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June 27, 1994

Blanca S. Bayo, Director
Division of Records and Reporting
Florida Public Service Commission
101 East Gaines Street
Tallahassee, FL 32399

RE: DOCKET NO. 940001-EI

Dear Ms. Bayo:

Enclosed for filing please find the original and fifteen (15) copies of Florida Power & Light Company's Petition For The Approval Of Its Levelized Fuel Recovery Charge, Oil Backout Cost Recovery Factor, Capacity Cost Recovery Factors, and GPIF Targets in the above referenced docket.

Also enclosed please find the original and fifteen (15) copies of the Testimony of R. Silva, B. T. Birkett and D. C. Poteralski.

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Very truly yours,

Matthew M. Childs
Matthew M. Childs, P.A.

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06351 JUN 27

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FPSC-RECORDS/REPORTING

Section

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**BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION**

DOCKET NO. 940001-EI

FLORIDA POWER & LIGHT COMPANY

JUNE 27, 1994

**IN RE: LEVELIZED FUEL COST
RECOVERY, CAPACITY COST RECOVERY,
AND OIL BACKOUT COST RECOVERY**

OCTOBER 1994 THROUGH MARCH 1995

**R. SILVA
D. C. POTERALSKI
B. T. BIRKETT**

DOCUMENT NUMBER-DATE

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FPSC-RECORDS/REPORTING

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RENE SILVA

DOCKET NO. 940001-EI

JUNE 27, 1994

1 Q. Please state your name and address.

2 A. My name is Rene Silva. My business address is
3 9250 W. Flagler Street, Miami, Florida 33174.

4

5 Q. By whom are you employed and what is your
6 position?

7 A. I am employed by Florida Power & Light Company
8 (FPL) as Manager of Forecasting and Regulatory
9 Response in the Power Generation Business Unit.

10

11 Q. Have you previously testified in this docket?

12 A. Yes.

13

14 Q. What is the purpose of your testimony?

15 A. The purpose of my testimony is to present and
16 explain FPL's projections for (1) dispatch costs
17 of heavy fuel oil, light fuel oil, coal and
18 natural gas, (2) availability of natural gas to
19 FPL, (3) generating unit heat rates and

1 availabilities, and (4) quantities and costs of
2 interchange and other power transactions. These
3 projected values were used as input values to
4 POWRSYM in the calculation of the proposed fuel
5 cost recovery factor for the period October,
6 1994 through March, 1995.

7
8 **Q. Have you prepared or caused to be prepared under**
9 **your supervision, direction and control an**
10 **Exhibit in this proceeding?**

11 **A. Yes, I have. It consists of pages 1 through 8**
12 **of Appendix I of this filing.**

13
14 **Q. What is the basis for FPL's projections of the**
15 **dispatch cost of heavy fuel oil?**

16 **A. FPL's projections of the dispatch cost of heavy**
17 **fuel oil are based on FPL's evaluation of a**
18 **broad range of information related to: (1) the**
19 **current and projected worldwide demand, supply**
20 **and price for crude oil; (2) the historical,**
21 **current and projected market relationship of**
22 **heavy fuel oil prices to crude oil prices; and**
23 **(3) the current and projected supply and demand**
24 **for heavy fuel oil in both the United States**
25 **Gulf Coast and East Coast markets, and on a**

1 worldwide basis.

2

3 FPL personnel with expertise in petroleum
4 economics and energy markets analyze information
5 obtained from industry publications and public
6 sources, hold discussions with energy industry
7 consultants and FPL oil procurement personnel,
8 and evaluate how these factors would affect the
9 cost of heavy fuel oil.

10

11 **Q. What are the key factors that could affect the**
12 **price for crude oil during the October, 1994**
13 **through March, 1995 period?**

14 **A.** The key factors are (1) demand for crude oil and
15 petroleum products, (2) non-OPEC crude oil
16 supply, and (3) the extent to which OPEC
17 production matches actual demand for OPEC crude
18 oil.

19

20 In general, world demand for crude oil and
21 petroleum products is projected to increase
22 moderately during the second half of 1994 and
23 the first quarter of 1995, as the effect of the
24 current recession in Western Europe and Japan is
25 offset by accelerated recovery in the United

1 States and growth in demand elsewhere in the
2 Pacific Rim area.

3
4 On the supply side, total non-OPEC crude oil
5 supply is projected to remain constant during
6 the second half of 1994 and the first quarter of
7 1995, as increased production in the North Sea
8 and Colombia is offset by the continuing gradual
9 decline in production in the United States.

10
11 Regarding OPEC oil production, it is projected
12 that in the second half of 1994 and the first
13 quarter of 1995 OPEC production will effectively
14 match demand for OPEC oil.

15
16 It is projected that these factors will cause
17 crude oil prices, and consequently heavy fuel
18 oil prices, to increase moderately during the
19 second half of 1994 and the first quarter of
20 1995.

21
22 **Q. What is the projected relationship between heavy**
23 **fuel oil and crude oil prices during the**
24 **October, 1994 through March, 1995 period?**

25 **A. Heavy fuel oil prices are projected to be**

1 approximately 80% of the delivered U.S.
2 Refiner's acquisition costs of crude oil during
3 this period.
4

5 **Q. Please provide FPL's projection for the dispatch**
6 **cost of heavy fuel oil for the October, 1994**
7 **through March, 1995 period based on FPL's**
8 **evaluation of the key factors discussed above.**

9 **A.** FPL's projection for the dispatch cost of heavy
10 fuel oil is provided on page 3 of Appendix I in
11 dollars per barrel at each of the oil-fired
12 plants. We project that during this period the
13 dispatch cost of heavy fuel oil will range from
14 \$11.40 to \$13.60 per barrel for 2.5% sulfur
15 grade fuel oil, \$12.35 to \$15.25 per barrel for
16 2.0% sulfur grade fuel oil, \$13.60 to \$16.70 per
17 barrel for 1.0% sulfur grade fuel oil, and from
18 \$15.20 to \$17.45 per barrel for 0.7% sulfur
19 grade fuel oil, approximately, (depending on the
20 month and the delivery location).
21

22 **Q. What is the basis for FPL's projection for the**
23 **dispatch cost of light fuel oil?**

24 **A.** FPL's projection of the dispatch cost of light
25 fuel oil is prepared in a similar manner to the

1 heavy fuel oil dispatch cost projections. The
2 key factors that affect the price for crude oil
3 and the factors that affect the market
4 relationship of light fuel oil to crude oil
5 prices are similar to those described above for
6 heavy fuel oil. Therefore, in general the
7 market price of light fuel oil is projected to
8 increase moderately during the second half of
9 1994 and the first quarter of 1995.

10
11 **Q. Please provide FPL's projection for the dispatch**
12 **cost of light fuel oil for the period from**
13 **October, 1994 through March, 1995 based on FPL's**
14 **evaluation of the key factors discussed above.**

15 **A. FPL's projection for the dispatch cost of light**
16 **oil for each of the combustion turbine and**
17 **combined cycle plants is shown on page 4 of**
18 **Appendix I. We project that during this period**
19 **the dispatch cost of light fuel oil will range**
20 **from \$22.70 per barrel to \$27.60 per barrel for**
21 **0.5% sulfur grade fuel oil and from \$22.70 per**
22 **barrel to \$29.00 per barrel for 0.3% sulfur**
23 **grade fuel oil, approximately, (depending on the**
24 **month and delivery location).**

1 Q. What is the basis for FPL's projections of the
2 average cost of coal at the St. Johns River
3 Power Park (SJRPP)?

4 A. FPL's projections of the average cost of coal at
5 SJRPP are based on the provisions of the coal
6 supply contracts in effect between Jacksonville
7 Electric Authority (JEA) and Sun Coal Company,
8 Ashland Coal, Inc. and International Colombia
9 Resources, Inc., the rail transportation
10 contract in effect between JEA and CSX,
11 Incorporated, and FPL's projection of spot coal
12 prices.

13

14 We project that about 75% of the coal purchased
15 for SJRPP during the period will be under the
16 terms of the three long-term coal supply
17 contracts. However, since annual contract coal
18 volumes are fixed on October 1st of the previous
19 year, the dispatch price of coal for SJRPP is
20 based on the projected spot coal price. We
21 project that about 25% of coal purchased will be
22 spot coal.

23

24 Q. Please provide FPL's projection for the dispatch
25 cost of coal for SJRPP for the period from

1 **October, 1994 through March, 1995.**

2 A. FPL's projection for the dispatch cost of coal
3 at SJRPP is shown on page 5 of Appendix I in
4 dollars per ton. We estimate that during this
5 period, the dispatch cost of coal for SJRPP will
6 range from \$30.80 to \$31.80 per ton delivered to
7 SJRPP.

8
9 Q. **What is the basis for FPL's projections of the**
10 **dispatch cost of coal at Scherer Unit 4 for the**
11 **October, 1994 through March, 1995 period?**

12 A. FPL's projected dispatch cost of coal for
13 Scherer Unit 4 is equal to the projected monthly
14 average cost of coal to the Scherer Plant. This
15 average coal cost is based on the assumption
16 that Plant Scherer will purchase Eastern coal
17 under the terms of the existing coal supply
18 contracts with the Zeigler Coal Holding Company,
19 Delta Coals, Inc. and Mingo-Logan Coal Company,
20 and will make spot purchases of Powder River
21 Basin (Western) coal as needed to meet total
22 Plant Scherer requirements. Approximately 77%
23 of the coal purchased is projected to be Western
24 coal. Eastern coal will be transported under
25 the terms of the existing rail transportation

1 contract with the Norfolk Southern Corporation,
2 and Western coal will be transported under the
3 terms of the existing rail transportation
4 contracts with Western Railroad Properties, Inc.
5 and the Norfolk Southern Corporation.
6

7 **Q. Please provide FPL's projection for the dispatch**
8 **cost of coal for Scherer Unit 4 during the**
9 **October, 1994 through March, 1995 period.**

10 **A.** FPL's projection for the dispatch cost of coal
11 at Scherer Unit 4 is shown on page 5 of Appendix
12 I in dollars per ton. We estimate that during
13 this period, the dispatch cost of coal for
14 Scherer Unit 4 will range from \$31.35 per ton to
15 \$34.90 per ton depending upon the quantity of
16 spot purchases of Powder River Basin coal
17 required each month to meet total Plant Scherer
18 requirements.
19

20 **Q. What is the basis for FPL's projections of**
21 **natural gas unit costs?**

22 **A.** FPL's projection for the unit cost of natural
23 gas is based on FPL's evaluation of a broad
24 range of factors related to: (1) the current and
25 projected domestic demand for natural gas; (2)

1 the projected supply (domestic production plus
2 imports) of natural gas; (3) the projected price
3 of heavy fuel oil; (4) the historical, current
4 and projected market relationship of natural gas
5 prices to heavy fuel oil prices; and (5) the
6 terms and conditions of FPL's natural gas supply
7 and transportation contracts.

8
9 On May 10, 1994, FPL entered into a long-term
10 natural gas supply agreement which replaces
11 FPL's prior natural gas supply contracts. The
12 base price for natural gas supply under the new
13 contract is governed by the market price of
14 natural gas.

15
16 FPL personnel with expertise in the natural gas
17 industry analyze information obtained from
18 industry publications and public sources, hold
19 discussions with energy industry consultants and
20 FPL natural gas procurement personnel, and
21 evaluate how these factors are likely to affect
22 the unit price of natural gas to FPL.

23
24 Q. What are the factors that affect natural gas
25 market prices during the October, 1994 through

1 **March, 1995 period?**

2 A. The key factors are (1) domestic natural gas
3 demand and supply, (2) foreign natural gas
4 imports , (3) heavy fuel oil prices.

5

6 In general, domestic demand for natural gas is
7 projected to increase moderately during the
8 second half of 1994 and the first quarter of
9 1995 due primarily to increased usage for
10 electric generation, while U.S. production of
11 natural gas is projected to increase slightly,
12 and imports from Canada continue to increase.
13 As indicated previously, heavy fuel oil prices
14 are projected to be somewhat higher.

15

16 It is projected that these factors will result
17 in slightly higher natural gas market prices
18 during the October, 1994 through March, 1995
19 period than prior year levels.

20

21 Q. **What are the factors that affect the availability**
22 **of natural gas to FPL during the October, 1994**
23 **through March, 1995 period?**

24 A. The key factors are (1) the projected capacity
25 of natural gas transportation facilities into

1 Florida and (2) the projected natural gas demand
2 in the State of Florida.

3
4 The capacity of natural gas transportation
5 facilities into the State of Florida is expected
6 to increase from 925,000 million BTU per day to
7 1,455,000 million BTU per day on January 1, 1995.

8
9 FPL's total firm transportation capacity will
10 range from 255,000 million BTU per day to 455,000
11 BTU per day. However, the projected demand for
12 natural gas in the State of Florida will range
13 from 40,000 million BTU per day to 125,000
14 million BTU per day below the capacity of the
15 Florida Gas Transmission Pipeline System during
16 the October, 1994 to March, 1995 period, allowing
17 FPL the opportunity to acquire additional natural
18 gas.

19
20 Q. Please provide FPL's projections for natural gas
21 unit costs and availability to FPL for the
22 October, 1994 through March, 1995 period based
23 on FPL's evaluation of these factors.

24 A. FPL's projections of delivered natural gas unit
25 costs and availability are provided on page 6 of

1 Appendix I. We project that during this period
2 the system-weighted-average cost of natural gas
3 to the FPL system will range from \$2.50 to \$3.00
4 per million BTU and the average total
5 availability of natural gas to FPL will range
6 from 305,000 to 580,000 million BTU per day.
7

8 Q. Please describe how you have developed the
9 projected unit Average Net Operating Heat Rates
10 shown on Schedule E5 of Appendix II.

11 A. The projected Average Net Operating Heat Rates
12 were developed using the actual monthly Average
13 Net Operating Heat Rates and the corresponding
14 Net Output Factors from the previous three
15 October through March periods. The standard
16 least squares regression method was used to
17 derive a first order Average Net Operating Heat
18 Rate equation using the historical data. An
19 efficiency factor, or heat rate multiplier, was
20 then calculated for each unit. The efficiency
21 factor represents the difference between the
22 unit's dispatch heat rate and the heat rate
23 projected by the Average Net Operating Heat Rate
24 equation. The most recent unit dispatch heat
25 rate curves, modified by the unit's efficiency

1 factors, were provided as input to the POWRSYM
2 model.

3

4 Q. Are you providing the outage factors projected
5 for the period October, 1994 through March,
6 1995?

7 A. Yes. This data is shown on page 7 of Appendix
8 I.

9

10 Q. How were the outage factors for this period
11 developed?

12 A. The unplanned outage factors were developed
13 using the actual historical full and partial
14 outage event data for each of the units. The
15 actual twelve-month-ending unplanned outage
16 factor for each corresponding month in the
17 previous year was used as the starting point for
18 the development of the factor for each month of
19 the projected period.

20

21 Q. Please describe the planned outages for the
22 October, 1994 through March, 1995 period.

23 A. Planned outages at our nuclear units are the
24 most significant in relation to Fuel Cost
25 Recovery. St. Lucie nuclear unit No. 1 is

1 scheduled to be out of service for refueling
2 from October 1, 1994 until December 3, 1994.
3 Turkey Point unit No. 4 will also be out of
4 service for refueling from October 18, 1994
5 until December 20, 1994.
6

7 Q. Are any changes to FPL's generation capacity
8 planned during the October, 1994 through March,
9 1995 period?
10 A. No.
11

12 Q. Have you forecasted an effective availability
13 rate associated with Scherer Unit No. 4?
14 A. Yes.

15 As part of the Scherer Unit No. 4
16 purchase, FPL and Southern Company Services
17 (Southern) entered into a transition energy
18 agreement which assures a 90% minimum effective
19 availability rate for the FPL capacity from the
20 unit. To the extent the unit is not available,
21 the capacity will be provided by Southern from
22 other resources.

23 Q. Please discuss the arrangements between FPL and
24 JEA regarding the St. Johns River Power Park
25 (SJRPP).

1 A. Under the terms of the contract, FPL owns 20% of
2 the units and has the right to schedule an
3 additional 30% of the capacity of the units from
4 JEA's portion. The difference between FPL's
5 scheduling rights and ownership share is the
6 result of power purchase provisions in the
7 contract. The portion of energy scheduled by
8 FPL related to FPL's 20% ownership of the units
9 is included in Fuel Cost Recovery Schedules as
10 FPL generation, and the balance of energy
11 scheduled and related energy costs are included
12 in Fuel Cost Recovery Schedules as purchased
13 power.

14
15 **Q. Are you providing the projected interchange and**
16 **purchased power transactions forecasted for**
17 **October, 1994 through March, 1995?**

18 A. Yes. This data is shown on Schedules E7, E7A,
19 E8, E8A and E9 of Appendix II of this filing.

20
21 **Q. In what types of interchange transactions does**
22 **FPL engage?**

23 A. FPL engages in several types of interchange
24 transactions which have been previously
25 described in this docket: Emergency - Schedule

1 A; Short Term Firm - Schedule B; Economy -
2 Schedule C; Extended Economy - Schedule X;
3 Opportunity Sales - Schedule OS; UPS Replacement
4 Energy - Schedule R and Economic Energy
5 Participation - Schedule EP. However, FPL
6 recently amended all of its Interchange
7 Contracts. These amendments include new
8 Interchange Service Schedules AF (Emergency), BF
9 (Scheduled Maintenance), CF (Economy), DF
10 (Outage), and XF (Extended Economy), which are
11 intended to replace and supersede existing
12 Interchange Service Schedules A, B, C, D, and X
13 for services provided by FPL to other utilities.
14 Interchange Service Schedules FPL uses to
15 purchase interchange have not changed.

16

17 Q. Does FPL have arrangements other than
18 interchange agreements for the purchase of
19 electric power and energy which are included in
20 your projections?

21 A. Yes. FPL purchases coal-by-wire electrical
22 energy under the Unit Power Sales Agreements
23 (UPS) with the Southern Companies. FPL has
24 contracts to purchase nuclear energy under the
25 St. Lucie Plant Nuclear Reliability Exchange

1 Agreements with Orlando Utilities Commission
2 (OUIC) and Florida Municipal Power Agency (FMPA).
3 FPL also purchases energy from JEA's portion of
4 the SJRPP Units as stated above. Additionally,
5 FPL purchases energy and capacity from
6 Qualifying Facilities under existing tariffs and
7 contracts.

8
9 **Q. Please provide the projected energy costs to be**
10 **recovered through the Fuel Cost Recovery Clause**
11 **for the power purchases referred to above during**
12 **the October, 1994 through March, 1995 period.**

13 **A. Under the UPS agreements with the Southern**
14 **Companies, FPL has contracted to purchase coal-**
15 **fired power from various designated units in the**
16 **Southern Companies systems'. FPL's capacity**
17 **entitlement during the projected period is 1,007**
18 **MW from October through December, 1994 and 1,006**
19 **MW from January through March, 1995. FPL**
20 **applied an estimated availability factor of 100%**
21 **to these capacity entitlements to calculate the**
22 **projected energy purchases used as input to**
23 **POWRSYM. The high availability assumption is**
24 **based upon the alternate and supplemental energy**
25 **provisions of the contract with the Southern**

1 Companies. The UPS energy cost estimates for
2 this period are based on data provided by
3 Southern which were used as inputs to POWRSYM.
4 For the period, FPL projects the purchase of
5 1,336,193 MWH of UPS Energy at a cost of
6 \$26,226,810. In addition, we project the
7 purchase of 1,808,326 MWH of UPS Replacement
8 energy (Schedule R) at a cost of \$32,112,000.
9 The total UPS Energy plus Schedule R projections
10 are presented on Schedule E8 of Appendix II.

11
12 Energy purchases from the JEA-owned portion of
13 the St. Johns River Power Park generation are
14 projected to be 1,359,922 MWH for the period at
15 an energy cost of \$19,710,410. FPL's cost for
16 energy purchases under the St. Lucie Plant
17 Reliability Exchange Agreements is a function of
18 the operation of St. Lucie Unit 2 and the fuel
19 costs to the owners. For the period, we project
20 purchases of 252,568 MWH at a cost of
21 \$1,291,520. These projections are shown on
22 Schedule E8 of Appendix II.

23
24 In addition, as shown on Schedule E8A of
25 Appendix II, we project that purchases from

1 Qualifying Facilities for the period will
2 provide 2,415,279 MWH at a cost to FPL of
3 \$42,767,956.

4
5 **Q. How were energy costs related to purchases from**
6 **Qualifying Facilities developed?**

7 A. For those contracts that entitle FPL to purchase
8 "as-available" energy we used FPL's fuel price
9 forecasts as inputs to the POWRSYM model to
10 project FPL's avoided energy cost that is used
11 to set the price of these energy purchases each
12 month. For those contracts that enable FPL to
13 purchase firm capacity and energy, the
14 applicable Unit Energy Cost mechanism prescribed
15 in the contract is used to project monthly
16 energy costs.

17
18 **Q. Please provide the avoidable variable O&M rate**
19 **for as-available energy purchases.**

20 A. Page 8 of Appendix I shows the 1993 data used to
21 update the maximum avoidable variable O&M
22 expenses which applies to as-available energy
23 purchases from qualifying facilities. The rate
24 was developed in accordance with the methodology
25 approved by the Commission in Docket No. 860001-

1 EI-E. The new rate of \$0.10/MWH (0.010
2 cents/KWH) will remain in effect until updated
3 next year. The rate has been included in the
4 applicable tariffs attached to the testimony of
5 Mr. B. T. Birkett.

6
7 Q. Have you projected Schedule A/AF - Emergency
8 Interchange Transactions?

9 A. No purchases or sales under Schedule A/AF have
10 been projected since it is not practical to
11 estimate emergency transactions.

12
13 Q. Have you projected Schedule B/BF - Short-Term
14 Firm Interchange Transactions?

15 A. No commitment for such transactions had been
16 made when projections were developed.
17 Therefore, we have estimated that no Schedule BF
18 sales or Schedule B purchases would be made in
19 the projected period.

20
21 Q. Please describe the method used to forecast the
22 Economy Transactions.

23 A. The quantity of economy purchase transactions
24 was projected by POWRSYM based on the expected
25 availability and prices of Economy energy.

1 Projected prices for Economy energy were
2 developed by adjusting recent actual average
3 Economy energy prices to reflect projected
4 changes in FPL generation costs. Economy energy
5 sales by FPL were projected based upon historic
6 transaction levels.

7

8 Q. What are the forecasted amounts and costs of
9 Economy energy sales?

10 A. We have projected 279,287 MWH of Economy energy
11 sales for the period. The projected fuel cost
12 related to these sales is \$6,804,040. The
13 projected transaction revenue from the sales is
14 \$9,256,250. Eighty percent of the gain for
15 Schedules C and X is \$1,734,687 and is credited
16 to our customers.

17

18 Q. In what document are the fuel costs of economy
19 energy sales transactions reported?

20 A. Schedule E7 of Appendix II provides the total MWH
21 of energy and total dollars for fuel adjustment.
22 The 80% of gain is provided on Schedule E7 and
23 E7A of Appendix II.

24

25 Q. What are the forecasted amounts and costs of

1 **Economy energy purchases?**

2 A. The costs of these purchases are shown on
3 Schedule E9 of Appendix II. For the October,
4 1994 through March, 1995 period FPL projects it
5 will purchase a total of 401,808 MWH at a cost
6 of \$7,573,310. If generated, we estimate that
7 this energy would cost \$8,484,038. Therefore,
8 these purchases are projected to result in
9 savings of \$910,728.

10

11 **Q. What are the forecasted amounts and cost of**
12 **energy being sold under the St. Lucie Plant**
13 **Reliability Exchange Agreement?**

14 A. We project the sale of 168,528 MWH of energy at
15 a cost of \$717,521. These projections are shown
16 on Schedule E7 of Appendix II.

17

18 **Q. Would you please summarize your testimony?**

19 A. Yes. In my testimony, I have presented FPL's
20 fuel price projections for the fuel cost
21 recovery period of October, 1994 through March,
22 1995. In addition, I have presented FPL's
23 projections for generating unit heat rates and
24 availabilities, and the quantities and costs of
25 interchange and other power transactions for the

1 same period. These projections were based on
2 the best information available to FPL, and were
3 used as inputs to POWRSYM in developing the
4 projected Fuel Cost Recovery Factor for the
5 October, 1994 through March, 1995 period.

6

7 Q. Does this conclude your testimony?

8 A. Yes, it does.

9

10

11

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF D. C. POTERALSKI

DOCKET NO. 940001-EI

June 27, 1994

1 Q. Please state your name and address.

2

3 A. My name is Daniel C. Poteralski. My business
4 address is 700 Universe Boulevard, Juno Beach,
5 Florida 33408.

6

7 Q. By whom are you employed and what is your position?

8

9 A. I am employed by Florida Power & Light Company
10 (FPL) as Manager of Nuclear Fuel.

11

12 Q. Have you previously testified in this docket?

13

14 A. Yes, I have.

15

16 Q. What is the purpose of your testimony?

17

18 A. The purpose of my testimony is to present and
19 explain FPL's projections for nuclear fuel costs

1 associated with the thermal energy (MMBTU) to be
2 produced by our nuclear units, costs of disposal of
3 spent nuclear fuel and costs charged to FPL for
4 Decommissioning and Decontamination of the
5 Department of Energy's enrichment facilities (D&D
6 costs). All of these costs were input values to
7 POWRSYM for the calculation of the proposed fuel
8 cost recovery factor for the period October 1994
9 through March 1995.

10

11 Q. What is the basis for FPL's projections of nuclear
12 fuel costs?

13

14 A. FPL's nuclear fuel cost projections are developed
15 using the projected energy to be produced at our
16 nuclear units, based on the projected operating
17 schedules, for the period October 1994 through
18 March 1995.

19

20 Q. Please provide FPL's projection for nuclear fuel
21 unit costs and energy for the period October 1994
22 through March 1995.

23

24 A. We estimate the nuclear units will produce
25 107,534,485 MBTU of energy at a cost of \$0.437 per

1 MMBTU, excluding spent fuel disposal costs and D&D
2 costs for the period October 1994 through March
3 1995. Projections by nuclear unit and by month are
4 provided on Schedule E-5 of Appendix II.
5

6 Q. Please provide FPL's projection for nuclear spent
7 fuel disposal costs for the period October 1994
8 through March 1995 and what is the basis for FPL's
9 projection.
10

11 A. FPL's projections for nuclear spent fuel disposal
12 costs are provided on Schedule E-2 of Appendix II.
13 These projections are based on FPL's contract with
14 the DOE, which calculates the spent fuel disposal
15 fee at 1 mill per net Kwh generated minus
16 transmission and distribution line losses. There
17 is still one more refund due FPL from the DOE for
18 past overpayment, when the utilities were required
19 to pay on the basis of net generation without
20 adjustments for transmission and distribution line
21 losses. FPL has already received \$14,249,617 as
22 refund for past overpayments. We expect to receive
23 our final refund credit of \$529,000 during this
24 reporting period, and have included such credit in
25 our projection.

1 Q. Please provide FPL's projection for Decontamination
2 and Decommissioning (D&D) costs to be paid in the
3 period October 1994 through March 1995 and what is
4 the basis for FPL's projection.

5
6 A. As testified previously, The National Energy Policy
7 Act of 1992 (The Act) requires FPL to make certain
8 payments to a fund established at the U.S.
9 Treasury, to cover the cost of decontamination and
10 decommissioning DOE's enrichment facilities. D&D
11 payments are in direct proportion to the amount of
12 enrichment services purchased by FPL divided by the
13 amount produced by the DOE through October 1992.
14 Currently, FPL has contributed \$9,282,972 into the
15 D&D fund, which consists of two payments, and
16 expects to make annual deposits over a total period
17 of fifteen years. FPL's projection for D&D costs
18 to be paid during the period October 1994 through
19 March 1995 is provided on Schedule E-2 of Appendix
20 II. This projection is based on the assessment
21 paid to DOE in May 1994, escalated for inflation
22 using the CPI-U (consumer price index - for urban
23 customers). We have assumed a CPI-U of 2.1% per
24 annum which represents the trend for the last six
25 months. We expect to make the next payment to DOE

1 on October 31, 1994 for an estimated amount of
2 \$4.66 million, which has been included in this Fuel
3 Cost Recovery Period. These quantities are still
4 subject to final reconciliation with the DOE when
5 the final rule is published. However, we do not
6 expect major changes in the assessment.

7

8 Q. Are there currently any unresolved disputes under
9 FPL's nuclear fuel contracts?

10

11 A. Yes. There are two unresolved disputes.

12

13 The first dispute is under FPL's contract with the
14 Department of Energy (DOE) for final disposal of
15 spent nuclear fuel. FPL, along with 13 other
16 electric utilities, has filed suit against the DOE
17 over DOE's denial of its obligation to accept spent
18 nuclear fuel beginning in 1998. The suit requests
19 that the court affirm DOE's legal obligation to
20 begin accepting spent nuclear fuel in 1998.
21 Further, the court is requested to direct the DOE
22 to develop a program of acceptance of spent nuclear
23 fuel on a timely basis and make regular periodic
24 reports on its progress. In addition, the suit
25 requests that, if appropriate, all or a portion of

1 the utilities' Nuclear Waste Fund Fees be paid into
2 an escrow account.

3
4 Secondly, FPL is currently seeking to resolve a
5 price dispute for uranium enrichment services
6 purchased from the United States (US) government,
7 after October 1, 1992.

8
9 The Energy Policy Act of 1992 (The Act) created a
10 new US Government corporation, the United States
11 Enrichment Corporation (USEC). The Act transferred
12 from the DOE to the USEC all US Government
13 contracts for the sale of enrichment services. Our
14 contract for enrichment services with the US
15 Government calls for pricing to be calculated in
16 accordance with "Established DOE Pricing Policy".
17 Such policy had always been one of recovery of
18 DOE's costs, including costs related to the
19 Decontamination and Decommissioning (D&D) of the
20 DOE's enrichment facilities. With the transfer to
21 the USEC, cost of producing enrichment services has
22 decreased significantly. For example, the USEC no
23 longer needs to account for the costs of D&D,
24 because the Act requires that utilities make
25 separate payments for D&D, which FPL has been doing

1 (see page 4 of this testimony). However, the USEC
2 has continued to charge the same price charged by
3 DOE prior to the transfer.

4
5 FPL is preparing to file a claim against USEC,
6 challenging the price for enrichment services. FPL
7 believes that USEC's price should be based on
8 recovery of its costs. At a minimum, FPL believes
9 that the price must be lowered to reflect the
10 separate payment it is making to cover D&D costs.
11 USEC has not modified its price to date, and FPL is
12 currently paying the invoices submitted by the
13 USEC, while objecting under a reservation of
14 rights. The current price paid to the USEC is
15 assumed in our projection. FPL will continue to
16 keep the Commission informed on all aspects of this
17 dispute with the USEC.

18
19 Q. Does this conclude your testimony?

20
21 A. Yes, it does.
22
23
24
25

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF BARRY T. BIRKETT

DOCKET NO. 940001-E1

JUNE 27, 1994

1 Q. Please state your name and address.

2 A. My name is Barry T. Birkett and my business address is 9250 West
3 Flagler Street, Miami, Florida 33174.

4

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

6 A. I am employed by Florida Power & Light Company (FPL) as the
7 Manager of Rates and Tariff Administration.

8

9 Q. Have you previously testified in this docket?

10 A. Yes, I have.

11

12 Q. What is the purpose of your testimony?

13 A. The purpose of my testimony is to present for Commission review
14 and approval the fuel factors, the capacity payment factors and the
15 oil backout factor for the Company's rate schedule, including the
16 Time of Use rates, for the period October 1994 through March
17 1995. The calculation of the fuel factors is based on projected fuel
18 cost and operational data as set forth in Commission Schedules E1

1 through E11, H1 and other exhibits filed in this proceeding and data
2 previously approved by the Commission.

3
4 In addition, my testimony presents the schedules necessary to
5 support the calculation of the Estimated/Actual True-up amounts for
6 the Fuel Cost Recovery Clause (FCR), Capacity Cost Recovery
7 Clause(CCR), and Oil Backout Cost Recovery Clause (OB), for the
8 period April 1994 through September 1994. I have included
9 explanations for the variances between the original projections for
10 the period April 1994 through September 1994 approved at the
11 March 1994 hearings, versus the two months actual/four months
12 revised projections for the same period (Estimated/Actual).

13
14 Q. Have you prepared or caused to be prepared under your
15 direction, supervision or control an exhibit in this proceeding?

16 A. Yes, I have. It consists of various schedules included in
17 Appendices II, III, IV, and V. Appendices II and III contain the FCR
18 related schedules, Appendix IV contains the capacity related
19 schedules, and Appendix V contains the Oil-backout related
20 schedules.

21
22 Also, included in Appendix III (pages 7 through 53) are the
23 Commission Schedules A1 through A13 for April and May 1994.
24 These schedules were prepared by various departments including

1 Power Supply, Rates, Power Generation and Accounting, and
2 present a monthly comparison between the original projections and
3 the actual generation, sales and fuel costs for the two months.
4

5 Q. What is the source of the data which you will present by way
6 of testimony or exhibits in this proceeding?

7 A. Unless otherwise indicated, the actual data is taken from the books
8 and records of FPL. The books and records are kept in the regular
9 course of our business in accordance with generally accepted
10 accounting principles and practices and provisions of the Uniform
11 System of Accounts as prescribed by this Commission.
12

13 FUEL COST RECOVERY CLAUSE
14

15 Q. What are the proposed fuel factors for which the Company
16 requests approval?

17 A. The proposed Fuel factors for which the Company is requesting
18 approval are shown on Schedule E1, Page 4 of Appendix II for Non
19 Time of Use Rates and Schedule E1, Page 5 of Appendix II for
20 Time of Use Rates. Schedule E2, Page 7 of Appendix II indicates
21 the monthly fuel factors for October 1994 through March 1995.
22
23
24

1 Q. Has the Company made any changes to the Fuel Cost
2 Recovery Clause being proposed?

3 A. Yes, we have. The Company is proposing to change the allocation
4 of fuel costs.

5

6 Q. Please describe why FPL is proposing to change the allocation
7 of fuel costs?

8 A. The current method of charging customers in all classes based on
9 the same average cost per kWh assigns cost responsibility as if all
10 kWhs have an equal impact on FPL's fuel cost. This may have
11 been appropriate in the past, when there was less diversity in the
12 fuels and units used, but does not fit the FPL system of today. A
13 more appropriate methodology would recognize and take into
14 account differences in prices between fuels and efficiencies
15 between generating units. Such a methodology would reflect the
16 fact that fuel cost is not the same in all hours of the day, nor in all
17 days of the year. A more appropriate allocation methodology would
18 take into account that each rate class does not comprise the same
19 proportion of system kWh sales for each hour. A methodology that
20 took all of this into account would reflect that some classes use
21 more energy in higher cost periods than do other classes rather
22 than having all customers classes pay the same average fuel costs.
23 FPL is proposing a change to the allocation of fuel costs through
24 the Fuel Cost Recovery Clause which addresses differences in

1 differences in costs and class kWh usage between hours and
2 results in a more appropriate allocation of cost between customer
3 classes.

4
5 Q. How has FPL addressed these problems with the allocation of
6 costs in the Fuel Cost Recovery clause?

7 A. The allocation method which FPL is proposing recognizes that the
8 fuel cost per kWh increases as load increases in each hour. This
9 is the result of the use of economic dispatch, under which the most
10 economical units are called upon to serve load first. As load grows,
11 units with higher incremental costs are called upon, resulting in
12 increasing costs per kWh. It would be impractical to attempt to
13 project fuel cost by hour for a six month period and to match that
14 with a projection of kWh sales by rate class. Instead, our proposed
15 methodology looks at the hourly loads from the previous year and
16 the contribution of each class to those hourly loads. The kWhs
17 consumed in each hour are weighted such that kWhs consumed in
18 hours with higher loads are allocated a higher proportion of fuel
19 cost. This is consistent with the higher fuel cost per kWh necessary
20 to meet those higher loads. The kWhs consumed in hours with
21 lower loads receive lower weights and thus are allocated a lower
22 proportion of total fuel cost. This weighting of kWhs by the load in
23 the hour in which they were consumed is done for each rate class.
24 By doing this, the method proposed by FPL would result in the

price would be highest for those classes which contribute the most to the hours with the highest load. Let me illustrate with the following simplified example with two customer classes and two hours such that:

	<u>Hour A</u>	<u>Hour B</u>	<u>Total</u>	<u>% kWh</u>
Class X	10 kWh	0 kWh	10 kWh	50%
Class Y	<u>5 kWh</u>	<u>5 kWh</u>	<u>10 kWh</u>	<u>50%</u>
	15 kWh	5 kWh	20 kWh	100%

Hour A kWh are 15/20 or 75% or 75% of the total

Hour B kWh are 5/20 or 25% of the total.

Under the current methodology: Both classes pay the same fuel rate per kWh. Because both classes use the same number of kWh, they both pay the same total Fuel Cost Recovery revenues.

Under FPL's proposal:

Class X's weighted kWh = $(10 \times 75\%) + (0 \times 25\%) = 7.5$

Class Y's weighted kWh = $(5 \times 75\%) + (5 \times 25\%) = 5$

Total weighted kWh = $7.5 + 5 = 12.5$

Class X uses $7.5/12.5$ or 60% of weighted kWh

Class Y uses $5/12.5$ or 40% of weighted kWh.

Each class's price multiplier = $\frac{\% \text{ weighted kWh}}{\% \text{ total kWh}}$

Class X's price multiplier = $60\% / 50\% = 1.2$

Class Y's price multiplier = $40\% / 50\% = 0.8$

Class X pays 1.2 times the average fuel rate

Class Y pays 0.8 times the average fuel rate.

Q. Please describe the method proposed by FPL.

A. In FPL's proposed methodology, each hour from the historic period is given a weight based upon that hour's contribution to total retail kWh for the period. The weight calculated for each hour is then applied to the kWh for each class in that hour. These "weighted kWhs" are summed for each class and the contribution of each class to the total weighted kWhs for the historic period is determined. A ratio of weighted kWh contribution to unweighted kWh contribution, or price multiplier, is then calculated for each rate class. This price multiplier is then applied to the system average Fuel Cost Recovery factor for the projected period to determine the class factor before losses. The delivery loss multipliers for each rate class then are applied to establish the Fuel Cost Recovery factors for the classes. The calculation of the non-time of use factors is shown on Schedule E1, Page 4 of Appendix II.

