Florida Power
CORPORATION

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ORIGINAL FILE COPY

June 24, 1996

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

Re: Docket No. 960001-EI

Dear Ms. Bayó:

Enclosed for filing in the subject docket are an original and fifteen copies each of the direct testimony and exhibits of Karl H. Wieland and Larry G. Turner on behalf of Florida Power Corporation.

Please acknowledge your receipt of the above filing on the enclosed copy of this letter and return to the undersigned. Also enclosed is a 3.5 inch diskette containing the above-referenced document in WordPerfect format. Thank you for your assistance in this matter.

Very truly yours,

James A. McGee

JAM/kg
Enclosure

cc: Parties of record

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CERTIFICATE OF SERVICE
Docket No. 960001

I HEREBY CERTIFY that a true and correct copy of the testimony of Larry G. Turner and Karl H. Wieland, filed on behalf of Florida Power Corporation, has been sent by regular U.S. mail to the following individuals this 24th day of June, 1996:

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Florida Power
CORPORATION

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 960001-EI

LEVELIZED FUEL COST FACTORS OCTOBER 1996 THROUGH MARCH 1997

DIRECT TESTIMONY AND EXHIBITS OF

KARL H. WIELAND

For Filing June 24, 1996

FLORIDA POWER CORPORATION

DOCKET NO. 960001-EI

Levelized Fuel and Capacity Cost Factors
October 1996 through March 1997

DIRECT TESTIMONY OF
KARL H. WIELAND

Q. Please state your name and business address.

A. My name is Karl H. Wieland. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

Q. By whom are you employed and in what capacity?

A. I am employed by Florida Power Corporation as Director of Business Planning.

Q. Have the duties and responsibilities of your position with the Company remained the same since you last testified in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the Company's levelized fuel and capacity cost factors for the period of October 1996 through March 1997.

Q. **Do you have an exhibit to your testimony?**

A. Yes. I have prepared an exhibit attached to my prepared testimony consisting of Parts A through D and the Commission's minimum filing requirements for these proceedings, Schedules E1 through E10 and H1, which contain the Company's levelized fuel cost factors and the supporting data. Parts A through C contain the assumptions which support the Company's cost projections, Part D contains the Company's capacity cost recovery factors and supporting data.

FUEL COST RECOVERY

Q. **Please describe the levelized fuel cost factors calculated by the Company for the upcoming projection period.**

A. Schedule E1, page 1 of the "E" Schedules in my exhibit, shows the calculation of the Company's basic fuel cost factor of 2.058 ¢/kWh (before line loss adjustment). The basic factor consists of a fuel cost for the projection period of 1.7514 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.0105 ¢/kWh, a coal market price true-up credit of 0.0016 ¢/kWh and an estimated prior period true-up charge of 0.2963 ¢/kWh.

Utilizing this basic factor, Schedule E1-D shows the calculation and supporting data for the Company's levelized fuel cost factors for secondary, primary, and transmission metering tariffs. To accomplish this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales (forecasted at meter level). This is consistent with the methodology being used in the development of the capacity cost recovery factors.

Schedule E1-E develops the TOU factors 1.181 ¢/kWh On-peak and 0.926 ¢/kWh Off-peak. The levelized fuel cost factors (by metering voltage) are then multiplied by the TOU factors, which results in the final fuel factors to be applied to customer bills during the projection period. The final fuel cost factor for residential service is 2.062 ¢/kWh.

Q. What is included in Schedule E1, line 4, "Adjustments to Fuel Cost"?

A. Line 4 shows costs for tne conversion of four Intercession City combustion turbine units to burn natural gas instead of distillate fuel oil, and an annual payment to the Department of Energy for the decommissioning and decontamination of their enrichment facilities.

Q. What is included in Schedule E1, line 6, "Energy Cost of Purchased Power"?

A. Line 6 includes energy costs for the purchase of 50 MWs from Tampa Electric Company and the purchase of 409 MWs under a Unit Power Sales (UPS) agreement with the Southern Company. Capacity costs for these purchases are included in the capacity cost recovery factor. Both of these contracts have been in place and have been approved for cost recovery by the Commission.

Q. What is included in Schedule E1, line 8, "Energy Cost of Economy Purchases (Non-Broker)"?

A. Line 8 includes energy costs for purchases from Seminole Electric Cooperative (SECI) for load following, off-peak hydroelectric purchases from the Southeast Electric Power Agency (SEPA), and miscellaneous economy purchases from within or outside the state which are not made through the Florida Broker System. The SECI contract is an ongoing contract under which the Company purchases energy from SECI at 95% of its avoided fuel cost. Purchases from SEPA are on an as-available basis. There are no capacity payments associated with either of these purchases. Other purchases may have non-fuel charges, but since such purchases are made only if the total cost of the purchase is lower than the Company's cost to generate the energy, it is appropriate to recover the associated non-fuel costs through the fuel adjustment clause rather than the capacity cost recovery factor.

Q. Please explain the entry on Schedule E1, line 17, "Fuel Cost of Stratified Sales."

A. The Company has a wholesale contract with Seminole for the sale of supplemental energy to supply the portion of their load in excess of 689 MW. The fuel costs charged to Seminole for these supplemental sales are calculated on a "stratified" basis, in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. The Company also has wholesale contracts with

Georgia Power Company and the municipal utilities of Kissimmee and St. Cloud under which fuel costs are charged in a similar manner. Unlike interchange sales, the fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the Stratified sales are not recovered on an average cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation. This adjustment is necessary to avoid an over-recovery by the Company which would result from the treatment of these fuel costs on an average cost basis in this proceeding, while actually recovering the costs from these customers on a higher, stratified cost basis. The development of this adjustment is shown on Schedule E6.

Q. How was the estimated true-up shown on line 28 of Schedule E1 developed?

A. The total true-up amount was determined in two parts. First, a period-to-date actual under-recovery of $60,552,885 through May 1996 was obtained from the Company's Operating Report. This balance was projected to the end of September 1996, including interest estimated at the May ending rate of 0.45% per month. The projection assumes that the Commission approves the Company's petition for mid-course correction, with revised rates in effect for July through September. The development of the estimated true-up amount for the current April through September 1996 period is shown on Schedule E1B, Sheet 1. Second, the total estimated under-recovery of $18,230,634 for the current period was combined with the prior period (October 1995 through March 1996) under-recovery of $29,993,960 and $5,915,935 being collected during the current period for a total under-recovery of $42,308,659 at the end of September 1996. This results in an estimated true-up charge on line 28 of Schedule E1 (Basic) of 0.2963 ¢/kWh for application in the October 1996 through March 1997 projection period.

Q. What are the primary reasons for the projected September 1996 under-recovery of $42.3 million?

A. The $30.0 million actual under-recovery for the period ending March 1996 being rolled forward into the current period, the longer than anticipated nuclear outage, and higher than projected oil prices were the primary factors contributing to the $42.3 million under-recovery in September.

Q. How was the market price true-up for Powell Mountain coal purchases calculated?

A. The calculation was performed in accordance with the market pricing methodology approved by the Commission for Powell Mountain coal purchases in Docket No. 860001-EI-G and has been made available for Staff review. The true-up is based on the difference between the previously recovered cost of Powell Mountain coal purchases during 1995, and a calculated cost using the market price index for compliance coal in BOM District 8 for 1995, as adopted in Order No. 22401. The true-up amount of $235,010 also includes interest through May 1996.

Q. **Please explain the procedure for forecasting the unit cost of nuclear fuel.**

A. The cost per million BTU of the nuclear fuel which will be in the reactor during the projection period (primarily Cycle 11) was developed from the projected cost of fuel added during the current period's refueling outage and the unamortized investment cost of the fuel remaining in the reactor from the prior cycle (Cycle 10). Cycle 11 consists of several "batches" of fuel assemblies which are separately accounted for throughout their life in several fuel cycles. The cost for each batch is determined from the actual cost incurred by the Company, which is audited and reviewed by the Commission's field auditors. The expected available energy from each batch over its life is developed from an evaluation of various fuel management schemes and estimated fuel cycle lengths. From this information, a cost per unit of energy (cents per million BTU) is calculated for each batch. However, since the rate of energy consumption is not uniform among the individual fuel assemblies and batches within the reactor core, an estimate of consumption within each batch must be made to properly weigh the batch unit costs in calculating a composite unit cost for the overall fuel cycle.

Q. How was the rate of energy consumption for each batch within Cycle 11 estimated for the upcoming projection period?

A. The consumption rate of each batch has been estimated by utilizing a core physics computer program which simulates reactor operations over the projection period. When this consumption pattern is applied to the individual batch costs, the resultant composite Cycle 11 is $0.33 per million BTU.

Q. Would you give a brief overview of the procedure used in developing the projected fuel cost data from which the Company's basic fuel cost recovery factor was calculated?

A. Yes. The process begins with the fuel price forecast and the system sales forecast. These forecasts are input into PROMOD, along with purchased power information, generating unit operating characteristics, maintenance schedules, and other pertinent data. PROMOD then computes system fuel consumption, replacement fuel costs, and energy purchases and costs. This data is input into a fuel inventory model, which calculates average inventory fuel costs. This information is the basis for the calculation of the Company's levelized fuel cost factors and supporting schedules.

Q. What is the source of the system sales forecast?

A. The system sales forecast is made by the Forecasting section of the Business Planning Department using the most recently available data. The forecast used for this projection period was prepared in June 1995.

Q. Is the methodology used to produce the sales forecast for this projection period the same as previously used by the Company in these proceedings?

A. The methodology employed to produce the forecast for the projection period is the same as used in the Company's most recent filings, and was developed with a hybrid econometric/end-use forecasting model. The forecast assumptions are shown in Part A of my exhibit.

Q. What is the source of the Company's fuel price forecast?

A. The fuel price forecast was made by the Fuel and Special Projects Department based on forecast assumptions for residual oil, #2 fuel oil, natural gas, and coal. The assumptions for the projection period are shown in Part B of my exhibit. The forecasted prices for each fuel type are shown in Part C.

CAPACITY COST RECOVERY

Q. How was the Capacity Cost Recovery factor developed?

A. The calculation of the capacity cost recovery factor (CCRF) is shown in Part D of my exhibit. The factor allocates capacity costs to rate classes in the same manner that they would be allocated if they were recovered in base rates. A brief explanation of the schedules in the exhibit follows.

Sheet 1: Projected Capacity Payments. This schedule contains system capacity payments for UPS, TECO and QF purchases. The retail portion of the capacity payments are calculated using separation factors consistent with the Company's rate case filing. The estimated jurisdictional recoverable capacity payments for the October 1996 through March 1997 period are $131,182,318.

Sheet 2: Estimated/Actual True-Up. This schedule presents the actual ending true-up balance after two months of the current period and re-forecasts the over/(under) recovery balances for the next four months to obtain an ending balance for the current period. This estimated/actual balance of $10,754,129 is then carried forward to Sheet 1, to be refunded during the October 1996 through March 1997 period.

Sheet 3: Development of Jurisdictional Loss Multipliers: The same delivery efficiencies and loss multipliers as presented on Schedule E1-F.

Sheet 4: Calculation of 12 CP and Annual Average Demand. The calculation of average 12 CP and annual average demand is based on 1994 load research data and the delivery efficiencies on Sheet 3.

Sheet 5: Calculation of Capacity Cost Recovery Factors. The total demand allocators in column (7) are computed by adding 12/13 of the 12 CP demand allocators to 1/13 of the annual average demand allocators. The CCRF for each secondary delivery rate class in cents per kWh is the product of total jurisdictional capacity costs (including revenue taxes) from Sheet 1, times the class demand allocation factor, divided by projected effective sales at the secondary level. The CCRF for primary and transmission rate classes reflect the application of metering reduction factors of 1% and 2% from the secondary CCRF.

Q. Please discuss the increase in jurisdictional capacity payments compared to the prior six- month period.

A. The increase in capacity payments from $126.1 million in the April through September 1996 period to $131.2 million for the October 1996 through March 1997 period is primarily due to the escalation provisions in the contracts which take effect in January of each year.

GENERIC ISSUE

Q. At the last fuel adjustment proceeding an issue regarding the appropriate use of average fuel costs for cost recovery purposes was raised and deferred to this proceeding. What is Florida Power's position on the use of average cost fuel pricing?

A. As a general rule, Florida Power believes that any sale, either retail or wholesale, should be priced at the average cost of the generation resources used to make the sale. In other words, sales from a utility's system should be based on system average fuel costs, and sales from a single generating unit (*e.g.,* a Unit Power Sales arrangement) or from a combination of units (*e.g.,* a "stratified" sales arrangement) should be based on the average cost of the particular unit or units involved with the sale. Following this approach will ensure that retail customers do not subsidize wholesale sales. Should a utility choose to price its product in the wholesale markets in a manner that recovers less than the average cost of the sale, the Commission should still allocate costs to that sale on an average cost basis.

Q. **Are there exceptions to this general rule of average cost pricing?**

A. Yes. Average cost pricing should not be applied to sales made for economy purposes, *i.e.,* sales made to more efficiently utilize existing capacity. Sales of economy energy, such as sales on the broker system, have always been and should continue to be made at incremental rather than average cost in order to gain economic efficiency and maximize use of existing resources. In order to eliminate discriminatory pricing and reduce the risk of increasing cost for retail ratepayers, Florida Power restricts the use of incremental cost pricing, when below average cost, to sales that meet the following criteria:

1. Short term (less than one year) non-firm sales.

2. Firm sales from existing reserves which do not commit the Company to construct or purchase additional capacity.

3. Sales that are made from the system and for which resources are not subject to jurisdictional separation.

4. Sales for which all revenues (fuel as well as non-fuel) are credited back to the retail customers. Consideration of incentive compensation (such as the 80/20 sharing of profits from broker sales) is a separate issue and should be used when appropriate.

There may be other valid applications of incremental pricing, such as economic development rates which may be desirable from a retail ratepayer perspective, but such applications should be made on a case-by-case basis with specific approval by the Commission.

Q. Would you please summarize Florida Power's position on this issue?

A. Except in the case of economy sales, Florida Power believes that there should be consistency in cost allocation between retail and wholesale sales. Allocation for both fuel and non-fuel costs should continue to be on an average, embedded cost basis, applied to the generation resources from which sales are made. Incremental pricing should be allowed for the specific types of wholesale sales listed above, as long as all revenues from these sales (less incentives if appropriate) are credited back to retail ratepayers. Such practice will ensure that retail customers are not charged fuel costs which exceed the average cost of generation out of any of its units.

Q. Does this conclude your testimony?

A. Yes.

EXHIBITS TO THE TESTIMONY OF
KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
OCTOBER 1996 THROUGH MARCH 1997

PART A - SALES FORECAST ASSUMPTIONS

Florida Power Corporation
Docket No. 960001-EI
Witness: K. H. Weiland
Exhibit No. ________
Part A

SALES FORECAST ASSUMPTIONS

1. This five-year forecast of customers, sales and peak demand utilizes the short-term load forecasting methodology developed for budgeting and financial planning purposes. This forecast was prepared in June 1995 and replaces the June 1994 Corporate Forecast.

2. Normal weather conditions are assumed. Normal weather is based on a ten-year average of service area weighted billing month degree days in order to project Kilowatt-hour sales. A ten-year average of service area weighted temperatures at time of system peak is used to forecast Megawatt peak demand.

3. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida provide the basis for development of the customer forecast. This forecast incorporates "Population Studies", Bulletin No. 111 (February 1995) as well as THE FLORIDA OUTLOOK, First Quarter 1995.

4. FPC's largest electric consumers, its phosphate mining customers, have experienced a significant improvement of late. Improved market conditions for phosphate rock have firmed market prices and allowed for expansion of operations at some mining sites. New mining operations with scheduled openings in the 1995-1996 period include Mobil Chemical Company in South Ft. Meade and C.F. Industries in Ft. Green. As a result, a significant increase in phosphate energy consumption is assumed in this forecast over the next few years.

5. Florida Power Corporation (FPC) supplies load and energy service to wholesale customers on an "full", "partial" and "supplemental" requirements basis. Full requirements customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Partial requirements customers' load is assumed to reflect the current contractual obligations received by FPC as of May 31, 1995. The forecast of energy and demand to the partial requirements customers reflect their ability to receive dispatched energy from the Florida broker system any time it is more economical to do so. FPC's arrangement with Seminole Electric Cooperative, Inc. (SECI) is to serve "supplemental" service over and above 665 MW in 1995, 689 MW in 1996, 703 MW in 1997 and 1998, and 827 MW in 1999 and 2000. SECI's projection of their system's supplemental demand and energy requirements has been incorporated into this forecast. This forecast also assumes that FPC will successfully renew all upcoming franchise agreements.

6. This forecast includes cost effective amounts of demand and energy reductions from FPC'S dispatchable and nondispatchable DSM programs approved by the Florida Public Service Commission.

7. The expected energy and demand impacts of self-service cogeneration are subtracted from the forecast. The forecast assumes that FPC will supply the supplemental load of self-service cogeneration customers. This forecast assumes an increase of 6 MW of self-service capacity by Occidental Corporation at its Swift Creek operation. Supplemental load is defined as the cogeneration customers' total load less their normal generation output. While FPC offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for standby power.

8. The economic outlook for this 5-year forecast projects a soft landing from the strong growth in economic activity experienced in 1993 and 1994. Seven consecutive interest rate hikes by the Federal Reserve Board (FED) have begun to constrain growth in the national economy in an effort to hold down inflationary pressures. Recent declines in interest rates of late has been influenced by the rate of growth in the national economy which has slowed significantly during the first half of 1995. The FED has been seeking to reach a natural rate of GDP growth of 2.5% -- far lower than the torrid rate experienced in 1994. It is assumed that interest rates have peaked for the current business cycle and will remain at the lower Q2:95 level for the remainder of 1995. No economic recession is predicted for the forecast horizon but growth will be lower than that experienced in 1993 and 1994. Federal government efforts to balance the federal budget will place downward pressure on interest rates as we move through the forecast period. A consolidating Federal government will lighten demand for credit in the marketplace and be less of a consumer to the whole economy. This is expected to help home-building as well as other capital intensive industries.

Personal income growth is expected to continue growing but not at the pace experienced in recent years. As interest rates fall, so will the return on interest-bearing accounts and, correspondingly, income levels of Florida retirees. Employment growth will moderate from the strong pace experienced over the past two years resulting in reduced growth in total wages. The strong employment growth in the service sector will continue. Export-related job growth is also expected to fair well in the year ahead. The weak dollar will encourage American exports as well as attract higher numbers of foreign tourists to Florida.

