86,700	1,028,039	89,131.0	613,160	9.70	7.07
16. POLK #3 CT OIL	165	2,107	1.7	0.0	-	14,101	LGT OIL	5,100	5,825,490	29,710.0	212,875	10.10	41.74
17. POLK #3 TOTAL	**165**	**8,429**	**6.9**	**95.8**	**55.5**	**14,099**		**-**	**-**	**118,841.0**	**826,035**	**9.80**	**-**
18. CITY OF TAMPA GAS	**6**	**828**	**18.5**	**100.0**	**96.3**	**10,452**	GAS	**8,418**	1,028,035	**8,654.0**	**78,347**	**9.46**	**9.31**
19. BAYSIDE #1	702	331,082	63.4	93.9	87.9	7,490	GAS	2,412,300	1,028,027	2,479,910.0	17,060,268	5.15	7.07
20. BAYSIDE #2	930	485,112	70.1	93.7	89.8	7,453	GAS	3,517,200	1,027,988	3,615,640.0	24,874,342	5.13	7.07
21. BAYSIDE TOTAL	**1,632**	**816,194**	**67.2**	**93.8**	**44.8**	**7,468**	**GAS**	**5,929,500**	**1,028,004**	**6,095,550.0**	**41,934,610**	**5.14**	**7.07**
22. B.B.C.T.#1	14	71	0.7	71.8	84.5	19,620	LGT OIL	240	5,804,167	1,393.0	10,805	15.22	45.02
23. B.B.C.T.#2	66	454	0.9	71.1	76.4	16,388	LGT OIL	1,284	5,794,393	7,440.0	57,807	12.73	45.02
24. B.B.C.T.#3	60	312	0.7	70.7	74.3	17,369	LGT OIL	935	5,795,722	5,419.0	42,095	13.49	45.02
25. C.T. TOTAL (OIL)	**140**	**837**	**0.8**	**71.0**	**27.2**	**17,027**	**LGT OIL**	**2,459**	**5,795,852**	**14,252.0**	**110,707**	**13.23**	**45.02**
26. TOT COAL (BB,POLK)	**1,967**	**948,000**	**64.8**	**64.4**	**20.8**	**10,698**	**COAL**	**417,516**	**24,291,189**	**10,141,960.0**	**21,429,837**	**2.26**	**51.33**
27. SYSTEM	**4,104**	**1,801,095**	**59.0**	**84.3**	**11.0**	**9,274**	**-**	**-**	**-**	**16,702,615.0**	**66,684,526**	**3.70**	**-**

LEGEND:
B.B. = BIG BEND
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: AUGUST 2005

	(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1.	B.B.#1	421	202,823	64.8	76.0	80.6	10,697	COAL	89,063	24,359,947	2,169,570.0	4,608,739	2.27	51.75
2.	B.B.#2	411	210,066	68.7	66.1	83.7	10,753	COAL	92,726	24,360,050	2,258,810.0	4,798,288	2.28	51.75
3.	B.B.#3	428	212,603	66.8	73.1	80.8	10,789	COAL	94,387	24,302,181	2,293,810.0	4,884,240	2.30	51.75
4.	B.B.#4	452	191,572	57.0	80.1	83.1	10,774	COAL	88,774	23,249,938	2,063,990.0	4,593,785	2.40	51.75
5.	**B.B. STA.**	**1,712**	**817,064**	**64.1**	**74.0**	**20.4**	**10,753**	**COAL**	**364,950**	**24,075,024**	**8,786,180.0**	**18,885,052**	**2.31**	**51.75**
6.	PHILLIPS #1 (HVY OIL)	17	3,104	24.5	92.9	98.7	9,752	HVY OIL	4,830	6,266,977	30,269.5	214,579	6.91	44.43
7.	PHILLIPS #2 (HVY OIL)	17	3,092	24.4	92.6	99.4	9,790	HVY OIL	4,812	6,290,420	30,269.5	213,779	6.91	44.43
8.	**SEB-PHILLIPS TOTAL**	**34**	**6,196**	**24.5**	**92.7**	**49.5**	**9,771**	**HVY OIL**	**9,642**	**6,278,677**	**60,539.0**	**428,358**	**6.91**	**44.43**
9.	POLK #1 GASIFIER	255	139,690	73.6	-	-	10,365	COAL	56,400	25,672,163	1,447,910.0	2,652,168	1.90	47.02
10.	POLK #1 CT OIL	255	7,352	3.9	-	-	10,362	LGT OIL	13,100	5,815,267	76,180.0	573,158	7.80	43.75
11.	**POLK #1 TOTAL**	**255**	**147,042**	**77.5**	**84.6**	**84.6**	**10,365**		**-**	**-**	**1,524,090.0**	**3,225,326**	**2.19**	**-**
12.	POLK #2 CT GAS	160	10,187	8.6	-	-	14,078	GAS	139,500	1,028,065	143,415.0	987,562	9.69	7.08
13.	POLK #2 CT OIL	160	3,396	2.9	-	-	14,077	LGT OIL	8,200	5,829,878	47,805.0	345,181	10.16	42.10
14.	**POLK #2 TOTAL**	**160**	**13,583**	**11.4**	**95.8**	**58.5**	**14,078**		**-**	**-**	**191,220.0**	**1,332,743**	**9.81**	**-**
15.	POLK #3 CT GAS	165	7,014	5.7	0.0	-	13,928	GAS	95,000	1,028,316	97,690.0	672,534	9.59	7.08
16.	POLK #3 CT OIL	165	2,338	1.9	0.0	-	13,928	LGT OIL	5,600	5,814,821	32,563.0	235,734	10.08	42.10
17.	**POLK #3 TOTAL**	**165**	**9,352**	**7.6**	**95.8**	**57.8**	**13,928**		**-**	**-**	**130,253.0**	**908,268**	**9.71**	**-**
18.	**CITY OF TAMPA GAS**	**6**	**784**	**17.6**	**100.0**	**96.2**	**10,455**	GAS	**7,974**	1,027,966	**8,197.0**	**74,293**	**9.48**	**9.32**
19.	BAYSIDE #1	702	329,235	63.0	93.9	87.4	7,490	GAS	2,398,700	1,027,982	2,465,820.0	16,981,117	5.16	7.08
20.	BAYSIDE #2	930	487,570	70.5	93.7	89.6	7,454	GAS	3,535,200	1,027,996	3,634,170.0	25,026,741	5.13	7.08
21.	**BAYSIDE TOTAL**	**1,632**	**816,805**	**67.3**	**93.8**	**44.6**	**7,468**	**GAS**	**5,933,900**	**1,027,990**	**6,099,990.0**	**42,007,858**	**5.14**	**7.08**
22.	B.B.C.T.#1	14	70	0.7	71.8	83.3	19,557	LGT OIL	236	5,800,847	1,369.0	10,554	15.08	44.72
23.	B.B.C.T.#2	66	446	0.9	71.1	84.5	16,386	LGT OIL	1,261	5,795,400	7,308.0	56,390	12.64	44.72
24.	B.B.C.T.#3	60	307	0.7	70.7	85.3	17,329	LGT OIL	918	5,795,207	5,320.0	41,052	13.37	44.72
25.	**C.T. TOTAL (OIL)**	**140**	**823**	**0.8**	**71.0**	**29.4**	**17,007**	**LGT OIL**	**2,415**	**5,795,859**	**13,997.0**	**107,996**	**13.12**	**44.72**
26.	**TOT COAL (BB,POLK)**	**1,967**	**956,754**	**65.4**	**64.4**	**20.8**	**10,697**	**COAL**	**421,350**	**24,288,810**	**10,234,090.0**	**21,537,220**	**2.25**	**51.11**
27.	**SYSTEM**	**4,104**	**1,811,649**	**59.3**	**84.3**	**11.1**	**9,281**	-	-	-	**16,814,466.0**	**66,969,894**	**3.70**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: SEPTEMBER 2005

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	421	195,971	64.7	76.0	80.5	10,610	COAL	85,352	24,360,179	2,079,190.0	4,389,339	2.24	51.43
2. B.B.#2	411	200,922	67.9	66.1	82.6	10,708	COAL	88,320	24,360,054	2,151,480.0	4,541,972	2.26	51.43
3. B.B.#3	428	201,645	65.4	73.1	79.2	10,710	COAL	88,869	24,302,063	2,159,700.0	4,570,205	2.27	51.43
4. B.B.#4	452	177,559	54.6	80.1	80.7	10,743	COAL	82,041	23,249,960	1,907,450.0	4,219,066	2.38	51.43
5. B.B. STA.	**1,712**	**776,097**	**63.0**	**74.0**	**20.1**	**10,692**	**COAL**	**344,582**	**24,080,828**	**8,297,820.0**	**17,720,582**	**2.28**	**51.43**
6. PHILLIPS #1 (HVY OIL)	17	2,529	20.7	93.1	98.5	9,749	HVY OIL	3,935	6,265,565	24,655.0	176,354	6.97	44.82
7. PHILLIPS #2 (HVY OIL)	17	2,518	20.6	92.5	98.7	9,792	HVY OIL	3,918	6,292,751	24,655.0	175,592	6.97	44.82
8. SEB-PHILLIPS TOTAL	**34**	**5,047**	**20.6**	**92.8**	**49.3**	**9,770**	**HVY OIL**	**7,853**	**6,279,129**	**49,310.0**	**351,946**	**6.97**	**44.82**
9. POLK #1 GASIFIER	255	135,184	73.6	-	-	10,365	COAL	54,500	25,710,459	1,401,220.0	2,561,876	1.90	47.01
10. POLK #1 CT OIL	255	7,115	3.9	-	-	10,361	LGT OIL	12,700	5,804,882	73,722.0	551,929	7.76	43.46
11. POLK #1 TOTAL	**255**	**142,299**	**77.5**	**84.6**	**84.6**	**10,365**		**-**	**-**	**1,474,942.0**	**3,113,805**	**2.19**	**-**
12. POLK #2 CT GAS	160	2,292	2.0	-	-	14,338	GAS	32,000	1,026,969	32,863.0	226,995	9.90	7.09
13. POLK #2 CT OIL	160	764	0.7	-	-	14,338	LGT OIL	1,900	5,765,263	10,954.0	80,624	10.55	42.43
14. POLK #2 TOTAL	**160**	**3,056**	**2.7**	**95.8**	**54.6**	**14,338**		**-**	**-**	**43,817.0**	**307,619**	**10.07**	**-**
15. POLK #3 CT GAS	165	1,186	1.0	0.0	-	14,238	GAS	16,400	1,029,634	16,886.0	116,335	9.81	7.09
16. POLK #3 CT OIL	165	395	0.3	0.0	-	14,251	LGT OIL	1,000	5,629,000	5,629.0	42,434	10.74	42.43
17. POLK #3 TOTAL	**165**	**1,581**	**1.3**	**95.8**	**53.2**	**14,241**		**-**	**-**	**22,515.0**	**158,769**	**10.04**	**-**
18. CITY OF TAMPA GAS	**6**	**662**	**15.3**	**100.0**	**96.3**	**10,458**	GAS	**6,734**	1,028,067	**6,923.0**	**62,572**	**9.45**	**9.29**
19. BAYSIDE #1	702	298,571	59.1	93.9	88.0	7,496	GAS	2,177,100	1,028,005	2,238,070.0	15,443,477	5.17	7.09
20. BAYSIDE #2	930	459,391	68.6	93.7	88.9	7,454	GAS	3,330,900	1,027,986	3,424,120.0	23,628,072	5.14	7.09
21. BAYSIDE TOTAL	**1,632**	**757,962**	**64.5**	**93.8**	**44.7**	**7,470**	**GAS**	**5,508,000**	**1,027,994**	**5,662,190.0**	**39,071,549**	**5.15**	**7.09**
22. B.B.C.T.#1	14	6	0.1	71.7	42.9	20,667	LGT OIL	21	5,904,762	124.0	952	15.87	45.33
23. B.B.C.T.#2	66	45	0.1	71.1	68.2	16,467	LGT OIL	128	5,789,063	741.0	5,803	12.90	45.34
24. B.B.C.T.#3	60	28	0.1	70.7	46.7	17,786	LGT OIL	86	5,790,698	498.0	3,899	13.93	45.34
25. C.T. TOTAL (OIL)	**140**	**79**	**0.1**	**71.0**	**18.8**	**17,253**	**LGT OIL**	**235**	**5,800,000**	**1,363.0**	**10,654**	**13.49**	**45.34**
26. TOT COAL (BB,POLK)	**1,967**	**911,281**	**64.3**	**64.4**	**20.6**	**10,643**	**COAL**	**399,082**	**24,303,376**	**9,699,040.0**	**20,282,458**	**2.23**	**50.82**
27. SYSTEM	**4,104**	**1,686,783**	**57.1**	**84.3**	**11.1**	**9,224**	**-**	**-**	**-**	**15,558,880.0**	**60,797,496**	**3.60**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: OCTOBER 2005

	(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1.	B.B.#1	428	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2.	B.B.#2	433	116,194	36.1	36.3	80.1	10,635	COAL	50,730	24,359,945	1,235,780.0	2,592,218	2.23	51.10
3.	B.B.#3	438	223,790	68.7	73.1	83.1	10,642	COAL	97,640	24,391,848	2,381,620.0	4,989,240	2.23	51.10
4.	B.B.#4	460	254,877	74.5	80.1	87.1	10,571	COAL	115,890	23,249,892	2,694,430.0	5,921,784	2.32	51.10
5.	**B.B. STA.**	**1,759**	**594,861**	**45.5**	**48.1**	**21.3**	**10,611**	**COAL**	**264,260**	**23,884,924**	**6,311,830.0**	**13,503,242**	**2.27**	**51.10**
6.	PHILLIPS #1 (HVY OIL)	17	1,418	11.2	92.9	98.1	9,719	HVY OIL	2,207	6,244,223	13,781.0	99,338	7.01	45.01
7.	PHILLIPS #2 (HVY OIL)	17	1,403	11.1	92.6	98.2	9,823	HVY OIL	2,183	6,312,872	13,781.0	98,258	7.00	45.01
8.	**SEB-PHILLIPS TOTAL**	**34**	**2,821**	**11.2**	**92.7**	**49.1**	**9,770**	**HVY OIL**	**4,390**	**6,278,360**	**27,562.0**	**197,596**	**7.00**	**45.01**
9.	POLK #1 GASIFIER	260	114,260	59.1	-	-	10,251	COAL	45,600	25,685,088	1,171,240.0	2,140,752	1.87	46.95
10.	POLK #1 CT OIL	260	6,014	3.1	-	-	10,246	LGT OIL	10,600	5,813,019	61,618.0	456,121	7.58	43.03
11.	**POLK #1 TOTAL**	**260**	**120,274**	**62.2**	**81.6**	**91.4**	**10,250**		**-**	**-**	**1,232,858.0**	**2,596,873**	**2.16**	**-**
12.	POLK #2 CT GAS	180	2,201	1.6	-	-	14,431	GAS	30,900	1,027,896	31,762.0	214,282	9.74	6.93
13.	POLK #2 CT OIL	180	734	0.5	-	-	14,424	LGT OIL	1,800	5,881,667	10,587.0	74,118	10.10	41.18
14.	**POLK #2 TOTAL**	**180**	**2,935**	**2.2**	**95.8**	**49.4**	**14,429**		**-**	**-**	**42,349.0**	**288,400**	**9.83**	**-**
15.	POLK #3 CT GAS	180	1,104	0.8	0.0	-	14,352	GAS	15,400	1,028,896	15,845.0	106,794	9.67	6.93
16.	POLK #3 CT OIL	180	368	0.3	0.0	-	14,353	LGT OIL	900	5,868,889	5,282.0	37,059	10.07	41.18
17.	**POLK #3 TOTAL**	**180**	**1,472**	**1.1**	**95.8**	**48.1**	**14,353**		**-**	**-**	**21,127.0**	**143,853**	**9.77**	**-**
18.	**CITY OF TAMPA GAS**	**6**	**319**	**7.1**	**100.0**	**96.3**	**10,458**	GAS	**3,245**	1,028,043	**3,336.0**	**30,223**	**9.47**	**9.31**
19.	BAYSIDE #1	787	335,269	57.3	93.9	79.0	7,434	GAS	2,424,600	1,027,996	2,492,480.0	16,813,874	5.02	6.93
20.	BAYSIDE #2	1,040	454,482	58.7	93.7	75.9	7,436	GAS	3,287,300	1,028,002	3,379,350.0	22,796,439	5.02	6.93
21.	**BAYSIDE TOTAL**	**1,827**	**789,751**	**58.1**	**93.8**	**38.8**	**7,435**	**GAS**	**5,711,900**	**1,027,999**	**5,871,830.0**	**39,610,313**	**5.02**	**6.93**
22.	B.B.C.T.#1	15	5	0.0	55.5	0.0	19,600	LGT OIL	17	5,764,706	98.0	768	15.36	45.18
23.	B.B.C.T.#2	80	45	0.1	71.1	56.3	16,600	LGT OIL	129	5,790,698	747.0	5,831	12.96	45.20
24.	B.B.C.T.#3	70	28	0.1	70.7	40.0	17,357	LGT OIL	84	5,785,714	486.0	3,797	13.56	45.20
25.	**C.T. TOTAL (OIL)**	**165**	**78**	**0.1**	**69.5**	**23.6**	**17,064**	**LGT OIL**	**230**	**5,786,957**	**1,331.0**	**10,396**	**13.33**	**45.20**
26.	**TOT COAL (BB,POLK)**	**2,019**	**709,121**	**47.2**	**41.9**	**22.1**	**10,553**	**COAL**	**309,860**	**24,149,842**	**7,483,070.0**	**15,643,994**	**2.21**	**50.49**
27.	**SYSTEM**	**4,411**	**1,512,511**	**46.1**	**74.1**	**11.7**	**8,934**	**-**	**-**	**-**	**13,512,223.0**	**56,380,896**	**3.73**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: NOVEMBER 2005

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. B.B.#1	428	32,864	10.7	12.7	80.0	10,495	COAL	14,159	24,359,418	344,905.0	724,911	2.21	51.20
2. B.B.#2	433	204,717	65.7	66.1	96.4	10,651	COAL	89,510	24,359,960	2,180,460.0	4,582,723	2.24	51.20
3. B.B.#3	438	108,317	34.3	39.0	77.8	10,637	COAL	47,410	24,302,257	1,152,170.0	2,427,292	2.24	51.20
4. B.B.#4	460	243,800	73.6	80.1	86.2	10,597	COAL	111,118	23,249,969	2,583,490.0	5,689,007	2.33	51.20
5. B.B. STA.	**1,759**	**589,698**	**46.6**	**50.0**	**20.7**	**10,617**	**COAL**	**262,197**	**23,879,087**	**6,261,025.0**	**13,423,933**	**2.28**	**51.20**
6. PHILLIPS #1 (HVY OIL)	17	2,058	16.8	93.1	94.6	9,653	HVY OIL	3,199	6,209,753	19,865.0	140,856	6.84	44.03
7. PHILLIPS #2 (HVY OIL)	17	2,012	16.4	92.5	95.4	9,873	HVY OIL	3,128	6,350,703	19,865.0	137,730	6.85	44.03
8. SEB-PHILLIPS TOTAL	**34**	**4,070**	**16.6**	**92.8**	**47.5**	**9,762**	**HVY OIL**	**6,327**	**6,279,437**	**39,730.0**	**278,586**	**6.84**	**44.03**
9. POLK #1 GASIFIER	260	50,828	27.2	-	-	10,243	COAL	19,600	26,562,041	520,616.0	933,515	1.84	47.63
10. POLK #1 CT OIL	260	2,675	1.4	-	-	10,243	LGT OIL	4,700	5,830,000	27,401.0	200,876	7.51	42.74
11. POLK #1 TOTAL	**260**	**53,503**	**28.6**	**77.0**	**93.5**	**10,243**		**-**	**-**	**548,017.0**	**1,134,391**	**2.12**	**-**
12. POLK #2 CT GAS	180	532	0.4	-	-	13,280	GAS	6,900	1,023,913	7,065.0	48,441	9.11	7.02
13. POLK #2 CT OIL	180	177	0.1	-	-	13,305	LGT OIL	400	5,887,500	2,355.0	15,962	9.02	39.91
14. POLK #2 TOTAL	**180**	**709**	**0.5**	**95.8**	**56.3**	**13,286**		**-**	**-**	**9,420.0**	**64,403**	**9.08**	**-**
15. POLK #3 CT GAS	180	406	0.3	0.0	-	13,502	GAS	5,300	1,034,340	5,482.0	37,208	9.16	7.02
16. POLK #3 CT OIL	180	135	0.1	0.0	-	13,533	LGT OIL	300	6,090,000	1,827.0	11,972	8.87	39.91
17. POLK #3 TOTAL	**180**	**541**	**0.4**	**95.8**	**50.1**	**13,510**		**-**	**-**	**7,309.0**	**49,180**	**9.09**	**-**
18. CITY OF TAMPA GAS	**6**	**170**	**3.9**	**100.0**	**95.7**	**10,447**	**GAS**	**1,728**	**1,027,778**	**1,776.0**	**16,398**	**9.65**	**9.49**
19. BAYSIDE #1	787	245,642	43.4	93.9	71.9	7,412	GAS	1,771,100	1,027,994	1,820,680.0	12,433,830	5.06	7.02
20. BAYSIDE #2	1,045	469,816	62.4	93.7	76.1	7,428	GAS	3,394,900	1,028,013	3,490,000.0	23,833,556	5.07	7.02
21. BAYSIDE TOTAL	**1,832**	**715,458**	**54.2**	**93.8**	**38.1**	**7,423**	**GAS**	**5,166,000**	**1,028,006**	**5,310,680.0**	**36,267,386**	**5.07**	**7.02**
22. B.B.C.T.#1	15	0	0.0	71.7	0.0	0	LGT OIL	1	8,000,000	8.0	44	0.00	44.00
23. B.B.C.T.#2	80	4	0.0	71.1	0.0	17,750	LGT OIL	12	5,916,667	71.0	529	13.23	44.08
24. B.B.C.T.#3	70	2	0.0	70.7	0.0	17,000	LGT OIL	6	5,666,667	34.0	264	13.20	44.00
25. C.T. TOTAL (OIL)	**165**	**6**	**0.0**	**71.0**	**0.0**	**18,833**	**LGT OIL**	**19**	**5,947,368**	**113.0**	**837**	**13.95**	**44.05**
26. TOT COAL (BB,POLK)	**2,019**	**640,526**	**44.1**	**43.6**	**19.6**	**10,588**	**COAL**	**281,797**	**24,065,696**	**6,781,641.0**	**14,357,448**	**2.24**	**50.95**
27. SYSTEM	**4,416**	**1,364,155**	**42.9**	**74.7**	**10.6**	**8,927**	**-**	**-**	**-**	**12,178,070.0**	**51,235,114**	**3.76**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: DECEMBER 2005

	(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1.	B.B.#1	428	197,905	62.1	76.0	79.3	10,460	COAL	84,979	24,360,136	2,070,100.0	4,347,494	2.20	51.16
2.	B.B.#2	433	153,463	47.6	66.1	75.4	10,682	COAL	67,295	24,359,908	1,639,300.0	3,442,787	2.24	51.16
3.	B.B.#3	438	207,531	63.7	73.1	77.0	10,649	COAL	90,942	24,301,973	2,210,070.0	4,652,559	2.24	51.16
4.	B.B.#4	460	241,878	70.7	80.1	84.8	10,573	COAL	109,999	23,250,030	2,557,480.0	5,627,508	2.33	51.16
5.	**B.B. STA.**	**1,759**	**800,777**	**61.2**	**73.9**	**19.9**	**10,586**	**COAL**	**353,215**	**23,999,405**	**8,476,950.0**	**18,070,348**	**2.26**	**51.16**
6.	PHILLIPS #1 (HVY OIL)	17	786	6.2	92.9	96.3	9,646	HVY OIL	1,223	6,199,101	7,581.5	53,796	6.84	43.99
7.	PHILLIPS #2 (HVY OIL)	17	766	6.1	92.6	95.9	9,898	HVY OIL	1,192	6,360,319	7,581.5	52,433	6.85	43.99
8.	**SEB-PHILLIPS TOTAL**	**34**	**1,552**	**6.1**	**92.7**	**48.0**	**9,770**	**HVY OIL**	**2,415**	**6,278,675**	**15,163.0**	**106,229**	**6.84**	**43.99**
9.	POLK #1 GASIFIER	260	157,670	81.5	-	-	10,248	COAL	60,800	26,574,507	1,615,730.0	2,831,736	1.80	46.57
10.	POLK #1 CT OIL	260	8,298	4.3	-	-	10,245	LGT OIL	14,700	5,783,129	85,012.0	622,194	7.50	42.33
11.	**POLK #1 TOTAL**	**260**	**165,968**	**85.8**	**84.6**	**93.6**	**10,247**		**-**	**-**	**1,700,742.0**	**3,453,930**	**2.08**	**-**
12.	POLK #2 CT GAS	180	132	0.1	-	-	14,265	GAS	1,800	1,046,111	1,883.0	13,299	10.08	7.39
13.	POLK #2 CT OIL	180	44	0.0	-	-	14,273	LGT OIL	100	6,280,000	628.0	4,104	9.33	41.04
14.	**POLK #2 TOTAL**	**180**	**176**	**0.1**	**95.8**	**48.9**	**14,267**		**-**	**-**	**2,511.0**	**17,403**	**9.89**	**-**
15.	POLK #3 CT GAS	180	50	0.0	0.0	-	13,440	GAS	700	960,000	672.0	5,172	10.34	7.39
16.	POLK #3 CT OIL	180	17	0.0	0.0	-	13,176	LGT OIL	0	0	224.0	0	0.00	0.00
17.	**POLK #3 TOTAL**	**180**	**67**	**0.1**	**95.8**	**37.2**	**13,373**		**-**	**-**	**896.0**	**5,172**	**7.72**	**-**
18.	**CITY OF TAMPA GAS**	**6**	**42**	**0.9**	**100.0**	**95.1**	**10,548**	**GAS**	**431**	**1,027,842**	**443.0**	**4,167**	**9.92**	**9.67**
19.	BAYSIDE #1	787	284,410	48.6	78.8	80.0	7,354	GAS	2,034,500	1,028,017	2,091,500.0	15,031,293	5.29	7.39
20.	BAYSIDE #2	1,045	221,643	28.5	72.5	67.2	7,470	GAS	1,610,700	1,027,957	1,655,730.0	11,900,174	5.37	7.39
21.	**BAYSIDE TOTAL**	**1,832**	**506,053**	**37.1**	**75.2**	**36.0**	**7,405**	**GAS**	**3,645,200**	**1,027,990**	**3,747,230.0**	**26,931,467**	**5.32**	**7.39**
22.	B.B.C.T.#1	15	0	0.0	71.8	0.0	0	LGT OIL	1	7,000,000	7.0	56	0.00	56.00
23.	B.B.C.T.#2	80	4	0.0	71.1	0.0	15,250	LGT OIL	10	6,100,000	61.0	563	14.08	56.30
24.	B.B.C.T.#3	70	2	0.0	70.7	0.0	15,500	LGT OIL	5	6,200,000	31.0	281	14.05	56.20
25.	**C.T. TOTAL (OIL)**	**165**	**6**	**0.0**	**71.0**	**0.0**	**16,500**	**LGT OIL**	**16**	**6,187,500**	**99.0**	**900**	**15.00**	**56.25**
26.	**TOT COAL (BB,POLK)**	**2,019**	**958,447**	**63.8**	**64.4**	**20.7**	**10,530**	**COAL**	**414,015**	**24,377,571**	**10,092,680.0**	**20,902,084**	**2.18**	**50.49**
27.	**SYSTEM**	**4,416**	**1,474,641**	**44.9**	**76.9**	**10.6**	**9,456**	**-**	**-**	**-**	**13,944,034.0**	**48,589,616**	**3.30**	**-**

LEGEND:
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE
SEB-PHIL = SEBRING-PHILLIPS

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	728	135	365	329	5,760	6,912
3. UNIT COST ($/BBL)	49.38	48.70	47.82	46.32	45.03	44.02
4. AMOUNT ($)	35,947	6,575	17,454	15,238	259,400	304,272
5. BURNED:						
6. UNITS (BBL)	728	135	365	329	5,760	6,912
7. UNIT COST ($/BBL)	43.23	45.70	43.50	44.37	44.18	44.34
8. AMOUNT ($)	31,469	6,169	15,876	14,599	254,453	306,452
9. ENDING INVENTORY:						
10. UNITS (BBL)	11,605	11,605	11,605	11,605	11,605	11,605
11. UNIT COST ($/BBL)	41.54	41.62	41.81	41.94	42.96	43.36
12. AMOUNT ($)	482,089	483,045	485,238	486,678	498,605	503,183
13. DAYS SUPPLY:	1,261	160	82	46	40	38
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	22,993	19,643	19,868	14,202	20,602	22,073
16. UNIT COST ($/BBL)	48.23	47.50	46.47	45.04	43.66	42.54
17. AMOUNT ($)	1,108,881	932,962	923,291	639,650	899,516	939,069
18. BURNED:						
19. UNITS (BBL)	16,639	13,306	15,019	9,107	14,127	16,311
20. UNIT COST ($/BBL)	46.69	46.83	46.67	46.34	45.52	44.38
21. AMOUNT ($)	776,823	623,159	700,873	421,978	643,077	723,917
22. ENDING INVENTORY:						
23. UNITS (BBL)	85,068	85,068	85,068	85,068	85,068	85,068
24. UNIT COST ($/BBL)	46.10	46.33	46.33	46.14	45.68	45.14
25. AMOUNT ($)	3,921,508	3,941,622	3,941,495	3,925,437	3,886,005	3,839,769
26. DAYS SUPPLY: NORMAL	143	138	138	101	86	86
27. DAYS SUPPLY: EMERGENCY	12	12	12	12	12	12
COAL						
28. PURCHASES:						
29. UNITS (TONS)	428,800	400,708	413,800	398,900	482,100	405,300
30. UNIT COST ($/TON)	50.14	50.94	50.70	51.15	49.86	50.31
31. AMOUNT ($)	21,498,536	20,412,176	20,981,124	20,404,169	24,037,998	20,391,249
32. BURNED:						
33. UNITS (TONS)	414,921	371,240	396,780	403,042	411,195	398,425
34. UNIT COST ($/TON)	52.23	52.39	51.78	52.07	51.50	51.35
35. AMOUNT ($)	21,671,751	19,448,843	20,546,723	20,985,895	21,178,278	20,460,979
36. ENDING INVENTORY:						
37. UNITS (TONS)	773,010	802,478	819,498	815,356	886,261	893,136
38. UNIT COST ($/TON)	51.70	51.55	51.38	51.31	50.85	50.76
39. AMOUNT ($)	39,963,433	41,365,903	42,102,981	41,839,500	45,068,901	45,333,539
40. DAYS SUPPLY:	59	59	62	60	66	66
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	3,322,810	3,059,237	2,702,017	3,127,103	5,250,779	5,502,338
43. UNIT COST ($/MCF)	8.09	8.01	7.85	7.21	7.08	6.98
44. AMOUNT ($)	26,886,126	24,495,380	21,216,473	22,556,869	37,159,399	38,406,183
45. BURNED:						
46. UNITS (MCF)	3,322,810	3,059,237	2,702,017	3,127,103	5,250,779	5,502,338
47. UNIT COST ($/MCF)	8.09	8.01	7.85	7.21	7.08	6.98
48. AMOUNT ($)	26,886,127	24,495,380	21,216,474	22,556,869	37,159,399	38,406,183
49. ENDING INVENTORY:						
50. UNITS (MCF)	0	0	0	0	0	0
51. UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
52. AMOUNT ($)	0	0	0	0	0	0
53. DAYS SUPPLY:	0	0	0	0	0	0
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

		Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	TOTAL
	HEAVY OIL							
1.	PURCHASES:							
2.	UNITS (BBL)	10,258	9,642	7,853	4,390	6,327	2,415	55,114
3.	UNIT COST ($/BBL)	43.54	43.94	44.31	43.09	41.86	43.03	43.82
4.	AMOUNT ($)	446,671	423,641	348,001	189,169	264,879	103,921	2,415,168
5.	BURNED:							
6.	UNITS (BBL)	10,258	9,642	7,853	4,390	6,327	2,415	55,114
7.	UNIT COST ($/BBL)	44.19	44.43	44.82	45.01	44.03	43.99	44.36
8.	AMOUNT ($)	453,316	428,358	351,946	197,596	278,586	106,229	2,445,049
9.	ENDING INVENTORY:							
10.	UNITS (BBL)	11,605	11,605	11,605	11,605	11,605	11,605	11,605
11.	UNIT COST ($/BBL)	43.45	43.67	43.93	43.70	43.05	43.05	43.05
12.	AMOUNT ($)	504,191	506,780	509,805	507,135	499,625	499,583	499,583
13.	DAYS SUPPLY:	49	57	80	113	326	861	-
	LIGHT OIL							
14.	PURCHASES:							
15.	UNITS (BBL)	34,343	35,090	21,606	16,255	9,189	21,486	257,350
16.	UNIT COST ($/BBL)	42.00	42.35	42.74	41.37	40.35	41.37	43.63
17.	AMOUNT ($)	1,442,368	1,485,998	923,366	672,536	370,800	888,921	11,227,358
18.	BURNED:							
19.	UNITS (BBL)	28,559	29,315	15,835	13,530	5,419	14,816	191,983
20.	UNIT COST ($/BBL)	43.16	43.05	43.30	42.70	42.38	42.33	44.30
21.	AMOUNT ($)	1,232,532	1,262,069	685,641	577,694	229,647	627,198	8,504,608
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	85,068	85,068	85,068	85,068	85,068	85,068	85,068
24.	UNIT COST ($/BBL)	44.55	44.16	43.93	43.63	43.34	42.99	42.99
25.	AMOUNT ($)	3,789,819	3,756,262	3,737,418	3,711,652	3,686,805	3,656,843	3,656,843
26.	DAYS SUPPLY: NORMAL	107	166	165	146	122	124	-
27.	DAYS SUPPLY: EMERGENCY	12	12	12	12	12	12	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	432,100	427,100	435,300	316,200	315,500	437,700	4,893,508
30.	UNIT COST ($/TON)	50.04	50.25	49.32	49.60	49.89	49.16	50.11
31.	AMOUNT ($)	21,621,999	21,463,407	21,470,778	15,684,669	15,740,369	21,519,055	245,225,529
32.	BURNED:							
33.	UNITS (TONS)	417,516	421,350	399,082	309,860	281,797	414,015	4,639,223
34.	UNIT COST ($/TON)	51.33	51.11	50.82	50.49	50.95	50.49	51.40
35.	AMOUNT ($)	21,429,837	21,537,220	20,282,458	15,643,994	14,357,448	20,902,084	238,445,510
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	907,720	913,470	949,688	956,028	989,731	1,013,416	1,013,416
38.	UNIT COST ($/TON)	50.60	50.56	50.23	50.14	50.07	49.88	49.88
39.	AMOUNT ($)	45,928,583	46,185,946	47,704,616	47,939,896	49,559,711	50,545,850	50,545,850
40.	DAYS SUPPLY:	74	85	86	79	76	78	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	6,157,918	6,176,374	5,563,134	5,761,445	5,179,928	3,648,131	55,451,214
43.	UNIT COST ($/MCF)	7.08	7.08	7.10	6.94	7.02	7.39	7.23
44.	AMOUNT ($)	43,568,841	43,742,247	39,477,451	39,961,612	36,369,433	26,954,104	400,794,118
45.	BURNED:							
46.	UNITS (MCF)	6,157,918	6,176,374	5,563,134	5,761,445	5,179,928	3,648,131	55,451,214
47.	UNIT COST ($/MCF)	7.08	7.08	7.10	6.94	7.02	7.39	7.23
48.	AMOUNT ($)	43,568,841	43,742,247	39,477,451	39,961,612	36,369,433	26,954,105	400,794,121
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	0	0	0	0	0	0	0
51.	UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52.	AMOUNT ($)	0	0	0	0	0	0	0
53.	DAYS SUPPLY:	0	0	0	0	0	0	-
	NUCLEAR							
54.	BURNED:							
55.	UNITS (MMBTU)	0	0	0	0	0	0	0
56.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57.	AMOUNT ($)	0	0	0	0	0	0	0
	OTHER							
58.	PURCHASES:							
59.	UNITS (MMBTU)	0	0	0	0	0	0	0
60.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	AMOUNT ($)	0	0	0	0	0	0	0
62.	BURNED:							
63.	UNITS (MMBTU)	0	0	0	0	0	0	0
64.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65.	AMOUNT ($)	0	0	0	0	0	0	0
66.	ENDING INVENTORY:							
67.	UNITS (MMBTU)	0	0	0	0	0	0	0
68.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69.	AMOUNT ($)	0	0	0	0	0	0	0
70.	DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

POWER SOLD
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
				MWH		CENTS/KWH				
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $	GAINS ON MARKET BASED SALES
Jan-05										
	VARIOUS	JURISD. SCH. -D	1,338.0	0.0	1,338.0	2.010	2.010	26,900.00	26,900.00	
	VARIOUS	JURISD. MKT. BASE	25,085.0	0.0	25,085.0	3.205	5.826	803,900.00	1,461,500.00	573,100.00
	TOTAL		**26,423.0**	**0.0**	**26,423.0**	**3.144**	**5.633**	**830,800.00**	**1,488,400.00**	**573,100.00**
Feb-05										
	VARIOUS	JURISD. SCH. -D	1,210.0	0.0	1,210.0	1.686	1.686	20,400.00	20,400.00	
	VARIOUS	JURISD. MKT. BASE	47,500.0	0.0	47,500.0	4.788	6.213	2,274,100.00	2,951,200.00	517,000.00
	TOTAL		**48,710.0**	**0.0**	**48,710.0**	**4.711**	**6.101**	**2,294,500.00**	**2,971,600.00**	**517,000.00**
Mar-05										
	VARIOUS	JURISD. SCH. -D	1,785.0	0.0	1,785.0	2.768	2.768	49,400.00	49,400.00	
	VARIOUS	JURISD. MKT. BASE	8,495.0	0.0	8,495.0	2.612	4.790	221,900.00	406,900.00	156,400.00
	TOTAL		**10,280.0**	**0.0**	**10,280.0**	**2.639**	**4.439**	**271,300.00**	**456,300.00**	**156,400.00**
Apr-05										
	VARIOUS	JURISD. SCH. -D	1,728.0	0.0	1,728.0	2.697	2.697	46,600.00	46,600.00	
	VARIOUS	JURISD. MKT. BASE	10,904.0	0.0	10,904.0	3.356	5.153	365,900.00	561,900.00	159,300.00
	TOTAL		**12,632.0**	**0.0**	**12,632.0**	**3.266**	**4.817**	**412,500.00**	**608,500.00**	**159,300.00**
May-05										
	VARIOUS	JURISD. SCH. -D	1,784.0	0.0	1,784.0	2.769	2.769	49,400.00	49,400.00	
	VARIOUS	JURISD. MKT. BASE	28,696.0	0.0	28,696.0	3.749	5.842	1,075,800.00	1,676,500.00	504,000.00
	TOTAL		**30,480.0**	**0.0**	**30,480.0**	**3.692**	**5.662**	**1,125,200.00**	**1,725,900.00**	**504,000.00**
Jun-05										
	VARIOUS	JURISD. SCH. -D	1,728.0	0.0	1,728.0	2.697	2.697	46,600.00	46,600.00	
	VARIOUS	JURISD. MKT. BASE	26,354.0	0.0	26,354.0	4.083	6.151	1,076,100.00	1,621,000.00	456,100.00
	TOTAL		**28,082.0**	**0.0**	**28,082.0**	**3.998**	**5.938**	**1,122,700.00**	**1,667,600.00**	**456,100.00**

POWER SOLD
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

(1)	(2)		(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
							CENTS/KWH				
MONTH	SOLD TO		TYPE & SCHEDULE	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $	GAINS ON MARKET BASED SALES
Jul-05											
	VARIOUS	JURISD.	SCH. -D	1,785.0	0.0	1,785.0	2.768	2.768	49,400.00	49,400.00	
	VARIOUS	JURISD.	MKT. BASE	23,752.0	0.0	23,752.0	3.882	6.021	922,100.00	1,430,100.00	428,000.00
	TOTAL			**25,537.0**	**0.0**	**25,537.0**	**3.804**	**5.794**	**971,500.00**	**1,479,500.00**	**428,000.00**
Aug-05											
	VARIOUS	JURISD.	SCH. -D	1,785.0	0.0	1,785.0	2.768	2.768	49,400.00	49,400.00	
	VARIOUS	JURISD.	MKT. BASE	21,492.0	0.0	21,492.0	3.723	6.343	800,100.00	1,363,300.00	490,800.00
	TOTAL			**23,277.0**	**0.0**	**23,277.0**	**3.650**	**6.069**	**849,500.00**	**1,412,700.00**	**490,800.00**
Sep-05											
	VARIOUS	JURISD.	SCH. -D	1,583.0	0.0	1,583.0	2.476	2.476	39,200.00	39,200.00	
	VARIOUS	JURISD.	MKT. BASE	24,491.0	0.0	24,491.0	3.957	6.250	969,200.00	1,530,800.00	479,100.00
	TOTAL			**26,074.0**	**0.0**	**26,074.0**	**3.867**	**6.021**	**1,008,400.00**	**1,570,000.00**	**479,100.00**
Oct-05											
	VARIOUS	JURISD.	SCH. -D	1,636.0	0.0	1,636.0	2.561	2.561	41,900.00	41,900.00	
	VARIOUS	JURISD.	MKT. BASE	109.0	0.0	109.0	3.028	5.138	3,300.00	5,600.00	1,900.00
	TOTAL			**1,745.0**	**0.0**	**1,745.0**	**2.590**	**2.722**	**45,200.00**	**47,500.00**	**1,900.00**
Nov-05											
	VARIOUS	JURISD.	SCH. -D	1,296.0	0.0	1,296.0	1.906	1.906	24,700.00	24,700.00	
	VARIOUS	JURISD.	MKT. BASE	2,007.0	0.0	2,007.0	5.326	6.966	106,900.00	139,800.00	26,100.00
	TOTAL			**3,303.0**	**0.0**	**3,303.0**	**3.984**	**4.980**	**131,600.00**	**164,500.00**	**26,100.00**
Dec-05											
	VARIOUS	JURISD.	SCH. -D	1,339.0	0.0	1,339.0	2.009	2.009	26,900.00	26,900.00	
	VARIOUS	JURISD.	MKT. BASE	9,810.0	0.0	9,810.0	2.441	4.892	239,500.00	479,900.00	207,300.00
	TOTAL			**11,149.0**	**0.0**	**11,149.0**	**2.389**	**4.546**	**266,400.00**	**506,800.00**	**207,300.00**
Jan-05	VARIOUS	JURISD.	SCH. -D	18,997.0	0.0	18,997.0	2.478	2.478	470,800.00	470,800.00	
THRU	VARIOUS	JURISD.	MKT. BASE	228,695.0	0.0	228,695.0	3.874	5.959	8,858,800.00	13,628,500.00	3,999,100.00
Dec-05	**TOTAL**			**247,692.0**	**0.0**	**247,692.0**	**3.767**	**5.692**	**9,329,600.00**	**14,099,300.00**	**3,999,100.00**

PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
Jan-05									
	VARIOUS	SCH. J	186.0	0.0	101.0	85.0	11.765	11.765	10,000.00
	HPP	IPP	3,383.0	0.0	0.0	3,383.0	11.357	11.357	384,200.00
	VARIOUS	OTHER	91,291.0	0.0	0.0	91,291.0	3.673	3.673	3,353,100.00
	VARIOUS	MKT BASED	12,364.0	0.0	0.0	12,364.0	4.914	4.914	607,600.00
	TOTAL		**107,224.0**	**0.0**	**101.0**	**107,123.0**	**4.065**	**4.065**	**4,354,900.00**
Feb-05									
	VARIOUS	SCH. J	4.0	0.0	3.0	1.0	10.000	10.000	100.00
	HPP	IPP	297.0	0.0	0.0	297.0	46.128	46.128	137,000.00
	VARIOUS	OTHER	79,731.0	0.0	0.0	79,731.0	3.454	3.454	2,753,900.00
	VARIOUS	MKT BASED	13,837.0	0.0	0.0	13,837.0	3.489	3.489	482,800.00
	TOTAL		**93,869.0**	**0.0**	**3.0**	**93,866.0**	**3.594**	**3.594**	**3,373,800.00**
Mar-05									
	VARIOUS	SCH. J	115.0	0.0	79.0	36.0	7.500	7.500	2,700.00
	HPP	IPP	2,021.0	0.0	0.0	2,021.0	12.563	12.563	253,900.00
	VARIOUS	OTHER	87,955.0	0.0	0.0	87,955.0	3.182	3.182	2,798,700.00
	VARIOUS	MKT BASED	110,955.0	0.0	0.0	110,955.0	4.707	4.707	5,222,300.00
	TOTAL		**201,046.0**	**0.0**	**79.0**	**200,967.0**	**4.119**	**4.119**	**8,277,600.00**
Apr-05									
	VARIOUS	SCH. J	56.0	0.0	43.0	13.0	7.692	7.692	1,000.00
	HPP	IPP	1,199.0	0.0	0.0	1,199.0	16.063	16.063	192,600.00
	VARIOUS	OTHER	84,695.0	0.0	0.0	84,695.0	3.228	3.228	2,734,000.00
	VARIOUS	MKT BASED	21,484.0	0.0	0.0	21,484.0	4.626	4.626	993,900.00
	TOTAL		**107,434.0**	**0.0**	**43.0**	**107,391.0**	**3.652**	**3.652**	**3,921,500.00**
May-05									
	VARIOUS	SCH. J	895.0	0.0	596.0	299.0	8.060	8.060	24,100.00
	HPP	IPP	7,184.0	0.0	0.0	7,184.0	7.898	7.898	567,400.00
	VARIOUS	OTHER	89,378.0	0.0	0.0	89,378.0	3.492	3.492	3,121,100.00
	VARIOUS	MKT BASED	52,413.0	0.0	0.0	52,413.0	6.653	6.653	3,486,900.00
	TOTAL		**149,870.0**	**0.0**	**596.0**	**149,274.0**	**4.823**	**4.823**	**7,199,500.00**
Jun-05									
	VARIOUS	SCH. J	1,444.0	0.0	924.0	520.0	8.077	8.077	42,000.00
	HPP	IPP	26,609.0	0.0	0.0	26,609.0	6.638	6.638	1,766,200.00
	VARIOUS	OTHER	89,671.0	0.0	0.0	89,671.0	3.776	3.776	3,385,700.00
	VARIOUS	MKT BASED	98,731.0	0.0	0.0	98,731.0	6.053	6.053	5,976,300.00
	TOTAL		**216,455.0**	**0.0**	**924.0**	**215,531.0**	**5.183**	**5.183**	**11,170,200.00**

PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
Jul-05									
	VARIOUS	SCH. J	4,024.0	0.0	2,195.0	1,829.0	8.278	8.278	151,400.00
	HPP	IPP	40,672.0	0.0	0.0	40,672.0	6.697	6.697	2,723,900.00
	VARIOUS	OTHER	98,463.0	0.0	0.0	98,463.0	3.859	3.859	3,799,400.00
	VARIOUS	MKT BASED	106,634.0	0.0	0.0	106,634.0	6.015	6.015	6,413,600.00
	TOTAL		**249,793.0**	**0.0**	**2,195.0**	**247,598.0**	**5.286**	**5.286**	**13,088,300.00**
Aug-05									
	VARIOUS	SCH. J	4,297.0	0.0	2,316.0	1,981.0	9.455	9.455	187,300.00
	HPP	IPP	38,071.0	0.0	0.0	38,071.0	6.730	6.730	2,562,000.00
	VARIOUS	OTHER	98,467.0	0.0	0.0	98,467.0	3.915	3.915	3,854,600.00
	VARIOUS	MKT BASED	102,578.0	0.0	0.0	102,578.0	6.305	6.305	6,467,100.00
	TOTAL		**243,413.0**	**0.0**	**2,316.0**	**241,097.0**	**5.421**	**5.421**	**13,071,000.00**
Sep-05									
	VARIOUS	SCH. J	1,868.0	0.0	1,184.0	684.0	8.026	8.026	54,900.00
	HPP	IPP	29,461.0	0.0	0.0	29,461.0	6.711	6.711	1,977,000.00
	VARIOUS	OTHER	89,012.0	0.0	0.0	89,012.0	3.668	3.668	3,265,000.00
	VARIOUS	MKT BASED	98,053.0	0.0	0.0	98,053.0	6.237	6.237	6,115,700.00
	TOTAL		**218,394.0**	**0.0**	**1,184.0**	**217,210.0**	**5.254**	**5.254**	**11,412,600.00**
Oct-05									
	VARIOUS	SCH. J	2,744.0	0.0	1,756.0	988.0	8.097	8.097	80,000.00
	HPP	IPP	11,636.0	0.0	0.0	11,636.0	7.182	7.182	835,700.00
	VARIOUS	OTHER	102,209.0	0.0	0.0	102,209.0	3.793	3.793	3,876,800.00
	VARIOUS	MKT BASED	129,224.0	0.0	0.0	129,224.0	5.375	5.375	6,945,400.00
	TOTAL		**245,813.0**	**0.0**	**1,756.0**	**244,057.0**	**4.809**	**4.809**	**11,737,900.00**
Nov-05									
	VARIOUS	SCH. J	147.0	0.0	111.0	36.0	8.611	8.611	3,100.00
	HPP	IPP	3,403.0	0.0	0.0	3,403.0	9.674	9.674	329,200.00
	VARIOUS	OTHER	95,783.0	0.0	0.0	95,783.0	3.466	3.466	3,319,800.00
	VARIOUS	MKT BASED	36,503.0	0.0	0.0	36,503.0	4.640	4.640	1,693,800.00
	TOTAL		**135,836.0**	**0.0**	**111.0**	**135,725.0**	**3.939**	**3.939**	**5,345,900.00**
Dec-05									
	VARIOUS	SCH. J	60.0	0.0	40.0	20.0	6.500	6.500	1,300.00
	HPP	IPP	1,367.0	0.0	0.0	1,367.0	15.135	15.135	206,900.00
	VARIOUS	OTHER	90,254.0	0.0	0.0	90,254.0	3.238	3.238	2,922,400.00
	VARIOUS	MKT BASED	42,178.0	0.0	0.0	42,178.0	3.610	3.610	1,522,800.00
	TOTAL		**133,859.0**	**0.0**	**40.0**	**133,819.0**	**3.477**	**3.477**	**4,653,400.00**
Jan-05	VARIOUS	SCH. J	15,840.0	0.0	9,348.0	6,492.0	8.594	8.594	557,900.00
THRU	HPP	IPP	165,303.0	0.0	0.0	165,303.0	7.221	7.221	11,936,000.00
Dec-05	VARIOUS	OTHER	1,096,909.0	0.0	0.0	1,096,909.0	3.572	3.572	39,184,500.00
	VARIOUS	MKT BASED	824,954.0	0.0	0.0	824,954.0	5.567	5.567	45,928,200.00
	TOTAL		**2,103,006.0**	**0.0**	**9,348.0**	**2,093,658.0**	**4.662**	**4.662**	**97,606,600.00**

SCHEDULE E8

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
Jan-05	VARIOUS	CO-GEN.	36,924.0	0.0	0.0	36,924.0	2.527	2.527	933,100.00
Feb-05	VARIOUS	CO-GEN.	36,419.0	0.0	0.0	36,419.0	2.528	2.528	920,500.00
Mar-05	VARIOUS	CO-GEN.	36,924.0	0.0	0.0	36,924.0	2.504	2.504	924,600.00
Apr-05	VARIOUS	CO-GEN.	38,666.0	0.0	0.0	38,666.0	2.486	2.486	961,300.00
May-05	VARIOUS	CO-GEN.	38,899.0	0.0	0.0	38,899.0	2.497	2.497	971,400.00
Jun-05	VARIOUS	CO-GEN.	38,666.0	0.0	0.0	38,666.0	2.510	2.510	970,400.00
Jul-05	VARIOUS	CO-GEN.	38,899.0	0.0	0.0	38,899.0	2.530	2.530	984,000.00
Aug-05	VARIOUS	CO-GEN.	38,899.0	0.0	0.0	38,899.0	2.530	2.530	984,300.00
Sep-05	VARIOUS	CO-GEN.	38,666.0	0.0	0.0	38,666.0	2.515	2.515	972,300.00
Oct-05	VARIOUS	CO-GEN.	38,899.0	0.0	0.0	38,899.0	2.516	2.516	978,700.00
Nov-05	VARIOUS	CO-GEN.	36,758.0	0.0	0.0	36,758.0	2.524	2.524	927,900.00
Dec-05	VARIOUS	CO-GEN.	36,928.0	0.0	0.0	36,928.0	2.499	2.499	922,800.00
TOTAL			**455,547.0**	**0.0**	**0.0**	**455,547.0**	**2.514**	**2.514**	**11,451,300.00**

SCHEDULE E9

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
						COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	(A) CENTS PER KWH	(B) ($000)	FUEL SAVINGS (7B)-(6)
Jan-05	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Feb-05	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Mar-05	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Apr-05	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
May-05	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Jun-05	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Jul-05	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Aug-05	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Sep-05	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Oct-05	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Nov-05	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Dec-05	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL			**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**

SCHEDULE E10

RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH
TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD: JANUARY 2005 THROUGH DECEMBER 2005

	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	TOTAL
Base Rate Revenue	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92
Fuel Recovery Revenue	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52	39.52
Conservation Revenue	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
Capacity Revenue	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77	3.77
Environmental Revenue	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04
Florida Gross Receipts Tax Revenue	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50
TOTAL REVENUE	**$ 99.85**	**$ 99.85**	**$ 99.85**	**$ 99.85**	**$ 99.85**	**$ 99.85**	**$ 99.85**	**$ 99.85**	**$ 99.85**	**$ 99.85**	**$ 99.85**	**$ 99.85**	**$ 99.85**

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY

SCHEDULE H1

PERIOD: JANUARY THROUGH DECEMBER

	ACTUAL 2002	ACTUAL 2003	ACT/EST 2004	EST 2005	DIFFERENCE (%) 2003-2002	2004-2003	2005-2004
FUEL COST OF SYSTEM NET GENERATION ($)							
1 HEAVY OIL [1]	4,372,207	5,680,792	2,106,560	2,445,049	29.9%	-62.9%	16.1%
2 LIGHT OIL [1]	9,851,474	7,068,479	8,562,673	8,504,608	-28.2%	21.1%	-0.7%
3 COAL	310,692,261	269,619,940	241,510,866	238,445,510	-13.2%	-10.4%	-1.3%
4 NATURAL GAS	31,676,384	183,341,150	370,490,982	400,794,121	478.8%	102.1%	8.2%
5 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6 OTHER	0	0	0	0	0.0%	0.0%	0.0%
7 TOTAL ($)	**356,592,326**	**465,710,361**	**622,671,081**	**650,189,288**	**30.6%**	**33.7%**	**4.4%**
SYSTEM NET GENERATION (MWH)							
8 HEAVY OIL [1]	86,648	103,238	38,962	35,422	19.1%	-62.3%	-9.1%
9 LIGHT OIL [1]	191,196	103,103	110,644	100,743	-46.1%	7.3%	-8.9%
10 COAL	14,875,280	12,321,871	10,792,080	10,622,275	-17.2%	-12.4%	-1.6%
11 NATURAL GAS	473,450	3,561,167	6,986,158	7,605,725	652.2%	96.2%	8.9%
12 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13 OTHER	0	0	0	0	0.0%	0.0%	0.0%
14 TOTAL (MWH)	**15,626,574**	**16,089,379**	**17,927,844**	**18,364,165**	**3.0%**	**11.4%**	**2.4%**
UNITS OF FUEL BURNED							
15 HEAVY OIL (BBL) [1]	137,183	159,945	60,893	55,114	16.6%	-61.9%	-9.5%
16 LIGHT OIL (BBL) [1]	322,371	184,718	195,868	191,983	-42.7%	6.0%	-2.0%
17 COAL (TON)	7,100,139	5,736,824	4,845,385	4,639,223	-19.2%	-15.5%	-4.3%
18 NATURAL GAS (MCF)	5,151,423	27,084,260	50,793,913	55,451,214	425.8%	87.5%	9.2%
19 NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20 OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)							
21 HEAVY OIL [1]	860,634	1,003,422	382,051	346,051	16.6%	-61.9%	-9.4%
22 LIGHT OIL [1]	1,855,534	1,036,758	1,300,940	1,113,145	-44.1%	25.5%	-14.4%
23 COAL	165,425,948	137,018,691	114,252,503	112,574,199	-17.2%	-16.6%	-1.5%
24 NATURAL GAS	5,420,729	28,464,067	52,428,028	57,003,966	425.1%	84.2%	8.7%
25 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26 OTHER	0	0	0	0	0.0%	0.0%	0.0%
27 TOTAL (MMBTU)	**173,562,845**	**167,522,938**	**168,363,522**	**171,037,361**	**-3.5%**	**0.5%**	**1.6%**
GENERATION MIX (% MWH)							
28 HEAVY OIL [1]	0.55	0.64	0.22	0.19	-	-	-
29 LIGHT OIL [1]	1.22	0.64	0.62	0.55	-	-	-
30 COAL	95.20	76.59	60.19	57.84	-	-	-
31 NATURAL GAS	3.03	22.13	38.97	41.42	-	-	-
32 NUCLEAR	0.00	0.00	0.00	0.00	-	-	-
33 OTHER	0.00	0.00	0.00	0.00	-	-	-
34 TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**-**	**-**	**-**
FUEL COST PER UNIT							
35 HEAVY OIL ($/BBL) [1]	31.87	35.52	34.59	44.36	11.5%	-2.6%	28.2%
36 LIGHT OIL ($/BBL) [1]	30.56	38.27	43.72	44.30	25.2%	14.2%	1.3%
37 COAL ($/TON)	43.76	47.00	49.84	51.40	7.4%	6.0%	3.1%
38 NATURAL GAS ($/MCF)	6.15	6.77	7.29	7.23	10.1%	7.7%	-0.8%
39 NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
40 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)							
41 HEAVY OIL [1]	5.08	5.66	5.51	7.07	11.4%	-2.7%	28.3%
42 LIGHT OIL [1]	5.31	6.82	6.58	7.64	28.4%	-3.5%	16.1%
43 COAL	1.88	1.97	2.11	2.12	4.8%	7.1%	0.5%
44 NATURAL GAS	5.84	6.44	7.07	7.03	10.3%	9.8%	-0.6%
45 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47 TOTAL ($/MMBTU)	**2.05**	**2.78**	**3.70**	**3.80**	**35.6%**	**33.1%**	**2.7%**
BTU BURNED PER KWH (BTU/KWH)							
48 HEAVY OIL [1]	9,933	9,720	9,806	9,769	-2.1%	0.9%	-0.4%
49 LIGHT OIL [1]	9,705	10,056	11,758	11,049	3.6%	16.9%	-6.0%
50 COAL	11,121	11,120	10,587	10,598	0.0%	-4.8%	0.1%
51 NATURAL GAS	11,449	7,993	7,505	7,495	-30.2%	-6.1%	-0.1%
52 NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
54 TOTAL (BTU/KWH)	11,107	10,412	9,391	9,314	-6.3%	-9.8%	-0.8%
GENERATED FUEL COST PER KWH (cents/KWH)							
55 HEAVY OIL [1]	5.05	5.50	5.41	6.90	8.9%	-1.6%	27.5%
56 LIGHT OIL [1]	5.15	6.86	7.74	8.44	33.2%	12.8%	9.0%
57 COAL	2.09	2.19	2.24	2.24	4.8%	2.3%	0.0%
58 NATURAL GAS	6.69	5.15	5.30	5.27	-23.0%	2.9%	-0.6%
59 NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60 OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61 TOTAL (cents/KWH)	2.28	2.89	3.47	3.54	26.8%	20.1%	2.0%

[1] DISTILLATE (BBLS, MWH & $) USED FOR FIRING, HOT STANDBY, ETC. IS INCLUDED IN FOSSIL STEAM PLANTS.

TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
FILED: 9/9/04

EXHIBIT TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 3

PROPOSED 2005 COST RECOVERY FACTORS
RESIDENTIAL BILL COMPOSITE EFFECT

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
(JDJ-3)
DOCUMENT NO. 3
PAGE 1 OF 1
FILED: 9/9/04

RESIDENTIAL BILL COMPARISON

1,000 kWh MONTHLY USAGE

Bill Component	Jan - Dec 2004	Jan - Dec 2005
Customer Charge	$8.50	$8.50
Energy Charge	43.42	43.42
Fuel	39.39	39.52
Capacity	2.67	3.77
Energy Conservation	1.11	1.10
Environmental	1.44	1.04
Subtotal	**$96.53**	**$97.35**
Gross Receipts Tax	2.48	2.50
TOTAL	**$99.01**	**$99.85**

TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
FILED: 10/18/04

EXHIBIT TO THE REBUTTAL TESTIMONY OF

J. DENISE JORDAN

Calculation of Incremental Security Expenses Using the Auditor's Approach

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 44
COMPANY/ TECO
WITNESS: J. Denise Jordan (JDJ-4)
DATE: 11-08-04

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
(JDJ-4)
DOCUMENT NO. 1
PAGE 1 OF 1
FILED: 10/18/04

Security Expenses	2000	2004
Guard Services O&M Expenses	$ 1,927,252	$ 3,209,852
Employee Salary and Benefits	543,906	528,684
Vehicle Expenses	78,144	73,884
Stores and Materials	96,810	78,456
Other Contracted Services	145,344	164,744
Miscellaneous	34,802	50,216
Gross Security O&M Expense Baseline [1]	**$ 2,826,258**	**$ 4,105,836**

[1] The 2000 security expenses cited in Audit Control No. 02-340-2-1 totaled $2,731,227 because a few security FERC accounts were inadvertently excluded from the calculation. These accounts and a reconciliation of the two amounts were provided to the FPSC audit staff during the review of base year security costs in Docket No. 040001-EI.

Calculation of Incremental Security Expenses Based on Audit Approach:

	Energy Sales Growth		
2004 Gross Security O&M Expense			$ 4,105,836
2000 Gross Security O&M Expense Baseline		$ 2,826,858	
2001 Baseline Adjusted for Energy Sales Growth	2.72%		
2002 Baseline Adjusted for Energy Sales Growth	5.03%		
2003 Baseline Adjusted for Energy Sales Growth	2.66%		
Less Baseline Adjusted for Energy Sales Growth			$ (3,130,932)
2004 Incremental Security Costs			$ 974,904
Retail Jurisdictional Separation Factor			0.9543611
2004 Recoverable Retail Incremental Security			**$ 930,410**

EXHIBIT NO. _____
DOCKET NO. 040001-EI
TAMPA ELECTRIC COMPANY
(WAS-1)

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2003 - DECEMBER 2003

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO 45
COMPANY/ TECO
WITNESS: David R. Knapp (WAS-1)
DATE 11-08-04

EXHIBIT NO. _____
DOCKET NO. 040001-EI
TAMPA ELECTRIC COMPANY
(WAS-1)

GENERATING PERFORMANCE INCENTIVE FACTOR

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EXHIBIT NO. _____
DOCKET NO. 040001-EI
TAMPA ELECTRIC COMPANY
(WAS-1)
DOCUMENT NO. 1

EXHIBITS TO THE TESTIMONY OF

WILLIAM A. SMOTHERMAN

DOCKET NO. 040001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2003 - DECEMBER 2003

TRUE-UP

DOCUMENT NO. 1

GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2003 - DECEMBER 2003
TRUE-UP
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ACTUAL
JANUARY 2003 - DECEMBER 2003

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	29,158.5	5,750.1
+9	26,242.6	5,175.1
+8	23,326.8	4,600.1
+7	20,410.9	4,025.0
+6	17,495.1	3,450.0
+5	14,579.2	2,875.0
+4	11,663.4	2,300.0
+3	8,747.5	1,725.0
+2	5,831.7	1,150.0
+1	2,915.8	575.0
0	0.0	0.0
-1	(3,520.2)	(575.0)
-2	(7,040.4)	(1,150.0)
-3	(10,560.7)	(1,725.0)
-4	(14,080.9)	(2,300.0)
-5	(17,601.1)	(2,875.0)
-6	(21,121.3)	(3,450.0)
-7	(24,641.5)	(4,025.0)
-8	(28,161.8)	(4,600.1)
-9	(31,682.0)	(5,175.1)
-10	(35,202.2)	(5,750.1)

GPI POINTS -6.397

REWARD DOLLARS ($3,678,414)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS - ACTUAL
JANUARY 2003 - DECEMBER 2003

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,569,600,653
Line 2	Month of January	2003	$	1,549,122,043
Line 3	Month of February	2003	$	1,558,730,692
Line 4	Month of March	2003	$	1,521,720,989
Line 5	Month of April	2003	$	1,398,795,832
Line 6	Month of May	2003	$	1,398,542,946
Line 7	Month of June	2003	$	1,409,641,764
Line 8	Month of July	2003	$	1,434,014,236
Line 9	Month of August	2003	$	1,409,541,142
Line 10	Month of September	2003	$	1,422,638,318
Line 11	Month of October	2003	$	1,381,593,158
Line 12	Month of November	2003	$	1,389,179,250
Line 13	Month of December	2003	$	1,386,339,366
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,448,420,030
Line 15	25 Basis points			0.0025
Line 16	Revenue Expansion Factor			61.38%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	5,899,320
Line 18	Jurisdictional Sales			18,060,815 MWH
Line 19	Total Sales			18,529,606 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			97.47%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**5,750,070**

TAMPA ELECTRIC COMPANY
CALCULATION OF SYSTEM GPIF POINTS - ACTUAL
JANUARY 2003 - DECEMBER 2003

PLANT / UNIT	12 MONTH ADJ. ACTUAL PERFORMANCE		WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
BIG BEND 1	61.2%	EAF	10.36%	-8.421	-0.873
BIG BEND 2	58.1%	EAF	14.61%	-3.607	-0.527
BIG BEND 3	60.1%	EAF	10.41%	-5.998	-0.624
BIG BEND 4	72.0%	EAF	6.96%	-9.503	-0.662
GANNON 5	78.3%	EAF	0.34%	10.000	0.034
GANNON 6	63.2%	EAF	4.41%	-10.000	-0.441
POLK 1	67.5%	EAF	3.06%	-10.000	-0.306
BIG BEND 1	10,884	ANOHR	8.95%	-5.041	-0.451
BIG BEND 2	10,522	ANOHR	7.40%	-7.258	-0.537
BIG BEND 3	10,678	ANOHR	10.01%	-7.816	-0.782
BIG BEND 4	10,297	ANOHR	8.50%	-4.991	-0.424
GANNON 5	11,400	ANOHR	0.50%	-7.097	-0.035
GANNON 6	11,600	ANOHR	6.66%	-10.000	-0.666
POLK 1	10,547	ANOHR	7.81%	-1.308	-0.102
			100.00%		-6.397

GPIF REWARD	**$ (3,678,414)**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	EAF ADJUSTED ACTUAL (%)	ACTUAL FUEL SAVINGS/ LOSS ($000)
BIG BEND 1	10.36%	69.89203679	75.1	59.6	3,021.7	(1,669.5)	61.2%	(1,405.9)
BIG BEND 2	14.61%	63.0079089	69.9	49.4	4,261.3	(5,768.6)	58.1%	(2,080.5)
BIG BEND 3	10.41%	67.26418235	73.2	55.3	3,034.2	(4,512.7)	60.1%	(2,706.7)
BIG BEND 4	6.96%	77.73252489	80.7	71.7	2,030.2	(3,893.4)	72.0%	(3,699.8)
GANNON 5	0.34%	71.93220921	77.5	60.7	100.5	(274.6)	78.3%	274.6
GANNON 6	4.41%	75.94878654	80.8	66.3	1,287.1	(2,883.1)	63.2%	(2,883.1)
POLK 1	3.06%	74.55554092	77.8	68.0	892.7	(1,669.5)	67.5%	(1,669.5)
GPIF SYSTEM	**50.17%**				**14,627.7**	**(20,671.4)**		

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR (Btu/kwh)	TARGET NOF (%)	ANOHR TARGET RANGE MIN.	ANOHR TARGET RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	ACTUAL ADJUSTED ANOHR	ACTUAL FUEL SAVINGS/ LOSS ($000)
BIG BEND 1	8.95%	10,533	70.7	9,912	11,155	2,610.9	(2,610.9)	10,884	(1,316.3)
BIG BEND 2	7.40%	10,111	79.7	9,574	10,649	2,158.4	(2,158.4)	10,522	(1,566.5)
BIG BEND 3	10.01%	10,132	75.5	9,455	10,810	2,917.7	(2,917.7)	10,678	(2,280.5)
BIG BEND 4	8.50%	10,028	88.2	9,565	10,491	2,477.8	(2,477.8)	10,297	(1,236.6)
GANNON 5	0.50%	10,862	64.9	10,134	11,589	145.8	(145.8)	11,400	(103.5)
GANNON 6	6.66%	10,775	69.5	10,007	11,542	1,942.0	(1,942.0)	11,600	(1,942.0)
POLK 1	7.81%	10,382	96.0	9,615	11,148	2,278.3	(2,278.3)	10,547	(298.0)
GPIF SYSTEM	**49.83%**					**14,530.8**	**(14,530.8)**		

TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2003 - DECEMBER 2003

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS (1) TO EAF (%)	EAF JAN 03 - DEC 03 ACTUAL (%)
BIG BEND 1	64.7	-3.5	61.2
BIG BEND 2	60.2	-2.1	58.1
BIG BEND 3	62.4	-2.3	60.1
BIG BEND 4	71.3	0.7	72.0
GANNON 5	78.4	-0.1	78.3
GANNON 6	63.2	0.0	63.2
POLK 1	68.4	-0.9	67.5

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS (2) TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
BIG BEND 1	10,968	-84	10,884
BIG BEND 2	10,623	-101	10,522
BIG BEND 3	11,030	-352	10,678
BIG BEND 4	10,662	-365	10,297
GANNON 5	11,425	-25	11,400
GANNON 6	11,629	-29	11,600
POLK 1	10,665	-118	10,547

(1) Documentation of adjustments to Actual EAF on pages 7 - 13

(2) Documentation of adjustments to Actual ANOHR on pages 14 - 20

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 1
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 10.36%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760	8,760	8,760
EAF	69.9	64.7	61.2
POH	504.0	0.0	504.0
FOH + EFOH	1,416.3	2,580.1	2,431.7
MOH + EMOH	717.1	491.2	462.9
POF	5.8	0.0	5.8
EFOF	16.2	29.5	27.8
EMOF	8.2	5.6	5.3
	-8.421	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8{,}760 - 504}{8{,}760 - 0} \times (2{,}580.1 + 491.2) = 2{,}894.6$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 5.8 - \frac{2{,}894.6}{8{,}760} \times 100 = 61.2$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 2
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 14.61%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760	8,760	8,760
EAF	63.0	60.2	58.1
POH	336.0	0.0	336.0
FOH + EFOH	1,932.3	2,896.3	2,785.2
MOH + EMOH	972.2	570.5	548.6
POF	3.8	0.0	3.8
EFOF	22.1	33.1	31.8
EMOF	11.1	6.5	6.3
	-3.607	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8,760 - 336}{8,760 - 0} \times (2,896.3 + 570.5) = 3,333.8$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 3.8 - \frac{3,333.8}{8,760} \times 100 = 58.1$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 3
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 10.41%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760	8,760	8,760
EAF	67.3	62.4	60.1
POH	336.0	0.0	336.0
FOH + EFOH	1,535.9	2,685.9	2,582.9
MOH + EMOH	995.8	604.3	581.1
POF	3.8	0.0	3.8
EFOF	17.5	30.7	29.5
EMOF	11.4	6.9	6.6

-5.998 **EQUIVALENT AVAILABILITY POINTS**

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8,760 - 336}{8,760 - 0} \times (2,685.9 + 604.3) = 3,164.0$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 3.8 - \frac{3,164.0}{8,760} \times 100 = 60.1$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 4
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 6.96%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760	8,760	8,760
EAF	77.7	71.3	72.0
POH	840.0	921.4	840.0
FOH + EFOH	765.9	1,290.2	1,303.6
MOH + EMOH	344.8	304.6	307.8
POF	9.6	10.5	9.6
EFOF	8.7	14.7	14.9
EMOF	3.9	3.5	3.5
	-9.503	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8{,}760 - 840}{8{,}760 - 921.4} \times (1{,}290.2 + 304.6) = 1611.4$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 9.6 - \frac{1{,}611.4}{8{,}760} \times 100 = 72.0$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
GANNON UNIT NO. 5
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 0.34%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	912	744	912
EAF	71.9	78.4	78.3
POH	0.0	0.0	0.0
FOH + EFOH	175.7	158.9	158.9
MOH + EMOH	80.2	2.2	2.2
POF	0.0	0.0	0.0
EFOF	19.3	21.4	17.4
EMOF	8.8	0.3	0.2
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{912 - 0}{744 - 0} \times (158.9 + 2.2) = 197.5$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 0 - \frac{197.5}{912} \times 100 = 78.3$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
GANNON UNIT NO. 6
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 4.41%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	6,551	6,551	6,551
EAF	75.9	63.2	63.2
POH	0.0	0.0	0.0
FOH + EFOH	806.4	2,106.1	2,106.1
MOH + EMOH	596.2	302.6	302.6
POF	0.0	0.0	0.0
EFOF	12.3	32.1	32.1
EMOF	9.1	4.6	4.6
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{6,551 - 0}{6,551 - 0} \times (2,106.1 + 302.6) = 2,408.7$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 0 - \frac{2,408.7}{6,551} \times 100 = 63.2$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
POLK UNIT NO. 1
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 3.06%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760	8,760	8,760
EAF	74.6	68.4	67.5
POH	1,056.0	968.3	1,056.0
FOH + EFOH	740.8	423.7	418.9
MOH + EMOH	432.1	1,379.4	1,363.9
POF	12.1	11.1	12.1
EFOF	8.5	4.8	4.8
EMOF	4.9	15.7	15.6
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8{,}760 - 1{,}056}{8{,}760 - 968.3} \times (423.7 + 1{,}379.4) = 1{,}782.8$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 12.1 - \frac{1{,}782.8}{8{,}760} \times 100 = 67.5$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 1
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 8.95%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,533	10,968
NET GENERATION (GWH)	2,122.2	2,156.0
OPERATING BTU (10^9)	22,922.8	23,646.268
NET OUTPUT FACTOR	70.7	66.8

-5.041 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-21.58) + 12,058.44 = ANOHR

66.8 * (-21.58) + 12,058.44 = 10,617

10,968 - 10,617 = 351

10,533 + 351 = 10,884 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 2
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 7.40%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,111	10,623
NET GENERATION (GWH)	2,381.8	2,052.8
OPERATING BTU (10^9)	25,398.6	21,806.107
NET OUTPUT FACTOR	79.7	71.8

-7.258 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-12.78) + 11,130.21 = ANOHR

71.8 * (-12.78) + 11,130.21 = 10,212

10,623 - 10,212 = 410

10,111 + 410 = 10,522 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 3
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 10.01%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,132	11,030
NET GENERATION (GWH)	2,210.8	1,986.7
OPERATING BTU (10^9)	23,654.2	21,913.260
NET OUTPUT FACTOR	75.5	67.2

-7.816 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-42.21) + 13,320.32 = ANOHR

67.2 * (-42.21) + 13,320.32 = 10,484

11,030 - 10,484 = 546

10,132 + 546 = 10,678 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 4
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 8.50%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,028	10,662
NET GENERATION (GWH)	2,741.5	2,482.7
OPERATING BTU (10^9)	28,736.8	26,471.417
NET OUTPUT FACTOR	88.2	77.0

-4.991 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-32.63) + 12,906.03 = ANOHR

77 * (-32.63) + 12,906.03 = 10,394

10,662 - 10,394 = 268

10,028 + 268 = 10,297 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
GANNON UNIT NO. 5
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 0.50%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,862	11,425
NET GENERATION (GWH)	96.8	73.7
OPERATING BTU (10^9)	1,063.9	842.454
NET OUTPUT FACTOR	64.9	51.6

-7.097 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-1.9) + 10,985.08 = ANOHR

51.6 * (-1.9) + 10,985.08 = 10,887

11,425 - 10,887 = 538

10,862 + 538 = 11,400 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
GANNON UNIT NO. 6
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 6.66%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,775	11,629
NET GENERATION (GWH)	1,274.9	1,165.8
OPERATING BTU (10^9)	14,060.2	13,558.177
NET OUTPUT FACTOR	69.5	65.4

-10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-7.12) + 11,269.02 = ANOHR

65.4 * (-7.12) + 11,269.02 = 10,803

11,629 - 10,803 = 826

10,775 + 826 = 11,600 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
POLK UNIT NO. 1
JANUARY 2003 - DECEMBER 2003

WEIGHTING FACTOR = 7.81%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,382	10,665
NET GENERATION (GWH)	1,459.7	1,306.9
OPERATING BTU (10^9)	16,283.9	13,938.251
NET OUTPUT FACTOR	96.0	82.5

-1.308 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-8.77) + 11,222.67 = ANOHR

82.5 * (-8.77) + 11,222.67 = 10,500

10,665 - 10,500 = 165

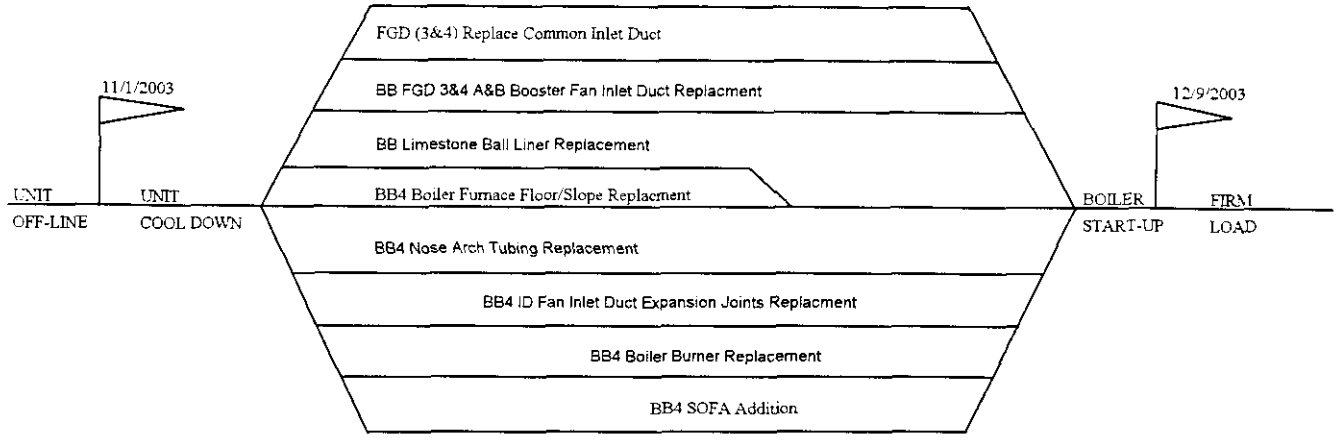
10,382 + 165 = 10,547 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ACTUAL)
GPIF UNITS
JANUARY 2003 - DECEMBER 2003

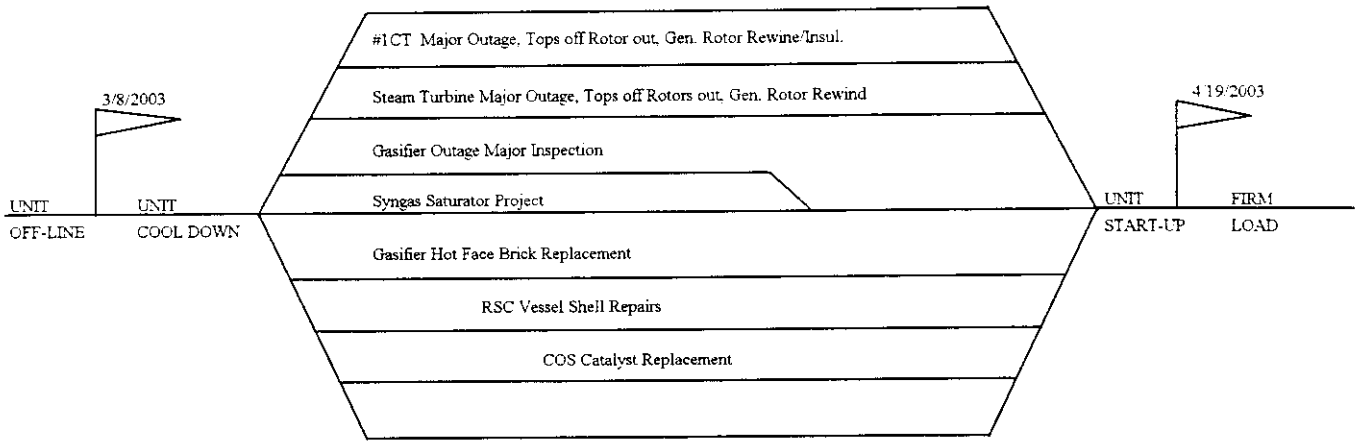
PLANT / UNIT	PLANNED OUTAGE DATES	OUTAGE DESCRIPTION
BIG BEND 4	Nov 01 - Dec 09	FGD (3&4) Replace Common Inlet Duct, BB Limestone Ball Liner Replacement, BB FGD 3&4 A&B Booster Fan Inlet Duct Replacment, BB4 Boiler Burner Replacement, BB4 ID Fan Inlet Duct Expansion Joints Replacment, BB4 Nose Arch Tubing Replacement, BB4 Burner Replacement, BB4 SOFA Addition
POLK 1	Mar 08 - Apr 19	#1CT Major Outage: Tops off Rotor out, Gen. Rotor Rewind/Insul., Steam Turbine Major Outage: Tops off Rotors out, Gen. Rotor Rewind, Gasifier Outage Major Inspection, Syngas Saturator Project, Gasifier Hot Face Brick Replacement, RSC Vessel Shell Repairs

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2003 - DECEMBER 2003



TAMPA ELECTRIC COMPANY
BIG BEND UNT #4
Planned Outage 2003
PROJECTED CPM
04/01/04

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2003 - DECEMBER 2003



TAMPA ELECTRIC COMPANY
POLK #1
PLANNED OUTAGE 2003
PROJECTED CPM
04/01/04

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2003 - DECEMBER 2003

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	3,021.7	75.1	+10	2,610.9	9,912
+9	2,719.5	74.6	+9	2,349.9	9,966
+8	2,417.4	74.1	+8	2,088.8	10,021
+7	2,115.2	73.5	+7	1,827.7	10,076
+6	1,813.0	73.0	+6	1,566.6	10,130
+5	1,510.9	72.5	+5	1,305.5	10,185
+4	1,208.7	72.0	+4	1,044.4	10,240
+3	906.5	71.5	+3	783.3	10,294
+2	604.3	70.9	+2	522.2	10,349
+1	302.2	70.4	+1	261.1	10,404
					10,458
0	0.0	69.9	0	0.0	10,533
					10,608
-1	(167.0)	68.9	-1	(261.1)	10,663
-2	(333.9)	67.8	-2	(522.2)	10,718
-3	(500.9)	66.8	-3	(783.3)	10,772
-4	(667.8)	65.8	-4	(1,044.4)	10,827
-5	(834.8)	64.7	-5	(1,305.5)	10,882
-6	(1,001.7)	63.7	-6	(1,566.6)	10,936
-7	(1,168.7)	62.7	-7	(1,827.7)	10,991
-8	(1,335.6)	61.6	-8	(2,088.8)	11,046
-9	(1,502.6)	60.6	-9	(2,349.9)	11,100
-10	(1,669.5)	59.6	-10	(2,610.9)	11,155
Weighting Factor =		10.36%	Weighting Factor =		8.95%

EAF POINTS 8.421

Adjusted EAF 61.2

AHR POINTS 5.041

Adjusted ANOHR 10.884

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2003 - DECEMBER 2003

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	4,261.3	69.9	+10	2,158.4	9,574
+9	3,835.2	69.2	+9	1,942.5	9,620
+8	3,409.0	68.5	+8	1,726.7	9,666
+7	2,982.9	67.8	+7	1,510.9	9,713
+6	2,556.8	67.1	+6	1,295.0	9,759
+5	2,130.7	66.5	+5	1,079.2	9,805
+4	1,704.5	65.8	+4	863.4	9,851
+3	1,278.4	65.1	+3	647.5	9,898
+2	852.3	64.4	+2	431.7	9,944
+1	426.1	63.7	+1	215.8	9,990
					10,036
0	0.0	63.0	0	0.0	10,111
					10,186
-1	(576.9)	61.6	-1	(215.8)	10,233
-2	(1,153.7)	60.3	-2	(431.7)	10,279
-3	(1,730.6)	58.9	-3	(647.5)	10,325
-4	(2,307.4)	57.6	-4	(863.4)	10,371
-5	(2,884.3)	56.2	-5	(1,079.2)	10,418
-6	(3,461.2)	54.8	-6	(1,295.0)	10,464
-7	(4,038.0)	53.5	-7	(1,510.9)	10,510
-8	(4,614.9)	52.1	-8	(1,726.7)	10,556
-9	(5,191.7)	50.8	-9	(1,942.5)	10,603
-10	(5,768.6)	49.4	-10	(2,158.4)	10,649

EAF POINTS 3.607 → Adjusted EAF 58.1

AHR POINTS 7.258 → Adjusted ANOHR 10,522

Weighting Factor = 14.61%

Weighting Factor = 7.40%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2003 - DECEMBER 2003