Q. How are charges for TOU classes established in your proposed

1 Q. How are charges for TOU classes established in your proposed
2 methodology?

3 A. The charges for Time of Use (TOU) rate classes start with the
4 factor calculated as discussed above for the non-TOU counterpart
5 to each class (e.g. the RS-1 factor is the basis for the RST-1 factor,
6 etc.). The calculation also uses the on-peak, off-peak and average
7 marginal fuel costs projected for the period. These factors are
8 calculated each period and presented in Schedule COG-1, which
9 is provided as pages 38 through 41 of Appendix II. The ratio of the
10 onpeak marginal cost to the average marginal cost would be
11 applied to the class Fuel Cost Recovery factor to determine the
12 onpeak fuel factor. Likewise, the ratio of the offpeak marginal cost
13 to the average marginal cost would be used to calculate the offpeak
14 fuel factor. These factors based on the marginal cost ratios are
15 then adjusted, both by the same percentage, to achieve revenue
16 neutrality. The calculation of the Fuel Cost Recovery factors for the
17 TOU classes is shown on Schedule E1, Page 6 of Appendix II.

18
19 Q. Is this the method currently used to calculate Fuel Cost Recov-
20 ery factors for TOU classes?

21 A. No, it is not. Under the method currently used, system average
22 onpeak and offpeak factors are calculated using totals system fuel
23 costs and kWhs projected for the onpeak and offpeak periods. The
24 proposed method improves upon that in two ways. First, the use

1 of the Fuel Cost Recovery factor for the counterpart non-TOU class
2 result in the same allocation improvement discussed above. In
3 addition, the use of the marginal cost ratios to calculate onpeak and
4 offpeak fuel factors results in a price signal to TOU customers
5 which better reflects the impacts on the system of onpeak and
6 offpeak usage.

7
8 **Q. What adjustments are included in the calculation of the six-**
9 **month levelized fuel factor shown on Schedule E1, Page 3 of**
10 **Appendix II?**

11 **A.** As shown on line 28 of Schedule E1, Page 3, of Appendix II the
12 estimated/actual fuel cost overrecovery for the April 1994 through
13 September 1994 period amounts to \$32,451,868. This
14 estimated/actual overrecovery for the April 1994 through September
15 1994 period plus the final overrecovery \$2,066,794 for the October
16 1993 through March 1994 period results in a total overrecovery of
17 \$34,518,662. This amount, divided by the projected retail sales of
18 33,310,414 MWh for October 1994 through March 1995 results in
19 a decrease of .1036¢ per kWh before applicable revenue taxes. In
20 his testimony for the Generating Performance Incentive Factor, FPL
21 Witness R. Silva calculated a reward of \$3,107,919 for the period
22 ending March 1994, to be applied to the October 1994 through
23 March 1995 period. This \$3,107,919 divided by the projected retail
24 sales of 33,310,414 MWh during the projected period, results in an

1 increase of .0093¢ per kWh, as shown on line 32 of Schedule E1,
2 Page 3 of Appendix II.

3

4 Q. Please explain the calculation of the FCR Estimated/Actual
5 True-up amount you are requesting this Commission to
6 approve.

7 A. Appendix III, page 3, shows the calculation of the FCR
8 Estimated/Actual True-up amount. The calculation of the
9 estimated/actual true-up amount for the April 1994 through
10 September 1994 is an overrecovery, including interest, of
11 \$32,451,866 (Column g, lines D7 plus D8). This amount, when
12 combined with the Final True-up overrecovery of \$2,066,794
13 (Column g, line D9a) deferred from the period October 1993
14 through March 1994, presented in my Final True-up testimony filed
15 on May 20, 1994, results in the End of Period overrecovery of
16 \$34,518,662 (Column g, line D11).

17

18 This schedule also provides a summary of the Fuel and Net Power
19 Transactions (lines A1 through A7), kWh Sales (lines C1 through
20 C4), Jurisdictional Fuel Revenues (line D1 through D3), the True-up
21 and Interest calculation (lines D4 through D10) for this period, and
22 the End of Period True-up amount (line D11).

23

24 The data for April and May 1994, columns (a) and (b), reflects the

1 actual results of operations and the data for June 1994 through
2 September 1994, columns (c) through (f), are based on updated
3 estimates.

4
5 The true-up calculations follow the procedures established by this
6 Commission as set forth on Commission Schedule A2 "Calculation
7 of True-Up and Interest Provision" filed in this proceeding in
8 Appendix III, pages 7 through 53.

9
10 **Q. Have you provided a schedule showing the variances between**
11 **the Original Projections and the Estimated/Actuals?**

12 **A.** Yes. Appendix III, page 4, shows Estimated/Actual fuel costs and
13 revenues compared to the original estimates for the April 1994 -
14 September 1994 period.

15
16 **Q. What is the variance in fuel costs for the period?**

17 **A.** As shown on line A7, fuel costs on a total system basis are now
18 projected to be \$11.1 million lower than originally estimated. This
19 variance is detailed by major cost components on page 5. The
20 \$11.1 million total system variance relating to the estimated/actual
21 period is primarily caused by a \$8.1 million decrease in the fuel
22 cost of system net generation, a \$10.4 million decrease in the cost
23 of purchased power offset by a \$7.8 million increase in energy cost
24 of economy purchases.

1 Q. What is the variance in retail (jurisdictional) Fuel Cost
2 Recovery revenues for the period?

3 A. As shown on Page 4, line D1, jurisdictional fuel revenues, net of
4 revenue taxes, are now projected to be \$16.8 million higher than
5 originally estimated. This increase is primarily due to higher
6 jurisdictional kWh sales. Jurisdictional sales are now estimated to
7 be 1,263,208,425 kWh (3.32%) higher than originally forecasted,
8 primarily due to above normal weather and higher than projected
9 economic growth for the period.
10

11 Q. Have you provided a schedule explaining the reasons for these
12 variances?

13 A. Yes. Appendix III, pages 5 and 6, contain a more detailed analysis
14 of the cost variances with a corresponding explanation for variances
15 deemed material.
16

17 Q. Please describe Page 6 of Appendix II.

18 A. Page 6 of Appendix II shows the revised loss factors for each rate
19 group and for the retail sales in accordance with the annual energy
20 loss report for 1993. The Company requests approval of these loss
21 factors for the calculation of any fuel factors applicable to each rate
22 group.
23
24

1 Q. What is shown on Pages 38-41 of Appendix II?

2 A. Pages 38-41 of Appendix II contain revised Tariff Schedules COG-1
3 and COG-2. These tariff sheets contain, for informational purposes,
4 updated projections of avoided energy costs for purchases from
5 small power producers and cogenerators.
6

7 **CAPACITY PAYMENT RECOVERY CLAUSE**
8

9 Q. Please describe Page 3 of Appendix IV.

10 A. Page 3 of Appendix IV provides a summary of the requested
11 capacity payments for the projected period of October 1994 through
12 March 1995. Total recoverable capacity payments amount to
13 \$152,074,783 and include payments of \$126,194,478 to non-
14 cogenerators and payments of \$73,431,219 to cogenerators. This
15 amount is offset by revenues from capacity sales of \$474,015 and
16 \$28,472,796 of jurisdictional capacity related payments included in
17 Base Rates less the net overrecovery of \$16,781,361 reflected on
18 line 8. The net overrecovery of \$16,781,361 includes the final
19 overrecovery of \$8,570,760 for the October 1993 through March
20 1994 period plus the estimated/actual overrecovery of \$8,210,602
21 for the April 1994 through September 1994 period.
22
23
24

1 Q. Please describe Page 4 of Appendix IV.

2 A. Page 4 of Appendix IV calculates the allocation factors for demand
3 and energy at generation. The demand allocation factors are
4 calculated by determining the percentage each rate class
5 contributes to the monthly system peaks. The energy allocators are
6 calculated by determining the percentage each rate contributes to
7 total kWh sales, as adjusted for losses, for each rate class.

8

9 Q. Please describe Page 5 of Appendix IV.

10 A. Page 5 of Appendix IV presents the calculation of the proposed
11 Capacity Payment Recovery Clause (CCR) factors by rate class.

12

13 Q. Is FPL proposing any changes to the method by which the
14 Capacity Clause is recovered from customers?

15 A. Yes. FPL is proposing to change the way Capacity costs are
16 recovered from Standby customers, those taking Standby service
17 under Schedule SST-1 or ISST-1. Last year, when I proposed
18 recovery on a demand basis for those customers in classes with a
19 demand charge, the Commission approved recovery of Capacity
20 Costs from these customers using a charge applied to their
21 Reservation, or Contract demand. This method is easy for the
22 customers to understand and results in stable recovery of Capacity
23 costs. With a year of experience in recovering CPRC on a demand
24 basis and after discussion with the Commission Staff, I believe it is

1 appropriate at this time to take the next step in the recovery of
2 these costs from Standby customers. This step would result in
3 recovery that is more complex, but matches the recovery of
4 production plant costs through base rates for these customers.

5

6 Q. Would you please describe the method you are proposing?

7 A. Yes. It is the same method approved by the Commission (Order
8 17159, Docket No. 850673-EU) for recovery of production plant
9 costs from Standby customers. FPL proposes a Reservation
10 Component and a Daily Demand component for CPRC recovery.
11 The Reservation component, applied the same way as the
12 Reservation Charge in the base rate, is calculated as 10% of the
13 system average CPRC cost per kW. The Daily Demand
14 component, applied in the same way as the Daily Demand charge
15 in the base rate, is calculated by dividing the system average
16 CPRC cost per kW by 21 on-peak days per month. I have
17 discussed both of these calculations with Commission Staff and
18 received concurrence that the calculations match those ordered by
19 the Commission for use in the development of the Standby Service
20 base rates.

21

22 Q. Is FPL proposing any other changes to the recovery of costs
23 under CPRC?

24 A. No. With the proposed change discussed above, CPRC recovery

1 will be consistent with the recovery of production plant costs
2 through base rates for all rate classes at FPL.

3

4 Q. Please explain the calculation of the CCR Estimated/Actual
5 True-up amount you are requesting this Commission to
6 approve.

7 A. Appendix IV, page 6, shows the calculation of the CCR
8 Estimated/Actual True-up amount. The Estimated/Actual True-up for
9 the period April 1994 through September 1994 is an overrecovery,
10 including interest, of \$8,210,602 (Column 7, lines 14 plus 15). This
11 amount, plus the Final True-up overrecovery of \$6,570,760 (Column
12 7, line 17) deferred from the period October 1993 through March
13 1994, presented in my Final True-up testimony filed on May 20,
14 1994, results in the End of Period overrecovery of \$16,781,361
15 (Column 7, line 19).

16

17 Q. Is this true-up calculation consistent with the true-up
18 methodology used for the other cost recovery clauses?

19 A. Yes it is. The calculation of the true-up amount follows the
20 procedures established by this Commission as set forth on
21 Commission Schedule A2 "Calculation of True-Up and Interest
22 Provision" for the Fuel Cost Recovery clause.

23

24 The resulting overrecovery of \$16,781,361 has been included in the

1 calculation of the Capacity Cost Recovery factor for the period
2 October 1994 through March 1995.

3

4 Q. Please explain the calculation of the Interest Provision.

5 A. Appendix IV, page 7, shows the calculation of the interest provision
6 and follows the same methodology used in calculating the interest
7 provision for the other cost recovery clauses, as previously
8 approved by this Commission.

9

10 The interest provision is the result of multiplying the monthly
11 average true-up amount (line 4) times the monthly average interest
12 rate (line 9). The average interest rate for the months reflecting
13 actual data is developed using the 30 day commercial paper rate
14 as published in the Wall Street Journal on the first business day of
15 the current and subsequent months. The average interest rate for
16 the projected months is the actual rate as of the first business day
17 in June 1994.

18

19 Q. Have you provided a schedule showing the variances between
20 the Estimated/Actuals and the Original Projections?

21 A. Yes, Appendix IV, page 8, shows the Estimated/Actual capacity
22 charges and applicable revenues compared to the original
23 projections for the period.

24

1 Q. What is the variance related to capacity charges?

2 A. The variance related to capacity charges is a \$1.7 million
3 decrease. This variance is primarily due to a \$3.2 million decrease
4 in unit power capacity charges offset by a \$0.7 million increase in
5 capacity payments to qualifying facilities and a \$0.7 million
6 decrease in revenues from capacity sales. The decrease in unit
7 power capacity charges is primarily due to \$1.1 million transmission
8 true-up credit reflected on May's invoice and also to common
9 investment balances being lower than projected.

10

11 Q. What is the variance in Capacity Cost Recovery revenues?

12 A. As shown on line 13, Capacity Cost Recovery revenues, net of
13 revenue taxes, are now estimated to be \$6.5 million higher than
14 originally projected. This increase is primarily due to higher
15 jurisdictional kWh sales. Jurisdictional sales are now estimated to
16 be 1,263,209,425 kWh (3.32%) higher than originally forecasted,
17 primarily due to above normal weather and higher than projected
18 economic growth for the period.

19

20 OIL BACKOUT COST RECOVERY CLAUSE (OB)

21

22 Q. Please explain the calculation of the OB Factor you are
23 requesting this Commission to approve.

24 A. Appendix V, page 3, shows the derivation of the OB Factor of .011

1 cents per kWh requested for the projected period October 1994
2 through March 1995. This Factor represents the \$4,253,037 in
3 projected costs divided by the total kWh sales projected for the
4 period, less the End of Period overrecovery of \$508,252, divided by
5 the retail kWh sales projected for the period October 1994 through
6 March 1995. The resulting factor was then multiplied by the
7 Revenue Tax Factor to arrive at the OB Factor for the period. Both
8 the Revenue Tax Factor and the kWh sales are the same as those
9 used in our Fuel Cost Recovery Clause included in this filing.

10
11 Q. What are the projected costs requested for recovery through
12 the OB Factor for the period October 1994 through March
13 1995?

14 A. Appendix V, page 4, reflects the total projected costs requested for
15 recovery for the period. These costs consist solely of the 500 kV
16 Transmission Line Project (Project) revenue requirements, which
17 total \$4,253,037 for the projected period.

18
19 As detailed on page 4, the Project revenue requirements include a
20 return on investment, taxes other than income taxes, income taxes,
21 and O&M expenses. No depreciation is included since the capital
22 investment in the 500 kV line was fully depreciated in October
23 1989. A detailed description of the methodology used to calculate
24 the revenue requirements of the Project was included in E.L.

1 Hoffman's testimony, Document No. 1 for the February 1983
2 hearing.

3

4 Q. Have you also presented the Estimated/Actual costs for the
5 period April 1994 through September 1994?

6 A. Yes, Appendix V, page 6, shows the components of the \$4,435,914
7 Estimated/Actual Project revenue requirements requested for the
8 period. It contains similar information as that described in the
9 previous paragraph, except it reflects two months actual data and
10 four months updated estimates.

11

12 Q. What is the purpose of the schedules showing kWh sales?

13 A. The purpose of the schedules showing kWh sales on pages 5 and
14 7, is to show the calculation of the monthly percentage of retail
15 (jurisdictional) kWh sales to total kWh sales, for the projected and
16 Estimate/Actual periods respectively. These monthly percentages
17 (jurisdictional factor) are used to allocate costs between retail and
18 wholesale customers. The kWh sales reflected on these schedules
19 are consistent with the kWh sales shown in the FCR and CCR
20 schedules.

21

22 Q. Please explain the calculation of the OB Estimated/Actual True-
23 up amount you are requesting this Commission to approve.

24 A. Appendix V, page 8, shows the calculation of the OB

1 Estimated/Actual True-up amount. The Estimated/Actual True-up for
2 OB is an overrecovery, including interest, of \$250,389 (Column 9,
3 lines 7 plus 8). This amount, when combined with the Final True-up
4 overrecovery of \$257,863 (Column 9, line 10) deferred from the
5 period October 1993 through March 1994, presented in my Final
6 True-up testimony filed on May 20, 1994, results in the End of
7 Period overrecovery of \$508,252 (Column 9, line 12).

8
9 Q. Please explain the calculation of the interest provision.

10 A. Appendix V, page 9, shows the calculation of the interest provision
11 for the period April 1994 through September 1994 and is consistent
12 with the procedures used in calculating the interest for the FCR and
13 CCR clauses. The interest FPL owes its customers as result of net
14 overrecoveries during the period is \$5,028 as shown on line 10.

15
16 Q. Have you provided a schedule showing the variances between
17 Estimated/Actuals and the Original Projections?

18 A. Yes. Appendix V, page 10, entitled "Calculation of Estimated/Actual
19 True-up Variances", shows the estimated/actual Oil Backout costs
20 and revenues compared to the original projections for the period
21 April 1994 through September 1994.

1 Q Have you provided a schedule explaining the reasons for these
2 variances?

3 A Yes. Pages 11 and 12, of Appendix V, provide a more detailed
4 analysis of the variances with corresponding explanations for
5 Revenue Requirements, and Jurisdictional kWh Sales, respectively.
6

7 Q. What effective date is the Company requesting for the new
8 factors?

9 A. The Company is requesting that the new factors become effective
10 with customer billings on cycle day 3 of October 1994 and continue
11 through Customer billings on cycle day 2 of April 1995. This will
12 provide for 6 months of billing on these factors for all our
13 customers.
14

15 Q. What will be the charge for a Residential customer using 1,000
16 kWh effective October 1994?

17 A. The total residential bill, excluding taxes and franchise, for 1,000
18 kWh will be \$71.73. The base bill for 1,000 residential kWh is
19 \$47.38, the fuel cost recovery charge from Schedule E1, Page 5 of
20 Appendix II for a residential customer is \$15.81, the Conservation
21 charge is \$2.43, the Oil Backout charge is \$.11, the Capacity
22 Recovery charge is \$5.17, the Environmental Cost Recovery charge
23 is \$.10 and the Gross Receipt Tax is \$.73. A Residential Bill
24 Comparison (1000kWh) is presented in Schedule E10, Page 33 of

1 Estimated/Actual True-up amount. The Estimated/Actual True-up for
2 OB is an overrecovery, including interest, of \$250,389 (Column 9,
3 lines 7 plus 8). This amount, when combined with the Final True-up
4 overrecovery of \$257,863 (Column 9, line 10) deferred from the
5 period October 1993 through March 1994, presented in my Final
6 True-up testimony filed on May 20, 1994, results in the End of
7 Period overrecovery of \$508,252 (Column 9, line 12).

8
9 **Q. Please explain the calculation of the interest provision.**

10 **A.** Appendix V, page 9, shows the calculation of the interest provision
11 for the period April 1994 through September 1994 and is consistent
12 with the procedures used in calculating the interest for the FCR and
13 CCR clauses. The interest FPL owes its customers as result of net
14 overrecoveries during the period is \$5,028 as shown on line 10.

15
16 **Q. Have you provided a schedule showing the variances between**
17 **Estimated/Actuals and the Original Projections?**

18 **A.** Yes. Appendix V, page 10, entitled "Calculation of Estimated/Actual
19 True-up Variances", shows the estimated/actual Oil Backout costs
20 and revenues compared to the original projections for the period
21 April 1994 through September 1994.

1 Q Have you provided a schedule explaining the reasons for these
2 variances?

3 A Yes. Pages 11 and 12, of Appendix V, provide a more detailed
4 analysis of the variances with corresponding explanations for
5 Revenue Requirements, and Jurisdictional kWh Sales, respectively.
6

7 2. What effective date is the Company requesting for the new
8 factors?

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10 with customer billings on cycle day 3 of October 1994 and continue
11 through Customer billings on cycle day 2 of April 1995. This will
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13 customers.
14

15 Q. What will be the charge for a Residential customer using 1,000
16 kWh effective October 1994?

17 A. The total residential bill, excluding taxes and franchise, for 1,000
18 kWh will be \$71.73. The base bill for 1,000 residential kWh is
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21 charge is \$2.43, the Oil Backout charge is \$.11, the Capacity
22 Recovery charge is \$5.17, the Environmental Cost Recovery charge
23 is \$.10 and the Gross Receipt Tax is \$.73. A Residential Bill
24 Comparison (1000kWh) is presented in Schedule E10, Page 33 of

1 Appendix II.

2

3 **Q. Does this conclude your testimony.**

4 **A. Yes, it does.**

APPENDIX I

FUEL COST RECOVERY

FORECAST ASSUMPTIONS

**APPENDIX I
FUEL COST RECOVERY
FORECAST ASSUMPTIONS**

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7	Projected Unit Availabilities and Outage Schedules	R. Silva
8	Variable O&M Expenses	R. Silva

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

HEAVY FUEL OIL (\$/BBL)

OCTOBER, 1994 THROUGH MARCH, 1995

FOSSIL STEAM PLANTS	SULFUR GRADE	1994			1995		
		OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
MARTIN	0.7%	\$17.45	\$17.30	\$16.35	\$17.05	\$15.18	\$15.22
CANAVERAL	2.0%	\$14.72	\$14.33	\$13.37	\$14.28	\$12.66	\$12.50
PORT EVERGLADES	1.0%	\$16.14	\$15.65	\$14.68	\$15.79	\$13.91	\$13.90
FT. MYERS	2.0%	\$14.58	\$14.16	\$13.20	\$14.16	\$12.48	\$12.35
MANATEE	1.0%	\$15.85	\$15.37	\$14.40	\$15.51	\$13.62	\$13.62
RIVIERA	2.5%	\$13.61	\$13.26	\$12.30	\$13.12	\$11.63	\$11.40
SANFORD	2.0%	\$15.24	\$14.84	\$13.88	\$14.80	\$13.17	\$13.02
TURKEY POINT	1.0%	\$16.68	\$16.20	\$15.23	\$16.34	\$14.45	\$14.44

FLORIDA POWER & LIGHT COMPANY

PROJECTED DISPATCH COSTS

LIGHT OIL (\$/BBL)

OCTOBER, 1994 THROUGH MARCH, 1995

COMBUSTION TURBINES (CT'S) & COMBINED CYCLES (CC'S)	SULFUR GRADE	1994			1995		
		OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
PORT EVERGLADES CT'S	0.5%	\$27.39	\$26.50	\$25.35	\$25.35	\$23.42	\$22.71
FORT MYERS CT'S	0.5%	\$27.55	\$26.67	\$25.52	\$25.52	\$23.59	\$22.88
LAUDERDALE CT'S	0.5%	\$27.61	\$26.72	\$25.57	\$25.57	\$23.64	\$22.93
LAUDERDALE 4 & 5 CC'S	0.3%	\$28.46	\$27.58	\$26.43	\$26.43	\$24.51	\$23.80
MARTIN 3 & 4 CC'S	0.3%	\$27.38	\$26.50	\$25.35	\$25.35	\$23.43	\$22.72
PUTNAM	0.3%	\$28.96	\$28.08	\$26.94	\$26.93	\$25.01	\$24.30
MMBTU/BARREL :		0.5%\$ = 5.83					
		0.3%\$ = 5.83					

FLORIDA POWER & LIGHT COMPANY
 PROJECTED DISPATCH COSTS
 SJRPP AND SCHERER (FPL OWNERSHIP SHARE ONLY*)
 OCTOBER, 1994 THROUGH MARCH, 1995

FOSSIL STEAM PLANTS		1994			1995		
		OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
ST JOHNS RIVER POWER PARK	COAL (\$/TON)	\$30.80	\$30.80	\$30.80	\$31.32	\$31.76	\$31.81
SCHERER UNIT 4	COAL (\$/TON)	\$31.38	\$31.51	\$31.38	\$31.60	\$32.39	\$34.68

* FPL'S OWNERSHIP SHARE OF SJRPP IS 20%.
 FPL'S OWNERSHIP SHARE OF SCHERER UNIT 4 IS 65.72% DURING THE OCTOBER, 1994 THROUGH MARCH, 1995 PERIOD.

FLORIDA POWER & LIGHT COMPANY

PROJECTED NATURAL GAS PRICES AND TRANSPORTATION CAPACITY AVAILABILITY

OCTOBER 1994 THROUGH MARCH 1995

NATURAL GAS TRANSPORTATION CAPACITY AVAILABILITY TO FPL BY SERVICE TYPE (MMBTU/DAY) (000'S)	1994			1995		
	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH
FIRM	280	255	255	455	455	455
NON-FIRM	100	75	50	40	55	125
TOTAL	380	330	305	495	510	580
UNIT PRICE BY TYPE OF TRANSPORTATION SERVICE (\$/MMBTU)						
FIRM	\$2.40	\$2.59	\$3.05	\$2.94	\$2.80	\$2.73
NON-FIRM	\$2.73	\$2.86	\$2.82	\$2.83	\$2.50	\$2.42
SYSTEM WEIGHTED AVERAGE	\$2.48	\$2.65	\$3.01	\$2.93	\$2.77	\$2.66

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
OCTOBER, 1994 THROUGH MARCH, 1995

PLANT/UNIT	PROJECTED FORCED OUTAGE FACTOR (%)	PROJECTED MAINTENANCE OUTAGE FACTOR (%)	PLANNED OUTAGE FACTOR (%)	OVERHAUL DATES *
Cape Canaveral 1	2.0	5.6	0.0	NONE
Cape Canaveral 2	2.0	8.1	0.0	NONE
Cutler 5	2.0	2.0	0.0	NONE
Cutler 6	2.0	2.0	0.0	NONE
Lauderdale 4	3.7	2.0	1.7	03/21/95 - (03/31/95)**
Lauderdale 5	2.0	5.3	0.0	NONE
Fort Myers 1	2.0	2.8	0.0	NONE
Fort Myers 2	4.1	2.6	0.0	NONE
Manatee 1	1.8	3.1	9.3	03/15/95 - (03/31/95)
Manatee 2	2.0	2.3	0.0	NONE
Martin 1	1.7	4.7	14.8	(10/01/94) - 10/27/94
Martin 2	2.7	2.0	0.0	NONE
Martin 3	1.9	1.9	3.9	11/12/94 - 11/25/94 **
Martin 4	1.9	1.9	6.6	11/26/94 - 12/19/94 **
Port Everglades 1	1.4	1.4	30.8	10/22/94 - 12/16/94
Port Everglades 2	2.0	2.9	0.0	NONE
Port Everglades 3	2.0	3.5	0.0	NONE
Port Everglades 4	2.0	2.1	0.0	NONE
Putnam 1	2.0	3.8	0.0	NONE
Putnam 2	1.7	3.1	13.3	03/01/95 - 03/12/95 ** 03/01/94 - (03/31/95)**
Riviera 3	7.1	2.0	0.0	NONE
Riviera 4	3.7	4.2	9.3	03/15/95 - (03/31/95)
Sanford 3	2.0	3.0	0.0	NONE
Sanford 4	2.4	3.0	0.0	NONE
Sanford 5	3.9	2.0	0.0	NONE
Turkey Point 1	2.6	8.0	9.3	03/15/95 - (03/31/95)
Turkey Point 2	2.6	2.3	34.6	10/15/94 - 12/16/94
Turkey Point 3	3.2	3.2	0.0	NONE
Turkey Point 4	2.1	2.1	35.2	10/18/94 - 12/20/94
St. Lucie 1	2.1	2.1	35.2	(10/01/94) - 12/03/94
St. Lucie 2	5.2	3.2	0.0	NONE
SJRRP 1	2.0	2.0	19.2	02/25/95 - (03/31/95)
SJRRP 2	2.9	2.0	0.0	NONE
Scherer 4	1.8	1.8	12.1	02/04/95 - 02/24/95

* Note: Overhaul dates shown in parentheses begin before or end after the projected period.

** Note: Partial Planned Outage.

FLORIDA POWER & LIGHT COMPANY
SUMMARY OF FOSSIL STEAM EXPENSES
TWELVE MONTHS ENDED DECEMBER, 1993
TO DETERMINE MAXIMUM AVOIDABLE
VARIABLE O&M EXPENSES

FOSSIL PLANT EAC	ASH DISPOSAL 700	CHEMICALS 699	UTILITIES (WATER) 642	MAXIMUM VARIABLE EXPENSES	NET OUTPUT MWH
CUTLER	\$9,020	\$21,191	\$99,147	\$129,358	241,579
RIVIERA	\$0	\$155,284	\$140,686	\$295,970	2,929,006
PUTNAM	\$0	\$334,455	\$14,646	\$349,101	2,992,026
FT LAUDERDALE	\$0	\$246,786	\$28,874	\$275,660	3,854,301
SANFORD	\$0	\$197,885	\$16,201	\$214,086	3,599,515
FT MYERS	\$133,781	\$165,974	\$26,494	\$326,249	3,065,293
PORT EVERGLADES	\$150,412	\$352,820	\$222,734	\$725,966	6,130,408
CAPE CANAVERAL	\$0	\$207,104	\$41,102	\$248,286	3,759,301
MANATEE	\$128,641	\$311,721	\$13,678	\$454,040	4,739,488
MARTIN	\$713	\$173,022	\$4,330	\$178,065	2,853,028
TURKEY POINT	\$39,408	\$40,974	\$43,164	\$123,546	2,982,588

REGRESSION FORMULA: EXPENSES = $(\$22,492.84) + \$0.09605 \cdot \text{MW}$

MARGINAL EXPENSE PER MW = $\$0.09605$

SLOPE OF BEST FIT LINE

Y - INTERCEPT (\$)

PEARSON PRODUCT-MOMENT COR. COEF.

r - square

t VALUE

$\$0.09605$
 $(\$22,492.84)$
 (0.8033)
 0.6453
 4.046

APPENDIX II
FUEL COST RECOVERY
PROJECTED PERIOD

BTB - 5
DOCKET NO 940001-EI
FPL WITNESS: B.T. BIRKETT
EXHIBIT _____
PAGES 1-41
JUNE 27, 1994

**APPENDIX II
FUEL COST RECOVERY
PROJECTED PERIOD**

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8-9	Schedule E3 Monthly Summary of Generating System Data	R Silva/D.Poteralski
10	Schedule E4 Monthly Electric Energy Data	R. Silva
11-24	Schedule E5 Monthly Generation and Fuel Cost by Unit	R.Silva/D.Poteralski
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29	Schedule E7a Monthly Cost of Power Sold Data including Gain on Economy Sales	R. Silva
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FLORIDA POWER & LIGHT COMPANY

Schedule E1

Page 1 of 4

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: OCTOBER 1994 - MARCH 1995

	(a)	(b)	(c)
	DOLLARS	MWH	c/KWH
1 Fuel Cost of System Net Generation (E3)	\$417,030,531	28,184,276	1.4797
2 Nuclear Fuel Disposal Costs (E2)	8,958,421	9,755,442	0.0918
3 Fuel Related Transactions (E2)	7,069,705	0	0.0000
4 Fuel Cost of Sales to FKEC / CKW	(7,342,807)	(379,284)	1.9359
5 TOTAL COST OF GENERATED POWER	\$425,716,050	27,804,992	1.5311
6 Fuel Cost of Purchased Power (Exclusive of Economy) (E8)	79,340,740	4,757,009	1.6679
7 Energy Cost of Sched C & X Econ Purch (Broker) (E9)	7,130,110	381,899	1.8670
8 Energy Cost of Other Econ Purch (Non-Broker) (E9)	443,200	19,909	2.2261
9 Energy Cost of Sched E Economy Purch (E9)	0	0	0.0000
10 Capacity Cost of Sched E Economy Purchases (E2)	0	0	0.0000
11 Payments to Qualifying Facilities (E8a)	42,767,956	2,415,279	1.7707
12 TOTAL COST OF PURCHASED POWER	\$129,682,006	7,574,096	1.7122
13 TOTAL AVAILABLE KWH (LINE 5 + LINE 12)		35,379,088	
14 Fuel Cost of Economy Sales (E7)	(6,804,040)	(279,287)	2.4362
15 Gain on Economy Sales (E7a)	(1,734,687)	(279,287)	0.6211
16 Fuel Cost of Unit Power Sales (SL2 Partpts) (E7)	(717,521)	(168,528)	0.4258
17 Fuel Cost of Other Power Sales (E7)	0	0	0.0000
18 TOTAL FUEL COST AND GAINS OF POWER SALES	(\$9,256,248)	(447,815)	2.0670
19 Net Inadvertent Interchange (E4)	0	0	
20 TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	\$546,141,809	34,931,273	1.5635
21 Net Unbilled Sales (E4)	13,681,159 **	875,048	0.0410
22 Company Use (E4)	1,656,221 **	105,932	0.0050
23 T & D Losses (E4)	36,326,331 **	2,323,435	0.1088
24 SYSTEM MWH SALES (Excl sales to FKEC / CKW)	\$546,141,809	33,387,503	1.6358
25 Wholesale MWH Sales (Excl sales to FKEC / CKW)	\$1,260,987	77,089	1.6358
26 Jurisdictional MWH Sales	\$544,880,822	33,310,414	1.6358
26a Jurisdictional Loss Multiplier	-	-	1.00053
27 Jurisdictional MWH Sales Adjusted for Line Losses	\$545,169,609	33,310,414	1.6366
28 FINAL TRUE-UP OCT 93 - MARCH 94 (\$2,066,794) overrecovery	EST/ACT TRUE-UP APRIL 1994 - SEPT 1994 (\$32,451,868) overrecovery	(34,518,662)	33,310,414 (0.1036)
29 TOTAL JURISDICTIONAL FUEL COST	\$510,650,947	33,310,414	1.5330
30 Revenue Tax Factor			1.01609
31 Fuel Factor Adjusted for Taxes			1.5577
32 GPIF *** reward	\$3,107,919	33,310,414	0.0093
33 Fuel Factor including GPIF (Line 31 + Line 32)			1.5670
34 FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			1.567

** For Informational Purposes Only

*** Calculation Based on Jurisdictional KWH Sales

**FLORIDA POWER & LIGHT COMPANY
DETERMINATION OF FUEL RECOVERY FACTOR
NON - TIME OF USE RATE SCHEDULE
OCTOBER 1994 - MARCH 1995**

Rate Schedule	(1) Weighted kWh	(2) Weighted %	(3) kWh Sales	(4) kWh %	(5) Price Multiplier	(6) Retail Class Avg Factor	(7) Rate Class Avg Factor	(8) Loss Multiplier	(9) Fuel Recovery Factor (¢/kWh)
RS - 1	3,961,065	50.48%	16,364,502,843	50.14%	1.007	1.567	1.578	1.00210	1.581
GS - 1	526,295	6.71%	2,159,742,840	6.62%	1.014	1.567	1.588	1.00210	1.592
GSD - 1	1,901,216	24.23%	7,896,783,525	24.19%	1.001	1.567	1.569	1.00204	1.572
GSLD - 1	770,386	9.82%	3,241,453,198	9.93%	0.988	1.567	1.549	1.00092	1.550
GSLD - 2	182,303	2.32%	778,290,310	2.38%	0.974	1.567	1.527	0.99500	1.519
GSLD - 3	100,097	1.28%	433,459,956	1.33%	0.960	1.567	1.505	0.96091	1.446
CS - 1	32,374	0.41%	134,940,991	0.41%	0.998	1.567	1.564	1.00024	1.564
CS - 2	26,507	0.34%	114,825,395	0.35%	0.960	1.567	1.504	0.99656	1.499
CILC - D	166,379	2.12%	710,732,651	2.18%	0.974	1.567	1.526	0.99757	1.522
CILC - G	6,263	0.08%	26,548,067	0.08%	0.981	1.567	1.537	1.00210	1.541
CILC - T	117,363	1.50%	511,860,512	1.57%	0.954	1.567	1.494	0.96091	1.436
MET	9,080	0.12%	38,567,925	0.12%	0.979	1.567	1.534	0.98063	1.505
OL - 1	9,818	0.13%	47,006,297	0.14%	0.869	1.567	1.361	1.00210	1.364
SL - 1	30,453	0.39%	145,837,574	0.45%	0.869	1.567	1.361	1.00210	1.364
SL - 2	7,701	0.10%	33,580,796	0.10%	0.954	1.567	1.495	1.00210	1.498
Total	7,847,298	100%	32,638,112,878	100%	1.00	1.567	1.567	1.00000	1.567

(1) 1993 Jan - March & Oct - Dec actual sales with each rate's usage in a given hour is weighted by the total usage in that hour.

(2) Col (1) / total col (1)

(3) 1993 Jan - March & Oct - Dec actual sales.

(4) Col (3) / total col (3)

(5) Col (2) / col (4) (full precision not shown).

(6) Schedule E 1 page 1 of 5, line 34.

(7) Col (5) * (8)

(8) 1993 energy losses.

(9) Col (7) * col (8)

Note:

SST 1 - (T) and SST 1 - (D) grouped with applicable GSLDT rate classes.

ISST 1-(D) grouped with applicable CILC rate classes.

OS - 2 based on GSD - 1 rate.

FLORIDA POWER & LIGHT COMPANY
DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULE
OCTOBER 1994 - MARCH 1995

Rate Schedule	(1) Rate Class Avg Factor	(2) On Peak Factor	(3) Off Peak Factor	(4) Loss Multiplier	(5) On Peak Fuel Recovery Factor (¢/kWh)	(6) Off Peak Fuel Recovery Factor (¢/kWh)
RST - 1	1.578	1.707	1.527	1.00210	1.710	1.531
GST - 1	1.588	1.718	1.537	1.00210	1.721	1.540
GSDT - 1	1.589	1.697	1.519	1.00204	1.700	1.522
GSLDT - 1	1.549	1.675	1.499	1.00092	1.677	1.501
GSLDT - 2	1.527	1.852	1.478	0.99500	1.643	1.471
GSLDT - 3	1.505	1.828	1.457	0.98091	1.564	1.400
CST - 1	1.584	1.692	1.514	1.00024	1.692	1.514
CST - 2	1.504	1.827	1.456	0.99656	1.621	1.451
CILC - D	1.526	1.650	1.477	0.99757	1.646	1.474
CILC - G	1.537	1.662	1.488	1.00210	1.666	1.491
CILC - T	1.494	1.616	1.446	0.96091	1.553	1.390

Note:

SST 1 - (T) and SST 1 - (D) grouped with applicable GSLDT rate classes.

ISST 1-(D) grouped with applicable CILC rate classes.

(1) Schedule E 1, page 3 of 5, col 7

(2) Col 1 * On-peak multiplier * Revenue Correction Factor

(3) Col 1 * Off-peak multiplier * Revenue Correction Factor

(4) 1993 energy losses.