Average use per residential customer will continue to grow as electricity prices are projected to decline in real dollar terms. Also contributing to this trend are homebuilders' surveys reporting increased median square footage of new homes and new apartments constructed. New housing preferences have continued to demand larger living quarters than the current housing stock. Increasing central air conditioning saturation rates, as well as greater saturation of clothes washers and dryers in multi-family dwellings, all serve to boost average electric use per customer.

EXHIBITS TO THE TESTIMONY OF KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
OCTOBER 1996 THROUGH MARCH 1997

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, no radical changes in world energy markets (OPEC actions, governmental rule changes, etc.). It does anticipate a gradual return of crude oil exports from Iraq. Prices have been levelized and don't reflect the normal daily market fluctuations. They are based on expected contract structures, specifications, and spot market purchases for 1996 and 1997.

FPC Residual Fuel Oil (#6) and Distillate Fuel Oil (#2) prices were derived from PIRA and Chem Data forecasts as well as current market information.

Transportation to the Tampa Bay area plus applicable environment taxes were added to the above prices (an adjustment was later made to transportation costs for individual plant locations when purchased from locations other than Tampa Bay).

B. Coal

Coal price projections are provided by Electric Fuels Corporation and represent an estimate of EFC's price to Florida Power 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 EFC has or expects to have in place during 1996 and 1997 and estimated spot purchase volumes and prices for the period. It assumes environmental restrictions on coal quality remain in effect as per current plant: 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 normal weather, no material changes in energy markets, government rule changes, etc. Prices have been levelized and don't reflect normal daily market fluctuations. They are based on expected contract structures and spot market purchases for 1996 and 1997. Gas supply prices were derived from PIRA and Chem Data forecasts as well as current market information.

Transportation costs from the Southern Natural and South Georgia Pipeline systems to the Suwannee Plant and from the Florida Gas Transmission pipeline to the University of Florida cogeneration plant are based on their published tariff prices. Interruptible transportation rates and availability on the pipelines were also estimated based on published tariff prices and expected market conditions. Additional transportation charges from GRU for the University of Florida cogeneration plant and from KUA for the Intercession combustion turbine units are also included.

EXHIBITS TO THE TESTIMONY OF KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
OCTOBER 1996 THROUGH MARCH 1997

PART C - FUEL PRICE FORECAST

Florida Power Corporation
Docket No. 960001-EI
Witness: K. H. Wieland
Exhibit No. ______
Part C
Sheet 1 of 5

FUEL PRICE FORECAST

Residual Oil

	2.5 %		Steam 1.5%		1.0%	
	$/bbl.	$/million BTUs (1)	$/bbl.	$/million BTUs (2)		$/million BTUs (3)
1996						
June	16.00	2.50	17.60	2.75	18.56	2.90
July	15.36	2.40	16.32	2.55	16.96	2.65
August	15.36	2.40	16.32	2.55	16.96	2.65
September	15.36	2.40	16.32	2.55	16.96	2.65
October	15.36	2.40	16.32	2.55	16.96	2.65
November	15.36	2.40	16.32	2.55	16.96	2.65
December	15.36	2.40	16.32	2.55	16.96	2.65
1997						
January	16.00	2.50	16.96	2.65	17.60	2.75
February	16.00	2.50	16.96	2.65	17.60	2.75
March	16.00	2.50	16.96	2.65	17.60	2.75

(1) 6.4 million BTU/bbl.
(2) 6.4 million BTU/bbl.
(3) 6.4 million BTU/bbl.

FUEL PRICE FORECAST

#2 Fuel Oil

	$/bbl.	cents/ gal.	$/million BTUs (1)
1996			
June	24.65	58	4.25
July	24.36	58	4.20
August	24.36	58	4.20
September	24.36	58	4.20
October	24.36	58	4.20
November	24.36	58	4.20
December	24.36	58	4.20
1997			
January	26.10	62	4.50
February	26.10	62	4.50
March	26.10	62	4.50

(1) 5.8 million BTU/bbl. & 42 gal. per bbl.

Florida Power Corporation
Docket No. 960001-EI
Witness: K. H. Wieland
Exhibit No. ______
Part C
Sheet 3 of 5

FUEL PRICE FORECAST

Coal

	Crystal River 1 & 2			Crystal River 4 & 5		
	BTU/lb.	$/ton	$/million BTUs	BTU/lb.	$/ton	$/million BTUs
1996						
June	12,571	43.17	1.72	12,589	49.69	1.97
July	12,575	43.27	1.72	12,578	50.21	2.00
August	12,577	42.63	1.69	12,601	49.61	1.97
September	12,581	43.32	1.72	12,588	50.00	1.99
October	12,600	42.50	1.69	12,555	50.49	2.01
November	12,594	42.67	1.69	12,561	50.74	2.02
December	12,604	42.36	1.68	12,556	50.53	2.01
1997						
January	12,588	42.61	1.69	12,542	51.18	2.04
February	12,588	42.64	1.69	12,542	51.18	2.04
March	12,594	42.75	1.70	12,542	51.24	2.04

Florida Power Corporation
Docket No. 960001-EI
Witness: K. H. Wieland
Exhibit No. ______
Part C
Sheet 4 of 5

FUEL PRICE FORECAST

Natural Gas

	FLORIDA GAS TRANSMISSION		SOUTH GEORGIA GAS	
	Volume MCF	$/million BTU (1)	Volume MCF	$/million BTU (1)
1996				
June	13,300	2.30	6,000	2.30
July	13,300	2.30	6,000	2.30
August	13,300	2.30	6,000	2.30
September	13,300	2.30	6,000	2.30
October	15,300	2.30	6,000	2.30
November	23,515	2.30	6,000	2.30
December	23,515	2.30	6,000	2.30
1997				
January	23,515	2.10	0	2.10
February	23,515	2.10	0	2.10
March	23,515	2.10	0	2.10

(1) 1000 BTU/CF

FUEL PRICE FORECAST

Transporation Costs

Residual and Distillate Oil

FUEL	Location	Transportation $/bbl	$/million BTU
Residual			
	(1) ANCLOTE	0.00	0.00
	(1) BARTOW	0.00	0.00
	(1) HIGGINS	0.00	0.00
	(1) SUWANNEE	4.16	0.66
	(1) TURNER	0.00	0.00
Distillate			
	(2) AVON PARK PKR	1.16	0.20
	(2) BARTOW-BARGE	0.93	0.16
	(2) BAYBORO-BARGE	0.93	0.16
	(2) DEBARY	1.39	0.24
	(2) HIGGINS	0.52	0.09
	(2) INT CITY	1.10	0.19
	(2) PORT ST.JOE	1.39	0.24
	(2) RIO PINAR	1.28	0.22
	(2) SUWANNEE	1.22	0.21
	(2) TURNER	1.39	0.24
	(2) UNIV OF FLA	0.68	0.12

(1) 6.3 million BTU/bbl.
(2) 5.8 million BTU/bbl.

EXHIBITS TO THE TESTIMONY OF
KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
OCTOBER 1996 THROUGH MARCH 1997

PART D - CAPACITY COST RECOVERY CALCULATIONS

FLORIDA POWER CORPORATION

CAPACITY COST RECOVERY CLAUSE

PROJECTED CAPACITY PAYMENTS

For the Period of: October 1996 through March 1997

Florida Power Corporation
Docket 960001-EI
Witness: K. H. Wieland
Exhibit No. ________
Part D
Sheet 1 of 5

	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	TOTAL
Base Production Level Capacity Charges:							
1 Bay County Qualifying Facility	$143,880	$143,880	$143,880	$152,790	$152,790	$152,790	$890,010
2 Eco Peat Qualifying Fqacility	859,766	859,766	859,766	903,762	903,762	903,762	5,290,584
3 General Peat Qualifying Facility	2,927,496	2,927,496	2,927,496	3,112,824	3,112,824	3,112,824	18,120,960
4 Auburndale LFC Qualifying Facility	473,570	473,570	473,570	491,930	491,930	491,930	2,896,500
5 Dade County Qualifying Facility	602,000	602,000	602,000	632,960	632,960	632,960	3,704,880
6 Lake County Qualifying Facility	271,830	271,830	271,830	289,043	289,043	289,043	1,682,619
7 Pasco County Qualifying Facility	490,360	490,360	490,360	521,410	521,410	521,410	3,035,310
8 Pinellas County 1&2 Qualifying Facility	1,167,270	1,167,270	1,167,270	1,241,183	1,241,183	1,241,183	7,225,359
9 El Dorado Qualifying Facility	1,550,372	1,550,372	1,550,372	1,630,105	1,630,105	1,630,105	9,541,431
10 Lake Cogen Qualifying Facility	1,669,880	1,669,880	1,669,880	1,755,759	1,755,759	1,755,759	10,276,917
11 Orange Cogen Qualifying Facility	1,409,160	1,409,160	1,409,160	1,479,146	1,479,146	1,479,146	8,664,918
12 Orlando Cogen Qualifying Facility	1,236,178	1,236,178	1,236,178	1,299,753	1,299,753	1,299,753	7,607,793
13 Pasco Cogen Qualifying Facility	1,654,699	1,654,699	1,654,699	1,739,798	1,739,798	1,739,798	10,183,491
14 Ridge Generating Station Qualifying Facility	800,946	800,946	800,946	800,946	800,946	800,946	4,805,676
15 Timber Energy 1 Qualifying Facility	292,701	292,701	292,701	292,701	292,701	292,701	1,756,206
16 Timber Energy 2 Qualifying Facility	102,360	102,360	102,360	108,840	108,840	108,840	633,600
17 Mulberry Energy Qualifying Facility	1,795,741	1,795,741	1,795,741	1,887,632	1,887,632	1,887,632	11,050,119
18 Royster Phosphates Qualifying Facility	643,058	643,058	643,058	675,964	675,964	675,964	3,957,066
19 Seminole Fertilizer Qualifying Facility	321,150	321,150	321,150	337,500	337,500	337,500	1,975,950
20 Panda Kathleen Qualifying Facility	0	0	0	0	0	0	0
21 US Agrichem Qualifying Facility	0	0	0	32,019	32,019	32,019	96,057
22 Tiger Bay (EcoPeat lease credit)	(66,666)	(66,667)	(66,667)	(66,666)	(216,667)	(66,667)	(550,000)
23 Subtotal - Base Level Capacity Charges	$18,345,751	$18,345,750	$18,345,750	$19,319,399	$19,169,398	$19,319,398	$112,845,446
24 Base Production Jurisdictional Responsibility	94.711%	94.711%	94.711%	94.711%	94.711%	94.711%	94.711%
25 Base Level Jurisdictional Capacity Charges	$17,375,444	$17,375,443	$17,375,443	$18,297,596	$18,155,529	$18,297,595	$106,877,050
Intermediate Production Level Capacity Charges:							
26 TECO Power Purchase	$471,367	471,367	471,367	471,367	471,367	471,367	2,828,202
27 UPS Purchase (409 MW)	$4,833,809	$4,789,836	$4,783,702	5,058,103	5,058,103	5,058,103	29,581,656
28 Capacity Sales	0	0	0	0	0	0	0
29 Subtotal - Intermediate Level Capacity Charges	$5,305,176	$5,261,203	$5,255,069	$5,529,470	$5,529,470	$5,529,470	$32,409,858
30 Intermediate Production Jurisdictional Responsibility	80.851%	80.851%	80.851%	80.851%	80.851%	80.851%	80.851%
31 Intermediate Level Jurisdictional Capacity Charges	$4,289,288	$4,253,735	$4,248,776	$4,470,632	$4,470,632	$4,470,632	$26,203,695
32 Sebring Base Rate Credits	($336,275)	($284,550)	($300,849)	($350,738)	($327,122)	($298,893)	($1,898,427)
33 Jurisdictional Capacity Payments (lines 25 + 31 + 32)	$21,328,457	$21,344,628	$21,323,370	$22,417,490	$22,299,039	$22,469,334	$131,182,318
34 Estimated/Actual True-Up Provision for the period April through September 1996							($10,754,129)
35 TOTAL (Sum of lines 33 & 34)							$120,428,189
36 Revenue Tax Multiplier							1.00083
37 TOTAL RECOVERABLE CAPACITY PAYMENTS							$120,528,144

Lines 24 & 30: Copied from 1995 Jurisdictional Separation Study.
Line 34: Copied from Sheet 2, line 42.

FLORIDA POWER CORPORATION

CAPACITY COST RECOVERY CLAUSE

CALCULATION OF ESTIMATED / ACTUAL TRUE-UP

For the Period of: April through September 1996

	Actual Apr-96	Actual May-96	Estimated Jun-96	Estimated Jul-96	Estimated Aug-96	Estimated Sep-96	TOTAL	Original Estimate	Variance
Base Production Level Capacity Charges:									
1 Bay County Qualifying Facility	$143,880	$143,880	$143,880	$143,880	$143,880	$143,880	$863,280	$863,280	$0
2 Eco Peat Qualifying Fqacility	874,076	859,766	859,766	859,766	859,766	859,766	5,172,907	5,158,598	14,309
3 General Peat Qualifying Facility	2,927,496	2,927,496	2,927,496	2,927,496	2,927,496	2,927,496	17,564,976	17,564,976	0
4 Auburndale LFC Qualifying Facility	473,570	473,570	473,570	473,570	473,570	473,570	2,841,420	2,841,420	0
5 Dade County Qualifying Facility	558,618	571,510	602,000	602,000	602,000	602,000	3,538,128	3,612,000	(73,872)
6 Lake County Qualifying Facility	271,830	271,830	271,830	271,830	271,830	271,830	1,630,980	1,630,980	0
7 Pasco County Qualifying Facility	490,360	490,360	490,360	490,360	490,360	490,360	2,942,160	2,942,160	0
8 Pinellas County Qualifying Facility	341,360	1,145,950	1,167,270	1,167,270	1,167,270	1,167,270	6,156,390	7,131,540	(975,150)
9 El Dorado Qualifying Facility	1,550,372	1,550,372	1,550,372	1,550,372	1,550,372	1,550,372	9,302,232	9,302,231	0
10 Lake Cogen Qualifying Facility	1,669,880	1,677,886	1,669,880	1,669,880	1,669,880	1,669,880	10,027,286	10,019,279	8,007
11 Orange Cogen Qualifying Facility	1,097,052	1,409,160	1,409,160	1,409,160	1,409,160	1,409,160	8,142,851	8,454,958	(312,107)
12 Orlando Cogen Qualifying Facility	1,209,539	1,173,633	1,236,178	1,236,178	1,236,178	1,236,178	7,327,884	7,417,069	(89,185)
13 Pasco Cogen Qualifying Facility	1,654,699	1,654,699	1,654,699	1,654,699	1,654,699	1,654,699	9,928,194	9,928,193	0
14 Ridge Generating Station Qualifying Facilit	766,106	763,308	800,946	800,946	800,946	800,946	4,733,198	4,805,676	(72,478)
15 Timber Energy 1 Qualifying Facility	277,639	292,701	292,701	292,701	292,701	292,701	1,741,146	1,756,209	(15,063)
16 Timber Energy 2 Qualifying Facility	102,360	102,360	102,360	102,360	102,360	102,360	614,160	614,160	0
17 Mulberry Energy Qualifying Facility	1,795,741	1,795,741	1,795,741	1,795,741	1,795,741	1,795,741	10,774,445	10,774,444	1
18 Royster Phosphates Qualifying Facility	643,058	643,058	643,058	643,058	643,058	643,058	3,858,348	3,858,348	(0)
19 Seminole Fertilizer Qualifying Facility	321,150	321,150	321,150	321,150	321,150	321,150	1,926,900	1,926,900	0
20 Tiger Bay (EcoPeat lease credit)	(66,667)	(66,667)	(66,667)	(66,666)	(66,667)	(66,667)	(400,001)	(400,000)	(1)
21 Subtotal - Base Level Capacity Charges	$17,102,119	$18,201,763	$18,345,750	$18,345,751	$18,345,750	$18,345,750	$108,686,884	$110,202,422	($1,515,539)
22 Base Production Jurisdictional Responsibility	94.711%	94.711%	94.711%	94.711%	94.711%	94.711%	94.711%	94.595%	- n/a -
23 Base Level Jurisdictional Capacity Charges	$16,197,588	$17,239,072	$17,375,443	$17,375,444	$17,375,444	$17,375,444	102,938,435	$104,245,982	($1,307,547)
Intermediate Production Level Capacity Charges:									
24 TECO Power Purchase	$471,367	$471,367	$471,367	$471,367	$471,367	$471,367	$2,828,202	$2,828,202	$0
25 UPS Purchase (409 MW)	4,719,198	4,408,044	4,809,029	4,807,862	4,802,810	4,775,278	28,322,221	28,839,292	(517,071)
26 Capacity Sales	4,992	(2,511)	0	0	0	0	0	0	0
27 Subtotal - Intermediate Level Capacity Charges	$5,195,557	$4,876,900	$5,280,396	$5,279,229	$5,274,177	$5,246,645	$31,150,423	$31,667,494	($517,071)
28 Intermediate Production Jurisdict. Responsibility	80.851%	80.851%	80.851%	80.851%	80.851%	80.851%	80.857%	80.759%	- n/a -
29 Intermediate Level Jurisdictional Capacity Charges	$4,200,660	$3,943,022	$4,269,253	$4,268,309	$4,264,225	$4,241,965	$25,187,434	$25,574,352	($386,918)
30 Sebring Base Rate Credits	($327,855)	($279,994)	($338,188)	($361,309)	($365,055)	($388,699)	($2,061,100)	($2,035,550)	($25,550)
31 **Jurisdictional Capacity Charges** (lines 23+29+30)	$20,070,393	$20,902,100	$21,306,508	$21,282,444	$21,274,614	$21,228,710	$126,064,769	$127,784,784	($1,720,015)
32 Jurisdictional kWh Sales (000)	2,222,507	2,287,889	2,666,172	2,933,090	3,020,691	3,000,744	16,131,093	16,028,890	102,203
33 **Capacity Cost Recovery Revenues** (net of revenue taxes)	$16,851,819	$17,228,979	$20,569,990	$22,629,309	$23,305,166	$23,151,272	$123,736,535	$123,665,727	$70,808
33a Miscellaneous Revenue Adjustments	0	0	0	0	0	0	0	0	0
34 Prior Period True-Up Provision	2,144,079	2,144,079	2,144,079	2,144,079	2,144,079	2,144,078	$12,864,473	$4,119,057	8,745,416
35 **Current Period Capacity Cost Recovery Revenues** (net of revenue taxes) (sum lines 33 through 34)	$18,995,898	$19,373,058	$22,714,069	$24,773,388	$25,449,245	$25,295,350	$136,601,008	$127,784,784	$8,816,224
36 **Current Period Over/(Under) Recovery** (line 35 - line 31)	($1,074,495)	($1,529,042)	$1,407,561	$3,490,944	$4,174,631	$4,066,640	$10,536,239	$0	$10,536,239
37 Interest Provision for Month	51,121	35,372	25,610	27,098	34,819	43,870	217,890	(73,854)	291,744
38 Current Cycle Balance	(1,023,374)	(2,517,044)	(1,083,873)	2,434,169	6,643,619	10,754,129	10,754,129	(73,854)	10,827,983
39 plus: Prior Period Balance	12,864,473	12,864,473	12,864,473	12,864,473	12,864,473	12,864,473	12,864,473	4,119,057	8,745,416
40 plus: Cumulative True-Up Provision	(2,144,079)	(4,288,158)	(6,432,237)	(8,576,316)	(10,720,395)	(12,864,473)	(12,864,473)	(4,119,057)	(8,745,416)
41 plus: Other	0	0	0	0	0	0	0	0	0
42 **End of Period Net True-Up** (sum lines 38 through 41)	$9,697,020	$6,059,271	$5,348,363	$6,722,326	$8,787,697	$10,754,129	$10,754,129	($73,854)	$10,827,983

Line 33: Calculated at net-of-taxes rate of $123768370 / 16028890 MWh / 10 / 1.00083 = 0.77151772 ¢/kWh

Line 37: Estimated interest calculated at May 1996 ending rate of 5.400 / 12 = 0.4500 % per month.