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	3,034.2	73.2	+10	2,917.7	9,455
+9	2,730.8	72.6	+9	2,625.9	9,515
+8	2,427.4	72.0	+8	2,334.1	9,575
+7	2,123.9	71.4	+7	2,042.4	9,635
+6	1,820.5	70.8	+6	1,750.6	9,696
+5	1,517.1	70.2	+5	1,458.8	9,756
+4	1,213.7	69.6	+4	1,167.1	9,816
+3	910.3	69.0	+3	875.3	9,876
+2	606.8	68.5	+2	583.5	9,937
+1	303.4	67.9	+1	291.8	9,997
					10,057
0	0.0	67.3	0	0.0	10,132
					10,207
-1	(451.3)	66.1	-1	(291.8)	10,267
-2	(902.5)	64.9	-2	(583.5)	10,328
-3	(1,353.8)	63.7	-3	(875.3)	10,388
-4	(1,805.1)	62.5	-4	(1,167.1)	10,448
-5	(2,256.3)	61.3	-5	(1,458.8)	10,508
-6	(2,707.6)	60.1	-6	(1,750.6)	10,569
-7	(3,158.9)	58.9	-7	(2,042.4)	10,629
-8	(3,610.2)	57.7	-8	(2,334.1)	10,689
-9	(4,061.4)	56.5	-9	(2,625.9)	10,749
-10	(4,512.7)	55.3	-10	(2,917.7)	10,810

EAF POINTS -5.998

Adjusted EAF 60.1

AHR POINTS 7.816

Adjusted ANOHR 10.678

Weighting Factor = 10.41%

Weighting Factor = 10.01%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2003 - DECEMBER 2003

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	2,030.2	80.7	+10	2,477.8	9,565
+9	1,827.2	80.4	+9	2,230.0	9,604
+8	1,624.2	80.1	+8	1,982.2	9,643
+7	1,421.1	79.8	+7	1,734.4	9,682
+6	1,218.1	79.5	+6	1,486.7	9,721
+5	1,015.1	79.2	+5	1,238.9	9,759
+4	812.1	78.9	+4	991.1	9,798
+3	609.1	78.6	+3	743.3	9,837
+2	406.0	78.3	+2	495.6	9,876
+1	203.0	78.0	+1	247.8	9,915
					9,953
0	0.0	77.7	0	0.0	10,028
					10,103
-1	(389.3)	77.1	-1	(247.8)	10,142
-2	(778.7)	76.5	-2	(495.6)	10,181
-3	(1,168.0)	75.9	-3	(743.3)	10,220
-4	(1,557.4)	75.3	-4	(991.1)	10,259
-5	(1,946.7)	74.7	-5	(1,238.9)	10,297
-6	(2,336.0)	74.1	-6	(1,486.7)	10,336
-7	(2,725.4)	73.5	-7	(1,734.4)	10,375
-8	(3,114.7)	72.9	-8	(1,982.2)	10,414
-9	(3,504.1)	72.3	-9	(2,230.0)	10,453
-10	(3,893.4)	71.7	-10	(2,477.8)	10,491

EAF POINTS 9.503

Adjusted EAF 72.0

AHR POINTS 4.991

Adjusted ANOHR 10,297

Weighting Factor = 6.96%

Weighting Factor = 8.50%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2003 - DECEMBER 2003

GANNON 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10 ← EAF POINTS 10.000	100.5	77.5	+10	145.8	10,134
+9	90.5	76.9	+9	131.2	10,199
+8	80.4	76.4	+8	116.6	10,265
+7	70.4	75.8	+7	102.1	10,330
+6	60.3	75.3	+6	87.5	10,395
+5	50.3	74.7	+5	72.9	10,460
+4	40.2	74.2	+4	58.3	10,526
+3	30.2	73.6	+3	43.7	10,591
+2	20.1	73.0	+2	29.2	10,656
+1	10.1	72.5	+1	14.6	10,722
					10,787
0	0.0	71.9	0	0.0	10,862
					10,937
-1	(27.5)	70.8	-1	(14.6)	11,002
-2	(54.9)	69.7	-2	(29.2)	11,067
-3	(82.4)	68.6	-3	(43.7)	11,133
-4	(109.8)	67.4	-4	(58.3)	11,198
-5	(137.3)	66.3	-5	(72.9)	11,263
-6	(164.8)	65.2	-6	(87.5)	11,328
-7	(192.2)	64.1	-7 ← AHR POINTS -7.097	(102.1)	11,394 → Adjusted ANOHR 11,400
-8	(219.7)	63.0	-8	(116.6)	11,459
-9	(247.1)	61.8	-9	(131.2)	11,524
-10	(274.6)	60.7	-10	(145.8)	11,589

Adjusted EAF 78.3

Weighting Factor = 0.34%

Weighting Factor = 0.50%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2003 - DECEMBER 2003

GANNON 6

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,287.1	80.8	+10	1,942.0	10,007
+9	1,158.4	80.3	+9	1,747.8	10,077
+8	1,029.7	79.8	+8	1,553.6	10,146
+7	901.0	79.3	+7	1,359.4	10,215
+6	772.3	78.9	+6	1,165.2	10,284
+5	643.5	78.4	+5	971.0	10,354
+4	514.8	77.9	+4	776.8	10,423
+3	386.1	77.4	+3	582.6	10,492
+2	257.4	76.9	+2	388.4	10,561
+1	128.7	76.4	+1	194.2	10,630
					10,700
0	0.0	75.9	0	0.0	10,775
					10,850
-1	(288.3)	75.0	-1	(194.2)	10,919
-2	(576.6)	74.0	-2	(388.4)	10,988
-3	(864.9)	73.1	-3	(582.6)	11,057
-4	(1,153.2)	72.1	-4	(776.8)	11,126
-5	(1,441.5)	71.1	-5	(971.0)	11,196
-6	(1,729.9)	70.2	-6	(1,165.2)	11,265
-7	(2,018.2)	69.2	-7	(1,359.4)	11,334
-8	(2,306.5)	68.3	-8	(1,553.6)	11,403
-9	(2,594.8)	67.3	-9	(1,747.8)	11,472
-10	(2,883.1)	66.3	-10	(1,942.0)	11,542

EAF POINTS -10.000 → Adjusted EAF 63.2

AHR POINTS -10.000 → Adjusted ANOHR 11.600

Weighting Factor = 4.41%

Weighting Factor = 6.66%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2003 - DECEMBER 2003

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	892.7	77.8	+10	2,278.3	9,615
+9	803.4	77.5	+9	2,050.4	9,684
+8	714.2	77.2	+8	1,822.6	9,753
+7	624.9	76.8	+7	1,594.8	9,822
+6	535.6	76.5	+6	1,367.0	9,891
+5	446.4	76.2	+5	1,139.1	9,961
+4	357.1	75.9	+4	911.3	10,030
+3	267.8	75.5	+3	683.5	10,099
+2	178.5	75.2	+2	455.7	10,168
+1	89.3	74.9	+1	227.8	10,237
					10,307
0	0.0	74.6	0	0.0	10,382
					10,457
-1	(167.0)	73.9	-1	(227.8)	10,526
-2	(333.9)	73.2	-2	(455.7)	10,595
-3	(500.9)	72.6	-3	(683.5)	10,664
-4	(667.8)	71.9	-4	(911.3)	10,733
-5	(834.8)	71.3	-5	(1,139.1)	10,802
-6	(1,001.7)	70.6	-6	(1,367.0)	10,872
-7	(1,168.7)	70.0	-7	(1,594.8)	10,941
-8	(1,335.6)	69.3	-8	(1,822.6)	11,010
-9	(1,502.6)	68.6	-9	(2,050.4)	11,079
-10	(1,669.5)	68.0	-10	(2,278.3)	11,148

EAF POINTS 10.000

Adjusted EAF 67.5

AHR POINTS -1.308

Adjusted ANOHR 10,547

Weighting Factor = 3.06%

Weighting Factor = 7.81%

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 03 - DEC 03 POF	EUOF	EUOR	ACTUAL PERFORMANCE JAN 03 - DEC 03 POF	EUOF	EUOR
BIG BEND 1	10.36%	20.7%	5.8	31.2	33.2	0.0	35.1	35.1
BIG BEND 2	14.61%	29.1%	3.8	12.2	12.7	0.0	39.6	39.6
BIG BEND 3	10.41%	20.7%	3.8	33.7	35.0	0.0	37.6	37.6
BIG BEND 4	6.96%	13.9%	9.6	28.0	31.0	10.5	18.2	20.3
GANNON 5	0.34%	0.7%	0.0	0.0	0.0	0.0	1.8	1.8
GANNON 6	4.41%	8.8%	0.0	0.0	0.0	0.0	27.5	27.5
POLK 1	3.06%	6.1%	12.1	10.5	12.0	11.1	20.6	23.1
GPIF SYSTEM	**50.17%**	**100.0%**	**5.2**	**21.5**	**22.8**	**2.1**	**32.8**	**33.2**

GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%) 73.3 65.1

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
8.4	**21.1**	**23.2**	**70.5**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 03 - DEC 03	ADJUSTED ACTUAL HEAT RATE JAN 03 - DEC 03
BIG BEND 1	8.95%	18.0%	10,533	10,884
BIG BEND 2	7.40%	14.9%	10,111	10,522
BIG BEND 3	10.01%	20.1%	10,132	10,678
BIG BEND 4	8.50%	17.1%	10,028	10,297
GANNON 5	0.50%	1.0%	10,862	11,400
GANNON 6	6.66%	13.4%	10,775	11,600
POLK 1	7.81%	15.7%	10,382	10,547
GPIF SYSTEM	**49.83%**	**100.0%**		

GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh) 10,316 10,737

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS CALCULATION
JANUARY 2003 - DECEMBER 2003

Points are calculated according to the formula:

$$GPIP = \sum_{i=1}^{n} \left[a_i(EAP_i) + e_i(AHRP_i) \right]$$

Where:

$GPIP$ = Generating performance incentive points

a_i = Percentage of total system fuel cost reduction attributed to maximum reasonably attainable equivalent availability of unit i during the period

e_i = Percentage of total system fuel cost reduction attributed to minimum reasonably attainable average heat rate of unit i during the period

EAP_i = Equivalent availability points awarded/deducted for unit i

$AHRP_i$ = Average heat rate points awarded/deducted for unit i

Weighting factors and point values are listed on page 4.

GPIP =	10.36%	*	(BB 1 EAP)	+	14.61%	*	(BB 2 EAP)	+	10.41%	*	(BB 3 EAP)
+	6.96%	*	(BB 4 EAP)	+	0.34%	*	(GN 5 EAP)	+	4.41%	*	(GN 6 EAP)
+	3.06%	*	(PK 1 EAP)	+	8.95%	*	(BB 1 AHRP)	+	7.40%	*	(BB 2 AHRP)
+	10.01%	*	(BB 3 AHRP)	+	8.50%	*	(BB 4 AHRP)	+	0.50%	*	(GN 5 AHRP)
+	6.66%	*	(GN 6 AHRP)	+	7.81%	*	(PK 1 AHRP)				

GPIP =	10.36%	*	-8.421	+	14.61%	*	-3.607	+	10.41%	*	-5.998
+	6.96%	*	-9.503	+	0.34%	*	10.000	+	4.41%	*	-10.000
+	3.06%	*	-10.000	+	8.95%	*	-5.041	+	7.40%	*	-7.258
+	10.01%	*	-7.816	+	8.50%	*	-4.991	+	0.50%	*	-7.097
+	6.66%	*	-10.000	+	7.81%	*	-1.308				

GPIP =	-0.873	+	-0.527	+	-0.624
+	-0.662	+	0.034	+	-0.441
+	-0.306	+	-0.451	+	-0.537
+	-0.782	+	-0.424	+	-0.035
+	-0.666	+	-0.102		

GPIP = -6.397 POINTS

REWARD/PENALTY dollar amounts of the Generating Performance Incentive Factor (GPIF) are determined directly from the table for the corresponding Generating Performance Points (GPIP) on page 2.

GPIF REWARD = ($3,678,414)

EXHIBIT NO. _____
DOCKET NO. 040001-EI
TAMPA ELECTRIC COMPANY
(WAS-1)
DOCUMENT NO. 2

EXHIBITS TO THE TESTIMONY OF

WILLIAM A. SMOTHERMAN

DOCKET NO. 040001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2003 - DECEMBER 2003

TRUE-UP

DOCUMENT NO. 2

ACTUAL UNIT PERFORMANCE DATA

TAMPA ELECTRIC COMPANY
ACTUAL UNIT PERFORMANCE DATA
JANUARY 2003 - DECEMBER 2003
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BIG BEND 1 GPIF(w/o FGD) - ACTUAL UNIT PERFORMANCE DATA	3
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BIG BEND 2 GPIF(w/o FGD) - ACTUAL UNIT PERFORMANCE DATA	5
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ORIGINAL SHEET NO. 8.401.02A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1	JAN 03	FEB 03	MAR 03	APR 03	MAY 03	JUN 03	JUL 03	AUG 03	SEP 03	OCT 03	NOV 03	DEC 03	2003
1. EAF (%)	71.4	73.9	67.1	82.5	54.9	59.1	58.9	80.0	66.5	49.3	72.7	61.7	64.7
2. PH	744.0	672.0	744.0	719.0	744.0	720.0	744.0	744.0	720.0	745.0	720.0	744.0	8,760.0
3. SH	659.8	629.5	612.7	719.0	510.6	598.6	587.6	619.0	695.0	487.2	720.0	703.5	7,542.4
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	84.2	42.5	131.3	0.0	233.4	121.4	156.4	125.1	25.0	257.8	0.0	40.5	1,217.6
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	84.2	0.0	71.6	0.0	233.4	121.4	156.4	125.1	1.3	121.6	0.0	25.0	939.9
8. MOH	0.0	42.5	59.7	0.0	0.0	0.0	0.0	0.0	23.7	136.2	0.0	15.5	277.7
9. PFOH	637.8	615.2	599.1	642.0	483.1	553.0	553.6	584.9	660.3	467.8	676.8	629.0	7,302.4
10. LR PF (MW)	78.2	87.6	75.8	70.8	74.4	110.4	97.2	115.8	124.9	97.6	108.2	106.0	96.2
11. PMOH	21.8	15.0	13.2	32.2	26.4	45.1	31.2	22.4	32.9	19.1	42.5	170.1	471.7
12. LR PM (MW)	232.2	196.8	233.8	233.8	262.7	263.2	287.8	222.8	263.1	256.7	227.4	99.2	193.9
13. NSC (MW)	426	428	428	421	421	421	421	421	421	421	421	428	423
14. OPR BTU(GBTU)	2,135.6	1,922.7	2,089.0	2,381.1	1,641.4	1,787.3	1,894.4	1,855.9	2,103.9	1,580.0	2,228.4	2,026.6	23,646.3
15. NET GEN (MWH)	194,245	176,959	190,435	211,988	145,812	157,833	169,176	162,277	183,308	141,855	200,071	181,978	2,117,534
16. ANOHR (BTU/KWH)	10,994	10,744	10,970	11,232	11,272	11,324	11,198	11,436	11,478	11,154	11,128	11,147	11,167
17. NOF (%)	69.1	68.4	72.6	70.0	67.7	62.6	66.4	62.3	62.6	69.1	68.0	60.4	66.3
18. NPC (MW)	426	428	428	421	421	421	421	421	421	421	421	428	423
19. ANOHR EQUATION	ANOHR = NOF(-21.583) + 12058												

EXHIBIT NO. _____
DOCKET NO 040001-EI
TAMPA ELECTRIC COMPANY
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ORIGINAL SHEET NO. 8.401.02A
TAMPA ELECTRIC COMPANY

UNIT PERFORMANCE DATA w/o FGD

JANUARY 2003 - DECEMBER 2003

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1 w/o FGD	JAN 03	FEB 03	MAR 03	APR 03	MAY 03	JUN 03	JUL 03	AUG 03	SEP 03	OCT 03	NOV 03	DEC 03	2003
1. OPR BTU (GBTU)	2,135.6	1,922.7	2,089.0	2,361.1	1,641.4	1,787.3	1,894.4	1,855.9	2,103.9	1,580.0	2,226.4	2,028.6	23,846.3
2. NET GEN w/FGD (MWH)	194,245	178,959	190,435	211,988	145,612	157,833	169,176	162,277	183,306	141,855	200,071	181,978	2,117,534
3. FGD CONSUMED (MWH)	3,569	3,458	3,726	3,731	3,354	2,752	2,914	3,173	3,158	2,817	2,240	3,598	38,487
4. NET GEN w/o FGD (MWH)	197,814	182,417	194,160	215,719	148,966	160,586	172,090	165,450	186,462	144,672	202,311	185,576	2,156,021
5. ANOHR w/FGD (BTU/KWH)	10,994	10,744	10,970	11,232	11,272	11,324	11,198	11,436	11,478	11,154	11,128	11,147	11,167
6. ANOHR w/o FGD (BTU/KWH)	10,796	10,540	10,759	11,038	11,018	11,130	11,008	11,217	11,284	10,936	11,005	10,931	10,966
7. NOF w/FGD (%)	69.1	66.4	72.6	70.0	67.7	62.6	68.4	62.3	62.6	69.1	66.0	60.4	66.3
8. NOF w/o FGD (%)	69.6	66.9	73.2	70.4	68.5	63.0	68.8	62.7	63.0	69.6	66.0	60.9	66.8
9. NPC (MW) w/FGD	426	428	428	421	421	421	421	421	421	421	421	428	423
10. NPC (MW) w/o FGD	431	433	433	426	426	426	426	426	426	426	426	433	428

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ORIGINAL SHEET NO. 8.401 02A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2	JAN 03	FEB 03	MAR 03	APR 03	MAY 03	JUN 03	JUL 03	AUG 03	SEP 03	OCT 03	NOV 03	DEC 03	2003
1. EAF (%)	43.3	30.6	72.7	88.8	84.6	75.9	78.0	50.6	51.4	60.1	39.0	44.6	60.2
2. PH	744.0	672.0	744.0	719.0	744.0	720.0	744.0	744.0	720.0	745.0	720.0	744.0	8,760.0
3. SH	377.7	230.2	640.1	690.6	740.4	692.5	744.0	469.5	514.7	718.6	444.2	504.4	6,786.7
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	366.3	441.8	103.9	28.4	3.6	27.5	0.0	274.5	205.3	26.4	275.8	239.7	1,993.3
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	366.3	441.8	103.9	28.4	3.6	27.5	0.0	25.8	62.4	26.4	274.2	225.0	1,585.5
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	248.7	142.9	0.0	1.6	14.7	407.8
9. PFOH	377.2	155.6	608.9	322.6	697.0	636.2	703.5	456.8	482.1	724.6	475.3	401.5	6,041.3
10. LR PF (MW)	62.8	49.9	65.5	32.0	41.3	81.8	82.6	78.6	112.0	145.2	139.3	180.0	91.7
11. PMOH	0.0	12.5	18.5	50.8	66.4	31.7	39.7	9.3	27.2	75.9	14.3	11.1	357.2
12. LR PM (MW)	0.0	231.1	174.9	217.8	254.3	256.4	233.6	237.2	203.5	82.5	57.2	226.3	192.5
13. NSC (MW)	426	433	433	411	411	411	411	411	411	411	411	433	418
14. OPR BTU(GBTU)	1,308	747	2,218	2,425	2,415	2,126	2,316	1,548	1,517	2,418	1,468	1,301	21,806
15. NET GEN (MWH)	123,813	73,719	206,163	227,232	220,950	193,418	213,042	139,794	138,368	224,289	136,885	120,784	2,018,456
16. ANOHR (BTU/KWH)	10,567	10,133	10,756	10,673	10,930	10,994	10,873	11,077	10,960	10,771	10,725	10,772	10,803
17. NOF (%)	77.0	74.0	74.4	80.1	72.6	68.0	69.7	72.4	65.4	75.9	75.0	55.3	71.4
18. NPC (MW)	426	433	433	411	411	411	411	411	411	411	411	433	418
19. ANOHR EQUATION	ANOHR = NOF(-12.783) + 11130												

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TAMPA ELECTRIC COMPANY

UNIT PERFORMANCE DATA w/o FGD

JANUARY 2003 - DECEMBER 2003

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2 w/o FGD	JAN 03	FEB 03	MAR 03	APR 03	MAY 03	JUN 03	JUL 03	AUG 03	SEP 03	OCT 03	NOV 03	DEC 03	2003
1. OPR BTU (GBTU)	1,308.3	747.0	2,217.5	2,425.3	2,415.1	2,126.4	2,316.3	1,548.4	1,518.5	2,415.9	1,468.1	1,301.1	21,806.1
2. NET GEN w/FGD (MWH)	123,813	73,719	206,163	227,232	220,950	193,418	213,042	139,794	138,388	224,289	136,885	120,784	2,018,458
3. FGD CONSUMED (MWH)	2,241	1,345	4,035	3,590	3,187	3,198	3,605	2,720	2,291	4,155	1,460	2,511	34,317
4. NET GEN w/o FGD (MWH)	126,054	75,064	210,198	230,822	224,117	196,616	216,647	142,514	140,659	228,443	138,345	123,295	2,052,773
5. ANOHR w/FGD (BTU/KWH)	10,567	10,133	10,756	10,673	10,930	10,994	10,873	11,077	10,960	10,771	10,725	10,772	10,803
6. ANOHR w/o FGD (BTU/KWH)	10,379	9,951	10,550	10,507	10,776	10,815	10,692	10,865	10,782	10,576	10,612	10,553	10,623
7. NOF w/FGD (%)	77.0	74.0	74.4	80.1	72.6	68.0	69.7	72.4	65.4	75.9	75.0	55.3	71.4
8. NOF w/o FGD (%)	77.4	74.5	75.0	80.3	72.8	68.2	70.0	73.0	65.7	76.4	74.9	55.8	71.8
9. NPC (MW) w/FGD	426	433	433	411	411	411	411	411	411	411	411	433	418
10. NPC (MW) w/o FGD	431	438	438	416	416	416	416	416	416	416	416	438	423

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TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	JAN 03	FEB 03	MAR 03	APR 03	MAY 03	JUN 03	JUL 03	AUG 03	SEP 03	OCT 03	NOV 03	DEC 03	2003
1. EAF (%)	78.6	92.6	86.4	79.5	58.1	71.1	68.5	68.5	41.6	58.3	41.6	26.4	62.4
2. PH	744.0	672.0	744.0	719.0	744.0	720.0	744.0	744.0	720.0	745.0	720.0	744.0	8,760.0
3. SH	662.4	672.0	585.3	617.9	601.3	657.4	743.0	701.3	550.3	517.9	351.1	196.1	6,656.0
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	81.6	0.0	158.8	101.1	142.7	62.6	1.0	42.8	169.7	227.1	368.9	547.8	1,904.0
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	81.6	0.0	158.8	101.1	142.7	62.6	1.0	42.8	0.0	46.0	368.9	477.4	1,482.8
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	169.7	181.1	0.0	70.4	421.2
9. PFOH	614.1	391.9	550.2	582.3	557.2	604.7	714.2	700.1	543.2	480.7	307.1	0.0	6,045.6
10. LR PF (MW)	41.4	40.2	57.3	21.7	107.4	90.2	126.9	117.0	195.1	55.6	39.1	0.0	85.8
11. PMOH	47.8	27.3	34.6	32.6	43.9	32.6	27.9	0.0	5.0	36.7	43.7	0.0	332.1
12. LR PM (MW)	169.7	221.4	247.5	221.7	281.5	241.7	285.7	0.0	291.6	250.4	231.4	0.0	237.6
13. NSC (MW)	433	438	438	428	428	428	428	428	428	428	428	438	431
14. OPR BTU(GBTU)	2,304.0	2,381.5	2,000.6	2,210.6	1,783.0	2,091.3	2,083.3	2,183.7	1,332.6	1,741.7	1,201.1	600.0	21,913.3
15. NET GEN (MWH)	214,627	223,190	186,320	208,037	159,606	189,726	178,586	188,794	115,134	154,680	111,433	58,579	1,986,711
16. ANOHR BTU/KWH	10,735	10,670	10,737	10,626	11,171	11,023	11,665	11,566	11,574	11,260	10,779	10,605	11,030
17. NOF (%)	74.8	75.8	72.7	78.7	62.0	67.4	56.2	62.9	48.9	69.8	74.2	65.9	67.2
18. NPC (MW)	433	438	438	428	428	428	428	428	428	428	428	438	431
19. ANOHR EQUATION	ANOHR = NOF(-42.211) + 13328												

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ACTUAL UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	*PERIOD*
BIG BEND 4	JAN 03	FEB 03	MAR 03	APR 03	MAY 03	JUN 03	JUL 02	AUG 03	SEP 03	OCT 03	NOV 03	DEC 03	2003
1. EAF (%)	77.9	74.1	82.5	76.7	88.1	79.6	66.9	92.1	86.9	74.7	0.3	54.4	71.3
2. PH	744.0	672.0	744.0	719.0	744.0	720.0	744.0	744.0	720.0	745.0	720.0	744.0	8,760.0
3. SH	640.8	568.6	722.9	578.3	728.8	710.1	557.9	744.0	715.6	703.1	2.8	440.2	7,112.8
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	103.2	103.4	21.1	140.7	15.2	9.9	186.1	0.0	4.4	41.9	717.2	303.8	1,647.2
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	717.2	204.2	921.4
7. FOH	103.2	0.0	21.1	140.7	15.2	9.9	186.1	0.0	4.4	41.9	0.0	17.8	540.6
8. MOH	0.0	103.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	81.8	185.2
9. PFOH	640.3	531.2	673.8	262.8	698.6	671.5	491.9	728.4	705.4	668.2	2.8	146.1	6,221.0
10. LR PF (MW)	42.6	52.1	63.6	32.6	36.2	84.7	34.4	33.9	54.5	86.3	138.9	91.6	54.7
11. PMOH	0.0	36.6	42.8	20.5	29.5	26.0	63.1	10.9	9.6	34.2	0.0	13.7	287.0
12. LR PM (MW)	0.0	126.3	173.4	169.5	263.9	195.2	161.4	174.8	224.1	247.1	0.0	216.8	188.6
13. NSC (MW)	447	460	460	452	452	452	452	452	452	452	452	460	454
14. OPR BTU(GBTU)	2299.2	2088.3	2641.9	2258.5	2725.4	2472.9	2115.3	3000.2	2845.2	2492.4	0.0	1532.1	26471.4165
15. NET GEN (MWH)	221,664	197,136	245,982	212,390	258,678	232,398	191,005	275,957	262,409	237,353	191	147,521	*2,482,684*
16. ANOHR BTU/KWH	10,373	10,593	10,740	10,634	10,536	10,641	11,074	10,872	10,842	10,501	0	10,386	10,662
17. NOF (%)	77.4	75.4	74.0	81.3	78.5	72.4	75.7	82.1	81.1	74.7	15.3	72.9	77.0
18. NPC (MW)	447	460	460	452	452	452	452	452	452	452	452	460	454

19. ANOHR EQUATION ANOHR = NOF(-37.857) + 13241

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ACTUAL UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON 5	JAN 03	FEB 03	MAR 03	APR 03	MAY 03	JUN 03	JUL 02	AUG 03	SEP 03	OCT 03	NOV 03	DEC 03	2003
1. EAF (%)	78.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	78.4
2. PH	744.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	744.0
3. SH	658.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	658.0
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	86.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	86.0
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	86.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	86.0
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PFOH	338.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	338.5
10. LR PF (MW)	46.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.7
11. PMOH	5.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.9
12. LR PM (MW)	80.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	80.2
13. NSC (MW)	217	0	0	0	0	0	0	0	0	0	0	0	217
14. OPR BTU(GBTU)	842.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	842.4539
15. NET GEN (MWH)	73,740	0	0	0	0	0	0	0	0	0	0	0	73,740
16. ANOHR BTU/KWH	11,425	0	0	0	0	0	0	0	0	0	0	0	11,425
17. NOF (%)	51.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	51.6
18. NPC (MW)	217	0	0	0	0	0	0	0	0	0	0	0	217
19. ANOHR EQUATION	ANOHR = NOF(-8.6611) + 11322												

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ACTUAL UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON 6	JAN 03	FEB 03	MAR 03	APR 03	MAY 03	JUN 03	JUL 02	AUG 03	SEP 03	OCT 03	NOV 03	DEC 03	2003
1. EAF (%)	74.2	68.6	57.5	51.6	78.9	34.7	63.7	61.1	77.8	0.0	0.0	0.0	63.2
2. PH	744.0	672.0	744.0	719.0	744.0	720.0	744.0	744.0	720.0	0.0	0.0	0.0	6,551.0
3. SH	562.3	500.3	472.1	403.7	687.1	344.2	589.7	590.4	706.6	0.0	0.0	0.0	4,858.2
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	81.8	171.7	272.0	315.4	56.9	375.8	154.3	153.6	11.4	0.0	0.0	0.0	1,592.9
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	81.8	171.7	272.0	315.4	56.9	112.4	154.3	153.6	11.4	0.0	0.0	0.0	1,329.5
8. MOH	0.0	0.0	0.0	0.0	0.0	263.4	0.0	0.0	0.0	0.0	0.0	0.0	263.4
9. PFOH	507.2	176.6	209.8	217.6	395.8	310.5	536.8	574.8	694.0	0.0	0.0	0.0	3,622.9
10. LR PF (MW)	80.7	72.5	78.0	53.0	73.2	106.9	72.9	81.9	70.6	0.0	0.0	0.0	77.0
11. PMOH	0.0	10.1	0.0	0.0	36.5	0.0	14.8	19.8	26.6	0.0	0.0	0.0	107.8
12. LR PM (MW)	0.0	189.6	0.0	0.0	175.3	0.0	112.9	40.0	124.8	0.0	0.0	0.0	130.8
13. NSC (MW)	372.0	372.0	372.0	353.0	353.0	353.0	353.0	353.0	353.0	0.0	0.0	0.0	359
14. OPR BTU(GBTU)	1,745.9	1,437.8	1,322.4	1,156.2	1,922.4	822.0	1,604.6	1,664.5	1,882.4	0.0	0.0	0.0	13,558.2
15. NET GEN (MWH)	152,641	128,435	116,781	98,704	162,321	70,031	133,883	139,688	163,359	0	0	0	1,165,844
16. ANOHR BTU/KWH	11,438	11,195	11,323	11,713	11,843	11,738	11,985	11,916	11,523	0	0	0	11,629
17. NOF (%)	62.0	59.0	56.5	69.3	66.9	57.6	64.3	67.0	65.3	0.0	0.0	0.0	65.4
18. NPC (MW)	372	372	372	353	353	353	353	353	353	0	0	0	359
19. ANOHR EQUATION	ANOHR = NOF(5.8759) + 10194												

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ORIGINAL SHEET NO. 8.401.02A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2003 - DECEMBER 2003

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 1	JAN 03	FEB 03	MAR 03	APR 03	MAY 03	JUN 03	JUL 02	AUG 03	SEP 03	OCT 03	NOV 03	DEC 03	2003
1. EAF (%)	95.6	92.4	21.9	34.4	92.9	84.5	88.7	92.8	21.7	2.8	96.7	97.0	68.4
2. PH	744.0	672.0	744.0	719.0	744.0	720.0	744.0	744.0	720.0	745.0	720.0	744.0	8,760.0
3. SH	737.3	670.3	165.2	198.3	740.4	618.5	744.1	698.7	170.4	27.4	720.9	700.8	6,192.3
4. RSH	-5.5	-11.8	573.7	444.8	-9.9	21.7	-5.0	35.4	-5.1	-8.4	-1.8	22.1	1,052.2
5. UH	12.2	13.3	5.1	75.9	13.6	79.8	4.8	10.0	554.6	724.1	0.9	21.2	1,515.5
6. POH	0.0	0.0	575.7	392.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	968.3
7. FOH	12.2	8.7	5.1	74.1	2.5	10.9	4.8	1.6	0.6	0.0	0.9	14.7	136.1
8. MOH	0.0	4.5	0.0	1.8	11.1	69.0	0.0	8.4	554.0	724.1	0.0	6.5	1,379.4
9. PFOH	342.3	404.8	0.0	38.0	709.3	518.2	1,282.8	1,318.3	148.5	0.0	970.0	12.7	5,744.9
10. LR PF (MW)	14.9	24.4	0.0	21.9	14.0	15.7	15.7	8.4	15.7	0.0	6.0	26.4	12.8
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13. NSC (MW) **	250	260	260	255	255	255	255	255	255	255	255	260	256
14. OPR BTU(GBTU)	1,617.2	1,449.5	434.4	327.7	1,680.3	1,362.1	1,707.6	1,618.0	390.6	44.7	1,659.7	1,546.5	13,938.3
15. NET GEN (MWH)	147,278	141,418	33,870	15,513	166,070	130,694	158,287	146,260	33,695	-4,132	172,122	165,792	1,306,867
16. ANOHR BTU/KWH	10,980	10,250	12,826	21,123	10,118	10,422	10,786	11,062	11,593	-10,829	9,642	9,931	10,665
17. NOF (%)	80.3	81.9	78.9	32.6	88.4	84.1	83.6	82.6	78.6	-60.6	93.8	91.2	82.5
18. NPC (MW) **	250	260	260	255	255	255	255	255	255	255	255	260	256

19. ANOHR EQUATION ANOHR = NOF(-49.528) + 14782

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TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
FILED: 09/9/04

EXHIBIT TO THE TESTIMONY OF

DAVID R. KNAPP

DOCKET NO. 040001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2005 - DECEMBER 2005

DOCUMENT NO. 1

GPIF SCHEDULES

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 46
COMPANY/ TECO
WITNESS: David R. Knapp (DRK-1)
DATE: 11-08-04

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2005 - DECEMBER 2005
TARGETS
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ESTIMATED
JANUARY 2005 - DECEMBER 2005

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	35,060.9	5,807.6
+9	31,554.8	5,226.9
+8	28,048.7	4,646.1
+7	24,542.6	4,065.4
+6	21,036.5	3,484.6
+5	17,530.4	2,903.8
+4	14,024.3	2,323.1
+3	10,518.3	1,742.3
+2	7,012.2	1,161.5
+1	3,506.1	580.8
0	0.0	0.0
-1	(6,036.0)	(580.8)
-2	(12,072.0)	(1,161.5)
-3	(18,108.0)	(1,742.3)
-4	(24,144.0)	(2,323.1)
-5	(30,180.0)	(2,903.8)
-6	(36,216.0)	(3,484.6)
-7	(42,252.0)	(4,065.4)
-8	(48,288.0)	(4,646.1)
-9	(54,324.0)	(5,226.9)
-10	(60,360.0)	(5,807.6)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
(ESTIMATED)
JANUARY 2005 - DECEMBER 2005

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,404,189,000
Line 2	Month of January	2005	$	1,448,158,351
Line 3	Month of February	2005	$	1,462,338,234
Line 4	Month of March	2005	$	1,476,656,963
Line 5	Month of April	2005	$	1,418,647,933
Line 6	Month of May	2005	$	1,432,538,860
Line 7	Month of June	2005	$	1,446,565,803
Line 8	Month of July	2005	$	1,490,821,253
Line 9	Month of August	2005	$	1,505,418,878
Line 10	Month of September	2005	$	1,520,159,438
Line 11	Month of October	2005	$	1,461,450,698
Line 12	Month of November	2005	$	1,475,760,736
Line 13	Month of December	2005	$	1,490,210,893
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,464,070,542
Line 15	25 Basis points			0.0025
Line 16	Revenue Expansion Factor			61.38%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	5,963,066
Line 18	Jurisdictional Sales			19,176,209 MWH
Line 19	Total Sales			19,689,398 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			97.39%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**5,807,644**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2005 - DECEMBER 2005

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	15.68%	52.6	59.8	38.3	5,498.6	(12,805.0)
BIG BEND 2	17.44%	61.6	68.7	47.5	6,112.9	(12,376.3)
BIG BEND 3	18.30%	60.6	67.9	45.9	6,414.7	(13,384.7)
BIG BEND 4	11.68%	78.7	82.4	71.3	4,096.8	(6,982.3)
POLK 1	5.44%	79.8	76.9	65.5	1,906.3	(3,780.1)
GPIF SYSTEM	68.54%					

AVERAGE NET OPERATING HEAT RATE

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR TARGET Btu/kwh	NOF	ANOHR RANGE MIN.	ANOHR RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	5.27%	10,853	76.8	10,324	11,382	1,848.1	(1,848.1)
BIG BEND 2	4.72%	10,672	77.2	10,251	11,093	1,656.1	(1,656.1)
BIG BEND 3	7.40%	10,663	72.0	10,006	11,319	2,593.2	(2,593.2)
BIG BEND 4	7.74%	10,350	85.7	9,868	10,833	2,712.8	(2,712.8)
POLK 1	6.34%	10,342	89.1	9,624	11,060	2,221.4	(2,221.4)
GPIF SYSTEM	31.46%					11,031.6	(11,031.6)

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 05 - DEC 05 POF	EUOF	EUOR	TARGET PERIOD JUL 03 - JUN 04 POF	EUOF	EUOR	TARGET PERIOD JUL 02 - JUN 03 POF	EUOF	EUOR	TARGET PERIOD JUL 01 - JUN 02 POF	EUOF	EUOR
BIG BEND 1	15.68%	22.9%	15.3	32.0	37.8	7.9	33.8	36.7	0.0	28.9	28.9	4.5	24.8	26.0
BIG BEND 2	17.44%	25.4%	3.8	34.5	35.9	0.0	37.8	37.8	23.3	24.4	31.8	0.0	28.2	28.2
BIG BEND 3	18.30%	26.7%	3.8	35.6	37.0	0.0	37.4	37.4	0.0	28.6	28.6	16.2	27.7	33.0
BIG BEND 4	11.68%	17.0%	3.8	17.5	18.2	10.6	15.8	17.7	6.1	16.0	17.1	0.0	12.4	12.4
POLK 1	5.44%	7.9%	3.8	16.5	17.1	3.3	18.7	19.3	11.1	7.1	8.0	0.7	14.3	14.4
GPIF SYSTEM	**68.54%**	**100.0%**	**6.5**	**29.9**	**32.1**	**3.9**	**31.5**	**32.5**	**7.8**	**23.7**	**25.9**	**5.4**	**23.5**	**25.2**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**63.6**			**64.6**			**68.4**			**71.1**	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
5.7	**26.3**	**27.9**	**68.0**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 05 - DEC 05	ADJUSTED PRIOR HEAT RATE JUL 03 - JUN 04	ADJUSTED PRIOR HEAT RATE JUL 02 - JUN 03	ADJUSTED PRIOR HEAT RATE JUL 01 - JUN 02
BIG BEND 1	5.27%	16.8%	10,853	10,748	10,920	10,693
BIG BEND 2	4.72%	15.0%	10,672	10,658	10,803	10,426
BIG BEND 3	7.40%	23.5%	10,663	10,831	10,752	10,395
BIG BEND 4	7.74%	24.6%	10,350	10,356	10,293	10,331
POLK 1	6.34%	20.1%	10,342	10,024	10,039	10,373
GPIF SYSTEM	**31.46%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh)			**10,555**	**10,512**	**10,531**	**10,429**

TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2005 - DECEMBER 2005
PRODUCTION COSTING SIMULATION
FUEL COST ($000)

UNIT PERFORMANCE INDICATOR	AT TARGET (1)	AT MAXIMUM IMPROVEMENT (2)	SAVINGS (3)	WEIGHTING FACTOR (% OF SAVINGS)
EQUIVALENT AVAILABILITY				
EA_1 BIG BEND 1	781,574	776,075	5,499	15.68%
EA_2 BIG BEND 2	781,574	775,461	6,113	17.44%
EA_3 BIG BEND 3	781,574	775,159	6,415	18.30%
EA_4 BIG BEND 4	781,574	777,477	4,097	11.68%
EA_7 POLK 1	781,574	779,667	1,906	5.44%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	781,574	779,726	1,848	5.27%
AHR_2 BIG BEND 2	781,574	779,918	1,656	4.72%
AHR_3 BIG BEND 3	781,574	778,980	2,593	7.40%
AHR_4 BIG BEND 4	781,574	778,861	2,713	7.74%
AHR_7 POLK 1	781,574	779,352	2,221	6.34%
TOTAL SAVINGS			**35,061**	**100.00%**

(1) Fuel Adjustment Base Case - All unit performance indicators at target.
(2) All other units performance indicators at target.
(3) Expressed in replacement energy cost.