(5) Col 2 * col 4

(6) Col 3 * col 4

TIME OF USE DERIVATION

	<u>kWh %</u>	<u>Merch Fuel Cost ¢/kWh</u>
On-Peak	26.2	On-Peak 2.19
Off-Peak	71.8	Off-Peak 1.98
	100	All Hours 2.02
<u>On-Peak Multiplier</u> = on-peak ¢/kWh / all hours ¢/kWh = 1.084158416 <u>Off-Peak Multiplier</u> = off-peak ¢/kWh / all hours ¢/kWh = .97029703 <u>Revenue Correction Factor</u> = .98759834 (see formula below) 1		
$\frac{(\text{on-peak multiplier} * \text{on-peak kWh \%}) + (\text{off-peak multiplier} * \text{off-peak kWh \%})}{1}$		

Florida Power & Light Company
1993 Actual Energy Losses by Rate Class

Line No	Rate Class	MWH Sales	Expansion Factor	Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	RS-1 Sec	36,322,850	1.072653616	38,961,836	0.932267	2,638,986	1.00210
2							
3	GS-1 Sec	4,512,421	1.072653616	4,840,264	0.932267	327,844	1.00210
4							
5	GSD-1 Pri	48,306	1.049677128	50,790	0.952674	2,404	
6	GSD-1 Sec	16,261,851	1.072653616	17,443,333	0.932267	1,181,482	
7	Subtot GSD-1	16,310,237	1.072585454	17,494,123	0.932327	1,183,886	1.00204
8							
9	OS-2 Pri	20,067	1.049677128	21,063	0.952674	997	0.98063
10							
11	GSLD-1 Pri	366,391	1.049677128	384,593	0.952674	18,201	
12	GSLD-1 Sec	6,289,055	1.072653616	6,745,978	0.932267	456,923	
13	Subtot GSLD-1	6,655,447	1.071388729	7,130,570	0.933368	475,124	1.00092
14							
15	CS-1 Pri	23,774	1.049677128	24,955	0.952674	1,181	
16	CS-1 Sec	250,775	1.072653616	268,995	0.932267	18,220	
17	Subtot CS-1	274,549	1.070663990	293,950	0.934000	19,401	1.00024
18							
19	Subtot GSLD1 / CS1	6,929,996	1.071360016	7,424,521	0.933393	494,525	1.00089
20							
21	GSLD-2 Pri	514,993	1.049677128	540,576	0.952674	25,583	
22	GSLD-2 Sec	1,042,016	1.072653616	1,117,722	0.932267	75,706	
23	Subt GSLD-2	1,557,008	1.065053963	1,658,298	0.938920	101,290	0.99500
24							
25	CS-2 Pri	58,580	1.049677128	61,490	0.952674	2,910	
26	CS-2 Sec	168,483	1.072653616	180,724	0.932267	12,241	
27	Subtot CST-2	227,063	1.066725905	242,214	0.937448	15,151	0.99656
28							
29	Subtot GSLD2 / CS2	1,784,072	1.065266755	1,900,512	0.938732	116,441	0.99520
30							
31	GSLD-3 Tm	873,316	1.028561922	898,269	0.972231	24,944	0.96091
32							
33	CS-3 Tm	11	1.028561922	11	0.972231	0	0.96091
34							
35	Subtot GSLD3 / CS3	873,327	1.028561922	898,271	0.972231	24,944	0.96091
36							
37	ISST-1 Sec	2,000	1.072653616	2,145	0.932267	145	1.00210
38							
39	SST-1 Pri	13,101	1.049677128	13,752	0.952674	651	
40	SST-1 Sec	12,912	1.072653616	13,850	0.932267	938	
41	SST-1 (D)	26,013	1.061081741	27,602	0.943434	1,589	0.99129
42							
43	SST-1 Tm	74,852	1.028561922	76,990	0.972231	2,138	0.96091
44							
45	CILC D Pri	302,069	1.049677128	317,075	0.952674	15,006	
46	CILC D Sec	1,130,657	1.072653616	1,212,804	0.932267	82,146	
47	CILC D	1,432,726	1.067509371	1,529,878	0.936497	97,152	0.99757
48							
49	CILC G Sec	53,459	1.072653616	57,343	0.932267	3,884	1.00210
50							
51	Subtot CILC D / CILC G	1,486,185	1.067993620	1,587,221	0.936344	101,036	0.99774
52							
53	CILC T Tm	964,604	1.028561922	992,155	0.972231	27,551	0.96091
54							
55	ISST-D & CILC-D	1,434,726	1.067816124	1,532,023	0.936491	97,298	0.91758
56							
57	MET Pri	70,724	1.049677128	82,635	0.952674	3,911	0.98063
58							
59	OS-2, GSLD2, CS2, & MET	1,882,863	1.06648791	2,004,211	0.939453	121,348	0.99443
60							
61	OL-1 Sec	95,252	1.072653616	102,173	0.932267	6,920	1.00210
62							
63	SL-1 Sec	290,281	1.072653616	311,371	0.932267	21,090	1.00210
64							
65	Subtot OL1 / SL1	385,534	1.072653616	413,544	0.932267	28,010	1.00210
66							
67	SL-2 Sec	59,945	1.072653616	64,300	0.932267	4,355	1.00210
68							
69	Total FPSC	68,830,826	1.070976645	74,797,182	0.933727	4,956,358	1.00053
70							
71	Total FERC Sales	957,907	1.028795728	985,490	0.972010	27,584	
72	Company Use	186,973	1.072653616	200,357	0.932267	13,384	
73	Change in Unbilled Sales	(185,379)	1.072653616	(198,847)	0.932267	(13,468)	
74							
75	Total FPL	70,790,325	1.070405907	75,774,382	0.934225	4,964,057	1.00000
76							
77							
78							
79	CILC-1(T), CS-3, and SST-1(T) rate classes have the same loss multiplier as the GSLD-3 (Transmission) rate class.						
80							
81							

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD OCTOBER 1994 - MARCH 1995

SCHEDULE E2

LINE NO.	(a) OCTOBER	(b) NOVEMBER	(c) ESTIMATED DECEMBER	(d) JANUARY	(e) FEBRUARY	(f) MARCH	(g) TOTAL PERIOD	LINE NO.
A1 FUEL COST OF SYSTEM GENERATION	\$81,737,507	\$77,343,940	\$68,478,736	\$65,132,353	\$57,633,016	\$66,704,979	\$417,030,531	A1
1a NUCLEAR FUEL DISPOSAL	1,164,767	894,257	1,449,972	1,878,657	1,696,851	1,873,917	8,958,421	1a
1b COAL CAR INVESTMENT	38,223	37,990	37,757	140,928	295,380	397,501	947,779	1b
1c ORIMULSION	0	0	0	0	0	0	0	1c
1d GAS LATERAL ENHANCEMENTS	336,559	334,997	333,435	331,874	330,312	328,749	1,995,926	1d
1e DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	4,655,000	0	0	0	0	4,655,000	1e
1f DOE CREDIT - SPENT FUEL	0	(529,000)	0	0	0	0	(529,000)	1f
2 FUEL COST OF POWER SOLD	(1,507,805)	(2,339,891)	(1,063,595)	(1,024,646)	(570,219)	(2,750,092)	(9,258,248)	2
3 FUEL COST OF PURCHASED POWER	17,086,424	16,129,509	14,926,736	12,762,763	8,993,707	9,421,601	79,340,740	3
3a QUALIFYING FACILITIES	7,380,292	7,541,412	7,150,960	7,072,733	6,424,282	7,198,277	42,767,956	3a
4 ENERGY COST OF ECONOMY PURCHASES	2,405,520	2,348,500	1,427,060	763,820	268,390	360,020	7,573,310	4
4a FUEL COST OF SALES TO FKEC / CKW	(1,485,794)	(1,320,816)	(1,187,341)	(1,093,113)	(1,151,458)	(1,104,085)	(7,342,607)	4a
5 TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	\$107,155,693	\$105,095,898	\$91,553,720	\$85,985,369	\$73,920,261	\$82,430,867	\$546,141,809	5
6 SYSTEM KWH SOLO (MWH) (Excl sales to FKEC / CKW)	6,636,334	5,670,967	5,445,198	5,488,383	5,062,602	5,084,019	33,387,503	6
7 COST PER KWH SOLD (c/KWH)	1.6147	1.8532	1.6814	1.5667	1.4601	1.6214	1.6358	7
7a JURISDICTIONAL LOSS MULTIPLIER	1.00053	1.00053	1.00053	1.00053	1.00053	1.00053	1.00053	7a
7b JURISDICTIONAL COST (c/KWH)	1.6155	1.8542	1.6823	1.5675	1.4609	1.6222	1.6366	7b
9 TRUE-UP (c/KWH)	(0.0871)	(0.1016)	(0.1058)	(0.1050)	(0.1139)	(0.1134)	(0.1036)	9
10 TOTAL	1.5284	1.7526	1.5765	1.4625	1.3470	1.5088	1.5330	10
11 REVENUE TAX FACTOR 0.01609	0.0246	0.0282	0.0254	0.0235	0.0217	0.0243	0.0247	11
12 RECOVERY FACTOR ADJUSTED FOR TAXES	1.5530	1.7808	1.6019	1.4860	1.3687	1.5331	1.5577	12
13 GPIF (c/KWH)	0.0078	0.0091	0.0095	0.0094	0.0103	0.0102	0.0093	13
14 RECOVERY FACTOR including GPIF	1.5608	1.7899	1.6114	1.4954	1.3790	1.5433	1.5670	14
15 RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	1.561	1.790	1.611	1.495	1.379	1.543	1.567	15

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD OF: OCTOBER, 1994 THRU MARCH, 1995

	OCTOBER 1994	NOVEMBER 1994	DECEMBER 1994	JANUARY 1995	FEBRUARY 1995	MARCH 1995	TOTAL
FUEL COST OF SYSTEM NET GENERATION (\$)							
1 HEAVY OIL	39,965,942	37,059,405	26,171,664	15,924,423	17,235,372	22,418,361	158,775,167
2 LIGHT OIL	112,009	572,603	166,645	99,925	23,034	30,526	1,004,742
3 COAL	8,807,677	9,089,365	8,519,770	7,725,452	3,035,925	6,554,657	43,732,846
4 GAS	26,205,539	25,601,317	26,040,959	31,815,705	28,694,200	28,157,903	166,515,623
5 NUCLEAR	6,646,340	5,021,250	7,579,698	9,566,848	8,644,485	9,543,532	47,002,153
6 TOTAL (\$)	81,737,507	77,343,940	68,478,736	65,132,351	57,633,016	66,704,979	417,030,531
SYSTEM NET GENERATION (MWH)							
7 HEAVY OIL	1,806,283	1,661,253	1,226,715	751,654	844,561	1,126,119	7,416,584
8 LIGHT OIL	2,023	10,369	5,096	1,533	353	468	19,844
9 COAL	549,747	562,813	531,932	483,387	199,974	392,505	2,720,359
10 GAS	1,422,432	1,319,659	1,167,597	1,494,989	1,401,740	1,445,629	8,272,046
11 NUCLEAR	1,268,395	973,818	1,578,974	2,045,799	1,847,818	2,040,637	9,755,442
12 TOTAL (MWH)	5,048,880	4,527,912	4,530,317	4,777,361	4,294,447	5,005,358	28,194,276
UNITS OF FUEL BURNED							
13 HEAVY OIL (BBLs)	2,747,190	2,539,816	1,869,250	1,147,272	1,286,263	1,702,811	11,292,603
14 LIGHT OIL (BBLs)	3,507	17,353	6,436	3,456	797	1,056	32,605
15 COAL (TONS)	253,754	262,719	247,980	224,075	103,480	188,152	1,260,159
16 GAS (MCF)	10,729,628	9,707,934	8,613,739	11,110,791	10,438,425	10,658,986	61,259,504
17 NUCLEAR (MBTU)	14,128,856	10,782,824	17,379,576	22,492,119	20,315,461	22,435,650	107,534,485
BTU BURNED (MBTU)							
18 HEAVY OIL	17,502,825	16,186,212	11,897,651	7,303,882	8,186,079	10,825,356	71,902,005
19 LIGHT OIL	20,445	100,845	36,279	20,159	4,647	6,158	188,534
20 COAL	5,318,890	5,503,705	5,202,532	4,733,235	1,912,041	3,870,635	26,541,038
21 GAS	10,729,628	9,707,934	8,613,739	11,110,791	10,438,425	10,658,986	61,259,504
22 NUCLEAR	14,128,856	10,782,824	17,379,576	22,492,119	20,315,461	22,435,650	107,534,485
23 TOTAL (MBTU)	47,700,645	42,281,520	43,129,777	45,660,186	40,856,654	47,796,785	267,425,567

DATE: 16/JUN/94
 COMPANY: FLORIDA POWER & LIGHT

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 SCHEDULE E3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
 ESTIMATED FOR THE PERIOD OF: OCTOBER, 1994 THRU MARCH, 1995

	OCTOBER 1994	NOVEMBER 1994	DECEMBER 1994	JANUARY 1995	FEBRUARY 1995	MARCH 1995	TOTAL
GENERATION MIX (MMWH)							
24 HEAVY OIL	35.78	36.69	27.08	15.73	19.67	22.50	26.31
25 LIGHT OIL	0.04	0.23	0.11	0.03	0.01	0.01	0.07
26 COAL	10.89	12.43	11.74	10.12	4.66	7.84	9.65
27 GAS	28.17	29.14	26.21	31.29	32.64	28.88	29.35
28 NUCLEAR	25.12	21.51	34.85	42.82	43.03	40.77	34.61
29 TOTAL (%)	100.00	100.00	100.00	100.00	100.00	100.00	100.00
FUEL COST PER UNIT							
30 HEAVY OIL (\$/BBL)	14.5479	14.5914	14.0012	13.9802	13.3996	13.1655	14.0601
31 LIGHT OIL (\$/BBL)	31.9351	32.9972	25.8934	28.9125	28.9118	28.9127	30.8158
32 COAL (\$/TON)	34.7096	34.5973	34.3567	34.4771	36.3671	34.8371	34.7042
33 GAS (\$/MCF)	2.4424	2.6372	3.0232	2.8635	2.7489	2.6417	2.7182
34 NUCLEAR (\$/MBTU)	0.4704	0.4657	0.4361	0.4253	0.4255	0.4254	0.4371
FUEL COST PER MBTU (\$/MBTU)							
35 HEAVY OIL	2.2834	2.2896	2.1997	2.1803	2.1054	2.0709	2.2082
36 LIGHT OIL	5.4785	5.6780	4.5934	4.9569	4.9569	4.9569	5.3292
37 COAL	1.6559	1.6515	1.6376	1.6322	1.5878	1.6934	1.6477
38 GAS	2.4424	2.6372	3.0232	2.8635	2.7489	2.6417	2.7182
39 NUCLEAR	0.4704	0.4657	0.4361	0.4253	0.4255	0.4254	0.4371
BTU BURNED PER KWH (BTU/KWH)							
40 HEAVY OIL	9,690	9,743	9,699	9,717	9,693	9,613	9,695
41 LIGHT OIL	10,107	9,726	7,116	13,152	13,153	13,153	9,501
42 COAL	9,675	9,779	9,780	9,792	9,561	9,861	9,756
43 GAS	7,543	7,356	7,253	7,432	7,447	7,373	7,406
44 NUCLEAR	11,139	11,073	11,007	10,994	10,994	10,994	11,023
GENERATED FUEL COST PER KWH (CENTS/KWH)							
45 HEAVY OIL	2.2126	2.2308	2.1335	2.1186	2.0408	1.9908	2.1408
46 LIGHT OIL	5.5371	5.5223	3.2687	6.5191	6.5197	6.5199	5.0631
47 COAL	1.6021	1.6150	1.6017	1.5982	1.5182	1.6700	1.6076
48 GAS	1.8423	1.9400	2.1927	2.1282	2.0470	1.9478	2.0130
49 NUCLEAR	0.5240	0.5156	0.4800	0.4676	0.4678	0.4677	0.4818
50 TOTAL (CENTS/KWH)	1.6189	1.7082	1.5116	1.3634	1.3420	1.3327	1.4797

DATE: 22/JUN/94
 COMPANY: FLORIDA POWER & LIGHT

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 SCHEDULE B4

ELECTRIC ENERGY ACCOUNT

ESTIMATED FOR THE PERIOD OF: OCTOBER, 1994 THRU MARCH, 1995

	OCTOBER 1994	NOVEMBER 1994	DECEMBER 1994	JANUARY 1995	FEBRUARY 1995	MARCH 1995	TOTAL
(MWH)							
1 SYSTEM NET GENERATION	5,048,880	4,527,912	4,530,317	4,777,361	4,294,447	5,005,358	28,184,276
2 POWER SOLD	(46,920)	(65,841)	(64,396)	(58,435)	(55,648)	(146,575)	(447,815)
3 INADVERTENT INTERCHANGE DELIVERED	0	0	0	0	0	0	0
4 PURCHASED POWER	1,007,073	952,321	911,874	770,746	554,894	560,101	4,757,009
4A QUALIFYING FACILITIES	410,331	420,274	405,391	399,526	367,563	412,194	2,415,279
5 ECONOMY PURCHASES	124,867	124,052	78,961	40,051	14,096	19,780	401,806
6 INADVERTENT INTERCHANGE RECEIVED	0	0	0	0	0	0	0
7 NET ENERGY FOR LOAD	6,544,231	5,958,718	5,862,148	5,919,250	5,175,352	5,850,858	35,310,557
8 SALES (BILLED)	6,710,949	6,737,297	6,504,825	6,543,276	6,120,427	6,139,465	33,756,232
8A UNBILLED SALES PRIOR MONTH (EST.)	3,855,250	3,238,289	3,049,750	3,003,757	3,972,487	3,671,348	3,855,250
8B UNBILLED SALES CURRENT MONTH (EST.)	3,238,289	3,049,750	3,003,757	3,972,487	3,671,348	2,980,202	2,980,202
9 COMPANY USE	19,633	17,876	17,586	17,756	15,526	17,553	105,932
10 T & D LOSSES (ESTIMATED)	430,610	392,084	385,729	389,487	340,538	384,986	2,323,435
11 UNACCOUNTED FOR ENERGY (ESTIMATED)	0	0	0	0	0	0	0
12 % COMPANY USE TO NEL	0.3	0.3	0.3	0.3	0.3	0.3	0.3
13 % T & D LOSSES TO NEL	6.6	6.6	6.6	6.6	6.6	6.6	6.6
14 % UNACCOUNTED FOR ENERGY TO NEL	0.0	0.0	0.0	0.0	0.0	0.0	0.0

10 (\$)							
16 FUEL COST OF SYSTEM NET GEN.	81,737,507	77,343,940	68,478,736	65,132,353	57,633,016	66,704,979	417,030,531
16A FUEL RELATED TRANSACTIONS	1,010,549	5,922,244	1,821,164	2,351,458	2,322,543	2,600,168	16,028,126
17 FUEL COST OF POWER SOLD	(1,507,805)	(2,339,631)	(1,053,595)	(1,024,646)	(570,219)	(2,750,092)	(9,256,247)
18 FUEL COST OF PURCHASED POWER	17,086,424	16,129,509	14,926,736	12,762,763	8,993,707	9,421,601	79,340,740
18A FUEL COST OF SALES TO FERC / CKN	(1,485,794)	(1,320,616)	(1,187,141)	(1,093,113)	(1,151,458)	(1,104,085)	(7,342,607)
18B QUALIFYING FACILITIES	7,380,292	7,541,412	7,150,960	7,072,733	6,424,282	7,199,277	42,767,955
19 ENERGY COST OF ECONOMY PURCHASES	2,405,520	2,348,500	1,427,060	763,820	268,390	360,020	7,573,310
20 TOTAL FUEL & NET POWER TRANSACTIONS	106,626,693	105,624,899	91,553,719	85,985,316	73,920,261	82,430,868	546,141,809

(CENTS/KWH)							
21 FUEL COST OF SYSTEM NET GEN.	1.6189	1.7082	1.5116	1.3634	1.3420	1.3327	1.4797
21A FUEL RELATED TRANSACTIONS	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
22 FUEL COST OF POWER SOLD	3.2136	3.5539	1.6516	1.4973	1.0247	1.8762	2.0670
23 FUEL COST OF PURCHASED POWER	1.6966	1.6937	1.6369	1.6585	1.6208	1.6821	1.6679
23A FUEL COST OF SALES TO FERC / CKN	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
23B QUALIFYING FACILITIES	1.7986	1.7944	1.7640	1.7703	1.7478	1.7463	1.7707
24 ENERGY COST OF ECONOMY PURCHASES	1.9265	1.8932	1.8073	1.9071	1.9640	1.8201	1.8848
25 TOTAL FUEL & NET POWER TRANSACTIONS	1.6293	1.7726	1.5618	1.4526	1.4283	1.4089	1.5467

SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD OF: OCTOBER, 1994

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT	NET CAPAB (MW)	NET GEN (MWH)	CAPAC FAC (%)	BOU/TV AVAIL FAC (%)	NET OUT FAC (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
1	TRKY O 1	406	73,851	30.0	88.3	80.6	9,572	HEAVY OIL	109,548 BBLs	6,412,004	702,421	1,683,420	2.2795
2			13,813					GAS	136,697 MCF	1,000,000	136,697	311,669	2.2563
3	TRKY O 2	389	13,658	5.4	41.8	80.0	9,907	HEAVY OIL	21,017 BBLs	6,412,002	134,760	322,984	2.3648
4			1,587					GAS	16,287 MCF	1,000,000	16,287	37,133	2.3394
5	TRKY N 3	688	461,680	93.2	93.6	99.6	11,106	NUCLEAR	5,127,354 MBTU	1,000,000	5,127,354	2,428,733	0.5261
6	TRKY N 4	688	291,361	58.8	51.3	99.4	11,247	NUCLEAR	3,276,820 MBTU	1,000,000	3,276,820	1,577,633	0.5415
7	FT LAUD4	467	312,759	93.0	94.2	98.8	7,389	GAS	2,310,919 MCF	1,000,000	2,310,919	5,680,407	1.8162
8	FT LAUD5	467	287,539	85.5	92.7	99.1	7,471	GAS	2,148,151 MCF	1,000,000	2,148,151	5,206,370	1.8107
9	PT EVER1	212	29,187	19.1	65.0	79.1	10,128	HEAVY OIL	46,275 BBLs	6,387,996	295,603	720,606	2.4689
10	PT EVER2	213	48,186	31.4	95.1	83.2	10,013	HEAVY OIL	75,529 BBLs	6,387,998	482,482	1,175,342	2.4392
11	PT EVER3	391	155,292	55.2	94.5	90.5	9,426	HEAVY OIL	229,137 BBLs	6,388,000	1,463,729	3,568,737	2.2981
12	PT EVER4	386	135,511	48.8	95.9	87.5	9,511	HEAVY OIL	201,753 BBLs	6,387,998	1,288,799	3,141,067	2.3179
13	RIV 3	289	139,275	66.9	90.9	90.6	9,876	HEAVY OIL	215,196 BBLs	6,392,001	1,375,535	2,885,997	2.0722
14	RIV 4	289	159,736	76.8	91.3	89.6	9,628	HEAVY OIL	240,612 BBLs	6,392,002	1,537,991	3,226,076	2.0196
15	ST LUC 1	853	37,654	6.1	0.0	98.1	10,994	NUCLEAR	413,982 MBTU	1,000,000	413,982	200,409	0.5322
16	ST LUC 2	725	477,700	91.5	91.6	99.8	11,117	NUCLEAR	5,310,701 MBTU	1,000,000	5,310,701	2,439,565	0.5107
17	CAP CN	400	161,593	56.1	92.4	89.8	9,461	HEAVY OIL	241,130 BBLs	6,340,000	1,528,764	3,445,221	2.1320
18	CAP CN 2	400	169,043	58.7	89.9	89.3	9,445	HEAVY OIL	251,822 BBLs	6,339,999	1,596,554	3,598,034	2.1285
19	SANFRD 3	147	7,621	7.2	95.0	85.0	10,285	HEAVY OIL	12,434 BBLs	6,303,990	78,386	183,066	2.4020
20	SANFRD 4	394	104,892	37.0	94.6	80.4	10,021	HEAVY OIL	166,738 BBLs	6,303,999	1,051,119	2,448,085	2.3339
21	SANFRD 5	394	120,847	42.6	94.1	83.8	10,004	HEAVY OIL	191,775 BBLs	6,304,000	1,208,953	2,815,883	2.3301
22	PUTNAM 1	250	144,114	80.1	94.2	91.2	8,894	GAS	1,281,721 MCF	1,000,000	1,281,721	3,420,796	2.3737
23	PUTNAM 2	250	1,084	16.5	94.5	89.2	8,822	LIGHT OIL	1,532 BBLs	5,824,086	8,923	54,892	5.0657
24			28,585					GAS	252,810 MCF	1,000,000	252,810	605,165	2.1171
25	MANATE 1	805	78,779	13.6	94.6	66.1	10,049	HEAVY OIL	122,961 BBLs	6,438,000	791,624	1,808,976	2.2963
26	MANATE 2	805	153,159	26.4	95.7	72.9	9,964	HEAVY OIL	237,050 BBLs	6,437,999	1,526,129	3,485,929	2.2760
27	FT MY 1	144	48,801	47.1	95.2	91.6	10,153	HEAVY OIL	78,080 BBLs	6,346,007	495,494	1,100,995	2.2561

SYSTEM NET GENERATION AND FUEL COST
 ESTIMATED FOR THE PERIOD OF: OCTOBER, 1994

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT	NET CAPAB (MW)	NET GEN (MWH)	CAPAC FAC (%)	ROUTV AVAIL FAC (%)	NET OUT FAC (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
1	FT MY 2	394	190,981	67.3	93.3	89.9	9,352	HEAVY OIL	281,446 BBLs	6,346,000	1,786,055	3,966,816	2.0771
2													
3	CUTLER 5	72	453	0.9	96.0	89.9	12,826	GAS	5,810 MCF	1,000,000	5,810	13,908	3.0709
4													
5	CUTLER 6	145	1,131	1.1	96.0	86.7	11,047	GAS	12,494 MCF	1,000,000	12,494	29,902	2.6432
6													
7	MARTIN 1	821					*** UNIT DOWN FOR THE PERIOD ***						
8													
9	MARTIN 2	805	15,872	2.9	95.3	52.0	10,059	HEAVY OIL	24,685 BBLs	6,417,992	158,428	388,708	2.4490
10			888					GAS	10,160 MCF	1,000,000	10,160	23,268	2.6217
11													
12	MARTIN 3	460	315,516	95.3	96.0	99.1	7,206	GAS	2,273,645 MCF	1,000,000	2,273,645	5,428,804	1.7206
13													
14	MARTIN 4	460	315,516	95.3	95.9	99.1	7,206	GAS	2,273,645 MCF	1,000,000	2,273,645	5,428,804	1.7206
15													
16	FM GT	708	939	0.2	0.0	7.8	12,271	LIGHT OIL	1,975 BBLs	5,833,097	11,523	57,117	6.0808
17													
18	FL GT	840	476	0.1	0.0	7.1	13,561	GAS	6,455 MCF	1,000,000	6,455	17,043	3.5797
19													
20	PE GT	420	55	0.0	0.0	6.5	15,138	GAS	832 MCF	1,000,000	832	2,270	4.1273
21													
22	SJRPP 10	116	84,015	100.6	95.0	100.6	9,474	COAL	32,599 TONS	24,417,963	795,991	1,243,132	1.4796
23													
24	SJRPP 20	116	83,926	100.5	95.1	100.5	9,384	COAL	32,252 TONS	24,417,964	787,523	1,229,908	1.4655
25													
26	SCHER 4	530	381,806	100.1	95.9	100.1	9,783	COAL	188,903 TONS	19,774,006	3,735,375	6,334,637	1.6591
27													
28	TOTAL	16,339	5,048,880	42.9			9,448				47,700,645	81,737,507	1.6189
29													
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SYSTEM NET GENERATION AND FUEL COST
 ESTIMATED FOR THE PERIOD OF: NOVEMBER, 1994

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT	NET CAPAB (MW)	NET GEN (MMH)	CAPAC FAC (%)	BOU TV AVAIL FAC (%)	NET OUT FAC (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
1	TRKY O 1	406	61,909	20.5	88.3	73.0	9,529	HEAVY OIL	92,000 BBLs	6,412,000	589,903	1,421,265	2.2957
2	TRKY O 2	389					*** UNIT DOWN FOR THE PERIOD ***						
3	TRKY N 3	688	479,112	93.6	93.6	100.1	10,906	NUCLEAR	5,224,979 MBTU	1,000,000	5,224,979	2,471,381	0.5158
4	TRKY N 4	688					*** UNIT DOWN FOR THE PERIOD ***						
5	FT LAUD4	467	396 326,679	94.1	94.2	99.9	7,252	LIGHT OIL GAS	482 BBLs 2,369,171 MCF	5,623,964 1,000,000	2,713 2,369,171	12,290 6,422,024	3.1043 1.9659
6	FT LAUD5	467	320,796	92.3	92.7	99.7	7,340	GAS	2,354,689 MCF	1,000,000	2,354,689	6,163,680	1.9214
7	PT EVER1	212	20,012	12.7	0.0	70.4	10,223	HEAVY OIL	32,025 BBLs	6,387,994	204,575	501,315	2.5051
8	PT EVER2	213	31,963	20.2	95.1	75.4	10,047	HEAVY OIL	50,269 BBLs	6,388,001	321,118	786,905	2.4619
9	PT EVER3	391	127,851	43.9	94.5	83.0	9,563	HEAVY OIL	191,395 BBLs	6,387,999	1,222,634	2,996,105	2.3434
10	PT EVER4	386	95,274	33.2	95.9	77.6	9,691	HEAVY OIL	144,530 BBLs	6,388,003	923,260	2,262,476	2.3747
11	RIV 3	289	132,878	61.8	90.9	86.8	9,872	HEAVY OIL	205,217 BBLs	6,392,001	1,311,744	2,734,167	2.0577
12	RIV 4	289	149,228	69.4	91.3	86.5	9,679	HEAVY OIL	225,967 BBLs	6,392,000	1,444,382	3,010,591	2.0174
13	ST LUC 1	853					*** UNIT DOWN FOR THE PERIOD ***						
14	ST LUC 2	725	494,706	91.7	91.6	100.1	11,235	NUCLEAR	5,557,846 MBTU	1,000,000	5,557,846	2,549,869	0.5154
15	CAP ON 1	400	145,461	48.9	92.4	82.6	9,571	HEAVY OIL	219,590 BBLs	6,340,002	1,392,202	3,139,952	2.1586
16	CAP ON 2	400	155,931	52.4	89.9	84.4	9,482	HEAVY OIL	233,212 BBLs	6,340,000	1,478,562	3,334,737	2.1386
17	SANFRD 3	147	11,465	10.5	95.0	76.5	10,495	HEAVY OIL	19,087 BBLs	6,303,981	120,322	281,463	2.4550
18	SANFRD 4	394	104,960	35.8	94.6	77.4	9,862	HEAVY OIL	164,199 BBLs	6,303,998	1,035,108	2,421,358	2.3069
19	SANFRD 5	394	100,792	34.4	94.1	78.7	9,954	HEAVY OIL	159,143 BBLs	6,304,003	1,003,241	2,346,810	2.3284
20	PUTNAM 1	250	2,732 12,589	8.2	94.2	46.8	10,395	LIGHT OIL GAS	4,017 BBLs 135,870 MCF	5,824,030 1,000,000	23,393 135,870	143,915 376,776	5.2683 2.9928
21	PUTNAM 2	250	4,469 25,630	16.2	94.5	67.6	9,204	LIGHT OIL GAS	6,523 BBLs 239,033 MCF	5,823,964 1,000,000	37,990 239,033	233,720 673,750	5.2300 2.6287
22	MANATE 1	805	94,653	15.8	94.6	65.3	10,052	HEAVY OIL	147,781 BBLs	6,437,999	951,415	2,217,058	2.3423
23	MANATE 2	805	167,717	28.0	95.7	71.4	9,840	HEAVY OIL	256,341 BBLs	6,438,001	1,650,323	3,845,653	2.2929
24	FT MY 1	144	46,688	43.6	95.2	83.3	10,118	HEAVY OIL	74,438 BBLs	6,346,003	472,384	1,053,819	2.2572

SYSTEM NET GENERATION AND FUEL COST
 ESTIMATED FOR THE PERIOD OF: NOVEMBER, 1994

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT	NET CAPAB (MW)	NET GEN (MWH)	CAPAC FAC (%)	EQUIV AVAIL FAC (%)	NET OUT FAC (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
1	FT MY 2	394	172,568	58.9	93.3	86.0	9,392	HEAVY OIL	255,406 BBLs	6,345,999	1,620,804	3,615,787	2.0953
2	CUTLER 5	72	1,644	3.1	96.0	78.7	13,229	GAS	21,749 MCF	1,000,000	21,749	56,335	3.4269
3	CUTLER 6	145	7,979	7.4	96.0	83.4	11,626	GAS	92,763 MCF	1,000,000	92,763	240,323	3.0121
4	MARTIN 1	821					*** UNIT DOWN FOR THE PERIOD ***						
5	MARTIN 2	805	41,904	7.0	95.3	48.2	10,724	HEAVY OIL	69,217 BBLs	6,417,997	444,233	1,089,944	2.6011
6			0					GAS	5,145 MCF	1,000,000	5,145	13,326	0.0000
7	MARTIN 3	460	305,808	89.4	73.6	93.5	7,188	GAS	2,198,173 MCF	1,000,000	2,198,173	5,704,743	1.8655
8	MARTIN 4	460	317,480	92.8	87.9	96.7	7,169	GAS	2,276,134 MCF	1,000,000	2,276,134	5,906,873	1.8606
9	FM GT	708	2,451	0.5	0.0	7.5	13,201	LIGHT OIL	5,547 BBLs	5,832,952	32,355	160,379	6.5445
10	FL GT	840	84	0.1	0.0	7.2	14,339	LIGHT OIL	205 BBLs	5,603,213	1,151	5,840	6.9359
11			525					GAS	7,582 MCF	1,000,000	7,582	21,684	4.1303
12	FE GT	420	238	0.2	0.0	7.9	14,186	LIGHT OIL	579 BBLs	5,604,458	3,243	16,459	6.9243
13			529					GAS	7,624 MCF	1,000,000	7,624	21,803	4.1247
14	SJRPP 10	116	86,649	100.4	95.0	100.4	9,433	COAL	33,475 TONS	24,417,982	817,390	1,271,029	1.4669
15	SJRPP 20	116	86,529	100.3	95.1	100.3	9,312	COAL	32,999 TONS	24,418,030	805,761	1,252,948	1.4480
16	SCHER 4	530	389,635	98.8	95.9	98.8	9,959	COAL	196,245 TONS	19,774,002	3,880,555	6,565,388	1.6850
17	TOTAL	16,339	4,527,912	37.2			9,338				42,281,520	77,343,940	1.7082
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SYSTEM NET GENERATION AND FUEL COST
 ESTIMATED FOR THE PERIOD OF: DECEMBER, 1994

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT	NET CAPAB (MW)	NET GEN (MWH)	CAPAC FAC (%)	EQUIV AVAIL FAC (%)	NET OUT FAC (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
1	TRKY O 1	406	15,460	5.3	88.3	64.5	9,605	HEAVY OIL	23,159 BBLs	6,411,975	148,496	357,616	2.3132
2	TRKY O 2	406	4,813	1.6	44.8	69.7	9,686	HEAVY OIL	7,270 BBLs	6,412,033	46,617	112,207	2.3315
3	TRKY N 3	688	463,657	93.6	93.6	100.0	10,892	NUCLEAR	5,050,035 MBTU	1,000,000	5,050,035	2,386,292	0.5147
4	TRKY N 4	688	138,949	28.0	33.2	100.0	10,974	NUCLEAR	1,524,882 MBTU	1,000,000	1,524,882	612,190	0.4406
5	FT LAUD 4	467	3,613	93.7	94.2	99.7	7,241	LIGHT OIL	4,403 BBLs	5,623,989	24,761	112,169	3.1043
6			311,559					GAS	2,257,342 MCF	1,000,000	2,257,342	6,731,565	2.1606
7	FT LAUD 5	467	1,212	81.9	92.7	96.7	7,344	LIGHT OIL	1,495 BBLs	5,623,888	8,405	38,074	3.1412
8			274,289					GAS	2,014,856 MCF	1,000,000	2,014,856	6,110,695	2.2278
9	PT EVER 1	212	6,118	4.0	46.4	68.7	10,209	HEAVY OIL	9,778 BBLs	6,387,977	62,461	151,292	2.4729
10	PT EVER 2	213	10,967	7.2	95.1	67.7	10,163	HEAVY OIL	17,447 BBLs	6,387,986	111,453	268,259	2.4461
11	PT EVER 3	391	103,290	36.7	94.5	81.0	9,577	HEAVY OIL	154,848 BBLs	6,388,004	989,170	2,359,468	2.2843
12	PT EVER 4	386	53,663	19.3	95.9	65.9	9,810	HEAVY OIL	82,408 BBLs	6,387,999	526,424	1,258,410	2.3450
13	RI V 3	289	129,497	62.2	90.9	90.3	9,860	HEAVY OIL	199,756 BBLs	6,392,002	1,276,841	2,551,418	1.9703
14	RI V 4	289	145,357	69.9	91.3	91.4	9,662	HEAVY OIL	219,718 BBLs	6,391,999	1,404,439	2,805,893	1.9303
15	ST LUC 1	853	497,674	81.0	84.5	100.1	10,896	NUCLEAR	5,422,807 MBTU	1,000,000	5,422,807	2,114,498	0.4249
16	ST LUC 2	725	478,695	91.7	91.6	100.0	11,243	NUCLEAR	5,381,853 MBTU	1,000,000	5,381,853	2,466,718	0.5153
17	CAP CN 1	400	131,961	45.8	92.4	81.3	9,567	HEAVY OIL	199,127 BBLs	6,340,000	1,262,468	2,759,331	2.0910
18	CAP CN 2	400	149,585	51.9	89.9	85.8	9,464	HEAVY OIL	223,301 BBLs	6,339,999	1,415,727	3,093,292	2.0679
19	SANFRD 3	147	1,490	1.4	95.0	67.6	10,486	HEAVY OIL	2,478 BBLs	6,303,986	15,624	36,032	2.4187
20	SANFRD 4	394	83,350	29.4	94.6	68.7	9,911	HEAVY OIL	131,037 BBLs	6,304,000	826,056	1,890,215	2.2671
21	SANFRD 5	394	68,615	24.2	94.1	69.7	10,019	HEAVY OIL	109,045 BBLs	6,303,999	687,421	1,574,577	2.2948
22	PUDM 1	250	3,092	1.7	94.2	82.5	8,701	GAS	26,903 MCF	1,000,000	26,903	75,931	2.4559
23	PUDM 2	250	95	8.4	94.5	87.7	8,499	LIGHT OIL	128 BBLs	5,824,493	747	4,594	4.8511
24			15,036					GAS	127,849 MCF	1,000,000	127,849	361,305	2.4029
25	MANATE 1	805	14,707	2.5	94.6	57.1	10,052	HEAVY OIL	22,962 BBLs	6,437,999	147,829	343,610	2.3364
26	MANATE 2	805	92,110	15.9	95.7	59.3	9,943	HEAVY OIL	142,260 BBLs	6,438,000	915,867	2,124,805	2.3068
27	FT MY 1	144	39,950	38.5	95.2	82.1	10,149	HEAVY OIL	63,893 BBLs	6,346,009	405,468	881,694	2.2070