Florida Power Corporation
Docket 960001-EI
Witness: K. H. Wieland
Exhibit No. ________
Part D
Sheet 3 of 5

FLORIDA POWER CORPORATION

CAPACITY COST RECOVERY CLAUSE

DEVELOPMENT OF JURISDICTIONAL DELIVERY LOSS MULTIPLIERS

Based on Actual Calendar Year 1995 Data

For the Period of: October 1996 through March 1997

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		ENERGY DELIVERED				ENERGY REQ'D @ SOURCE		JURISDICTIONAL LOSS
	SALES MWH	NET UNBILLED MWH	TOTAL MWH	% OF TOTAL	PER UNIT DELIVERY EFFICIENCY	MWH (3)/(5)	% OF TOTAL	MULTIPLIER 0.9470255 / (5)
I. CLASS LOADS								
A. RETAIL								
1. Transmission	807,005	6,748	813,753		0.9750000	834,618		
2. Distribution Primary	3,905,316	32,657	3,937,973		0.9650000	4,080,801		
3. Distribution Secondary	24,787,156	207,278	24,994,434		0.9419021	26,536,126		
TOTAL RETAIL	29,499,477	246,683	29,746,160	96.33%	0.9457774	31,451,545	96.45%	1.0013
B. WHOLESALE								
1. Source Level	310,763	9,878	320,641		1.0000000	320,641		
2. Transmission	661,993	44,928	706,921		0.9750000	725,047		
3. Distribution Primary	98,806	7,823	106,629		0.9650000	110,496		
4. Distribution Secondary	0	0	0		0.9419021	0		
TOTAL WHOLESALE	1,071,562	62,629	1,134,191	3.67%	0.9809779	1,156,184	3.55%	0.9654
TOTAL CLASS LOADS	30,571,039	309,312	30,880,351	100.00%	0.9470255	32,607,729	100.00%	1.0000
II. NON-CLASS LOADS								
A. Company Use	152,774	0	152,774		0.9419021	162,197		
B. Seminole Electric	672,040	91,064	763,104		1.0000000	763,104		
C. Kissimmee	41,915	194	42,109		0.9750000	43,189		
D. St. Cloud	42,008	2,125	44,133		0.9750000	45,265		
E. Interchange	1,056,702	0	1,056,702		0.9750000	1,083,797		
F. SEPA	18,894	(611)	18,283		1.0000000	18,283		
TOTAL NON-CLASS	1,984,333	92,772	2,077,135		0.9816952	2,115,835		
TOTAL SYSTEM	32,555,372	402,084	32,957,456		0.9491381	34,723,564		

FLORIDA POWER CORPORATION

CAPACITY COST RECOVERY CLAUSE

CALCULATION OF AVERAGE 12 CP AND ANNUAL AVERAGE DEMAND

For the Period of: October 1996 through March 1997

Florida Power Corporation
Docket 960001-EI
Witness: K. H. Wieland
Exhibit No. ______
Part D
Sheet 4 of 5

RATE CLASS	(1) MWH Sales @ Meter Level (Oct'96-Mar'97)	(2) 12 CP Load Factor	(3) Average CP MW @ Meter Level (1)/4380 hrs/(2)	(4) Delivery Efficiency Factor	(5) Average CP MW @ Source Level (3)/(4)	(6) MWH Sales @ Meter Level (Oct'96-Mar'97)	(7) Delivery Efficiency Factor	(8) Source Level MWH (6)/(7)	(9) Annual Average Demand (8) / 4380 hrs
I. Residential Service	7,009,636	0.516	3,101.5	0.9419021	3,292.8	7,009,636	0.9419021	7,442,000	1,699.1
II. General Service Non-Demand									
Transmission	0	0.662	0.0	0.9750000	0.0	0	0.9750000	0	0.0
Primary	3,311	0.662	1.1	0.9650000	1.2	3,311	0.9650000	3,431	0.8
Secondary	515,233	0.662	177.7	0.9419021	188.7	515,233	0.9419021	547,013	124.9
Total	518,544				189.8	518,544		550,444	125.7
III. GS - 100% L.F.	21,325	1.000	4.9	0.9419021	5.2	21,325	0.9419021	22,640	5.2
IV. General Service Demand									
SS1 - Transmission	7,207	1.218	1.4			7,207			
GSD - Transmission	10,689	0.802	3.0			10,689			
SubTotal - Transmission	17,896		4.4	0.9750000	4.5	17,896	0.9750000	18,355	4.2
SS1 - Primary	641	1.218	0.1			641			
GSD - Primary	1,102,518	0.802	313.9			1,102,518			
SubTotal - Primary	1,103,159		314.0	0.9650000	325.4	1,103,159	0.9650000	1,143,170	261.0
GSD - Secondary	4,213,022	0.802	1,199.3	0.9419021	1,273.3	4,213,022	0.9419021	4,472,887	1,021.2
Total	5,334,077				1,603.2	5,334,077		5,634,412	1,286.4
V. Curtailable Service									
CS - Primary	102,119	0.966	24.1			102,119			
SS3 - Primary	273	1.039	0.1			273			
SubTotal - Primary	102,392		24.2	0.9650000	25.1	102,392	0.9650000	106,106	24.2
CS - Secondary	1,605	0.966	0.4	0.9419021	0.4	1,605	0.9419021	1,704	0.4
Total	103,997		24.6		25.5	103,997		107,810	24.6
VI. Interruptible Service									
IS - Transmission	344,224	0.960	81.9			344,224			
SS2 - Transmission	55,515	1.044	12.1			55,515			
SubTotal - Transmission	399,739		94.0	0.9750000	96.4	399,739	0.9750000	409,989	93.6
IS - Primary	755,363	0.960	179.6			755,363			
SS2 - Primary	16,424	1.044	3.6			16,424			
SubTotal - Primary	771,787		183.2	0.9650000	189.9	771,787	0.9650000	799,779	182.6
IS - Secondary	22,912	0.960	5.4	0.9419021	5.8	22,912	0.9419021	24,325	5.6
Total	1,194,438				292.1	1,194,438		1,234,093	281.8
VII. Lighting Service	98,202	3.551	6.3	0.9419021	6.7	98,202	0.9419021	104,259	23.8
TOTAL RETAIL	14,280,219				5,415.3	14,280,219		15,095,659	3,446.5

Cols (1) & (6): Florida Power Corp. sales forecast for period October 1996 through March 1997.
Col (2): Florida Power Corp. Load Research Study Results, for the period April 1993 to March 1994, adjusted to remove load management effects.
Col (7): Copied from Sheet 3, col (5).

FLORIDA POWER CORPORATION

CAPACITY COST RECOVERY CLAUSE

CALCULATION OF CAPACITY COST RECOVERY FACTOR

For the Period of: October 1996 through March 1997

Florida Power Corporation
Docket 960001-EI
Witness: K. H. Wieland
Exhibit No. ________
Part D
Sheet 5 of 5

RATE CLASS	(1) AVERAGE 12 CP DEMAND MW	(2) %	(3) ANNUAL AVERAGE DEMAND MW	(4) %	(5) 12/13 of 12 CP 12/13 * (2)	(6) 1/13 of Ann. Demand 1/13 * (4)	(7) Demand Allocation (5) + (6)	(8) Dollar Allocation (7) * $120528144	(9) Effective MWHs @ Secondary Level (Oct96-Mar97)	(10) Capacity Cost Recovery Factor (¢/kWh)
I. Residential Service	3,292.8	60.806%	1,699.1	49.299%	56.129%	3.792%	59.921%	$72,221,356	7,009,636	1.030
II. General Service Non-Demand										
Transmission									0	0.801
Primary									3,278	0.809
Secondary									515,233	0.817
Total	189.8	3.506%	125.7	3.646%	3.236%	0.280%	3.516%	$4,238,275	518,511	
III. GS - 100% L.F.	5.2	0.095%	5.2	0.150%	0.088%	0.012%	0.100%	$120,103	21,325	0.563
IV. General Service Demand										
Transmission									17,538	0.670
Primary									1,092,127	0.677
Secondary									4,213,022	0.684
Total	1,603.2	29.605%	1,286.4	37.325%	27.328%	2.871%	30.199%	$36,398,287	5,322,687	
V. Curtailable Service										
Transmission									0	0.561
Primary									101,368	0.567
Secondary									1,605	0.573
Total	25.5	0.470%	24.6	0.714%	0.434%	0.055%	0.489%	$589,613	102,973	
VI. Interruptible Service										
Transmission									391,744	0.562
Primary									764,069	0.568
Secondary									22,912	0.573
Total	292.1	5.394%	281.8	8.175%	4.979%	0.629%	5.608%	$6,758,757	1,178,725	
VII. Lighting Service	6.7	0.124%	23.8	0.691%	0.114%	0.053%	0.167%	$201,753	98,202	0.205
TOTAL RETAIL	5,415.3	100.000%	3,446.5	100.000%	92.308%	7.692%	100.000%	$120,528,144	14,252,059	0.844022 (¢ / avg kWh)

Col (1): Copied from Sheet 4, col (5).
Col (3): Copied from Sheet 4, col (9).
Col (8): Computed from Sheet 1, line 37.
Col (9): Is Sheet 4, col (1) adjusted by metering reduction factor of 1% for primary and 2% for transmission.
Col (10): Secondary factors calculated as total col. (8) ÷ total col. (9) ÷ 10, primary factors reflect 1% reduction and transmission reflect 2% reduction.

EXHIBITS TO THE TESTIMONY OF KARL H. WIELAND

LEVELIZED FUEL COST FACTORS
OCTOBER 1996 THROUGH MARCH 1997

SCHEDULES E1 THROUGH E10 AND H1

COMPANY: FPC

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
CALCULATION OF BASIC FACTOR

Schedule E1

For the Period of: October 1996 through March 1997

	Classification	(A) DOLLARS	(B) MWH	(C) cents/kwh
1.	Fuel Cost of System Net Generation (E3)	186,603,588	11,847,029	1.5751
2.	Spent Nuclear Fuel Disposal Cost	3,013,932	3,223,456 *	0.0935
3.	Coal Car Investment	0	0	-
4.	Adjustments to Fuel Cost	2,141,931	0	-
5.	TOTAL COST OF GENERATED POWER	191,759,451	11,847,029	1.6186
6.	Energy Cost of Purchased Power (Excl. ECON & COGENS) (E7)	6,299,350	325,532	1.9351
7.	Energy Cost of Sch.C,X Economy Purchases (Broker) (E9)	7,643,927	309,205	2.4721
8.	Energy Cost of Economy Purchases (Non-Broker) (E9)	886,978	42,858	2.0696
9.	Energy Cost of Sched. E Economy Purchases (E9)	0	0	0.0000
10.	Capacity Cost of Economy Purchases (E9)	681,600	24,858 *	2.7420
11.	Payments to Qualifying Facilities (E8)	73,322,010	3,705,732	1.9786
12.	TOTAL COST OF PURCHASED POWER	88,833,864	4,383,327	2.0266
13.	TOTAL AVAILABLE KWH		16,230,356	
14.	Fuel Cost of Economy Sales (E6)	(12,040,410)	(650,000)	1.8524
14a.	Gain on Economy Sales - 80% (E6)	(2,075,760)	(650,000)*	0.3193
15.	Fuel Cost of Other Power Sales (E6)	0	0	0.0000
15a.	Gain on Other Power Sales (E6)	0	0 *	0.0000
16.	Fuel Cost of Unit Power Sales (E6)	0	0	0.0000
16a.	Gain on Unit Power Sales (E6)	0	0 *	0.0000
17.	Fuel Cost of Stratified Sales (E6)	(8,890,650)	(341,352)	2.6045
18.	TOTAL FUEL COST AND GAINS ON POWER SALES	(23,006,820)	(991,352)	2.3208
19.	Net Inadvertent Interchange		0	
20.	TOTAL FUEL AND NET POWER TRANSACTIONS	257,586,495	15,239,004	1.6903
21.	Net Unbilled	(6,847,997)*	405,135	-0.0465
22.	Company Use	1,597,334 *	(94,500)	0.0108
23.	T & D Losses	13,850,267 *	(819,397)	0.0940
24.	Adjusted System KWH Sales	257,586,495	14,730,242	1.7487
25.	Wholesale KWH Sales (Excluding Supplemental Sales)	(7,803,435)	(450,023)	1.7340
26.	Jurisdictional KWH Sales	249,783,060	14,280,219	1.7492
27.	Jurisdictional KWH Sales Adjusted for Line Losses: x 1.0013	250,107,779	14,280,219	1.7514
28.	Prior Period True-Up (E1-B, Sheet 1)**	42,308,659	14,280,219	0.2963
28a.	Market Price True-Up for 1995 **	(235,010)	14,280,219	-0.0016
29.	Total Jurisdictional Fuel Cost	292,181,428	14,280,219	2.04606
30.	Revenue Tax Factor			1.00083
31.	Fuel Cost Adjusted for Taxes	292,423,939	14,280,219	2.04776
32.	GPIF **	1,498,216	14,280,219	0.01049
33.	Fuel Factor adjusted for taxes including GPIF	293,922,155	14,280,219	2.05825
34.	TOTAL FUEL COST FACTOR rounded to the nearest .001 cents/kwh			2.058

* For Informational Purposes Only
** Based on Jurisdictional Sales

COMPANY: FPC

SCHEDULE E1-A

CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)

For the Period: October 1996 through March 1997

1.	ESTIMATED OVER/(UNDER) RECOVERY (2 months actual, 4 months projected) (Schedule E1-B, Sheet 1)	($18,230,634)
2.	FINAL TRUE-UP (6 months prior period) (Schedule E1-B, Sheet 1)	($24,078,025)
3.	TOTAL OVER/(UNDER) RECOVERY (to be included in projected period) (line 1 + line 2)	($42,308,659)
4.	JURISDICTIONAL kWh SALES (projected period)	14,280,219 mWh
5.	TRUE-UP FACTOR to nearest .0001 cents/kWh (to be included in projected period) (line 3 / line 4 * 10)	0.2963 cents/kWh

COMPANY: FPC

SCHEDULE E1-A

CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)

For the Period: October 1996 through March 1997

1.	ESTIMATED OVER/(UNDER) RECOVERY (2 months actual, 4 months projected) (Schedule E1-B, Sheet 1)	($18,230,634)
2.	FINAL TRUE-UP (6 months prior period) (Schedule E1-B, Sheet 1)	($24,078,025)
3.	TOTAL OVER/(UNDER) RECOVERY (to be included in projected period) (line 1 + line 2)	($42,308,659)
4.	JURISDICTIONAL kWh SALES (projected period)	14,280,219 mWh
5.	TRUE-UP FACTOR to nearest .0001 cents/kWh (to be included in projected period) (line 3 / line 4 * 10)	0.2963 cents/kWh

COMPANY: FPC

SCHEDULE E1-B
Sheet 1

CALCULATION OF ESTIMATED TRUE-UP
(2 MONTHS ACTUAL, 4 MONTHS ESTIMATED)

Re-Estimated For the Period of:
April 1996 through September 1996

		Apr-96	May-96	Jun-96	Jul-96	Aug-96	Sep-96	PERIOD TOTAL
	FUEL REVENUE							
1	JURSIDICTIONAL KWH SALES (000)	2,222,507	2,287,889	3,034,917	2,933,090	3,020,691	3,000,744	16,499,838
2	TOTAL JURISD. FUEL REVENUE (1)	41,320,821	42,703,178	57,221,383	62,949 978	64,830,070	64,401,968	333,427,398
3	less TRUE-UP PROVISION	(985,989)	(985,989)	(985,989)	(985,989)	(985,989)	(985,990)	(5,915,935)
4	less GPIF PROVISION	(242,492)	(242,492)	(242,495)	(242,493)	(242,493)	(242,490)	(1,454,953)
4a								
4b								
5	NET FUEL REVENUE	40,092,340	41,474,697	55,992,899	61,721,496	63,601,588	63,173,488	326,056,510
	FUEL EXPENSE							
6	TOTAL COST OF GENERATED POWER	32,396,883	43,609,796	43,083,793	50,054,396	50,231,459	46,081,012	265,457,338
7	TOTAL COST OF PURCHASED POWER	20,698,090	26,054,996	18,229,988	19,366,990	19,384,947	18,009,620	121,744,631
8	TOTAL COST OF POWER SALES	(2,115,680)	(2,040,456)	(3,658,850)	(7,506,650)	(8,382,960)	(8,397,400)	(32,101,996)
9	TOTAL FUEL AND NET POWER	50,979,293	67,624,336	57,654,931	61,914,736	61,233,446	55,693,232	355,099,973
10	Jurisd. Percentage	95.54	95.92	96.80	96.85	96.83	96.65	96.44
11	Jurisd. Loss Multiplier	1.0014	1.0013	1.0013	1.0013	1.0013	1.0013	1.0013
12	JURISDICTIONAL FUEL COST	48,773,807	64,949,598	55,885,324	60,040,340	59,372,447	53,899,537	342,921,053
	COST RECOVERY							
13	NET FUEL REVENUE LESS EXPENSE	(8,681,467)	(23,474,901)	107,575	1,681,156	4,229,141	9,273,951	
14	INTEREST PROVISION (2)	(153,641)	(220,894)	(270,027)	(262,781)	(246,228)	(212,518)	
15	CURRENT CYCLE BALANCE	(8,835,108)	(32,530,903)	(32,693,355)	(31,274,980)	(27,292,067)	(18,230,634)	
16	plus: PRIOR PERIOD BALANCE (3)	(29,993,960)	(29,993,960)	(29,993,960)	(29,993,960)	(29,993,960)	(29,993,960)	
17	plus: CUMULATIVE TRUE-UP PROVISION	985,989	1,971,978	2,957,967	3,943,956	4,929,945	5,915,935	
18	TOTAL RETAIL BALANCE	(37,843,079)	(60,552,885)	(59,729,348)	(57,324,984)	(52,356,082)	(42,308,659)	

TRUE-UP COMPUTATION: ($42,308,659) X (100 cents/$) / 14,280,219 Jurisdict. MWH = -0.2963 cents/kwh

(1): June computed using effective fuel adjustment, on pre-tax basis, of 1.8854 cents/kwh; July - Sept computed using 2.1462 cents/kwh.