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2005 - DECEMBER 2005

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	5,498.6	59.8	+10	1,848.1	10,324
+9	4,948.7	59.1	+9	1,663.3	10,369
+8	4,398.9	58.4	+8	1,478.5	10,415
+7	3,849.0	57.6	+7	1,293.6	10,460
+6	3,299.2	56.9	+6	1,108.8	10,506
+5	2,749.3	56.2	+5	924.0	10,551
+4	2,199.4	55.5	+4	739.2	10,596
+3	1,649.6	54.8	+3	554.4	10,642
+2	1,099.7	54.1	+2	369.6	10,687
+1	549.9	53.3	+1	184.8	10,733
					10,778
0	0.0	52.6	0	0.0	10,853
					10,928
-1	(1,280.5)	51.2	-1	(184.8)	10,973
-2	(2,561.0)	49.8	-2	(369.6)	11,019
-3	(3,841.5)	48.3	-3	(554.4)	11,064
-4	(5,122.0)	46.9	-4	(739.2)	11,109
-5	(6,402.5)	45.5	-5	(924.0)	11,155
-6	(7,683.0)	44.0	-6	(1,108.8)	11,200
-7	(8,963.5)	42.6	-7	(1,293.6)	11,246
-8	(10,244.0)	41.2	-8	(1,478.5)	11,291
-9	(11,524.5)	39.7	-9	(1,663.3)	11,336
-10	(12,805.0)	38.3	-10	(1,848.1)	11,382
	Weighting Factor =	15.68%		Weighting Factor =	5.27%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2005 - DECEMBER 2005

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	6,112.9	68.7	+10	1,656.1	10,251
+9	5,501.6	68.0	+9	1,490.5	10,286
+8	4,890.3	67.3	+8	1,324.9	10,320
+7	4,279.0	66.6	+7	1,159.2	10,355
+6	3,667.7	65.9	+6	993.6	10,389
+5	3,056.5	65.2	+5	828.0	10,424
+4	2,445.2	64.5	+4	662.4	10,459
+3	1,833.9	63.8	+3	496.8	10,493
+2	1,222.6	63.1	+2	331.2	10,528
+1	611.3	62.4	+1	165.6	10,562
					10,597
0	0.0	61.6	0	0.0	10,672
					10,747
-1	(1,237.6)	60.2	-1	(165.6)	10,782
-2	(2,475.3)	58.8	-2	(331.2)	10,816
-3	(3,712.9)	57.4	-3	(496.8)	10,851
-4	(4,950.5)	56.0	-4	(662.4)	10,886
-5	(6,188.2)	54.5	-5	(828.0)	10,920
-6	(7,425.8)	53.1	-6	(993.6)	10,955
-7	(8,663.4)	51.7	-7	(1,159.2)	10,989
-8	(9,901.0)	50.3	-8	(1,324.9)	11,024
-9	(11,138.7)	48.9	-9	(1,490.5)	11,059
-10	(12,376.3)	47.5	-10	(1,656.1)	11,093
	Weighting Factor =	17.44%		Weighting Factor =	4.72%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2005 - DECEMBER 2005

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	6,414.7	67.9	+10	2,593.2	10,006
+9	5,773.2	67.2	+9	2,333.9	10,064
+8	5,131.8	66.4	+8	2,074.6	10,122
+7	4,490.3	65.7	+7	1,815.3	10,181
+6	3,848.8	65.0	+6	1,555.9	10,239
+5	3,207.3	64.2	+5	1,296.6	10,297
+4	2,565.9	63.5	+4	1,037.3	10,355
+3	1,924.4	62.8	+3	778.0	10,413
+2	1,282.9	62.0	+2	518.6	10,471
+1	641.5	61.3	+1	259.3	10,530
					10,588
0	0.0	60.6	0	0.0	10,663
					10,738
-1	(1,338.5)	59.1	-1	(259.3)	10,796
-2	(2,676.9)	57.6	-2	(518.6)	10,854
-3	(4,015.4)	56.2	-3	(778.0)	10,912
-4	(5,353.9)	54.7	-4	(1,037.3)	10,970
-5	(6,692.4)	53.2	-5	(1,296.6)	11,028
-6	(8,030.8)	51.8	-6	(1,555.9)	11,087
-7	(9,369.3)	50.3	-7	(1,815.3)	11,145
-8	(10,707.8)	48.9	-8	(2,074.6)	11,203
-9	(12,046.2)	47.4	-9	(2,333.9)	11,261
-10	(13,384.7)	45.9	-10	(2,593.2)	11,319
	Weighting Factor =	18.30%		Weighting Factor =	7.40%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2005 - DECEMBER 2005

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	4,096.8	82.4	+10	2,712.8	9,868
+9	3,687.1	82.0	+9	2,441.6	9,908
+8	3,277.4	81.7	+8	2,170.3	9,949
+7	2,867.8	81.3	+7	1,899.0	9,990
+6	2,458.1	80.9	+6	1,627.7	10,031
+5	2,048.4	80.5	+5	1,356.4	10,071
+4	1,638.7	80.2	+4	1,085.1	10,112
+3	1,229.0	79.8	+3	813.9	10,153
+2	819.4	79.4	+2	542.6	10,194
+1	409.7	79.1	+1	271.3	10,235
					10,275
0	0.0	78.7	0	0.0	10,350
					10,425
-1	(698.2)	77.9	-1	(271.3)	10,466
-2	(1,396.5)	77.2	-2	(542.6)	10,507
-3	(2,094.7)	76.5	-3	(813.9)	10,548
-4	(2,792.9)	75.7	-4	(1,085.1)	10,589
-5	(3,491.2)	75.0	-5	(1,356.4)	10,629
-6	(4,189.4)	74.3	-6	(1,627.7)	10,670
-7	(4,887.6)	73.5	-7	(1,899.0)	10,711
-8	(5,585.8)	72.8	-8	(2,170.3)	10,752
-9	(6,284.1)	72.0	-9	(2,441.6)	10,793
-10	(6,982.3)	71.3	-10	(2,712.8)	10,833
	Weighting Factor =	11.68%		Weighting Factor =	7.74%

TAMPA ELECTRIC COMPANY

GPIF TARGET AND RANGE SUMMARY

JANUARY 2005 - DECEMBER 2005

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,906.3	76.9	+10	2,221.4	9,624
+9	1,715.7	77.2	+9	1,999.2	9,688
+8	1,525.0	77.5	+8	1,777.1	9,753
+7	1,334.4	77.8	+7	1,555.0	9,817
+6	1,143.8	78.0	+6	1,332.8	9,881
+5	953.1	78.3	+5	1,110.7	9,945
+4	762.5	78.6	+4	888.5	10,010
+3	571.9	78.9	+3	666.4	10,074
+2	381.3	79.2	+2	444.3	10,138
+1	190.6	79.5	+1	222.1	10,203
					10,267
0	0.0	79.8	0	0.0	10,342
					10,417
-1	(378.0)	78.3	-1	(222.1)	10,481
-2	(756.0)	76.9	-2	(444.3)	10,546
-3	(1,134.0)	75.5	-3	(666.4)	10,610
-4	(1,512.0)	74.1	-4	(888.5)	10,674
-5	(1,890.0)	72.6	-5	(1,110.7)	10,739
-6	(2,268.1)	71.2	-6	(1,332.8)	10,803
-7	(2,646.1)	69.8	-7	(1,555.0)	10,867
-8	(3,024.1)	68.4	-8	(1,777.1)	10,931
-9	(3,402.1)	66.9	-9	(1,999.2)	10,996
-10	(3,780.1)	65.5	-10	(2,221.4)	11,060
	Weighting Factor =	5.44%		Weighting Factor =	6.34%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2005 - DECEMBER 2005

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	2005
1. EAF (%)	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	62.2	0.0	10.4	62.2	52.6
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	100.0	83.3	0.0	15.34
3. EUOF	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	0.0	6.3	37.8	32.03
4. EUOR	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	37.8	0.0	37.8	37.8	37.8
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	503	454	503	486	503	486	498	503	486	0	81	491	4,993
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	241	218	241	234	241	234	246	241	234	744	639	253	3,767
9. POH	0	0	0	0	0	0	0	0	0	744	600	0	1,344
10. FOH & EFOH	201	181	201	194	201	194	201	201	194	0	32	201	2,001
11. MOH & EMOH	81	73	81	78	81	78	81	81	78	0	13	81	804
12. OPER BTU (GBTU)	1,769	1,601	1,778	1,715	1,771	1,717	1,753	1,775	1,716	0	286	1,732	17,612
13. NET GEN (MWH)	162,706	147,304	163,593	158,191	163,292	158,331	161,642	163,676	158,300	0	26,428	159,316	1,622,779
14. ANOHR (Btu/kwh)	10,874	10,871	10,867	10,844	10,845	10,843	10,846	10,842	10,843	0	10,840	10,870	10,853
15. NOF (%)	75.6	75.8	76.1	77.3	77.2	77.3	77.1	77.4	77.3	0.0	77.4	75.9	76.8
16. NPC (MW)	428	428	428	421	421	421	421	421	421	421	421	428	423
17. ANOHR EQUATION	ANOHR = NOF(	-18.920	) +	12,306									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2005 - DECEMBER 2005

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	2005
1. EAF (%)	64.1	64.1	64.1	64.1	64.1	64.1	64.1	64.1	64.1	35.2	64.1	64.1	61.6
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.2	0.0	0.0	3.84
3. EUOF	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	19.7	35.9	35.9	34.52
4. EUOR	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9	35.9
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	512	459	515	498	398	499	508	515	499	283	499	393	5,575
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	232	213	229	222	346	221	236	229	221	462	221	351	3,185
9. POH	0	0	0	0	0	0	0	0	0	336	0	0	336
10. FOH & EFOH	192	173	192	186	192	186	192	192	186	105	186	192	2,171
11. MOH & EMOH	75	68	75	73	75	73	75	75	73	41	73	75	853
12. OPER BTU (GBTU)	1,740	1,567	1,792	1,702	1,326	1,732	1,770	1,797	1,731	987	1,742	1,317	19,205
13. NET GEN (MWH)	162,435	146,301	167,531	159,571	124,053	162,710	166,275	168,837	162,599	92,788	163,679	122,729	1,799,508
14. ANOHR (Btu/kwh)	10,714	10,710	10,695	10,664	10,686	10,648	10,644	10,644	10,648	10,642	10,642	10,727	10,672
15. NOF (%)	73.3	73.7	75.1	77.9	75.9	79.4	79.7	79.7	79.4	79.9	79.9	72.1	77.2
16. NPC (MW)	433	433	433	411	411	411	411	411	411	411	411	433	418
17. ANOHR EQUATION	ANOHR = NOF(	-10.937	) +	11,516									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2005 - DECEMBER 2005

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	2005
1. EAF (%)	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	63.0	33.6	63.0	60.6
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.7	0.0	3.84
3. EUOF	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	19.7	37.0	35.61
4. EUOR	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0	37.0
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	531	479	531	514	531	514	531	531	514	531	274	531	6,010
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	213	193	213	206	213	206	213	213	206	213	446	213	2,750
9. POH	0	0	0	0	0	0	0	0	0	0	336	0	336
10. FOH & EFOH	190	171	190	184	190	184	190	190	184	190	98	190	2,148
11. MOH & EMOH	86	78	86	83	86	83	86	86	83	86	44	86	972
12. OPER BTU (GBTU)	1,750	1,587	1,711	1,681	1,742	1,679	1,764	1,774	1,687	1,860	943	1,792	19,973
13. NET GEN (MWH)	163,376	148,282	158,870	157,495	163,327	157,257	165,852	167,114	158,160	176,305	88,982	168,191	1,873,211
14. ANOHR (Btu/kwh)	10,712	10,702	10,767	10,673	10,665	10,676	10,633	10,617	10,664	10,552	10,600	10,652	10,663
15. NOF (%)	70.3	70.6	68.3	71.6	71.9	71.5	73.0	73.6	71.9	75.8	74.1	72.3	72.0
16. NPC (MW)	438	438	438	428	428	428	428	428	428	438	438	438	433
17. ANOHR EQUATION	ANOHR = NOF(	-28.859	) +	12,740									

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2005 - DECEMBER 2005

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	2005
1. EAF (%)	81.8	76.0	50.1	81.8	81.8	81.8	81.8	81.8	81.8	81.8	81.8	81.8	78.7
2. POF	0.0	7.1	38.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.84
3. EUOF	18.2	16.9	11.1	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	17.48
4. EUOR	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2	18.2
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	613	514	376	594	613	589	603	611	590	613	594	598	6,908
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	131	158	368	126	131	131	141	133	130	131	126	146	1,852
9. POH	0	48	288	0	0	0	0	0	0	0	0	0	336
10. FOH & EFOH	88	74	54	85	88	85	88	88	85	88	85	88	994
11. MOH & EMOH	47	40	29	46	47	46	47	47	46	47	46	47	537
12. OPER BTU (GBTU)	2,465	2,083	1,536	2,403	2,460	2,337	2,418	2,455	2,341	2,510	2,412	2,432	27,857
13. NET GEN (MWH)	236,424	200,466	148,540	233,261	237,711	224,607	233,663	237,383	225,031	245,054	234,610	234,589	2,691,339
14. ANOHR (Btu/kwh)	10,427	10,390	10,342	10,300	10,348	10,403	10,347	10,341	10,402	10,242	10,280	10,367	10,350
15. NOF (%)	83.8	84.7	85.9	86.9	85.7	84.4	85.8	85.9	84.4	88.4	87.4	85.3	85.7
16. NPC (MW)	460	460	460	452	452	452	452	452	452	452	452	460	455
17. ANOHR EQUATION	ANOHR = NOF(	-40.19208525	) +		13,794								

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2005 - DECEMBER 2005

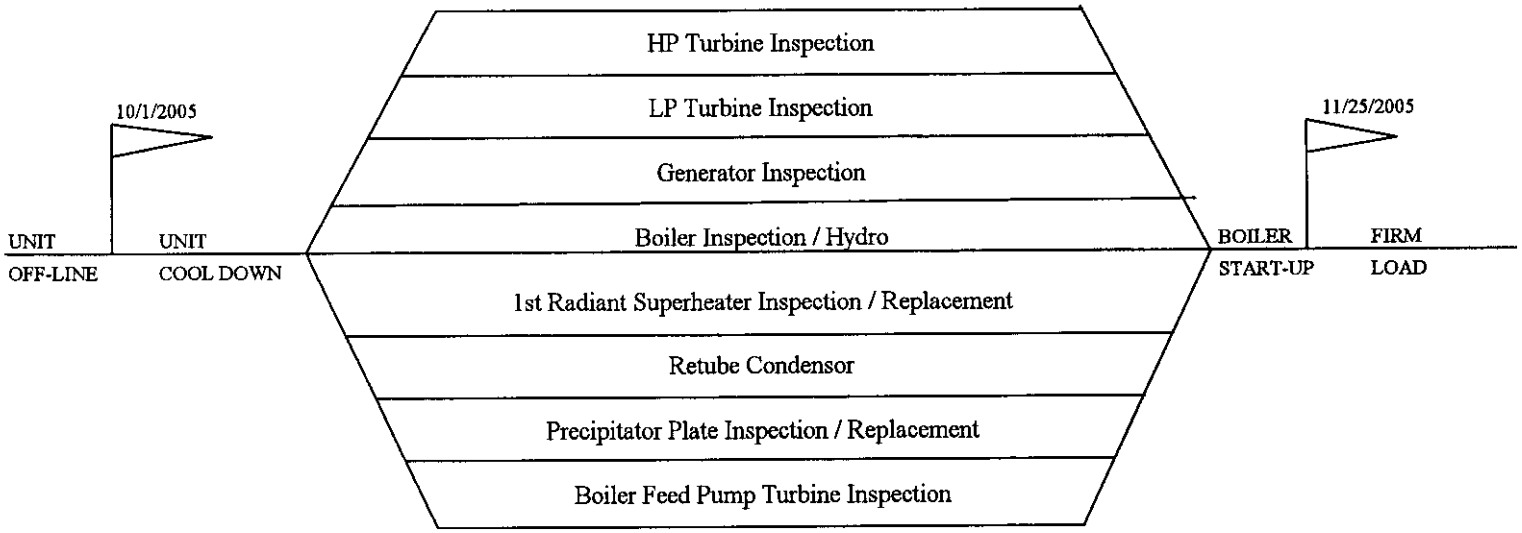
PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK I	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05	2005
1. EAF (%)	82.9	82.9	82.9	55.3	82.9	82.9	82.9	82.9	82.9	80.0	75.4	82.9	79.76
2. POF	0.0	0.0	0.0	33.3	0.0	0.0	0.0	0.0	0.0	3.5	9.0	0.0	3.77
3. EUOF	17.1	17.1	17.1	11.4	17.1	17.1	17.1	17.1	17.1	16.5	15.6	17.1	16.47
4. EUOR	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
5. PH	744	672	744	720	744	720	744	744	720	744	720	744	8,760
6. SH	628	567	628	405	628	607	628	628	607	466	202	628	6,621
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	116	105	116	315	116	113	116	116	113	278	518	116	2,139
9. POH	0	0	0	240	0	0	0	0	0	26	65	0	330
10. FOH & EFOH	24	22	24	16	24	24	24	24	24	24	22	24	277
11. MOH & EMOH	103	93	103	66	103	100	103	103	100	99	91	103	1,166
12. OPER BTU (GBTU)	1,531	1,383	1,531	957	1,445	1,398	1,445	1,445	1,398	1,126	493	1,530	15,711
13. NET GEN (MWH)	153,110	138,375	153,209	93,330	135,391	131,023	135,391	135,391	131,023	110,743	49,283	152,874	1,519,143
14. ANOHR (Btu/kwh)	9,997	9,993	9,992	10,249	10,673	10,673	10,673	10,673	10,673	10,170	10,012	10,008	10,342
15. NOF (%)	93.8	93.9	93.9	90.4	84.6	84.6	84.6	84.6	84.6	91.5	93.6	93.7	89.1
16. NPC (MW)	260	260	260	255	255	255	255	255	255	260	260	260	257
17. ANOHR EQUATION	ANOHR = NOF(	-73.21622695	) +		16,866								

TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ESTIMATED)
GPIF UNITS
JANUARY 2005 - DECEMBER 2005

	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
	BIG BEND 1	Oct 01	-	Nov 25	Fuel System Clean-up
+	BIG BEND 2	Oct 15	-	Oct 28	Fuel System Clean-up
+	BIG BEND 3	Nov 05	-	Nov 18	Fuel System Clean-up
+	BIG BEND 4	Feb 27	-	Mar 12	Fuel System Clean -up
+	POLK 1	Apr 09	-	Apr 18	#1CT Combustion Path

+ Critical Path Method diagrams for units with outages of less than 4 weeks are not included.

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAM
GPIF UNITS ≥ FOUR WEEKS
JANUARY 2005 - DECEMBER 2005



TAMPA ELECTRIC COMPANY
BIG BEND UNIT NUMBER 1
PLANNED OUTAGE 2005
PROJECTED CPM
08/24/2004

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAM
GPIF UNITS ≥ FOUR WEEKS
JANUARY 2005 - DECEMBER 2005

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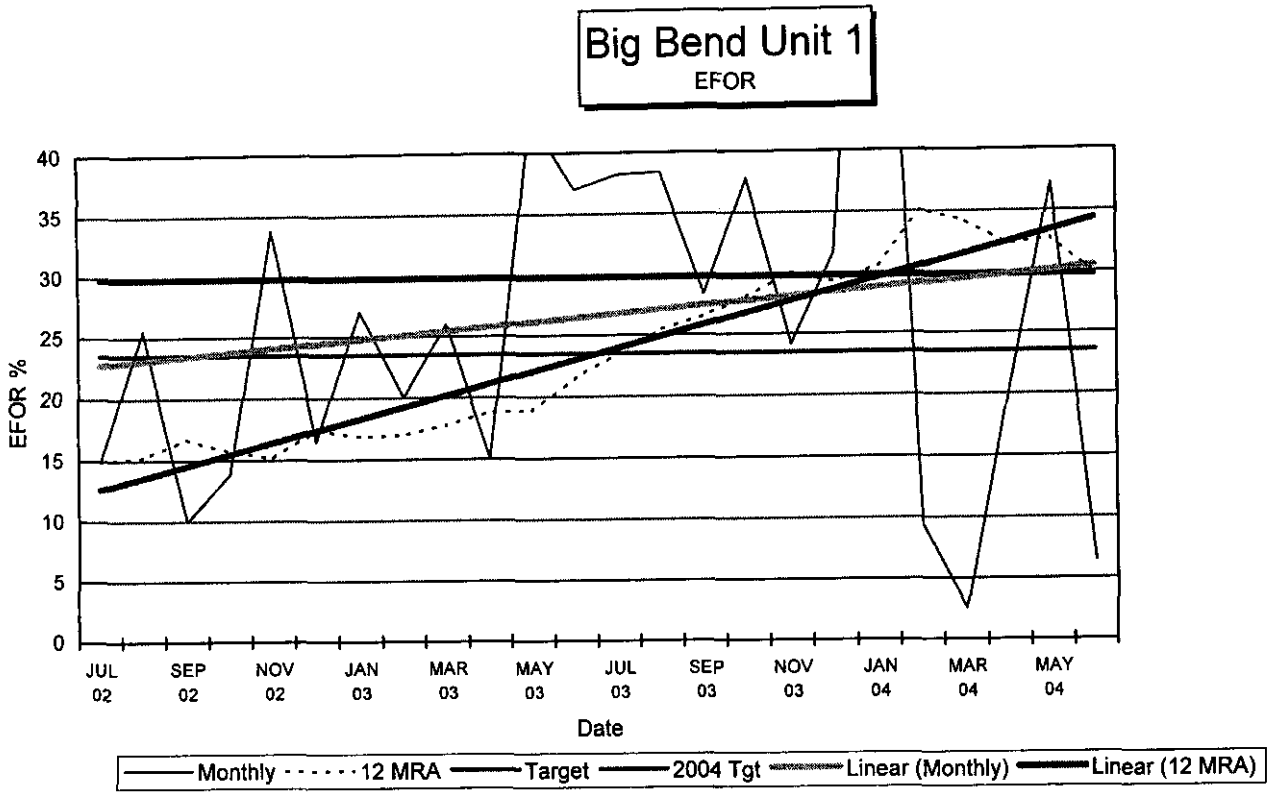
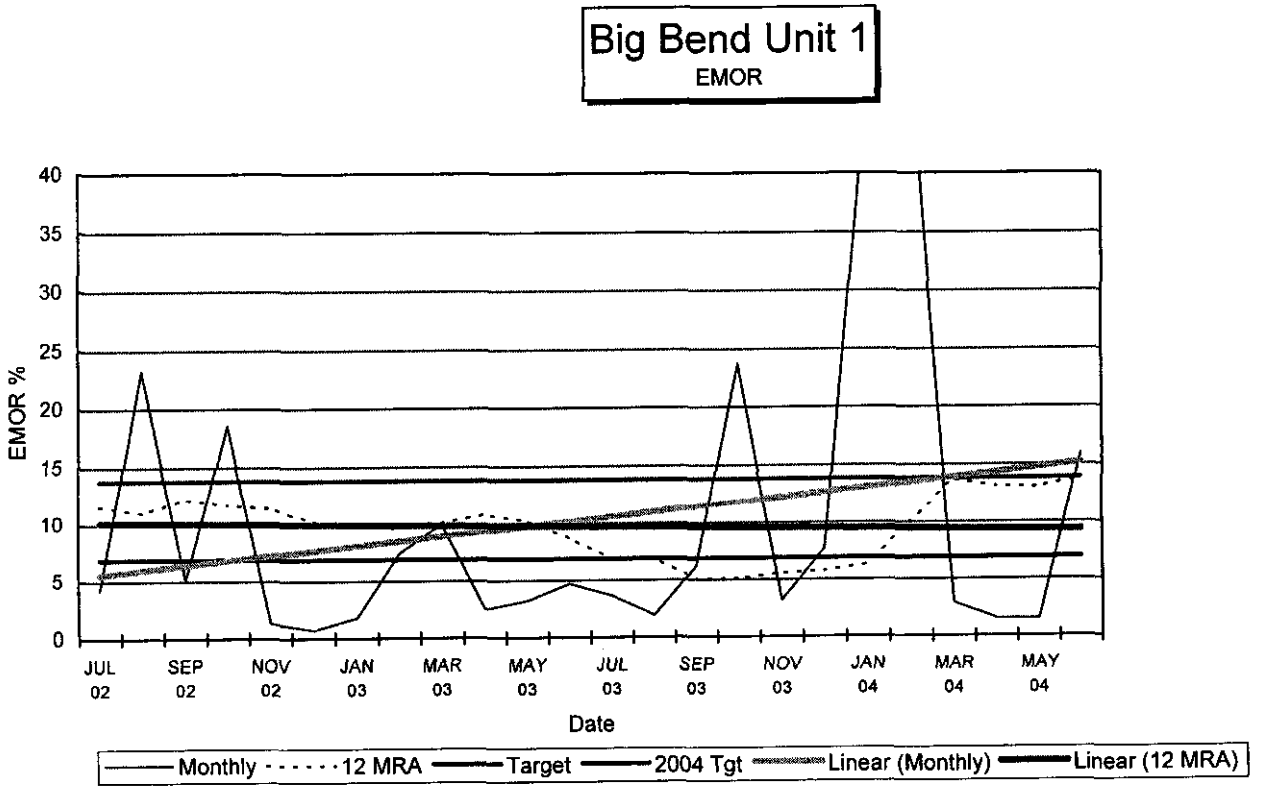
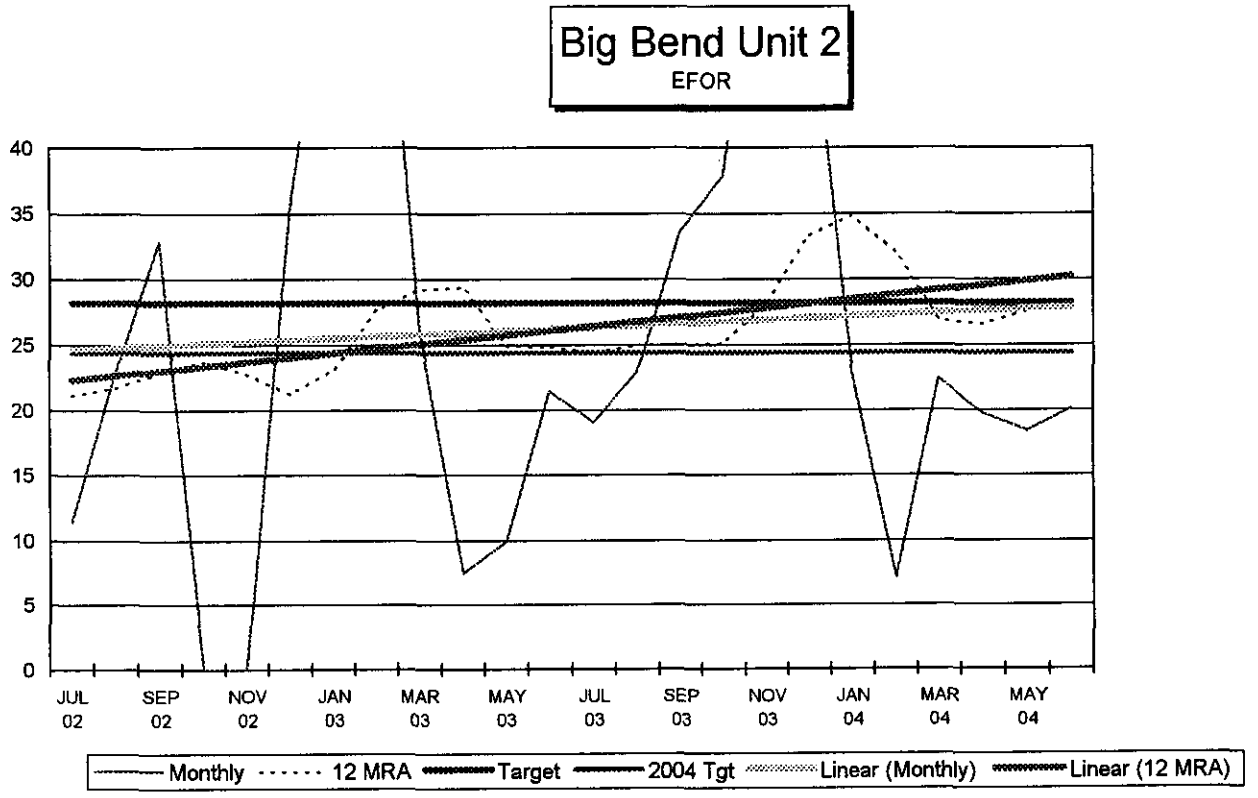
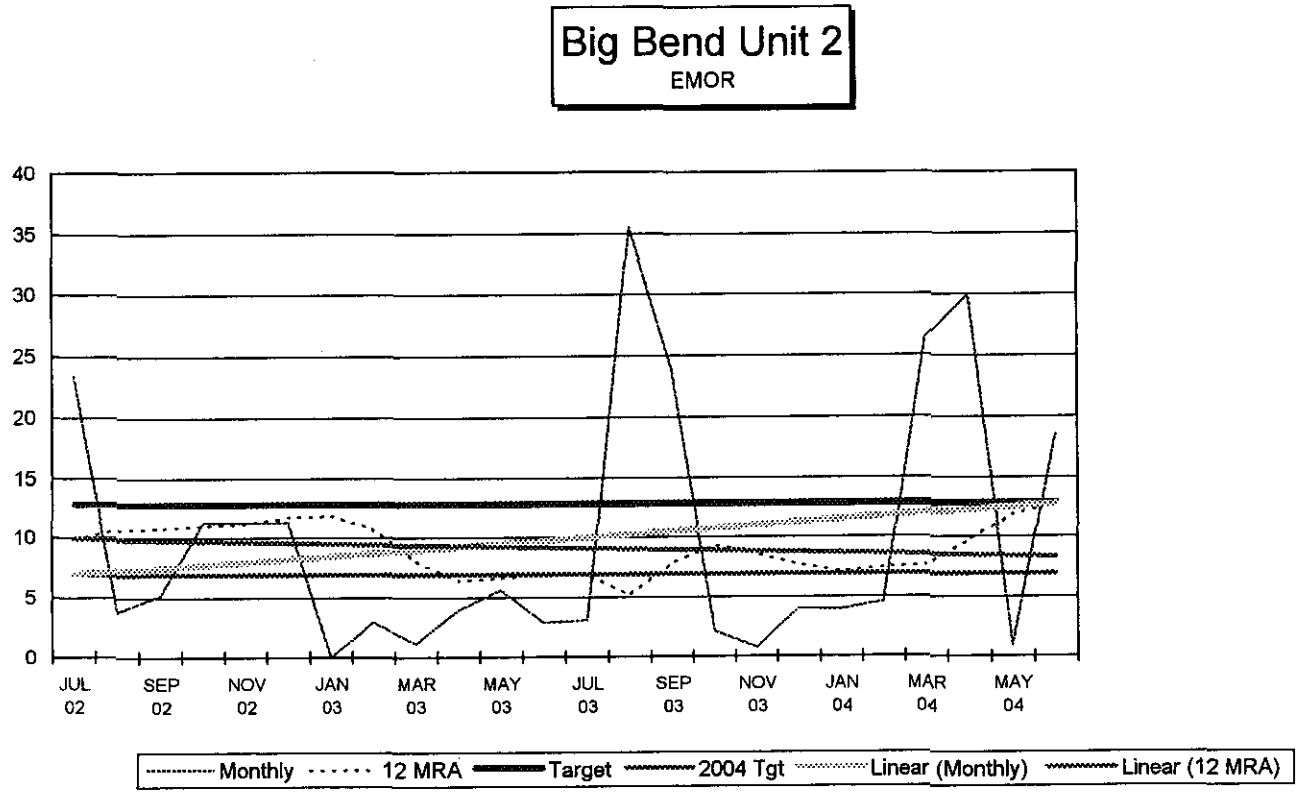