SYSTEM NET GENERATION AND FUEL COST
 ESTIMATED FOR THE PERIOD OF: DECEMBER, 1994

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT	NET CAPAB (MW)	NET GEN (MWH)	CAPAC FAC (t)	ROUTV AVAIL FAC (t)	NET OUT FAC (t)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
1	FT MY 2	394	171,825	60.6	93.3	87.7	9,375	HEAVY OIL	253,845 BBLs	6,346,002	1,610,902	3,500,084	2.0370
2													
3	CUTLER 5	72	51	0.1	96.0	70.8	12,708	GAS	648 MCF	1,000,000	648	1,977	3.8689
4													
5	CUTLER 6	145	556	0.5	96.0	76.7	11,704	GAS	6,507 MCF	1,000,000	6,507	19,847	3.5696
6													
7	MARTIN 1	821	949	0.2	92.5	57.8	9,596	HEAVY OIL	1,419 BBLs	6,418,211	9,107	22,344	2.3550
8													
9	MARTIN 2	805	3,011	0.5	95.3	37.4	10,945	HEAVY OIL	5,497 BBLs	6,417,992	35,280	81,117	2.6937
10													
11	MARTIN 3	460	316,010	95.4	96.0	99.4	7,145	GAS	2,257,989 MCF	1,000,000	2,257,989	6,882,718	2.1780
12													
13	MARTIN 4	460	267,003	80.6	66.5	92.1	7,197	GAS	1,921,610 MCF	1,000,000	1,921,610	5,856,823	2.1935
14													
15	FM GT	708	131	0.0	0.0	9.3	13,105	LIGHT OIL	294 BBLs	5,833,503	1,717	8,510	6.5211
16													
17	FL GT	840	17	0.0	0.0	0.0	13,717	LIGHT OIL	42 BBLs	5,600,473	237	1,202	6.9480
18			1					GAS	10 MCF	1,000,000	10	28	4.0000
19													
20	PE GT	420	30	0.0	0.0	7.6	13,678	LIGHT OIL	74 BBLs	5,602,442	413	2,096	6.9175
21			2					GAS	25 MCF	1,000,000	25	70	4.1176
22													
23	SJRPP 10	116	83,918	100.5	95.0	100.5	9,430	COAL	32,409 TONS	24,418,007	791,358	1,198,729	1.4285
24													
25	SJRPP 20	116	83,883	100.4	95.1	100.4	9,307	COAL	31,971 TONS	24,417,970	780,660	1,182,518	1.4097
26													
27	SCHER 4	530	364,132	95.4	95.9	95.4	9,970	COAL	183,600 TONS	19,773,998	3,630,514	6,138,523	1.6858
28													
29	TOTAL	16,356	4,530,317	38.5			9,520				43,129,777	68,478,736	1.5116
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SYSTEM NET GENERATION AND FUEL COST
 ESTIMATED FOR THE PERIOD OF: JANUARY, 1995

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT	NET CAPAB (MW)	NET GEN (MWH)	CAPAC FAC (%)	ROUTV AVAIL FAC (%)	NET OUT FAC (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
1	TRKY O 1	406	12,986	4.3	88.3	66.6	9,613	HEAVY OIL	19,470 BBLs	6,411,995	124,841	303,947	2.3406
2	TRKY O 2	406	9,592	3.2	92.5	71.6	9,737	HEAVY OIL	14,567 BBLs	6,412,025	93,401	227,402	2.3708
3	TRKY N 3	688	479,112	93.6	93.6	100.1	10,892	NUCLEAR	5,218,369 MBTU	1,000,000	5,218,369	2,434,369	0.5081
4	TRKY N 4	688	478,600	93.5	93.5	99.9	10,962	NUCLEAR	5,246,235 MBTU	1,000,000	5,246,235	2,103,740	0.4396
5	FT LAUD4	467	318,746	91.7	94.2	99.8	7,245	GAS	2,309,384 MCF	1,000,000	2,309,384	7,032,499	2.2063
6	FT LAUD5	467	287,401	82.7	92.7	96.6	7,348	GAS	2,111,935 MCF	1,000,000	2,111,935	6,435,607	2.2392
7	PT EVER1	212	3,072	1.9	96.0	80.5	10,102	HEAVY OIL	4,858 BBLs	6,388,012	31,034	74,092	2.4116
8	PT EVER2	213	5,932	3.7	95.1	71.4	10,097	HEAVY OIL	9,376 BBLs	6,387,989	59,896	143,000	2.4108
9	PT EVER3	391	30,426	10.5	94.5	70.7	9,689	HEAVY OIL	46,149 BBLs	6,388,003	294,803	703,828	2.3133
10	PT EVER4	386	19,728	6.9	95.9	75.2	9,647	HEAVY OIL	29,790 BBLs	6,388,003	190,300	454,336	2.3031
11	RIV 3	289	107,826	50.1	90.9	85.6	9,894	HEAVY OIL	166,896 BBLs	6,392,002	1,066,798	2,147,236	1.9914
12	RIV 4	289	121,358	56.4	91.3	89.5	9,696	HEAVY OIL	184,095 BBLs	6,392,000	1,176,736	2,368,329	1.9515
13	ST LUC 1	853	593,381	93.5	93.5	99.9	10,896	NUCLEAR	6,465,654 MBTU	1,000,000	6,465,654	2,512,554	0.4234
14	ST LUC 2	725	494,706	91.7	91.6	100.1	11,243	NUCLEAR	5,561,861 MBTU	1,000,000	5,561,861	2,516,185	0.5086
15	CAP CN 1	400	57,562	19.3	92.4	68.5	9,670	HEAVY OIL	87,795 BBLs	6,339,998	556,619	1,219,924	2.1193
16	CAP CN 2	400	94,682	31.8	89.9	72.6	9,554	HEAVY OIL	142,679 BBLs	6,339,997	904,585	1,982,024	2.0933
17	SANFRD 3	147	2,005	1.8	95.0	75.8	10,444	HEAVY OIL	3,322 BBLs	6,303,850	20,940	47,978	2.3927
18	SANFRD 4	394	47,871	16.3	94.6	70.6	9,865	HEAVY OIL	74,911 BBLs	6,304,001	472,240	1,081,866	2.2599
19	SANFRD 5	394	37,946	12.9	94.1	71.3	9,971	HEAVY OIL	60,016 BBLs	6,303,998	378,342	866,850	2.2845
20	PUTNAM 1	250	113,506	61.0	94.2	95.8	8,684	GAS	985,709 MCF	1,000,000	985,709	2,981,744	2.6270
21	PUTNAM 2	250	123,385	66.3	94.5	96.4	8,390	GAS	1,035,150 MCF	1,000,000	1,035,150	2,937,806	2.3810
22	MANATE 1	805	16,834	2.8	94.6	61.5	10,092	HEAVY OIL	26,389 BBLs	6,437,980	169,892	393,819	2.3394
23	MANATE 2	805	35,416	5.9	95.7	67.7	9,828	HEAVY OIL	54,064 BBLs	6,438,001	348,067	806,837	2.2782
24	FT MY 1	144	17,451	16.3	95.2	80.3	10,149	HEAVY OIL	27,910 BBLs	6,346,004	177,116	385,742	2.2104
25	FT MY 2	394	122,818	41.9	93.3	79.7	9,428	HEAVY OIL	182,473 BBLs	6,346,000	1,157,972	2,520,193	2.0520

SYSTEM NET GENERATION AND FUEL COST
 ESTIMATED FOR THE PERIOD OF: JANUARY, 1995

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT	NET CAPAB (MW)	NET GEN (MWH)	CAPAC FAC (%)	BOUIV AVAIL FAC (%)	NET OUT FAC (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
1	CUTLER 5	72	282	0.5	96.0	97.9	12,691	GAS	3,579 MCF	1,000,000	3,579	8,518	3.0184
2													
3	CUTLER 6	145	661	0.6	96.0	91.2	11,340	GAS	7,496 MCF	1,000,000	7,496	17,840	2.6985
4													
5	MARTIN 1	821	8,150	1.3	92.5	58.4	9,853	HEAVY OIL	12,512 BBLs	6,418,017	80,300	197,020	2.4174
6													
7	MARTIN 2	805					*** UNIT DOWN FOR THE PERIOD ***						
8													
9	MARTIN 3	460	327,097	95.6	96.0	99.5	7,145	GAS	2,337,260 MCF	1,000,000	2,337,260	6,673,028	2.0401
10													
11	MARTIN 4	460	323,336	94.5	95.9	98.7	7,150	GAS	2,311,979 MCF	1,000,000	2,311,979	5,703,349	1.7639
12													
13	FM GT	708	1,533	0.3	0.0	7.7	13,150	LIGHT OIL	3,456 BBLs	5,833,015	20,159	99,925	6.5191
14													
15	FL GT	840	230	0.0	0.0	6.8	14,464	GAS	3,327 MCF	1,000,000	3,327	10,147	4.4060
16													
17	PE GT	420	345	0.1	0.0	8.2	14,414	GAS	4,973 MCF	1,000,000	4,973	15,167	4.3988
18													
19	SJRPP 10	116	84,232	97.6	95.0	97.6	9,442	COAL	32,569 TONS	24,418,026	795,278	1,206,581	1.4324
20													
21	SJRPP 20	116	85,341	98.9	95.1	98.9	9,311	COAL	32,542 TONS	24,418,024	794,604	1,205,571	1.4127
22													
23	SCHER 4	487	313,814	86.6	95.9	91.4	10,017	COAL	158,964 TONS	19,773,995	3,143,353	5,313,300	1.6931
24													
25	TOTAL	16,313	4,777,361	39.4			9,558				45,660,186	65,132,353	1.3634
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SYSTEM NET GENERATION AND FUEL COST
 ESTIMATED FOR THE PERIOD OF: FEBRUARY, 1995

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT	NET CAPAB (MW)	NET GEN (MWH)	CAPAC FAC (%)	EQUIV AVAIL FAC (%)	NET OUT FAC (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
1	TRKY O 1	406	8,511	3.1	88.3	52.4	9,807	HEAVY OIL	13,018 BBLs	6,411,985	83,469	202,639	2.3808
2	TRKY O 2	406	2,446	0.9	92.5	54.8	9,970	HEAVY OIL	3,803 BBLs	6,411,853	24,386	59,202	2.4203
3	TRKY N 3	688	432,746	93.6	93.6	100.0	10,892	NUCLEAR	4,713,366 MBTU	1,000,000	4,713,366	2,199,239	0.5082
4	TRKY N 4	688	432,284	93.5	93.5	100.1	10,962	NUCLEAR	4,738,535 MBTU	1,000,000	4,738,535	1,901,065	0.4398
5	FT LAUD4	467	288,099	91.8	94.2	99.8	7,245	GAS	2,087,216 MCF	1,000,000	2,087,216	5,681,661	1.9721
6	FT LAUD5	467	280,769	89.5	92.7	98.1	7,341	GAS	2,061,157 MCF	1,000,000	2,061,157	5,606,077	1.9967
7	PT EVER1	212	158	0.1	96.0	74.5	9,847	HEAVY OIL	244 BBLs	6,387,110	1,556	3,607	2.2829
8	PT EVER2	213	6,403	4.5	95.1	57.8	10,362	HEAVY OIL	10,386 BBLs	6,387,947	66,346	153,796	2.4020
9	PT EVER3	391	49,545	18.9	94.5	73.2	9,622	HEAVY OIL	74,630 BBLs	6,387,996	476,734	1,105,105	2.2305
10	PT EVER4	386	36,693	14.1	95.9	67.9	9,750	HEAVY OIL	56,005 BBLs	6,387,992	357,756	829,305	2.2601
11	RIV 3	289	115,618	59.5	90.9	91.8	9,859	HEAVY OIL	178,328 BBLs	6,392,000	1,139,873	2,176,041	1.8821
12	RIV 4	289	124,720	64.2	91.3	92.2	9,671	HEAVY OIL	188,693 BBLs	6,392,002	1,206,125	2,303,724	1.8471
13	ST LUC 1	853	535,957	93.5	93.5	100.1	10,896	NUCLEAR	5,839,946 MBTU	1,000,000	5,839,946	2,270,529	0.4236
14	ST LUC 2	725	446,831	91.7	91.6	100.1	11,243	NUCLEAR	5,023,616 MBTU	1,000,000	5,023,616	2,273,652	0.5088
15	CAP CN 1	400	99,952	37.2	92.4	81.1	9,582	HEAVY OIL	151,069 BBLs	6,340,000	957,777	2,013,420	2.0144
16	CAP CN 2	400	115,746	43.1	89.9	84.4	9,477	HEAVY OIL	173,015 BBLs	6,340,000	1,096,912	2,306,021	1.9923
17	SANFRD 3	147	841	0.9	95.0	57.2	10,641	HEAVY OIL	1,419 BBLs	6,304,121	8,949	19,979	2.3745
18	SANFRD 4	394	60,773	23.0	94.6	70.8	9,846	HEAVY OIL	94,917 BBLs	6,303,997	598,356	1,335,875	2.1981
19	SANFRD 5	394	30,062	11.4	94.1	62.5	10,083	HEAVY OIL	48,081 BBLs	6,303,999	303,101	676,691	2.2510
20	PUTNAM 1	250	115,482	68.7	94.2	95.2	8,689	GAS	1,003,456 MCF	1,000,000	1,003,456	2,633,638	2.2806
21	PUTNAM 2	250	126,742	75.4	94.5	95.7	8,391	GAS	1,063,461 MCF	1,000,000	1,063,461	2,669,751	2.1064
22	MANATE 1	805	10,917	2.0	94.6	46.8	10,261	HEAVY OIL	17,400 BBLs	6,437,980	112,021	258,787	2.3705
23	MANATE 2	805	39,499	7.3	95.7	55.1	9,948	HEAVY OIL	61,032 BBLs	6,438,003	392,922	907,709	2.2980
24	FT MY 1	144	27,340	28.3	95.2	81.5	10,116	HEAVY OIL	43,582 BBLs	6,345,997	276,574	584,426	2.1376
25	FT MY 2	394	112,519	42.5	93.3	89.2	9,372	HEAVY OIL	166,165 BBLs	6,346,001	1,054,482	2,228,535	1.9806

SYSTEM NET GENERATION AND FUEL COST
 ESTIMATED FOR THE PERIOD OF: FEBRUARY, 1995

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT	NET CAPAB (MW)	NET GEN (MMH)	CAPAC FAC (%)	BOU/IV AVAIL FAC (%)	NET OUT FAC (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
1	CUTLER 5	72	69	0.1	96.0	95.8	12,661	GAS	874 MCF	1,000,000	874	2,586	3.7533
2													
3	CUTLER 6	145	162	0.2	96.0	111.7	11,309	GAS	1,832 MCF	1,000,000	1,832	5,423	3.3558
4													
5	MARTIN 1	821	2,816	0.5	92.5	38.1	10,205	HEAVY OIL	4,478 BBLs	6,417,928	28,738	70,510	2.5036
6													
7	MARTIN 2	805					*** UNIT DOWN FOR THE PERIOD ***						
8													
9	MARTIN 3	460	295,738	95.7	96.0	99.5	7,145	GAS	2,113,077 MCF	1,000,000	2,113,077	5,906,889	1.9973
10													
11	MARTIN 4	460	294,540	95.3	95.9	99.1	7,148	GAS	2,105,328 MCF	1,000,000	2,105,328	6,182,686	2.0991
12													
13	FM GT	708	353	0.1	0.0	8.3	13,164	LIGHT OIL	797 BBLs	5,832,685	4,647	23,034	6.5197
14													
15	FL GT	840	55	0.0	0.0	6.5	14,480	GAS	796 MCF	1,000,000	796	2,158	3.9165
16													
17	PE GT	420	85	0.0	0.0	6.7	14,459	GAS	1,229 MCF	1,000,000	1,229	3,331	3.9096
18													
19	SJRPP 10	116	70,898	91.0	81.5	94.3	9,468	COAL	27,490 TONS	24,417,981	671,250	1,037,688	1.4636
20													
21	SJRPP 20	116	75,364	96.7	95.1	96.7	9,324	COAL	28,777 TONS	24,418,041	702,680	1,086,315	1.4414
22													
23	SCHER 4	487	53,712	16.4	20.6	89.7	10,018	COAL	27,213 TONS	19,774,027	538,111	911,922	1.6978
24													
25	TOTAL	16,313	4,294,447	39.2			9,514				40,856,654	57,633,016	1.3420
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SYSTEM NET GENERATION AND FUEL COST
 ESTIMATED FOR THE PERIOD OF: MARCH, 1995

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT	NET CAPAB (MW)	NET GEN (MWH)	CAPAC FAC (%)	BOU TIV AVAIL FAC (%)	NET OUT FAC (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
1	TRKY O 1	403	1,861	0.6	39.9	66.0	9,310	HEAVY OIL	2,702 BBLs	6,411,991	17,325	42,006	2.2575
2	TRKY O 2	406	4,422	1.5	92.5	68.1	9,554	HEAVY OIL	6,589 BBLs	6,411,923	42,249	102,407	2.3158
3	TRKY N 3	666	478,060	96.5	93.6	103.1	10,892	NUCLEAR	5,206,970 MBTU	1,000,000	5,206,970	2,428,938	0.5081
4	TRKY N 4	666	477,421	96.4	93.5	103.1	10,962	NUCLEAR	5,233,372 MBTU	1,000,000	5,233,372	2,098,817	0.4396
5	FT LAUD4	467	320,047	92.1	85.1	99.9	7,243	GAS	2,318,146 MCF	1,000,000	2,318,146	5,701,625	1.7815
6	FT LAUD5	467	317,605	91.4	92.7	99.3	7,334	GAS	2,329,238 MCF	1,000,000	2,329,238	6,039,407	1.9015
7	PT EVER1	211	3,358	2.1	96.0	66.3	10,174	HEAVY OIL	5,348 BBLs	6,388,086	34,165	76,731	2.2850
8	PT EVER2	212	7,039	4.5	95.1	75.5	9,940	HEAVY OIL	10,951 BBLs	6,387,972	69,957	157,393	2.2362
9	PT EVER3	389	99,167	34.3	94.5	82.2	9,514	HEAVY OIL	147,691 BBLs	6,387,998	943,447	2,134,862	2.1528
10	PT EVER4	386	51,192	17.8	95.9	75.8	9,619	HEAVY OIL	77,086 BBLs	6,387,996	492,427	1,111,278	2.1708
11	RIV 3	287	111,476	52.2	90.9	96.4	9,832	HEAVY OIL	171,476 BBLs	6,391,999	1,096,074	2,021,401	1.8133
12	RIV 4	287	79,697	37.3	41.2	95.8	9,659	HEAVY OIL	120,431 BBLs	6,392,000	769,792	1,438,513	1.8050
13	ST LUC 1	839	591,625	94.8	93.5	101.6	10,896	NUCLEAR	6,446,594 MBTU	1,000,000	6,446,594	2,505,534	0.4235
14	ST LUC 2	713	493,531	93.0	91.6	101.6	11,243	NUCLEAR	5,548,715 MBTU	1,000,000	5,548,715	2,510,243	0.5086
15	CAP CN 1	397	147,761	50.0	92.4	92.8	9,532	HEAVY OIL	222,144 BBLs	6,340,000	1,408,394	2,864,407	1.9385
16	CAP CN 2	397	158,948	53.8	89.9	93.8	9,440	HEAVY OIL	236,658 BBLs	6,339,999	1,500,412	3,050,820	1.9194
17	SANFRD 3	145	1,157	1.1	95.0	79.8	10,369	HEAVY OIL	1,903 BBLs	6,304,099	11,997	25,835	2.2325
18	SANFRD 4	394	116,299	39.7	94.6	83.4	9,786	HEAVY OIL	180,543 BBLs	6,303,998	1,138,140	2,473,281	2.1267
19	SANFRD 5	394	46,011	15.7	94.1	75.8	9,861	HEAVY OIL	71,970 BBLs	6,303,999	453,701	988,184	2.1477
20	PUTNAM 1	239	140,978	79.3	94.2	100.0	8,665	GAS	1,221,626 MCF	1,000,000	1,221,626	2,972,984	2.1088
21	PUTNAM 2	239	14,984	8.4	20.8	88.3	8,450	GAS	126,608 MCF	1,000,000	126,608	310,211	2.0702
22	MANATE 1	798	1,270	0.2	42.7	39.8	9,895	HEAVY OIL	1,952 BBLs	6,438,064	12,567	28,373	2.2334
23	MANATE 2	798	57,472	9.7	95.7	63.7	9,728	HEAVY OIL	86,841 BBLs	6,437,998	559,083	1,261,264	2.1946
24	FT MY 1	143	47,874	45.0	95.2	92.7	10,071	HEAVY OIL	75,973 BBLs	6,345,993	482,122	980,111	2.0473
25	FT MY 2	391	187,346	64.4	93.3	93.8	9,372	HEAVY OIL	276,669 BBLs	6,346,001	1,755,742	3,568,843	1.9049

DATE: 22/JUN/94
 COMPANY: FLORIDA POWER & LIGHT

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SYSTEM NET GENERATION AND FUEL COST
 ESTIMATED FOR THE PERIOD OF: MARCH, 1995

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT	NET CAPAB (MW)	NET GEN (MWH)	CAPAC FAC (%)	SCV AVAIL FAC (%)	NET OUT FAC (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
1	CUTLER 5	71	109	0.2	96.0	76.8	12,704	GAS	1,385 MCF	1,000,000	1,385	4,024	3.6850
2													
3	CUTLER 6	144	323	0.3	96.0	56.1	12,099	GAS	3,908 MCF	1,000,000	3,908	11,354	3.5119
4													
5	MARTIN 1	821	3,769	0.6	92.5	41.7	10,019	HEAVY OIL	5,884 BBLs	6,417,954	37,763	92,652	2.4585
6													
7	MARTIN 2	798					*** UNIT DOWN FOR THE PERIOD ***						
8													
9	MARTIN 3	430	325,911	101.9	96.0	106.5	7,145	GAS	2,328,781 MCF	1,000,000	2,328,781	6,355,483	1.9501
10													
11	MARTIN 4	430	325,404	101.7	95.9	106.3	7,146	GAS	2,325,434 MCF	1,000,000	2,325,434	6,752,637	2.0752
12													
13	FM GT	564	468	0.1	0.0	9.2	13,159	LIGHT OIL	1,056 BBLs	5,832,828	6,158	30,526	6.5199
14													
15	FL GT	720	127	0.0	0.0	8.8	14,494	GAS	1,841 MCF	1,000,000	1,841	4,864	3.8269
16													
17	PE GT	360	140	0.1	0.0	9.7	14,431	GAS	2,020 MCF	1,000,000	2,020	5,314	3.7930
18													
19	SJRPP 10	116					*** UNIT DOWN FOR THE PERIOD ***						
20													
21	SJRPP 20	116	84,714	98.2	95.1	98.2	9,318	COAL	32,328 TONS	24,417,972	789,372	1,245,891	1.4707
22													
23	SCHER 4	487	307,791	84.9	95.9	90.7	10,011	COAL	155,824 TONS	19,773,995	3,081,263	5,308,766	1.7248
24													
25	TOTAL	15,791	5,005,358	42.6			9,549				47,796,785	66,704,979	1.3327
26													
27													
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SYSTEM NET GENERATION AND FUEL COST

ESTIMATED FOR THE PERIOD OCTOBER, 1994 THRU MARCH, 1995

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT /UNIT	NET CAPAB (MW)	NET GEN (MWH)	CAPAC FAC (%)	EQUIV AVAIL FAC (%)	NET OUT FAC (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
1	TRKY O 1	406	174,577	10.7	0.0	73.6	9,571	HEAVY OIL	259,896 BBLs	6,411,998	1,666,456	4,010,893	2.2975
2			13,813					GAS	136,697 MCF	1,000,000	136,697	311,669	2.2563
3	TRKY O 2	400	34,931	2.1	0.0	72.4	9,795	HEAVY OIL	53,246 BBLs	6,411,992	341,414	824,202	2.3595
4			1,587					GAS	16,287 MCF	1,000,000	16,287	37,133	2.3394
5	TRKY N 3	684	2,794,367	94.0	0.0	100.5	10,930	NUCLEAR	30,541,071 MBTU	1,000,000	30,541,071	14,348,952	0.5135
6	TRKY N 4	684	1,818,615	61.2	0.0	100.4	11,008	NUCLEAR	20,019,843 MBTU	1,000,000	20,019,843	8,293,445	0.4560
7	FT LAUD 4	467	4,009	92.8	0.0	99.6	7,269	LIGHT OIL	4,885 BBLs	5,623,987	27,474	124,459	3.1043
8			1,877,888					GAS	13,652,178 MCF	1,000,000	13,652,178	37,249,781	1.9836
9	FT LAUD 5	467	1,212	87.2	0.0	98.3	7,362	LIGHT OIL	1,495 BBLs	5,623,888	8,405	38,074	3.1412
10			1,768,399					GAS	13,020,025 MCF	1,000,000	13,020,025	35,561,836	2.0110
11	PT EVER 1	212	61,905	6.7	0.0	74.4	10,167	HEAVY OIL	98,528 BBLs	6,387,997	629,394	1,527,643	2.4677
12	PT EVER 2	213	110,489	12.0	0.0	76.1	10,058	HEAVY OIL	173,960 BBLs	6,387,992	1,111,253	2,684,695	2.4298
13	PT EVER 3	391	565,571	33.3	0.0	82.6	9,531	HEAVY OIL	843,850 BBLs	6,388,000	5,390,517	12,868,105	2.2752
14	PT EVER 4	386	392,060	23.4	0.0	77.4	9,639	HEAVY OIL	591,573 BBLs	6,387,999	3,778,966	9,056,872	2.3101
15	RIV 3	289	736,569	58.7	0.0	90.1	9,866	HEAVY OIL	1,136,869 BBLs	6,392,001	7,266,866	14,516,260	1.9708
16	RIV 4	289	780,095	62.2	0.0	90.4	9,665	HEAVY OIL	1,179,516 BBLs	6,392,000	7,539,465	15,153,126	1.9425
17	ST LUC 1	851	2,256,291	61.1	0.0	100.2	10,898	NUCLEAR	24,588,981 MBTU	1,000,000	24,588,981	9,603,524	0.4256
18	ST LUC 2	723	2,886,168	91.9	0.0	100.3	11,221	NUCLEAR	32,384,590 MBTU	1,000,000	32,384,590	14,756,232	0.5113
19	CAP CN 1	400	744,290	42.9	0.0	84.1	9,548	HEAVY OIL	1,120,856 BBLs	6,340,000	7,106,225	15,442,255	2.0748
20	CAP CN 2	400	843,934	48.6	0.0	85.6	9,471	HEAVY OIL	1,260,687 BBLs	6,339,999	7,992,753	17,364,928	2.0576
21	SANFRD 3	147	24,580	3.9	0.0	77.6	10,424	HEAVY OIL	40,644 BBLs	6,303,984	256,217	594,353	2.4181
22	SANFRD 4	394	518,145	30.3	0.0	76.1	9,883	HEAVY OIL	812,345 BBLs	6,303,999	5,121,020	11,650,680	2.2485
23	SANFRD 5	394	404,272	23.6	0.0	75.9	9,980	HEAVY OIL	640,031 BBLs	6,304,000	4,034,759	9,268,995	2.2928
24	FUTNAM 1	248	2,732	49.4	0.0	92.2	8,786	LIGHT OIL	4,017 BBLs	5,824,030	23,393	143,915	5.2683
25			529,761					GAS	4,655,286 MCF	1,000,000	4,655,286	12,461,869	2.3524
26	FUTNAM 2	248	5,647	31.5	0.0	91.8	8,507	LIGHT OIL	8,183 BBLs	5,823,995	47,659	293,206	5.1922
27			334,362					GAS	2,844,911 MCF	1,000,000	2,844,911	7,557,988	2.2604
28	MANATE 1	804	217,161	6.2	0.0	63.3	10,063	HEAVY OIL	339,445 BBLs	6,437,997	2,185,349	5,050,623	2.3258
29	MANATE 2	804	545,373	15.6	0.0	67.0	9,888	HEAVY OIL	837,588 BBLs	6,438,000	5,392,391	12,432,197	2.2796

SYSTEM NET GENERATION AND FUEL COST

ESTIMATED FOR THE PERIOD OCTOBER, 1994 THRU MARCH, 1995

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
PLANT /UNIT	NET CAPAB (MW)	NET GEN (MWH)	CAPAC FAC (%)	SCV AVAIL FAC (%)	NET OUT PAC (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (C/KWH)
FT MY 1	144	228,104	36.5	0.0	86.1	10,123	HEAVY OIL	363,876 BBLs	6,346,002	2,309,158	4,986,787	2.1862
FT MY 2	394	958,057	56.0	0.0	88.0	9,379	HEAVY OIL	1,416,003 BBLs	6,346,001	6,985,956	19,400,258	2.0250
CUTLER 5	72	2,608	0.8	0.0	82.5	13,054	GAS	34,045 MCF	1,000,000	34,045	87,348	3.3490
CUTLER 6	145	10,812	1.7	0.0	82.9	11,561	GAS	125,000 MCF	1,000,000	125,000	324,689	3.0030
MARTIN 1	821	15,684	0.4	0.0	49.0	9,941	HEAVY OIL	24,292 BBLs	6,417,997	155,908	382,526	2.4390
MARTIN 2	804	60,787 888	1.8	0.0	48.6	10,554	HEAVY OIL GAS	99,399 BBLs 15,305 MCF	6,417,995 1,000,000	637,940 15,305	1,559,769 36,594	2.5660 4.1233
MARTIN 3	455	1,886,079	95.4	0.0	99.5	7,162	GAS	13,508,926 MCF	1,000,000	13,508,926	36,951,665	1.9592
MARTIN 4	455	1,843,279	93.3	0.0	98.7	7,169	GAS	13,214,130 MCF	1,000,000	13,214,130	35,831,172	1.9439
FM GT	684	5,875	0.2	0.0	8.0	13,031	LIGHT OIL	13,125 BBLs	5,832,977	76,558	379,491	6.4598
FL GT	820	101 1,414	0.0	0.0	7.4	14,124	LIGHT OIL GAS	248 BBLs 20,011 MCF	5,602,745 1,000,000	1,388 20,011	7,042 55,924	6.9379 3.9542
PE GT	410	268 1,155	0.1	0.0	8.1	14,307	LIGHT OIL GAS	652 BBLs 16,703 MCF	5,604,231 1,000,000	3,656 16,703	18,555 47,955	6.9235 4.1505
SJRPP 10	116	409,713	81.3	0.0	98.8	9,449	COAL	158,542 TONS	24,417,992	3,871,267	5,957,159	1.4540
SJRPP 20	116	499,756	99.2	0.0	99.2	9,326	COAL	190,867 TONS	24,418,000	4,660,600	7,203,151	1.4413
SCHER 4	509	1,810,891	82.0	0.0	96.0	9,945	COAL	910,750 TONS	19,774,000	18,009,171	30,572,536	1.6883
TOTAL	16,242	28,184,276	39.9			9,488				267,425,567	417,030,531	1.4797

ESTIMATED FOR THE PERIOD OF: OCTOBER, 1994 THRU MARCH, 1995

		OCTOBER 1994	NOVEMBER 1994	DECEMBER 1994	JANUARY 1995	FEBRUARY 1995	MARCH 1995	TOTAL
HEAVY OIL								
1								
2								
3	PURCHASES:							
4	UNITS	(BBLs)						
5	UNIT COST	{ \$/BBLs)						
6	AMOUNT	{ \$)						
7		2,422,506	2,270,601	1,862,333	1,134,762	1,181,396	1,996,926	10,868,524
8		15,0196	14,5564	13,4464	14,2571	12,5497	12,6950	13,8780
9		36,384,960	33,051,790	25,041,680	16,178,380	14,826,170	25,350,890	150,833,870
10								
11	BURNED:							
12	UNITS	(BBLs)						
13	UNIT COST	{ \$/BBLs)						
14	AMOUNT	{ \$)						
15		2,747,190	2,539,818	1,868,820	1,147,274	1,286,263	1,702,810	11,292,175
16		14,5479	14,5914	14,0037	13,8802	13,3996	13,1655	14,0605
17		39,965,943	37,059,404	26,170,355	15,924,423	17,235,373	22,418,359	158,773,857
18								
19	ENDING INVENTORY:							
20	UNITS	(BBLs)						
21	UNIT COST	{ \$/BBLs)						
22	AMOUNT	{ \$)						
23		3,775,942	3,506,727	3,500,238	3,487,728	3,382,862	3,676,979	21,330,476
24		14,9046	14,9060	14,6112	14,7364	14,4811	14,1203	14,6268
25		56,278,996	52,271,379	51,142,715	51,396,678	48,987,462	51,919,983	311,997,213
26								
27	DAYS SUPPLY:							
28								
29								
30								
31								
32								
LIGHT OIL								
33								
34								
35	PURCHASES:							
36	UNITS	(BBLs)						
37	UNIT COST	{ \$/BBLs)						
38	AMOUNT	{ \$)						
39		0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
40		0	0	0	0	0	0	0
41								
42	BURNED:							
43	UNITS	(BBLs)						
44	UNIT COST	{ \$/BBLs)						
45	AMOUNT	{ \$)						
46		3,507	17,353	6,435	3,456	797	1,056	32,604
47		31,5387	32,9973	25,8967	28,9135	28,9009	28,9072	30,8165
48		112,009	572,603	166,645	99,925	23,034	30,526	1,004,742
49								
50	ENDING INVENTORY:							
51	UNITS	(BBLs)						
52	UNIT COST	{ \$/BBLs)						
53	AMOUNT	{ \$)						
54		188,428	171,075	164,639	161,183	160,386	159,330	1,005,041
55		30,2044	29,9211	30,0786	30,1036	30,1095	30,1175	30,0905
56		5,691,353	5,118,752	4,952,107	4,852,181	4,829,147	4,798,622	30,242,162
57								
58	DAYS SUPPLY:							

SYSTEM GENERATED FUEL COST
 INVENTORY ANALYSIS
 ESTIMATED FOR THE PERIOD OF: OCTOBER, 1994 THRU MARCH, 1995

		OCTOBER 1994	NOVEMBER 1994	DECEMBER 1994	JANUARY 1995	FEBRUARY 1995	MARCH 1995	TOTAL
COAL								
33	PURCHASES:							
34	UNITS	(TONS)						
35	UNIT COST	(\$/TONS)						
36	AMOUNT	(\$)						
37								
38	BURNED:							
39	UNITS	(TONS)						
40	UNIT COST	(\$/TONS)						
41	AMOUNT	(\$)						
42								
43	ENDING INVENTORY:							
44	UNITS	(TONS)						
45	UNIT COST	(\$/TONS)						
46	AMOUNT	(\$)						
47								
48	DAYS SUPPLY:							
GAS								
48	BURNED:							
49	UNITS	(MCF)						
50	UNIT COST	(\$/MCF)						
51	AMOUNT	(\$)						
52								
NUCLEAR								
53	BURNED:							
54	UNITS	(MBTU)						
55	UNIT COST	(\$/MBTU)						
56	AMOUNT	(\$)						
57								

POWER SOLD
 ESTIMATED FOR THE PERIOD OF: OCTOBER, 1994 THRU MARCH, 1995

(1)	(2)	(3)	(4)	(5)	(6)	(7A)	(7B)	(8)
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	FUEL COST (CENTS/KWH)	TOTAL COST (CENTS/KWH)	TOTAL \$ FOR FUEL ADJUSTMENT (6) X (7A)
OCTOBER 1994	ST. LUCIE REL.	C S	44,116 0	0 0	44,116 0	2.580 0.000	3.585 0.000	1,138,192 0
	80% OF GAIN (SEE E7A)		2,804	0	2,804	0.532	0.532	14,917
TOTAL *			46,920	0	46,920	2.458	3.403	354,696
NOVEMBER 1994	ST. LUCIE REL.	C S	65,841 0	0 0	65,841 0	2.740 0.000	3.757 0.000	1,804,041 0
	80% OF GAIN (SEE E7A)		0	0	0	0.000	0.000	0
TOTAL *			65,841	0	65,841	2.740	3.757	535,850
DECEMBER 1994	ST. LUCIE REL.	C S	26,850 0	0 0	26,850 0	2.680 0.000	3.539 0.000	719,580 0
	80% OF GAIN (SEE E7A)		37,546	0	37,546	0.425	0.425	159,570
TOTAL *			64,396	0	64,396	1.365	1.723	184,444
JANUARY 1995	ST. LUCIE REL.	C S	24,240 0	0 0	24,240 0	2.840 0.000	3.610 0.000	688,416 0
	80% OF GAIN (SEE E7A)		44,195	0	44,195	0.423	0.423	186,945
TOTAL *			68,435	0	68,435	1.279	1.552	149,285
FEBRUARY 1995	ST. LUCIE REL.	C S	15,730 0	0 0	15,730 0	2.240 0.000	2.626 0.000	352,352 0
	80% OF GAIN (SEE E7A)		39,918	0	39,918	0.424	0.424	169,252
TOTAL *			55,648	0	55,648	0.937	1.047	48,615
								570,219

POWER SOLD
 ESTIMATED FOR THE PERIOD OF: OCTOBER, 1994 THRU MARCH, 1995

(1)	(2)	(3)	(4)	(5)	(6)	(7A)	(7B)	(8)
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	FUEL COST (CENTS/MWH)	TOTAL COST (CENTS/MWH)	TOTAL \$ FOR FUEL ADJUSTMENT (6) X (7A)
MARCH 1995	ST. LUCIE REL.	C S	102,510 0	0 0	102,510 0	2.050 0.000	2.613 0.000	2,101,460 0
	80% OF GAIN (SEE E7A)		44,065	0	44,065	0.424	0.424	186,836
TOTAL *			146,575	0	146,575	1.561	1.955	461,796
PERIOD TOTAL	ST. LUCIE REL.	C S	279,287 0	0 0	279,287 0	2.436 0.000	3.213 0.000	6,804,040 0
	80% OF GAIN (SEE E7A)		168,528	0	168,528	0.426	0.426	717,521
TOTAL *			447,815	0	447,815	1.680	2.164	1,734,687
								9,256,247