(2): Interest for period calculated at the May 1996 ending rate of 0.4500% (monthly).

(3): Actual Jurisdictional True-Up Balance (as filed on Schedule A2, page 3 of 4) for the month of March, 1996.

COMPANY: FPC

COMPARISON OF ACTUAL/REVISED ESTIMATE VERSUS ORIGINAL ESTIMATE
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
For the Period of: April 1996 through September 1996

SCHEDULE E1-B
Sheet 2

	DOLLARS				MWH				cents/kwh			
	ACTUAL/ REV ESTIMATE	ORIGINAL ESTIMATE	DIFFERENCE AMOUNT	%	ACTUAL/ REV ESTIMATE	ORIGINAL ESTIMATE	DIFFERENCE AMOUNT	%	ACTUAL/ REV.EST.	ORIGINAL ESTIMATE	DIFFERENCE AMOUNT	%
1 Fuel Cost of System Net Generation (E3)	263,965,796	222,523,546	41,442,250	18.6	13,900,652	13,901,829	(1,177)	(0.0)	1.8989	1.6007	0.2982	18.6
2 Spent Nuclear Fuel Disposal Cost	2,120,319	2,809,162	(688,843)	(24.5)	2,268,612 *	3,004,452 *	(735,840)	(24.5)	0.0935	0.0935	0.0000	0.0
3 Coal Car Investments	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4 Adjustments to Fuel Cost	(628,777)	487,259	(1,116,036)	(229.0)	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
5 TOTAL COST OF GENERATED POWER	265,457,338	225,819,967	39,637,371	17.6	13,900,652	13,901,829	(1,177)	(0.0)	1.9097	1.6244	0.2853	17.6
6 Energy Cost of Purchased Power (Excl. ECON & COGEN	26,254,569	19,833,930	6,420,639	32.4	1,358,683	1,072,216	286,467	26.7	1.9324	1.8498	0.0826	4.5
7 Energy Cost of Sch.C,X Economy Purchases (Broker)	13,174,285	9,781,900	3,392,385	34.7	423,952	415,000	8,952	2.2	3.1075	2.3571	0.7504	31.8
8 Energy Cost of Economy Purchases (Non-Broker) (E9)	5,925,709	1,141,301	4,784,408	419.2	227,967	56,405	171,562	304.2	2.5994	2.0234	0.5760	28.5
9 Energy Cost of Sched. E Economy Purchases (E9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10 Capacity Cost of Economy Purchases (E9)	454,400	340,800	113,600	33.3	0 *	0 *	0	0.0	0.0000	0.0000	0.0000	0.0
11 Payments to Qualifying Facilities (E8)	75,935,668	71,340,740	4,594,928	6.4	3,570,497	3,532,551	(62,054)	(1.7)	2.1268	1.9639	0.1629	8.3
12 TOTAL COST OF PURCHASED POWER	121,744,631	102,438,671	19,305,960	18.9	5,581,099	5,176,172	404,927	7.8	2.1814	1.9790	0.2024	10.2
13 TOTAL AVAILABLE KWH					19,481,751	19,078,001	403,750	2.1				
14 Fuel Cost of Economy Sales (E6)	(13,726,661)	(7,058,200)	(6,668,461)	94.5	(596,194)	(390,000)	(206,194)	52.9	2.3024	1.8098	0.4926	27.2
14aGain on Economy Sales - 80% (E6)	(1,896,658)	(1,248,000)	(648,658)	52.0	(596,194)*	(390,000)*	(206,194)	52.9	0.3181	0.3200	(0.0019)	(0.6)
15 Fuel Cost of Other Power Sales (E6)	(519,054)	0	(519,054)	0.0	(18,408)	0	(18,408)	0.0	2.8197	0.0000	2.8197	0.0
15aGain on Other Power Sales (E6)	(104,999)	0	(104,999)	0.0	(18,408)*	0 *	(18,408)	0.0	0.5704	0.0000	0.5704	0.0
16 Fuel Cost of Unit Power Sales (E6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
16aGain on Unit Power Sales (E6)	0	0	0	0.0	0 *	0 *	0	0.0	0.0000	0.0000	0.0000	0.0
17 Fuel Cost of Stratified Sales (E6)	(15,854,624)	(15,721,770)	(132,854)	0.9	(415,261)	(368,944)	(46,317)	12.6	3.8180	4.2613	(0.4433)	(10.4)
18 TOTAL FUEL COST AND GAINS ON POWER SALES	(32,101,996)	(24,027,970)	(8,074,026)	33.6	(1,029,863)	(758,944)	(270,919)	35.7	3.1171	3.1660	(0.0489)	(1.5)
19 Net Inadvertent Interchange					3,717	0	3,717					
20 TOTAL FUEL AND NET POWER TRANSACTIONS	355,099,973	304,230,668	50,869,305	16.7	18,455,605	18,319,057	136,548	0.8	1.9241	1.6607	0.2634	15.9
21 Net Unbilled	(3,019,827)*	10,684,064 *	(13,703,891)	(128.3)	(654,351)	(643,347)	(11,004)	1.7	(0.0181)	0.0645	(0.0826)	(128.1)
22 Company Use	1,859,142 *	1,569,362 *	289,780	18.5	(99,867)	(94,500)	(5,367)	5.7	0.0111	0.0095	0.0016	16.8
23 T & D Losses	18,284,274 *	17,010,683 *	1,273,591	7.5	(982,991)	(1,024,308)	41,317	(4.0)	0.1094	0.1027	0.0067	6.5
24 Adjusted System KWH Sales	355,099,973	304,230,668	50,869,305	16.7	16,718,396	16,556,902	161,494	1.0	2.1240	1.8375	0.2865	15.6
25 Wholesale KWH Sales (Excluding Stratified Sales)	(12,629,003)	(9,692,677)	(2,936,326)	30.3	(587,303)	(528,012)	(59,291)	11.2	2.1503	1.8357	0.3146	17.1
26 Jurisdictional KWH Sales	342,470,970	294,537,991	47,932,979	16.3	16,131,093	16,028,890	102,203	0.6	2.1230	1.8375	0.2855	15.5
26aJurisdictional Loss Multiplier	x 1.0013	x 1.0014										
27 Jurisdictional KWH Sales Adjusted for Line Losses:	342,921,053	294,950,343	47,970,710	16.3	16,131,093	16,028,890	102,203	0.6	2.1258	1.8401	0.2857	15.5
28.Prior Period True-Up*	5,915,935	5,915,935	0	0.0	16,131,093	16,028,890	102,203	0.6	0.0367	0.0369	(0.0002)	(0.5)
28aMarket Price True-Up for 1995 **	0	0	0		16,131,093	16,028,890	102,203	0.6	0.0000	0.0000	0.0000	
29 TOTAL JURISDICTIONAL FUEL COST	348,836,988	300,866,278	47,970,710	15.9	16,131,093	16,028,890	102,203	0.6	2.1625	1.8770	0.2855	15.2
30 REVENUE TAX FACTOR									1.00083	1.00083		
31 FUEL FACTOR ADJUSTED FOR TAXES									2.1643	1.8786	0.2857	15.2
32 GPIF **	1,456,161	1,381,926	74,235	5.4	16,131,093	16,028,890	102,203	0.6	0.0090	0.0086	0.0004	4.7
33 FUEL FACTOR to the nearest .001 cents/kwh									2.173	1.887	0.286	15.2

* Included for Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

COMPANY: FPC

SCHEDULE E1-C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE
AND TRUE-UP ADJUSTMENT FACTORS

For the Period of: October 1996 through March 1997

1. TOTAL AMOUNT OF ADJUSTMENTS:	
A. GENERATING PERFORMANCE INCENTIVE REWARD/(PENALTY)	$1,498,216
B. TRUE-UP (OVER)/UNDER RECOVERY	$42,308,659
C. MARKET PRICE TRUE-UP FOR 1995 **	($235,010)
2. JURISDICTIONAL KWH SALES (projected period)	14,280,219 mwh
3. ADJUSTMENT FACTORS (cents/kwh):	
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0105 cents/kwh
B. TRUE-UP FACTOR	0.2963 cents/kwh
C. MARKET PRICE TRUE-UP FOR 1995 **	(0.0016)cents/kwh

** BASED ON JURISDICTIONAL SALES

Company: FPC

Schedule E1-D

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE

CALCULATION OF LEVELIZED FUEL COST FACTORS

For the Period of: October 1996 through March 1997

Line		
1.	Period Jurisdictional Fuel Cost (E1,line 27)	$250,107,779
2.	Prior Period True-up (E1, line 28)	42,308,659
2a.	Market Price True-Up for 1995 (E1, line 28a.)	(235,010)
3.	Regulatory Assessment Fee (E1, line 30)	242,511
4.	GPIF (E1, line 32)	1,498,216
5.	Total Jurisdictional Fuel Cost	$293,922,155
6.	Jurisdictional Sales	14,280,219 MWH
7.	Jurisdictional Cost per KWH Sold (line 5 / line 6 / 10)	2.058 ¢/kWh
8.	Effective Jurisdictional Sales (See below)	14,252,059 MWH

LEVELIZED FUEL FACTORS:

9.	Fuel Factor at Secondary Metering (line 5 / line 8 / 10)	**2.062** ¢/kWh
10.	Fuel Factor at Primary Metering (line 9 * .99)	**2.041** ¢/kWh
11.	Fuel Factor at Transmission Metering (line 9 * .98)	**2.021** ¢/kWh

	JURISDICTIONAL SALES (MWH)	
METERING VOLTAGE:	@ METER	EFFECTIVE @ SECONDARY *
Distribution Secondary	11,881,935	11,881,934
Distribution Primary	1,980,649	1,960,843
Transmission	417,635	409,282
Total	14,280,219	14,252,059

* Reflects Metering Reduction Factor of 1% for Primary and 2% for Transmission

Company FPC

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE

CALCULATION OF FINAL FUEL COST FACTORS

For the Period of: October 1996 through March 1997

		(1)	(2)	(3)
			------ TIME OF USE ------	
Line:	Metering Voltage:	LEVELIZED FACTORS ¢/kWh	ON-PEAK MULTIPLIER 1.181	OFF-PEAK MULTIPLIER 0.926
1.	Distribution Secondary	**2.062**	**2.435**	**1.909**
2.	Distribution Primary	**2.041**	**2.410**	**1.890**
3.	Transmission	**2.021**	2.387	**1.871**
4.	Lighting Service	**2.008**	-	-

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Col. (1): Copied from Schedule E1 (Levelized)
Col. (2): Calculated as col.(1) * Off-Peak multiplier 1.181
Col. (3): Calculated as col.(1) * Off-Peak multiplier 0.926
Line 4: Calculated at secondary rate 2.062 * (18.7% * On-Peak multiplier 1.181 + 81.3% * Off-Peak multiplier 0.926).

DEVELOPMENT OF TIME OF USE MULTIPLIERS

	------ON-PEAK PERIOD------			------OFF-PEAK PERIOD------			---------SYSTEM 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)
10/96	943,791	22,505,640	2.385	1,797,017	30,916,436	1.720	2,740,808	53,422,076	1.949
11/96	672,163	15,554,020	2.314	1,738,680	31,967,534	1.839	2,410,843	47,521,554	1.971
12/96	742,326	15,114,314	2.036	1,892,559	30,758,815	1.625	2,634,885	45,873,129	1.741
1/97	745,267	15,862,635	2.128	1,954,745	32,950,740	1.686	2,700,012	48,813,375	1.808
2/97	671,196	14,614,454	2.177	1,738,596	30,507,198	1.755	2,409,792	45,121,652	1.872
3/97	718,925	16,924,213	2.354	1,848,982	35,314,401	1.910	2,567,907	52,238,614	2.034
TOTAL	4,493,668	100,575,276	2.238	10,970,579	192,415,124	1.754	15,464,247	292,990,400	1.895
MARGINAL FUEL COST WEIGHTING MULTIPLIER			ON-PEAK 1.181			OFF-PEAK 0.926			AVERAGE 1.000

COMPANY: FPC

Schedule E1-F

DEVELOPMENT OF JURISDICTIONAL AND RETAIL DELIVERY LOSS MULTIPLIERS

BASED ON ACTUAL CALENDAR YEAR 1995 DATA

For the Period of: October 1996 through March 1997

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	ENERGY DELIVERED				PER UNIT	ENERGY REQ'D @ SOURCE		JURISDICTIONAL LOSS
I. CLASS LOADS	SALES MWH	UNBILLED MWH	TOTAL MWH	% OF TOTAL	DELIVERY EFFICIENCY	MWH (3)/(5)	% OF TOTAL	MULTIPLIER 0.9470255/COL(5)
A. RETAIL - FIRM								
1. TRANSMISSION (Metering)	807,005	6,748	813,753		0.9750000	834,618		
2. DISTRIBUTION PRIMARY	3,905,316	32,657	3,937,973		0.9650000	4,080,801		
3. DISTRIBUTION SECONDARY	24,787,156	207,278	24,994,434		0.9419021	26,536,126		
TOTAL RETAIL	29,499,477	246,683	29,746,160	96.33%	0.9457774	31,451,545	96.45%	1.0013
B. WHOLESALE								
1. SOURCE LEVEL	310,763	9,878	320,641		1.0000000	320,641		
2. TRANSMISSION	661,993	44,928	706,921		0.9750000	725,047		
4. DISTRIBUTION PRIMARY	98,806	7,823	106,629		0.9650000	110,496		
5. DISTRIBUTION SECONDARY	0	0	0		0.9419021	0		
TOTAL WHOLESALE	1,071,562	62,629	1,134,191	3.67%	0.9809779	1,156,184	3.55%	0.9654
C. TOTAL CLASS LOADS	30,571,039	309,312	30,880,351	100.00%	0.9470255	32,607,729	100.00%	1.0000
II. NON-CLASS LOADS								
A. COMPANY USE	152,774	0	152,774		0.9419021	162,197		
B. SEMINOLE ELECTRIC CO-OP	672,040	91,064	763,104		1.0000000	763,104		
C. KISSIMMEE	41,915	194	42,109		0.9750000	43,189		
D. ST. CLOUD	42,008	2,125	44,133		0.9750000	45,265		
E. INTERCHANGE	1,056,702	0	1,056,702		0.9750000	1,083,797		
F. SEPA	18,894	(611)	18,283		1.0000000	18,283		
TOTAL NON-CLASS	1,984,333	92,772	2,077,105		0.9816952	2,115,835		
TOTAL SYSTEM	32,555,372	402,084	32,957,456		0.9491381	34,723,564		

COMPANY: FPC

SCHEDULE E2

FUEL AND PURCHASED POWER COST RECOVERY CALCULATION

Estimated For The Period of:
October 1996 through March 1997

			Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	TOTAL
1	Fuel Cost of Sys.Net Generation		33,069,059	27,517,260	32,063,738	32,671,525	30,264,389	31,017,617	186,603,588
1a	Nuclear Fuel Disposal Cost		519,910	510,458	527,474	501,542	453,006	501,542	3,013,932
1b	Adjustments to Fuel Cost		119,631	1,554,626	118,081	117,306	116,531	115,756	2,141,931
2	Fuel Cost of Power Sold		(2,341,300)	(2,475,200)	(1,951,410)	(1,429,600)	(2,063,600)	(1,779,300)	(12,040,410)
2a	Fuel Cost of Stratified Sales		(2,645,780)	(2,096,380)	(439,250)	(435,680)	(1,442,610)	(1,830,950)	(8,890,650)
2b	Gains on Power Sales		(410,800)	(413,920)	(347,600)	(257,920)	(354,640)	(290,880)	(2,075,760)
3	Fuel Cost of Purchased Power		1,560,440	1,778,760	528,630	844,540	374,040	1,212,940	6,299,350
3a	Recov. Non-Fuel Cost of Econ.Purchs		113,600	113,600	113,600	113,600	113,600	113,600	681,600
3b	Payments to Qualifying Facilities		12,095,330	11,961,520	11,553,120	12,348,030	11,678,480	13,685,530	73,322,010
4	Fuel Cost of Economy Purchases		808,730	689,673	875,559	2,189,605	1,682,876	2,284,462	8,530,904
5	Total Fuel & Net Power Transacts.		42,888,820	39,140,397	43,041,942	46,662,948	40,822,072	45,030,317	257,586,495
6	Adjusted System Sales	MWH	2,800,948	2,366,218	2,379,777	2,496,659	2,403,043	2,283,597	14,730,242
7	System Cost per KWH Sold	c/kwh	1.5312	1.6541	1.8087	1.8690	1.6988	1.9719	1.7487
7a	Jurisdictional Loss Multiplier	x	1.0013	1.0013	1.0013	1.0013	1.0013	1.0013	1.0013
7b	Jurisdict. Cost per KWH Sold	c/kwh	1.5332	1.6563	1.8110	1.8714	1.7010	1.9745	1.7514
8	Prior Period True-Up**	c/kwh	0.2614	0.3088	0.3053	0.2906	0.3010	0.3176	0.2963
8a	Market Price True-Up for 1995**	c/kwh	-0.0015	-0.0017	-0.0017	-0.0016	-0.0017	-0.0018	-0.0016
9	Total Jurisd. Fuel Expense	c/kwh	1.7931	1.9634	2.1146	2.1604	2.0003	2.2903	2.0461
10	Revenue Tax Multiplier	x	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083	1.00083
11	Fuel Cost Factor Adjusted for Taxes	c/kwh	1.7946	1.9650	2.1164	2.1622	2.0020	2.2922	2.0478
12	GPIF	c/kwh	0.0093	0.0109	0.0108	0.0103	0.0107	0.0112	0.0105
13	Total Fuel Cost Factor rounded to nearest .001	c/kwh	1.804	1.976	2.127	2.173	2.013	2.303	2.058