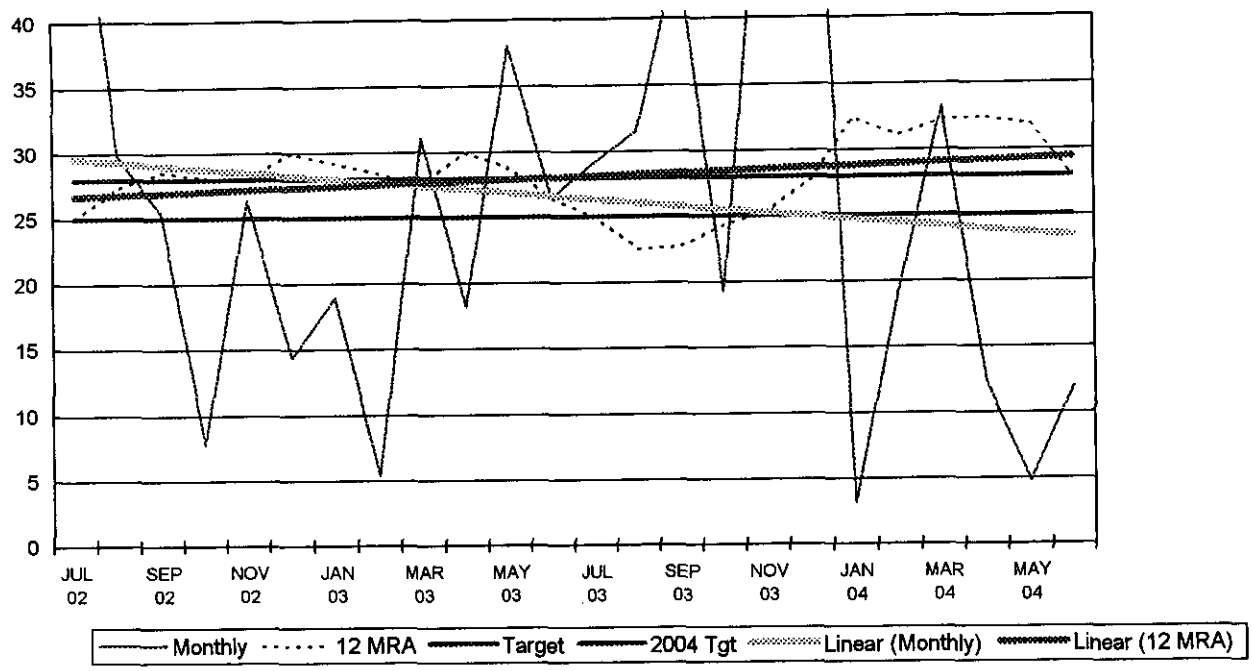
12 MRA = 12 Month Rolling Average



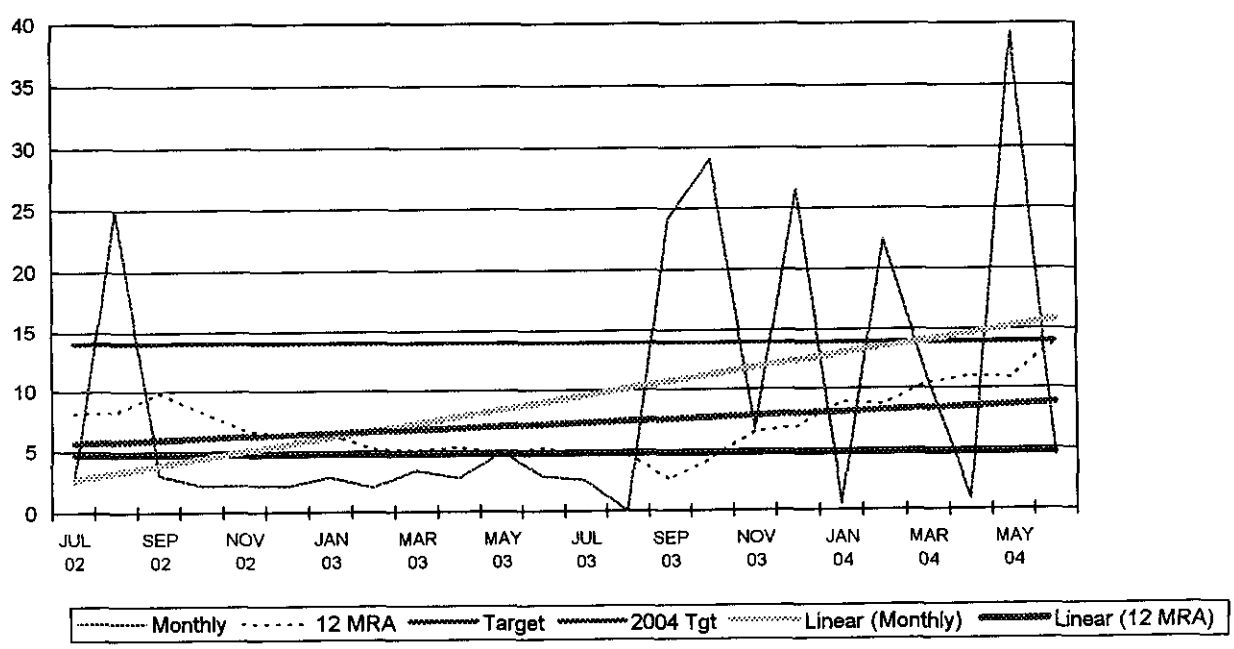


12 MRA = 12 Month Rolling Average

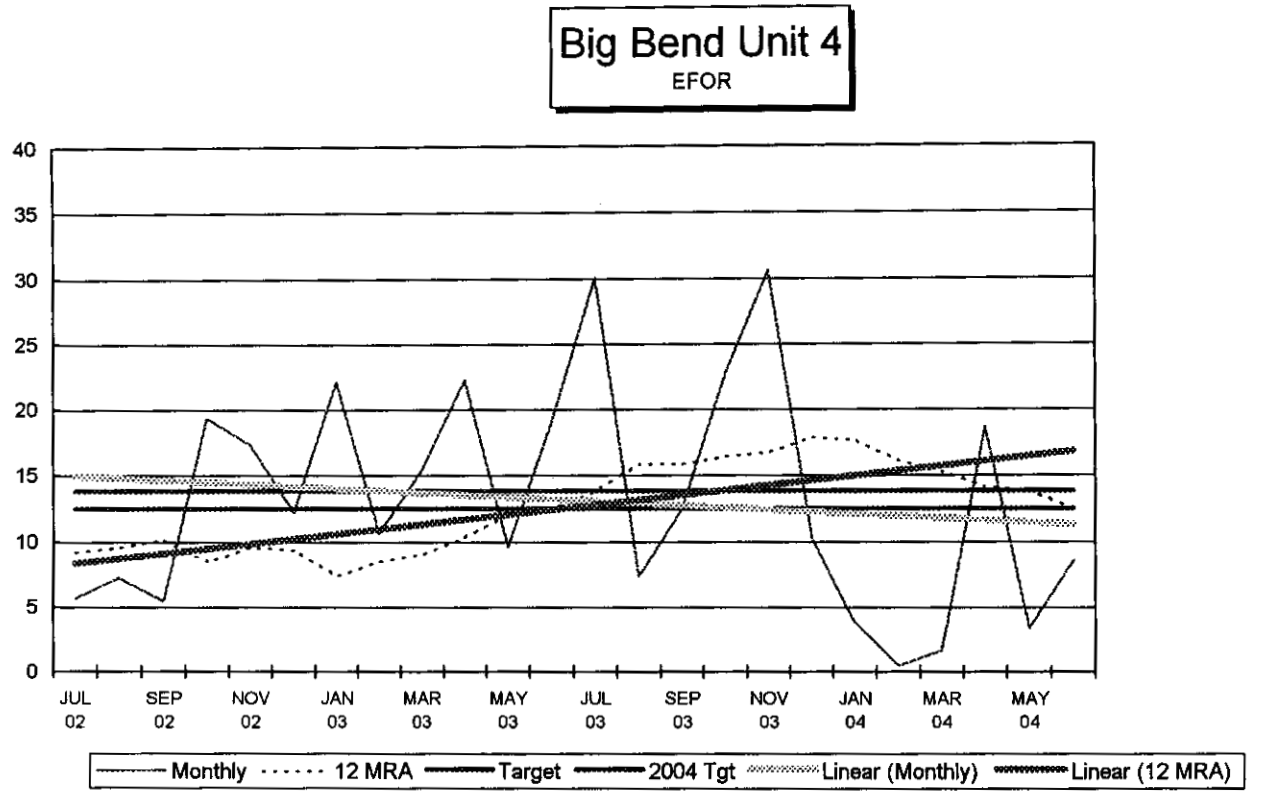
Big Bend Unit 3
EFOR

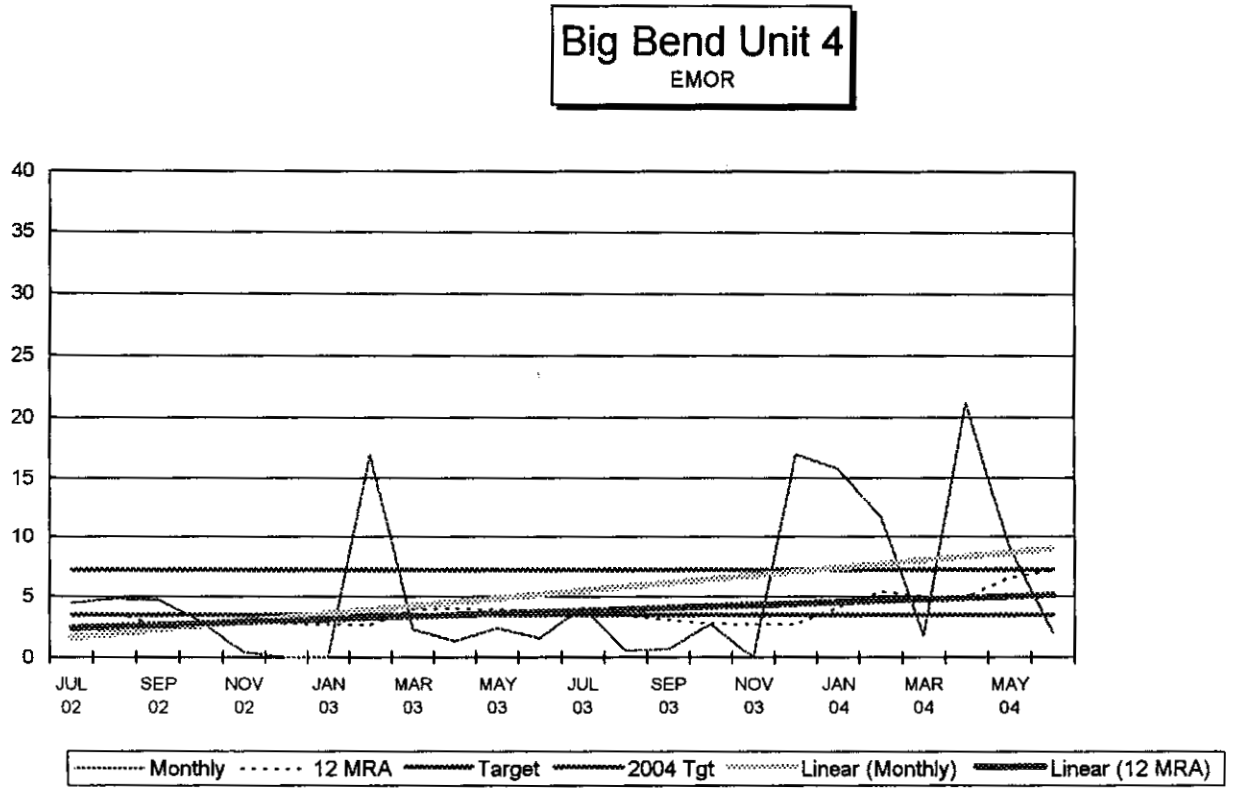


Big Bend Unit 3
EMOR

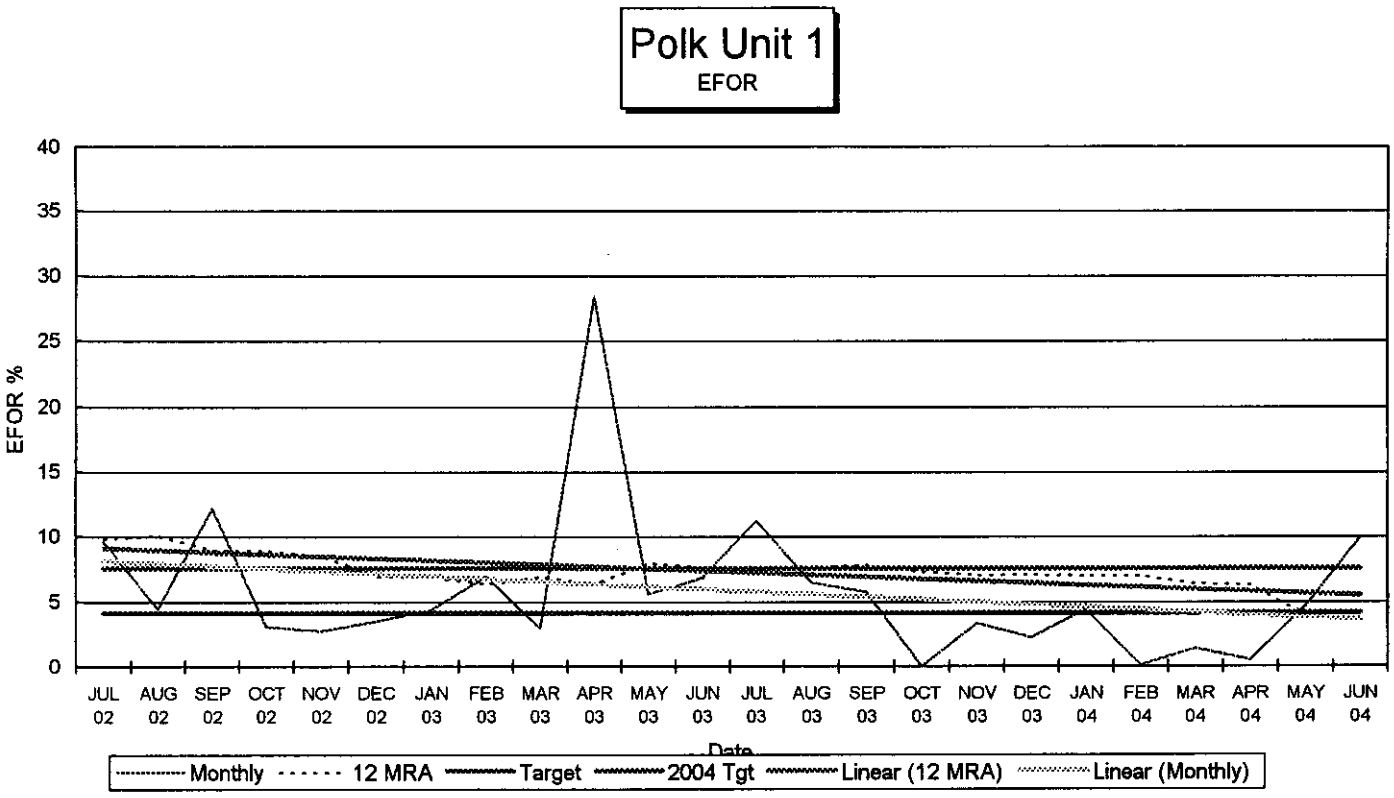


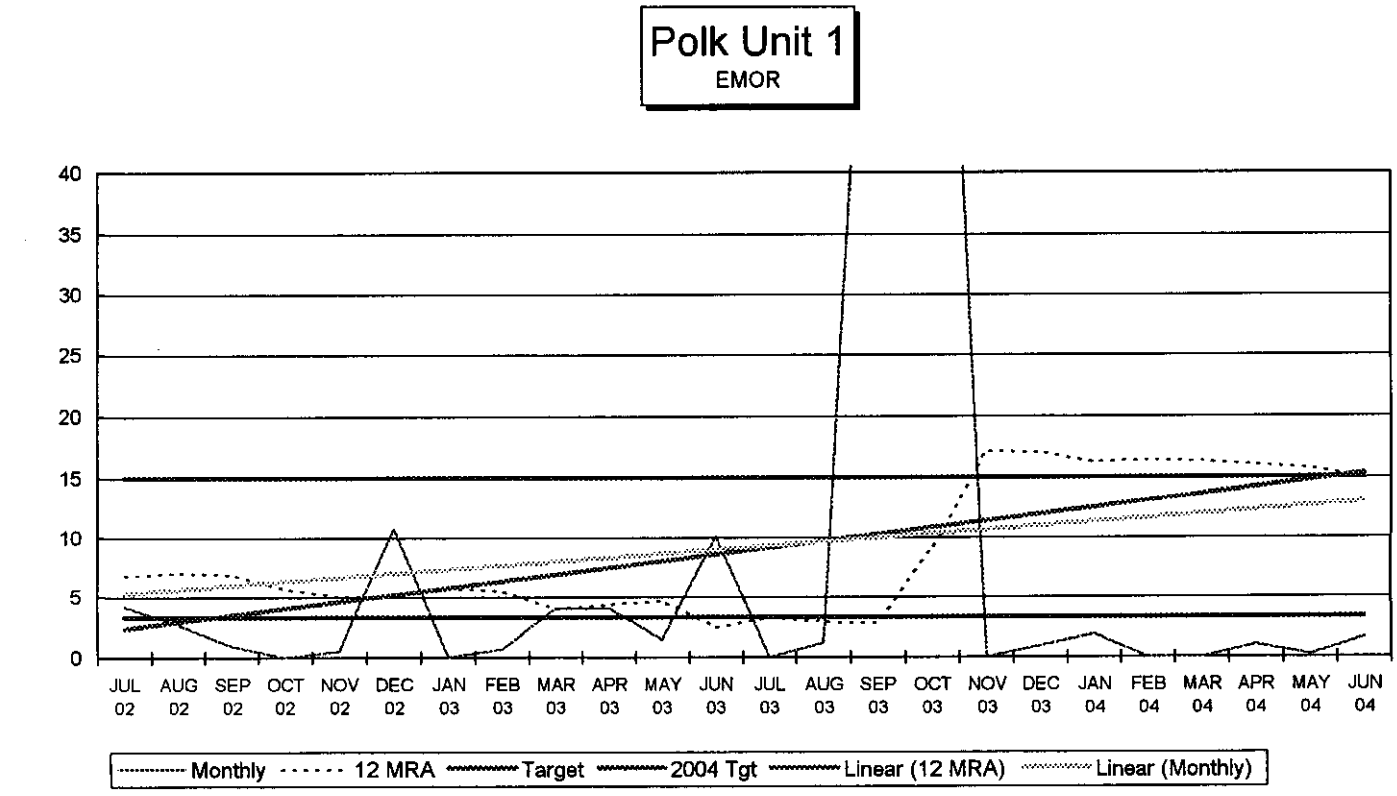
12 MRA = 12 Month Rolling Average





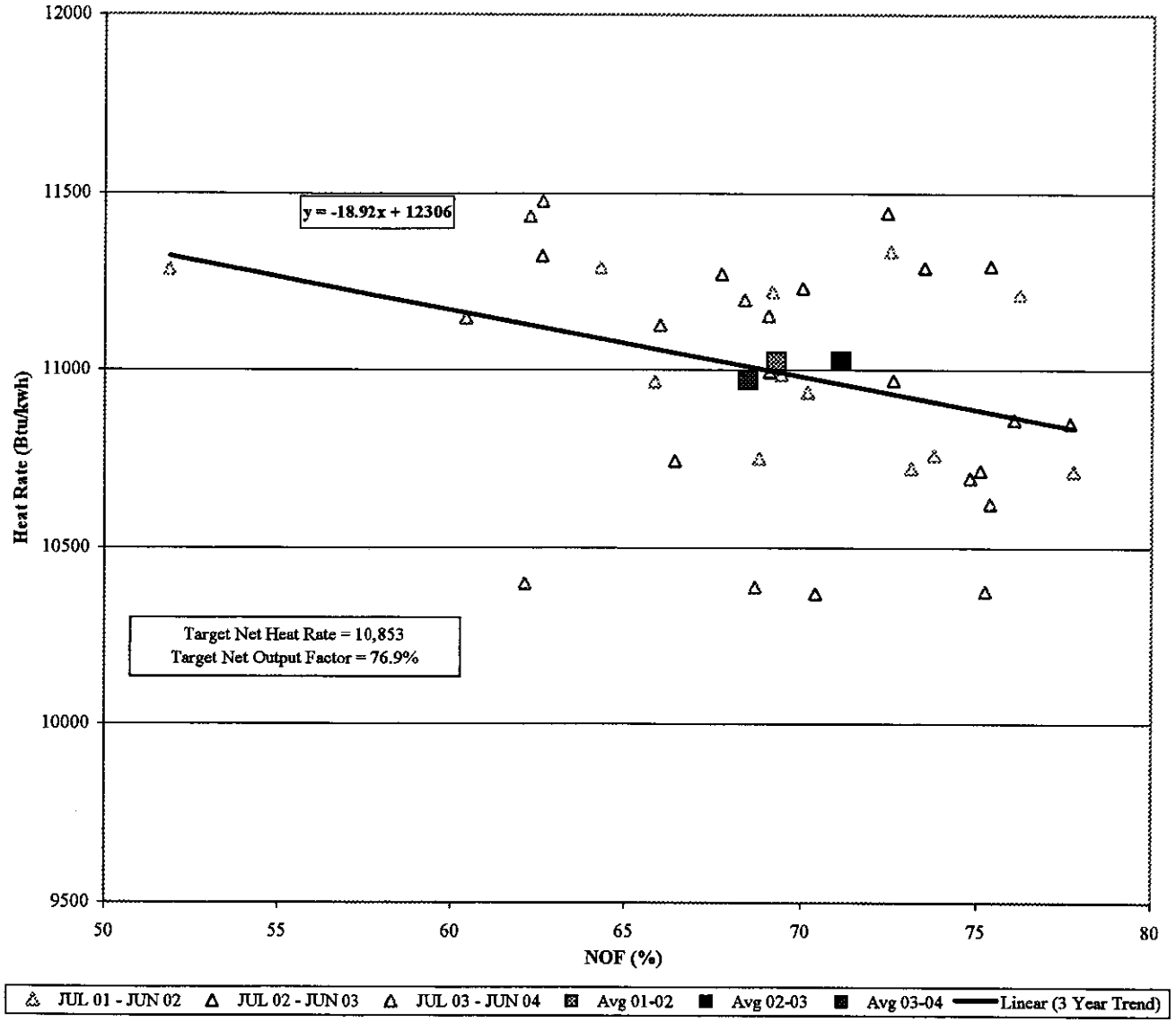
12 MRA = 12 Month Rolling Average



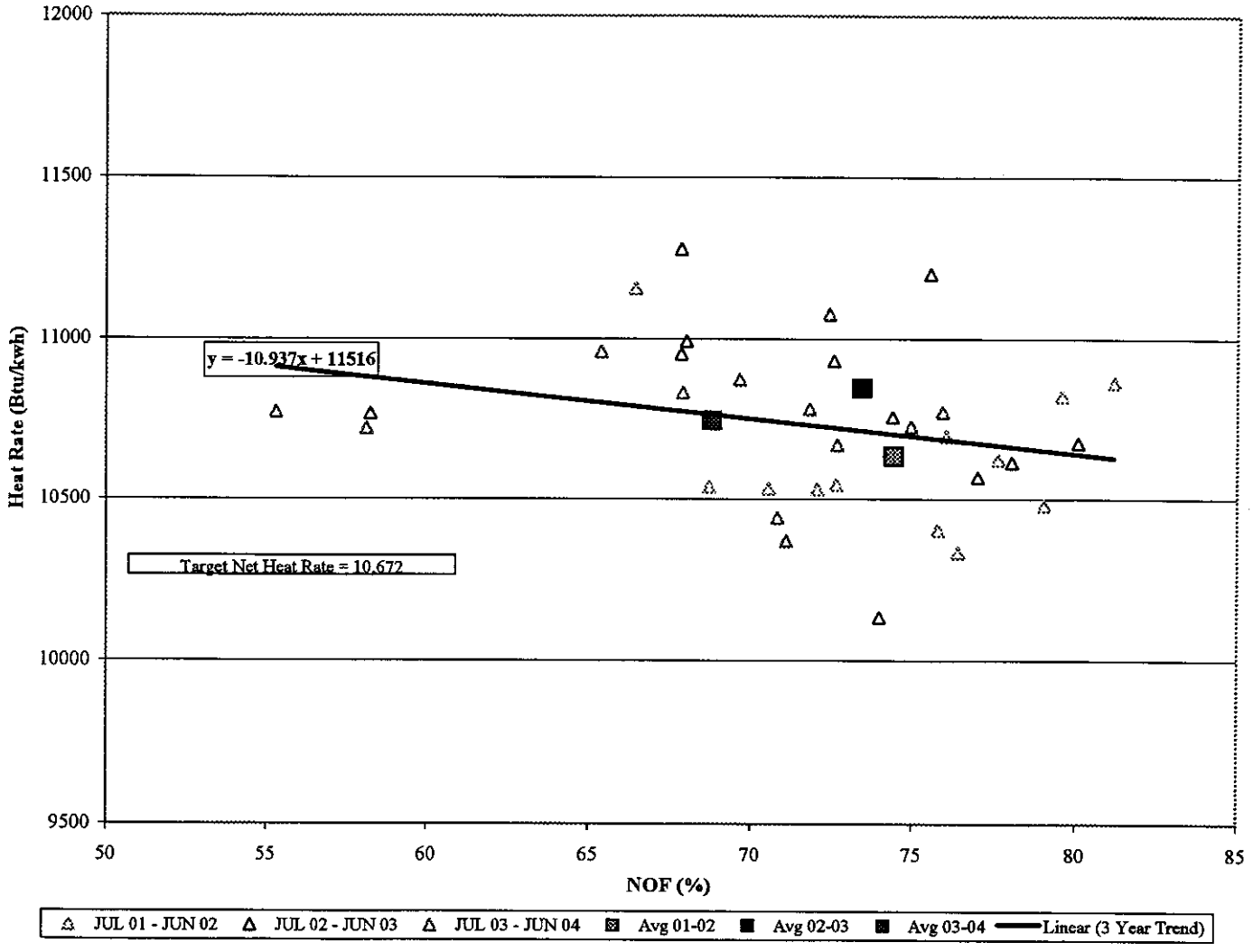


12 MRA = 12 Month Rolling Avreage

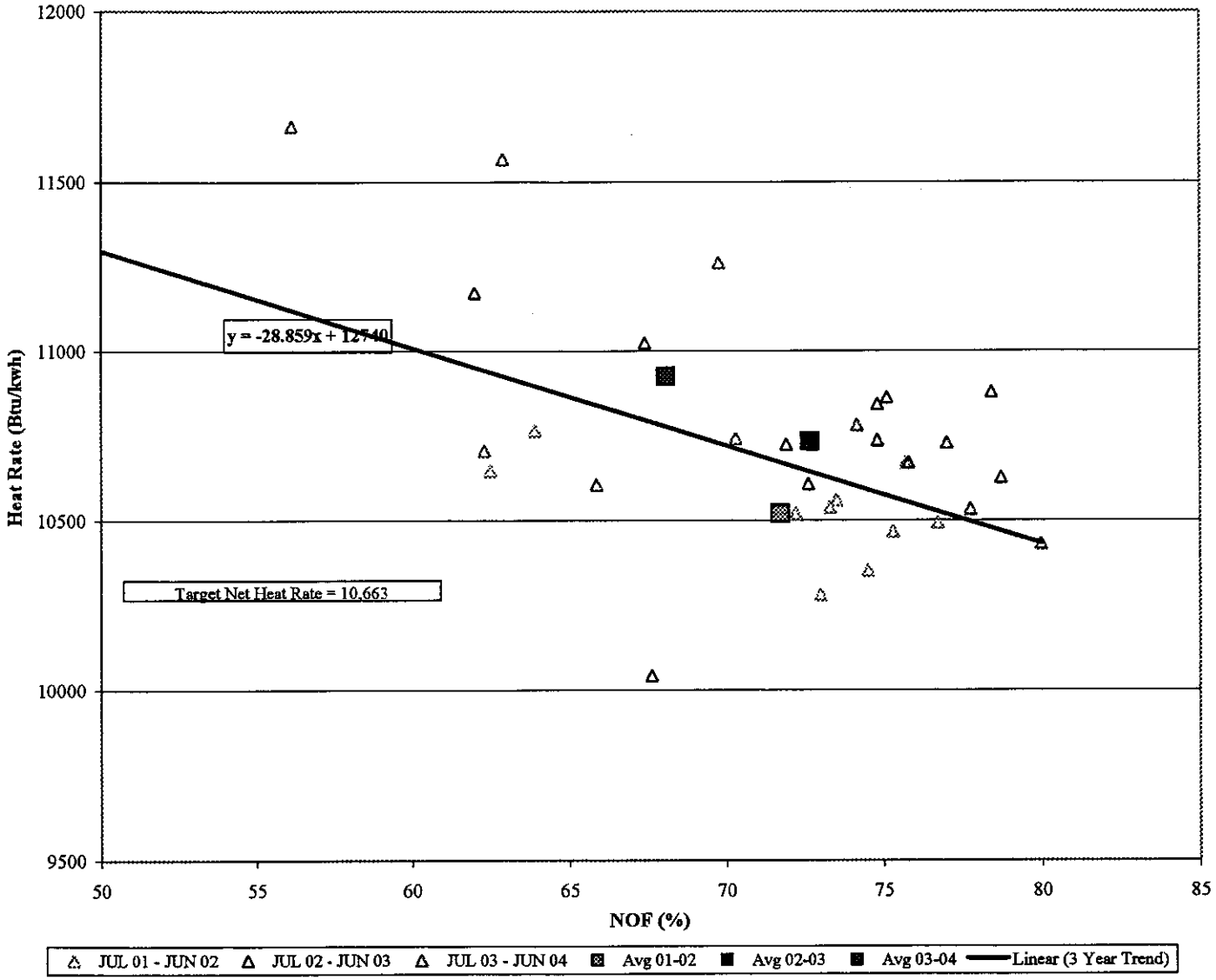
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #1



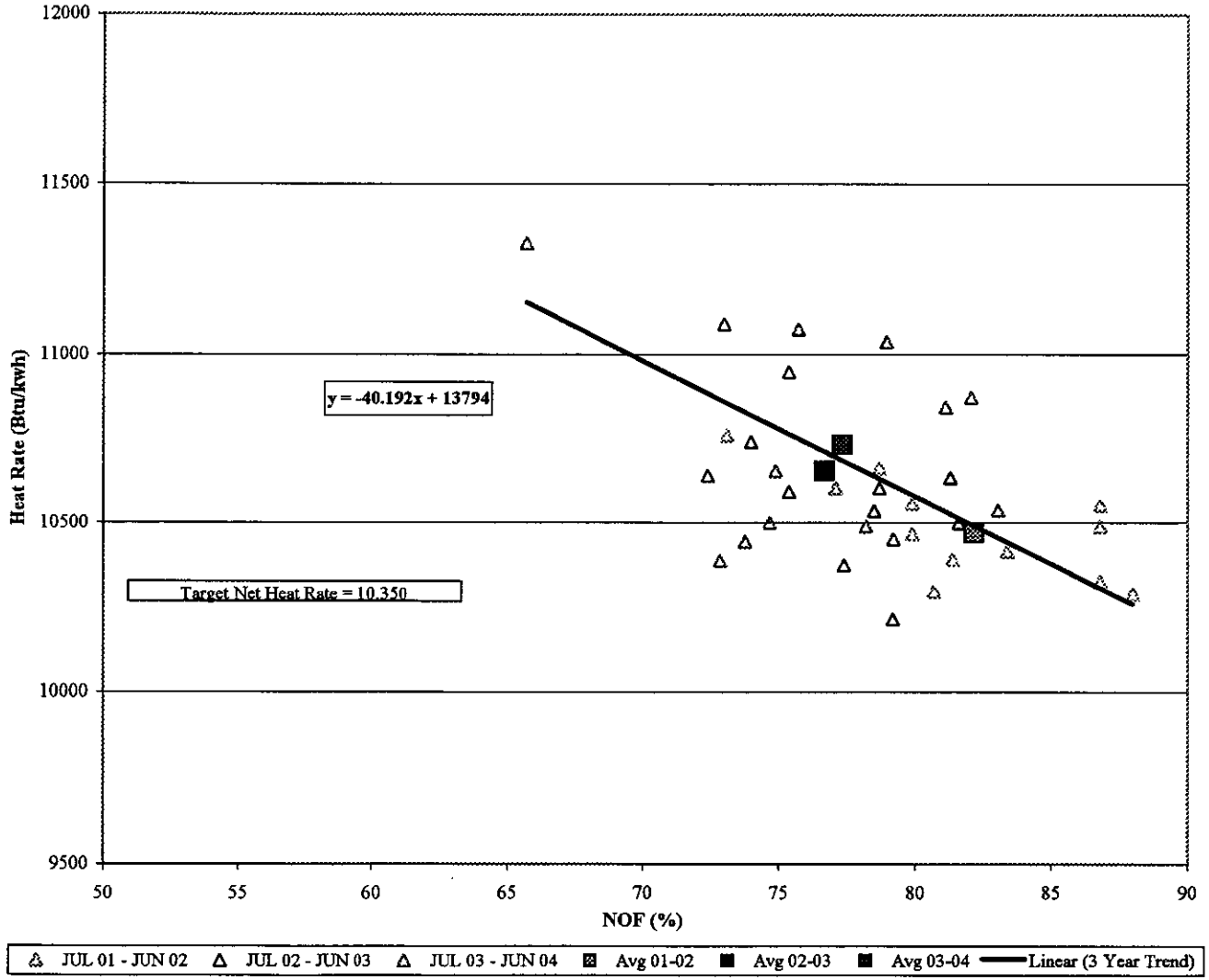
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #2



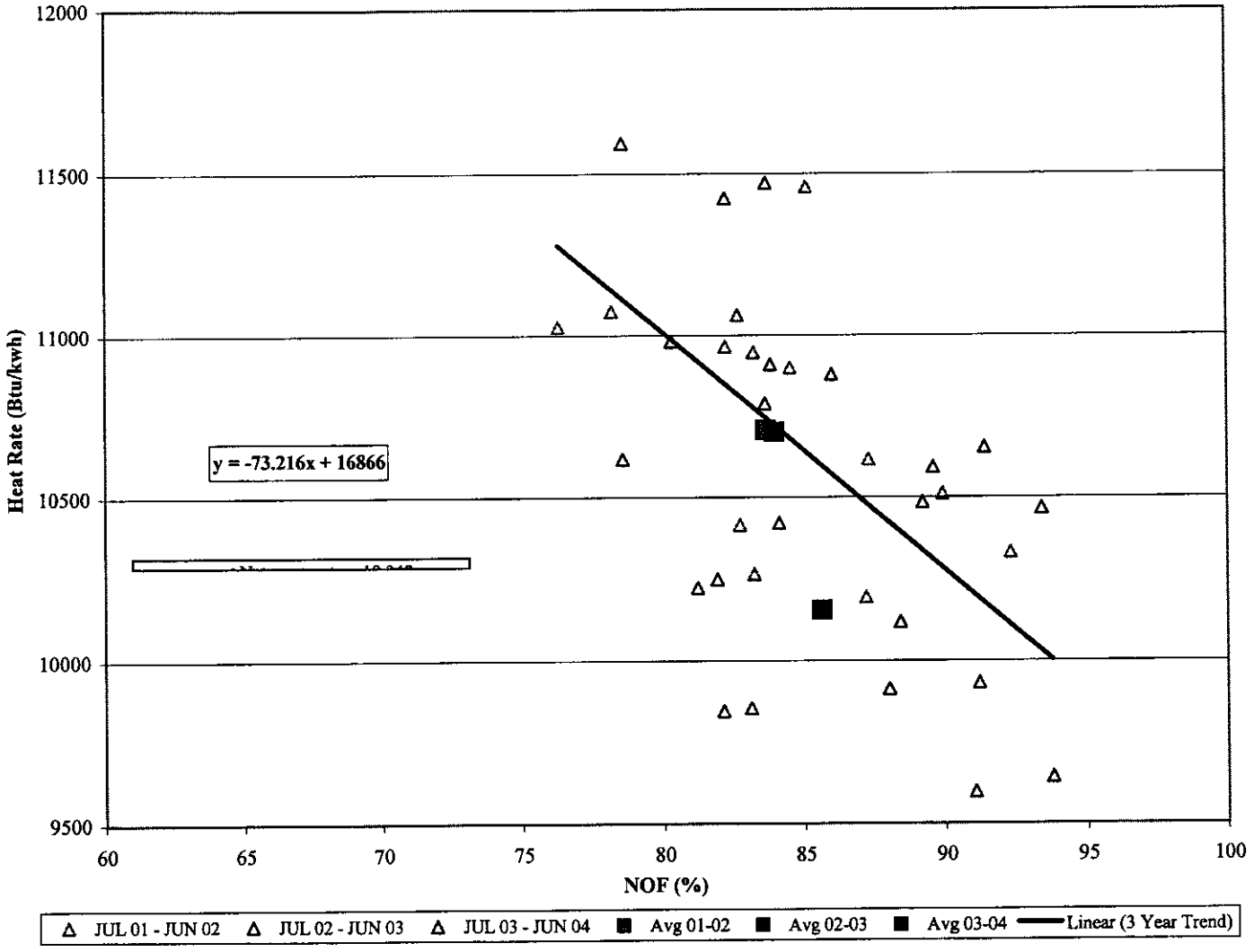
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #3



Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #4



Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit #1



TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2005 - DECEMBER 2005

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		447	425
BIG BEND 2		452	422
BIG BEND 3		455	433
BIG BEND 4		488	456
POLK 1		325	258
	GPIF TOTAL	2,167	1,993
	SYSTEM TOTAL	4,547	4,252
	% OF SYSTEM TOTAL	47.66%	46.88%

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2005 - DECEMBER 2005

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		447	425
BIG BEND 2		452	422
BIG BEND 3		455	433
BIG BEND 4		488	456
	BIG BEND TOTAL	1,842	1,736
BIG BEND CT1		15	15
BIG BEND CT2		80	73
BIG BEND CT3		70	65
	CT TOTAL	165	153
PHILLIPS 1		18	17
PHILLIPS 2		18	17
	PHILLIPS TOTAL	36	34
POLK 1		325	258
POLK 2		180	170
POLK 3		180	173
	POLK TOTAL	685	600
BAYSIDE 1		787	745
BAYSIDE 2		1,032	985
	BAYSIDE TOTAL	1,819	1,730
	SYSTEM TOTAL	**4,547**	**4,252**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2005 - DECEMBER 2005

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,674,230	26.33%	26.33%
BIG BEND	4	2,691,339	15.16%	41.50%
BAYSIDE	1	3,402,421	19.17%	60.67%
BIG BEND	3	1,873,211	10.55%	71.22%
BIG BEND	2	1,799,508	10.14%	81.36%
BIG BEND	1	1,622,779	9.14%	90.50%
POLK	1	1,519,143	8.56%	99.06%
POLK	2	79,166	0.45%	99.51%
PHILLIPS	1	20,010	0.11%	99.62%
PHILLIPS	2	20,068	0.11%	99.73%
POLK	3	41,910	0.24%	99.97%
BIG BEND CT	3	2,162	0.01%	99.98%
BIG BEND CT	1	488	0.00%	99.98%
BIG BEND CT	2	3,061	0.02%	100.00%
TOTAL GENERATION		17,749,496	100.00%	

GENERATION BY COAL UNITS:	9,505,980 MWH	GENERATION BY NATURAL GAS UNITS:	8,197,727 MWH
% GENERATION BY COAL UNITS:	53.56%	% GENERATION BY NATURAL GAS UNITS:	46.19%
GENERATION BY OIL UNITS:	45,789 MWH	GENERATION BY GPIF UNITS:	9,505,980 MWH
% GENERATION BY OIL UNITS:	0.26%	% GENERATION BY GPIF UNITS:	53.56%

EXHIBIT TO THE TESTIMONY OF

DAVID R. KNAPP

DOCKET NO. 040001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2005 - DECEMBER 2005

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

EXHIBIT NO. ___
TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
(DRK-1)
DOCUMENT NO. 2
PAGE 1 OF 1
FILED: 9/9/04

Tampa Electric Company
Summary of GPIF Targets
January 2005 - December 2005

	Availability			Net
Unit	EAF	POF	EUOF	Heat Rate
Big Bend 1 [1]	52.6	15.34	32.03	10,853
Big Bend 2 [2]	61.6	3.84	34.52	10,672
Big Bend 3 [3]	60.6	3.84	35.61	10,663
Big Bend 4 [4]	78.7	3.84	17.48	10,350
Polk 1 [5]	79.76	3.77	15.47	10,342

[1] Original Sheet 8.401.05E, Page 12

[2] Original Sheet 8.401.05E, Page 13

[3] Original Sheet 8.401.05E, Page 14

[4] Original Sheet 8.401.05E, Page 15

[5] Original Sheet 8.401.05E, Page 16

EXHIBIT NO. ___
DOCKET NO. 040001-EI
TAMPA ELECTRIC COMPANY
(JTW-1)
PAGE 1 OF 1

Calculation of Incremental Hedging Expenses		
	Actual Expenses	
	2001	2003
Payroll and Fringe Benefits	$ 159,723	$ 256,362
Travel Costs	2,500	210
Training	6,930	-
Consultants / Legal	-	20,682
License Fees / Other	-	$ 645
Total	$ 169,153	$ 277,899
2003 Incremental Hedging Costs (2003 Expenses Less 2001 'Base Year' Expenses)	**$ 108,746**	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 47
COMPANY/ TECO
WITNESS. Joann T. Wehle
DATE: 11-08-04

TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
FILED: 9/9/04

EXHIBIT TO THE TESTIMONY OF

JOANN WEHLE

DOCUMENT NO. 1

APPLICATION OF THE WATERBORNE
TRANSPORTATION COSTS BENCMARK

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001 EI EXHIBIT NO 48
COMPANY/ TECO
WITNESS. Joann T. Wehle (JTW-2)
DATE 11-08-04

EXHIBIT NO. ___
TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
(JTW-2)
DOCUMENT NO. 1
PAGE 1 OF 2
FILED: 9/9/04

2003 TRANSPORTATION BENCHMARK CALCULATION

Average Rail Mileage to Tampa		1,082	miles		(Note 1)
x	Average of Lowest Two Publicly Available Florida Rail Rates	1.96	¢ / ton mile		(Note 2)
+	Costs of Privately Owned Rail Cars	$ 1.75	per ton		(Note 3)
Transportation Benchmark for the Year Ended 12/31/03		$ 22.96	per ton		(Note 4)

Notes

1/ Weighted average domestic rail miles from all Tampa Electric waterborne coal supplies to plants. Rail miles for imported coal sources are measured from port of entry.

2/ Cents per ton-mile for publicly available Florida utility rail coal transportation rates including discounts for volume and private rail cars. The current publicly available rail rates to Florida utilities on a cents per ton-mile basis for 2003 are as follows:

JEA	¢	2.55
Orlando	¢	2.07
Lakeland	¢	2.01
Gainesville	¢	1.91
* Average of Lowest Two	¢	1.96

3/ The cost of private rail cars was approved in the original stipulation as $2.00 per ton. Subsequent negotiation between Tampa Electric and Public Service Commission Staff resulted in an agreed upon estimated cost of $1.75 per ton.

4/ Calculated by multiplying average domestic rail mileage to Tampa by Florida rail coal market costs (cents per ton-mile), then adding the costs of privately-owned rail cars.

EXHIBIT NO. ___
TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
(JTW-2)
DOCUMENT NO. 1
PAGE 2 OF 2
FILED: 9/9/04

2003 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources ([redacted] divided by 4,816,698.19 tons)	[redacted]
Transportation Benchmark	$22.96
Over/(Under) Benchmark	[redacted]
Total Tons Transported in 2003	4,816,698.19
Total Transportation Cost in 2003	[redacted]
Total Amount Allowable for Recovery Using Benchmark ($22.96 x 4,816,698.19 tons)	$110,591,390.44
Total Cost Over/(Under) Benchmark – 2003	[redacted]
Prior Year's Cumulative Benefit (1988-2002)	[redacted]
Net Benefit for 1988 – 2003	[redacted]

TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
FILED: 9/9/04

EXHIBIT TO THE TESTIMONY OF

JOANN WEHLE

DOCUMENT NO. 2

PROJECTED INCREMENTAL O&M HEDGING COSTS

EXHIBIT NO. ___
TAMPA ELECTRIC COMPANY
DOCKET NO. 040001-EI
(JTW-2)
DOCUMENT NO. 2
PAGE 1 OF 1
FILED: 9/9/04

Tampa Electric Company
2005 Projected Incremental O&M Hedging Costs

O&M Hedging Costs	
Labor and related charges	$ 203,767
Software system fees	60,110
Consulting and subscription fees	16,392
Total O&M Hedging Costs	**$ 280,269**
Less Base Year O&M Hedging Costs	169,153
Incremental O&M Hedging Costs	**$ 111,116**

Contribution of Contracts to Total Purchase Agreement

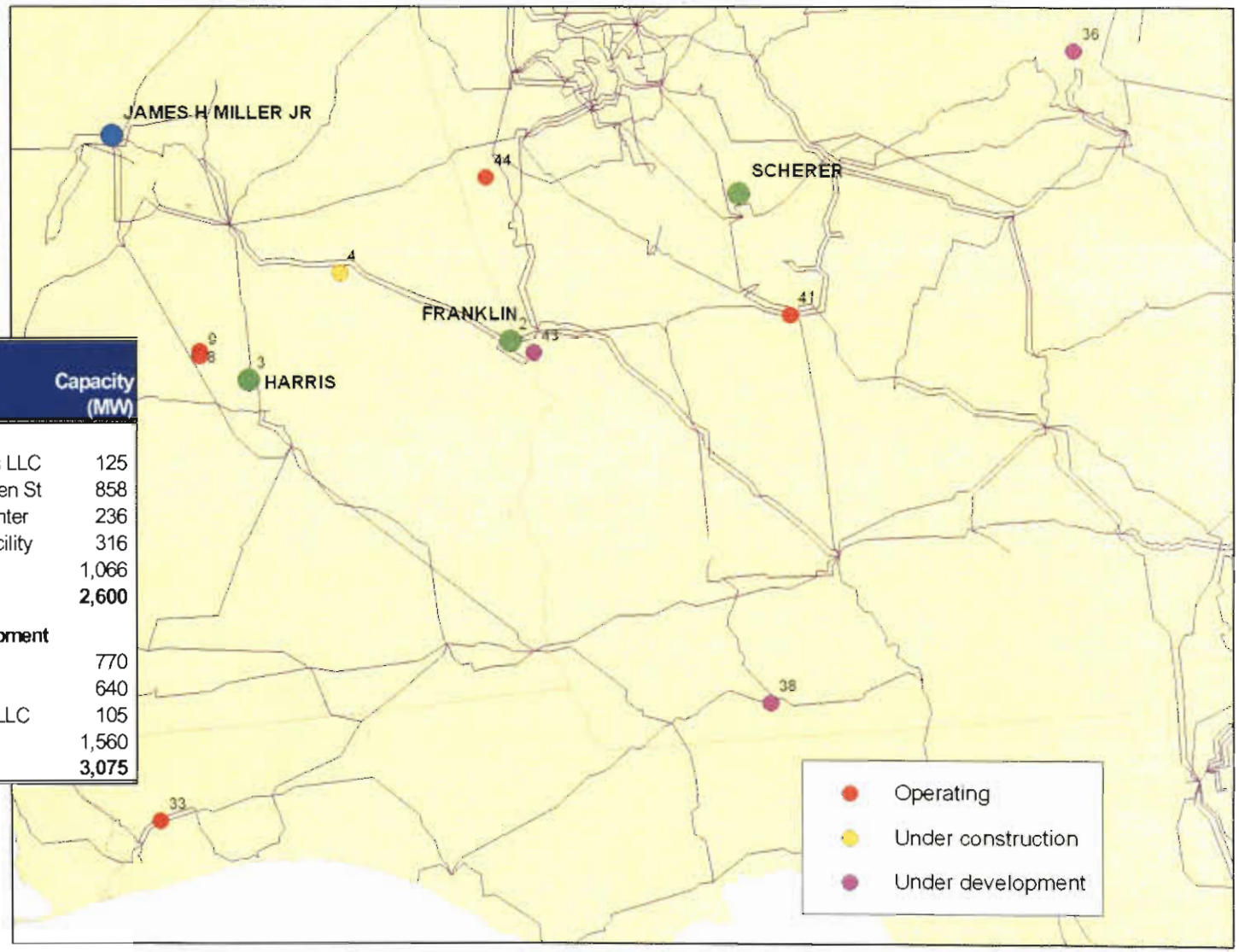
Contracted Unit	Fuel Type	Contracted Capacity (MW)	Percent of Total Contract
Robert W. Scherer Unit 3	Coal	165	17.3%
Harris Unit 1	Natural Gas	600	62.8%
Franklin Unit 1	Natural Gas	190	19.9%
Total		**955**	**100.0%**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 49
COMPANY/ Thurbuck/FIPUC
WITNESS: David E. Dismukes (DED-1)
DATE: 11-08-04

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 50
COMPANY/ Chesapeake/FIPUG
WITNESS: David E. Dismukes (DED-2)
DATE: 11-09-04

Merchant Facilities Located in Proximity to Contracted Units

Plant Name	Capacity (MW)
Operating Plants	
6 Mobile Energy Services LLC	125
9 Tenaska Lindsay Hill Gen St	858
33 Santa Rosa Energy Center	236
41 Mid-Georgia Cogen Facility	316
44 Wansley	1,066
Total	**2,600**
Under construction/development	
4 Hillabee Energy Center	770
36 Augusta Energy Center	640
38 Georgia Energy Proj 1 LLC	105
43 Peace Valley	1,560
Total	**3,075**



Note: Does not include peaking facilities

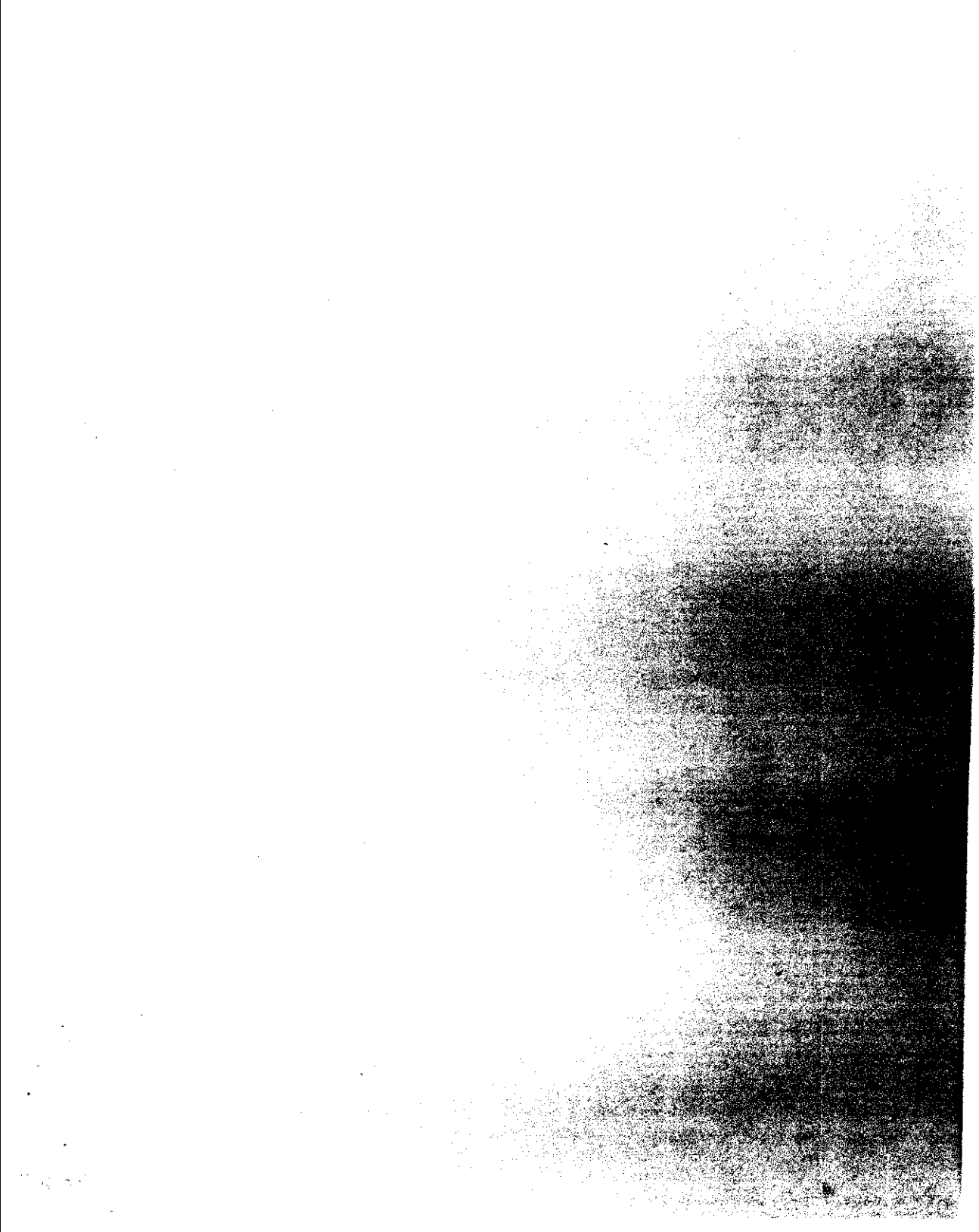
Estimated Natural Gas Transmission Capacity

Pipeline	System Capacity (Bcf/day)
Existing Pipelines	
Florida Gas Transmission	2.20
Gulfstream	1.10
Current State Capacity	**3.30**
Estimated Natural Gas Demand	**2.75**
Estimated Excess Capacity	**0.55**
Proposed Pipelines (2005 through 2007)	
Gulfstream -- Phase II	0.35
Gulfstream -- Phase III	n.a.
AES Ocean Express / AES	0.84
Calypso Natural Gas Pipeline / Tractebel	0.83
Seafarer Pipeline System / El Paso	0.70
Total Proposed Capacity	**2.72**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040007-EI
COMPANY/ Churbuck/FIPUG
WITNESS: David E. Dismukes (DED-3)
DATE 11-08-04
EXHIBIT NO. 51

Note: n.a. is not available

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040007-EI EXHIBIT NO. 52
COMPANY/ Churbuck/FIPUG (DED-4)
WITNESS: David E. Dismukes
DATE: 11-03-04