* ONLY TOTAL \$ INCLUDES 80% GAIN ON ECONOMY ENERGY SALES

GAIN ON ECONOMY ENERGY SALES
 ESTIMATED FOR THE PERIOD OF: OCTOBER, 1994 THRU MARCH, 1995

(1)	(2)	(3)	(4)	(5A)	(5B)	(6A)	(6B)	(7)
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	FUEL COST (\$)	TOTAL COST (\$)	FUEL COST (CENTS/KWH)	TOTAL COST (CENTS/KWH)	GAIN OF ECONOMY ENERGY SALES (5B) - (5A)
OCTOBER 1994		C	44,116	1,138,192	1,581,561	2.580	3.585	443,370
TOTAL *	80% OF GAIN		44,116	1,138,192	1,581,561	2.580	3.585	354,696
NOVEMBER 1994		C	65,841	1,804,041	2,473,853	2.740	3.757	669,813
TOTAL *	80% OF GAIN		65,841	1,804,041	2,473,853	2.740	3.757	535,850
DECEMBER 1994		C	26,850	719,580	950,135	2.680	3.539	230,555
TOTAL *	80% OF GAIN		26,850	719,580	950,135	2.680	3.539	184,444
JANUARY 1995		C	24,240	688,416	875,022	2.840	3.610	186,607
TOTAL *	80% OF GAIN		24,240	688,416	875,022	2.840	3.610	149,285
FEBRUARY 1995		C	15,730	352,352	413,120	2.240	2.626	60,768
TOTAL *	80% OF GAIN		15,730	352,352	413,120	2.240	2.626	48,615
MARCH 1995		C	102,510	2,101,460	2,678,705	2.050	2.613	577,245
TOTAL *	80% OF GAIN		102,510	2,101,460	2,678,705	2.050	2.613	461,796
PERIOD TOTAL		C	279,287	6,804,040	8,972,398	2.436	3.213	2,168,358
TOTAL *	80% OF GAIN		279,287	6,804,040	8,972,398	2.436	3.213	1,734,687

* TOTAL \$ IN COLUMN (7) IS 80% OF TOTAL GAIN

PURCHASED POWER
 (EXCLUSIVE OF ECONOMY ENERGY PURCHASES)
 ESTIMATED FOR THE PERIOD OF: OCTOBER, 1994 THRU MARCH, 1995

30

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	FUEL COST (CENTS/KWH)	TOTAL COST (CENTS/KWH)	TOTAL \$ FOR FUEL ADJ (7) X (8A)
OCT 1994	SOU. CO. (UPS+R)		713,356	0	0	713,356	1.843		13,191,130
	ST. LUCIE REL.		41,805	0	0	41,805	0.511		213,624
	SJRPP		251,911	0	0	251,911	1.461		3,681,670
TOTAL			1,007,073	0	0	1,007,073	1.697		17,086,424
NOV 1994	SOU. CO. (UPS+R)		649,370	0	0	649,370	1.870		12,142,110
	ST. LUCIE REL.		43,291	0	0	43,291	0.515		222,949
	SJRPP		259,660	0	0	259,660	1.450		3,764,450
TOTAL			952,321	0	0	952,321	1.694		16,129,509
DEC 1994	SOU. CO. (UPS+R)		618,299	0	0	618,299	1.923		11,270,910
	ST. LUCIE REL.		41,890	0	0	41,890	0.515		215,736
	SJRPP		251,685	0	0	251,685	1.367		3,440,090
TOTAL			911,874	0	0	911,874	1.637		14,926,736
JAN 1995	SOU. CO. (UPS+R)		474,194	0	0	474,194	1.878		8,904,820
	ST. LUCIE REL.		43,291	0	0	43,291	0.509		220,353
	SJRPP		253,261	0	0	253,261	1.444		3,657,590
TOTAL			770,746	0	0	770,746	1.658		12,782,763
FEB 1995	SOU. CO. (UPS+R)		298,642	0	0	298,642	1.859		5,552,720
	ST. LUCIE REL.		39,102	0	0	39,102	0.509		199,027
	SJRPP		217,151	0	0	217,151	1.493		3,241,960
TOTAL			554,894	0	0	554,894	1.621		8,993,707
MAR 1995	SOU. CO. (UPS+R)		390,658	0	0	390,658	1.863		7,277,120
	ST. LUCIE REL.		43,189	0	0	43,189	0.509		219,831
	SJRPP		126,254	0	0	126,254	1.524		1,924,650
TOTAL			560,101	0	0	560,101	1.682		9,421,601
PERIOD TOTAL	SOU. CO. (UPS+R)		3,144,519	0	0	3,144,519	1.855		58,338,810
	ST. LUCIE REL.		252,568	0	0	252,568	0.511		1,291,520
	SJRPP		1,359,922	0	0	1,359,922	1.449		19,710,410
TOTAL			4,757,009	0	0	4,757,009	1.668		79,340,740

ENERGY PAYMENT TO QUALIFYING FACILITIES
 ESTIMATED FOR THE PERIOD OF: OCTOBER, 1994 THRU MARCH, 1995

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUPTIBLE	MWH FOR FIRM	FUEL COST (CENTS/KWH)	TOTAL COST (CENTS/KWH)	TOTAL \$ FOR FUEL ADJ (7) X (8A)
OCT 1994	QUAL. FACILITIES		410,331	0	0	410,331	1.799	1.799	7,380,292
TOTAL			410,331	0	0	410,331	1.799	1.799	7,380,292
NOV 1994	QUAL. FACILITIES		420,274	0	0	420,274	1.794	1.794	7,541,412
TOTAL			420,274	0	0	420,274	1.794	1.794	7,541,412
DEC 1994	QUAL. FACILITIES		405,391	0	0	405,391	1.764	1.764	7,150,960
TOTAL			405,391	0	0	405,391	1.764	1.764	7,150,960
JAN 1995	QUAL. FACILITIES		399,526	0	0	399,526	1.770	1.770	7,072,733
TOTAL			399,526	0	0	399,526	1.770	1.770	7,072,733
FEB 1995	QUAL. FACILITIES		367,563	0	0	367,563	1.748	1.748	6,424,282
TOTAL			367,563	0	0	367,563	1.748	1.748	6,424,282
MAR 1995	QUAL. FACILITIES		412,194	0	0	412,194	1.746	1.746	7,198,277
TOTAL			412,194	0	0	412,194	1.746	1.746	7,198,277
PERIOD TOTAL	QUAL. FACILITIES		2,415,279	0	0	2,415,279	1.771	1.771	42,767,956
TOTAL			2,415,279	0	0	2,415,279	1.771	1.771	42,767,956

DATE: 16/JUN/94
 COMPANY: FLORIDA POWER & LIGHT

PAGE 1
 SCHEDULE E9

ECONOMY ENERGY PURCHASES
 ESTIMATED FOR THE PERIOD OF: OCTOBER, 1994 THRU MARCH, 1995

(1)	(2)	(3)	(4)	(5)	(6)	(7A)	(7B)	(8)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MMWH PURCHASED	TRANSACTION COST (CENTS/KWH)	TOTAL \$ FOR FUEL ADJ (4) * (5)	COST IF GENERATED (CENTS/KWH)	COST IF GENERATED (\$)	FUEL SAVINGS (7B) - (6)
OCT 1994	FLORIDA SOUTHERN CO.	C	115,429	1.908	2,202,100	2.170	2,504,840	302,700
		C	9,439	2.155	203,420	2.410	227,473	24,053
TOTAL			124,867	1.926	2,405,520	2.188	2,732,273	326,753
NOV 1994	FLORIDA SOUTHERN CO.	C	115,845	1.862	2,157,460	2.070	2,397,988	240,528
		C	8,207	2.328	191,040	2.540	208,458	17,418
TOTAL			124,052	1.893	2,348,500	2.101	2,606,446	257,946
DEC 1994	FLORIDA SOUTHERN CO.	C	78,515	1.806	1,417,360	2.010	1,578,154	160,194
		C	446	2.039	9,100	2.250	10,039	939
TOTAL			78,961	1.807	1,427,060	2.011	1,588,193	161,133
JAN 1995	FLORIDA SOUTHERN CO.	C	38,234	1.894	724,180	2.090	799,094	74,914
		C	1,817	2.182	39,640	2.380	43,236	3,596
TOTAL			40,051	1.907	763,820	2.103	842,330	78,510
FEB 1995	FLORIDA SOUTHERN CO.	C	14,096	1.904	268,390	2.110	297,431	29,041
		C	0	0.000	0	0.000	0	0
TOTAL			14,096	1.904	268,390	2.110	297,431	29,041
MAR 1995	FLORIDA SOUTHERN CO.	C	19,780	1.820	360,020	2.110	417,365	57,345
		C	0	0.000	0	0.000	0	0
TOTAL			19,780	1.820	360,020	2.110	417,365	57,345
PERIOD TOTAL	FLORIDA SOUTHERN CO.	C	381,939	1.867	7,130,110	2.093	7,994,832	864,722
		C	19,909	2.226	443,200	2.457	489,207	46,007
TOTAL			401,808	1.885	7,573,310	2.111	8,484,038	910,728

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE E10

	<u>APRIL 94 - SEPT 94</u>	<u>OCT 94 - MARCH 95</u>	DIFFERENCE	
			<u>\$</u>	<u>%</u>
BASE	\$47.38	\$47.38	0	0.00%
FUEL	\$14.90	\$15.81	0.91	6.11%
CONSERVATION	\$2.43	\$2.43	0	0.00%
OIL BACKOUT	\$0.12	\$0.11	-0.01	-8.33%
CAPACITY PAYMENT	\$5.64	\$5.17	-0.47	-8.33%
ENVIRONMENTAL	<u>\$0.12</u>	<u>\$0.10</u>	<u>-0.02</u>	<u>0.00%</u>
SUBTOTAL	\$70.59	\$71.00	0.41	0.58%
GROSS RECEIPTS TAX	<u>\$0.72</u>	<u>\$0.73</u>	<u>\$0.01</u>	<u>1.39%</u>
TOTAL	<u>\$71.31</u>	<u>\$71.73</u>	<u>\$0.42</u>	<u>0.59%</u>

COMPANY: **FLORIDA POWER & LIGHT**
DATE: **6/17/94**

SCHEDULE E11

**KWH SALES AND CUSTOMER DATA
ESTIMATED FOR THE PERIOD OF OCT 1994 - MAR 1995**

OCT 1994	NOV 1994	DEC 1994	JAN 1995	FEB 1995	MAR 1995	TOTAL
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KWH SALES

1 RESIDENTIAL	3,497,529	2,827,717	2,671,069	2,829,812	2,638,261	2,581,743	17,046,131
2 COMMERCIAL	2,650,320	2,398,752	2,326,680	2,216,505	2,008,821	2,083,586	13,694,665
3 INDUSTRIAL	361,573	349,716	358,011	354,477	320,634	322,576	2,086,988
4 STREET & HIGHWAY LIGHTING	32,688	30,869	30,003	29,896	31,526	27,947	182,930
5 OTHER SALES TO PUBLIC AUTHORITY	55,247	48,002	44,826	44,118	46,430	41,708	280,331
6 RAILROADS & RAILWAYS	6,280	6,352	6,307	6,851	6,800	6,800	39,370
7 TOTAL JURISDICTIONAL SALES	6,803,617	5,661,410	5,436,896	5,481,658	5,052,473	5,074,360	33,310,414
8 SALES FOR RESALE	107,332	75,887	67,929	61,620	67,954	65,105	445,827
9 TOTAL SALES	6,710,949	5,737,297	5,504,825	5,543,278	5,120,427	5,139,465	33,756,241

NUMBER OF CUSTOMERS

10 RESIDENTIAL	3,052,109	3,075,929	3,100,018	3,115,378	3,129,240	3,138,964	3,101,939
11 COMMERCIAL	373,433	374,532	375,385	381,395	381,607	382,385	378,123
12 INDUSTRIAL	15,433	15,465	15,431	15,347	15,371	15,439	15,414
13 STREET & HIGHWAY LIGHTING	2,664	2,693	2,723	2,753	2,782	2,812	2,738
14 OTHER SALES TO PUBLIC AUTHORITY	295	294	294	294	293	293	294
15 RAILROADS & RAILWAYS	23	23	23	23	23	23	23
16 TOTAL JURISDICTIONAL CUSTOMERS	3,443,956	3,468,937	3,493,874	3,515,188	3,529,316	3,539,916	3,498,531
17 SALES FOR RESALE	10	10	9	9	9	9	8
18 TOTAL CUSTOMERS	3,443,966	3,468,947	3,493,883	3,515,197	3,529,325	3,539,925	3,498,541

KWH USE PER CUSTOMER

19 RESIDENTIAL	1,146	919	862	908	843	822	5,495
20 COMMERCIAL	7,097	6,405	6,198	5,812	5,264	5,475	36,217
21 INDUSTRIAL	23,429	22,613	23,201	23,098	20,859	20,893	134,095
22 STREET & HIGHWAY LIGHTING	12,270	11,463	11,018	10,859	11,332	9,939	66,816
23 OTHER SALES TO PUBLIC AUTHORITY	187,370	163,033	152,466	150,277	158,384	142,483	954,187
24 RAILROADS & RAILWAYS	272,196	276,178	274,197	297,848	295,652	295,652	1,711,723
25 TOTAL JURISDICTIONAL USE PER CUSTOMER	1,917	1,632	1,556	1,559	1,432	1,433	9,521
26 SALES FOR RESALE	10,733,200	7,588,700	7,547,667	6,846,667	7,550,444	7,233,889	47,767,179
27 TOTAL USE PER CUSTOMER	1,949	1,654	1,576	1,577	1,451	1,452	9,649

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

	PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
	OCT - MAR 1991 - 1992 (COLUMN 1)	OCT - MAR 1992 - 1993 (COLUMN 2)	OCT - MAR 1993 - 1994 (COLUMN 3)	OCT - MAR 1994 - 1995 (COLUMN 4)	(COLUMN 2) - (COLUMN 1)	(COLUMN 3) - (COLUMN 2)	(COLUMN 4) - (COLUMN 3)
FUEL COST OF SYSTEM NET GENERATION (\$)							
1 *HEAVY OIL	151,298,852	117,385,137	182,348,825	158,775,187	(22.4)	55.3	(12.9)
2 *LIGHT OIL	1,811,510	1,835,038	16,957	1,004,742	(8.6)	(99.0)	5,829.2
3 COAL	24,584,844	19,703,523	44,352,904	43,732,848	(19.9)	125.1	(1.4)
4 GAS	187,445,450	158,801,909	145,081,777	186,515,823	(15.4)	(8.5)	14.8
5 NUCLEAR	55,365,258	59,301,342	56,550,343	47,002,153	7.1	(4.6)	(16.9)
6 OTHER (FORMULSION)	2,586,011	0	0	0	(100.0)	0.0	0.0
7 TOTAL (\$)	423,091,555	356,846,944	428,331,806	417,030,531	(15.7)	20.1	(2.6)
SYSTEM NET GENERATION (MWH)							
8 *HEAVY OIL	5,355,040	4,589,133	6,808,725	7,416,584	(14.3)	48.4	8.9
9 *LIGHT OIL	30,814	28,832	231	19,844	(12.9)	(99.1)	8,490.5
10 COAL	1,370,510	1,198,981	2,487,084	2,720,359	(12.5)	107.4	9.4
11 GAS	6,564,807	6,448,675	5,725,854	8,272,048	(1.8)	(11.1)	44.2
12 NUCLEAR	9,133,181	10,813,910	10,016,782	9,755,442	18.2	(5.8)	(2.6)
13 OTHER (FORMULSION)	139,563	0	0	0	(100.0)	0.0	0.0
14 TOTAL (MWH)	22,593,715	22,877,531	25,048,676	28,184,278	1.3	9.5	12.5
UNITS OF FUEL BURNED							
15 *HEAVY OIL (Bbl)	8,292,185	7,088,868	10,469,253	11,292,803	(14.5)	47.7	7.9
16 *LIGHT OIL (Bbl)	73,858	65,814	606	32,805	(11.2)	(99.1)	5,280.4
17 COAL (TON)	578,267	459,151	989,288	1,280,159	(20.6)	110.9	30.2
18 GAS (MCF)	87,139,637	83,718,968	50,396,854	81,259,504	(5.1)	(20.8)	21.6
19 NUCLEAR (MMBTU)	99,675,138	116,028,825	110,356,780	107,534,485	16.4	(4.8)	(2.8)
20 OTHER (TONS)	55,287	0	0	0	(100.0)	0.0	0.0
BTU'S BURNED (MMBTU)							
21 *HEAVY OIL	52,831,279	45,064,906	66,679,040	71,902,005	(14.4)	48.0	7.8
22 *LIGHT OIL	428,378	380,559	3,516	188,534	(11.2)	(99.1)	5,280.4
23 COAL	13,287,171	11,441,782	24,106,001	26,541,038	(13.9)	110.7	10.1
24 GAS	88,621,509	83,670,820	50,393,373	81,259,504	(4.4)	(20.8)	21.6
25 NUCLEAR	99,675,138	116,028,825	110,356,780	107,534,485	16.4	(4.8)	(2.8)
26 OTHER (FORMULSION)	1,415,337	0	0	0	(100.0)	0.0	0.0
27 TOTAL (MMBTU)	234,058,812	236,586,872	251,528,889	287,425,567	1.1	6.3	6.3
GENERATION MIX (%MWH)							
28 *HEAVY OIL	23.70	20.06	27.18	26.31	-	-	-
29 *LIGHT OIL	0.14	0.12	0.00	0.07	-	-	-
30 COAL	6.07	5.24	9.93	9.65	-	-	-
31 GAS	29.09	28.19	22.90	29.35	-	-	-
32 NUCLEAR	40.42	48.39	39.99	34.61	-	-	-
33 OTHER (FORMULSION)	0.82	0.00	0.00	0.00	-	-	-
34 TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
FUEL COST PER UNIT							
35 *HEAVY OIL (\$/Bbl)	18.2480	18.5591	17.4176	14.0801	(9.3)	5.2	(19.3)
36 *LIGHT OIL (\$/Bbl)	24.5269	25.2240	27.9723	30.8156	2.8	10.9	10.2
37 COAL (\$/TON)	42.5143	41.9982	45.8095	34.7042	(1.2)	9.1	(24.2)
38 GAS (\$/MCF)	2.7919	2.4891	2.8784	2.7182	(10.8)	19.6	(5.6)
39 NUCLEAR (\$/MMBTU)	0.5555	0.5111	0.5124	0.4371	(8.0)	0.3	(14.7)
40 OTHER (\$/TON)	46.7743	0	0	0	(100.0)	0.0	0.0
FUEL COST PER MMBTU (\$/MMBTU)							
41 *HEAVY OIL	2.8747	2.6048	2.7347	2.2082	(9.4)	5.0	(19.3)
42 *LIGHT OIL	4.2288	4.2490	4.8228	5.2292	2.8	10.9	10.5
43 COAL	1.8503	1.7221	1.8399	1.8477	(6.9)	6.8	(10.8)
44 GAS	2.8138	2.4810	2.8792	2.7182	(11.5)	19.6	(5.6)
45 NUCLEAR	0.5555	0.5111	0.5124	0.4371	(8.0)	0.3	(14.7)
46 OTHER (FORMULSION)	1.8271	0.0000	0.0000	0.0000	(100.0)	0.0	0.0
47 TOTAL (\$/MMBTU)	1.9078	1.5075	1.7028	1.5564	(16.8)	19.0	(8.4)
BTU BURNED PER KWH (BTU/KWH)							
48 *HEAVY OIL	9,828	9,820	9,793	9,895	0.1	(0.3)	(1.0)
49 *LIGHT OIL	13,502	14,181	19,192	9,501	2.0	684.0	(83.7)
50 COAL	9,895	8,543	9,892	9,758	(1.5)	1.6	0.7
51 GAS	10,148	9,873	8,784	7,405	(2.7)	(11.0)	(15.7)
52 NUCLEAR	10,814	10,832	11,017	11,032	0.2	0.2	0.1
53 OTHER (FORMULSION)	10,141	0	0	0	(100.0)	0.0	0.0
54 TOTAL (BTU/KWH)	10,359	10,341	10,062	9,688	(0.2)	(2.9)	(5.5)
GENERATED FUEL COST PER KWH (\$/KWH)							
55 *HEAVY OIL	2.8254	2.5979	2.8783	2.1408	(8.5)	4.7	(20.1)
56 *LIGHT OIL	5.8789	6.1682	7.3288	8.0632	4.9	18.8	(20.9)
57 COAL	1.7935	1.6434	1.7833	1.8078	(8.4)	8.6	(0.8)
58 GAS	2.8944	2.4594	2.8290	2.6125	(12.9)	2.8	(20.4)
59 NUCLEAR	0.6062	0.5587	0.5444	0.4618	(7.8)	1.1	(14.7)
60 OTHER (FORMULSION)	1.8929	0.0000	0.0000	0.0000	(100.0)	0.0	0.0
61 TOTAL (\$/KWH)	1.8726	1.5599	1.7100	1.4797	(16.8)	9.7	(15.8)

*DISTILLATE (Bbl, MWH & \$) USED FOR FIBER, HOT STANDBY, ETC. IS INCLUDED IN FOSSIL STEAM PLANTS.

1992

DIFFERENCE (%) FROM PRIOR PERIOD		
(COLUMN 2)	(COLUMN 3)	(COLUMN 4)
(COLUMN 1)	(COLUMN 2)	(COLUMN 3)

1.3	0.5	12.5
29.5	25.2	275.2
0.0	46.4	3.0
(3.0)	(23.0)	(37.4)
18.0	37.8	87.2
54.0	8.4	(79.2)
0.0	0.0	0.0
2.0	0.8	10.2
3.0	3.8	(1.5)
(3.0)	18.2	55.5
(10.1)	(42.5)	184.5
2.0	0.8	10.3
1.8	10.3	18.8
0.0	0.0	0.0
0.0	0.0	0.0
0.0	(1.4)	18.2

(16.7)	20.1	(28.8)
62.7	(20.0)	306.7
0.0	0.0	0.0
2.8	50.5	(28.1)
(2.3)	(20.4)	(42.7)
0.0	0.0	0.0
(1.2)	34.2	50.1
37.2	0.7	(70.7)
(10.8)	2.8	(10.8)

(10.8)	8.7	(13.8)
0.0	0.0	0.0
(20.6)	26.0	(17.2)
0.7	(3.2)	(8.4)
0.0	0.0	0.0
(16.3)	(2.6)	(4.9)
(10.9)	(6.3)	(2.3)
(12.7)	2.9	(10.3)

KWH SALES AND CUSTOMER DATA

Exhibit 111
Page 2 of 2

KWH SALES (000)	PERIOD			
	OCT - MAR 1991 - 1992 (COLUMN 1)	OCT - MAR 1992 - 1993 (COLUMN 2)	OCT - MAR 1993 - 1994 (COLUMN 3)	OCT - MAR 1994 - 1995 (COLUMN 4)
1 RESIDENTIAL	16,213,511	16,958,257	17,321,921	17,046,151
2 COMMERCIAL	13,282,609	13,504,363	13,841,032	13,694,664
3 INDUSTRIAL	2,041,349	2,067,987	2,096,492	2,066,989
4 STREET & HIGHWAY LIGHTING	172,917	182,337	186,129	182,929
5 OTHER SALES TO PUBLIC AUTHOR.	324,409	346,745	340,962	280,331
6 RAILWAYS AND RAILROADS	40,920	40,901	41,003	39,370
7 INTERDEPARTMENTAL SALES	0	0	0	0
8 TOTAL JURISDICTIONAL SALES	32,076,175	33,100,590	33,827,529	33,310,414
9 SALES FOR RESALE	375,116	316,250	441,118	445,827
10 TOTAL SALES	32,451,291	33,416,840	34,268,647	33,756,241

DIFFERENCE (%) FROM PRIOR PERIOD			
(COLUMN 2) -(COLUMN 1)	(COLUMN 3) -(COLUMN 2)	(COLUMN 4) -(COLUMN 3)	(COLUMN 4) -(COLUMN 1)
4.6	2.1	(1.6)	(1.6)
1.7	2.5	(1.1)	(1.1)
1.3	1.4	(1.4)	(1.4)
5.5	2.1	(1.7)	(1.7)
6.9	(1.7)	(17.8)	(17.8)
(0.1)	0.3	(4.0)	(4.0)
0.0	0.0	0.0	0.0
3.2	2.2	(1.5)	(1.5)
(15.7)	39.5	1.1	1.1
3.0	2.6	(1.5)	(1.5)

NUMBER OF CUSTOMERS	PERIOD			
	OCT - MAR 1991 - 1992 (COLUMN 1)	OCT - MAR 1992 - 1993 (COLUMN 2)	OCT - MAR 1993 - 1994 (COLUMN 3)	OCT - MAR 1994 - 1995 (COLUMN 4)
10 RESIDENTIAL	2,919,397	2,969,406	3,013,538	3,101,938
11 COMMERCIAL	353,322	356,012	364,085	378,123
12 INDUSTRIAL	16,368	14,871	15,961	15,414
13 STREET & HIGHWAY LIGHTING	3,880	4,156	4,457	2,738
14 OTHER SALES TO PUBLIC AUTHOR.	318	307	302	294
15 RAILWAYS AND RAILROADS	23	23	23	23
16 INTERDEPARTMENTAL SALES	0	0	0	0
17 TOTAL JURISDICTIONAL SALES	3,293,307	3,344,774	3,398,345	3,498,531
18 SALES FOR RESALE	11	10	11	9
19 TOTAL CUSTOMERS	3,293,318	3,344,784	3,398,356	3,498,540

1.7	1.5	2.9
0.8	2.3	3.9
(9.2)	7.3	(3.4)
7.1	7.2	(38.6)
(3.5)	(1.6)	(2.7)
0.0	0.0	0.0
0.0	0.0	0.0
1.6	1.6	3.0
(9.1)	10.0	(18.2)
1.6	1.6	3.0

KWH USE PER CUSTOMER	PERIOD			
	OCT - MAR 1991 - 1992 (COLUMN 1)	OCT - MAR 1992 - 1993 (COLUMN 2)	OCT - MAR 1993 - 1994 (COLUMN 3)	OCT - MAR 1994 - 1995 (COLUMN 4)
19 RESIDENTIAL	5,554	5,711	5,748	5,495
20 COMMERCIAL	37,593	37,932	38,018	36,217
21 INDUSTRIAL	124,716	139,066	131,350	131,350
22 STREET & HIGHWAY LIGHTING	44,566	43,873	41,761	66,811
23 OTHER SALES TO PUBLIC AUTHOR.	1,020,154	1,130,076	1,129,604	1,129,604
24 RAILWAYS AND RAILROADS	1,778,130	1,778,304	1,782,739	1,711,739
25 INTERDEPARTMENTAL SALES	0	0	0	0
26 TOTAL JURISDICTIONAL SALES	9,740	9,896	9,954	9,121
27 SALES FOR RESALE	34,101,465	31,626,000	40,101,636	49,536,313
28 TOTAL SALES	9,854	9,891	10,084	9,649

2.8	0.7	(4.4)
0.9	0.2	(4.7)
11.5	(5.6)	0.0
(1.6)	(4.8)	80.0
10.8	(0.0)	0.0
(0.1)	0.3	(4.0)
0.0	0.0	0.0
1.6	0.6	(4.4)
(7.3)	26.8	23.5
1.4	0.8	(4.3)

(Continued from Sheet No. 10.203)

(2) Payments Starting on January 1, 1997:

The firm energy rate, in cents per kilowatt-hour (¢/kWh), shall be the following on an hour-by-hour basis: (a) to the extent that FPL's Avoided Unit would have operated, the Company's Avoided Unit Fuel Cost (as defined below), and (b) to the extent that the Company's Avoided Unit would not have been operated, the Company's as-available avoided energy costs calculated by the Company in accordance with Rule 25-17.0825, F.A.C., and FPL's Rate Schedule COG-1, as they may each be amended from time to time. The Company's Avoided Unit Fuel Cost, in cents per kilowatt-hour (¢/kWh) shall be defined as the product of: (a) the average monthly inventory charge-out price of coal burned at the St. Johns River Power Park (as can be calculated from the Company's Fuel Cost Recovery A-3 Schedule) with an appropriate adjustment for delivery to the Martin site in cents per million Btu; (b) an average annual heat rate of 8.42 million Btu per megawatt-hour based on the 1997 907 MW Company IGCC Avoided Unit; and (c) an additional .139 cents per kilowatt-hour in mid-1990 \$ for variable operation and maintenance expenses which will be escalated based on the actual Consumer Price Index.

Calculations of payments to the QF shall be based on the sum, over all hours of the billing period, of the product of each hour's avoided energy cost times the purchases by the Company for that hour. All purchases shall be adjusted for losses from the point of metering to the point of interconnection. The calculation of the Company's avoided energy cost reflects the delivery of energy from the geographical area of the Company in which the QF is located. Energy payments to QFs located outside the Company's service territory reflect the region in which the interchange point for the delivery of energy is located.

ESTIMATED AS-AVAILABLE ENERGY COST

For informational purposes only, the estimated incremental avoided energy costs for the next four semi-annual periods are as follows. In addition, avoided energy cost payments will include .010¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
October 1, 1994 - March 31, 1995	2.19	1.96	2.02
April 1, 1995 - September 30, 1995	2.57	2.12	2.24
October 1, 1995 - March 31, 1996	2.36	2.12	2.18
April 1, 1996 - September 30, 1996	2.66	2.23	2.35

A MW block size ranging from 76 MW to 104 MW has been used to calculate the estimated avoided energy cost.

ESTIMATED FIRM ENERGY COST

The estimated avoided fuel costs listed below are associated with the Company's Avoided Unit and are based on current estimates of the delivered price of coal to the St. Johns River Power Park coal-fired units.

<u>\$/MMBTU</u>									
<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>	<u>2001</u>	<u>2002</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>
1.54	1.53	1.56	1.60	1.65	1.64	1.72	1.77	1.83	1.90

DELIVERY VOLTAGE ADJUSTMENT

Energy payments to the QFs within the Company's service territory shall be adjusted according to the delivery voltage by the following multipliers:

<u>Delivery Voltage</u>	<u>Adjustment Factor</u>
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0253
Secondary Voltage Delivery	1.0429

(Continued on Sheet No. 10.205)

(Continued from Sheet No. 10.102)

Customer Rate Schedule	Charge(\$)	Customer Rate Schedule	Charge(\$)
GS-1	9.00	CST-1	110.00
GST-1	12.30	GSLD-2	170.00
GSD-1	35.00	GSLDT-2	170.00
GSDT-1	41.50	CS-2	170.00
RS-1	5.65	CST-2	170.00
RST-1	8.95	GSLD-3	400.00
GSLD-1	41.00	CS-3	400.00
GSLDT-1	41.00	CST-3	400.00
CS-1	110.00	GSLDT-3	400.00

B. Interconnection Charge for Non-Variable Utility Expenses:

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

C. Interconnection Charge for Variable Utility Expenses:

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

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

<u>Equipment Type</u>	<u>Charge</u>
Metering Equipment	0.265%
Distribution Equipment	0.369%
Transmission Equipment	0.212%

D. Taxes and Assessments

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

TERMS OF SERVICE

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

(Continued on Sheet No. 10.104)

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

For informational purposes only, the estimated incremental As-Available Energy costs for the next four semi-annual periods are as follows. In addition, As-Available Energy cost payments will include .010¢/KWH for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
October 1, 1994 - March 31, 1995	2.19	1.96	2.02
April 1, 1995 - September 30, 1995	2.57	2.12	2.24
October 1, 1995 - March 31, 1996	2.36	2.12	2.18
April 1, 1996 - September 30, 1996	2.66	2.23	2.35

A MW block size ranging from 76 MW to 104 MW has been used to calculate the estimated As-Available Energy cost.

DELIVERY VOLTAGE ADJUSTMENT

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

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0253
Secondary Voltage Delivery	1.0429

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

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

Year	Generation by Fuel Type (%)						Price by Fuel Type (\$/MMBTU)				
	Nuclear	Oil	Gas	Coal	Purchased Power	Ort*	Nuclear	Oil	Gas	Coal	Ort*
1994	25	22.3	21.4	7.5	23.8		.56	3.10	2.60	1.78	
1995	25.5	19.4	24.6	8.2	22.2		.52	3.54	2.78	1.74	
1996	23.4	13.3	29.3	8.3	25.7		.48	3.79	2.90	1.79	
1997	22.5	13.9	28.4	7.9	27.1		.45	3.98	3.03	1.83	
1998	21.5	9.0	26.0	8.1	24.9	10.3	.46	4.18	3.17	1.84	1.61
1999	21.7	9.5	24.8	7.3	25.1	11.5	.47	4.50	3.62	1.85	1.66
2000	21.6	9.8	24.8	7.7	24.8	11.3	.47	4.77	3.70	1.96	1.68
2001	22.2	10.5	23.8	7.6	24.8	11.1	.47	5.14	4.05	1.98	1.74
2002	20.6	12.2	24.5	7.3	24.5	10.9	.47	5.53	4.44	2.03	1.78
2003	20.4	8.9	24.2	13.3	22.4	10.7	.47	5.94	4.86	2.22	1.81

*Orimulsion

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

(Continued on Sheet No. 10.102)

(Continued from Sheet No. 10.205)

B. Interconnection Charge for Non-Variable Utility Expenses

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

C. Interconnection Charge for Variable Utility Expenses

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

In lieu of payment for actual charges, the QF may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities. The applicable percentages are as follows:

<u>Equipment Type</u>	<u>Charge</u>
Metering Equipment	0.265%
Distribution Equipment	0.369%
Transmission Equipment	0.212%

D. Taxes and Assessments

In the event that FPL becomes liable for additional taxes, including interest and/or penalties arising from the Internal Revenue Service's determination, through audit, ruling or other authority, that FPL's early, levelized or early levelized capacity payments to the QF are not fully deductible when paid (additional tax liability), FPL may bill the QF monthly for the costs, including carrying charges, interest and/or penalties, associated with the fact that all or a portion of these early, levelized or early levelized capacity payments are not currently deductible for federal and/or state income tax purposes. FPL, at its option, may offset these costs against amounts due the QF hereunder. These costs would be calculated so as to place FPL in the same economic position in which it would have been if the entire early, levelized or early levelized capacity payments had been deductible in the period in which the payments were made. If FPL decides to appeal the Internal Revenue Service's determination, the decision as to whether the appeal should be made through the administrative or judicial process or both, and all subsequent decisions pertaining to the appeal (both substantive and procedural), shall rest exclusively with FPL.

TERMS OF SERVICE

- (1) It shall be the QF's responsibility to inform the Company of any change in its electric generation capability.
- (2) Any electric service delivered by the Company to a QF located in the Company's service area shall be subject to the following terms and conditions:
 - (a) A QF shall be metered separately and billed under the applicable retail rate schedule, whose terms and conditions shall pertain.
 - (b) A security deposit will be required in accordance with FPSC Rules 25-17.082(5) and 25-6.097, F.A.C., and the following:
 - (i) In the first year of operation, the security deposit should be based upon the singular month in which the QF's projected purchases from the Company exceed, by the greatest amount, the Company's estimated purchases from the QF. The security deposit should be equal to twice the amount of the difference estimated for that month. The deposit is required upon interconnection.
 - (ii) For each year thereafter, a review of the actual sales and purchases between the QF and the Company will be conducted to determine the actual month of maximum difference. The security deposit should be adjusted to equal twice the greatest amount by which the actual monthly purchases by the QF exceed the actual sales to the Company in that month.

(Continued on Sheet No. 10.207)

**APPENDIX III
FUEL COST RECOVERY
ESTIMATED/ACTUAL PERIOD**

**BTB - 6
DOCKET NO 940001-EI
FPL WITNESS: B.T. BIRKETT
EXHIBIT _____
PAGES 1-53
JUNE 27, 1994**

**APPENDIX III
FUEL COST RECOVERY
ESTIMATED/ACTUAL PERIOD**

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FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF THE ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1994

LINE NO.	(a) ACTUAL APRIL	(b) ACTUAL MAY	(c) ESTIMATED JUNE	(d) ESTIMATED JULY	(e) ESTIMATED AUGUST	(f) ESTIMATED SEPTEMBER	(g) TOTAL PERIOD
A1 FUEL COST OF SYSTEM GENERATION	\$88,758,294	\$91,648,916	\$84,883,200	\$93,828,889	\$98,583,382	\$96,791,294	\$554,303,775
1a NUCLEAR FUEL DISPOSAL	1,000,804	1,483,358	1,648,364	1,691,813	1,748,631	1,756,908	9,307,864
1b COAL CARBON DEPRECIATION & RETURN	39,592	39,331	39,164	38,921	38,688	38,456	234,142
1c OIL FUEL DEPRECIATION & RETURN	0	0	0	0	0	0	0
1d GAS PIPELINES DEPRECIATION & RETURN	345,932	344,373	342,807	341,245	339,683	338,121	2,052,160
1e DOE DECONTAMINATION & DECOMMISSIONING COSTS	0	5,102,910	0	0	0	0	5,102,910
2 FUEL COST OF POWER SOLD	(4,698,809)	(5,622,784)	(2,461,102)	(3,963,530)	(3,870,894)	(4,006,174)	(24,621,093)
3 FUEL COST OF PURCHASED POWER	18,405,501	15,998,584	17,807,659	17,728,289	19,134,824	19,509,903	106,580,560
3a DEMAND & NONFUEL COST OF PURCHASED POWER	0	0	0	0	0	0	0
3b ENERGY PAYMENTS TO QUALIFYING FACILITIES	7,163,972	3,885,144	6,557,159	7,016,102	7,305,159	7,406,777	39,134,313
4 ENERGY COST OF ECONOMY PURCHASES	375,349	1,444,886	1,318,360	1,409,190	1,710,200	1,819,990	8,077,975
6 ADJUSTMENTS (a)	(1,432,344)	(1,477,089)	(1,387,695)	(1,556,520)	(1,676,358)	(1,660,752)	(9,190,758)
7 TOTAL FUEL & NET POWER TRANSACTIONS	\$107,960,289	\$112,525,627	\$108,855,896	\$116,332,199	\$123,313,315	\$121,994,521	\$690,981,847
(SUM OF LINES A1 THRU A6)							
C1 JURISDICTIONAL kWh SALES	5,637,907,164	5,876,127,271	6,238,083,000	7,036,658,000	7,344,201,000	7,166,318,000	39,299,294,425
2 SALES FOR RESALE kWh(b)	28,881,877	31,484,308	12,747,000	27,499,000	35,579,000	41,396,000	175,566,985
3 TOTAL kWh SALES (LINES C1 + C2)	5,664,788,831	5,907,591,579	6,250,830,000	7,064,157,000	7,379,780,000	7,207,714,000	39,474,861,410
4 JURISDICTIONAL % OF TOTAL SALES (LINE C1/C3)	99.52546%	99.46739%	99.79908%	99.81072%	99.51789%	99.42587%	n/a
D1 JURISDICTIONAL FUEL RECOVERY REVENUES (NET OF REVENUE TAXES)	\$83,251,811	\$85,999,147	\$91,363,014	\$103,047,999	\$107,551,454	\$104,946,463	\$575,919,558
2a TRUE-UP PROVISION	23,987,419	23,987,419	23,987,419	23,987,419	23,987,419	23,987,419	\$143,804,515
2b INCENTIVE PROVISION (NET)	(143,015)	(143,015)	(143,015)	(143,015)	(143,015)	(143,015)	(\$858,088)
3 FUEL REVENUE APPLICABLE TO PERIOD (LINE D1 THROUGH D2b)	\$106,879,216	\$108,793,652	\$116,177,418	\$128,872,074	\$131,375,858	\$128,770,867	\$718,865,985
4a NUCLEAR FUEL EXPENSE-100% RETAIL	185,716	220,845	0	0	0	0	386,360
4b DOE DISPOSAL COSTS CREDIT & D&D FUND COSTS	0	5,102,910	0	0	0	0	5,102,910
4c FUEL & NET POWER TRANSACTIONS, EXCL. 100% RETAIL NUCLEAR FUEL (Ln A7 - Ln 4a - Ln 4b)	107,794,574	107,202,073	108,855,896	116,332,189	123,313,315	121,994,521	685,492,578
6 JURISDICTIONAL FUEL COSTS (D4b x C4 x 1.00036(c)) ÷ D4a	107,488,310	111,981,879	108,671,839	116,019,899	122,761,761	121,336,323	688,168,211
7 TRUE-UP PROVISION THIS PERIOD - OVER(UNDER) RECOVERY	(9610,094)	(\$2,186,428)	\$8,605,479	\$10,852,175	\$8,814,067	\$7,434,544	\$30,887,773
8 INTEREST PROVISION THIS PERIOD (d)	422,456	365,241	319,841	262,828	212,044	154,888	1,754,095
9 TRUE-UP & INTEREST PROVISION BEGINNING OF PERIOD - OVER(UNDER) RECOVERY	143,804,515	119,649,456	\$3,968,651	78,723,751	\$3,871,133	48,829,854	143,804,515
9a DEFERRED TRUE-UP - OVER(UNDER) RECOVERY	2,066,794	2,066,794	2,066,794	2,066,794	2,066,794	2,066,794	2,066,794
10 PRIOR PERIOD TRUE-UP PROVISION- COLLECTED(REFUNDED) THIS PERIOD	(23,987,419)	(23,987,419)	(23,987,419)	(23,987,419)	(23,987,419)	(23,987,419)	(143,804,515)
11 END OF PERIOD NET TRUE-UP AMOUNT - OVER(UNDER) RECOVERY (LINES D7...D10)	\$121,719,250	\$96,635,645	\$78,780,546	\$86,037,827	\$50,898,648	\$34,518,662	\$34,518,662

(a) Includes the fuel costs of sales to Florida Keys Electric Coop. (FKEC), and the City of Key West (CKW).