** Based on Jurisdictional Sales only

COMPANY: FPC

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

SCHEDULE E3

Estimated for the Period of:
October 1996 through March 1997

		Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	PERIOD TOTAL
	FUEL COST OF SYSTEM NET GENERATION (DOLLARS)							
1	HEAVY OIL	5,279,996	3,900,268	3,161,596	3,302,689	3,523,285	7,095,803	26,263,637
2	LIGHT OIL	652,254	920,762	1,436,834	2,234,757	1,544,813	1,562,922	8,352,342
3	COAL	24,014,461	19,346,877	24,380,394	24,095,241	22,380,169	18,810,787	133,027,929
4	GAS	913,671	1,171,787	853,339	902,748	858,756	1,412,015	6,112,316
5	NUCLEAR	1,919,384	1,888,273	1,942,282	1,846,797	1,668,073	1,846,797	11,111,606
6	OTHER	289,293	289,293	289,293	289,293	289,293	289,293	1,735,758
7	TOTAL ($)	$33,069,059	$27,517,260	$32,063,738	$32,671,525	$30,264,389	$31,017,617	$186,603,588
	SYSTEM NET GENERATION (MWH)							
8	HEAVY OIL	186,708	135,308	83,138	82,593	92,933	228,194	808,874
9	LIGHT OIL	15,191	19,559	27,803	40,523	28,671	31,947	163,694
10	COAL	1,344,137	1,082,686	1,369,416	1,349,391	1,240,537	1,043,686	7,429,853
11	GAS	33,226	40,125	26,844	32,466	32,851	55,640	221,152
12	NUCLEAR	556,053	545,944	564,143	536,409	484,498	536,409	3,223,456
13	OTHER	0	0	0	0	0	0	0
14	TOTAL (MWH)	2,135,315	1,823,622	2,071,344	2,041,382	1,879,490	1,895,876	11,847,029
	UNITS OF FUEL BURNED							
15	HEAVY OIL (BBL)	265,158	195,996	156,347	160,933	167,076	329,797	1,275,307
16	LIGHT OIL (BBL)	25,392	35,785	55,914	84,769	58,009	58,464	318,332
17	COAL (TONS)	501,652	400,117	508,253	503,388	459,550	389,485	2,762,446
18	GAS (MCF)	382,771	474,642	364,376	411,007	393,657	602,848	2,629,301
19	NUCLEAR (MMBTU)	5,816,314	5,722,039	5,885,704	5,596,355	5,054,768	5,596,355	33,671,535
20	OTHER (BBL)	12,069	12,069	12,069	12,069	12,069	12,069	72,414
	BTU'S BURNED (MILLION BTU)							
21	HEAVY OIL	1,697,012	1,254,376	1,000,619	1,029,974	1,069,284	2,110,698	8,161,963
22	LIGHT OIL	147,272	207,552	324,301	491,659	336,451	339,093	1,846,328
23	COAL	12,610,916	10,058,729	12,778,518	12,643,286	11,538,336	9,782,716	69,412,501
24	GAS	382,771	474,642	364,376	411,007	393,657	602,848	2,629,301
25	NUCLEAR	5,816,314	5,722,039	5,885,704	5,596,355	5,054,768	5,596,355	33,671,535
26	OTHER	70,000	70,000	70,000	70,000	70,000	70,000	420,000
27	TOTAL (MBTU)	20,724,286	17,787,338	20,423,518	20,242,281	18,462,495	18,501,710	116,141,628
	GENERATION MIX (% MWH)							
28	HEAVY OIL	8.74	7.42	4.01	4.05	4.94	12.04	6.83
29	LIGHT OIL	0.71	1.07	1.34	1.99	1.53	1.69	1.38
30	COAL	62.95	59.37	66.11	66.10	66.00	55.05	62.71
31	GAS	1.56	2.20	1.30	1.59	1.75	2.93	1.87
32	NUCLEAR	26.04	29.94	27.24	26.28	25.78	28.29	27.21
33	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST ($/UNIT)							
35	HEAVY OIL	19.91	19.90	20.22	20.52	21.09	21.52	20.59
36	LIGHT OIL	25.69	25.73	25.70	26.36	26.63	26.73	26.24
37	COAL	47.87	48.35	47.97	47.87	48.70	48.30	48.16
38	GAS	2.39	2.47	2.34	2.20	2.18	2.34	2.32
39	NUCLEAR	0.33	0.33	0.33	0.33	0.33	0.33	0.33
40	OTHER	23.97	23.97	23.97	23.97	23.97	23.97	23.97
	FUEL COST PER MILLION BTU ($/MBTU)							
41	HEAVY OIL	3.11	3.11	3.16	3.21	3.29	3.36	3.22
42	LIGHT OIL	4.43	4.44	4.43	4.55	4.59	4.61	4.52
43	COAL	1.90	1.92	1.91	1.91	1.94	1.92	1.92
44	GAS	2.39	2.47	2.34	2.20	2.18	2.34	2.32
45	NUCLEAR	0.33	0.33	0.33	0.33	0.33	0.33	0.33
46	OTHER	4.13	4.13	4.13	4.13	4.13	4.13	4.13
47	SYSTEM ($/MBTU)	1.60	1.55	1.57	1.61	1.64	1.68	1.61
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL	9,089	9,271	12,036	12,470	11,506	9,250	10,091
49	LIGHT OIL	9,695	10,612	11,664	12,133	11,735	10,614	11,279
50	COAL	9,382	9,291	9,331	9,370	9,301	9,373	9,342
51	GAS	11,520	11,829	13,574	12,660	11,983	10,835	11,889
52	NUCLEAR	10,460	10,481	10,433	10,433	10,433	10,433	10,446
53	OTHER	0	0	0	0	0	0	0
54	SYSTEM (BTU/KWH)	9,705	9,754	9,860	9,916	9,823	9,759	9,803
	GENERATION FUEL COST PER KWH (CENTS/KWH)							
55	HEAVY OIL	2.83	2.88	3.80	4.00	3.79	3.11	3.25
56	LIGHT OIL	4.29	4.71	5.17	5.51	5.39	4.89	5.10
57	COAL	1.79	1.79	1.78	1.79	1.80	1.80	1.79
58	GAS	2.75	2.92	3.18	2.78	2.61	2.54	2.76
59	NUCLEAR	0.35	0.35	0.34	0.34	0.34	0.34	0.34
60	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	SYSTEM (CENTS/KWH)	1.55	1.51	1.55	1.60	1.61	1.64	1.58

COMPANY: FPC

SYSTEM NET GENERATION AND FUEL COST

SCHEDULE E4

Estimated for the Month of: Oct-96

	(A) PLANT /UNIT		(B) NET CAPAC. (MW)	(C) NET GENERATION (MWH)	(D) CAPAC. FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG.NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) HEAT VALUE (MBTU/ UNIT)	(K) FUEL BURNED (MBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (c/KWH)
1	CR NUC	3	756	556,053	98.9	98.9	100.0	10,460	NUCL	5,816,314 MBTU	1.00	5,816,314	1,919,384	0.35
2	CRYSTAL	1	372	119,751	43.3	54.8	76.6	9,739	COAL	46,280 TONS	25.20	1,166,255	1,981,266	1.65
3	CRYSTAL	1		0				0	L OIL	0 BBLS	5.80	0	0	0.00
4	CRYSTAL	2	468	305,311	87.8	90.1	98.6	9,427	COAL	114,213 TONS	25.20	2,878,167	4,889,508	1.60
5	CRYSTAL	2		543				9,427	L OIL	883 BBLS	5.80	5,119	22,934	4.22
6	CRYSTAL	4	697	422,741	81.7	96.2	84.6	9,344	COAL	157,312 TONS	25.11	3,950,092	7,905,117	1.87
7	CRYSTAL	4		779				9,344	L OIL	1,255 BBLS	5.80	7,279	32,612	4.19
8	CRYSTAL	5	697	496,334	95.7	97.7	97.7	9,301	COAL	183,847 TONS	25.11	4,616,403	9,238,570	1.86
9	CRYSTAL	5		0				0	L OIL	0 BBLS	5.80	0	0	0.00
10	ANCLOTE	1	503	146,730	41.5	97.6	62.1	8,768	H OIL	201,020 BBLS	6.40	1,286,529	4,170,346	2.84
11	ANCLOTE	1		8,657				8,768	L OIL	13,087 BBLS	5.80	75,905	334,770	3.87
12	ANCLOTE	2	503	16,263	4.7	12.5	54.2	8,757	H OIL	22,252 BBLS	6.40	142,415	461,646	2.84
13	ANCLOTE	2		1,182				8,757	L OIL	1,785 BBLS	5.80	10,351	45,651	3.86
14	BARTOW	1	115	5,548	6.9	99.7	82.7	10,532	H OIL	9,130 BBLS	6.40	58,432	141,247	2.55
15	BARTOW	1		333				10,532	L OIL	605 BBLS	5.80	3,507	15,131	4.54
16	BARTOW	2	117	6,192	7.1	99.5	81.7	10,730	H OIL	10,381 BBLS	6.40	66,440	160,606	2.59
17	BARTOW	3	208	11,975	15.8	96.7	36.8	11,958	H OIL	22,375 BBLS	6.40	143,197	346,151	2.89
18	BARTOW	3		12,475				12,388	GAS	154,540 MCF	1.00	154,540	424,986	3.41
19	SUWANNEE	1	33	0	0.0	0.0	0.0	0	H OIL	0 BBLS	6.40	0	0	0.00
20	SUWANNEE	2	32	0	0.0	0.0	0.0	0	H OIL	0 BBLS	6.40	0	0	0.00
21	SUWANNEE	3	80	229	3.9	100.0	84.6	11,941	L OIL	471 BBLS	5.80	2,734	12,078	5.27
22	SUWANNEE	3		2,072				12,371	GAS	25,633 MCF	1.00	25,633	77,923	3.76
23	DEBARY	1-6	324	1,163	0.5	100.0	89.4	12,056	L OIL	2,417 BBLS	5.80	14,021	62,642	5.39
24	DEBARY	7-10	332	1,189	0.5	100.0	82.3	12,469	L OIL	2,556 BBLS	5.80	14,826	66,236	5.57
25	INT CITY	1-6	282	2	0.0	100.0	42.6	13,159	L OIL	5 BBLS	5.80	26	117	5.86
26	INT CITY	7-10	332	894	1.0	100.0	85.9	11,969	L OIL	1,845 BBLS	5.80	10,700	47,649	5.33
27	INT CITY	7-10		1,486				12,400	GAS	18,426 MCF	1.00	18,426	55,279	3.72
28	INT CITY	11	135	0	0.0	0.0	0.0	0	L OIL	0 BBLS	5.80	0	0	0.00
29	PAVON PK	1-2	58	0	0.0	0.0	0.0	15,429	L OIL	0 BBLS	5.80	0	0	0.00
30	PBARTOW	1-4	187	24	0.0	100.0	85.6	13,093	L OIL	54 BBLS	5.80	314	1,356	5.65
31	PBAYBORO	1-4	188	15	0.0	100.0	79.8	13,093	L OIL	34 BBLS	5.80	196	886	5.90
32	PHIGGINS	1-2	58	0	0.0	0.0	0.0	22,000	L OIL	0 BBLS	5.80	0	0	0.00
33	PHIGGINS	3-4	70	0	0.0	0.0	0.0	14,615	L OIL	0 BBLS	5.80	0	0	0.00
34	PINAR	1	15	0	0.0	0.0	0.0	0	L OIL	0 BBLS	5.80	0	0	0.00
35	P SWAN	1-3	162	128	0.1	100.0	91.2	12,676	L OIL	280 BBLS	5.80	1,623	7,166	5.60
36	PTURNER	1-2	30	0	0.0	0.0	0.0	0	L OIL	0 BBLS	5.80	0	0	0.00
37	PTURNER	3-4	130	53	0.1	100.0	81.5	12,654	L OIL	116 BBLS	5.80	671	3,025	5.71
38	ST JOE	1	15	0	0	0	0.0	0	L OIL	0 BBLS	5.8	0	0	0.00
39	UNIVERS	1	36	17,193	64.2	96.0	66.9	10,712	GAS	184,171 MCF	1.00	184,171	355,483	2.07
40	OTHER		0	0	0.0	0.0	0.0	0	S OIL	12,069 BBLS	5.80	70,000	289,293	0.00
	TOTAL		6,935	2,135,315				9,705				20,724,286	33,069,059	1.55

COMPANY: FPC

SYSTEM NET GENERATION AND FUEL COST

SCHEDULE E4

Estimated for the Month of: Nov-96

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT /UNIT		NET CAPAC. (MW)	NET GENERATION (MWH)	CAPAC. FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		HEAT VALUE (MBTU/ UNIT)	FUEL BURNED (MBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (c/KWH)
1	CR NUC	3	767	545,944	98.9	98.9	100.0	10,481	NUCL	5,722,039	MBTU	1.00	5,722,039	1,888,273	0.35
2	CRYSTAL	1	373	0	0.0	0.0	0.0	0	COAL	0	TONS	25.19	0	0	0.00
3	CRYSTAL	1		0				0	L OIL	0	BBLS	5.80	0	0	0.00
4	CRYSTAL	2	469	297,014	88.1	90.5	99.0	9,426	COAL	111,141	TONS	25.19	2,799,654	4,751,514	1.60
5	CRYSTAL	2		543				9,426	L OIL	882	BBLS	5.80	5,118	22,853	4.21
6	CRYSTAL	4	717	441,111	85.6	96.6	88.6	9,288	COAL	163,099	TONS	25.12	4,097,039	8,237,656	1.87
7	CRYSTAL	4		611				9,288	L OIL	978	BBLS	5.80	5,675	25,338	4.15
8	CRYSTAL	5	717	344,561	66.8	68.5	97.4	9,177	COAL	125,877	TONS	25.12	3,162,036	6,357,706	1.85
9	CRYSTAL	5		385				9,177	L OIL	609	BBLS	5.80	3,533	15,775	4.10
10	ANCLOTE	1	517	117,103	33.3	81.2	51.6	8,949	H OIL	163,743	BBLS	6.40	1,047,955	3,401,285	2.90
11	ANCLOTE	1		6,940				8,949	L OIL	10,708	BBLS	5.80	62,106	273,910	3.95
12	ANCLOTE	2	517	0	0.0	0.0	0.0	0	H OIL	0	BBLS	6.40	0	0	0.00
13	ANCLOTE	2		0				0	L OIL	0	BBLS	5.80	0	0	0.00
14	BARTOW	1	117	5,954	7.5	76.3	84.0	10,479	H OIL	9,749	BBLS	6.40	62,392	150,821	2.53
15	BARTOW	1		335				10,479	L OIL	605	BBLS	5.80	3,510	15,146	4.52
16	BARTOW	2	119	4,271	5.0	76.4	83.7	10,700	H OIL	7,141	BBLS	6.40	45,700	110,470	2.59
17	BARTOW	3	213	7,980	16.7	95.7	28.9	12,322	H OIL	15,364	BBLS	6.40	98,330	237,643	2.98
18	BARTOW	3		17,703				12,766	GAS	225,996	MCF	1.00	225,996	621,490	3.51
19	SUWANNEE	1	34	0	0.0	0.0	0.0	0	H OIL	0	BBLS	6.40	0	0	0.00
20	SUWANNEE	2	33	0	0.0	0.0	0.0	0	H OIL	0	BBLS	6.40	0	0	0.00
21	SUWANNEE	3	80	286	4.9	100.0	91.2	11,955	L OIL	590	BBLS	5.80	3,419	15,096	5.28
22	SUWANNEE	3		2,558				12,385	GAS	31,681	MCF	1.00	31,681	96,310	3.77
23	DEBARY	1-6	390	1,425	0.5	100.0	92.9	12,043	L OIL	2,959	BBLS	5.80	17,161	76,645	5.38
24	DEBARY	7-10	396	1,517	0.5	100.0	83.3	12,319	L OIL	3,222	BBLS	5.80	18,688	83,463	5.50
25	INT CITY	1-6	354	565	0.2	100.0	90.3	12,390	L OIL	1,207	BBLS	5.80	7,000	31,173	5.52
26	INT CITY	7-10	396	2,252	1.9	99.9	90.2	11,815	L OIL	4,587	BBLS	5.80	26,607	118,485	5.26
27	INT CITY	7-10		3,032				12,241	GAS	37,115	MCF	1.00	37,115	111,344	3.67
28	INT CITY	11	165	3,152	2.7	99.9	88.0	11,303	L OIL	6,143	BBLS	5.80	35,627	158,650	5.03
29	PAVON PK	1-2	64	0	0.0	0.0	0.0	0	L OIL	0	BBLS	5.80	0	0	0.00
30	PBARTOW	1-4	217	122	0.1	100.0	93.7	12,848	L OIL	270	BBLS	5.80	1,567	6,763	5.54
31	PBAYBORO	1-4	232	3	0.0	100.0	51.7	13,079	L OIL	7	BBLS	5.80	39	177	5.90
32	PHIGGINS	1-2	74	0	0.0	0.0	0.0	14,667	L OIL	0	BBLS	5.80	0	0	0.00
33	PHIGGINS	3-4	84	0	0.0	100.0	0.0	13,969	L OIL	0	BBLS	5.80	0	0	0.00
34	PINAR	1	18	0	0.0	0.0	0.0	0	L OIL	0	BBLS	5.80	0	0	0.00
35	P SWAN	1-3	201	1,400	1.0	100.0	92.9	12,291	L OIL	2,967	BBLS	5.80	17,207	75,974	5.43
36	PTURNER	1-2	36	0	0.0	0.0	0.0	0	L OIL	0	BBLS	5.80	0	0	0.00
37	PTURNER	3-4	164	23	0.0	100.0	70.1	12,680	L OIL	50	BBLS	5.80	292	1,316	5.72
38	ST JOE	1	18	0	0	0	0.0	0	L OIL	0	BBLS	5.8	0	0	0.00
39	UNIVERS	1	42	16,832	55.7	96.0	58.0	10,685	GAS	179,850	MCF	1.00	179,850	342,643	2.04
40	OTHER		0	0	0.0	0.0	0.0	0	S OIL	12,069	BBLS	5.80	70,000	289,293	0.00
	TOTAL		7,524	1,823,622				9,754					17,787,338	27,517,260	1.51