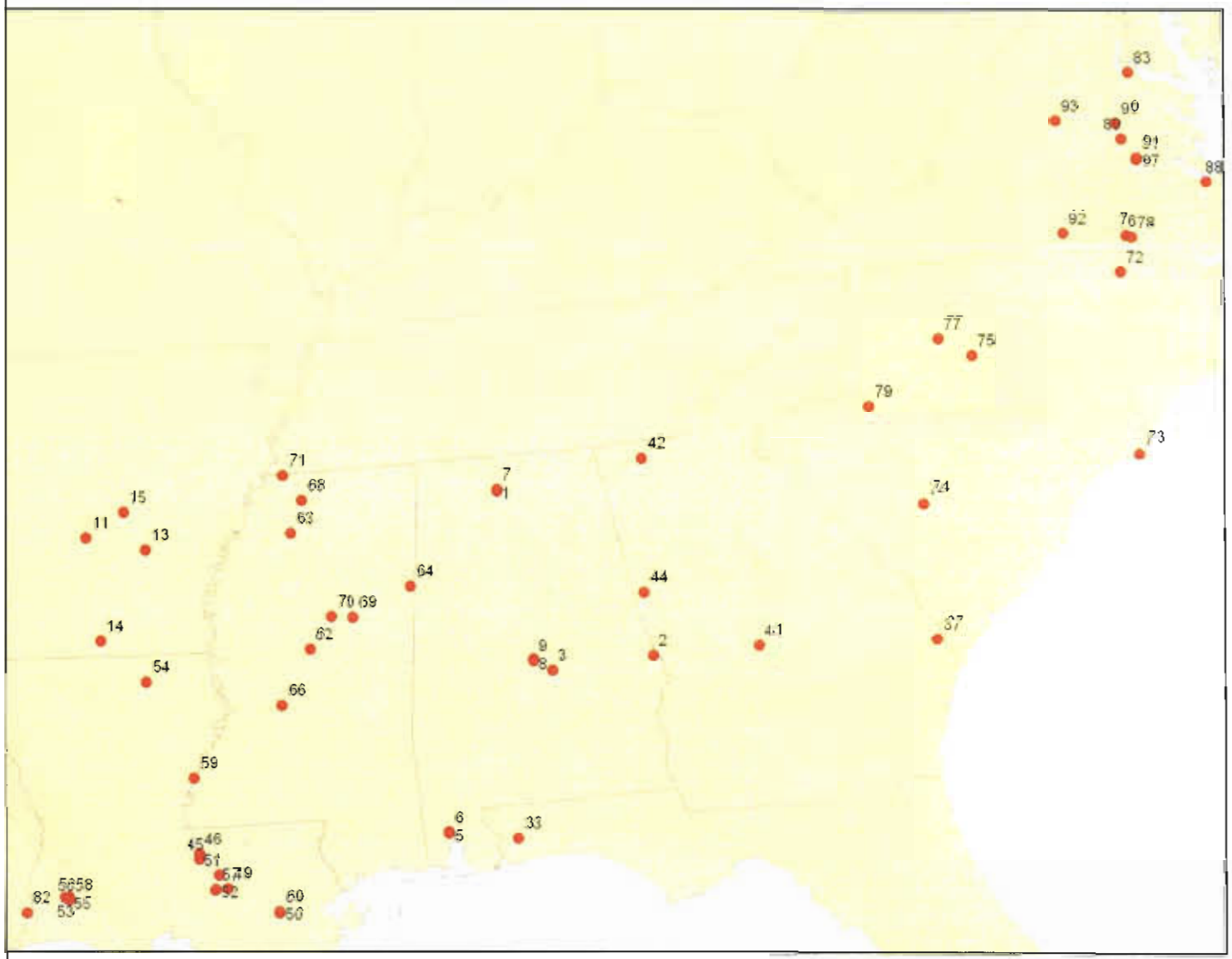


Merchant Development in SERC Region

Docket No. 040001-EI
David E. Dismukes
Exhibit DED-4
Page 1 of 1

	Plant Name	Capacity (MW)
1	Decatur Energy Center	624
2	Franklin	1,139
3	Harris	1,035
5	Hog Bayou Energy Center	230
6	Mobile Energy Services LLC	125
7	Morgan Energy Center	588
8	Tenaska Cntl Alabama Gen St	808
9	Tenaska Lindsay Hill Gen St	858
10	Hot Spring Energy Facility	652
13	Pine Bluff Energy Center	198
14	Union Power Station	2,020
15	Wrightsville Power Facility	568
33	Santa Rosa Energy Center	236
37	Effingham County Power Proj	490
41	Mid-Georgia Cog Fac	316
42	Murray Energy Facility	1,244
44	Wansley	1,066
45	Big Cajun 1	220
46	Big Cajun 2	1,730
49	Carville Energy LLC	500
50	Dow St Charles Operations	292
51	ExxonMobil Baton Rouge Cogen	332
52	LaO Energy Systems	588
53	Nelson Industrial Steam	213
54	Ouachita Generating Plant	816
55	PPG Powerhouse C	303
56	PPG Riverside	154
57	Plaquemine Cogeneration	859
58	RS Cogen	396
59	Sidney A Murray Jr Hydro	192
60	Taft Cogeneration Facility	790
62	Attala Generating LLC	459
63	Batesville Generation Facility	858
64	Caledonia	783
66	Hinds Energy Facility	450
68	Magnolia Power Plant	863
69	Red Hills Generating Facility	440
70	Reliant Energy Choctaw County	726
71	Southaven Energy LLC	783
72	Cogentrix Dw Collier Battle Cogen	105
73	Cogentrix Southport	107
74	Columbia Energy Center	580
75	Narrows	107
76	Panda Rosemary LP	165
77	Rowan	967
78	Westmoreland-LG&E Roanoke Val I	165
79	Cherokee County Cogen	95
82	SRW Cogen LP	420
83	Birchwood Power	238
87	Cogentrix Hopewell	93
88	Cogentrix Portsmouth	115
89	Cogentrix of Richmond	190
90	Doswell Energy Center	820
91	Hopewell Cogeneration	348
92	Mecklenburg Cog Fac	132
93	Tenaska Virginia Gen St	946
	Total	30,537

Note: Does not include peaking facilities



Merchant Development in SERC by Subregion

Subregion	Number of Plants	MW of Capacity
Entergy	22	12,934
Southern	11	7,548
TVA	7	4,882
VACAR	16	5,173
Total	**56**	**30,537**

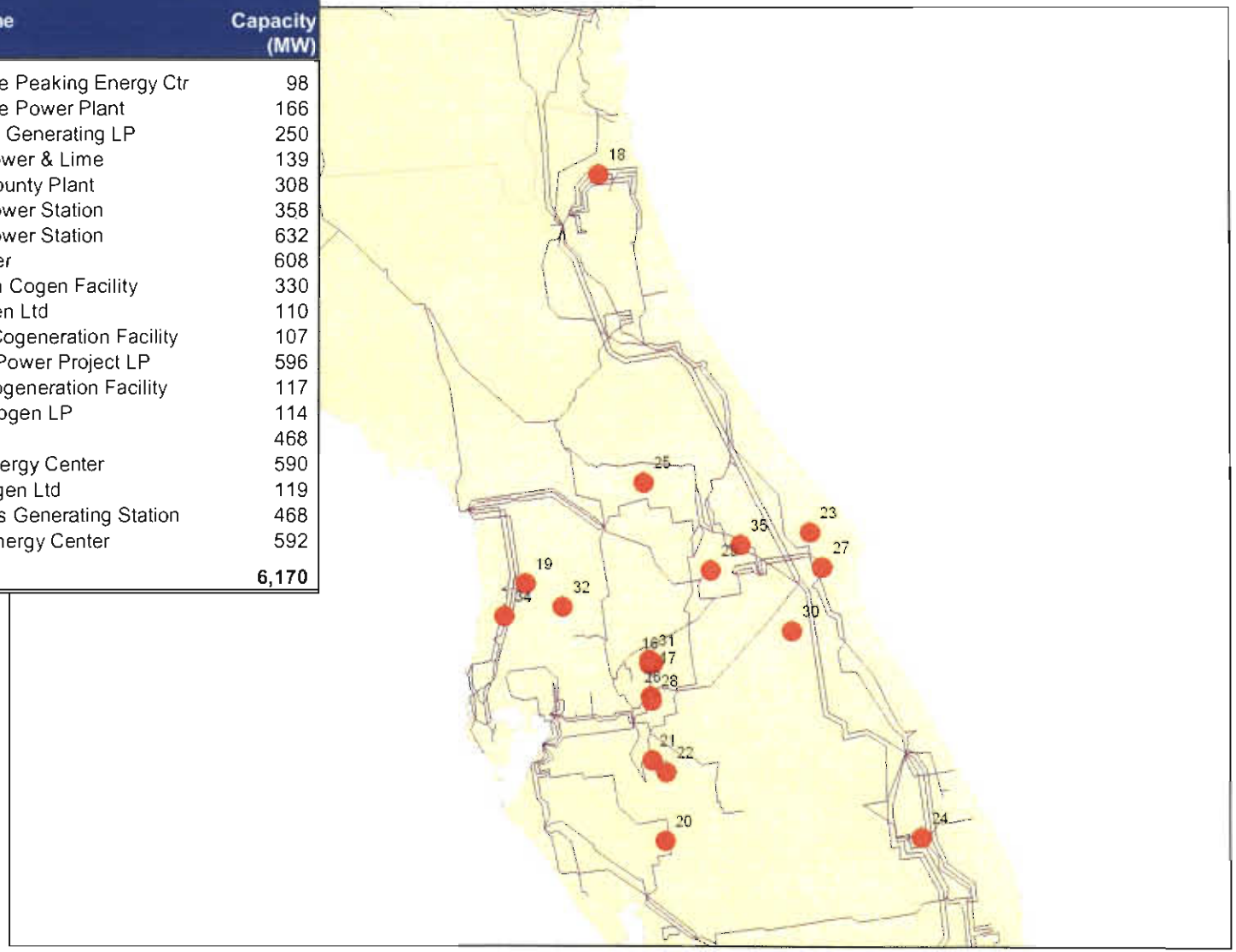
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO 53
COMPANY/Churbuck/FIPUG
WITNESS. David E. Dismukes (DED-5)
DATE 11-05-04

Note: Does not include peaking facilities

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 54
COMPANY/ Churbuck/FIPUG
WITNESS: David E. Dismukes (DED-4)
DATE: 11-03-04

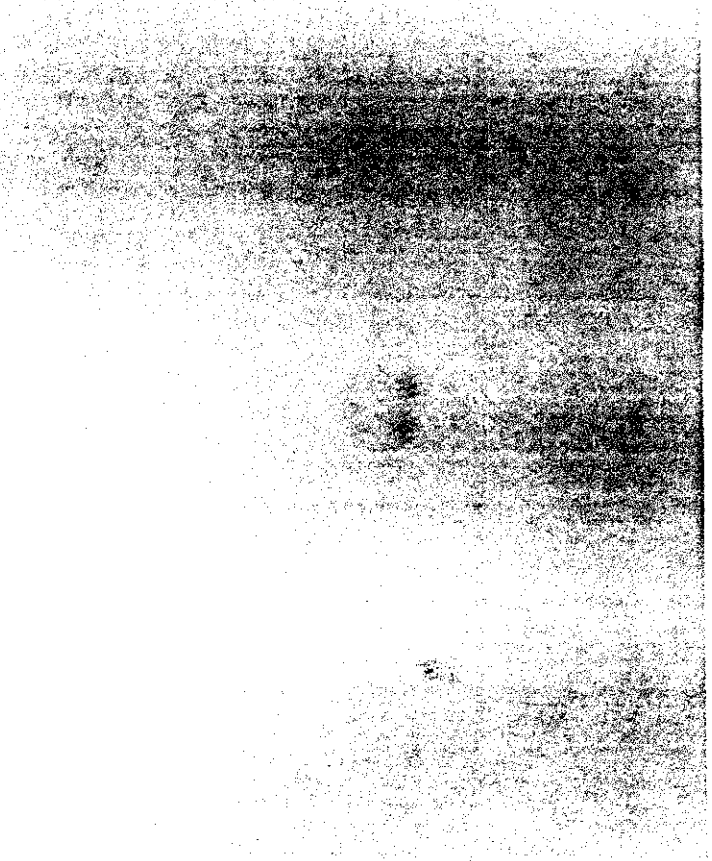
Merchant Development in FRCC Region

	Plant Name	Capacity (MW)
16	Auburndale Peaking Energy Ctr	98
17	Auburndale Power Plant	166
18	Cedar Bay Generating LP	250
19	Central Power & Lime	139
20	DeSoto County Plant	308
21	Hardee Power Station	358
22	Hardee Power Station	632
23	Indian River	608
24	Indiantown Cogen Facility	330
25	Lake Cogen Ltd	110
26	Mulberry Cogeneration Facility	107
27	Oleander Power Project LP	596
28	Orange Cogeneration Facility	117
29	Orlando Cogen LP	114
30	Osceola	468
31	Osprey Energy Center	590
32	Pasco Cogen Ltd	119
34	Shady Hills Generating Station	468
35	Stanton Energy Center	592
	Total	**6,170**



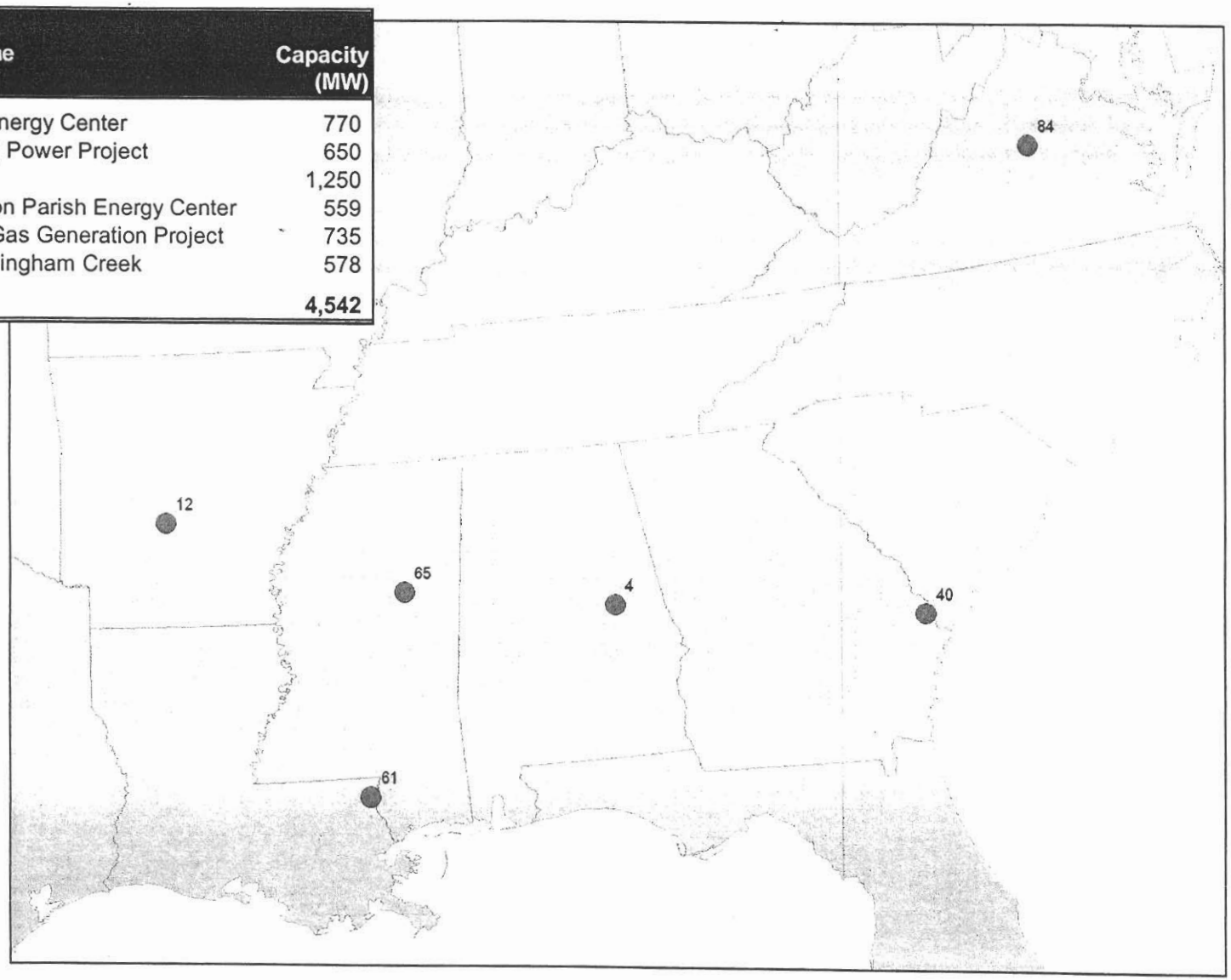
Note: Does not include peaking facilities

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 55
COMPANY/ Churbuck/FIPUG (DED-7)
WITNESS: David E. Dismukes
DATE: 11-08-04



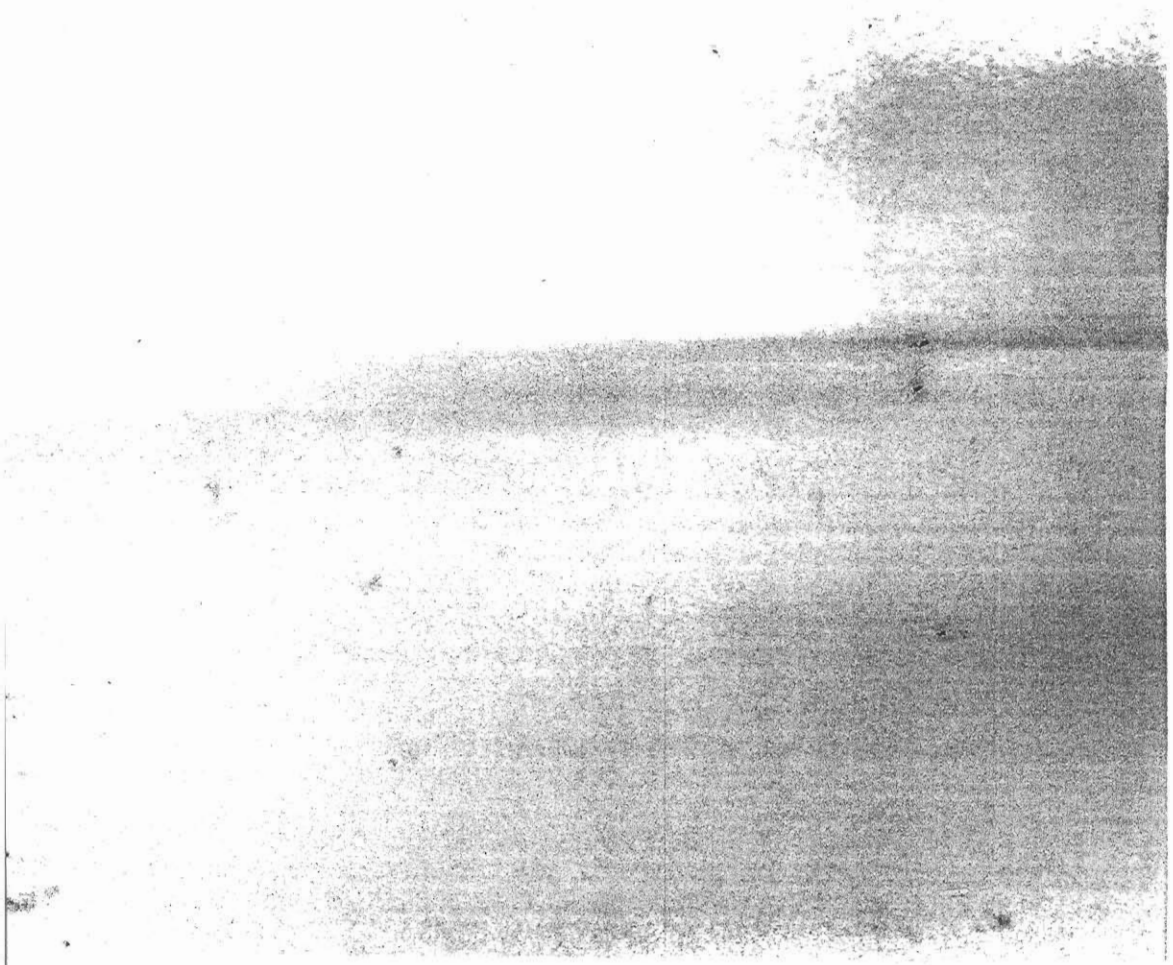
Merchant Facilities Under Construction in SERC

	Plant Name	Capacity (MW)
4	Hillabee Energy Center	770
12	Hot Spring Power Project	650
40	McIntosh	1,250
61	Washington Parish Energy Center	559
65	Choctaw Gas Generation Project	735
84	CPV Cunningham Creek	578
	Total	**4,542**



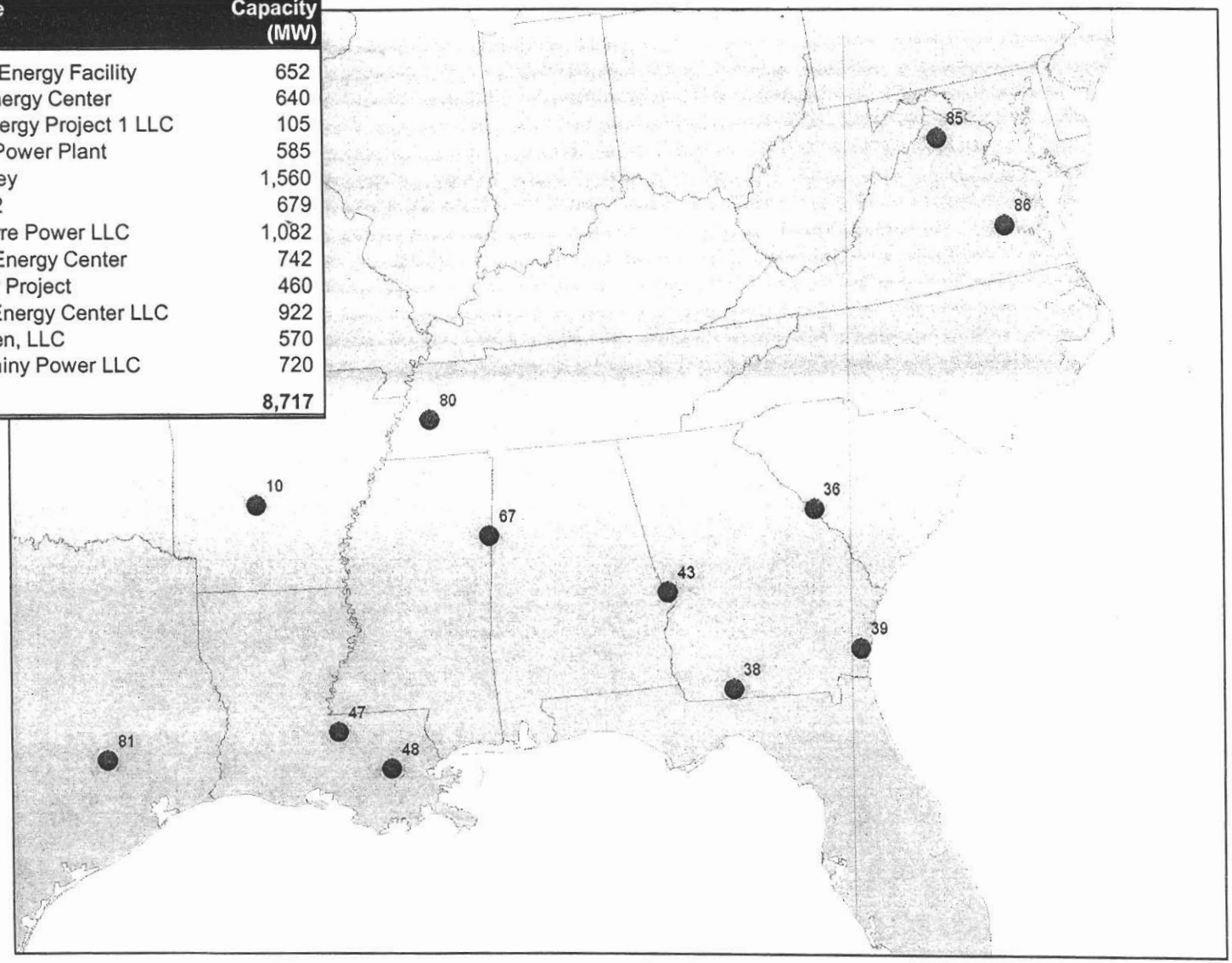
Note: Does not include peaking facilities

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040007-EI EXHIBIT NO. 56
COMPANY/ Churbuck / FIPUG
WITNESS: David E. Dismukes (DED-8)
DATE: 11-08-04

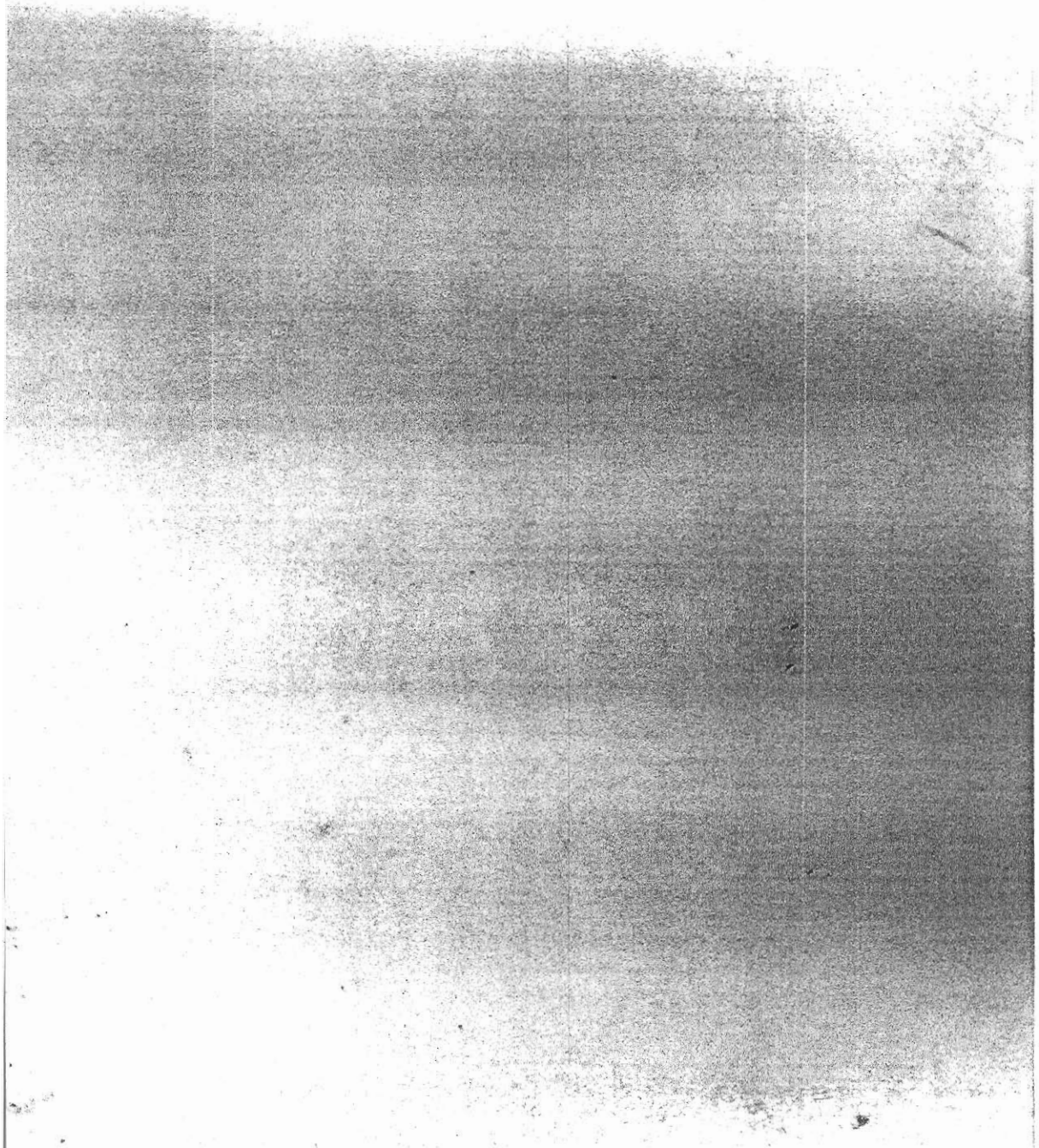


Merchant Facilities Under Development in SERC

Plant Name	Capacity (MW)
11 Hot Spring Energy Facility	652
36 Augusta Energy Center	640
38 Georgia Energy Project 1 LLC	105
39 Live Oaks Power Plant	585
43 Peace Valley	1,560
47 Big Cajun 2	679
48 Bonnet Carre Power LLC	1,082
67 Lone Oak Energy Center	742
81 MC Energy Project	460
80 Haywood Energy Center LLC	922
85 CPV Warren, LLC	570
86 Chickahominy Power LLC	720
Total	**8,717**



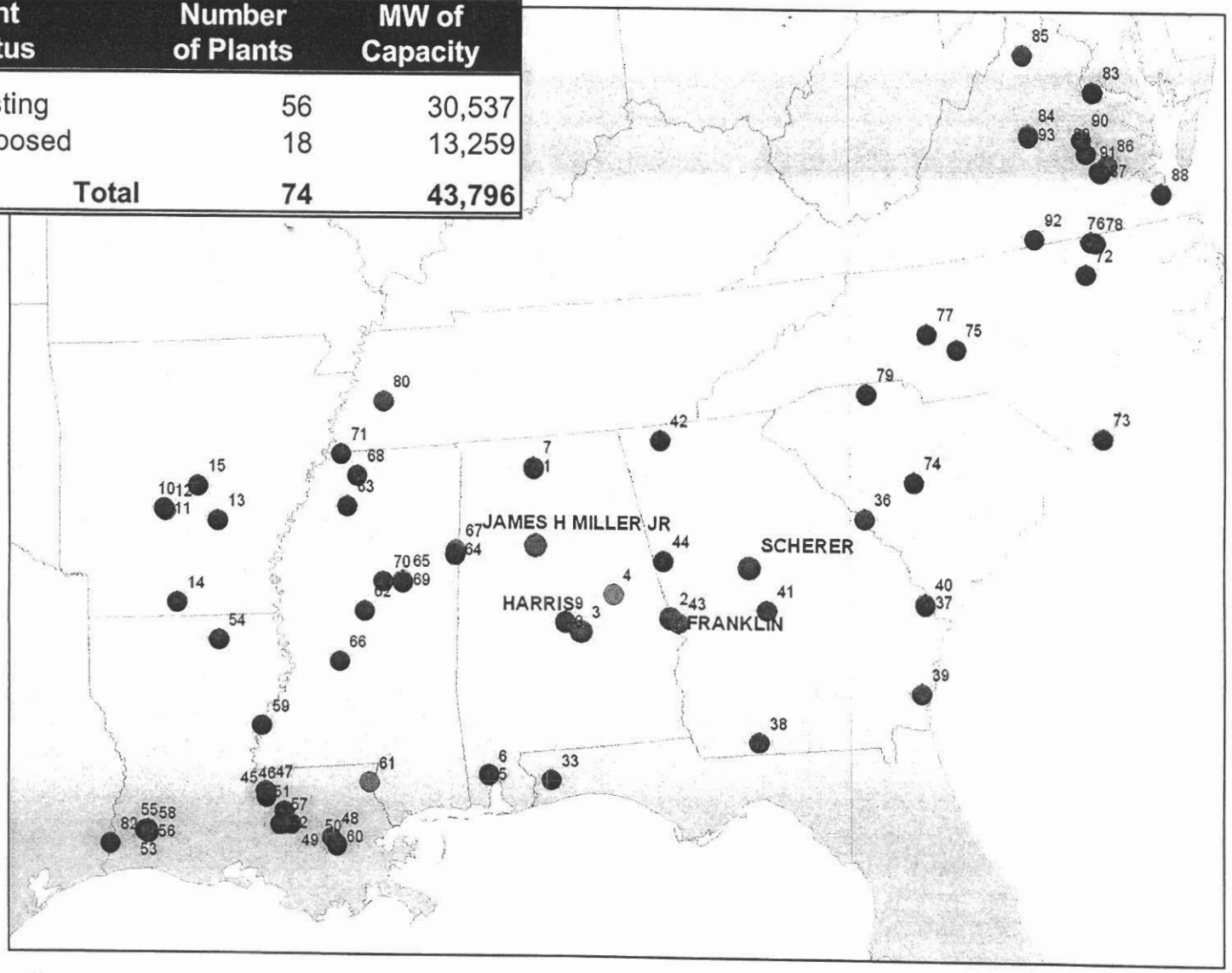
Note: Does not include peaking facilities



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. D40001-EI EXHIBIT NO. 57
COMPANY/ Churbuck/FIPUG
WITNESS: David E. Dismukes (DED-9)
DATE: 11-08-04

Merchant Alternatives in SERC

Plant Status	Number of Plants	MW of Capacity
Existing	56	30,537
Proposed	18	13,259
Total	**74**	**43,796**



Note: Does not include peaking facilities

Planned Transmission Additions (Circuit Miles)

	2003 Existing (miles)	Percent of Total Existing (%)	2004-2008 Additions	2009-2013 Additions	Total Additions	2013 Total Installed	Percent Increase (%)
			(miles)				
ECAR	16,439	17.4%	156	17	173	16,612	1.1%
FRCC	**6,894**	**7.3%**	**360**	**81**	**441**	**7,335**	**6.4%**
MAAC	7,057	7.5%	134	-	134	7,191	1.9%
MAIN	6,195	6.6%	374	260	634	6,829	10.2%
MAPP-US	14,705	15.6%	228	246	474	15,179	3.2%
NPCC-US	6,406	6.8%	376	-	376	6,782	5.9%
SERC	**28,868**	**30.6%**	**1,349**	**1,085**	**2,434**	**31,302**	**8.4%**
SPP	7,659	8.1%	191	17	208	7,867	2.7%
Total Eastern Interconnection*	**94,223**	**100.0%**	**3,168**	**1,706**	**4,874**	**99,097**	**5.2%**

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-GI EXHIBIT NO. 58
COMPANY/ Ehurbuck/PI PUG
WITNESS: David E. Dismukes (DED-10
DATE 11-08-04

DN 040001-EI
Issue 31A

Staff has reviewed the proposed stipulation between FPL and OPC to resolve the issue concerning certain costs associated with the NRC's Design Basis Threat Order. Based on this review, and with the anticipation that FPL's nuclear decommissioning accrual will actually decrease by at least $10 million, it appears that the immediate deferral and subsequent amortization of $38.3 million of DBT costs will result in benefits to the ratepayers. Therefore, staff recommends that the Commission approve the stipulation that resolves Issue 31A .

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 59
COMPANY/ Stipulated Issue
WITNESS: 31A between FPL + OPC
DATE 11-08-04

PROPOSED RESOLUTION OF ISSUE
DOCKET NO. 040001-EI
NOVEMBER 1, 2004

Background of Issue:

The Nuclear Regulatory Commission ("NRC") issued its Design Basis Threat Order EA-03-086 on April 29, 2003 (the "DBT Order"). FPL is required by the DBT Order to modify its security systems at the St. Lucie and Turkey Point nuclear units to defend against the design basis threat that has been defined pursuant to that order. FPL included $12 million for incremental nuclear security costs in the 2004 projections that were filed in Docket No. 030001-EI, of which $2 million was projected for compliance with the DBT Order. Since that time, the NRC has made numerous revisions and clarifications to the design basis threat originally described in the DBT Order. As a result, the scope of work required to comply with the DBT Order has increased substantially. FPL's 2004 estimated/actual true-up that was filed on August 10, 2004 in this docket included incremental nuclear security costs of $50.2 million, of which $40.4 million is estimated for compliance with the DBT Order. This is an increase of $38.3 million over the original projection. Consistent with the Commission's usual procedures, FPL has proposed to recover its 2004 estimated/actual true-up of the incremental nuclear security costs through the 2005 capacity cost recovery ("CCR") factor.

The Office of Public Counsel ("OPC") does not dispute that the costs of complying with the DBT Order are incremental security costs. OPC also recognizes that the Commission's current policy is to allow recovery of necessary and prudent incremental security costs via the CCR clause. However, OPC has raised concerns about FPL's use of the 2005 CCR factor to recover the extraordinary level of incremental nuclear security costs associated with the DBT Order (the "DBT Costs"). Recovery in that manner, OPC believes, could result in an inappropriate one-time "spike" in FPL's CCR factor.

FPL and OPC have worked together to identify a mutually acceptable alternative to the CCR factor through which FPL may recover the DBT Costs. They have agreed on the proposed resolution outlined below.

Components of Proposed Resolution:

FPL will ask the Commission to approve the following, and OPC agrees to support FPL's request:

1. FPL will remove $38.3 million of DBT Costs from the calculation of its 2005 CCR factor and will treat that amount as a deferred debit (the "DBT Deferred Debit").

2. FPL will accrue interest on the outstanding balance of the DBT Deferred Debit at the currently approved AFUDC rate of 7.29%, commencing on January 1, 2005.

3. FPL recovers via base rates an annual accrual amount to fund the estimated decommissioning costs for its St. Lucie and Turkey Point nuclear units. FPL is presently authorized and directed by Order No. PSC-02-0055-PAA-EI to accrue $78.5 million per year for the decommissioning fund. The order directs FPL to file an updated decommissioning cost study on or before January 1, 2006, for the purpose of evaluating and adjusting, as appropriate, FPL's annual decommissioning accrual. FPL intends to file its updated decommissioning study during 2005 and to ask that the revised annual decommissioning accrual be made retroactive to January 1, 2005. FPL presently anticipates that the updated decommissioning cost study will support a reduction in the annual decommissioning accrual. For 2005, FPL will reduce the DBT Deferred Debit by the amount of any reduction in the annual decommissioning accrual that is approved by the Commission. As a simplified illustration, and ignoring the accrual of interest described in Section 2 above, if the annual decommissioning accrual were reduced by $10 million, then the DBT Deferred Debit would be reduced from $38.3 million to $28.3 million in 2005.

4. The balance of the DBT Deferred Debit remaining after the adjustment described in Section 3 above will be amortized over a five year period starting on January 1, 2006; provided, however, that if FPL enters into a settlement applicable to FPL base rates commencing on January 1, 2006, the amortization will be over the time period to which the settlement applies.

5. $40.4 million is only an estimate of the DBT Costs. The actual amount of those costs almost certainly will vary. In the event the Commission ultimately determines that the actual amount of FPL's prudent and necessary DBT Costs exceeds $40.4 million, then the variance will be recovered via FPL's CCR factor pursuant to the Commission's usual procedures. For example, if FPL ultimately incurs $41 million in prudent and necessary DBT Costs, then the CCR true-up will reflect an under-recovery of $.6 million which will be included in determining the CCR factor for the subsequent year. On the other hand, if the actual amount of prudent and necessary DBT Costs is determined to be less than $40.4 million, then the variance will reduce the amount of the DBT Deferred Debit outstanding at that time.

6. This proposed resolution is a one-time response to an extraordinary situation. FPL and OPC acknowledge, and the Commission finds, that approval of this proposed resolution will establish no precedent, and may not be used as evidence, with respect to (a) the appropriate mechanism for recovery of future incremental security costs, (b) the appropriate mechanism for recovery of any other costs through the CCR or other adjustment clauses, (c) the appropriate level of FPL's annual decommissioning accruals, or (d) the adequacy of FPL's decommissioning fund.

7. This proposed resolution may be executed in counterparts, and all such counterparts shall constitute one instrument binding on the signatories, notwithstanding that all signatories are not signatories to the original or the same

counterpart. Facsimile transmission of an executed copy of this proposed resolution shall be accepted as evidence of a party's execution of the proposed resolution.

Agreed and accepted on behalf of:

Florida Power & Light Company
Steel Hector & Davis LLP
Suite 4000
200 South Biscayne Boulevard
Miami, Florida 33131-2398

By: John T. Butler
John T. Butler

Date: 11/1/04

Office of Public Counsel
111 West Madison Street, Suite 810
Tallahassee, FL 32399

By: _____
Harold A. McLean, Esq.

Date: 11/1/04

THE FLORIDA SENATE

Tallahassee, Florida 32399-1100

SENATOR MICHAEL S. "MIKE" BENNETT
21st District

November 5, 2004

Chairman Braulio Baez
Florida Public Service Commission
2540 Shummard Oak Boulevard
Tallahassee, Fl 32399-0850

Dear Chairman Baez:

It has come to my attention that a fuel docket hearing, slated to begin on November 8, also includes the approval of a contract totaling some 900 megawatts. While I do not have all the details, I am concerned that a three-day hearing to determine what Florida electric ratepayers will pay for fuel will also determine if this 900 megawatt contract makes sense for Florida. I do know that typical fuel clause hearings do not address long-term capacity contracts. I also understand that there are numerous issues surrounding these contracts.

Because of these issues, and the fact that we all would like to ensure that Floridians are getting the best electric deals possible, I would like to encourage the Commission to remove this issue from the fuel docket and address it within its own proceeding.

Thank you for your consideration.

Sincerely,

Michael S. "Mike" Bennett
MB/cre

Cc: Public Service Commissioners

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 60
COMPANY/ Letter From
WITNESS: Sen. Bennett
DATE 11-08-04

REPLY TO:
❒ Wildewood Professional Park, Suite 90, 3653 Cortez Road West, Bradenton, Florida 34210 (941) 727-6349
❒ 216 Senate Office Building, 404 South Monroe Street, Tallahassee, Florida 32399-1100 (850) 487-5078

Senate's Website: *www.flsenate.gov*

JAMES E. "JIM" KING, JR.
President

ALEX DIAZ DE LA PORTILLA
President Pro Tempore

PROGRESS ENERGY FLORIDA

SCHEDULE 6.1

ENERGY SOURCES (GWh)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
				-ACTUAL-											
	ENERGY SOURCES		UNITS	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
(1)	ANNUAL FIRM INTERCHANGE 1/		GWh	27	97	154	146	80	89	74	105	97	8	0	0
(2)	NUCLEAR		GWh	6,700	6,039	6,658	6,131	6,640	6,092	6,658	5,089	6,640	6,146	6,658	6,145
(3)	COAL		GWh	14,406	16,111	16,485	17,198	16,919	16,433	16,614	17,775	17,260	17,626	17,741	17,776
(4)	RESIDUAL	TOTAL	GWh	6,319	6,785	6,258	6,149	4,990	5,553	4,513	4,557	3,603	3,984	3,445	3,664
(5)		STEAM	GWh	6,319	6,785	6,258	6,149	4,990	5,553	4,513	4,557	3,603	3,984	3,445	3,664
(6)		CC	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	DISTILLATE	TOTAL	GWh	607	405	286	336	206	260	160	318	231	363	219	316
(10)		STEAM	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	0	19	0	0	0	0	0	0	0	0	0	0
(12)		CT	GWh	607	386	286	336	206	260	160	318	231	363	219	316
(13)		DIESEL	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	NATURAL GAS	TOTAL	GWh	6,446	6,155	7,020	7,589	10,101	11,558	13,054	15,018	18,362	20,645	21,821	23,314
(15)		STEAM	GWh	462	83	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	4,816	4,938	5,881	6,355	9,101	10,244	11,959	13,671	17,256	19,350	20,832	22,216
(17)		CT	GWh	1,168	1,134	1,139	1,234	1,000	1,314	1,095	1,347	1,106	1,295	989	1,098
(18)	OTHER 2/														
	QF PURCHASES		GWh	5,091	5,022	4,677	4,587	4,589	4,463	4,362	3,673	3,584	3,584	3,594	3,393
	IMPORT FROM OUT OF STATE		GWh	3,317	3,555	3,623	3,609	3,595	3,596	3,612	3,612	1,486	0	0	0
	EXPORT TO OUT OF STATE		GWh	-346	-258	0	0	0	0	0	0	0	0	0	0
(19)	NET ENERGY FOR LOAD		GWh	42,567	43,911	45,161	45,745	47,120	48,044	49,047	50,147	51,263	52,356	53,478	54,608

1/ NET ENERGY PURCHASED (−) OR SOLD (-) WITHIN THE FRCC REGION.