(b) The Sales for Resale kWh in Line C2, exclude the kWh sales to FKEC and CKW.

(c) Jurisdictional Loss Multiplier.

(d) Interest Provision for the month of May 1994, includes an adjustment of \$11,358, retroactive to July 1993, due to correction of an error.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL VARIANCES
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1994

LINE NO.	(1) Estimated/ Actual	(2) Original Estimates (b)	(3) Variance	(4) Percentage Change
A1 FUEL COST OF SYSTEM GENERATION	\$554,303,775	\$582,387,820	(\$28,083,845)	-1.44%
1a NUCLEAR FUEL DISPOSAL	9,307,884	9,485,082	(187,228)	-1.87%
1b COAL CAR INVESTMENT	234,142	184,738	39,406	20.24%
1c CRIMULSION	0	0	0	n/a
1d GAS LATERALS ENHANCEMENTS	2,062,180	1,718,884	333,298	18.39%
1e DOE DECONTAMINATION & DECOMMISSIONING	5,102,910	4,380,000	722,910	n/a
2 FUEL COST OF POWER SOLD	(24,821,083)	(24,809,678)	188,588	-0.78%
3 FUEL COST OF PURCHASED POWER	106,580,580	117,022,809	(10,442,049)	-8.82%
3a DEMAND & NONFUEL COST OF PURCHASED POWER	0	0	0	n/a
3b ENERGY PAYMENTS TO QUALIFYING FACILITIES	39,134,313	40,223,285	(1,088,862)	-2.71%
4 ENERGY COST OF ECONOMY PURCHASES	8,077,975	245,270	7,832,705	3193.50%
5 ADJUSTMENTS (a)	(9,190,758)	(8,763,525)	(427,233)	4.88%
7 TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A1 THRU A5)	\$590,981,847	\$702,094,252	(\$11,112,405)	-1.58%
C1 JURISDICTIONAL kWh SALES	39,299,294,425	38,036,086,000	1,263,208,425	3.32%
2 SALES FOR RESALE kWh	175,586,985	133,411,000	42,155,885	31.60%
3 TOTAL kWh SALES (LINES C1 + C2)	39,474,881,410	38,169,497,000	1,305,384,410	3.42%
4 JURISDICTIONAL % OF TOTAL SALES (LINE C1/C3)	n/a	n/a	n/a	n/a
D1 JURISDICTIONAL FUEL RECOVERY REVENUES (NET OF REVENUE TAXES)	\$575,919,668	\$559,147,825	\$16,771,733	3.00%
2a TRUE-UP PROVISION	143,804,515	143,804,515	0	0.00%
2b INCENTIVE PROVISION (NET)	(858,088)	(858,088)	0	0.00%
3 FUEL REVENUE APPLICABLE TO PERIOD (LINE D1 THROUGH D2b)	718,865,885	702,084,252	16,771,733	2.39%
4a NUCLEAR FUEL EXPENSE-100% RETAIL	\$388,380	n/a	n/a	n/a
4b DOE DISPOSAL COSTS CREDIT & D&D FUND COST	5,102,910	4,380,000	722,910	16.50%
4c FUEL & NET POWER TRANSACTIONS, EXCL. 100% RETAIL NUCLEAR FUEL TRANSACTIONS 4a & 4b	685,492,578	697,714,252	(12,221,674)	-1.75%
6 JURISDICTIONAL FUEL COSTS	\$688,168,211	\$702,084,252	(\$13,926,041)	-1.98%
7 TRUE-UP PROVISION THIS PERIOD - OVER(UNDER) RECOVERY	\$30,897,773	\$0	\$30,897,773	n/a
8 INTEREST PROVISION THIS PERIOD	1,754,085	0	1,754,085	n/a
9 TRUE-UP & INTEREST PROVISION BEGINNING OF PERIOD - OVER(UNDER) RECOVERY	143,804,515	143,804,515	0	0.00%
9a DEFERRED TRUE-UP - OVER(UNDER) RECOVERY	2,088,784	0	2,088,784	n/a
10 PRIOR PERIOD TRUE-UP PROVISION- COLLECTED(REFUNDED) THIS PERIOD	(143,804,515)	(143,804,515)	0	0.00%
11 END OF PERIOD NET TRUE-UP AMOUNT - OVER(UNDER) RECOVERY (LINES D7...D10)	\$34,518,862	\$0	\$34,518,862	n/a

NOTES:

(a) Includes the fuel costs of sales to Florida Keys Electric Corp. (FKEC), and the City of Key West (CKW), and DOE's Disposal Cost Credits.

(b) As approved at the March 1994 hearing. Per B. T. Birkett's Supplemental Testimony, revised Schedule E2.

**FLORIDA POWER & LIGHT COMPANY
ESTIMATED/ACTUAL VARIANCE ANALYSIS
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1984**

LINE NO.	FUEL COST OF SYSTEM GENERATION AND NET POWER TRANSACTIONS	REFERENCE (a)	VARIANCE (MILLIONS OF DOLLARS)		
1	Heavy Oil				
2	Variance in generation of 1,959,194 MWH times				
3	originally projected cost \$22.198/MWH	(1)	\$43.5		
4	Estimated/Actual generation of 14,518,719 MWH				
5	times variance in costs (\$1.642/MWH)	(2)	(23.8)	\$19.7	
6					
7	Light Oil				
8	Variance in generation of (26,378) times				
9	originally projected cost \$59.310/MWH	(3)	(1.6)		
10	Estimated/Actual generation of 13,787 MWH				
11	times variance in costs \$8.801/MWH		0.1	(1.5)	
12					
13	Coal				
14	Variance in generation of (80,619) MWH times				
15	originally projected cost \$16.507/MWH	(4)	(1.3)		
16	Estimated/Actual generation of 2,998,098 MWH				
17	times variance in costs (\$0.015/MWH)		0.0	(1.3)	
18					
19	Gas				
20	Variance in generation of 381,930 MWH times				
21	originally projected cost \$20.093/MWH	(5)	7.7		
22	Estimated/Actual generation of 9,091,935 MWH				
23	times variance in costs (\$3.534/MWH)	(6)	(32.1)	(24.4)	
24					
25	Nuclear				
26	Variance in generation of (216,209) MWH times				
27	originally projected cost \$5.366/MWH		(1.2)		
28	Estimated/Actual generation of 10,123,648 MWH				
29	times variance in costs \$0.070/MWH		0.7	(0.5)	(\$8.0)
30					
31					
32	Fuel Cost of Power Sold			0.2	
33	Fuel Cost of Purchased Power	(7)		(10.4)	
34	Payments to Qualifying Facilities	(8)		(1.1)	
35	Energy Cost of Economy Purchases	(9)		7.8	(3.5)
36					
37					
38	Nuclear Fuel Disposal Costs				(0.2)
39					
40	DOE's Decontamination & Decommissioning Costs				0.7
41					
42	Miscellaneous				(0.1)
43					
44	TOTAL FUEL COST OF SYSTEM GENERATION & NET POWER TRANSACTIONS				<u>(\$11.1)</u>

(a) Refer to page 6 of this appendix for an explanation of the variances

NOTE: Total may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
EXPLANATION OF TOTAL SYSTEM FUEL COSTS VARIANCES
ESTIMATED/ACTUAL TRUE-UP
FOR THE PERIOD APRIL 1994 THROUGH SEPTEMBER 1994

Ref. Variance Explanations:

1. Generation from heavy fuel oil was higher than originally projected. This was a result of higher than projected system load and a lower than projected heavy oil price.
2. The originally projected average unit cost of heavy oil generation for the six month period was \$22.198/MWH and the updated estimated average unit cost is \$20.556/MWH. This 7.4% decrease in the average unit cost of heavy oil is primarily due to lower than expected growth in petroleum product demand.
3. Fossil fuel generation by light oil was lower than projected due to lower than projected generation by the Ft. Myers Gas Turbine Units. This resulted from the increased availability of more efficient units.
4. The generation by coal is lower than originally projected. This is a result of lower than projected generation from Scherer Unit 4 due to the decreases in cost of heavy oil generation.
5. Fossil fuel generation by gas was lower than originally projected. The availability of the efficient combined cycle units was responsible for the increase in generation by gas.
6. The originally projected average unit cost of natural gas generation for the six month period was \$20.099/MWH and the updated estimated average unit cost is \$16.565/MWH. This 17.6% decrease in the average unit cost of natural gas was primarily due to lower than projected heavy oil prices and a change in the mix of units run on natural gas to more efficient units.
7. The decrease in the cost of purchased power is primarily attributable to lower than projected oil and gas costs combined with the high availability of FPL's more efficient units making FPL's generation more economical. Purchases from Southern were approximately 500,000 MWHs less than originally projected for April and May 1994.
8. Energy Payments to Qualifying Facilities was lower than originally projected due to lower than projected energy deliveries from Cedar Bay.
9. Due to economy energy prices being lower than originally estimated and their favorable comparison to the cost of other FPL sources of energy, economy purchases are higher than originally estimated.

A-SCHEDULES

MAY 1994

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH OF APRIL 1994 THRU MAY 1994

SCHEDULE A1

	DOLLARS				MWH				KWH			
	ACTUAL	ESTIMATED	DIFFERENCE		ACTUAL	ESTIMATED	DIFFERENCE		ACTUAL	ESTIMATED	DIFFERENCE	
			AMOUNT	%			AMOUNT	%			AMOUNT	%
1 Fuel Cost of System Net Generation (A3)	180,307,211	146,462,838	34,864,372	24.0	11,897,387	9,206,304	2,391,063	26.0	1,8647	1,8798	(0.0202)	(1.0)
2 Nuclear Fuel Disposal Costs (A13)	2,464,161	2,472,868	(8,707)	(0.4)	2,671,068	2,682,876	(21,808)	(0.8)	0.0923	0.0919	0.0004	0.8
3 Coal Car Investment	78,923	85,564	13,369	20.4	0	0	0	NA	0.0000	0.0000	0.0000	NA
3a DOE Decontamination and Decommissioning Cost	5,102,910	4,380,000	722,910	16.5	0	0	0	NA	0.0000	0.0000	0.0000	NA
3b Gas Pipeline Enhancements	690,306	676,761	113,544	19.7	0	0	0	NA	0.0000	0.0000	0.0000	NA
4 Adjustments to Fuel Cost (A2, page 1)	(2,809,434)	(2,482,189)	(427,235)	17.2	0	0	0	NA	1.8016	1.8344	(0.0329)	(2.0)
5 TOTAL COST OF GENERATED POWER	185,734,076	150,466,823	35,268,253	23.4	11,897,387	9,206,304	2,391,063	26.0	1.8078	1.8348	(0.0270)	(1.5)
6 Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	32,402,085	42,312,819	(9,910,734)	(23.4)	1,782,208	2,306,166	(613,958)	(22.3)	1.7118	2.1471	(0.4353)	(20.2)
7 Energy Cost of Sched C & X Econ Purch (Broker) (A9)	992,713	2,190	990,523	NA	67,892	102	67,790	NA	2.1618	0.0000	2.1618	NA
8 Energy Cost of Other Econ Purch (Non-Broker) (A9)	827,522	4,800	822,722	NA	38,468	0	38,468	NA	0.0000	0.0000	0.0000	NA
9 Energy Cost of Sched E Economy Purch (A9)	0	0	0	NA	0	0	0	NA	0.0000	0.0000	0.0000	NA
10 Capacity Cost of Sched E Economy Purches (A2)	0	0	0	NA	0	0	0	NA	1.7424	1.7763	(0.0339)	(1.9)
11 Energy Payments to Qualifying Facilities (A8a)	10,948,110	11,954,222	(1,106,108)	(9.2)	822,839	672,976	(50,337)	(7.5)	1.7947	1.8217	(0.0270)	(1.5)
12 TOTAL COST OF PURCHASED POWER	46,071,438	54,274,031	(8,202,695)	(17.0)	2,511,297	2,979,244	(467,947)	(16.7)				
13 TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					14,108,654	12,165,649	1,923,105	15.8	2.1848	2.4886	(0.3038)	(12.2)
14 Fuel Cost of Economy Sales (A7)	(7,630,766)	(2,498,213)	(5,132,543)	208.4	(349,302)	(100,390)	(248,912)	247.9	0.8108	0.4810	0.0188	4.0
15 Gain on Economy Sales (A7a)	(1,784,380)	(492,938)	(1,291,461)	282.0	(349,302)	(100,390)	(248,912)	247.9	0.6489	0.8400	0.1098	20.2
16 Fuel Cost of Unit Power Sales (SL2 Perpts) (A7)	(617,187)	(471,696)	(45,492)	9.8	(79,706)	(87,351)	7,646	(8.8)	2.4778	0.0000	2.4778	NA
17 Fuel Cost of Other Power Sales (A7)	(387,260)	0	(387,260)	NA	(15,629)	0	(15,629)	NA	2.3208	1.8448	0.4764	26.8
18 TOTAL FUEL COST AND GAINS OF POWER SALES	(10,319,593)	(3,462,847)	(6,856,746)	189.0	(444,636)	(187,741)	(256,895)	136.8				
19 Net Inadvertent Interchange (A10)	0	0	0	-	0	0	0	NA	1.8138	1.8778	(0.0640)	(3.8)
20 ADJUSTED TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	220,486,917	201,277,007	19,208,910	9.5	13,664,018	11,997,807	1,666,211	13.9	0.4818	0.8166	(0.1338)	(21.7)
21 Net Unbilled Sales (A4)	66,781,108 *	63,862,763 *	(8,231,667)	(12.8)	3,465,076	3,813,960	(358,874)	(9.4)	0.0042	0.0066	(0.0018)	(26.9)
22 Company Use (A4)	801,023 *	603,819 *	(102,798)	(17.0)	31,050	36,993	(4,943)	(13.7)	(0.2163)	(0.3817)	0.1654	(43.6)
23 T & D Losses (A4)	(24,817,869) *	(39,668,433) *	14,748,677	(37.2)	(1,544,240)	(2,364,475)	820,235	(34.7)	1.8063	1.8388	(0.0313)	(1.8)
24 SYSTEM KWH SALES (EXCL FKEC & CKW A2,p2)	220,486,917	201,277,007	19,208,910	9.5	11,572,380,410	10,393,384,000	1,178,016,410	11.3	1.8063	1.8388	(0.0313)	(1.8)
25 Wholesale KWH Sales (EXCL FKEC & CKW A2,p2)	1,111,646	313,628	798,117	264.8	58,345,886	16,190,000	42,155,886	260.4	1.8063	1.8388	(0.0313)	(1.8)
26 Jurisdictional KWH Sales	218,374,271	200,963,478	18,410,793	9.2	11,514,034,426	10,377,174,000	1,136,860,426	11.0	1.8063	1.8388	(0.0313)	(1.8)
26a Jurisdictional Loss Multiplier									1.00036	1.00036	0.0000	-
27 Jurisdictional KWH Sales Adjusted for Line Losses	218,461,062	201,033,816	18,417,237	9.2	11,514,034,426	10,377,174,000	1,136,860,426	11.0	1.8063	1.8373	(0.0310)	(1.8)
28 TRUE-UP **	(47,934,838)	(47,934,838)	0	0.0	11,514,034,426	10,377,174,000	1,136,860,426	11.0	(0.4163)	(0.4819)	0.0656	(19.5)
29 TOTAL JURISDICTIONAL FUEL COST	171,816,214	153,098,977	18,417,237	12.0	11,514,034,426	10,377,174,000	1,136,860,426	11.0	1.4888	1.4784	0.0142	1.0
30 Revenue Tax Factor									1.01008	1.01008	0.0000	-
31 Fuel Factor Adjusted for Taxes									1.8126	1.8881	0.0148	1.0
32 GPF **	290,932	290,832	0	0.0	11,514,034,426	10,377,174,000	1,136,860,426	11.0	0.0026	0.0028	(0.0003)	(10.7)
33 Fuel Factor Adjusted for Taxes									1.8181	1.8818	0.0142	0.8
34 FUEL PAC ROUNDED TO NEAREST .001 CENT/KWH									1.818	1.882	0.014	0.8

* For Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
MONTH OF: MAY 1994

	DOLLARS				MWH				MWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 Fuel Cost of System Net Generation (A3)	91,640,916	79,309,488	16,242,450	21.6	6,005,064	4,823,738	1,181,326	24.5	1.8248	1.6612	(0.0267)	(2.4)
2 Nuclear Fuel Disposal Costs (A13)	1,483,366	1,393,236	71,120	5.1	1,590,890	1,516,101	74,789	4.9	0.0920	0.0918	0.0002	0.2
3 Coal Car Investment	38,331	32,697	6,634	20.3	0	0	0	NA	0.0000	0.0000	0.0000	NA
3a DOE Decontamination and Decommissioning Cost	5,102,910	0	5,102,910	NA	0	0	0	NA	0.0000	0.0000	0.0000	NA
3b Gas Pipeline Enhancements	344,373	297,905	56,468	19.8	0	0	0	NA	0.0000	0.0000	0.0000	NA
4 Adjustments to Fuel Cost (A2, page 1)	(1,477,099)	(1,288,376)	(208,711)	16.8	0	0	0	NA	0.0000	0.0000	0.0000	NA
5 TOTAL COST OF GENERATED POWER	97,021,797	79,760,928	21,270,871	28.1	6,005,064	4,823,738	1,181,326	24.5	1.8187	1.6704	0.0463	2.9
6 Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	16,896,684	21,464,901	(5,467,917)	(26.4)	1,056,136	1,180,737	(124,602)	(10.8)	1.8168	1.8170	(0.0024)	(0.0)
7 Energy Cost of Sched C & X Econ Purch (Broker) (A9)	763,621	0	763,621	NA	44,295	0	44,295	NA	1.7014	0.0000	1.7014	NA
8 Energy Cost of Other Econ Purch (Non-Broker) (A9)	891,200	4,800	886,465	NA	30,125	0	30,125	NA	2.2947	0.0000	2.2947	NA
9 Energy Cost of Sched E Economy Purch (A9)	0	0	0	NA	0	0	0	NA	0.0000	0.0000	0.0000	NA
10 Capacity Cost of Sched E Economy Purchases (A2)	0	0	0	NA	0	0	0	NA	0.0000	0.0000	0.0000	NA
11 Energy Payments to Qualifying Facilities (A8a)	3,686,144	6,132,011	(1,446,867)	(28.2)	209,717	287,558	(77,839)	(27.1)	1.7672	1.7847	(0.0275)	(1.6)
12 TOTAL COST OF PURCHASED POWER	21,126,014	28,691,312	(5,464,698)	(20.6)	1,340,272	1,468,293	(128,021)	(8.7)	1.6783	1.8110	(0.2347)	(13.0)
13 TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					7,346,336	6,292,031	1,053,305	16.7				
14 Fuel Cost of Economy Sales (A7)	(4,360,706)	(809,973)	(3,550,732)	439.4	(209,776)	(30,915)	(178,860)	578.6	2.0788	2.8200	(0.8412)	(30.7)
15 Gain on Economy Sales (A7a)	(847,269)	(112,281)	(734,975)	743.6	(209,776)	(30,915)	(178,860)	578.6	0.4618	0.3832	0.0784	24.3
16 Fuel Cost of Unit Power Sales (SL2 Perpts) (A7)	(271,113)	(238,081)	(33,022)	13.9	(42,949)	(44,091)	1,142	(2.6)	0.8312	0.6400	0.0812	18.9
17 Fuel Cost of Other Power Sales (A7)	(43,710)	0	(43,710)	NA	(931)	0	(931)	NA	4.8960	0.0000	4.8960	NA
18 TOTAL FUEL COST AND GAINS OF POWER SALES	(5,622,784)	(1,160,346)	(4,462,439)	384.6	(253,655)	(76,006)	(178,649)	238.2	2.2167	1.5470	0.6697	43.3
19 Net Inadvertent Interchange (A10)	0	0	-	-	0	0	0	NA				
20 ADJUSTED TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	112,625,627	101,181,893	11,343,734	11.2	7,091,681	6,217,025	874,656	14.1	1.5887	1.8278	(0.0490)	(2.8)
21 Net Unbilled Sales (A4)	7,444,320 *	7,833,284 *	(188,964)	(2.5)	469,170	469,019	151	0.0	0.1280	0.1462	(0.0202)	(13.8)
22 Company Use (A4)	246,870 *	303,646 *	(57,676)	(19.0)	16,502	18,651	(3,149)	(19.0)	0.0042	0.0096	(0.0016)	(27.6)
23 T & D Losses (A4)	9,980,273 *	7,296,097 *	2,675,176	35.3	621,433	447,625	173,808	39.0	0.1689	0.1386	0.0274	19.8
24 SYSTEM KWH SALES (EXCL FKEC & CKW A2,p2)	112,626,627	101,181,893	11,343,734	11.2	5,907,581,579	5,220,935,000	686,656,579	13.2	1.8048	1.9380	(0.0332)	(1.7)
25 Wholesale KWH Sales (EXCL FKEC & CKW A2,p2)	699,323	187,446	431,877	267.9	31,464,308	8,640,000	22,824,308	284.2	1.8048	1.8380	(0.0332)	(1.7)
26 Jurisdictional KWH Sales	111,929,304	101,014,447	10,911,857	10.8	5,876,127,271	5,212,295,000	663,832,271	12.7	1.8048	1.9380	(0.0332)	(1.7)
26a Jurisdictional Loss Multiplier	-	-	-	-	-	-	-	-	1.00038	1.00035	0	-
27 Jurisdictional KWH Sales Adjusted for Line Losses	111,906,478	101,040,802	10,816,676	10.8	5,876,127,271	5,212,295,000	663,832,271	12.7	1.8064	1.9387	(0.0333)	(1.7)
28 TRUE-UP **	(23,967,419)	(23,967,419)	0	0.0	5,876,127,271	5,212,295,000	663,832,271	12.7	(0.4078)	(0.4598)	0.0518	(11.3)
29 TOTAL JURISDICTIONAL FUEL COST	87,999,089	77,092,383	10,816,676	14.2	5,876,127,271	5,212,295,000	663,832,271	12.7	1.4876	1.4789	0.0188	1.3
30 Revenue Tax Factor									1.01609	1.01608	0	-
31 Fuel Factor Adjusted for Taxes									1.5218	1.5027	0.0189	1.3
32 GPIF **	146,316	146,316	0	0.0	5,876,127,271	5,212,295,000	663,832,271	12.7	0.0026	0.0029	(0.0003)	(10.7)
33 Fuel Factor Including GPIF									1.5241	1.5056	0.0185	1.2
34 FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH									1.524	1.506	0.018	1.2

* For Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

Company: Florida Power & Light Company

Schedule A1a

**RECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1**

Month of May, 1994

<u>LINE</u>	<u>DESCRIPTION</u>	<u>REFERENCE</u>	<u>AMOUNT</u>
1	Fuel Cost of System Net Generation	Schedule A-3 Line 7	\$91,548,916
2	Nuclear Fuel Disposal Costs	Schedule A-2 Line A1c	1,463,356
3	Coal Car Investment	Schedule A-2 Line A1b	39,331
3a	DOE Decontamination and Decommissioning Cost	Schedule A-2 Line A1e	5,102,910
3b	Gas Pipeline Enhancements	Schedule A-2 Line A1d	344,373
4	Adjustments to Fuel Cost	Schedule A-2 Line A-6	(1,477,089)
6	Fuel Cost of Purchased Power	Schedule A-8 Col. 8	15,996,584
7+8+9	Energy Costs of Economy Purchases	Schedule A-9 Col. 5	1,444,886
11	Energy Payments to Qualifying Facilities	Schedule A-8a Col. 8	3,685,144
18	Fuel Cost of Power Sold	Schedule A-7 Col. 7	(5,622,784)
20	Total Fuel and Net Power Transactions		<u>\$112,525,627</u>

CALCULATION OF TRUE-UP AND INTEREST PROVISION

SCHEDULE A2

Page 1 of 4

Company: Florida Power & Light Company

Month of: MAY 1994

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
A. Fuel Costs & Net Power Transactions	\$	\$	\$		\$	\$	\$	
1. Fuel Cost of System Net Generation	91,548,916	76,306,466	16,242,450	21.6	180,307,210	145,452,839	34,854,371	24.0
1a. Nuclear Fuel Disposal Costs	1,463,356	1,392,236	71,120	5.1	2,464,160	2,472,868	(8,708)	(0.4)
1b. Coal Cans Depreciation & Return	39,331	32,697	6,634	20.3	78,923	65,554	13,369	20.4
1c. Orlimulsion	0	0	0	N/A	0	0	0	N/A
1d. Gas Pipelines Depreciation & Return	344,373	287,805	56,468	19.6	690,304	576,761	113,543	19.7
1e. DOE Decontamination & Decommissioning Fund Payment	5,102,910	0	5,102,910	N/A	5,102,910	4,380,000	722,910	16.5
2. Fuel Cost of Power Sold	(5,822,784)	(1,180,345)	(4,462,439)	384.6	(10,319,593)	(3,462,847)	(6,856,746)	198.0
3. Fuel Cost of Purchased Power	15,993,584	21,454,601	(5,457,917)	(25.4)	32,402,065	42,312,819	(9,910,734)	(23.4)
3a. Demand & Non Fuel Cost of Purchased Power	0	0	0	N/A	0	0	0	N/A
3b. Energy Payments to Qualifying Facilities	3,685,144	5,132,011	(1,446,867)	(28.2)	10,849,116	11,954,222	(1,105,106)	(9.2)
4. Energy Cost of Economy Purchases	1,444,886	4,800	1,440,086	—	1,820,235	6,990	1,813,245	—
5. Total Fuel Costs & Net Power Transactions	114,002,715	102,450,271	11,552,444	11.3	223,385,349	203,759,206	19,636,143	9.6
6. Adjustments to Fuel Cost: (Detailed below)								
Fuel Cost of Sales to Other FERC Customers *	(1,531,225)	(1,268,378)	(262,847)	N/A	(2,624,665)	(2,482,199)	(442,466)	17.8
Inventory Adjustments	19,005	0	19,005	N/A	21,381	0	21,381	N/A
Non Recoverable Oil	35,131	0	35,131	N/A	(6,149)	0	(6,149)	N/A
DOE - Nuclear Fuel Disposal Costs - Credit	0	0	0	N/A	0	0	0	N/A
7. Adjusted Total Fuel Costs & Net Power Transactions	\$ 112,525,627	\$ 101,181,893	\$ 11,343,734	11.2	\$ 220,465,910	\$ 201,277,007	\$ 19,208,909	9.5

* The other FERC customers are Florida Keys Electric Cooperative (FKEC) and the City of Key West (CKW)

CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: Florida Power & Light Company

Month of: MAY 1994

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
B. Sales Revenues (Excludes Franchise Fees)								
1. Jurisdictional Sales Revenues								
a. Base Fuel Revenues	\$ 0	\$ 0	\$ 0	—	\$ 0	\$ 0	\$ 0	—
b. Fuel Recovery Revenues (Excludes Revenue Taxes)	85,989,147	76,330,959	9,638,188	12.6	169,020,958	161,887,539	17,053,419	11.2
c. Jurisdictional Fuel Revenues	85,989,147	76,330,959	9,638,188	12.6	169,020,958	161,887,539	17,053,419	11.2
d. Non Fuel Revenues	256,791,017	227,781,088	29,009,951	12.7	494,866,369	227,781,088	267,085,303	117.3
e. Total Jurisdictional Sales Revenues	342,780,164	304,112,025	38,648,139	12.7	663,887,328	379,748,606	284,138,722	74.8
2. Non Jurisdictional Sales Revenues	5,244,970	3,327,448	1,917,521	57.8	10,354,350	3,327,448	7,026,902	211.2
3. Total Sales Revenues	348,005,134	307,439,473	40,565,661	13.2	674,241,678	383,076,053	291,165,624	76.0
C. kWh Sales								
1. Jurisdictional Sales kWh	5,876,127,271	5,212,285,000	663,832,271	12.7	11,514,034,425	10,377,174,000	1,136,860,425	11.0
2. Non Jurisdictional Sales (excluding FKEC & CKW)	31,464,308	8,640,000	22,824,308	264.2	58,345,985	16,190,000	42,155,985	260.4
3. Sales (excluding FKEC & CKW)	5,907,591,579	5,220,925,000	686,666,579	13.2	11,572,380,410	10,393,364,000	1,179,016,410	11.3
4. Non Jurisdictional Sales to Other FERC Customers	77,984,270	60,798,000	17,186,270	28.3	149,751,939	118,875,000	30,776,939	25.9
5. Total Sales	5,985,575,849	5,281,730,000	703,845,849	13.3	11,722,132,349	10,512,339,000	1,209,793,349	11.5
6. Jurisdictional Sales % of Total KWH Sales (lines C1/C3)	99.48739%	99.83451%	(0.38712)	(0.4)	99.49582%	99.84423%	(0.34841)	(0.3)

CALCULATION OF TRUE-UP AND INTEREST PROVISION

EXHIBIT A2

Page 3 of 4

Company: Florida Power & Light Company

Month of: MAY 1994

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. True-up Calculation								
1. Jurisdictional Fuel Revenues (line B-1c)	\$ 85,969,147	\$ 78,330,868	\$ 9,638,188	12.6	\$ 169,020,958	\$ 151,967,539	\$ 17,053,419	11.2
2. Fuel Adjustment Revenues Not Applicable to Period								
a. True-up Provision	23,967,419	23,967,419	0	0.0	47,934,838	47,934,838	0	0.0
b. In-Period True-up	0	0	0	N/A	0	0	0	N/A
c. Incentive Provision, Net of Revenue Taxes (a)	(143,015)	(143,015)	0	0.0	(286,030)	(286,030)	0	0.0
3. Jurisdictional Fuel Revenues Applicable to Period	109,793,551	100,155,383	9,638,188	9.6	216,669,766	199,616,347	17,053,419	8.5
4. Adj Total Fuel Costs & Net Power Transaction (Line A-7)	112,525,627	101,181,803	11,343,734	11.2	220,485,916	201,277,007	19,208,909	9.5
a. Nuclear Fuel Expense - 100% Retail	220,645	0	220,645	N/A	386,360	0	386,360	N/A
b. DOE Disposal Costs Credit & D&D Fund Pymnt-100% Retail	5,102,910	0	5,102,910	N/A	5,102,910	4,380,000	722,910	16.5
c. Adjusted Total Fuel Costs & Net Power Transaction excluding 100% Retail Nuclear Fuel Expense, DOE Credit and payment to DOE for the D&D Fund (Lines D4a & D4b)	107,202,073	101,181,803	6,020,180	5.9	214,996,647	196,897,007	18,099,640	9.2
5. Jurisdictional Sales % of Total kWh Sales (Line C-6)	99.46739%	99.83451%	(0.36712)	(0.4)	N/A	N/A	N/A	N/A
6. Jurisdictional Total Fuel Costs & Power Transaction (Line D4c x D5 x 1.00035(b)) + (Line D4a) + (Line D4b)	111,991,979	101,049,802	10,942,177	10.8	219,478,286	201,038,652	18,439,636	9.2
7. True-up Provision for the Month Over/(Under) Collection (Line D3 - Line D6)	(2,198,428)	(894,436)	(1,303,989)	145.8	(2,808,522)	(1,422,305)	(1,386,217)	97.5
8. Interest Provision for the Month (Line E10) (c)	385,241	0	385,241	N/A	807,696	0	807,696	N/A
9. True-up & Interest Provision Beg. of Month	119,649,456	110,309,230	340,226	0.3	143,804,515	143,804,516	0	0.0
9a. Deferred True-up Beginning of Period	2,066,794	0	2,066,794	N/A	2,066,794	0	2,066,794	N/A
10. True-up Collected (Refunded)	(23,967,419)	(23,967,419)	0	0.0	(47,934,838)	(47,934,838)	0	0.0
11. End of Period - Net True-up - Over/(Under) Recovery (Lines D7 through D10)	\$ 95,935,645	\$ 84,447,372	\$ 1,488,273	1.6	\$ 95,935,645	\$ 84,447,372	\$ 1,488,273	1.6

(a) GPIF REWARD OF \$871,893 / 6 Mos. x 98.4167% Revenue Tax Factor = \$143,015

(b) Jurisdictional Loss Multiplier

(c) Adjusted to reflect an additional \$11,358, retroactive to July 1993, due to an overcharge.