COMPANY: FPC

SYSTEM NET GENERATION AND FUEL COST

SCHEDULE E4

Estimated for the Month of: Dec-96

	(A) PLANT /UNIT	(B) NET CAPAC. (MW)	(C) NET GENERATION (MWH)	(D) CAPAC. FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) HEAT VALUE (MBTU/ UNIT)	(K) FUEL BURNED (MBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (c/KWH)
1	CR NUC 3	767	564,143	98.9	98.9	100.0	10,433	NUCL	5,885,704 MBTU	1.00	5,885,704	1,942,282	0.34
2	CRYSTAL 1	373	166,248	60.0	94.7	61.7	10,115	COAL	66,704 TONS	25.21	1,681,599	2,838,343	1.71
3	CRYSTAL 1		214				10,115	L OIL	373 BBLS	5.80	2,165	9,640	4.50
4	CRYSTAL 2	469	258,024	74.2	75.9	99.4	9,383	COAL	96,035 TONS	25.21	2,421,039	4,086,433	1.58
5	CRYSTAL 2		818				9,383	L OIL	1,323 BBLS	5.80	7,675	34,180	4.18
6	CRYSTAL 4	717	451,962	84.8	96.6	87.9	9,241	COAL	166,331 TONS	25.11	4,176,581	8,403,159	1.86
7	CRYSTAL 4		595				9,241	L OIL	948 BBLS	5.80	5,498	24,486	4.12
8	CRYSTAL 5	717	493,182	92.5	97.8	94.4	9,123	COAL	179,184 TONS	25.11	4,499,299	9,052,459	1.84
9	CRYSTAL 5		0				0	L OIL	0 BBLS	5.80	0	0	0.00
10	ANCLOTE 1	517	42,298	12.9	97.7	19.0	12,142	H OIL	80,247 BBLS	6.40	513,582	1,667,560	3.94
11	ANCLOTE 1		7,388				12,142	L OIL	15,466 BBLS	5.80	89,705	395,631	5.36
12	ANCLOTE 2	517	32,293	10.1	77.8	17.4	11,822	H OIL	59,651 BBLS	6.40	381,768	1,239,569	3.84
13	ANCLOTE 2		6,420				11,822	L OIL	13,086 BBLS	5.80	75,897	334,733	5.21
14	BARTOW 1	117	2,399	2.9	99.9	89.8	10,314	H OIL	3,866 BBLS	6.40	24,743	59,812	2.49
15	BARTOW 1		113				10,314	L OIL	201 BBLS	5.80	1,165	5,028	4.45
16	BARTOW 2	119	2,340	2.6	99.9	91.0	10,541	H OIL	3,854 BBLS	6.40	24,666	59,625	2.55
17	BARTOW 3	213	3,808	9.8	95.9	17.6	14,669	H OIL	8,728 BBLS	6.40	55,860	135,030	3.55
18	BARTOW 3		11,654				15,197	GAS	177,106 MCF	1.00	177,106	487,041	4.18
19	SUWANNEE 1	34	0	0.0	0.0	0.0	0	H OIL	0 BBLS	6.40	0	0	0.00
20	SUWANNEE 2	33	0	0.0	0.0	0.0	0	H OIL	0 BBLS	6.40	0	0	0.00
21	SUWANNEE 3	80	119	2.5	100.0	97.9	11,518	L OIL	236 BBLS	5.80	1,371	6,052	5.09
22	SUWANNEE 3		1,392				11,933	GAS	16,611 MCF	1.00	16,611	50,497	3.63
23	DEBARY 1-6	390	2,983	1.0	100.0	95.2	11,542	L OIL	5,936 BBLS	5.80	34,430	153,673	5.15
24	DEBARY 7-10	396	3,369	1.1	100.0	92.5	11,671	L OIL	6,779 BBLS	5.80	39,320	175,498	5.21
25	INT CITY 1-6	354	142	0.1	100.0	89.1	12,950	L OIL	317 BBLS	5.80	1,839	8,171	5.75
26	INT CITY 7-10	396	1,771	1.4	99.9	78.0	11,354	L OIL	3,467 BBLS	5.80	20,108	89,349	5.05
27	INT CITY 7-10		2,320				11,762	GAS	27,288 MCF	1.00	27,288	81,864	3.53
28	INT CITY 11	165	2,322	1.9	99.9	96.4	11,207	L OIL	4,487 BBLS	5.80	26,023	115,631	4.98
29	PAVON PK 1-2	64	0	0.0	100.0	0.0	15,437	L OIL	0 BBLS	5.80	0	0	0.00
30	PBARTOW 1-4	217	427	0.3	100.0	91.5	12,710	L OIL	936 BBLS	5.80	5,427	23,415	5.48
31	PBAYBORO 1-4	232	51	0.0	100.0	87.9	13,197	L OIL	116 BBLS	5.80	673	3,035	5.95
32	PHIGGINS 1-2	74	0	0.0	100.0	0.0	15,850	L OIL	0 BBLS	5.80	0	0	0.00
33	PHIGGINS 3-4	84	1	0.0	100.0	0.0	14,624	L OIL	3 BBLS	5.80	15	61	6.10
34	PINAR 1	18	0	0.0	0.0	0.0	0	L OIL	0 BBLS	5.80	0	0	0.00
35	P SWAN 1-3	201	281	0.2	100.0	87.4	13,038	L OIL	632 BBLS	5.80	3,664	16,176	5.76
36	PTURNER 1-2	36	0	0.0	0.0	0.0	0	L OIL	0 BBLS	5.80	0	0	0.00
37	PTURNER 3-4	164	789	0.6	99.9	95.3	11,821	L OIL	1,608 BBLS	5.80	9,327	42,075	5.33
38	ST JOE 1	18	0	0	0	0.0	0	L OIL	0 BBLS	5.8	0	0	0.00
39	UNIVERS 1	42	11,478	36.7	96.0	38.3	12,491	GAS	143,372 MCF	1.00	143,372	233,938	2.04
40	OTHER	0	0	0.0	0.0	0.0	0	S OIL	12,069 BBLS	5.80	70,000	289,293	0.00
	TOTAL	7,524	2,071,344				9,860				20,423,518	32,063,739	1.55

COMPANY: FPC

SYSTEM NET GENERATION AND FUEL COST

SCHEDULE E4

Estimated for the Month of: Jan-97

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT		NET CAPAC. (MW)	NET GENERATION (MWH)	CAPAC. FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG.NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	HEAT VALUE (MBTU/ UNIT)	FUEL BURNED (MBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (c/KWH)
1	CR NUC	3	767	536,409	94.0	98.9	100.0	10,433	NUCL	5,596,355 MBTU	1.00	5,596,355	1,846,797	0.34
2	CRYSTAL	1	373	170,735	61.5	94.7	63.3	10,072	COAL	68,294 TONS	25.18	1,719,643	2,908,192	1.70
3	CRYSTAL	1		0				0	L OIL	0 BBLS	5.80	0	0	0.00
4	CRYSTAL	2	469	309,004	88.7	90.5	99.6	9,369	COAL	114,975 TONS	25.18	2,895,058	4,896,008	1.58
5	CRYSTAL	2		546				9,369	L OIL	882 BBLS	5.80	5,115	22,781	4.17
6	CRYSTAL	4	717	379,875	71.4	96.6	73.9	9,375	COAL	141,999 TONS	25.08	3,561,328	7,226,398	1.90
7	CRYSTAL	4		989				9,375	L OIL	1,599 BBLS	5.80	9,272	41,290	4.17
8	CRYSTAL	5	717	489,777	91.8	97.8	93.7	9,121	COAL	178,120 TONS	25.08	4,467,256	9,064,644	1.85
9	CRYSTAL	5		0				0	L OIL	0 BBLS	5.80	0	0	0.00
10	ANCLOTE	1	517	35,022	10.9	97.6	15.4	13,234	H OIL	72,419 BBLS	6.40	463,481	1,528,328	4.36
11	ANCLOTE	1		6,778				13,234	L OIL	15,466 BBLS	5.80	89,700	419,301	6.19
12	ANCLOTE	2	517	38,124	11.8	96.4	16.4	11,929	H OIL	71,060 BBLS	6.40	454,781	1,499,640	3.93
13	ANCLOTE	2		7,230				11,929	L OIL	14,870 BBLS	5.80	86,247	403,158	5.58
14	BARTOW	1	117	2,533	3.0	99.9	92.3	10,280	H OIL	4,069 BBLS	6.40	26,039	64,036	2.53
15	BARTOW	1		114				10,280	L OIL	202 BBLS	5.80	1,172	5,056	4.44
16	BARTOW	2	119	2,598	2.9	99.8	92.1	10,471	H OIL	4,251 BBLS	6.40	27,204	66,899	2.58
17	BARTOW	3	213	4,316	12.0	95.8	20.8	13,547	H OIL	9,136 BBLS	6.40	58,469	143,786	3.33
18	BARTOW	3		14,650				14,035	GAS	205,613 MCF	1.00	205,613	524,313	3.58
19	SUWANNEE	1	0	0	0.0	0.0	0.0	0	H OIL	0 BBLS	6.40	0	0	0.00
20	SUWANNEE	2	0	0	0.0	0.0	0.0	0	H OIL	0 BBLS	6.40	0	0	0.00
21	SUWANNEE	3	0	0	0.0	0.0	0.0	0	L OIL	0 BBLS	5.80	0	0	0.00
22	SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23	DEBARY	1-6	390	4,493	1.5	99.9	97.6	11,585	L OIL	8,974 BBLS	5.80	52,051	235,115	5.23
24	DEBARY	7-10	396	4,414	1.5	99.9	96.7	11,621	L OIL	8,844 BBLS	5.80	51,295	231,699	5.25
25	INT CITY	1-6	354	2,379	0.9	100.0	98.3	12,879	L OIL	5,283 BBLS	5.80	30,639	137,214	5.77
26	INT CITY	7-10	396	2,985	2.1	99.9	84.6	11,393	L OIL	5,863 BBLS	5.80	34,008	152,301	5.10
27	INT CITY	7-10		3,180				11,803	GAS	37,534 MCF	1.00	37,534	105,094	3.30
28	INT CITY	11	165	3,007	2.4	99.9	95.9	11,196	L OIL	5,805 BBLS	5.80	33,666	150,771	5.01
29	PAVON PK	1-2	64	255	0.5	99.9	98.4	15,257	L OIL	671 BBLS	5.80	3,891	16,864	6.61
30	PBARTOW	1-4	217	1,879	1.2	100.0	98.7	12,539	L OIL	4,062 BBLS	5.80	23,561	101,651	5.41
31	PBAYBORO	1-4	232	1,395	0.8	100.0	98.2	13,057	L OIL	3,140 BBLS	5.80	18,215	83,360	5.98
32	PHIGGINS	1-2	74	333	0.6	100.0	97.8	15,796	L OIL	907 BBLS	5.80	5,260	22,775	6.84
33	PHIGGINS	3-4	84	353	0.6	100.0	98.9	14,329	L OIL	872 BBLS	5.80	5,058	21,901	6.20
34	PINAR	1	18	84	0.6	100.0	97.2	15,751	L OIL	228 BBLS	5.80	1,323	5,675	6.76
35	P SWAN	1-3	201	1,584	1.1	100.0	98.5	12,557	L OIL	3,429 BBLS	5.80	19,890	87,819	5.54
36	PTURNER	1-2	36	168	0.6	100.0	98.2	16,619	L OIL	481 BBLS	5.80	2,792	12,595	7.50
37	PTURNER	3-4	164	1,453	1.2	99.9	97.9	11,812	L OIL	2,959 BBLS	5.80	17,163	77,425	5.33
38	ST JOE	1	18	84	0.6	99.99	97.2	15963	L OIL	231 BBLS	5.8	1,341	6,005	7.15
39	UNIVERS	1	42	14,636	46.8	96.0	48.8	11,469	GAS	167,860 MCF	1.00	167,860	273,342	1.87
40	OTHER		0	0	0.0	0.0	0.0	0	S OIL	12,069 BBLS	5.80	70,000	289,293	0.00
	TOTAL		7,377	2,041,382				9,916				20,242,281	32,671,524	1.60

Estimated for the Month of: Feb-97

	(A) PLANT /UNIT		(B) NET CAPAC. (MW)	(C) NET GENERATION (MWH)	(D) CAPAC. FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG.NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) HEAT VALUE (MBTU/ UNIT)	(K) FUEL BURNED (MBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (c/KWH)
1	CR NUC	3	767	484,498	94.0	98.9	100.0	10,433	NUCL	5,054,768 MBTU	1.00	5,054,768	1,668,073	0.34
2	CRYSTAL	1	373	192,151	76.7	94.7	78.8	9,986	COAL	76,204 TONS	25.18	1,918,820	3,247,056	1.69
3	CRYSTAL	1		0				0	L OIL	0 BBLS	5.80	0	0	0.00
4	CRYSTAL	2	469	139,581	44.4	45.2	99.7	9,371	COAL	51,947 TONS	25.18	1,308,014	2,213,440	1.59
5	CRYSTAL	2		273				9,371	L OIL	441 BBLS	5.80	2,558	11,393	4.17
6	CRYSTAL	4	717	455,021	94.4	96.6	97.8	9,167	COAL	166,315 TONS	25.08	4,171,178	8,491,239	1.87
7	CRYSTAL	4		0				0	L OIL	0 BBLS	5.80	0	0	0.00
8	CRYSTAL	5	717	413,784	94.2	97.8	96.2	9,124	COAL	165,085 TONS	25.08	4,140,325	8,428,434	1.86
9	CRYSTAL	5		0				0	L OIL	0 BBLS	5.80	0	0	0.00
10	ANCLOTE	1	517	43,131	14.3	97.5	19.1	11,790	H OIL	79,455 BBLS	6.40	508,514	1,708,657	3.96
11	ANCLOTE	1		6,438				11,790	L OIL	13,087 BBLS	5.80	75,904	357,203	5.55
12	ANCLOTE	2	517	43,551	14.4	96.2	18.6	11,102	H OIL	75,547 BBLS	6.40	483,503	1,624,616	3.73
13	ANCLOTE	2		6,526				11,102	L OIL	12,492 BBLS	5.80	72,452	340,956	5.22
14	BARTOW	1	117	743	1.0	46.4	90.9	10,587	H OIL	1,229 BBLS	6.40	7,866	19,344	2.60
15	BARTOW	1		55				10,587	L OIL	100 BBLS	5.80	582	2,512	4.57
16	BARTOW	2	119	1,837	2.3	96.3	88.7	10,721	H OIL	3,077 BBLS	6.40	19,694	48,433	2.64
17	BARTOW	3	213	3,671	11.8	95.8	20.8	13,540	H OIL	7,766 BBLS	6.40	49,705	122,235	3.33
18	BARTOW	3		13,264				14,028	GAS	186,067 MCF	1.00	186,067	474,472	3.58
19	SUWANNEE	1	0	0	0.0	0.0	0.0	0	H OIL	0 BBLS	6.40	0	0	0.00
20	SUWANNEE	2	0	0	0.0	0.0	0.0	0	H OIL	0 BBLS	6.40	0	0	0.00
21	SUWANNEE	3	0	0	0.0	0.0	0.0	0	L OIL	0 BBLS	5.80	0	0	0.00
22	SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23	DEBARY	1-6	390	2,858	1.1	100.0	97.9	11,595	L OIL	5,714 BBLS	5.80	33,139	150,461	5.26
24	DEBARY	7-10	396	3,201	1.2	100.0	98.3	11,587	L OIL	6,395 BBLS	5.80	37,090	168,402	5.26
25	INT CITY	1-6	354	1,491	0.6	100.0	96.8	12,883	L OIL	3,312 BBLS	5.80	19,209	86,023	5.77
26	INT CITY	7-10	396	1,835	1.5	99.9	80.7	11,372	L OIL	3,598 BBLS	5.80	20,868	93,453	5.09
27	INT CITY	7-10		2,104				11,781	GAS	24,787 MCF	1.00	24,787	69,404	3.30
28	INT CITY	11	165	1,509	1.4	99.9	96.3	11,237	L OIL	2,924 BBLS	5.80	16,957	75,938	5.03
29	PAVON PK	1-2	64	118	0.3	100.0	97.0	15,318	L OIL	312 BBLS	5.80	1,808	7,952	6.74
30	PBARTOW	1-4	217	1,012	0.7	100.0	99.2	12,553	L OIL	2,190 BBLS	5.80	12,704	54,809	5.42
31	PBAYBORO	1-4	232	959	0.6	100.0	95.6	13,015	L OIL	2,152 BBLS	5.80	12,481	57,122	5.96
32	PHIGGINS	1-2	74	149	0.3	100.0	95.9	16,047	L OIL	412 BBLS	5.80	2,391	10,352	6.95
33	PHIGGINS	3-4	84	46	0.1	100.0	91.3	14,441	L OIL	115 BBLS	5.80	664	2,876	6.25
34	PINAR	1	18	58	0.5	100.0	97.6	15,778	L OIL	158 BBLS	5.80	915	3,925	6.77
35	P SWAN	1-3	201	892	0.7	100.0	97.9	12,572	L OIL	1,933 BBLS	5.80	11,214	50,517	5.66
36	PTURNER	1-2	36	107	0.4	100.0	97.4	16,636	L OIL	307 BBLS	5.80	1,780	8,145	7.61
37	PTURNER	3-4	164	1,091	1.0	99.9	96.4	11,813	L OIL	2,222 BBLS	5.80	12,888	58,973	5.41
38	ST JOE	1	18	53	0.4	99.99	98.1	16005	L OIL	146 BBLS	5.8	848	3,799	7.17
39	UNIVERS	1	42	17,483	61.9	96.0	64.5	10,456	GAS	182,802 MCF	1.00	182,802	314,880	1.80
40	OTHER		0	0	0.0	0.0	0.0	0	S OIL	12,069 BBLS	5.80	70,000	289,293	0.00
	TOTAL		7,377	1,879,490				9,823				18,462,495	30,264,390	1.61