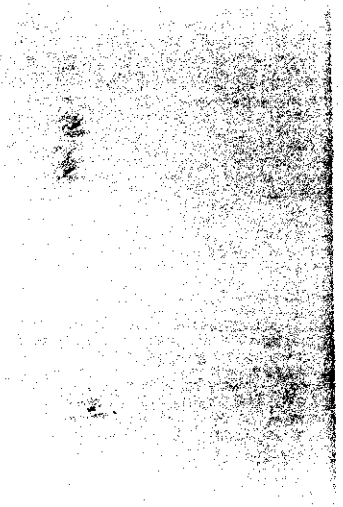
2/ NET ENERGY PURCHASED (−) OR SOLD (-).

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040007-EI EXHIBIT NO. 61
COMPANY/ FIPUG
WITNESS: PEF TYSP excerpt
DATE: 11-09-04

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 62
COMPANY/ OPC
WITNESS. PEF transloading Spreadsheet
DATE: 11-08-04

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 62
COMPANY/ OPC
WITNESS: PSC Order # 9558
DATE 11-04-04



In re: Investigation of Fuel Cost Recovery Clause Application to Investor-owned Electric Utilities.	DOCKET NO. 800400-CI
	ORDER NO. 9558
	ISSUED: 9-19-80

The following Commissioners participated in the disposition of this matter:

ROBERT T. MANN, Chairman
WILLIAM T. MAYO
GERALD L. GUNTER
JOSEPH P. CRESSE
JOHN R. MARKS, III

O R D E R

BY THE COMMISSION:

Throughout nearly all of 1980, this docket has concerned the investigation and implementation of a fuel cost recovery clause based upon projections of fuel expenses and kilowatt hour sales, with a built-in true-up mechanism. Following public hearings, we authorized the first projected charges to take effect during the period April-September, 1980.

Throughout the investigation, we have emphasized our determination to incorporate within the clause an explicit formula designed to provide to the utilities a monetary incentive to operate their generating units as efficiently as possible and thus minimize fuel costs borne by their customers. The Commission staff presented testimony on such a plan, labeled the Generating Performance Incentive Factor, during hearings held on February 20 and 21, 1980. When the utilities pledged to commit their resources to the task of offering alternatives or improvements to the staff proposal, we withheld a decision on this aspect of the projected clause.

The utilities presented their responses to the GPIF during hearings conducted on May 28 and 29, 1980. Final oral presentations were made by the parties on August 26, 1980.

The Generating Performance Incentive Factor initially proposed by the staff is designed to encourage the improvement of the productivity of base load generating units by focusing upon the areas of thermal efficiency (heat rate) and unit availability. These two factors are, to some extent, within the control of the utilities, and can be precisely measured and evaluated from plant records. In addition, they constitute independent variables in the generating system production costing simulations used to project system fuel requirements and expenses; thus, an incentive factor which monitors these parameters is easily meshed with the projected clause adopted by the Commission.

While the calculation of the GPIF does require complex engineering simulations of the utilities' dispatch, the concept

of the proposal is straightforward. First, equivalent availability and average heat rate performance targets are set for a utility's base load generating units. These targets reflect how each unit is expected to perform during the six month period encompassed by the projected fuel adjustment clause. For each target, a maximum reasonable attainable range of potential improvement is determined. Weighting factors are then calculated for each range to reflect the percent contribution to total system fuel savings of achieving the maximum potential improvement to each target.

At the end of the six month fuel adjustment period, actual unit equivalent availability and average heat rate are compared to the pre-established targets. Based on this comparison, a monetary reward is awarded for improvements from the performance targets; a monetary penalty is deducted for degradation from the performance targets.

Since performance targets are set prospectively in the GPIF, the Staff proposal also provides for adjustments to the equivalent availability and average heat rate performance indicators where such adjustments are determined to be warranted by the Commission.

Of the various proposals, the only one which differed conceptually from the staff's plan was that advanced by Gulf Power Company. Styled the Generating Efficiency and Reliability Improvement (GERI), Gulf's plan would attempt to measure the net savings or loss associated with operations and maintenance expenses over a given period of time by comparing at the end of such a period, experienced heat rates and unit availability factors to pre-established heat rate targets and to availability factors based upon national averages. Ten percent of the savings or loss would constitute the reward or penalty to be flowed through the clause.

Gulf's GERI incentive provision relies on an after-the-fact recreation of Gulf's operation in the Southern pool. In this recreation, EEI national average equivalent availability statistics compiled during the historic period would be used in lieu of Gulf's actually experienced unit availabilities. Gulf's system would then be dispatched using the BTU/hr fuel input versus MW output characteristics as determined by field testing prior to the historic period. The result of this after-the-fact recreation would be an estimate of the fuel and purchased energy expenses Gulf would have experienced had the Company maintained these unit availabilities and heat rates. Relevant operation and maintenance expenses had these availabilities and heat rates been experienced are also estimated. The after-the-fact recreation of fuel and purchased energy cost and operation and maintenance expense is then compared to Gulf's actual book fuel and purchased energy cost and book operation and maintenance expense for the period to calculate the "true net savings or loss" to Gulf's customers during the period.

As stated earlier, Gulf's plan is the only one submitted by the utilities which differs conceptually from the GPIF. Thus, the GPIF offers the advantages of consistency of treatment. In

addition, unlike the GPIF, Gulf's proposal does not offer pre-established goals which management could be striving to achieve during a particular period relying instead on an after-the-fact measurement. Finally, there is no assurance that the broad averages reflected in EEI statistics would provide meaningful comparisons to Gulf's particular units.

While the plans submitted by the other utilities were similar to the staff's GPIF, they offered refinements and improvements to the initial proposal. In fact, the final staff recommendation has, in our opinion, selected the best elements of those proposals and the final form of the GPIF differs materially from the plan which was first advanced. For instance, the recommendation now requires that a ceiling be placed on the amount of incentive dollars available, so that the incentive will never exceed the savings realized by ratepayers. The maximum amount of dollars has also been reduced to assure that uneconomic operating decisions are not encouraged. The weighting factors within the formula have been simplified, and the recommendation now provides that potential improvement and degradation ranges from the equivalent availability performance indicator be determined independently of each other, so that the "downside" potential is no longer automatically equivalent to the amount of potential improvement. Finally, having reviewed the varying testimony on the subject, we have decided to place a "neutral band" of 75 BTU/kwh around the heat rate measurement, to reflect the limitations upon accuracy inherent in such measurements. Fluctuations within the neutral band will result in neither rewards nor penalties.

We have reviewed Public Counsel's contention that the incentive factor address itself also to the fuel procurement practices of the utilities. However, it has been pointed out that those activities are frequently audited and are the subject of ongoing review, including the work of a presently active Commission task force on the subject. While we have determined that procurement practices shall not be brought within the GPIF, we shall not relax our efforts to monitor and evaluate such practices through other means.

We find and conclude that the GPIF plan encompassed with the staff's final recommendation is consistent with the evidence received during this proceeding, represents the best elements of the ideas advanced by the parties, and provides the promise of fulfilling our objective of an explicit incentive in the area of operating efficiency. The GPIF is described fully and presented in formulistic form in Appendix A, which is attached hereto and hereby made a part of this Order. As recommended by the staff proposal which we are implementing, the GPIF will be applicable only to Florida Power and Light Company, Tampa Electric Company, Florida Power Corporation, and Gulf Power Company. We hereby adopt the GPIF, as presented therein, and prescribe its use for the projection period October 1980-March 1981. The affected utilities shall provide the data required in Appendix A to facilitate the review and implementation of GPIF targets for that time frame.

Accordingly, it is

ORDERED by the Florida Public Service Commission that the Generating Performance Incentive Factor, as set forth in this Order and in Appendix A attached hereto, is hereby adopted as part of the fuel cost recovery clause utilized in this proceeding, said factor to be applicable to Florida Power & Light Co., Florida Power Corporation, Gulf Power Company, and Tampa Electric Company. It is further

ORDERED that said factor be implemented during the projection period October 1980-March 1981.

By Order of the Florida Public Service Commission, this 19th day of September 1980.

Appendix A

GENERATING PERFORMANCE INCENTIVE FACTOR

IMPLEMENTATION MANUAL

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I. INTRODUCTION

GENERATING PERFORMANCE INCENTIVE FACTOR

The purpose of the Generating Performance Incentive Factor (GPIF) is to encourage utilities to improve the productivity of their base load generating units. Two factors over which a utility maintains some degree of control and which affect system generating mix, and hence total system fuel expense, are unit availability and thermal efficiency (heat rate). These two factors also lend themselves to analytical scrutiny since they are readily determined historically from actual plant records and are also indepenednet variables[1] in the production costing simulations of generating system operation used to project system fuel requirements and expense. For these reasons, unit equivalent availability and average heat rate were selected as appropriate performance indicators for use in the GPIF.

The GPIF is designed to operate in conjunction with the projected levelized fuel adjustment clause. While the calculation of the GPIF does require complex engineering simulations of the utilities' dispatch, the concept is straightforward.

(1) This is not absolutely correct in the case of the average heat rate performance indicator used in the GPIF. Input/output (BTU/hr/MW) curves for each unit are the independent input variable to the production costing simulation. Unit dispatch is performed by multiplying each units' input/output curve by the fuel cost in ¢/MMBTU and loading units in the system to an equal incremental fuel cost (λ). The average heat rate is then calculated for the load level to which the unit is dispatched.

First, equivalent availability and average heat rate performance targets are set for a utility's base load generating units. These targets reflect how each unit is expected to perform during the six month period encompassed by the projected fuel adjustment clause. For each target, a maximum reasonably attainable range of potential improvement is determined. Weighting factors are then calculated for each range to reflect the percent contribution to total system fuel savings of achieving the maximum potential improvement to each target.

At the end of the six month fuel adjustment period, actual unit equivalent availability and average heat rate are compared to the pre-established targets. Based on this comparison, a monetary reward is awarded for improvements from the performance targets; a monetary penalty is deducted for degradation from the performance targets.

Since performance targets are set prospectively, provisions are made in the GPIF methodology for adjustments to be made to the equivalent availability and average heat rate performance indicators where such adjustments are determined to be warranted by the Commission.

II. FORMULAIC REPRESENTATION

MAXIMUM ALLOWED INCENTIVE DOLLARS

$$MAX(\$) = 0.5 \left[\frac{A \times B}{C} \right]$$

Where: MAX($) = Maximum allowed incentive dollars.

A = 25 basis points (0.0025).

B = Average common equity for the period being evaluated (7-month average).

C = Revenue expansion factor calculated as follows:

	%
Revenues	100.0000
Gross Receipts Tax	(1.5000)
Regulatory Assessment Fee	(0.0833)
	98.4167
Income Tax	47.9289(1)
Revenue Expansion Factor	50.4878

(1) 48.7% x 98.4167

NOTE: The MAX($) derived from this formula shall not exceed the gross amount of any fuel savings/loss experienced during the period being evaluated.

GENERATION PERFORMANCE INCENTIVE FACTOR

$$GPIF(\$) = \frac{MAX(\$) \times GPIP}{10}$$

Where: GPIF($) = Incentive Dollars awarded/deducted
MAX($) = Maximum allowed incentive dollars
GPIP = Generating performance incentive points

GENERATING PERFORMANCE INCENTIVE POINTS

$$GPIP = \sum_{i=1,n} 10 \left[a_i EAP_i + e_i AHRP_i \right]$$

Where: GPIP = Generating performance incentive points

a_i = Percentage of total system fuel cost reduction attributed to maximum reasonably attainable equivalent availability of unit i during the period

e_i = Percentage of total system fuel cost reduction attributed to minimum reasonably attainable average heat rate of unit i during the period

EAP_i = Equivalent availability points awarded/deducted for unit i

$AHRP_i$ = Average heat rate points awarded/deducted for unit i

UNIT EQUIVALENT AVAILABILITY POINTS

$$EAP_i = \frac{EA_i \text{ (actual)} - EA_i \text{ (target)} \pm EA_i \text{ (adjustment)}}{EA_i \text{ (max)} - EA_i \text{ (target)}}$$

When EA_i (actual) - EA_i (target $\pm$ EA_i (adjustment) ≥ 0

$$EAP_i = \frac{EA_i \text{ (actual)} - EA_i \text{ (target)} \pm EA_i \text{ (adjustment)}}{EA_i \text{ (target)} - EA_i \text{ (min)}}$$

When EA_i (actual) - EA_i (target) $\pm$ EA_i (adjustment) < 0

Where:

EA_i (target)	=	Equivalent availability target set for unit i for the period
EA_i (max)	=	Maximum reasonably attainable equivalent availability for unit i during the period
EA_i (min)	=	Minimum reasonably attainable equivalent availability for unit i during the period
EA_i (actual)	=	Actual equivalent availability experienced by unit i during the period
EA_i (adjust.)	=	Adjustment to actual equivalent availability of unit i to reflect unforeseen events beyond management control experienced during the period

EQUIVALENT AVAILABILITY FACTOR (DEFINITION)

$$EAF = \left[1 - \left[\frac{POH + MOH + FOH + EFOH}{PH}\right]\right] 100\%$$

$$= \left[1 - \left[\frac{POH + MOH + FOH}{PH} + \frac{PMOH \cdot LR}{PH \cdot NSC} + \frac{PFOH \cdot LR}{PH \cdot NSC}\right]\right] 100\%$$

Where:

EAF = Equivalent availability factor

POH = Planned outage hours

MOH = Maintenance outage hours

FOH = Forced outage hours

EFOH = Equivalent forced outage hours

PMOH = Partial maintenance outage hours

PFOH = Partial forced outage hours

LR = Average load reduction

NSC = Net summer continuous rating

PH = Period hours

ADJUSTMENTS TO EQUIVALENT AVAILABILITY

Since performance targets are set prospectively in the GPIF, certain circumstances may arise during the six month period which warrant adjustments to be made in the final GPIF calculation. Adjustments to the equivalent availability performance indicator will be considered by the Commission on a case by case basis. Generally, adjustments to the equivalent availability performance indicator which will be considered by the Commission are categorized as follows:

- Natural or externally cause disaster
- Unforeseen shutdown or continued operation at a unit pursuant to the actions of a Regulatory agency
- Rescheduling of planned maintenance into or out of the review period
- An identifiable and justifiable change in the workscope of a planned outage affecting total outage time.

AVERAGE HEAT RATE POINTS

$$AHRP_i = \frac{AHR_i \text{ (target)} - AHR_i \text{ (actual)} \pm AHR_i \text{ (adjustment)} \pm 75 \text{ BTU/KWH}}{AHR_i \text{ (target)} - AHR_i \text{ (min.)}}$$

Where:

AHR_i (target)	=	Average heat rate target set for unit i for the period
AHR_i (min)	=	Minimum reasonably attainable average heat rate for unit i during the period
AHR_i (actual)	=	Actual average heat rate experience by unit i during the period
AHR_i (adjust.)	=	Adjustment to actual average heat rate of unit i to reflect unforeseen changes in economic loading of unit i during the period

* A neutral band of ± 75 Btu/KWH is incorporated for the average heat rate performance indicator when AHR_i (target) - AHR_i (actual) ± AHR_i > 0 then 75 BTU/KWH is subtracted from this summation when AHR_i (target) - AHR_i (actual) ± AHR_i < 0 then 75 BTU/KWH is added to this summation.

AVERAGE HEAT RATE (DEFINITIONS)

For the purpose of the GPIF, average net operating heat rate is used as a performance indicator. Average net operating heat rate is defined as the total heat value of fuel burned (BTU) during the period while the unit is synchronized to the system, exclusive of start-up BTU, divided by the total net generation, exclusive of station use, produced during the period while the unit is synchronized to the system.

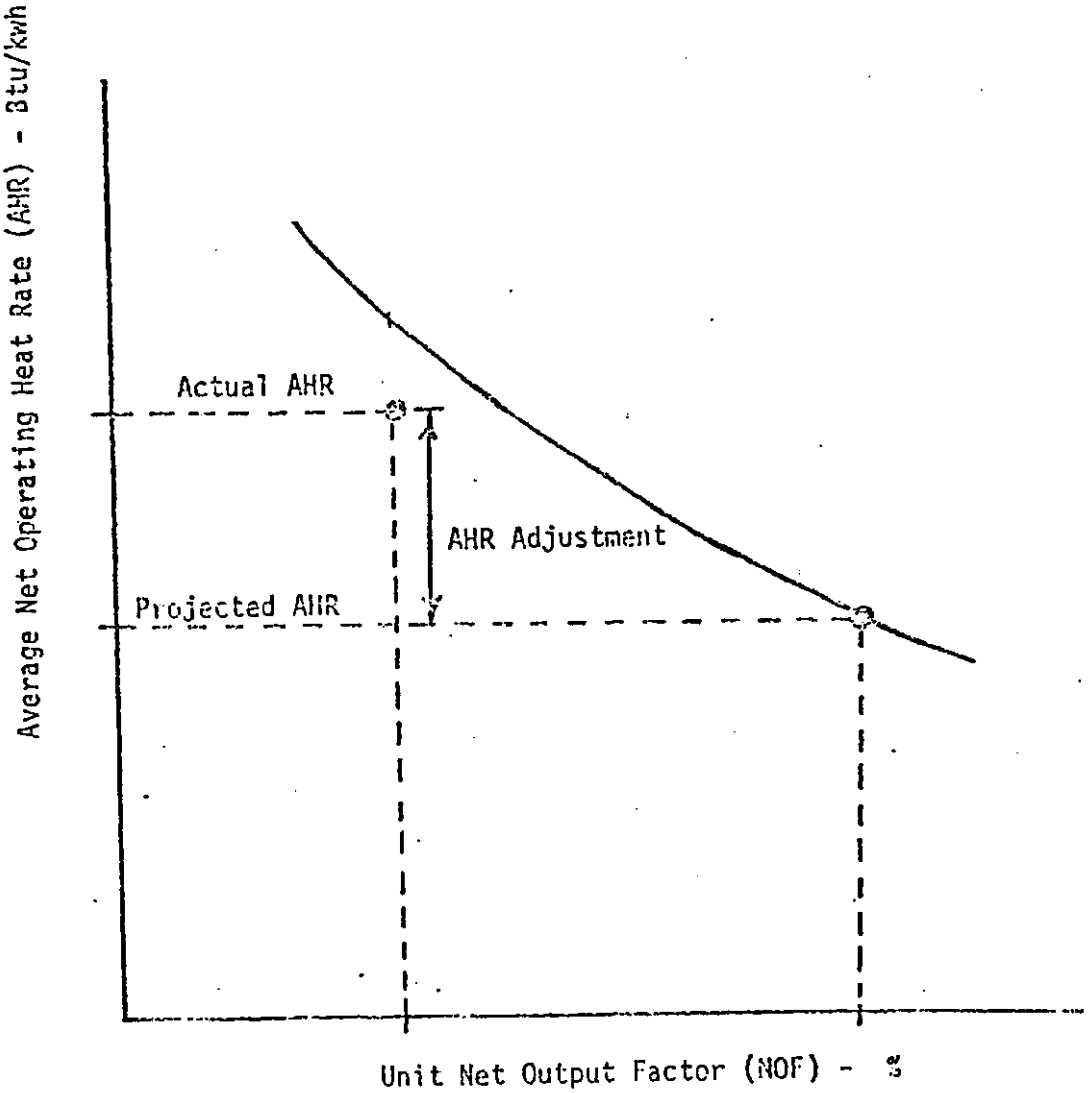
ADJUSTMENTS TO AVERAGE HEAT RATE

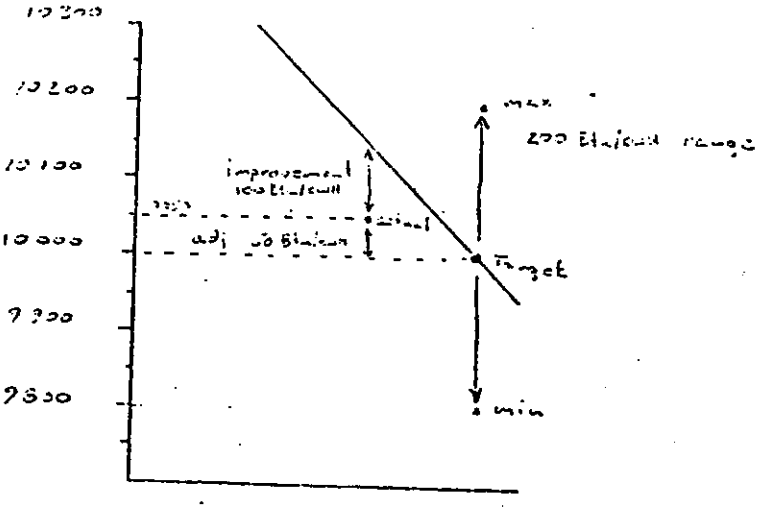
Since performance targets are set prospectively in the GPIF, certain circumstances may arise during the six month period which warrant adjustments to be made in the final GPIF calculation. Adjustments to the average heat rate performance indicator are necessary to reflect changes in the economic dispatch of units during the period due to conditions not anticipated in advance. Table 1 illustrates the method for calculating the average heat rate adjustment.

First, historic average net operating heat rate vs. unit net output factor[2] curves are developed for each unit under review in the GPIF. The average heat rate performance target for the period as calculated by the production costing simulation of system operation is then located on this curve. At the end of the period the actual average heat rate is plotted. The adjustment to the average heat rate performance indicator is computed as the vertical distance between the actual average heat rate and the target average heat rate at the actual net output factor for the period.

(2) Unit net output factor is defined as net generation divided by the product of service hours times net continuous rating.

AVERAGE HEAT RATE VS. NET OUTPUT FACTOR





$$AHRP = \frac{100}{200} = .5 \quad \text{(from graph)}$$

$$\frac{AHR(\text{target}) - AHR(\text{actual}) \pm AHR(\text{adj})}{AHR(\text{target}) - AHR(\text{min})} \qquad \text{(from formula)}$$

$$\frac{10\,000 - 10{,}050 + 50}{10{,}000 - 9800} = \frac{10{,}000 - 10{,}100}{-200} = \frac{-100}{-200} = .5$$

III. PERFORMANCE TARGETS AND RANGES

EQUIVALENT AVAILABILITY PERFORMANCE TARGETS

EQUIVALENT AVAILABILITY IMPROVEMENT/DEGRADATION RANGES

AVERAGE HEAT RATE PERFORMANCE TARGETS

AVERAGE HEAT RATE IMPROVEMENT/DEGRADATION RANGES

Each company subject to the GPIF incentive provision will submit for Commission review and approval suggested methodologies for establishing performance targets and ranges for each unit considered in the GPIF.

IV. STANDARD REPORTS AND DATA REQUIREMENTS

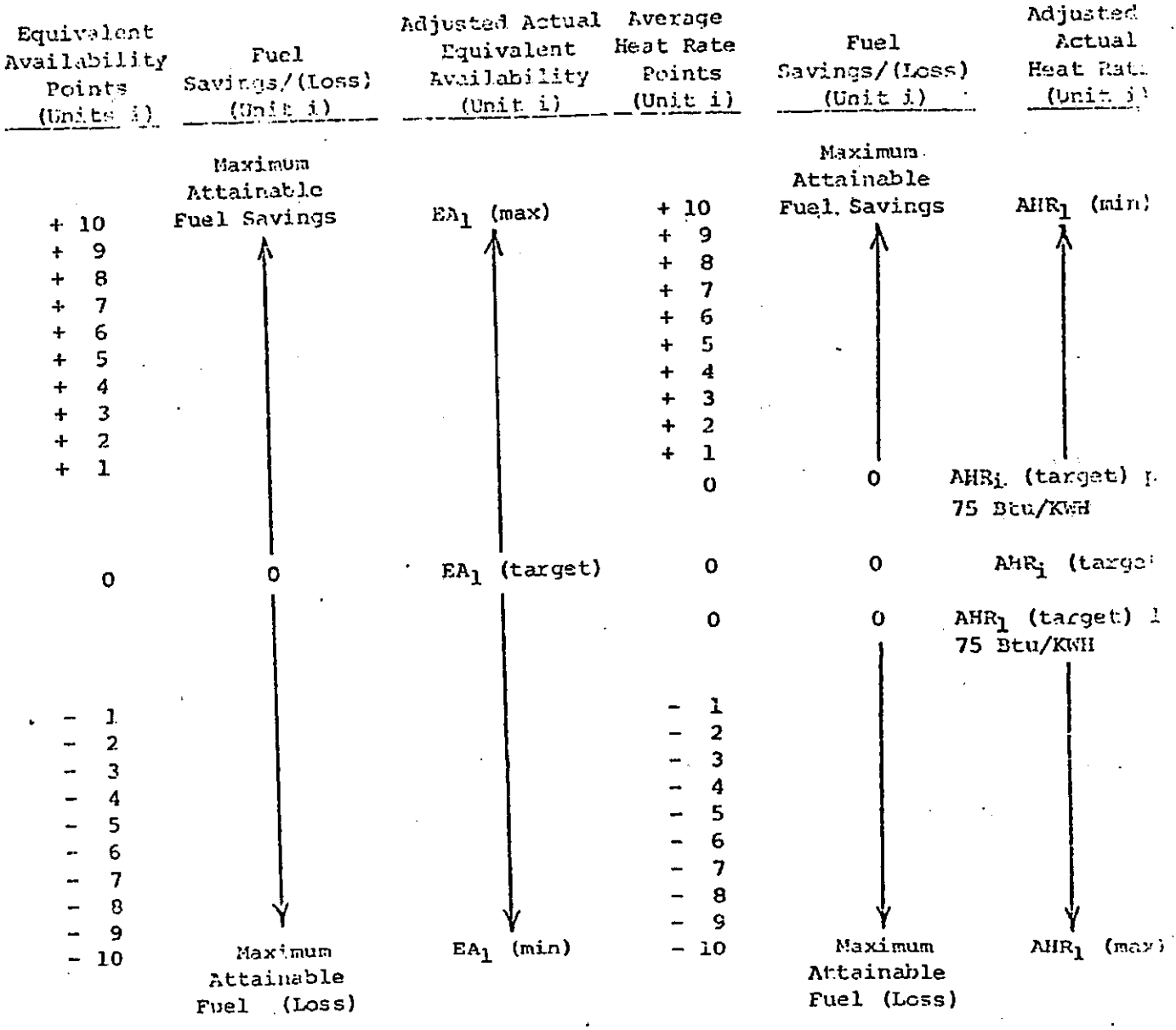
GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

Generating Performance Incentive Points (GPIP)	Fuel Savings/(Loss) ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10		
+ 9		
+ 8		
+ 7		
+ 6		
+ 5		
+ 4		
+ 3		
+ 2		
+ 1		
0	0	0
- 1		
- 2		
- 3		
- 4		
- 5		
- 6		
- 7		
- 8		
- 9		
- 10	Maximum Attainable Fuel (Loss)	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

GENERATING PERFORMANCE INCENTIVE POINTS

TABLE



Weighting Factor: a_i

Weighting Factor: e_i

Engineering by: GI
8/1/80

PEAK RESPONSE DATA

COMPANY: _____

MONTH/PERIOD: _____

	Plant/Unit:							
1	Equivalent Av. Maint. Factor = %							
2	Net Output Factor = %							
3	Avg. Net Op. Hr. Heat Rate = BTU/KWH							
4								
5	Period Hours							
6	Service Hours							
7	Reserve Shutdown Hours							
8	Unavailable Hours							
9								
10	Forced Outage Hours							
11	Partial FOH							
12	Avg. FOH Load Reduction = MW							
13								
14	Maintenance Outage Hours							
15	Partial MOH							
16	Avg. MOH Load Reduction = MW							
17								
18	Planned Outage Hours							
19								
20	Net Cont. Summer Rating = MW							
21								
22	Operating Req'd Furnace MWH							
23	Net Generation MWH							
24	Net Cont. Period Rating MW							
25								
26								
27								
28								
29								
30								

Form 423-1 (1)

UNIT INFORMATION DATA

COMPANY: _____

MONTH/PERIOD: _____

	Plant/Unit:							
1	Equivalent Avail. Factor - %							
2	Net Output Factor - %							
3	Ave Net Operat. Heat Rate - BTU/KWH							
4								
5	Period Hours							
6	Service Hours							
7	Reserve Shutdown Hours							
8	Unavailable Hours							
9								
10	Forse Outage Hours							
11	Partial FOH							
12	Avg. FOH Load Reduction - MW							
13								
14	Maintenance Outage Hours							
15	Partial MOH							
16	Avg. MOH Load Reduction - MW							
17								
18	Planned Outage Hours							
19								
20	Net Cont. Summer Rating - MW							
21								
22	Operating Hrs's Turbine - HRS							
23	Net Generation - MWH							
24	Net Cont. Period Rating - MW							
25								
26								
27								
28								
29								
30								

Company: _____

Engineering E1
Page 2 of 4
4/1/80

UNIT OUTAGE DATA

Month/Period of: _____

Plant/Unit:

Date	Type (1)	Hours	If Derated	Description

(1) FFO - Full Forced Outage
PFO - Partial Forced Outage
FMO - Full Maintenance Outage
PMO - Partial Maintenance Outage
PO - Planned Outage

Schedule A1
Revised 5/1/80

PLANT PERFORMANCE DATA

COMPANY: _____

MONTH/PERIOD: _____

	Plant/Unit:							
1	Equivalent Availability Factor - %							
2	Net Output Factor - %							
3	Ave. Net Operating Heat Rate - BTU/KWH							
4								
5	Period Hours							
6	Service Hours							
7	Reserve Shutdown Hours							
8	Unavailable Hours							
9								
10	Forced Outage Hours							
11	Partial FOH							
12	Avg. FOH Load Reduction - MW							
13								
14	Maintenance Outage Hours							
15	Partial MOH							
16	Avg. MOH Load Reduction - MW							
17								
18	Planned Outage Hours							
19								
20	Net Cont. Summer Rating - MW							
21								
22	Operating Hours Burned - MBTU							
23	Net Generation - MWH							
24	Net Cont. Period Rating - MW							
25								
26								
27								
28								
29								
30								

Company: _____

For the month of: All
Page 1 of 1
4/1/80

Unit 2 of 2

Month/Period of: _____

Plant, Unit:

Date	Type (1)	Hours	MW Affected	Description

(1) FFO - Full Forced Outage
PFO - Partial Forced Outage
FMO - Full Maintenance Outage
PMO - Partial Maintenance Outage
FO - Planned Outage

Company:_____

ACCOUNTING
SCHEDULE A

GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF AVERAGE COMMON EQUITY
For The Period _____,198_ to _____,198_

Beginning of the period balance	$
End of the month balances:	
Month of _____,198_	$
Month of _____,198_	$
Month of _____,198_	$
Month of _____,198_	$
Month of _____,198_	$
Month of _____,198_	$
Total	$
	÷ 7
Average Common Equity for the Period	$

"2001 - 2002 GPIF Reward / Penalty Amount"

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 64
COMPANY/ OPC
WITNESS. Knapp late-filed depo. exhib.
DATE 11-08-04

GPIF Reward / Penalty Amount	
2001	$831,029 penalty
2002	$2,496,021 penalty

"2004 Year-to-Date GPIF Performance"

Tampa Electric's 2004 GPIF performance, based on January through September actual results and projected October through December performance, is currently estimated to be a reward of $61,806. The actual reward/penalty amount for January through December 2004 will vary from this estimate.

"1998 – 2004 Actual Equivalent Availability Factors"

GPIF Unit Equivalent Availability Factors

2004 YTD

	Big Bend Unit 1	Big Bend Unit 2	Big Bend Unit 3	Big Bend Unit 4	Polk Unit 1
Jan-04	14.4	73.3	96.4	81.1	95.0
Feb-04	2.2	88.5	62.7	87.9	71.8
Mar-04	94.6	56.8	59.3	96.7	87.4
Apr-04	78.3	56.3	86.9	65.0	98.4
May-04	61.8	80.7	57.8	87.6	95.2
Jun-04	79.2	66.6	83.8	89.5	89.2
Jul-04	65.4	52.7	67.8	88.8	84.2
Aug-04	79.8	73.8	73.8	85.7	91.3
Sep-04	54.4	91.7	75.8	50.1	90.3

EXHIBIT NO. _____ (WAS-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 040001 - EI
DOCUMENT NO. 1
Page 6 OF 32

TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2003 - DECEMBER 2003

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS (1) TO EAF (%)	EAF JAN 03 - DEC 03 ACTUAL (%)
BIG BEND 1	64.7	-3.5	61.2
BIG BEND 2	60.2	-2.1	58.1
BIG BEND 3	62.4	-2.3	60.1
BIG BEND 4	71.3	0.7	72.0
GANNON 5	78.4	-0.1	78.3
GANNON 6	63.2	0.0	63.2
POLK 1	68.4	-0.9	67.5

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS (2) TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
BIG BEND 1	10,968	-84	10,884
BIG BEND 2	10,623	-101	10,522
BIG BEND 3	11,030	-352	10,678
BIG BEND 4	10,662	-365	10,297
GANNON 5	11,425	-25	11,400
GANNON 6	11,629	-29	11,600
POLK 1	10,665	-118	10,547

(1) Documentation of adjustments to Actual EAF on pages 7 - 13

(2) Documentation of adjustments to Actual ANOHR on pages 14 - 20

Source: Exhibit No. ___ (WAS-1) to the testimony of William A. Smotherman, filed on April 1, 2004, in Docket No. 040001-EI

EXHIBIT NO. _____ (WAS-1)
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001 - EI
DOCUMENT NO. 1
Page 6 OF 32

TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2002 - DECEMBER 2002

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS (1) TO EAF (%)	EAF ADJUSTED ACTUAL (%)
BIG BEND 1	70.7	0.4	71.1
BIG BEND 2	49.6	2.8	52.4
BIG BEND 3	53.2	0.6	53.8
BIG BEND 4	84.0	0.3	84.3
GANNON 5	61.0	4.2	65.2
GANNON 6	59.8	1.8	61.6
POLK 1	89.5	-4.9	84.6

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS (2) TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
BIG BEND 1	10,740	-221	10,519
BIG BEND 2	10,656	-258	10,398
BIG BEND 3	10,619	-344	10,275
BIG BEND 4	10,562	-74	10,488
GANNON 5	11,192	10	11,202
GANNON 6	11,040	152	11,192
POLK 1	10,725	-160	10,565

(1) Documentation of adjustments to Actual EAF on pages 7 - 13

(2) Documentation of adjustments to Actual ANOHR on pages 14 - 20

Source: Exhibit No. ___ (WAS-1) to the testimony of William A. Smotherman, filed on April 1, 2003, in Docket No. 030001-EI

TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2001 - DECEMBER 2001

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS (1) TO EAF (%)	EAF ADJUSTED ACTUAL (%)
BIG BEND 1	63.3	0.6	63.9
BIG BEND 2	73.3	0.1	73.4
BIG BEND 3	75.7	-4.4	71.3
BIG BEND 4	78.1	4.2	82.3
GANNON 5	58.3	2.9	61.2
GANNON 6	74.6	0.4	75.0
POLK 1	86.4	-3.6	82.8

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS (2) TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
BIG BEND 1	10717	-187	10530
BIG BEND 2	10289	-210	10079
BIG BEND 3	10397	-480	9917
BIG BEND 4	10382	-185	10197
GANNON 5	10763	27	10790
GANNON 6	10595	-26	10569
POLK 1	10725	-471	10254

(1) Documentation of adjustments to Actual EAF on pages 7 - 13

(2) Documentation of adjustments to Actual ANOHR on pages 14 - 20

Source: Exhibit No. ___ (WAS-1) to the testimony of William A. Smotherman, filed on April 1, 2002, in Docket No. 020001-EI

TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2000 - DECEMBER 2000

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS (1) TO EAF (%)	EAF ADJUSTED ACTUAL (%)
BIG BEND 1	75.8	-1.5	74.3
BIG BEND 2	85.6	-2.4	83.2
BIG BEND 3	75.0	4.6	79.6
BIG BEND 4	87.8	-1.7	86.1
GANNON 5	55.6	1.6	57.2
GANNON 6	33.2	-5.0	28.2

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS (2) TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
BIG BEND 1	10231	-140	10091
BIG BEND 2	9925	-114	9811
BIG BEND 3	9866	-25	9841
BIG BEND 4	9896	-97	9799
GANNON 5	10748	18	10766
GANNON 6	10501	28	10529

(1) Documentation of adjustments to Actual EAF on pages 7 - 12

(2) Documentation of adjustments to Actual ANOHR on pages 13 - 18

Source: Exhibit No. ___ (BSB-1) to the testimony of Brian S. Buckley, filed on April 2, 2001, in Docket No. 010001-EI

TAMPA ELECTRIC COMPANY
DOCKET NO. 000001-EI
SUBMITTED FOR FILING: 04/03/00
(TRUE-UP)
REVISED: 04/14/00

FINAL SHEET NO. 8.401.99A
PAGE 6 OF 29

TAMPA ELECTRIC COMPANY
ACTUAL UNIT PERFORMANCE DATA
JANUARY 1999 - DECEMBER 1999

PLANT / UNIT	ACTUAL EAF %	ADJUSTMENTS (1) EAF %	EAF ADJUSTED ACTUAL %
GANNON 5	69.4	2.5	71.9
GANNON 6	56.2	7.2	63.4
BIG BEND 1	78.9	-1.5	77.4
BIG BEND 2	81.4	-0.3	81.1
BIG BEND 3	65.2	3.3	68.5
BIG BEND 4	73.0	6.1	79.1

PLANT / UNIT	ACTUAL ANOHR Btu/kwh	ADJUSTMENTS (2) TO ANOHR Btu/kwh	ANOHR ADJUSTED ACTUAL Btu/kwh
GANNON 5	11029	-359	10670
GANNON 6	10971	-125	10846
BIG BEND 1	10236	-153	10083
BIG BEND 2	10072	-89	9983
BIG BEND 3	10006	-180	9826
BIG BEND 4	10211	-197	10014

(1) Documentation of adjustments to Actual EAF on pages 7 - 12

(2) Documentation of adjustments to Actual ANOHR on pages 13 - 18

Source: Exhibit No. ___ (BSB-1) to the testimony of Brian S. Buckley, filed on April 3, 2000, in Docket No. 000001-EI

OF `INAL SHEET NO. 7.401.99A
PAGE 6 OF 28

TAMPA ELECTRIC COMPANY
ACTUAL UNIT PERFORMANCE DATA
OCTOBER 1998 - DECEMBER 1998

PLANT / UNIT	ACTUAL EAF %	ADJUSTMENTS (1) EAF %	EAF ADJUSTED ACTUAL %
GANNON 5	62.3	9.2	71.5
GANNON 6	68.6	-0.0	68.6
BIG BEND 1	55.4	-0.1	55.3
BIG BEND 2	76.9	0.0	76.9
BIG BEND 3	79.6	0.0	79.6
BIG BEND 4	61.6	1.9	63.5

PLANT / UNIT	ACTUAL ANOHR Btu/kwh	ADJUSTMENTS (2) TO ANOHR Btu/kwh	ANOHR ADJUSTED ACTUAL Btu/kwh
GANNON 5	10166	-247	9919
GANNON 6	10399	-129	10270
BIG BEND 1	10487	-38	10449
BIG BEND 2	10335	-35	10300
BIG BEND 3	10231	-264	9967
BIG BEND 4	9794	-100	9694

(1) Documentation of adjustments to Actual EAF on pages 7 - 12

(2) Documentation of adjustments to Actual ANOHR on pages 13 - 18

Source: Exhibit No. ___ (CTAH-1) to the testimony of Chonta T. A. Haynes, filed on April 1, 1999, in Docket No. 990001-EI

TAMPA ELECTRIC COMPANY
ACTUAL UNIT PERFORMANCE DATA
APRIL 1998 - SEPTEMBER 1998

PLANT / UNIT	ACTUAL EAF %	ADJUSTMENTS (1) EAF %	EAF ADJUSTED ACTUAL %
GANNON 5	84.2	0.0	84.2
GANNON 6	82.0	-6.2	75.8
BIG BEND 1	85.5	-6.5	79.0
BIG BEND 2	67.8	17.8	85.6
BIG BEND 3	71.4	-7.1	64.3
BIG BEND 4	89.2	0.0	89.2

PLANT / UNIT	ACTUAL ANOHR Btu/kwh	ADJUSTMENTS (2) TO ANOHR Btu/kwh	ANOHR ADJUSTED ACTUAL Btu/kwh
GANNON 5	10475	-154	10321
GANNON 6	10540	103	10643
BIG BEND 1	10225	-108	10117
BIG BEND 2	10101	-131	9970
BIG BEND 3	10228	-329	9899
BIG BEND 4	10074	-189	9885

(1) Documentation of adjustments to Actual EAF on pages 7 - 12

(2) Documentation of adjustments to Actual ANOHR on pages 13 - 18

Source: Supplemental Testimony and Exhibit No. ___ (CTAH-1) of Chonta T. A. Haynes, filed on July 9, 1999, in Docket No. 990001-EI

ORIGINAL SHEET NO. 7.401.98A
PAGE 6 OF 28

TAMPA ELECTRIC COMPANY
ACTUAL UNIT PERFORMANCE DATA
OCTOBER 1997 - MARCH 1998

PLANT / UNIT	ACTUAL EAF %	ADJUSTMENTS (1) EAF %	EAF ADJUSTED ACTUAL %
GANNON 5	53.6	9.9	63.5
GANNON 6	63.6	9.0	72.6
BIG BEND 1	82.7	-6.4	76.3
BIG BEND 2	77.3	-1.6	75.7
BIG BEND 3	80.4	-9.2	71.2
BIG BEND 4	92.2	-10.7	81.5

PLANT / UNIT	ACTUAL ANOHR Btu/kwh	ADJUSTMENTS (1) TO ANOHR Btu/kwh	ANOHR ADJUSTED ACTUAL Btu/kwh
GANNON 5	10759	-155	10604
GANNON 6	10472	-19	10453
BIG BEND 1	10083	-85	9998
BIG BEND 2	10103	-110	9993
BIG BEND 3	10069	-283	9786
BIG BEND 4	10025	-14	10011

(1) Documentation of adjustments to Actual EAF on pages 7 - 12

(1) Documentation of adjustments to Actual ANOHR on pages 13 - 18

Source: Exhibit No. ___ (GAK-1) to the testimony of George A. Keselowsky, filed on May 20, 1998, in Docket No. 980001-EI

GPIF REWARDS/PENALTIES
January 2003 to December 2003

Utility	Amount	Reward/Penalty
Florida Power and Light Company	$ 6,615,282	Reward
Gulf Power Company	$ 625,280	Reward
Progress Energy Florida	$ 2,139,695	Reward
Tampa Electric Company	$ 3,678,414	Penalty

Utility/ Plant/Unit	EAF		Heat Rate	
FPL	Target	Adjusted Actual	Target	Adjusted Actual
Cape Canaveral 2	89.5	89.5	9,030	9,044
Fort Lauderdale 4	91.7	93.3	7,435	7,454
Fort Lauderdale 5	90.3	92.7	7,366	7,416
Manatee 2	87.7	91.1	9,862	9,888
Martin 1	91.8	95.9	9,546	9,453
Martin 2	83.5	86.9	9,590	9,534
Martin 3	92.8	77.0	6,829	7,009
Martin 4	93.8	88.1	6,753	6,903
Turkey Point 1	85.1	86.3	9,128	9,191
Turkey Point 2	94.9	93.3	9,512	9,424
Turkey Point 3	85.4	88.0	11,148	11,084
Turkey Point 4	85.4	91.8	11,119	11,132
St. Lucie 1	93.6	100.0	10,834	10,824
St. Lucie 2	85.4	85.6	10,843	10,878
Scherer 4	93.6	93.9	9,992	9,958
Gulf	Target	Adjusted Actual	Target	Adjusted Actual
Crist 4	91.2	92.3	10,591	10,780
Crist 5	89.8	91.4	10,418	10,529
Crist 6	84.3	89.4	10,501	10,400
Crist 7	79.5	89.5	10,150	10,207
Smith 1	86.8	83.2	10,029	10,300
Smith 2	67.8	69.3	10,113	10,103
Daniel 1	70.1	73.4	10,042	9,821
Daniel 2	83.0	89.2	9,789	9,634
PEF	Target	Adjusted Actual	Target	Adjusted Actual
Anclote 2	89.8	90.1	10,091	10,179
Crystal River 1	90.8	91.3	9,742	9,965
Crystal River 2	62.6	70.1	9,566	9,672
Crystal River 3	89.0	89.5	10,327	10,249
Crystal River 4	91.6	96.8	9,323	9,341
Crystal River 5	94.6	95.5	9,340	9,391
Hines 1	85.8	86.6	7,259	7,314

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO 65
COMPANY/ OPC
WITNESS. Attachment to Prehearing Order
DATE: 11-08-04

GPIF REWARDS/PENALTIES
January 2003 to December 2003

Utility/ Plant/Unit	EAF		Heat Rate	
	Target	Adjusted Actual	Target	Adjusted Actual
TECO				
Big Bend 1	69.9	61.2	10,533	10,884
Big Bend 2	63.0	58.1	10,111	10,522
Big Bend 3	67.3	60.1	10,132	10,678
Big Bend 4	77.7	72.0	10,028	10,297
Gannon 5	71.9	78.3	10,862	11,400
Gannon 6	75.9	63.2	10,775	11,600
Polk 1	74.6	67.5	10,382	10,547

GPIF TARGETS
January 2005 to December 2005

Utility/ Plant/Unit	EAF	Company POF	EUOF	Staff	Heat Rate Company	Staff
FPL						
Lauderdale 4	92.7	3.3	4.0	Agree	7,515	Agree
Lauderdale 5	75.5	19.7	4.8	Agree	7,511	Agree
Manatee 1	74.6	20.5	4.9	Agree	10,274	Agree
Manatee 2	96.0	0.0	4.0	Agree	10,248	Agree
Martin 1	76.0	17.3	6.7	Agree	9,994	Agree
Martin 2	92.9	0.0	7.1	Agree	9,964	Agree
Martin 3	92.2	0.8	7.0	Agree	6,977	Agree
Martin 4	92.5	2.5	5.0	Agree	6,926	Agree
Scherer 4	95.5	0.0	4.5	Agree	10,151	Agree
St Lucie 1	77.2	16.4	6.4	Agree	10,846	Agree
St Lucie 2	93.6	0.0	6.4	Agree	10,866	Agree
Turkey Point 3	93.6	0.0	6.4	Agree	11,043	Agree
Turkey Point 4	75.8	17.8	6.4	Agree	11,078	Agree
		Company		Staff	Company	Staff
Gulf	EAF	POF	EUOF			
Crist 4	98.8	0.0	1.2	Agree	10,610	Agree
Crist 5	96.9	0.0	3.1	Agree	10,548	Agree
Crist 6	72.9	19.7	7.4	Agree	10,416	Agree
Crist 7	70.9	21.6	7.5	Agree	10,340	Agree
Smith 1	90.0	8.2	1.8	Agree	10,273	Agree
Smith 2	72.2	19.7	8.1	Agree	10,213	Agree
Daniel 1	79.0	17.3	3.7	Agree	9,953	Agree
Daniel 2	88.2	8.2	3.6	Agree	9,742	Agree
		Company		Staff	Company	Staff
PEF	EAF	POF	EUOF			
Anclote 1	94.7	0.0	5.3	Agree	10,117	Agree
Anclote 2	94.9	0.0	5.1	Agree	10,128	Agree
Crystal River 1	92.4	0.0	7.6	Agree	9,921	Agree
Crystal River 2	85.7	0.0	14.3	Agree	9,662	Agree
Crystal River 3	90.5	7.7	1.8	Agree	10,298	Agree
Crystal River 4	89.6	5.8	4.7	Agree	9,342	Agree
Crystal River 5	90.1	6.3	3.6	Agree	9,390	Agree
Hines 1	89.0	7.7	3.4	Agree	7,317	Agree
Tiger Bay	91.4	3.8	4.8	Agree	7,903	Agree
		Company		Staff	Company	Staff
TECO	EAF	POF	EUOF			
Big Bend 1	52.6	15.3	32.0	Agree	10,853	Agree
Big Bend 2	61.6	3.8	34.5	Agree	10,672	Agree
Big Bend 3	60.6	3.8	35.6	Agree	10,663	Agree
Big Bend 4	78.7	3.8	17.5	Agree	10,350	Agree
Polk 1	79.8	3.8	16.5	Agree	10,342	Agree

Exh. 66

Florida Power & Light Company
Docket No. 040001-EI
Churbuck's First Set of Interrogatories
Question No. 36
Page 1 of 1

Q.
Why were all three contracts linked together for the purpose of seeking Commission approval, specifically as testified to by Mr. Hartman, "termination of any one contract required the termination of all three contracts?" Who negotiated this point?