CALCULATION OF TRUE-UP AND INTEREST PROVISION

Company: Florida Power & Light Company

Month of: MAY 1964

SCHEDULE A2

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[illegible]

MONTH OF: MAY 1994

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATE	AMOUNT	\$	ACTUAL	ESTIMATED	AMOUNT	\$
FUEL COST OF SYSTEM NET GENERATION (\$)								
1 • HEAVY OIL	52,664,340	30,880,787	21,783,553	70.5	111,047,304	65,129,188	45,918,116	70.5
2 • LIGHT OIL	58,996	95,676	(36,680)	(38.3)	119,865	153,304	(33,439)	(21.7)
3 COAL	6,974,235	7,207,800	(233,565)	(3.5)	12,548,710	14,783,370	(1,234,660)	(13.1)
4 GAS	22,853,044	28,979,908	(6,126,864)	(21.1)	40,975,278	50,874,446	(9,899,168)	(19.5)
5 NUCLEAR	9,036,601	8,142,295	894,306	11.0	15,316,153	14,512,331	803,822	5.1
6 OIL/NUCLEAR	0	0	0	0.0	0	0	0	0.0
7 TOTAL (\$)	91,548,616	75,306,466	16,242,150	21.6	180,307,210	145,451,839	34,855,371	24.0
SYSTEM NET GENERATION (MWH)								
8 HEAVY OIL	2,543,817	1,443,347	1,100,470	76.2	5,489,460	3,067,348	2,422,112	79.0
9 LIGHT OIL	446	1,547	(1,101)	(80.9)	1,108	2,482	(1,374)	(55.4)
10 COAL	406,872	441,884	(35,012)	(7.9)	767,607	897,321	(129,714)	(14.5)
11 GAS	1,443,859	1,439,878	4,081	3.0	2,688,317	2,546,673	1,212,344	4.8
12 NUCLEAR	1,980,890	1,516,101	464,789	4.9	2,671,068	2,692,876	(21,808)	(0.8)
13 OIL/NUCLEAR	0	0	0	0.0	0	0	0	0.0
14 TOTAL (MWH)	6,003,044	4,837,738	1,165,306	24.1	11,977,357	9,204,321	2,773,036	26.0
UNITS OF FUEL BURNED								
15 • HEAVY OIL (BBL)	3,946,352	2,309,587	1,736,765	78.6	8,464,966	4,702,727	3,762,239	80.0
16 • LIGHT OIL (BBL)	1,004	3,312	(1,408)	(42.5)	4,004	5,314	(1,310)	(24.7)
17 COAL (TON)	210,689	186,773	23,916	24.8	392,341	342,745	49,596	14.4
18 GAS (MMCF)	12,617,899	12,499,832	118,067	1.0	21,233,211	21,995,767	(762,556)	(3.5)
19 NUCLEAR (MMBTU)	17,874,881	17,072,743	802,138	4.7	30,035,873	30,358,478	(322,605)	(1.1)
20 OIL/NUCLEAR (TON)	0	0	0	0.0	0	0	0	0.0
BTU BURNED (MMBTU)								
21 HEAVY OIL	23,142,143	14,073,784	11,068,359	78.6	53,938,109	29,949,246	23,988,863	80.1
22 LIGHT OIL	11,691	19,212	(8,161)	(42.5)	23,232	30,826	(7,594)	(24.6)
23 COAL	4,873,673	4,199,632	(123,979)	(3.0)	7,584,309	8,528,611	(944,302)	(11.3)
24 GAS	12,617,899	12,499,832	118,067	1.0	21,233,211	21,995,766	(762,555)	(3.5)
25 NUCLEAR	17,874,881	17,072,743	802,138	4.7	30,035,873	30,358,478	(322,605)	(1.1)
26 OIL/NUCLEAR	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	59,721,617	47,864,423	11,857,194	24.8	112,799,954	90,862,925	21,937,029	24.1
GENERATION MIX (%MWH)								
28 HEAVY OIL	42.36	29.92	12.44	41.6	47.33	33.32	14.01	42.0
29 LIGHT OIL	0.01	0.03	(0.02)	(68.7)	0.01	0.03	(0.02)	(66.7)
30 COAL	6.77	9.16	(2.39)	(25.1)	6.62	9.75	(3.13)	(22.1)
31 GAS	24.36	29.46	(5.10)	(17.3)	23.01	27.86	(4.85)	(16.5)
32 NUCLEAR	26.49	31.43	(4.94)	(15.7)	23.83	29.25	(5.42)	(21.5)
33 OIL/NUCLEAR	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
34 TOTAL (%)	100.00	100.00	(0.00)	0.0	100.00	100.00	0.00	0.0
FUEL COST PER UNIT								
35 • HEAVY OIL (\$/MWH)	13.3450	13.9758	(0.6308)	(4.5)	13.1184	13.8492	(0.7308)	(5.3)
36 • LIGHT OIL (\$/MWH)	30.9853	28.8842	2.1011	7.3	29.9343	28.8867	1.0476	3.6
37 COAL (\$/TWH)	32.9122	42.7070	(9,7948)	(22.9)	32.7572	43.1323	(10,3751)	(24.1)
38 GAS (\$/MMCF)	1.8113	2.3186	(0.5073)	(21.9)	1.9298	2.3129	(0.3831)	(16.0)
39 NUCLEAR (\$/MMBTU)	0.5055	0.4760	0.0295	6.0	0.5099	0.4780	0.0319	6.7
40 OIL/NUCLEAR (\$/TWH)	0.0000	0.0000	0.0000	0.0	0.0000	0.0000	0.0000	0.0
FUEL COST PER MMBTU (\$/MMBTU)								
41 • HEAVY OIL	2.0947	2.1042	(0.0095)	(4.5)	2.0588	2.1747	(0.1159)	(5.3)
42 • LIGHT OIL	5.3383	4.9800	0.3583	7.2	5.1550	4.9800	0.1750	3.5
43 COAL	1.7814	1.7163	(0.0149)	(0.9)	1.6986	1.7334	(0.0348)	(2.0)
44 GAS	1.8113	2.3186	(0.5073)	(21.9)	1.9298	2.3129	(0.3831)	(16.0)
45 NUCLEAR	0.5055	0.4760	0.0295	6.0	0.5099	0.4780	0.0319	6.7
46 OIL/NUCLEAR	0.0000	0.0000	0.0000	0.0	0.0000	0.0000	0.0000	0.0
47 TOTAL (\$/MMBTU)	1.5329	1.5723	(0.0404)	(2.6)	1.5966	1.6008	(0.0042)	(0.1)
BTU BURNED PER KWH (BTU/KWH)								
48 HEAVY OIL	9,884	9,751	133	1.4	9,826	9,763	63	0.6
49 LIGHT OIL	23,713	12,417	11,296	91.0	21,024	12,419	8,605	60.3
50 COAL	10,818	9,504	1,314	5.4	9,857	9,505	352	3.7
51 GAS	8,634	8,797	(163)	(2.0)	7,938	8,639	(691)	(7.9)
52 NUCLEAR	11,236	11,761	(525)	(4.2)	11,345	11,774	(429)	(3.3)
53 OIL/NUCLEAR	0	0	0	0.0	0	0	0	0.0
54 TOTAL (BTU/KWH)	9,945	9,973	(28)	(0.2)	9,727	9,870	(143)	(1.4)
GENERATED FUEL COST PER KWH (\$/KWH)								
55 • HEAVY OIL	2.0703	2.1395	(0.0692)	(3.2)	2.0229	2.1237	(0.1008)	(4.7)
56 • LIGHT OIL	12.6401	6.1838	6.4563	104.7	10.8377	6.1847	4.6530	75.2
57 COAL	1.7044	1.6312	0.0732	4.5	1.6743	1.6475	0.0268	1.6
58 GAS	1.5821	2.0396	(0.4575)	(23.4)	1.3346	1.9982	(0.6636)	(23.2)
59 NUCLEAR	0.5480	0.5371	0.0109	5.8	0.5734	0.5370	0.0364	6.0
60 OIL/NUCLEAR	0.0000	0.0000	0.0000	0.0	0.0000	0.0000	0.0000	0.0
61 TOTAL (\$/KWH)	1.5245	1.5412	(0.0167)	(1.1)	1.5447	1.5780	(0.0333)	(2.1)

* Division A Program (File A) used for firing, has monthly, quarterly, and annual.

MONTH OF: MAY 1984

	(MWH)	CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE		ACTUAL	ESTIMATED	DIFFERENCE	
				AMOUNT	%			AMOUNT	%
1	SYSTEM NET GENERATION	8,008,084	4,823,738	1,181,328	14.6	11,887,387	8,208,304	2,381,083	24.0
2	POWER SOLD	(253,888)	(178,008)	(178,848)	238.2	(444,838)	(187,741)	(258,898)	138.8
3	INADVERTENT INTERCHANGE DELIVERED - NET	0	0	0	NA	0	0	0	NA
4	PURCHASED POWER	1,088,138	1,180,737	(124,802)	(10.8)	1,782,208	2,208,188	(813,888)	(22.3)
4a	ENERGY PURCH FROM QUALIFYING FACILITIES	208,717	287,888	(77,838)	(27.1)	822,838	872,878	(50,337)	(7.5)
8	ECONOMY PURCHASES	74,703	0	74,703	NA	88,733	102	88,831	NA
8	INADVERTENT INTERCHANGE RECEIVED - NET	0	0	0	NA	0	0	0	NA
7	NET ENERGY FOR LOAD	7,081,844	8,217,028	874,838	14.1	13,884,301	11,887,807	1,888,484	13.8
8	SALES (BILLED)	8,888,878	8,281,738	703,848	13.3	11,722,132	10,812,338	1,208,783	11.8
8a	UNBILLED SALES PRIOR MONTH (PERIOD)	2,888,808	3,344,831	(388,028)	(10.7)	2,838,188	3,228,318	(888,188)	(18.2)
8b	UNBILLED SALES CURRENT MONTH (PERIOD)	3,488,078	3,813,888	(388,874)	(8.4)	3,488,078	3,813,888	(388,874)	(8.4)
8	COMPANY USE	18,882	18,881	(3,148)	(18.8)	31,088	38,883	(4,843)	(13.7)
10	T & D LOSSES (ESTIMATED)	821,718	447,828	174,881	28.8	1,088,203	883,844	231,388	28.8
11	UNACCOUNTED FOR ENERGY (ESTIMATED)	0	0	0	-	0	0	0	-
12									
13	% COMPANY USE TO NEL	0.2	0.3	(0.1)	--	0.2	0.3	(0.1)	--
14	% T & D LOSSES TO NEL	8.77	7.20	1.57	--	8.02	7.20	0.82	--
15	% UNACCOUNTED FOR ENERGY TO NEL	0.0	0.0	0.0	--	0.0	0.0	0.0	--

(8)									
16	FUEL COST OF SYSTEM NET GENERATION	81,848,818	78,308,488	18,242,488	21.8	180,307,210	148,482,838	34,884,371	24.0
16a	FUEL RELATED TRANSACTIONS	8,848,870	1,712,838	8,237,132	308.8	8,338,288	7,488,183	841,118	11.2
16b	ADJUSTMENTS TO FUEL COST	(1,477,088)	(1,288,378)	(208,711)	18.8	(2,808,434)	(2,482,188)	(427,238)	17.2
17	FUEL COST OF POWER SOLD	(8,822,784)	(1,188,348)	(4,482,438)	384.8	(10,318,893)	(3,482,847)	(8,888,748)	188.8
18	FUEL COST OF PURCHASED POWER	18,888,884	21,484,801	(8,487,817)	(28.4)	32,402,088	42,312,818	(8,810,734)	(23.4)
18a	DEMAND & NON FUEL COST OF PURCH POWER	0	0	0	NA	0	0	0	NA
18b	ENERGY PAYMENTS TO QUALIFYING FACILITIES	3,888,144	8,122,011	(1,448,887)	(28.2)	10,848,118	11,884,222	(1,108,108)	(8.2)
18	ENERGY COST OF ECONOMY PURCHASES	1,444,888	4,800	1,448,088	NA	1,820,238	8,888	1,813,248	NA
20	TOTAL FUEL & NET POWER TRANSACTIONS	112,828,828	101,181,883	11,343,733	11.2	220,488,818	201,277,007	18,208,808	8.8

(c/KWH)									
21	FUEL COST OF SYSTEM NET GENERATION	1.8248	1.8812	(0.0367)	(2.4)	1.8847	1.8788	(0.0262)	(1.8)
21a	FUEL RELATED TRANSACTIONS	-	-	-	-	-	-	-	-
22	FUEL COST OF POWER SOLD	2.2187	1.8870	0.8887	43.3	2.3208	1.8448	0.4784	28.8
23	FUEL COST OF PURCHASED POWER	1.8148	1.8170	(0.3024)	(18.8)	1.8078	1.8348	(0.0288)	(1.8)
23a	DEMAND & NON FUEL COST OF PURCHASED POWER	-	-	-	-	-	-	-	-
23b	ENERGY PAYMENTS TO QUALIFYING FACILITIES	1.7872	1.7847	(0.0278)	(1.8)	1.7424	1.7783	(0.0338)	(1.8)
24	ENERGY COST OF ECONOMY PURCHASES	1.8342	0.0000	1.8342	NA	1.8817	8.8828	(4.8712)	(72.8)
25	TOTAL FUEL & NET POWER TRANSACTIONS	1.8887	1.8278	(0.0408)	(2.8)	1.8138	1.8778	(0.0840)	(3.8)

Florida Power & Light Company
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE A3

ACTUAL FOR THE PERIOD/MONTH OF:

MAY 1994

Page 1 of 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIVALENT AVAILABILITY FACTOR (%)	NET OUTPUT FACTOR (%)	AVERAGE NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (MMBTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (¢)	FUEL COST PER KWH (¢/KWH)	COST OF FUEL (\$/UNIT)
1	CAPE CANAVERAL # 1	367	188,662	76.7	98.9	77.5	9,423	#6 OIL	278,988 BBLs	6.338	1,768,226	3,665,037	1.9426	13.14
2	# 1		15,282					GAS	153,452 MCF	1.000	153,452	276,833	1.8115	1.80
3	# 2	367	115,058	48.5	64.3	74.3	9,673	#6 OIL	174,373 BBLs	6.338	1,105,176	2,290,707	1.9909	13.14
4	# 2		7,728					GAS	82,486 MCF	1.000	82,486	148,808	1.9256	1.80
5	FT. MYERS # 1	137	56,269	55.7	95.2	76.0	10,304	#6 OIL	91,078 BBLs	6.366	579,803	1,164,114	2.0688	12.78
6	# 2	367	216,798	78.5	96.9	81.8	9,483	#6 OIL	322,942 BBLs	6.366	2,053,849	4,127,684	1.9039	12.78
7	LAUDERDALE # 4	391	(320)	11.8	13.2	81.4	9,303	#2 OIL	0 BBLs	0.000	0	0	0.0000	0.00
	# 4		13,054					GAS	118,467 MCF	1.000	118,467	213,719	1.6372	1.80
17	# 5	391	0	99.0	99.1	99.0	7,690	#2 OIL	0 BBLs	0.000	0	0	0.0000	0.00
	# 5		276,332					GAS	2,125,113 MCF	1.000	2,125,113	3,833,776	1.3674	1.80
	MANATEE # 1	783	268,152	46.9	90.7	59.6	10,071	#6 OIL	424,097 BBLs	6.368	2,700,650	5,701,237	2.1261	13.44
	# 2	783	298,528	52.2	88.2	64.9	10,113	#6 OIL	474,069 BBLs	6.368	3,018,871	6,373,023	2.1348	13.44
13	MARTIN # 1	783	179,501	41.5	79.5	63.4	10,508	#6 OIL	287,057 BBLs	6.441	1,848,934	4,454,310	2.4815	15.52
14	# 1		78,245					GAS	859,339 MCF	1.000	859,339	1,550,277	1.9813	1.80
15	# 2	783	138,865	26.0	89.7	48.5	10,200	#6 OIL	217,877 BBLs	6.441	1,403,346	3,380,832	2.4346	15.52
16	# 2		19,117					GAS	208,021 MCF	1.000	208,021	375,277	1.9631	1.80
17	# 3	426	0	88.7	82.4	86.4	7,239	#2 OIL	0 BBLs	0.000	0	0	0.0000	0.00
18	# 3		279,588					GAS	2,023,836 MCF	1.000	2,023,836	3,651,069	1.3059	1.80
19	# 4	426	0	101.7	98.4	103.0	11,410	#2 OIL	0 BBLs	0.000	0	0	0.0000	0.00
20	# 4		314,279					GAS	2,576,398 MCF	1.000	2,576,398	4,739,833	1.3082	1.84
21	PT EVERGLADES # 1	204	93,011	58.4	84.7	70.2	10,231	#6 OIL	149,249 BBLs	6.357	948,776	1,907,812	2.0512	12.78
22	# 1		115					GAS	4,016 MCF	1.000	4,016	7,245	6.3000	1.80
23	# 2	204	(126)	0.0	0.0	0.0	0	#6 OIL	0 BBLs	0.000	0	0	0.0000	0.00
24	# 2		(123)					GAS	0 MCF	1.000	0	0	0.0000	0.00
25	# 3	367	181,431	76.2	98.3	78.8	9,695	#6 OIL	274,141 BBLs	6.357	1,742,714	3,904,274	1.9315	12.78
26	# 3		23,367					GAS	242,734 MCF	1.000	242,734	437,900	1.8740	1.80
27	# 4	367	148,994	66.1	99.0	73.5	9,836	#6 OIL	228,142 BBLs	6.357	1,450,299	2,916,281	1.9573	12.78
28	# 4		13,668					GAS	149,675 MCF	1.000	149,675	270,019	1.9756	1.80

Florida Power & Light Company
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE A5

ACTUAL FOR THE PERIOD/MONTH OF:

MAY 1994

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)		
	PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIVALENT AVAILABILITY FACTOR (%)	NET OUTPUT FACTOR (%)	AVERAGE NET HEAT RATE (BTU/EWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (MMBTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER EWH (\$/EWH)	COST OF FUEL (\$/UNIT)		
1	RIVIERA	# 3	272	(182)	0.1	3.1	10.2	0	#6 OIL	0	BBLs	0.000	0	0.0000	0.00	
2		# 3		(182)					GAS	62	MCF	1.000	62	1.12	1.81	
3		# 4	272	141,730	74.4	99.7	75.1	9,990	#6 OIL	219,721	BBLs	6.425	1,411,707	2,673,921	1.8866	12.17
4		# 4		5,330					GAS	59,354	MCF	1.000	59,354	107,077	1.9363	1.80
5	SANFORD	# 3	137	16,514	19.4	46.9	73.5	11,347	#6 OIL	29,802	BBLs	6.346	184,681	371,097	2.2472	12.75
6		# 3		184					GAS	4,791	MCF	1.000	4,791	8,643	4.6973	1.80
		# 4	362	112,896	43.2	98.5	64.4	10,105	#6 OIL	179,933	BBLs	6.342	1,141,135	2,294,430	2.0323	12.75
		# 4		255					GAS	2,095	MCF	1.000	2,095	3,779	1.4820	1.80
		# 5		252					GAS	2,736	MCF	1.000	2,736	4,936	1.9587	1.80
		# 5	362	121,942	41.9	88.1	69.3	10,129	#6 OIL	194,635	BBLs	6.346	1,235,154	2,481,904	2.0353	12.75
11	TURKEY POINT	# 1	387	124,773	71.3	99.7	77.0	9,497	#6 OIL	182,628	BBLs	6.352	1,160,053	2,440,325	1.9558	13.36
12		# 1		63,417					GAS	627,265	MCF	1.000	627,265	1,131,607	1.7844	1.80
13		# 2	367	141,001	59.4	98.9	71.4	9,957	#6 OIL	218,320	BBLs	6.352	1,386,769	2,917,252	2.0690	13.36
14		# 2		26,043					GAS	276,905	MCF	1.000	276,905	498,824	1.9154	1.80
15	CUTLER	# 5	67	0	15.2	99.9	65.6	9,342	#6 OIL	0	BBLs	0.000	0	0.0000	0.00	
16		# 5		7,612					GAS	71,111	MCF	1.000	71,111	128,287	1.6853	1.80
17		# 6	140	0	43.5	99.2	66.1	9,466	#6 OIL	0	BBLs	0.000	0	0.0000	0.00	
18		# 6		41,780					GAS	395,483	MCF	1.000	395,483	713,465	1.7077	1.80
19	FT MYERS	1-12	565	123	0.1	100.0	34.3	28,252	#2 OIL	996	BBLs	5.831	3,475	17,232	14.0098	28.91
20	LAUDERDALE	1-12	364	0	1.5	100.0	67.6	15,500	#2 OIL	0	BBLs	0.000	0	0.0000	0.00	
21		1-12		3,088					GAS	47,865	MCF	1.000	47,865	86,350	2.7963	1.80
22		13-24	364	0	2.1	100.0	64.1	17,827	#2 OIL	0	BBLs	0.000	0	0.0000	0.00	
23		13-24		5,109					GAS	91,078	MCF	1.000	91,078	164,308	3.2161	1.80
24	EVERGLADES	1-12	364	0	2.8	67.1	64.1	18,332	#2 OIL	145	BBLs	5.762	835	4,124	0.0000	28.44
25		1-12		7,041					GAS	128,240	MCF	1.000	128,240	231,349	3.2857	1.80

* INCLUDES CRANKING DIESELS

** EXCLUDES CRANKING DIESELS

Florida Power & Light Company
SYSTEM NET GENERATION AND FUEL COST

SCHEDULE A5

ACTUAL FOR THE PERIOD/MONTH OF:

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIVALENT AVAILABILITY FACTOR (%)	NET OUTPUT FACTOR (%)	AVERAGE NET HEAT RATE (BTU/EWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (MMBTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (¢)	FUEL COST PER EWH (¢/EWH)	COST OF FUEL (¢/UNIT)
1	PUTNAM	# 1	239	0	77.2	99.1	87.8	#6 OIL	0 BBLs	0.000	0	0	0.0000	0.00
2		# 1		145				#2 OIL	279 BBLs	5.823	1,625	9,997	6.8945	35.83
3		# 1		129,563				GAS	1,178,487 MCF	1.000	1,178,487	2,126,031	1.6409	1.80
4		# 2	239	0	82.0	99.8	87.6	#6 OIL	0 BBLs	0.000	0	0	0.0000	0.00
5		# 2		322				#2 OIL	557 BBLs	5.823	3,243	19,957	6.1978	35.83
6		# 2		132,717				GAS	1,189,290 MCF	1.000	1,189,290	2,145,520	1.6166	1.80
19	ST JOHNS (1)	# 1	(A) 125	(B) 90,501	98.5	99.7	(B) 98.8	COAL	(C) 36,951 TONS	23.322	861,771	1,470,169	1.6245	39.79
		# 1	(A)	(B) 105			(B)	#2 OIL	(C) 174 BBLs	5.719	995	4,117	3.9210	23.66
		# 2	(A) 125	(B) 91,321	99.4	99.7	(B) 99.4	COAL	(C) 35,694 TONS	24.356	869,363	1,420,149	1.5551	39.79
		# 2	(A)	(B) 73			(B)	#2 OIL	(C) 122 BBLs	5.719	698	2,897	3.9685	23.75
11	SCHERER	# 4	416	225,010	68.8	100.0	68.6	COAL	138,044 TONS	16.984	2,344,539	4,043,917	1.7972	29.29
12		# 4		18				#2 OIL	31 BBLs	5.817	180	672	3.7333	21.68
13	TURKEY POINT	# 3	666	76,365	22.8	23.7	63.6	NUCLEAR	938,286 MMBTU	---	938,286	482,434	0.6301	0.51
14		# 4	666	446,077	88.8	88.9	88.8	NUCLEAR	5,065,048 MMBTU	---	5,065,048	2,538,121	0.5690	0.30
15	ST LUCIE	# 1	839	584,059	97.0	97.3	97.0	NUCLEAR	6,461,898 MMBTU	---	6,461,898	3,367,049	0.5765	0.52
16		# 2	714	484,189	97.0	99.2	97.0	NUCLEAR	5,409,649 MMBTU	---	5,409,649	2,648,797	0.5471	0.49
17														
18														
19														
20	SYSTEM TOTALS	15,198	6,005,064	----	----	----	9,945	---	3,948,256 BBLs	---	59,721,647	91,548,916	1.5245	---
21									12,617,899 MCF					
22	--- EXCLUDES PARTICIPANTS								210,689 TONS	COAL				
23	--- INCLUDES PARTICIPANTS								0 TONS	ORIMULSION				
24	(1) CALCULATED ON CALENDAR MONTH PERIOD. OTHER DATA IS FUEL								17,874,881 MMBTU	NUCLEAR				

(A) FPL SHARE. (B) CALCULATED ON GENERATION RECEIVED NET OF LINE LOSSES. (C) #2 OIL - PREVIOUSLY REPORTED AS PART OF COAL.

MONTH OF MAY 1994

MONTH OF MAY 1994											
CURRENT MONTH					PERIOD TO DATE						
		ACTUAL	ESTIMATED	DIFFERENCE				ACTUAL	ESTIMATED	DIFFERENCE	
				AMOUNT	%					AMOUNT	%
1 PURCHASES		<<<<<< HEAVY OIL >>>>>>									
2 UNITS (BBL)		5,312,796	2,710,000	2,602,796	96.0	10,269,515		5,504,000		4,765,515	86.6
3 UNIT COST (\$/BBL)		13.5924	16.5255	.9531-	6.4-	13.2451		14.6368		1.1917-	8.3-
4 AMOUNT (\$)		72,213,458	39,366,050	32,849,408	83.5	136,820,300		79,460,040		56,560,260	71.2
5 BURNED		<<<<<< HEAVY OIL >>>>>>									
6 UNITS (BBL)		3,949,685	2,209,588	1,740,097	78.8	8,469,910		4,702,729		3,767,181	80.1
7 UNIT COST (\$/BBL)		13.3386	13.9758	.6372-	4.6-	13.1070		13.8492		.7422-	5.6-
8 AMOUNT (\$)		52,643,105	30,880,783	21,802,322	70.6	111,014,997		65,129,186		45,885,811	70.5
9 ENDING INVENTORY		<<<<<< HEAVY OIL >>>>>>									
10 UNITS (BBL)		5,311,471	4,712,422	599,049	12.7	5,311,471		4,712,422		599,049	12.7
11 UNIT COST (\$/BBL)		13.4420	14.6630	1.2210-	8.3-	13.4420		14.6630		1.2210-	8.3-
12 AMOUNT (\$)		71,396,623	69,098,453	2,298,170	3.3	71,396,623		69,098,453		2,298,170	3.3
13 OTHER USAGE (\$)		382,781				150,666					
14 DAYS SUPPLY		60									
15 PURCHASES		<<<<<< LIGHT OIL >>>>>>									
16 UNITS (BBL)		347	0	347	100.0	7,124		0		7,124	100.0
17 UNIT COST (\$/BBL)		32.4640	.0000	32.4640	100.0	27.1428		.0000		27.1428	100.0
18 AMOUNT (\$)		11,265	0	11,265	100.0	193,365		0		193,365	100.0
19 BURNED		<<<<<< LIGHT OIL >>>>>>									
20 UNITS (BBL)		2,506	3,312	.806-	26.3-	4,919		5,314		.395-	7.6-
21 UNIT COST (\$/BBL)		29.1879	28.8877	.3002	1.0	28.7483		28.8867		.1384-	5.0-
22 AMOUNT (\$)		73,145	95,676	22,531-	23.5-	141,613		153,504		12,091-	7.0-
23 ENDING INVENTORY		<<<<<< LIGHT OIL >>>>>>									
24 UNITS (BBL)		243,003	146,906	96,097	65.4	243,003		146,906		96,097	65.4
25 UNIT COST (\$/BBL)		29.7691	31.0990	1.3499-	4.3-	29.7691		31.0990		1.3499-	4.3-
26 AMOUNT (\$)		7,229,113	4,568,628	2,660,485	58.2	7,229,113		4,568,628		2,660,485	58.2
27 OTHER USAGE (\$)											
28 DAYS SUPPLY											
29 PURCHASES		<<<<<< COAL >>>>>>									
30 UNITS (TON)		222,147	224,080	1,933-	.8-	425,752		398,000		29,752	7.5
31 UNIT COST (\$/TON)		53.8118	42.0543	11.7575	19.6-	34.1546		42.7801		8.6255-	20.1-
32 AMOUNT (\$)		7,511,179	9,420,170	1,908,991-	20.3-	14,541,372		16,932,980		2,391,608-	14.1-
33 BURNED		<<<<<< COAL >>>>>>									
34 UNITS (TON)		210,689	168,773	41,916	24.8	392,261		342,765		49,496	16.4
35 UNIT COST (\$/TON)		32.9122	42.7071	9.7949-	22.9-	32.7572		43.1323		10.3751-	24.1-
36 AMOUNT (\$)		6,934,236	7,207,820	273,584-	3.8-	12,848,711		14,783,372		1,934,661-	13.1-
37 ENDING INVENTORY		<<<<<< COAL >>>>>>									
38 UNITS (TON)		241,979	319,566	77,585-	24.3-	241,979		319,566		77,585-	24.3-
39 UNIT COST (\$/TON)		38.6848	43.2882	4.6034-	10.6-	38.6848		43.2882		4.6034-	10.6-
40 AMOUNT (\$)		9,360,901	13,833,355	4,472,454-	32.3-	9,360,901		13,833,355		4,472,454-	32.3-
41 OTHER USAGE (\$)											
42 DAYS SUPPLY											
43 BURNED		<<<<<< GAS >>>>>>									
44 UNITS (MCF)		12,617,899	12,499,031	118,868	1.0	21,233,211		21,995,765		762,554-	3.5-
45 UNIT COST (\$/MCF)		1.8113	2.3186	.5073-	21.9-	1.9298		2.3129		.3831-	16.6-
46 AMOUNT (\$)		22,855,043	28,980,104	6,125,061-	21.1-	40,975,278		50,874,800		9,899,522-	19.5-
47 BURNED		<<<<<< NUCLEAR >>>>>>									
48 UNITS (MMBTU)		17,874,881	17,072,743	802,138	4.7	30,035,073		30,358,479		323,406-	1.1-
49 U. COST (\$/MMBTU)		.5055	.4769	.0286	6.0	.5099		.4780		.0319	6.7
50 AMOUNT (\$)		9,036,402	8,142,295	894,107	11.0	15,316,154		14,512,331		803,823	5.5
51 BURNED		<<<<<< ORIMULSION >>>>>>									
52 UNITS (TON)		0	0	0	100.0	0		0		0	100.0
53 UNIT COST (\$/TON)		.0000	.0000	.0000	100.0	.0000		.0000		.0000	100.0
54 AMOUNT (\$)		0	0	0	100.0	0		0		0	100.0
55 BURNED		<<<<<< PROPANE >>>>>>									
56 UNITS (GAL)		2,705	100	2,605	100.0 +	5,857		200		5,657	100.0 +
57 UNIT COST (\$/GAL)		.7826	1.0000	-.2174-	21.7-	.7697		1.0000		-.2303-	23.0-
58 AMOUNT (\$)		2,117	100	2,017	100.0 +	4,508		200		4,308	100.0 +

LINE 9 & 23 EXCLUDE 4,000 BARRELS, \$35,131 CURRENT MONTH AND 6,000 BARRELS, \$(6,150) PERIOD-TO-DATE.

LINE 50 EXCLUDES NUCLEAR DISPOSAL COST OF \$1,463,356 CURRENT MONTH AND \$2,464,160 PERIOD-TO-DATE.

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD (000)	KWH WHEELED FROM OTHER SYSTEMS (000)	KWH FROM OWN GENERATION (000)	cents/KWH		TOTAL \$ FOR FUEL ADJ. (5) x (6)(a)	TOTAL COST \$ (5) x (6)(b)
					(a) FUEL COST	(b) TOTAL COST		
ESTIMATED:								
	C, A, B, OS S	30,815 0	0 0	30,815 0	2.620 0.000	3.620 0.000	809,973 0	1,119,123 0
ST. LUCIE RELIABILITY 80% OF GAIN ON ECONOMY SALES		44,091	0	44,091	0.540	0.540	238,091 112.281	238,091
TOTAL		75,006	0	75,006	1.397	1.808	1,180,345 *	1,357,214
ACTUAL:								
ECONOMY		209,775	0	209,775	2.079	2.843	4,360,705	5,544,775
FMPA (SL 1)		25,391	0	25,391	0.810	0.810	154,759	154,759
OUC (SL 1)		17,558	0	17,558	0.883	0.883	116,354	116,354
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		(99)	0	(99)	0.540	0.821	(535)	(815)
FLORIDA KEYS ELECTRIC COOPERATIVE		1,030	0	1,030	4.298	4.298	44,245	44,245
ECONOMY SUB-TOTAL		209,775	0	209,775	2.079	2.843	4,360,705	5,544,775
ST. LUCIE PARTICIPATION SUB-TOTAL		42,949	0	42,949	0.631	0.631	271,113	271,113
SALES EXCLUSIVE OF ECONOMY AND ST. LUCIE PARTICIPATION SUB-TOTAL		931	0	931	4.695	4.696	43,710	43,630
80% OF GAIN ON ECONOMY SALES (SEE SCHED A7a)							947,258	
TOTAL		253,655	0	253,655	1.843	2.310	5,822,784 *	5,859,518
CURRENT MONTH:								
DIFFERENCE		178,849	0	178,849	0.448	0.501	4,462,439	4,502,304
DIFFERENCE (%)		238.2	0.0	238.2	31.9	27.7	384.6	331.7
PERIOD TO DATE:								
ACTUAL		444,638	0	444,638	1.920	2.438	10,319,993	10,845,587
ESTIMATED		187,741	0	187,741	1.582	2.089	3,462,847	3,883,490
DIFFERENCE		256,895	0	256,895	0.338	0.371	6,856,746	6,962,077
DIFFERENCE (%)		138.8	0.0	138.8	21.3	17.9	188.0	179.1

* ONLY TOTAL \$ INCLUDES 80% OF GAIN ON ECONOMY SALES.

COMPANY: FLORIDA POWER & LIGHT COMPANY

GAIN ON ECONOMY ENERGY SALES
FOR THE MONTH OF MAY, 1994

SCHEDULE A7a

(1)	(2)	(3)	(4)		(5)		(6)
SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD (000)	\$		cents/KWH		GAIN ON ECONOMY ENERGY SALES (4)(b) - (4)(a)
			(a) FUEL COST	(b) TOTAL COST	(a) FUEL COST	(b) TOTAL COST	
ESTIMATED:							
	C	23,056	817,163	757,534	2.677	3.286	140,351
80% OF GAIN ON ECONOMY SALES							112,281
TOTAL		23,056	817,163	757,534	2.677	3.286	112,281
ACTUAL:							
FLORIDA MUNICIPAL POWER AGENCY	C	5,107	101,481	118,745	1.987	2.325	17,264
FLORIDA POWER CORPORATION	C	73,379	1,079,824	2,208,857	2.289	3.133	618,733
FT. PIERCE UTILITIES AUTHORITY	C	1,881	34,831	38,827	2.080	2.375	5,298
CITY OF GAINESVILLE	C	1,148	22,828	28,880	1.992	2.329	3,881
CITY OF HOMESTEAD	C	320	6,881	8,358	2.150	2.812	1,477
JACKSONVILLE ELECTRIC AUTHORITY	C	100	2,329	2,918	2.329	2.918	587
UTILITY BOARD OF THE CITY OF KEY WEST	C	1,819	27,718	35,788	1.825	2.358	8,070
KISSIMEE UTILITY AUTHORITY	C	3,981	88,058	128,927	2.248	3.284	37,888
CITY OF LAKELAND	C	1,088	22,488	28,570	2.110	2.888	8,081
CITY OF LAKE WORTH UTILITIES	C	2,444	50,084	84,273	2.048	2.830	14,288
UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH	C	77	2,072	2,977	2.691	3.888	985
ORLANDO UTILITIES COMMISSION	C	17,452	333,201	378,788	1.918	2.188	43,585
REEDY CREEK IMPROVEMENT DISTRICT	C	2,323	48,878	58,742	1.788	2.184	8,884
SEMINOLE ELECTRIC COOPERATIVE, INC.	C	(1,023)	(18,888)	(23,958)	1.873	2.341	(7,882)
SOUTHERN COMPANIES	C	4,582	108,447	125,012	2.382	2.722	18,185
CITY OF ST. CLOUD	C	2,188	58,818	78,331	2.325	3.211	18,412
CITY OF STARKE	C	781	18,287	28,148	2.887	3.348	8,851
CITY OF TALLAHASSEE	C	841	12,801	14,828	2.013	2.287	1,828
TAMPA ELECTRIC COMPANY	C	4,725	113,782	177,848	2.488	3.747	83,284
CITY OF VERO BEACH	C	1,748	36,721	41,293	2.048	2.385	5,572
CITY OF GAINESVILLE	X	1,200	21,024	30,132	1.752	2.511	8,108
CITY OF HOMESTEAD	X	8,787	158,888	188,582	2.348	2.787	29,628
REEDY CREEK IMPROVEMENT DISTRICT	X	48,577	783,232	887,688	1.888	1.758	74,388
FT. PIERCE UTILITIES AUTHORITY	OS	4,848	114,343	155,773	2.358	3.213	41,438
UTILITY BOARD OF THE CITY OF KEY WEST	OS	15,817	358,218	454,584	2.258	2.858	88,384
CITY OF LAKE WORTH UTILITIES	OS	2,378	87,548	73,547	2.418	3.082	16,088
UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH	OS	381	10,883	13,375	2.825	3.818	3,372
OGLETHORPE POWER CORPORATION	OS	158	3,127	3,822	1.978	2.282	485
ORLANDO UTILITIES COMMISSION	OS	1,848	25,827	40,271	2.458	3.888	14,844
TAMPA ELECTRIC COMPANY	OS	845	23,448	28,888	2.778	3.325	4,847
CITY OF VERO BEACH	OS	2,438	88,571	77,401	2.451	3.185	17,838
SUB-TOTAL		289,775	4,388,785	5,544,775	2.079	2.843	1,184,878
80% OF GAIN ON ECONOMY SALES							947,215
TOTAL		289,775	4,388,785	5,544,775	2.079	2.843	947,215
CURRENT MONTH:							
DIFFERENCE		188,728	3,743,522	4,787,241	(8,588)	(8,843)	834,975
DIFFERENCE (%)		889.8	888.5	832.0	(22.3)	(19.8)	743.8
PERIOD TO DATE:							
ACTUAL		348,382	7,838,758	9,881,244	2.185	2.823	1,784,388
ESTIMATED		82,844	2,118,881	2,738,884	2.588	3.382	482,838
DIFFERENCE		288,458	5,811,878	7,125,388	(8,374)	(8,478)	1,291,451
DIFFERENCE (%)		321.8	288.0	288.4	(14.8)	(14.8)	288.8

PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASE)
FOR THE MONTH OF MAY, 1964

SCHEDULE AB

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	KWH FOR OTHER UTILITIES (000)	KWH FOR INTERSTATE TRADING (000)	KWH FOR FIRM (000)	cents/KWH		TOTAL \$ FOR FUEL ADJ. (6) x (7)(a) \$
						(a) FUEL COST	(b) TOTAL COST	
ESTIMATED:								
SOUTHERN COMPANIES (UPS & R)		893,394	0	0	893,394	1.951		17,429,270
ST. LUCIE RELIABILITY		30,041	0	0	30,041	0.540		162,221
SURPP		257,303	0	0	257,303	1.501		3,863,010
TOTAL		1,180,738	0	0	1,180,738	1.817		21,454,501
ACTUAL:								
SOUTHERN COMPANIES	UPS	258,965	0	0	258,965	2.041		5,244,781
SOUTHERN COMPANIES	R	393,970	0	0	393,970	1.904		7,502,873
PRIOR MONTH ADJUSTMENT		0	0	0	0			(28,436)
		650,935	0	0	650,935	1.954		12,719,218
FMPP (SL 2)		25,006	0	0	25,006	0.804		151,109
PRIOR MONTH ADJUSTMENT		0	0	0	0			1,409
		25,006	0	0	25,006	0.810		152,518
OUC (SL 2)		17,292	0	0	17,292	0.640		112,276
PRIOR MONTH ADJUSTMENT		0	0	0	0			1,047
		17,292	0	0	17,292	0.655		113,323
JACKSONVILLE ELECTRIC AUTHORITY	UPS	278,129	0	0	278,129	1.549		4,308,970
PRIOR MONTH ADJUSTMENT		83,791	0	0	83,791			(1,315,711)
		361,920	0	0	361,920	0.827		2,993,267
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		982	0	0	982	1.850		18,258
ST. LUCIE PARTICIPATION SUB-TOTAL								
		42,298	0	0	42,298	0.828		265,841
TOTAL		1,056,135	0	0	1,056,135	1.515		15,998,584
CURRENT MONTH:								
DIFFERENCE		(124,603)	0	0	(124,603)	(0.302)		(5,457,917)
DIFFERENCE (%)		(10.9)	0.0	0.0	(10.9)	(18.8)		(25.4)
PERIOD TO DATE:								
ACTUAL		1,792,208	0	0	1,792,208	1.808		32,402,085
ESTIMATED		2,306,188	0	0	2,306,188	1.835		42,312,819
DIFFERENCE		(513,980)	0	0	(513,980)	(0.027)		(9,910,734)
DIFFERENCE (%)		(22.3)	0.0	0.0	(22.3)	(1.5)		(23.4)