COMPANY: FPC

SYSTEM NET GENERATION AND FUEL COST

SCHEDULE E4

Estimated for the Month of: Mar-97

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT		NET CAPAC. (MW)	NET GENERATION (MWH)	CAPAC. FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG.NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	HEAT VALUE (MBTU/ UNIT)	FUEL BURNED (MBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (c/KWH)
1	CR NUC	3	767	536,409	94.0	98.9	100.0	10,433	NUCL	5,596,355 MBTU	1.00	5,596,355	1,846,797	0.34
2	CRYSTAL	1	373	237,743	85.7	94.7	88.1	9,964	COAL	94,040 TONS	25.19	2,368,871	4,013,189	1.69
3	CRYSTAL	1		0				0	L OIL	0 BBLS	5.80	0	0	0.00
4	CRYSTAL	2	469	99,351	28.6	29.2	99.7	9,404	COAL	37,090 TONS	25.19	934,297	1,582,825	1.59
5	CRYSTAL	2		544				9,404	L OIL	882 BBLS	5.80	5,116	23,123	4.25
6	CRYSTAL	4	717	491,660	92.2	96.6	95.5	9,189	COAL	180,138 TONS	25.08	4,517,864	9,213,998	1.87
7	CRYSTAL	4		392				9,189	L OIL	621 BBLS	5.80	3,602	16,281	4.15
8	CRYSTAL	5	717	214,932	40.3	41.0	98.0	9,127	COAL	78,217 TONS	25.08	1,961,684	4,000,775	1.86
9	CRYSTAL	5		0				0	L OIL	0 BBLS	5.80	0	0	0.00
10	ANCLOTE	1	517	106,102	29.5	97.2	35.7	9,444	H OIL	156,567 BBLS	6.40	1,002,027	3,405,048	3.21
11	ANCLOTE	1		7,307				9,444	L OIL	11,898 BBLS	5.80	69,007	324,995	4.45
12	ANCLOTE	2	517	114,903	31.8	95.9	38.3	8,938	H OIL	160,469 BBLS	6.40	1,027,003	3,489,919	3.04
13	ANCLOTE	2		7,334				8,938	L OIL	11,302 BBLS	5.80	65,551	308,719	4.21
14	BARTOW	1	117	0	0.0	0.0	0.0	0	H OIL	0 BBLS	6.40	0	0	0.00
15	BARTOW	1		0				0	L OIL	0 BBLS	5.80	0	0	0.00
16	BARTOW	2	119	567	0.6	12.9	95.3	11,174	H OIL	990 BBLS	6.40	6,336	15,581	2.75
17	BARTOW	3	213	6,622	20.8	95.6	34.8	11,376	H OIL	11,771 BBLS	6.40	75,332	185,256	2.80
18	BARTOW	3		26,337				11,786	GAS	310,408 MCF	1.00	310,408	791,540	3.01
19	SUWANNEE	1	0	0	0.0	0.0	0.0	0	H OIL	0 BBLS	6.40	0	0	0.00
20	SUWANNEE	2	0	0	0.0	0.0	0.0	0	H OIL	0 BBLS	6.40	0	0	0.00
21	SUWANNEE	3	0	0	0.0	0.0	0.0	0	L OIL	0 BBLS	5.80	0	0	0.00
22	SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
23	DEBARY	1-6	390	2,329	0.8	100.0	92.1	12,148	L OIL	4,878 BBLS	5.80	28,293	129,321	5.55
24	DEBARY	7-10	396	2,665	0.9	100.0	93.1	12,267	L OIL	5,636 BBLS	5.80	32,692	149,427	5.61
25	INT CITY	1-6	354	1,596	0.6	100.0	93.3	12,436	L OIL	3,422 BBLS	5.80	19,848	90,041	5.64
26	INT CITY	7-10	396	3,621	2.3	99.9	94.6	11,767	L OIL	7,346 BBLS	5.80	42,608	193,294	5.34
27	INT CITY	7-10		3,282				12,191	GAS	40,011 MCF	1.00	40,011	112,030	3.41
28	INT CITY	11	165	3,443	2.8	99.9	90.7	11,309	L OIL	6,713 BBLS	5.80	38,937	176,639	5.13
29	PAVON PK	1-2	64	2	0.0	100.0	62.5	14,625	L OIL	5 BBLS	5.80	29	129	6.43
30	PBARTOW	1-4	217	445	0.3	100.0	100.0	12,651	L OIL	971 BBLS	5.80	5,630	24,289	5.46
31	PBAYBORO	1-4	232	83	0.0	100.0	89.4	13,189	L OIL	189 BBLS	5.80	1,095	5,010	6.04
32	PHIGGINS	1-2	74	2	0.0	100.0	54.1	15,501	L OIL	5 BBLS	5.80	31	134	6.71
33	PHIGGINS	3-4	84	4	0.0	100.0	95.2	14,109	L OIL	10 BBLS	5.80	56	244	6.11
34	PINAR	1	18	0	0.0	0.0	0.0	0	L OIL	0 BBLS	5.80	0	0	0.00
35	P SWAN	1-3	201	1,919	1.3	100.0	97.1	12,146	L OIL	4,019 BBLS	5.80	23,308	106,223	5.54
36	PTURNER	1-2	36	0	0.0	0.0	0.0	0	L OIL	0 BBLS	5.80	0	0	0.00
37	PTURNER	3-4	164	261	0.2	100.0	77.6	12,605	L OIL	567 BBLS	5.80	3,290	15,054	5.77
38	ST JOE	1	18	0	0	0	0.0	0	L OIL	0 BBLS	5.8	0	0	0.00
39	UNIVERS	1	42	26,021	83.3	96.0	86.7	9,701	GAS	252,430 MCF	1.00	252,430	508,445	1.95
40	OTHER		0	0	0.0	0.0	0.0	0	S OIL	12,069 BBLS	5.80	70,000	289,293	0.00
	TOTAL		7,377	1,895,876				9,759				18,501,710	31,017,618	1.64

COMPANY: FPC

SYSTEM NET GENERATION AND FUEL COST

SCHEDULE E4

Estimated for the Period:
October 1996 through March 1997

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT		NET CAPAC. (MW)	NET GENERATION (MWH)	CAPAC. FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG.NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	HEAT VALUE (MBTU/ UNIT)	FUEL BURNED (MBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (c/KWH)
1	CR NUC	3	765	3,223,456	96.4	98.9	100.0	10,446	NUCL	33,671,535 MBTU	1.00	33,671,535	11,111,607	0.34
2	CRYSTAL	1	373	886,628	54.5	72.2	61.4	9,987	COAL	351,522 TONS	25.19	8,855,188	14,988,045	1.69
3	CRYSTAL	1		214				10,115	L OIL	373 BBLS	5.80	2,165	9,640	4.50
4	CRYSTAL	2	469	1,408,285	68.9	70.2	99.3	9,399	COAL	525,400 TONS	25.19	13,236,229	22,419,729	1.59
5	CRYSTAL	2		3,267				9,398	L OIL	5,293 BBLS	5.80	30,702	137,263	4.20
6	CRYSTAL	4	714	2,642,370	84.9	96.5	88.1	9,262	COAL	975,193 TONS	25.10	24,474,081	49,477,568	1.87
7	CRYSTAL	4		3,366				9,307	L OIL	5,401 BBLS	5.80	31,326	140,007	4.16
8	CRYSTAL	5	714	2,492,570	80.0	83.4	96.2	9,166	COAL	910,330 TONS	25.10	22,847,004	46,142,588	1.85
9	CRYSTAL	5		385				9,177	L OIL	609 BBLS	5.80	3,533	15,775	4.10
10	ANCLOTE	1	515	490,386	23.7	94.8	33.8	9,833	H OIL	753,451 BBLS	6.40	4,822,089	15,881,223	3.24
11	ANCLOTE	1		43,508				10,626	L OIL	79,712 BBLS	5.80	462,327	2,105,810	4.84
12	ANCLOTE	2	515	245,134	12.2	63.1	24.1	10,156	H OIL	388,980 BBLS	6.40	2,489,470	8,315,390	3.39
13	ANCLOTE	2		28,692				10,822	L OIL	53,534 BBLS	5.80	310,498	1,433,218	5.00
14	BARTOW	1	117	17,177	3.6			10,448	H OIL	28,043 BBLS	6.40	179,472	435,260	2.53
15	BARTOW	1		950				10,460	L OIL	1,713 BBLS	5.80	9,937	42,874	4.51
16	BARTOW	2	119	17,805	3.4	80.8	88.7	10,673	H OIL	29,694 BBLS	6.40	190,040	461,614	2.59
17	BARTOW	3	212	38,372	14.5	95.9	26.6	12,532	H OIL	75,139 BBLS	6.40	480,892	1,170,151	3.05
18	BARTOW	3		96,083				13,111	GAS	1,259,731 MCF	1.00	1,259,731	3,323,842	3.46
19	SUWANNEE	1		0				0	H OIL	0 BBLS	0.00	0	0	0.00
20	SUWANNEE	2		0				0	H OIL	0 BBLS	0.00	0	0	0.00
21	SUWANNEE	3		634				11,868	L OIL	1,297 BBLS	5.80	7,524	33,226	5.24
22	SUWANNEE	3		6,022				12,276	GAS	73,924 MCF	1.00	73,924	224,730	3.73
23	DEBARY	1-6	379	15,251	0.9	100.0	94.2	11,743	L OIL	30,878 BBLS	5.80	179,095	807,856	5.30
24	DEBARY	7-10	385	16,355	1.0	100.0	91.0	11,856	L OIL	33,433 BBLS	5.80	193,910	874,725	5.35
25	INT CITY	1-6	342	6,175	0.4	100.0	85.1	12,722	L OIL	13,545 BBLS	5.80	78,561	352,739	5.71
26	INT CITY	7-10	385	13,358	1.7	99.9	85.7	11,596	L OIL	26,707 BBLS	5.80	154,900	694,532	5.20
27	INT CITY	7-10		15,404				12,020	GAS	185,161 MCF	1.00	185,161	535,015	3.47
28	INT CITY	11	160	13,433	1.9	83.2	77.9	11,257	L OIL	26,071 BBLS	5.80	151,210	677,629	5.04
29	PAVON PK	1-2	63	375	0.1	66.6	43.0	15,273	L OIL	987 BBLS	5.80	5,727	24,945	6.65
30	PBARTOW	1-4	212	3,909	0.4	100.0	94.8	12,587	L OIL	8,483 BBLS	5.80	49,203	212,282	5.43
31	PBAYBORO	1-4	225	2,506	0.3	100.0	83.8	13,048	L OIL	5,638 BBLS	5.80	32,699	149,590	5.97
32	PHIGGINS	1-2	71	484	0.2	66.7	41.3	15,872	L OIL	1,324 BBLS	5.80	7,682	33,262	6.87
33	PHIGGINS	3-4	82	404	0.1	83.3	47.6	14,340	L OIL	999 BBLS	5.80	5,793	25,082	6.21
34	PINAR	1	18	142	0.2			15,762	L OIL	386 BBLS	5.80	2,238	9,600	6.76
35	P SWAN	1-3	195	6,204	0.7	100.0	94.2	12,396	L OIL	13,260 BBLS	5.80	76,906	343,876	5.54
36	PTURNER	1-2	35	275	0.2			16,626	L OIL	788 BBLS	5.80	4,572	20,740	7.54
37	PTURNER	3-4	158	3,670	0.5	100.0	86.5	11,888	L OIL	7,522 BBLS	5.80	43,630	197,868	5.39
38	ST JOE	1	18	137	0.2			15,979	L OIL	377 BBLS	5.80	2,189	9,803	7.16
39	UNIVERS	1	41	103,643	57.9	96.0	[illegible]	10,715	GAS	1,110,485 MCF	1.00	1,110,485	2,028,730	1.96
40	OTHER								S OIL	72,414 BBLS	5.80	420,000	1,735,759	0.00
	TOTAL		7,279	11,847,029				9,803				116,141,628	186,603,590	1.58

COMPANY: FPC

SCHEDULE E5

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS

Estimated for the Period of:
October 1996 through March 1997

		Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	PERIOD TOTAL
	HEAVY OIL							
1	PURCHASES:							
2	UNITS (BBL)	220,000	220,000	110,000	220,000	220,000	330,000	1,320,000
3	UNIT COST ($/BBL)	20.81	20.81	20.81	19.00	22.00	22.00	21.00
4	AMOUNT ($)	$4,577,100	$4,577,100	$2,288,550	$4,179,450	$4,838,900	$7,258,350	$27,719,450
5	BURNED:							
6	UNITS (BBL)	265,158	195,996	156,347	160,933	167,076	329,797	1,275,307
7	UNIT COST ($/BBL)	19.91	19.90	20.22	20.52	21.09	21.52	20.59
8	AMOUNT ($)	$5,279,996	$3,900,268	$3,161,596	$3,302,689	$3,523,285	$7,095,803	$26,263,637
9	ENDING INVENTORY:							
10	UNITS (BBL)	453,611	477,615	431,268	490,334	543,259	543,462	
11	UNIT COST ($/BBL)	18.92	19.38	19.44	18.89	19.47	19.76	
12	AMOUNT ($)	$8,580,901	$9,257,733	$8,384,688	$9,261,449	$10,577,063	$10,739,610	
13								
14	DAYS SUPPLY	51	73	83	91	98	49	
	LIGHT OIL							
15	PURCHASES:							
16	UNITS (BBL)	23,000	25,000	55,000	82,000	53,000	77,000	315,000
17	UNIT COST ($/BBL)	25.62	25.61	25.58	27.25	27.38	27.31	26.75
18	AMOUNT ($)	$589,190	$640,350	$1,406,800	$2,234,860	$1,451,300	$2,102,590	$8,425,090
19	BURNED:							
20	UNITS (BBL)	25,392	35,785	55,914	84,769	58,009	58,464	318,332
21	UNIT COST ($/BBL)	25.69	25.73	25.70	26.36	26.63	26.73	26.24
22	AMOUNT ($)	$652,254	$920,762	$1,436,834	$2,234,757	$1,544,813	$1,562,922	$8,352,341
23	ENDING INVENTORY:							
24	UNITS (BBL)	306,267	295,482	294,568	291,799	286,790	305,326	
25	UNIT COST ($/BBL)	25.65	25.64	25.61	25.86	25.98	26.17	
26	AMOUNT ($)	$7,855,656	$7,575,244	$7,545,210	$7,545,313	$7,451,801	$7,991,468	
27								
28	DAYS SUPPLY	362	248	158	103	148	157	
	COAL							
29	PURCHASES:							
30	UNITS (TONS)	510,000	390,000	510,000	500,000	460,000	390,000	2,760,000
31	UNIT COST ($/TON)	47.98	48.46	47.97	48.09	48.77	48.41	48.26
32	AMOUNT ($)	$24,471,500	$18,900,900	$24,463,100	$24,047,400	$22,432,600	$18,879,900	$133,195,400
33	BURNED:							
34	UNITS (TONS)	501,652	400,117	508,253	503,388	459,550	389,485	2,762,446
35	UNIT COST ($/TON)	47.87	48.35	47.97	47.87	48.70	48.30	48.16
36	AMOUNT ($)	$24,014,461	$19,346,877	$24,380,394	$24,095,241	$22,380,169	$18,810,787	$133,027,929
37	ENDING INVENTORY:							
38	UNITS (TONS)	408,885	398,768	400,514	397,127	397,576	398,091	
39	UNIT COST ($/TON)	47.45	47.53	47.53	47.82	47.89	48.01	
40	AMOUNT ($)	$19,400,512	$18,954,535	$19,037,241	$18,989,400	$19,041,831	$19,110,944	
41								
42	DAYS SUPPLY	25	30	24	24	27	31	
	GAS							
43	BURNED:							
44	UNITS (MCF)	382,771	474,642	364,376	411,007	393,657	602,848	2,629,301
45	UNIT COST ($/MCF)	2.39	2.47	2.34	2.20	2.18	2.34	2.32
46	AMOUNT ($)	$913,671	$1,171,787	$853,339	$902,748	$858,756	$1,412,015	$6,112,317
	NUCLEAR							
47	BURNED:							
48	UNITS (MMBTU)	5,816,314	5,722,039	5,885,704	5,596,355	5,054,768	5,596,355	33,671,535
49	UNIT COST ($/MMBTU)	0.33	0.33	0.33	0.33	0.33	0.33	0.33
50	AMOUNT ($)	$1,919,384	$1,888,273	$1,942,282	$1,846,797	$1,668,073	$1,846,797	$11,111,607

COMPANY: FPC

FUEL COST OF POWER SOLD

SCHEDULE E6

Estimated for the Period of: October 1996 through March 1997

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	c/KWH (A) FUEL COST	c/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) X (7)(A)	TOTAL COST $ (6) X (7)(B)	REFUNDABLE GAINS ON POWER SALES $
Oct-96	ECONSALE	C	130,000,000		130,000,000	1.801	2.196	2,341,300	2,854,800	410,800
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTH	-	0		0	0.000	0.000	0	0	0
	STRATIFIED	-	105,831,000		105,831,000	2.500	2.500	2,645,780	2,645,780	0
Month			235,831,000		235,831,000	2.115	2.332	4,987,080	5,500,580	410,800
Nov-96	ECONSALE	C	130,000,000		130,000,000	1.904	2.302	2,475,200	2,992,600	413,920
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTH	-	0		0	0.000	0.000	0	0	0
	STRATIFIED	-	83,855,000		83,855,000	2.500	2.500	2,096,380	2,096,380	0
Month			213,855,000		213,855,000	2.138	2.380	4,571,580		
Dec-96	ECONSALE	C	110,000,000		110,000,000	1.774	2.169	1,951,410	2,385,910	347,600
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTH	-	0		0	0.000	0.000	0	0	0
	STRATIFIED	-	12,550,000		12,550,000	3.500	3.500	439,250	439,250	0
Month			122,550,000		122,550,000	1.951	2.305	2,390,660	2,825,160	347,600
Jan-97	ECONSALE	C	80,000,000		80,000,000	1.787	2.190	1,429,600	1,752,000	257,920
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTH	-	0		0	0.000	0.000	0	0	0
	STRATIFIED	-	12,448,000		12,448,000	3.500	3.500	435,680	435,680	0
Month			92,448,000		92,448,000	2.018	2.366	1,865,280	2,187,680	257,920
Feb-97	ECONSALE	C	110,000,000		110,000,000	1.876	2.279	2,063,600	2,506,900	354,640
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTH	-	0		0	0.000	0.000	0	0	0
	STRATIFIED	-	53,430,000		53,430,000	2.700	2.700	1,442,610	1,442,610	0
Month			163,430,000		163,430,000	2.145	2.417	3,506,210	3,949,510	354,640
Mar-97	ECONSALE	C	90,000,000		90,000,000	1.977	2.381	1,779,300	2,142,900	290,880
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTH	-	0		0	0.000	0.000	0	0	0
	STRATIFIED	-	73,238,000		73,238,000	2.500	2.500	1,830,950	1,830,950	0
Month			163,238,000		163,238,000	2.212	2.434	3,610,250	3,973,850	290,880
PERIOD	ECONSALE	C	650,000,000		650,000,000	1.852	2.252	12,040,410	14,635,110	2,075,760
	SALE D	D	0		0	0.000	0.000	0	0	0
	SALE F	F	0		0	0.000	0.000	0	0	0
	SALE OTH	-	0		0	0.000	0.000	0	0	0
	STRATIFIED	-	341,352,000		341,352,000	2.605	2.605	8,890,650	8,890,650	0
TOTAL			991,352,000		991,352,000	2.111	2.373	20,931,060	23,525,760	2,075,760