A.
The three contracts, while nominally independent, were executed as a package deal. FPL was unwilling to just have the capacity and energy of the Harris and Franklin facilities, without the Scherer facility. Conversely, Southern was unwilling to just have a contract for the Scherer facility, without the contracts for their gas facilities. Therefore, selecting only portions of the package was unacceptable to at least one of the parties to the agreements, no matter what combination was chosen. Tom Hartman was the key negotiator on this point.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO 66
COMPANY/ FPL Response To Churchuck 1st Set of Interrogatories
WITNESS.
DATE: 11-08-04

Q.
What percentage of FPL's present generation portfolio does a purchase power agreement for 165 MW of energy and capacity represent?

A.
Schedule 1 of FPL's 2004 Ten Year Power Plant Site Plan 2004 - 2013 presents all of FPL's generation units and shows that this generation portfolio represents a total of 19,056 MW (Summer) capacity. A power purchase agreement for 165 MW represents 0.9% of this portfolio.

Q.

Describe all steps and identify all documents related to those efforts FPL took to assess the potential for meeting FPL's firm energy capacity needs represented by the PPAs by pursuing self-build options.

A.

FPL conducted an economic evaluation of the PPAs, a representative self-build option, and another proxy PPA that was based on a comparable bid submitted to FPL in response to FPL's 2003 RFP. The basic steps of the evaluation were: analyses of generation costs, analyses of potential arbitrage savings from off-peak purchases from the Southern system, analyses of transmission costs and impacts, and analyses of equity adjustments. Documents related to the economic evaluation were requested in FPL's response to Thomas K. Churbuck's First Set of Request for Production of Documents, No. 44. See FPL's objections filed on October 26, 2004.

Q.
Has SCSI communicated to you that the benefits you describe associated with the PPA's will not be available to you at any point in the future? If so, identify how that communication was made, the persons involved, the date of the communication and any documents associated with the communication.

A.
No, they have not. However, they also have not made any promise to keep these benefits available in the future for our customers except through these specific PPAs.

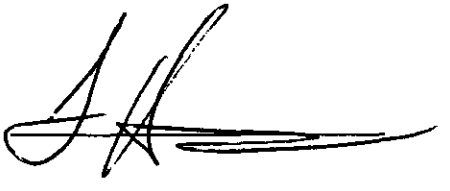
AFFIDAVIT

State of Florida)

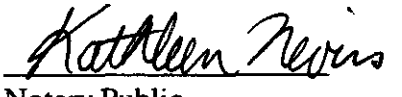
County of Palm Beach)

Before me, the undersigned authority, personally appeared Thomas L. Hartman, who first being duly sworn, deposes and states:

My name is Thomas L. Hartman. I am employed by Florida Power & Light Company (FPL) as Director of Business Management for Resource Assessment and Planning. I prepared or had prepared under my supervision and control FPL's response to Interrogatories Nos. 1 through 57 to Churbuck's First Set of Interrogatories to Florida Power & Light Company in Docket No. 040001-EI. This interrogatory response is true and correct to the best of my knowledge and belief.



Sworn to and subscribed before me this 20th day of October 2004, by Thomas L. Hartman, who is personally known to me.



Notary Public
State of Florida
Commission or Serial No.
My Commission Expires:

UNITED STATES OF AMERICA

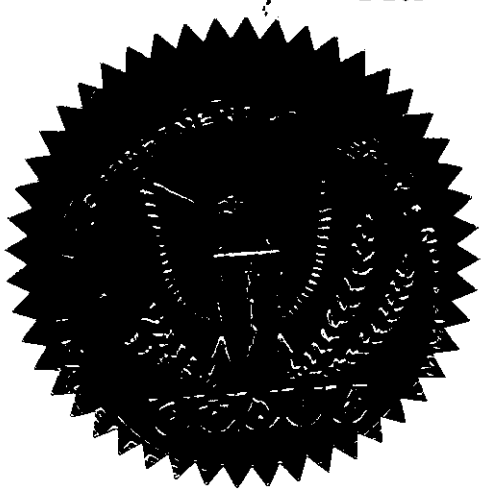
FEDERAL ENERGY REGULATORY COMMISSION

CERTIFICATION

I herby certify that the attached 7 pages are true and correct copies of a document on the file with the Commission.

11-3-2004
Date

Norma L. Anderson
Custodian



I herby certify that the Custodian or his designee, which signature appears above, is the official custodian of the records of the Federal Energy Regulatory Commission which certification is made and was such official custodian at the time of executing the above certification.

Magalie R. Salas
SECRETARY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 67
COMPANY/ F.E.R.C. 10-29-04
WITNESS. Letter to So. Company
DATE 11-08-04

20041029-3038 Issued by FERC OSEC 10/29/2004 in Docket#: ER97-4166-015

FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20426

In Reply Refer To:
Southern Company Energy Marketing, Inc. and
Southern Company Services, Inc.
Docket Nos. ER97-4166-015 and
ER96-780-005
October 29, 2004

Balch & Bingham LLP
1710 Sixth Avenue North
Birmingham, Alabama 35203-2015

Attn: Mr. Dan H. McCrary
Counsel for Southern Company Services, Inc.

Reference: Updated Market Power Analysis

Dear Mr. McCrary:

On August 9, 2004, you submitted for filing (compliance filing) with the Commission on behalf of Southern Company Services, Inc., acting as agent for Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, Savannah Electric and Power Company, and Southern Power Company (collectively, Southern Companies), revised generation market power screens in compliance with the Commission's orders issued on April 14, 2004 and July 8, 2004.[1] Please be advised that your submittal is deficient as described below.[2]

(1) The Commission Orders stated that uncommitted capacity is determined by adding the total nameplate capacity of generation owned or controlled through contract and firm purchases, less operating reserves, native load commitments and long-term firm

[1] *AEP Power Marketing, Inc., et al.*, 107 FERC ¶ 61,018 (April 14 Order), *order on reh'g*, 108 FERC ¶ 61,026 (2004) (July 8 Order) (collectively, Commission Orders).

[2] On August 27, 2004, you filed errata to the compliance filing, stating that the revisions are ministerial in nature.

20041029-3038 Issued by FERC OSEC 10/29/2004 in Docket#: ER97-4166-015

non-requirement sales.[3] Further, applicants are required to prepare the screens as designed.[4] You state that seasonal capacity data was used for the indicative screens. Please revise your submittal for Southern Companies' first-tier markets using nameplate capacity for all generating capacity used for calculation of the screens (including Southern Companies' capacity and competing suppliers' capacity), and submit the relevant work papers and documentation.

(2) Please provide justification for Southern Companies' reliance on seasonal capacity ratings as a more accurate representation of market conditions. Please discuss the rationale for using the seasonal ratings.

(3) Pages SC-7 and SC-8 of your August 9, 2004 submittal indicate that the Southern control area has been defined to include the control areas of Oglethorpe, AMEA and MEAG. Please separately state the generation and load data of each of these three entities utilized in the pivotal supplier and wholesale market share screens for the Southern control area.

(4) The Commission Orders stated that applicants are required to submit all data used to conduct the screens, including appropriate support and work papers.[5] Commission staff is unable to reproduce the results you submitted for each market share screen in the first-tier markets. Please provide documentation for the results and submit a detailed, step-by-step calculation of how Southern Companies developed the market shares in each market share screen in each first-tier market.

(5) You provided a simultaneous transmission import capability study. Southern Companies is directed to file all of the underlying data and work papers in electronic form supporting its first-tier import study required in the Appendix E of the April 14 Order.[6] Specifically, the information listed in Appendix A of this data request is needed

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[3] April 14 Order at P 95. Under the market share screen, planned outages may also be factored in during the three non-peak seasons.

[4] *Id.* at P 118.

[5] April 14 Order at Appendix G.

[6] April 14 Order at P 82-85 and Appendix E and July 8 Order at P 122-125.

20041029-3038 Issued by FERC OSEC 10/29/2004 in Docket#: ER97-4166-015

to support the results for the generation market power screens submitted for the first-tier control areas.[7]

(6) To the extent Southern Companies made a simplifying assumption in its simultaneous transmission import capability study submitted on August 9, 2004, or chooses to do so in its amended study as directed herein, please provide the analysis together with the rationale for making the simplifying assumption and all supporting work papers and documentation.[8] You are reminded that the Commission has determined that total transfer capability (TTC) alone is not an appropriate measure of the effect of transmission limitations on how much generation can be imported into the relevant geographic market and thus is not an acceptable proxy.

If Southern Companies chooses to submit the streamlined analysis that does not consider imports by competitors, the information requested in Appendix A as discussed in this data request need not be submitted.

(7) You failed to include revisions to Southern Companies' market-based rate tariffs incorporating the Commission's market behavior rules as required.[9] In the Market

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[7] Although Southern Companies' simultaneous transmission import capability study is similarly deficient for its home control area, Southern Companies is only directed to revise its import study for those markets where Southern Companies claims it passes the two indicative screens.

[8] For example, with respect to simultaneous transmission import capability, if an applicant can show that it passes the Commission's indicative screens for any geographic market without considering imports by competitors, no such simultaneous import analysis needs to be provided for that market (July 8 Order at P 124). Nevertheless, firm or network transmission reservations for the applicant's remote generation should be reflected in the simplified analysis so that uncommitted capacity from applicant's remote generation is included in the applicant's total uncommitted capacity amounts (*Id.* at P 45). This applies to transmission of the applicant's remote generation from first-tier markets into the applicant's control area as well as from the applicant's control area into a first-tier market when examining the applicant's potential for market power in the directly-interconnected first-tier markets (April 14 Order at P 95 and Appendix E).

[9] Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, 105 FERC ¶ 61,218 at Ordering Paragraph (A) (2003) (Market Behavior Rules Order).

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Behavior Rules Order, the Commission directed market-based rate sellers to include as an amendment to their market-based rate tariff the Commission's market behavior rules at such time as they seek continued authorization to sell at market-based rates. Therefore, you are directed to revise Southern Companies' tariffs to include the market behavior rules set forth in Appendix A to the Market Behavior Rules Order.

(8) Your filing included only a generation market power analysis and did not address the three other prongs of the Commission's four-part test to determine whether to grant public utilities market-based rate authority, namely transmission market power, barriers to entry and affiliate abuse/reciprocal dealing. Therefore, you are directed to file a demonstration that Southern Companies satisfies the Commission's concerns regarding transmission market power, barriers to entry, and affiliate abuse/reciprocal dealing.[10]

The information requested in this order will constitute an amendment to your filing. A notice of amendment will be issued upon receipt of your response. Accordingly, you are directed to submit a form of notice of amendment to the filing pursuant to section 35.8 of the Commission's regulations (18 C.F.R. § 35.8 (2004)).

This order is issued pursuant to the authority delegated to the Director, Division of Tariffs and Market Development – South, under 18 C.F.R. § 375.307(n)(2) and is interlocutory. This order is not subject to rehearing pursuant to 18 C.F.R. § 385.713 and a response to this order must be filed within twenty-one days of the date of this letter. Submit seven copies of your response to this deficiency order. Six copies of your response should be sent to:

Federal Energy Regulatory Commission
Office of the Secretary
888 First Street, N.E.
Washington, D.C. 20426

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[10] The Commission reserves the right to require such an analysis at any time. *Southern Company Energy Marketing, Inc.*, 81 FERC ¶ 61,099, n.11 (1997).

20041029-3038 Issued by FERC OSEC 10/29/2004 in Docket#: ER97-4166-015

The seventh copy should be sent to:

Federal Energy Regulatory Commission
Attn: Ms. Mary Elizabeth Tighe
Office of Markets, Tariffs, and Rates -South
888 First Street, N.E., Room 82-05
Washington, D.C. 20426

Sincerely,

Steve P. Rodgers, Director
Division of Tariffs and Market
Development – South

Appendix A

Regarding Southern Companies' Simultaneous Transmission Import Capability Study submitted on August 9, 2004 for first-tier markets, please provide the following:

1. Information and demonstrate that Southern Companies utilized this information to perform the Simultaneous Import Capability Study in conformance with the instructions in Appendix E of the Commission's April 14 Order:
   a) the stability transfer limits in effect for the applicable historical seasons and as applied to OASIS-posted transfer capabilities;
   b) the voltage transfer limits in effect for the applicable historical seasons and as applied to OASIS-posted transfer capabilities;
   c) the historical short-term network and firm reservations controlled by applicant and its affiliates utilized in the power flow cases submitted for each of the four seasonal peaks;
   d) the work papers and other documentation for historical short-term network and firm reservations controlled by applicant and its affiliates utilized in the power flow cases submitted for each of the four seasonal peaks;
   e) the historical operating limitations required by internal constraints imposed in real time upon both affiliated and non-affiliated generation resources during the historical seasonal peak periods;
   f) the work papers and other documentation supporting historical operating limitations imposed upon both affiliated and non-affiliated generation during the historical seasonal peak periods;
   g) the work papers and other documentation supporting all historical contingency scenarios used to manage OASIS-available transfer capability in assessing internal/external transmission availability;
   h) the work papers and other documentation supporting all historical monitored facilities used to manage OASIS-available transfer capability in assessing internal/external transmission availability;

2. Text-readable power flow, contingency, monitored facility, super area, and transaction files. (example file types: .raw, .sup, .mon, .con, .tra, and .trn). The response to this question may be filed under the protection of Critical Energy Infrastructure Information, 18 CFR § 388.113(c) (1) (2000).

3. The simultaneous import capability base cases for each of the four seasonal/historical peaks in text-readable (PSSE or .raw) format and provide text-readable output of the FCITC calculations. The response to this question may be filed under the protection of Critical Energy Infrastructure Information, 18 CFR § 388.113(c) (1) (2000).

20041029-3038 Issued by FERC OSEC 10/29/2004 in Docket#: ER97-4166-015

4. Support the allocation to Southern Companies of zero import capability into all first-tier markets during the fall season (i.e. zero exports of capacity from Southern Companies' home control area into Southern Companies first-tier markets).

5. Support the allocation to Southern Companies of zero import capability into the markets of Cajun Electric Cooperative, Inc., and South Mississippi Electric Power Association for all seasons.

CTR

Florida Power & Light Company, 215 S. Monroe St., Suite 810, Tallahassee, FL 32301
R. Wade Litchfield
Attorney
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 691-7101
(561) 691-7135 (Facsimile)

ORIGINAL

November 12, 2004

RECEIVED-FPSC
04 NOV 12 PM 4:16
COMMISSION CLERK

orig for transcript

VIA HAND DELIVERY
Ms. Blanca S. Bayó, Director
Division of the Commission Clerk and
Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
2540 Shumard Oak Boulevard, Room 110
Tallahassee, FL 32399-0850

Re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor - FPSC Docket No. 040001-EI

Dear Ms. Bayó:

Enclosed for filing on behalf of Florida Power & Light Company ("FPL") is an original and fifteen (15) copies of FPL's late-filed exhibit number 68, a map of the units that are subject of the proposed Unit Power Sales Contracts between FPL and Southern Company.

Please indicate receipt of this document by stamping the enclosed extra copy of this letter. Please contact me should you or your Staff have any questions regarding this filing.

Sincerely,

Lynne D. Adams

for R. Wade Litchfield

CMP ____
COM 5
CTR org
ECR ____
GCL ____
OPC ____
MMS ____
RCA ____
SCR ____
SEC 1
OTH ____

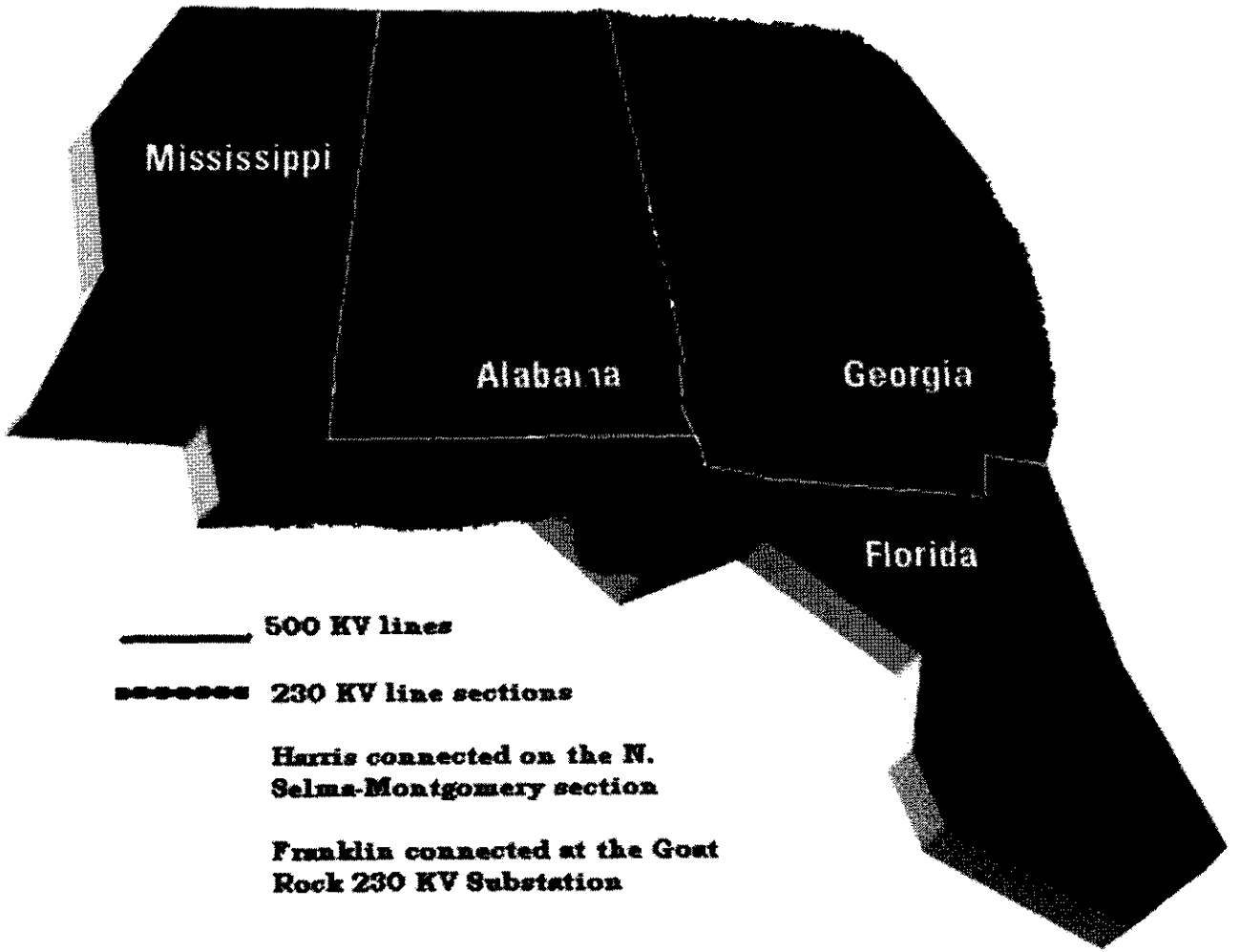
RWL:ec
Enclosures
cc: Parties of Record

RECEIVED & FILED
RUN
FPSC-BUREAU OF RECORDS

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 68
COMPANY/ F.P.+L. - T. Hartman
WITNESS. Map of Plant/Grid location
DATE: 11-08-04

DOCUMENT NUMBER-DATE
12134 NOV 12 ⁰⁴
FPSC-COMMISSION CLERK

UPS Existing & Proposed Plant Delivery Locations



Docket No. 040001-EI
FPL Witness T. Hartman
Late-Filed Exhibit No. 68
November 12, 2004

DOCUMENT NUMBER-DATE
12134 NOV 12 04
FPSC-COMMISSION CLERK

Southern Company Generation and Energy Marketing
270 Peachtree Street NW
Atlanta, Georgia 30303

SOUTHERN COMPANY
Energy to Serve Your World℠

August 11, 2004

Terry L. Morrison
Vice President, Energy Marketing and Trading
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Re: Contracts for the Purchase of Capacity and Energy and Plant Scherer

Dear Mr. Morrison:

On behalf of one or more of Georgia Power Company ("Georgia Power"), Gulf Power Company ("Gulf Power") and Southern Power Company ("Southern Power"), Southern Company Services, Inc. together with Florida Power & Light Company ("FPL") have entered into three (3) Contracts for the Purchase of Capacity and Energy described below (collectively the "PPAs"), each dated as of August 11, 2004. As used in this letter agreement, "SCS" means Southern Company Services, Inc. as agent for one or more of Georgia Power, Gulf Power and Southern Power.

1. Each of the PPAs involve the sale of capacity and energy to FPL beginning June 1, 2010 from a specified generation resource. Specifically, one PPA involves a portion of Plant Scherer Unit 3 owned by Georgia Power and Gulf Power ("Scherer PPA"), one PPA involves Southern Power's Franklin Unit 1 ("Franklin PPA"), and one PPA involves Southern Power's Harris Unit 1 ("Harris PPA"). Through this letter agreement, the parties desire to set forth their understanding regarding possible transactions involving capacity and energy from another portion of Plant Scherer Unit 3 in the event that such portion becomes available (under the circumstances described below) to SCS for making wholesale power transactions.

2. Georgia Power and Gulf Power are the owners of an additional portion of Plant Scherer Unit 3 that has a capacity of 75 MW and which is not involved in the Scherer PPA ("Additional Scherer Capacity").

[redacted]

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 040001-EI EXHIBIT NO. 69
COMPANY/ Right of First (Staff)
WITNESS. Refusal Agreement
DATE: 11-08-04

3. In the event that SCS finally determines in its sole discretion that the Third Party will not be obligated to purchase all or a substantial portion of the Additional Scherer Capacity under the Pending Transaction, SCS [redacted] determination provide FPL notice of such determination. Upon FPL's receipt of such notice, FPL shall [redacted] to notify SCS ("Scherer Notice") that it desires to purchase [redacted] the capacity and energy associated with the Additional Scherer Capacity that is not sold to the Third Party (such amount of the Additional Scherer Capacity is hereinafter referred to as the "Subject Scherer Capacity.")

4. If FPL provides the Scherer Notice in a timely manner, the parties shall [redacted] such notice execute a binding agreement in substantially the form of the Scherer PPA whereby SCS shall sell and FPL shall purchase all of the capacity and energy from the Subject Scherer Capacity (provided that any provisions conditioning the parties' obligations or the agreement on FPL's ability to obtain transmission service and/or regulatory approval shall not allow any party to terminate or otherwise modify any of the PPAs). In the event that FPL does not provide the Scherer Notice in a timely manner, SCS shall be entitled to sell such capacity and energy to any other party without restriction and shall have no further obligation to FPL regarding any portion of the Additional Scherer Capacity. In the event that the parties enter into an agreement for the purchase and sale of all of the capacity and energy associated with the Subject Scherer Capacity as contemplated in this letter agreement ("Second Scherer Agreement"), the parties shall negotiate to reduce the capacity and energy purchased by FPL on a megawatt for megawatt basis from the Franklin PPA (but if the Franklin PPA is no longer in effect, the Harris PPA). [redacted] In addition, if the amount of capacity purchased under the Franklin PPA and/or the Harris PPA is reduced, the parties shall negotiate to reach agreement on appropriate modifications to the terms of the affected PPA (including those pertaining to heat rate and scheduling requirements (as applicable) and appropriate pro rata reductions in the megawatt amounts in Section 7.4 of such PPA) that reflect the reduction in capacity purchased under that PPA. If the parties are unable to reach agreement on such modifications [redacted] after the Second Scherer Agreement is executed, the Second Scherer Agreement shall terminate and [redacted] the parties shall be obligated to sell and purchase the full amount of capacity and energy (prior to any reductions under this paragraph) under the PPAs as they were originally executed by the parties.

5. In the event that SCS finally determines in its sole discretion that the Third Party will be obligated to purchase all or a substantial portion of the Additional Scherer Capacity under the Pending Transaction, SCS shall provide FPL with written notice of the same and, upon such notice, this letter agreement shall immediately

terminate. Upon such termination, neither SCS nor any of its affiliates shall have any obligation to FPL hereunder with respect to the Additional Scherer Capacity or any portion thereof.

6. To the extent this letter agreement is not terminated as provided in paragraph 5 above, this letter agreement shall terminate upon the earlier to occur of: (i) the expiration and/or termination of both the Franklin PPA and the Harris PPA; (ii) the assignment by FPL of any of its rights or obligations under one or more of the PPAs to any other party; (iii) an Event of Default (as defined in the PPAs) under any PPA by FPL; or (iv) December 31, 2015. Upon such termination, no party shall have any further liability or obligation to the other under this letter agreement.

7. Any notice required under this letter agreement shall be in writing and shall be deemed provided when received. Facsimile (and the receipt thereof by the receiving party) shall be an acceptable form of notice; provided, however, that a paper copy of such notice must also be mailed to the receiving party on the day of such facsimile.

8. This letter agreement and the terms hereof shall be deemed to be Confidential Information under and as defined by the PPAs.

If the foregoing accurately reflects FPL's understanding, please sign your name on behalf of FPL in the space provided below.

Sincerely,

SOUTHERN COMPANY SERVICES, INC.

William N. McKenzie
Vice President, Business Development
As agent for
Georgia Power Company
Gulf Power Company
Southern Power Company

AGREED AND ACCEPTED

FLORIDA POWER & LIGHT COMPANY

By: Terry L. Morrison MAR 2010 PM
Name: Terry L. Morrison
Title: Vice President, Energy Marketing and Trading

Southern Company Generation
and Energy Marketing
270 Peachtree Street NW
Atlanta, Georgia 30303

SOUTHERN COMPANY
Energy to Serve Your World℠

August 11, 2004

Terry L. Morrison
Vice President, Energy Marketing and Trading
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Re: Contracts for the Purchase of Capacity and Energy and Plant Miller

Dear Mr. Morrison:

On behalf of one or more of Georgia Power Company ("Georgia Power"), Gulf Power Company ("Gulf Power") and Southern Power Company ("Southern Power"), Southern Company Services, Inc. together with Florida Power & Light Company ("FPL") have entered into three (3) Contracts for the Purchase of Capacity and Energy described below (collectively the "PPAs"), each dated as of August 11, 2004. As used in this letter agreement, "SCS" means Southern Company Services, Inc. as agent for one or more of Alabama Power Company ("Alabama Power"), Georgia Power, Gulf Power and Southern Power.

1. Each of the PPAs involve the sale of capacity and energy to FPL beginning June 1, 2010 from a specified generation resource. Specifically, one PPA involves a portion of Plant Scherer Unit 3 owned by Georgia Power and Gulf Power ("Scherer PPA"), one PPA involves Southern Power's Franklin Unit 1 ("Franklin PPA"), and one PPA involves Southern Power's Harris Unit 1 ("Harris PPA"). Through this letter agreement, the parties desire to set forth their understanding regarding possible transactions involving capacity and energy from portions of Alabama Power's Plant Miller in the event that such portions become available (under the circumstances described below) to SCS for making wholesale power transactions.

2. Alabama Power is the owner of Plant Miller Units 1 through 4 located in Jefferson County, Alabama. Currently, a portion of the capacity and associated energy from those units is being sold at wholesale to FPL, Florida Power Corporation and Jacksonville Electric Authority (such portion is referred to as the "Miller Capacity"). Beginning on June 1, 2010, it is Alabama Power's current intention to no longer make long term (i.e., greater than one (1) year) wholesale sales from the Miller Capacity[redacted]

[redacted]

3. However, in the event that Alabama Power finally determines in its sole discretion that it will sell a portion of the Miller Capacity at wholesale on a long term basis during any time from June 1, 2010 to December 31, 2015, then SCS shall [redacted] provide notice to FPL that Alabama Power has made such determination ("Miller Notice"). The portion of the Miller Capacity that Alabama Power determines to sell in this manner shall be referred to herein as the "Available Miller Capacity." The Miller Notice shall also specify the time period for which Alabama Power intends to sell such Available Miller Capacity at wholesale ("Sale Term"). Upon FPL's receipt of the Miller Notice, FPL shall have 30 days to notify SCS ("Miller Discussion Notice") that it desires to enter into discussions regarding the purchase of the lesser of [redacted]

4. If FPL does not provide the Miller Discussion Notice in a timely manner, SCS shall be free to market and sell the Subject Miller Capacity to any third party(ies) without restriction and without further obligation to FPL.

5. If FPL provides the Miller Discussion Notice in a timely manner, SCS shall engage in discussions exclusively with FPL for a period of 90 days after SCS receives the Miller Discussion Notice ("Miller Discussion Period") regarding a potential sale of all of the capacity and energy from all of the Subject Miller Capacity for a term equal to the Sale Term, but in no event beyond December 31, 2015 unless the parties mutually agree otherwise. In connection therewith, SCS shall provide FPL with SCS's proposal regarding the following terms for such sale: (i) capacity and energy prices; (ii) the charge for variable operation and maintenance costs; (iii) heat rate; and (iv) availability guarantees (such terms in (i) through (iv) are referred to as the "Specified Terms"); provided, however, neither party shall be required to enter into any agreement for the purchase or sale of the Subject Miller Capacity.

6. If the parties are unable to reach a mutually acceptable agreement during the Miller Discussion Period regarding such purchase and sale, SCS shall be free to market and sell the Subject Miller Capacity to other parties. Notwithstanding the foregoing sentence, however, for a period of [redacted] after the end of the Miller Discussion Period, before SCS sells some portion of the capacity and energy from the Subject Miller Capacity ("Marketed Portion") to any other party at Specified Terms materially more favorable in the aggregate than the Specified Terms previously offered to FPL (without regard to any other terms and conditions of a potential transaction) (such more favorable Specified Terms are referred to herein as the "Miller Specified Terms"), SCS shall first provide FPL the right to negotiate to purchase all of the capacity and energy from the Marketed Portion under the Miller Specified Terms for a term equal to

the Sale Term (but in no event beyond December 31, 2015 unless the parties mutually agree otherwise). However, in order to exercise such right to negotiate, FPL must provide SCS notice within [redacted] after receiving the Miller Specified Terms. If FPL timely provides such notice, SCS shall engage in such negotiations with FPL for a period [redacted] provided, however, neither party shall be required to enter into any agreement for the purchase or sale of the Subject Miller Capacity.

7. In the event that the parties enter into an agreement for the purchase and sale of capacity and energy from the Subject Miller Capacity as contemplated in this letter agreement ("Miller Agreement"), the parties shall negotiate to reduce the amount of capacity and energy purchased by FPL under the Franklin PPA and/or the Harris PPA during the term of the Miller Agreement by reducing such capacity and energy on a megawatt for megawatt basis first from the Franklin PPA and then from the Harris PPA. [redacted] In addition, if the amount of capacity purchased under the Franklin PPA and/or the Harris PPA is reduced, the parties shall negotiate to reach agreement on appropriate modifications to the terms of the affected PPA (including those pertaining to heat rate and scheduling requirements (as applicable) and appropriate pro rata reductions in the megawatt amounts in Section 7.4 of such PPA) that reflect the reduction in capacity purchased under that PPA. If the parties are unable to reach agreement on such modifications within [redacted] the Miller Agreement shall terminate and [redacted] the parties shall be obligated to sell and purchase the full amount of capacity and energy (prior to any reductions under this paragraph) under the PPAs as they were originally executed by the parties.

8. In the event that the parties do not reach a mutually acceptable agreement for the purchase and sale of capacity and energy from the Subject Miller Capacity as contemplated in this letter agreement, the PPAs will be unaffected.

9. This letter agreement shall immediately terminate upon the earlier to occur of: [redacted] Upon such termination, neither SCS nor any of its affiliates shall have any obligation to FPL hereunder with respect to the Miller Capacity or any portion thereof.

10. To the extent this letter agreement is not terminated as provided in paragraph 9 above, this letter agreement shall terminate upon the earlier to occur of: (i) the expiration and/or termination of both the Franklin PPA and the Harris PPA; (ii) the

assignment by FPL of any of its rights or obligations under one or more of the PPAs to any other party; (iii) an Event of Default (as defined in the PPAs) under any PPA by FPL; or (iv) December 31, 2015. Upon such termination, no party shall have any further liability or obligation to the other under this letter agreement.

11. Any notice required under this letter agreement shall be in writing and shall be deemed provided when received. Facsimile (and the receipt thereof by the receiving party) shall be an acceptable form of notice; provided, however, that a paper copy of such notice must also be mailed to the receiving party on the day of such facsimile.

12. This letter agreement and the terms hereof shall be deemed to be Confidential Information under and as defined by the PPAs.

If the foregoing accurately reflects FPL's understanding, please sign your name on behalf of FPL in the space provided below.

Sincerely,

SOUTHERN COMPANY SERVICES, INC.

William N. McKenzie
Vice President, Business Development
As agent for
Alabama Power Company
Georgia Power Company
Gulf Power Company
Southern Power Company

AGREED AND ACCEPTED

FLORIDA POWER & LIGHT COMPANY

By: _____
Name: Terry L. Morrison
Title: Vice President, Energy Marketing and Trading

Testimony of Dr. David E. Dismukes
Docket No. 040001-EI
Errata Sheet

Page 3, line 10:	"cost effect" should be "cost effective"
Page 11, line 4	"UNNCESSARILY" should be "Unnecessarily"
Page 12, line 9:	"Hartman Direct Testimony, 18:6" should be "Hartman Direct Testimony, 6:18"
Page 13, line 16-17:	"standard market assessment" should be "supply margin assessment"
Page 17, line 7:	"generation mix" should be "generation capacity mix"
Page 17, line 11:	"generating fuel mix" should be "generating capacity fuel mix"
Page 26, line 14:	"230" should be "245"

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 70
COMPANY/ FP+L/Moyle
WITNESS: Erratta Dismukes direct
DATE: 11-08-04

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 040001-EI EXHIBIT NO. 71
COMPANY/ FIPUG
WITNESS. Errata Sheet Krauth Direct
DATE 11-05-04

ERRATA SHEET

PRE-FILED TESTIMONY OF

KERRICK KNAUTH

PAGE & LINE NUMBER	ACTION	DESCRIPTION OF CHANGES OR DELETIONS
Page 5, Line 2	Delete	"Sam Waters and"
Page 5, Line 7 – 11	Delete	Lines 7 - 11.
Page 5, Line 12	Change	"Both utilities" to "FPL"
Page 5, Line 16	Delete	and Progress Energy
Page 5, Line 21	Change	"the" to "FPL"
Page 5, Line 21	Change	"1400" to "955"
Page 5, Line 22	Delete	"both" and "Progress Energy"
Page 5, Line 22	Change	"each" to "the"
Page 6, Line 2	Delete	Waters, page 6, lines 15-16
Page 6, Line 15-16	Delete	Waters
Page 6, Line 3	Change	"either utility" to "FPL"
Page 6, Line 10	Change	"neither utility" to "FPL has not"
Page 6, Line 11	Change	"both utilities are" to "FPL is"
Page 6, Line 15	Change	"are the utilities" to "is FPL"
Page 6, Line 18	Change	"Have the utilities" to "Has FPL"
Page 8, Line 13-22	Delete	Lines 13 - 22.
Page 9, Line 1 -2	Delete	Lines 1 – 2.
Page 9, Line 5	Change	"witnesses" to "witness"
Page 9, Line 5	Delete	"and Progress Energy"
Page 9, Line 5	Change	"claim" to "claims"
Page 9, Line 13	Change	"witnesses" to "witness"
Page 9, Line 13	Change	"stress" to "stresses"
Page 9, Line 19	Change	"either utility" to "FPL"
Page 9, Line 22	Delete	"and Progress Energy"
Page 9, Line 23	Change	"offer" to "offers"
Page 10, Line 2	Change	"utilities ask" to "FPL asks"

ERRATA SHEET

PRE-FILED TESTIMONY OF

KERRICK KNAUTH

Page 10, Line 6 – 15	Delete	Lines 6 – 15
Page 10, Line 18	Delete	"Progress Energy and"
Page 11, Line 9	Delete	"Progress Energy or"
Page 12, Line 2	Delete	"Progress Energy and/or"
Page 13, Line 6	Delete	"Progress Energy and"
Page 13, Line 6	Change	"propose" to "proposes"
Page 13, Line 13	Delete	"and 425 megawatts for Progress Energy"
Page 13, Line 17	Delete	"and Progress Energy"
Page 13, Line 17	Change	"make" to "makes"
Page 14, Line 3	Delete	"and Progress Energy"

EXH. 72

Deletions from Vogt Testimony

Page 3, lines 14-15: delete "and Progress Energy."

Page 4, line 1: delete "and Progress Energy"; change "seek" to "seeks"

Page 5 – 6: delete lines 15-22 through page 6, lines 1-2

Page 6, line 3: delete "both witnesses" and replace with "the FPL witness"
line 9: delete "and Progress Energy"

Page 7: delete lines 11 (beginning with Progress) - line 13 (ending with parties)

Page 8, line 3: delete "Neither" "nor Progress Energy", change "have" to "has not"
line 15: delete "and Progress Energy"
line 18: delete "and Progress Energy", change "Do" to "Does"

Page 8 – 9: delete lines 21 (beginning with "The testimony...") through page 9, line 9

Page 10, line 3: delete "and Progress Energy"; change "witnesses" to "witness"
line 15: delete: "and Progress Energy"; change "their" to "its"

Page 11, line 1: "Both witnesses offer" should be changed to "The FPL witness offers"
line 16: delete: "nor Progress Energy"
line 17: change "they" to "it"

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COMPANY/ FIPUG
WITNESS. Brattle Vaught Direct
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