COMPANY: FPC

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGEN PURCHASES)

Estimated for the Period of:
October 1996 through March 1997

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHED	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	cents/KWH (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) * (8)(B)
Oct-96	EMERGNCY	A&B	0		0	0	0.000	0.000	0
	TECO	-	472,000			472,000	2.555	2.555	12,060
	UPS PURC	UPS	84,086,000			84,086,000	1.841	1.841	1,548,380
Month			84,558,000		0	84,558,000	1.845	1.845	1,560,440
Nov-96	EMERGNCY	A&B	0		0	0	0.000	0.000	0
	TECO	-	442,000			442,000	2.550	2.550	11,270
	UPS PURC	UPS	97,136,000			97,136,000	1.820	1.820	1,767,490
Month			97,578,000		0	97,578,000	1.823	1.823	1,778,760
Dec-96	EMERGNCY	A&B	0		0	0	0.000		0
	TECO	-	15,000			15,000	2.600	2.600	390
	UPS PURC	UPS	29,326,000			29,326,000	1.801	1.801	528,240
Month			29,341,000		0	29,341,000	1.802	1.802	528,630
Jan-97	EMERGNCY	A&B	3,086,000		0	3,086,000	7.015	10.021	309,260
	TECO	-	0			0			0
	UPS PURC	UPS	28,864,000			28,864,000	1.854	1.854	535,280
Month			31,950,000		0	31,950,000	2.643	2.643	844,540
Feb-97	EMERGNCY	A&B	551,000		0	551,000	7.028	10.040	55,320
	TECO	-	12,000			12,000	2.667	2.667	320
	UPS PURC	UPS	16,868,000			16,868,000	1.888	1.888	318,400
Month			17,431,000		0	17,431,000	2.146	2.146	374,040
Mar-97	EMERGNCY	A&B	1,000		0	1,000	10.500	15.000	150
	TECO	-	250,000			250,000	2.596	2.596	6,490
	UPS PURC	UPS	64,423,000			64,423,000	1.872	1.872	1,206,300
Month			64,674,000		0	64,674,000	1.875	1.875	1,212,940
PERIOD	EMERGNCY	A&B	3,638,000		0	3,638,000	7.018	10.026	364,730
	TECO	-	1,191,000		0	1,191,000	2.563	2.563	30,530
	UPS PURC	UPS	320,703,000		0	320,703,000	1.841	1.841	5,904,090
TOTAL			325,532,000		0	325,532,000	1.935	1.935	6,299,350

COMPANY: FPC

SCHEDULE E8

ENERGY PAYMENT TO QUALIFYING FACILITIES

Estimated for the Period of:
October 1996 through March 1997

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							cents/KWH		
MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) ENERGY COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) * (8)(A)
Oct-96	QUALIFYING FACILITIES	COGEN	610,376,000	0	0	610,376,000	1.982	4.998	12,095,330
Month			610,376,000	0	0	610,376,000	1.982	4.998	12,095,330
Nov-96	QUALIFYING FACILITIES	COGEN	591,308,000	0	0	591,308,000	2.023	5.137	11,961,520
Month			591,308,000	0	0	591,308,000	2.023	5.137	11,961,520
Dec-96	QUALIFYING FACILITIES	COGEN	611,015,000	0	0	611,015,000	1.891	4.904	11,553,120
Month			611,015,000	0	0	611,015,000	1.891	4.904	11,553,120
Jan-97	QUALIFYING FACILITIES	COGEN	652,045,000	0	0	652,045,000	1.894	4.867	12,348,030
Month			652,045,000	0	0	652,045,000	1.894	4.867	12,348,030
Feb-97	QUALIFYING FACILITIES	COGEN	588,943,000	0	0	588,943,000	1.983	5.275	11,678,480
Month			588,943,000	0	0	588,943,000	1.983	5.275	11,678,480
Mar-97	QUALIFYING FACILITIES	COGEN	652,045,000	0	0	652,045,000	2.099	5.072	13,685,530
Month			652,045,000	0	0	652,045,000	2.099	5.072	13,685,530
PERIOD	QUALIFYING FACILITIES	COGEN	3,705,732,000	0	0	3,705,732,000	1.979	5.039	73,322,010
TOTAL			3,705,732,000	0	0	3,705,732,000	1.979	5.039	73,322,010

COMPANY: FPC

SCHEDULE E9

ECONOMY ENERGY PURCHASES

Estimated for the Period of:
October 1996 through March 1997

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST			COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL KWH PURCHASED	ENERGY COST c/kWh	TOTAL COST c/kWh	TOTAL $ FOR FUEL ADJ. (4) * (5)	(A) cents/kWh	(B) $	FUEL SAVINGS (8)(B) - (7)
Oct-96	ECONPURC	C	30,000,000	2.048	2.048	614,400	3.866	1,159,800	545,400
	OTHER	-	3,000,000	2.371	2.371	71,130	2.371	71,130	0
	OUC PURC	J	7,040,000	1.750	3.364	123,200	2.278	160,371	37,171
Month			40,040,000	2.020	2.304	808,730	3.475	1,391,301	582,571
Nov-96	ECONPURC	C	20,000,000	2.607	2.607	521,400	3.866	773,200	251,800
	OTHER	-	3,000,000	2.497	2.497	74,910	2.497	74,910	0
	OUC PURC	J	5,335,000	1.750	3.879	93,363	2.276	121,425	28,062
Month			28,335,000	2.434	2.835	689,673	3.422	969,535	279,862
Dec-96	ECONPURC	C	30,000,000	2.433	2.433	729,900	4.095	1,228,500	498,600
	OTHER	-	3,000,000	2.415	2.415	72,450	2.415	72,450	0
	OUC PURC	J	4,181,000	1.751	4.468	73,209	1.953	81,655	8,446
Month			37,181,000	2.355	2.660	875,559	3.719	1,382,605	507,046
Jan-97	ECONPURC	C	87,615,000	2.361	2.361	2,068,590	4.095	3,587,834	1,519,244
	OTHER	-	3,000,000	2.530	2.530	75,900	2.530	75,900	0
	OUC PURC	J	2,559,000	1.763	6.202	45,115	2.056	52,613	7,498
Month			93,174,000	2.350	2.472	2,189,605	3.989	3,716,347	1,526,742
Feb-97	ECONPURC	C	63,975,000	2.421	2.421	1,548,835	4.095	2,619,776	1,070,941
	OTHER	-	3,000,000	2.617	2.617	78,510	2.617	78,510	0
	OUC PURC	J	3,175,000	1.749	5.327	55,531	2.138	67,882	12,351
Month			70,150,000	2.399	2.561	1,682,876	3.943	2,766,168	1,083,292
Mar-97	ECONPURC	C	77,615,000	2.784	2.784	2,160,802	4.095	3,178,334	1,017,532
	OTHER	-	3,000,000	2.624	2.624	78,720	2.624	78,720	0
	OUC PURC	J	2,568,000	1.750	6.174	44,940	1.911	49,074	4,134
Month			83,183,000	2.746	2.883	2,284,462	3.975	3,306,128	1,021,666
PERIOD	ECONPURC	C	309,205,000	2.472	2.472	7,643,927	4.058	12,547,444	4,903,518
	OTHER	-	18,000,000	2.509	2.509	451,620	2.509	451,620	0
	OUC PURC	J	24,858,000	1.751	4.493	435,358	2.144	533,020	97,662
TOTAL			352,063,000	2.423	2.617	8,530,904	3.844	13,532,084	5,001,180

COMPANY: FLA. POWER CORP. SCHEDULE E10

RESIDENTIAL BILL COMPARISON

FOR MONTHLY USAGE OF 1000 KWH

For the Period of: October 1996 through March 1997

		Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	PERIOD AVERAGE	PRIOR RESIDENTIAL BILL *	Oct-96 VS PRIOR
1. BASE RATE REVENUES	($)	$49.05	$49.05	$49.05	$49.05	$49.05	$49.05	$49.05	$49.05	$0.00
2. FUEL RECOVERY FACTOR	(cents/kWh)	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.148	
3. FUEL COST RECOVERY REVENUES	($)	$20.62	$20.62	$20.62	$20.62	$20.62	$20.62	$20.62	$21.52	($0.90)
4. CAPACITY COST RECOVERY REVENUES	($)	$10.30	$10.30	$10.30	$10.30	$10.30	$10.30	$10.30	$9.36	$0.94
5. ENERGY CONSERVATION COST REVENUES	($)	$1.38	$1.38	$1.38	$1.38	$1.38	$1.38	$1.38	$1.38	$0.00
6. GROSS RECEIPTS TAXES	($)	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.08	$0.01
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7. TOTAL REVENUES	($)	$83.44	$83.44	$83.44	$83.44	$83.44	$83.44	$83.44	$83.39	$0.05

* Actual Residential Billing for September 1996.

COMPANY: FLA. POWER CORP.

SCHEDULE E10

RESIDENTIAL BILL COMPARISON

FOR MONTHLY USAGE OF 1000 KWH

For the Period of: October 1996 through March 1997

		Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	PERIOD AVERAGE	PRIOR RESIDENTIAL BILL *	Oct-96 VS PRIOR
1. BASE RATE REVENUES	($)	$49.05	$49.05	$49.05	$49.05	$49.05	$49.05	$49.05	$49.05	$0.00
2. FUEL RECOVERY FACTOR	(cents/kWh)	2.058	2.058	2.058	2.058	2.058	2.058	2.058	2.148	
3. FUEL COST RECOVERY REVENUES	($)	$20.62	$20.62	$20.62	$20.62	$20.62	$20.62	$20.62	$21.52	($0.90)
4. CAPACITY COST RECOVERY REVENUES	($)	$10.30	$10.30	$10.30	$10.30	$10.30	$10.30	$10.30	$9.36	$0.94
5. ENERGY CONSERVATION COST REVENUES	($)	$1.38	$1.38	$1.38	$1.38	$1.38	$1.38	$1.38	$1.38	$0.00
6. GROSS RECEIPTS TAXES	($)	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.09	$2.08	$0.01
7. TOTAL REVENUES	($)	$83.44	$83.44	$83.44	$83.44	$83.44	$83.44	$83.44	$83.39	$0.05

* Actual Residential Billing for September 1996.

COMPANY: FPC

GENERATION SYSTEM COMPARATIVE DATA BY FUEL TYPE

SCHEDULE H1

		PERIOD				% Difference from Prior Period		
		Oct-93 thru Mar-94	Oct-94 thru Mar-95	Oct-95 thru Mar-96	Projected Oct-96 thru Mar-97	Actual 1995 vs 1994	Actual 1996 vs 1995	Projected 1997 vs 1996
	FUEL COST OF SYSTEM NET GENERATION (DOLLARS)							
1	HEAVY OIL	50,376,355	27,394,617	40,476,442	26,263,637	-45.6	47.8	-35.1
2	LIGHT OIL	5,618,126	4,310,603	11,590,105	8,352,342	-23.3	168.9	-27.9
3	COAL	101,186,972	105,186,694	134,461,735	133,027,929	4.0	27.8	-1.1
4	GAS	1,732,814	6,336,200	10,293,692	6,112,316	265.7	62.5	-40.6
5	NUCLEAR	15,620,385	14,476,383	9,861,094	11,111,606	-7.3	-31.9	12.7
6	OTHER	1,927,791	1,781,540	1,476,275	1,735,758	-7.6	-17.1	17.6
7	TOTAL ($)	176,462,443	159,486,037	208,159,343	186,603,588	-9.6	30.5	-10.4
	SYSTEM NET GENERATION (MWH)							
8	HEAVY OIL	2,615,731	1,138,375	1,715,067	808,874	-56.5	50.7	-52.8
9	LIGHT OIL	100,561	75,196	199,743	163,694	-25.2	165.6	-18.0
10	COAL	5,511,118	5,889,277	7,480,460	7,429,853	6.9	27.0	-0.7
11	GAS	38,580	275,579	380,228	221,152	0.0	38.0	-41.8
12	NUCLEAR	3,258,132	3,281,676	2,142,937	3,223,456	0.7	-34.7	50.4
13	OTHER	0	0	0	0	0.0	0.0	0.0
14	TOTAL (MWH)	11,524,122	10,660,103	11,918,435	11,847,029	-7.5	11.8	-0.6
	UNITS OF FUEL BURNED							
15	HEAVY OIL (BBL)	4,145,994	1,828,115	2,654,196	1,275,307	-55.9	45.2	-52.0
16	LIGHT OIL (BBL)	232,322	179,195	470,002	318,332	-22.9	162.3	-32.3
17	COAL (TONS)	2,082,708	2,232,630	2,811,045	2,762,446	7.2	25.9	-1.7
18	GAS (MCF)	481,568	3,091,892	4,010,338	2,629,301	0.0	29.7	-34.4
19	NUCLEAR (MMBTU)	33,999,263	33,933,310	22,247,580	33,671,535	-0.2	-34.4	51.3
20	OTHER	82,162	77,689	68,658	72,414	-5.4	-11.6	5.5
	BTU'S BURNED (MILLION BTU)							
21	HEAVY OIL	26,462,627	11,731,454	17,218,684	8,161,963	-55.7	46.8	-52.6
22	LIGHT OIL	1,362,485	1,050,120	2,614,118	1,846,328	-22.9	148.9	-29.4
23	COAL	52,001,027	55,830,618	70,517,350	69,412,501	7.4	26.3	-1.6
24	GAS	502,832	3,179,352	4,180,553	2,629,301	0.0	31.5	-37.1
25	NUCLEAR	33,999,263	33,933,310	22,247,580	33,671,535	-0.2	-34.4	51.3
26	OTHER	481,850	455,272	399,824	420,000	-5.5	-12.2	5.0
27	TOTAL (MBTU)	114,810,084	106,180,126	117,178,109	116,141,628	-7.5	10.4	-0.9
	GENERATION MIX (% MWH)							
28	HEAVY OIL	22.70	10.68	14.39	6.83	-53.0	34.8	-52.6
29	LIGHT OIL	0.87	0.71	1.68	1.38	-19.2	137.6	-17.6
30	COAL	47.82	55.25	62.76	62.71	15.5	13.6	-0.1
31	GAS	0.33	2.59	3.19	1.87	0.0	23.4	-41.5
32	NUCLEAR	28.27	30.78	17.98	27.21	8.9	-41.6	51.3
33	OTHER	0.00	0.00	0.00	0.00	0.0	0.0	0.0
34	TOTAL (%)	100.00	100.00	100.00	100.00			
	FUEL COST ($/UNIT)							
35	HEAVY OIL	12.15	14.99	15.25	20.59	23.3	1.8	35.0
36	LIGHT OIL	24.18	24.06	24.66	26.24	-0.5	2.5	6.4
37	COAL	48.58	47.11	47.83	48.16	-3.0	1.5	0.7
38	GAS	3.60	2.05	2.57	2.32	-43.0	25.3	-9.4
39	NUCLEAR	0.46	0.43	0.44	0.33	-7.1	3.9	-25.5
40	OTHER	23.46	22.93	21.50	23.97	-2.3	-6.2	11.5
	FUEL COST PER MILLION BTU ($/MBTU)							
41	HEAVY OIL	1.90	2.34	2.35	3.22	22.7	0.7	36.9
42	LIGHT OIL	4.12	4.10	4.43	4.52	-0.5	8.0	2.0
43	COAL	1.95	1.88	1.91	1.92	-3.2	1.2	0.5
44	GAS	3.45	1.99	2.46	2.32	-42.2	23.6	-5.6
45	NUCLEAR	0.46	0.43	0.44	0.33	-7.1	3.9	-25.5
46	OTHER	4.00	3.91	3.69	4.13	-2.2	-5.6	11.9
47	SYSTEM ($/MBTU)	1.54	1.50	1.78	1.61	-2.3	18.3	-9.6
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL	10,117	10,305	10,040	10,091	1.9	-2.6	0.5
49	LIGHT OIL	13,549	13,965	13,087	11,279	3.1	-6.3	-13.8
50	COAL	9,436	9,480	9,427	9,342	0.5	-0.6	-0.9
51	GAS	13,033	11,537	10,995	11,889	-11.5	-4.7	8.1
52	NUCLEAR	10,435	10,340	10,382	10,446	-0.9	0.4	0.6
53	OTHER	0	0	0	0	0.0	0.0	0.0
54	SYSTEM (BTU/KWH)	9,963	9,961	9,832	9,803	-0.0	-1.3	-0.3
	GENERATION FUEL COST PER KWH (CENTS/KWH)							
55	HEAVY OIL	1.93	2.41	2.36	3.25	25.0	-1.9	37.6
56	LIGHT OIL	5.59	5.73	5.80	5.10	2.6	1.2	-12.1
57	COAL	1.84	1.79	1.80	1.79	-2.7	0.6	-0.4
58	GAS	4.49	2.30	2.71	2.76	-48.8	17.7	2.1
59	NUCLEAR	0.48	0.44	0.46	0.34	-8.0	4.3	-25.1
60	OTHER	0.00	0.00	0.00	0.00	0.0	0.0	0.0
61	SYSTEM (CENTS/KWH)	1.53	1.50	1.75	1.58	-2.3	16.7	-9.8