COMPANY: FLORIDA POWER & LIGHT COMPANY

ENERGY PAYMENT TO QUALIFYING FACILITIES
FOR THE MONTH OF MAY, 1994

SCHEDULE A8a

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	KWH FOR OTHER UTILITIES (000)	KWH FOR INTERMIT- TIBLE (000)	KWH FOR FIRM (000)	cents/KWH		TOTAL \$ FOR FUEL ADJ. (8) x (7)(b) \$
						(a) FUEL COST	(b) TOTAL COST	
ESTIMATED:								
QUALIFYING FACILITIES		287,556	0	0	287,556	1.785	1.785	5,132,011
TOTAL		287,556	0	0	287,556	1.785	1.785	5,132,011
ACTUAL:								
ROYSTER COMPANY		6,419	0	0	6,419	1.530	1.530	98,216
DOWNTOWN GOVERNMENT CENTER		4,683	0	0	4,683	2.618	2.618	122,607
BIO-ENERGY PARTNERS, INC.		6,708	0	0	6,708	2.146	2.146	143,941
SOLID WASTE AUTHORITY OF PALM BEACH COUNTY		20,926	0	0	20,926	1.458	1.458	305,083
TROPICANA PRODUCTS, INC.		179	0	0	179	1.898	1.898	3,388
FLORIDA CRUSHED STONE		0	0	0	0	0.000	0.000	66,905
BROWARD COUNTY RESOURCE RECOVERY - SOUTH SITE		33,897	0	0	33,897	2.037	2.037	690,361
BROWARD COUNTY RESOURCE RECOVERY - NORTH SITE		34,151	0	0	34,151	2.043	2.043	697,864
U. S. SUGAR CORPORATION - BRYANT		0	0	0	0	0.000	0.000	0
U. S. SUGAR CORPORATION - CLEWISTON		0	0	0	0	0.000	0.000	0
GEORGIA PACIFIC CORPORATION		151	0	0	151	2.093	2.093	3,161
CEDAR BAY GENERATING COMPANY		102,603	0	0	102,603	1.514	1.514	1,553,808
TOTAL		209,717	0	0	209,717	1.757	1.757	3,685,144
CURRENT MONTH:								
DIFFERENCE		(77,839)	0	0	(77,839)	(0.028)	(0.028)	(1,446,867)
DIFFERENCE (%)		(27.1)	0.0	0.0	(27.1)	(1.5)	(1.5)	(28.2)
PERIOD TO DATE:								
ACTUAL		622,639	0	0	622,639	1.742	1.742	10,849,116
ESTIMATED		672,976	0	0	672,976	1.776	1.776	11,954,222
DIFFERENCE		(50,337)	0	0	(50,337)	(0.034)	(0.034)	(1,105,106)
DIFFERENCE (%)		(7.5)	0.0	0.0	(7.5)	(1.9)	(1.9)	(9.2)

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
FOR THE MONTH OF MAY, 1984

SCHEDULE A9

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS. COST cents/KWH	TOTAL \$ FOR FUEL ADJ. (3) x (4) \$	COST IF GENERATED		FUEL SAVINGS (6)(b) - (5) \$
					(a) cents/KWH	(b) \$	
ESTIMATED:							
FLORIDA	C	0	0.000	0	0.000	0	0
SOUTHERN COMPANY	C	0	0.000	0	0.000	0	0
TOTAL		0	0.000	0	0.000	0	0
ACTUAL:							
FLORIDA POWER CORPORATION	C	1,075	1.645	17,688	1.780	19,131	1,443
FT. PIERCE UTILITIES AUTHORITY	C	6	4.133	248	5.000	300	62
CITY OF GAINESVILLE	C	2,711	1.687	45,741	1.848	50,104	4,363
JACKSONVILLE ELECTRIC AUTHORITY	C	522	2.809	13,618	3.108	16,215	2,597
CITY OF LAKE WORTH UTILITIES	C	95	1.692	1,607	1.664	1,790	183
ORLANDO UTILITIES COMMISSION	C	72	4.158	2,992	5.000	3,600	608
SEMINOLE ELECTRIC COOPERATIVE, INC.	C	18,920	1.825	307,372	1.775	335,788	28,416
CITY OF TALLAHASSEE	C	38	1.658	597	1.893	681	84
TAMPA ELECTRIC COMPANY	C	20,858	1.744	363,758	1.900	396,252	32,494
SOUTHERN COMPANIES	C	283	2.990	8,461	3.240	9,189	708
OGLETHORPE POWER CORPORATION	OS	30,125	2.287	682,804	2.838	854,348	171,542
FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		44,295	1.701	753,621	1.880	823,661	70,240
NON-FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		30,408	2.273	691,265	2.840	863,515	172,250
TOTAL		74,703	1.934	1,444,886	2.259	1,687,376	242,490
CURRENT MONTH:							
DIFFERENCE		74,703	1.934	1,444,886	2.259	1,687,376	242,490
DIFFERENCE (%)		100.0	100.0	100.0	100.0	100.0	100.0
PERIOD TO DATE:							
ACTUAL		98,733	1.882	1,820,235	2.188	2,114,385	294,130
ESTIMATED		102	2.147	2,190	2.370	2,417	227
DIFFERENCE		98,631	(0.265)	1,818,045	(0.184)	2,111,948	293,903
DIFFERENCE (%)		94,738.3	(12.4)	83,015.8	(7.8)	87,378.8	129,472.7

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE A10

06/13/94

ACTUAL UNSCHEDULED (IN ADVERTANT) INTERCHANGE
FOR THE PERIOD/MONTH OF: MAY 1994

**RECEIVED FROM
OR
DELIVERED TO**

**TOTAL KWH
EXCHANGED**

SEE ATTACHED

INTERCHANGE FOR FISCAL MONTH OF MAY, 1994

SCHEDULED INTERCHANGE (MWH)

	Receipts	Deliveries	Net
*SCS Southern Company Services	878537	6074	(872,463)
TEC Tampa Electric Company	27,493	6,579	(20,914)
FPC Florida Power Corporation	4,098	77,508	73,410
FMP Florida Municipal Power Agency	1,113	4,910	3,797
OUC Orlando Utilities Commission	0	54,079	54,079
JEA Jacksonville Electric Authority	439,142	711	(438,431)
JEA Loss Payback	720	0	(720)
VER City of Vero Beach	0	11,117	11,117
FTP Ft. Pierce Utilities Authority	0	13,766	13,766
LWU Lake Worth Utilities Authority	92	17,702	17,610
NSB UMI, Correll, City of New Smyrna Beach	0	5,492	5,492
HST City of Homestead	0	12,119	12,119
SEC Seminole Electric Cooperative, Inc.	18,424	1,107	(17,317)
SEC Loss Payback	0	0	0
SEC Inadvertent Payback	0	0	0
STK City of Starke	0	1,988	1,988
GVL City of Gainesville	2,684	995	(1,689)
ALC City of Alachua	0	223	223
CLW City of Clewiston	0	1,151	1,151
KIS Kissimmee Utility Authority	0	9,011	9,011
LAK City of Lakeland	0	1,066	1,066
STC City of St. Cloud	0	2,165	2,165
GCS City of Green Cove Springs	0	903	903
JBH City of Jacksonville Beach	0	5,432	5,432
KEY City Board of The City of Key West	0	43,893	43,893
TAL City of Tallahassee	35	533	498
RCI Ready Green Energy Services, Inc.	0	30,215	30,215
TOTAL SCHEDULED INTERCHANGE	493,799	302,663	(1,063,599)

ACTUAL INTERCHANGE (MWH)

FPC at Oakland	0	18,023	18,023
FPC at Barberville	0	0	0
FPC at Suwannee	4,114	573	(3,541)
FPC at Palmetto	0	118,837	118,837
FPC at North Longwood	8	210,854	210,856
FPC at Sanford	29	44,336	44,307
FPC at Ocala	27,868	0	(27,868)
TEC at Johnson	127,917	4	(127,913)
TEC at Marianna	92,350	2,454	(89,896)
TEC at Marianna 2B	102,413	1,106	(101,307)
OUC at Indian River	4,043	102,440	98,397
FMP at Green Cove Springs #1	0	4,057	4,057
FMP at Green Cove Springs #2	0	5,180	5,180
FMP at Jacksonville Beach #1	0	10,379	10,379
FMP at Jacksonville Beach #2	0	11,015	11,015
FMP at Hendry	0	8,938	8,938
FMP at Jacksonville Beach #3	0	22,019	22,019
JEA at Suwannee	183,917	0	(183,917)
JEA at Duval #1	79,973	763	(79,210)
JEA at Duval #2	80,268	742	(79,526)
JEA at Monticello 115 kV	19,850	1	(19,849)
JEA at Epon	0	65,981	65,981
FTP at West	19,822	215	(19,607)
FTP at Midway	23	41,255	41,232
LWU at Hypokiso	3	18,928	18,925
VER at West M	19,917	55	(19,862)
VER at West E	0	35,108	35,108
HST at Lucy	3,388	21,116	17,728
NSB at Smyrna V1	13	8,493	8,479
NSB at Smyrna V2	0	22,222	22,222
*SCS at Kingsland	9,603	14,125	4,522
*SCS at Hatch #1	494,109	0	(494,109)
*SCS at Hatch #2	579,381	0	(579,381)
SEC at Black Creek	0	0	0
SEC at Putnam	0	0	0
SEC at Rice #1	150,286	59	(150,227)
SEC at Rice #2	145,558	0	(145,558)
SEC at Lee	92,943	0	(92,943)
STK at Starke	0	5,029	5,029
GVL at Deerhaven	1,828	15,383	13,555
RCI at Marianna	0	48,230	48,230
Subtotal - Metered Exchange	2,239,631	857,910	(1,381,721)
Less Transfers SCS/JEA	160,568	160,568	0
Less Transmission for others	61,311	60,181	(1,130)
Less Partial Requirements	0	25,381	25,381
Less SEC Load Replacement	342,150	0	(342,150)
TOTAL ACTUAL INTERCHANGE	1,675,602	611,780	(1,063,822)

INADVERTENT NET INTERCHANGE Received

(223)

*adjusted to Eastern Prevailing Time and includes Unit Power Sales

RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 KWH

APRIL 1994	MAY 1994	JUNE 1994	JULY 1994	AUGUST 1994	SEPTEMBER 1994	AVERAGE PERIOD TO DATE
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ESTIMATED:

Base Rate Revenues (\$)	47.38	47.38					47.38
Fuel Recovery Factor (c/KWH)	1.498	1.506					1.502
Group Loss Multiplier	1.00161	1.00161					1.00161
Fuel Recovery Revenues (\$)	15.00	15.08					15.04
Total Revenues (\$)	62.38	62.46					62.42

ACTUAL:

Base Rate Revenues (\$)	47.38	47.38					47.38
Fuel Recovery Factor (c/KWH)	1.508	1.524					1.516
Group Loss Multiplier	1.00161	1.00161					1.00161
Fuel Recovery Revenues (\$)	15.10	15.26					15.18
Total Revenues (\$)	62.48	62.64					62.56

DIFFERENCE

Base Rate Revenues (\$)	0	0					0
Fuel Adj Revenues (\$)	0.10	0.18					0.14
Total Revenues (\$)	0.10	0.18					0.14

DIFFERENCE (%)

Base Rate Revenues	0	0					0
Fuel Adj Revenues	0.67	1.19					0.93
Total Revenues	0.16	0.29					0.23

CURRENT MONTH				PERIOD TO DATE			
ACTUAL	ESTIMATED	DIFFERENCE		ACTUAL	ESTIMATED	DIFFERENCE	
		AMOUNT	%			AMOUNT	%

KWH SALES (000)

1	Residential	3,136,448	2,576,316	560,132	21.7%	5,897,152	5,072,555	824,597	16.3%
2	Commercial	2,328,890	2,229,347	99,543	4.5%	4,819,978	4,471,146	348,832	7.8%
3	Industrial	325,447	327,110	(1,663)	-0.5%	634,069	672,543	(38,474)	-5.7%
4	Street & Highway Lighting	29,492	26,499	2,993	11.3%	57,148	54,671	2,477	4.5%
5	Other Sales to Public Authority	49,387	46,716	2,671	5.7%	92,614	93,645	(1,031)	-1.1%
5A	Railways & Railroads	6,463	6,307	156	2.5%	13,072	12,614	458	3.6%
7	Total Jurisdictional Sales	5,876,127	5,212,295	663,832	12.7%	11,514,033	10,377,174	1,136,859	11.0%
8	Sales for Resale	108,661	69,435	39,226	56.5%	206,484	135,165	71,319	52.8%
9	Total Sales	5,984,788	5,281,730	703,058	13.3%	11,720,517	10,512,339	1,208,178	11.5%

NUMBER OF CUSTOMERS

10	Residential	3,028,412	3,032,546	(4,134)	-0.1%	3,041,021	3,050,885	(9,864)	-0.3%
11	Commercial	365,964	370,877	(4,913)	-1.3%	365,333	370,417	(5,084)	-1.4%
12	Industrial	15,366	15,187	179	1.2%	15,389	15,189	201	1.3%
13	Street & Highway Lighting	2,302	2,516	(214)	-8.5%	2,304	2,492	(188)	-7.6%
14	Other Sales to Public Authority	297	297	0	0.0%	298	297	1	0.3%
14A	Railways & Railroads	23	23	0	0.0%	23	23	0	0.0%
16	Total Jurisdictional Customers	3,412,364	3,421,446	(9,082)	-0.3%	3,424,368	3,439,303	(14,935)	-0.4%
17	Sales for Resale	12	12	0	0.0%	12	12	0	0.0%
18	Total Customers	3,412,376	3,421,458	(9,082)	-0.3%	3,424,380	3,439,315	(14,935)	-0.4%

KWH USE PER CUSTOMER

19	Residential	1,036	850	186	21.9%	1,939	1,663	277	16.6%
20	Commercial	6,364	6,011	353	5.9%	13,193	12,071	1,123	9.3%
21	Industrial	21,180	21,539	(359)	-1.7%	41,202	44,279	(3,077)	-7.0%
22	Street & Highway Lighting	12,811	10,531	2,280	21.7%	24,807	21,940	2,867	13.1%
23	Other Sales to Public Authority	166,286	157,294	8,992	5.7%	310,959	315,303	(4,344)	-1.4%
23A	Railways & Railroads	281,000	274,217	6,783	2.5%	568,348	548,435	19,913	3.6%
25	Total Jurisdictional Use Per Customer	1,722	1,523	199	13.0%	3,362	3,017	345	11.4%
26	Sales for Resale	9,055,083	5,786,250	3,268,833	56.5%	17,207,000	11,263,750	5,943,250	52.8%
27	Total Use Per Customer	1,754	1,544	210	13.6%	3,423	3,057	366	12.1%

SCHEDULE A13

SPENT FUEL DISPOSAL COSTS

MAY 1994

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE		ACTUAL	ESTIMATED	DIFFERENCE	
				AMOUNT	%			AMOUNT	%
ST LUCIE 1									
1	Amortization of Fuel Burned	0	0	0		0	0	0	
2	Fuel Burned During Month	536,341	518,000	18,341	3.5%	995,876	1,053,000	(57,124)	-5.4%
ST LUCIE 2									
3	Fuel Burned During Month	446,574	370,000	76,574	20.7%	446,574	489,000	(42,426)	-8.7%
TURKEY POINT 3									
4	Amortization of Fuel Burned	0	0	0		0	0	0	
5	Fuel Burned During Month	70,808	92,000	(21,192)	-23.0%	149,772	92,000	57,772	62.8%
TURKEY POINT 4									
6	Fuel Burned During Month	409,633	412,000	(2,367)	-0.6%	871,938	838,000	33,938	4.0%
7	TOTAL	1,463,356	1,392,000	71,356	5.1%	2,464,160	2,472,000	(7,840)	-0.3%

AMOUNTS MAY NOT TIE TO OTHER SCHEDULES DUE TO ROUNDING

EFFECTIVE JANUARY 1994 THIS SCHEDULE EXCLUDES ALL DOE CREDITS.

A-SCHEDULES

APRIL 1994

MONTH OF: APRIL 1984

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** Calculation Based on Jurisdictional KWH Sales

Company: Florida Power & Light CompanySchedule A1aRECAP OF ACTUAL FUEL & PURCHASED POWER COSTS
SHOWN ON SCHEDULE A1

Month of April, 1994

<u>LINE</u>	<u>DESCRIPTION</u>	<u>REFERENCE</u>	<u>AMOUNT</u>
1	Fuel Cost of System Net Generation	Schedule A-3 Line 7	\$88,758,294
2	Nuclear Fuel Disposal Costs	Schedule A-2 Line A1a	1,000,804
3	Coal Car Investment	Schedule A-2 Line A1b	39,592
3a	DOE Decontamination and Decommissioning Cost	Schedule A-2 Line A1e	0
3b	Gas Pipeline Enhancements	Schedule A-2 Line A1d	345,932
4	Adjustments to Fuel Cost	Schedule A-2 Line A-6	(1,432,345)
6	Fuel Cost of Purchased Power	Schedule A-8 Col. 8	16,405,501
7+8+9	Energy Costs of Economy Purchases	Schedule A-9 Col. 5	375,349
11	Energy Payments to Qualifying Facilities	Schedule A-8a Col. 8	7,163,972
18	Fuel Cost of Power Sold	Schedule A-7 Col. 7	(4,696,809)
20	Total Fuel and Net Power Transactions		<u>\$107,960,289</u>

Company: Florida Power & Light Company

APRIL 1994

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE ACTUAL - ESTIMATED	%	ACTUAL	ESTIMATED	DIFFERENCE ACTUAL - ESTIMATED	%
A. Fuel Costs & Net Power Transactions	\$	\$	\$		\$	\$	\$	
1. Fuel Cost of System Net Generation	88,758,294	70,146,373	18,611,921	26.5	88,758,294	70,146,373	18,611,921	26.5
1a. Nuclear Fuel Disposal Costs	1,000,804	1,000,632	(170,820)	(17.4)	1,000,804	1,000,632	(170,820)	(17.4)
1b. SJRPP Coal Costs	39,592	32,857	6,735	20.5	39,592	32,857	6,735	20.5
1c. Orismus	0	0	0	N/A	0	0	0	N/A
1d. Gas Pipeline Laterals	345,932	288,856	57,076	19.8	345,932	288,856	57,076	19.8
1e. DOE Decontamination & Decommissioning Fund Payment	0	4,380,000	(4,380,000)	N/A	0	4,380,000	(4,380,000)	N/A
2. Fuel Cost of Power Sold	(4,696,809)	(2,302,502)	(2,394,307)	104.0	(4,696,809)	(2,302,502)	(2,394,307)	104.0
3. Fuel Cost of Purchased Power	16,405,501	20,858,318	(4,452,817)	(27.3)	16,405,501	20,858,318	(4,452,817)	(27.3)
3a. Demand & Non Fuel Cost of Purchased Power	0	0	0	N/A	0	0	0	N/A
3b. Energy Payments to Qualifying Facilities	7,163,972	6,822,211	341,761	5.0	7,163,972	6,822,211	341,761	5.0
4. Energy Cost of Economy Purchases	375,349	2,190	373,159	N/A	375,349	2,190	373,159	N/A
5. Total Fuel Costs & Net Power Transactions	109,392,634	101,308,935	8,083,699	8.0	109,392,634	101,308,935	8,083,699	8.0
6. Adjustments to Fuel Cost: (Detailed below)								
Fuel Cost of Sales to Other FERC Customers *	(1,393,440)	(1,213,821)	(179,619)	N/A	(1,393,440)	(1,213,821)	(179,619)	N/A
Inventory Adjustments	2,376	0	2,376	N/A	2,376	0	2,376	N/A
Non Recoverable Oil	(41,281)	0	(41,281)	N/A	(41,281)	0	(41,281)	N/A
DOE - Nuclear Fuel Disposal Costs - Credit	0	0	0	N/A	0	0	0	N/A
Air Operating Permit Fees	0	0	0	N/A	0	0	0	N/A
7. Adjusted Total Fuel Costs & Net Power Transactions	\$ 107,960,299	\$ 100,095,114	\$ 7,865,175	7.9	\$ 107,960,299	\$ 100,095,114	\$ 7,865,175	7.9

* The other FERC customers are Florida Keys Electric Cooperative (FKEC) and the City of Key West (CKW)

CALCULATION OF TRUE UP AND INTEREST PROVISION

SCHEDULE A2

Page 2 of 4

Company: Florida Power & Light Company

Month of: APRIL 1994

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
B. Sales Revenues (Excludes Franchise Fees)								
1. Jurisdictional Sales Revenues								
a. Base Fuel Revenues	0	0	0	0	0	0	0	0
b. Fuel Recovery Revenues (Excludes Revenue Taxes)	83,051,811	75,636,500	7,415,231	9.8	83,051,811	75,636,500	7,415,231	9.8
c. Jurisdictional Fuel Revenues	83,051,811	75,636,500	7,415,231	9.8	83,051,811	75,636,500	7,415,231	9.8
d. Non Fuel Revenues	238,075,352	210,100,503	19,974,849	9.2	238,075,352	210,100,503	19,974,849	9.2
e. Total Jurisdictional Sales Revenues	321,127,163	285,737,003	27,390,080	9.3	321,127,163	285,737,003	27,390,080	9.3
2. Non Jurisdictional Sales Revenues	5,109,380	3,404,377	1,705,003	50.1	5,109,380	3,404,377	1,705,003	50.1
3. Total Sales Revenues	326,236,544	289,141,460	29,095,084	9.8	326,236,544	289,141,460	29,095,084	9.8
C. kWh Sales								
1. Jurisdictional Sales kWh	5,637,907,154	5,164,879,000	473,028,154	9.2	5,637,907,154	5,164,879,000	473,028,154	9.2
2. Non Jurisdictional Sales (excluding FERC & CEV)	26,881,677	7,550,000	19,331,677	256.0	26,881,677	7,550,000	19,331,677	256.0
3. Sales (excluding FERC & CEV)	5,664,788,831	5,172,429,000	492,359,831	9.5	5,664,788,831	5,172,429,000	492,359,831	9.5
4. Non Jurisdictional Sales to Other FERC Customers	71,767,669	58,180,000	13,587,669	23.4	71,767,669	58,180,000	13,587,669	23.4
5. Total Sales	5,736,556,500	5,230,609,000	505,947,500	9.7	5,736,556,500	5,230,609,000	505,947,500	9.7
6. Jurisdictional Sales % of Total kWh Sales (lines C1/C3)	99.525463	99.854033	(0.32857)3	(0.3)	99.525463	99.854033	(0.32857)3	(0.3)

CALCULATION OF TRUE-UP AND INTEREST PROVISION

SCHEDULE A2

Page 3 of 4

Company: Florida Power & Light Company

Month of: April 1994

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
D. True-up Calculation								
1. Jurisdictional Fuel Revenues (line 8-1c)	\$ 83,051,811	\$ 75,636,580	\$ 7,415,231	9.8	\$ 83,051,811	\$ 75,636,580	\$ 7,415,231	9.8
2. Fuel Adjustment Revenues Not Applicable to Period								
a. True-up Provision	23,967,419	23,967,419	0	0.0	23,967,419	23,967,419	0	0.0
b. In-Period True-up	0	0	0	N/A	0	0	0	N/A
c. Incentive Provision, Net of Revenue Taxes (a)	(143,015)	(143,015)	0	0.0	(143,015)	(143,015)	0	(0.0)
3. Jurisdictional Fuel Revenues Applicable to Period	106,876,216	99,460,984	7,415,232	7.5	106,876,216	99,460,984	7,415,232	7.5
4. Adj Total Fuel Costs & Net Power Transaction (Line A-7)	107,960,289	100,095,114	7,865,175	7.9	107,960,289	100,095,114	7,865,175	7.9
a. Nuclear Fuel Expense - 100% Retail	165,715	0	165,715	N/A	165,715	0	165,715	N/A
b. DOE Disposal Costs Credit & D&D Fund Pymnt-100% Retail	0	4,380,000	(4,380,000)	(100.0)	0	4,380,000	(4,380,000)	(100.0)
c. Adjusted Total Fuel Costs & Net Power Transaction excluding 100% Retail Nuclear Fuel Expense, DOE Credit and payment to DOE for the D&D fund (Lines D4a & D4b)	107,794,574	95,715,114	12,079,460	12.6	107,794,574	95,715,114	12,079,460	12.6
5. Jurisdictional Sales % of Total kWh Sales (Line C-6)	99.52546%	99.85403%	(0.32857)%	(0.3)	N/A	N/A	---	N/A
6. Jurisdictional Total Fuel Costs & Power Transaction (Line D4c x D5 x 1.00035(b)) + (Line D4a) + (Line D4b)	107,486,310	99,988,850	7,497,460	7.5	107,486,310	99,988,850	7,497,460	7.5
7. True-up Provision for the Month Over/(Under) Collection (Line D3 - Line D6)	(610,094)	(527,866)	(82,228)	15.6	(610,094)	(527,866)	(82,228)	15.6
8. Interest Provision for the Month (Line E10)	422,455	0	422,455	N/A	422,455	0	422,455	N/A
9. True-up & Interest Provision Beg. of Month	143,804,515	143,804,515	0	---	143,804,515	143,804,515	0	0.0
9a. Deferred True-up Beginning of Period	2,066,794	0	2,066,794	N/A	2,066,794	0	2,066,794	N/A
10. True-up Collected (Refunded)	(23,967,419)	(23,967,419)	0	0.0	(23,967,419)	(23,967,419)	0	0.0
11. End of Period - Net True-up - Over/(Under) Recovery (Lines D7 through D10)	\$ 121,716,250	\$ 119,309,230	\$ 2,407,020	2.0	\$ 121,716,250	\$ 119,309,230	\$ 2,407,020	2.0

(a) GPIF REWARD OF \$871,893 / 6 Mo. x 98.4167% Revenue Tax Factor = \$143,015

(b) Jurisdictional Loss Multiplier

CALCULATION OF TRUE-UP AND INTEREST PROVISION

SCHEDULE A2

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Company: Florida Power & Light Company

Month of: APRIL 1996

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
8. Interest Provision								
1. Beginning True-up Amount (Lines 09 + 09a)	\$ 145,873	N/A	N/A	---	N/A	N/A	---	---
2. Ending True-up Amount Before Interest (Line 07 + Lines 09 + 09a + 010)	121,203	N/A	N/A	---	N/A	N/A	---	---
3. Total of Beginning & Ending True-up Amount	267,103	N/A	N/A	---	N/A	N/A	---	---
4. Average True-up Amount (50% of Line 03)	\$ 133,562	N/A	N/A	---	N/A	N/A	---	---
5. Interest Rate - First Day Reporting Business Month	3.4%	N/A	N/A	---	N/A	N/A	---	---
6. Interest Rate - First Day Subsequent Business Month	3.4%	N/A	N/A	---	N/A	N/A	---	---
7. Total (Line 05 + Line 06)	7.5%	N/A	N/A	---	N/A	N/A	---	---
8. Average Interest Rate (50% of Line 07)	3.75%	N/A	N/A	---	N/A	N/A	---	---
9. Monthly Average Interest Rate (Line 08 / 12)	0.3125%	N/A	N/A	---	N/A	N/A	---	---
10. Interest Provision (Line 04 x Line 09)	\$ 422,455	N/A	N/A	---	N/A	N/A	---	---

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

MONTH OF: APRIL 1964

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATE	DIFFERENCE AMOUNT	\$	ACTUAL	ESTIMATE	DIFFERENCE AMOUNT	\$
FUEL COST OF SYSTEM NET GENERATION (\$)								
1 * HEAVY OIL	58,382,964	54,348,491	24,134,543	70.5	58,382,964	54,348,491	24,134,543	70.5
2 * LIGHT OIL	60,869	57,828	3,041	5.3	60,869	57,828	3,041	5.3
3 COAL	5,914,475	7,575,570	(1,661,095)	(21.9)	5,914,475	7,575,570	(1,661,095)	(21.9)
4 GAS	18,120,234	21,894,538	(3,774,304)	(17.2)	18,120,234	21,894,538	(3,774,304)	(17.2)
5 NUCLEAR	6,279,752	6,370,806	(90,054)	(1.4)	6,279,752	6,370,806	(90,054)	(1.4)
6 OILDERIVATION	0	0	0	0.0	0	0	0	0.0
7 TOTAL CO	88,758,294	79,166,375	19,591,919	24.5	88,758,294	79,166,375	19,591,919	24.5
SYSTEM NET GENERATION (KW)								
8 HEAVY OIL	2,945,643	1,624,201	1,321,442	81.4	2,945,643	1,624,201	1,321,442	81.4
9 LIGHT OIL	640	975	(295)	(21.6)	640	975	(295)	(21.6)
10 COAL	380,575	455,457	(74,882)	(20.8)	380,575	455,457	(74,882)	(20.8)
11 GAS	1,284,258	1,125,195	159,063	7.1	1,284,258	1,125,195	159,063	7.1
12 NUCLEAR	1,080,178	1,176,775	(96,597)	(8.3)	1,080,178	1,176,775	(96,597)	(8.3)
13 OILDERIVATION	0	0	0	0.0	0	0	0	0.0
14 TOTAL (KW)	5,392,294	4,382,546	1,009,748	27.6	5,392,294	4,382,546	1,009,748	27.6
UNITS OF FUEL BURNED								
15 * HEAVY OIL (MM)	4,518,614	2,693,140	2,825,474	91.2	4,518,614	2,693,140	2,825,474	91.2
16 * LIGHT OIL (MM)	2,100	2,002	98	4.9	2,100	2,002	98	4.9
17 COAL (TON)	181,552	175,972	7,580	4.4	181,552	175,972	7,580	4.4
18 GAS (MMCU)	8,615,312	9,694,735	(881,423)	(9.3)	8,615,312	9,694,735	(881,423)	(9.3)
19 NUCLEAR (MMBTU)	12,160,192	13,285,735	(1,125,543)	(9.3)	12,160,192	13,285,735	(1,125,543)	(9.3)
20 OILDERIVATION (TON)	0	0	0	0.0	0	0	0	0.0
21 BTU BURNED (MMBTU)	28,795,966	15,875,464	12,920,502	81.4	28,795,966	15,875,464	12,920,502	81.4
22 LIGHT OIL	12,201	11,612	589	5.1	12,201	11,612	589	5.1
23 COAL	3,488,634	4,328,959	(840,325)	(19.4)	3,488,634	4,328,959	(840,325)	(19.4)
24 GAS	8,615,312	9,694,735	(881,423)	(9.3)	8,615,312	9,694,735	(881,423)	(9.3)
25 NUCLEAR	12,160,192	13,285,735	(1,125,543)	(9.3)	12,160,192	13,285,735	(1,125,543)	(9.3)
26 OILDERIVATION	0	0	0	0.0	0	0	0	0.0
27 TOTAL (MMBTU)	53,672,307	42,998,902	10,673,405	23.4	53,672,307	42,998,902	10,673,405	23.4
GENERATION MIX (PERCENT)								
28 HEAVY OIL	52.67	37.06	15.61	42.1	52.67	37.06	15.61	42.1
29 LIGHT OIL	0.01	0.02	(0.01)	(30.1)	0.01	0.02	(0.01)	(30.1)
30 COAL	6.45	10.39	(3.94)	(57.9)	6.45	10.39	(3.94)	(57.9)
31 GAS	21.55	25.67	(4.12)	(16.4)	21.55	25.67	(4.12)	(16.4)
32 NUCLEAR	19.32	24.85	(7.53)	(28.6)	19.32	24.85	(7.53)	(28.6)
33 OILDERIVATION	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
34 TOTAL (%)	100.00	100.00	(0.01)	0.0	100.00	100.00	0.00	0.0
FUEL COST PER UNIT								
35 * HEAVY OIL (\$/KW)	12.9285	13.7371	(0.8186)	(5.9)	12.9285	13.7371	(0.8186)	(5.9)
36 * LIGHT OIL (\$/KW)	28.9852	28.8837	0.1015	0.4	28.9852	28.8837	0.1015	0.4
37 COAL (\$/TON)	32.5773	43.5448	(10.9675)	(25.2)	32.5773	43.5448	(10.9675)	(25.2)
38 GAS (\$/MMCU)	2.1033	2.3055	(0.2022)	(8.8)	2.1033	2.3055	(0.2022)	(8.8)
39 NUCLEAR (\$/MMBTU)	0.5164	0.4795	0.0369	7.7	0.5164	0.4795	0.0369	7.7
40 OILDERIVATION (\$/TON)	0.0000	0.0000	0.0000	0.0	0.0000	0.0000	0.0000	0.0
FUEL COST PER MMBTU (\$/MMBTU)								
41 * HEAVY OIL	2.0275	2.1573	(0.1298)	(6.0)	2.0275	2.1573	(0.1298)	(6.0)
42 * LIGHT OIL	4.9889	4.9889	0.0000	0.0	4.9889	4.9889	0.0000	0.0
43 COAL	1.0934	1.7500	(0.6566)	(21.1)	1.0934	1.7500	(0.6566)	(21.1)
44 GAS	2.1033	2.3055	(0.2022)	(8.8)	2.1033	2.3055	(0.2022)	(8.8)
45 NUCLEAR	0.5164	0.4795	0.0369	7.7	0.5164	0.4795	0.0369	7.7
46 OILDERIVATION	0.0000	0.0000	0.0000	0.0	0.0000	0.0000	0.0000	0.0
47 TOTAL (\$/MMBTU)	1.6724	1.6314	0.0410	2.5	1.6724	1.6314	0.0410	2.5
BTU BURNED PER KW (\$/TUEW)								
48 HEAVY OIL	9.776	9.776	0	0.0	9.776	9.776	0	0.0
49 LIGHT OIL	19.884	12.417	6.467	53.5	19.884	12.417	6.467	53.5
50 COAL	9.675	9.505	0.170	1.8	9.675	9.505	0.170	1.8
51 GAS	7.148	8.440	(1.292)	(15.3)	7.148	8.440	(1.292)	(15.3)
52 NUCLEAR	11.258	11.258	0.000	0.0	11.258	11.258	0.000	0.0
53 OILDERIVATION	0	0	0	0.0	0	0	0	0.0
54 TOTAL (\$/TUEW)	9.675	9.511	0.164	1.7	9.675	9.511	0.164	1.7
GENERATED FUEL COST PER KW (\$/KWH)								
55 * HEAVY OIL	1.9838	2.1088	(0.1250)	(6.0)	1.9838	2.1088	(0.1250)	(6.0)
56 * LIGHT OIL	9.5106	6.1835	3.3271	53.8	9.5106	6.1835	3.3271	53.8
57 COAL	1.6889	1.6833	0.0056	(0.4)	1.6889	1.6833	0.0056	(0.4)
58 GAS	1.5034	1.9456	(0.4422)	(22.7)	1.5034	1.9456	(0.4422)	(22.7)
59 NUCLEAR	0.5214	0.5413	(0.0199)	(3.4)	0.5214	0.5413	(0.0199)	(3.4)
60 OILDERIVATION	0.0000	0.0000	0.0000	0.0	0.0000	0.0000	0.0000	0.0
61 TOTAL (\$/KWH)	1.5872	1.5872	(0.0134)	(0.8)	1.5872	1.5872	0.0000	0.0

* Coalbed & Propane (C&P) used for

MONTH OF: APRIL 1994

	BPM9	CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	AMOUNT	DIFFERENCE %
1	SYSTEM NET GENERATION	6,692,764	4,362,663	1,208,731	27.6	6,692,763	4,363,666	1,208,727	27.6
2	POWER SOLD	(190,861)	(112,726)	(78,248)	69.4	(190,861)	(112,736)	(78,248)	69.4
3	INADVERTENT INTERCHANGE DELIVERED - NET	0	0	0	NA	0	0	0	NA
4	PURCHASED POWER	736,073	1,126,428	(391,369)	(34.8)	736,073	1,126,428	(391,369)	(34.8)
4a	ENERGY PURCH FROM QUALIFYING FACILITIES	412,822	386,420	27,602	7.1	412,822	386,420	27,602	7.1
6	ECONOMY PURCHASES	22,030	102	21,828	NA	22,030	102	21,828	NA
6	INADVERTENT INTERCHANGES RECEIVED - NET	0	0	0	NA	0	0	0	NA
7	NET ENERGY FOR LOAD	6,672,336	6,780,778	781,668	13.7	6,672,337	6,780,782	781,668	13.7
8	SALES (BILLED)	6,736,667	6,230,606	606,848	8.7	6,736,667	6,230,606	606,848	8.7
8a	UNBILLED SALES PRIOR MONTH (PERIOD)	2,636,160	3,226,318	(600,168)	(18.2)	2,636,160	3,226,318	(600,168)	(18.2)
8b	UNBILLED SALES CURRENT MONTH (PERIOD)	2,898,808	3,344,931	(368,026)	(10.7)	2,898,808	3,344,931	(368,026)	(10.7)
9	COMPANY USE	18,848	17,342	(1,784)	(10.3)	18,848	17,342	(1,784)	(10.3)
10	T & D LOSSES (ESTIMATED)	473,488	416,218	67,271	13.8	473,488	416,218	67,271	13.8
11	UNACCOUNTED FOR ENERGY (ESTIMATED)	0	0	0	-	0	0	0	-
12									
13	% COMPANY USE TO NEL	0.2	0.3	(0.1)	--	0.2	0.3	(0.1)	--
14	% T & D LOSSES TO NEL	7.20	7.20	0.00	--	7.20	7.20	0.00	--
15	% UNACCOUNTED FOR ENERGY TO NEL	0.0	0.0	0.0	--	0.0	0.0	0.0	--

(8)									
16	FUEL COST OF SYSTEM NET GENERATION	88,768,294	70,146,373	18,611,821	26.5	88,768,294	70,146,373	18,611,821	26.5
16a	FUEL RELATED TRANSACTIONS	1,386,328	6,782,346	(4,396,017)	(78.0)	1,386,328	6,782,346	(4,396,017)	(78.0)
16b	ADJUSTMENTS TO FUEL COST	(1,432,346)	(1,213,821)	(218,524)	18.0	(1,432,346)	(1,213,821)	(218,524)	18.0
17	FUEL COST OF POWER SOLD	(4,886,808)	(2,302,602)	(2,384,307)	104.0	(4,886,808)	(2,302,602)	(2,384,307)	104.0
18	FUEL COST OF PURCHASED POWER	18,406,601	20,868,318	(4,462,817)	(21.3)	18,406,601	20,868,318	(4,462,817)	(21.3)
18a	DEMAND & NON FUEL COST OF PURCH POWER	0	0	0	NA	0	0	0	NA
18b	ENERGY PAYMENTS TO QUALIFYING FACILITIES	7,163,872	6,822,211	341,761	6.0	7,163,872	6,822,211	341,761	6.0
19	ENERGY COST OF ECONOMY PURCHASES	376,348	2,180	373,168	NA	376,348	2,180	373,168	NA
20	TOTAL FUEL & NET POWER TRANSACTIONS	107,860,289	100,086,114	7,886,175	7.8	107,860,289	100,086,114	7,886,175	7.8

(9/KWH)									
21	FUEL COST OF SYSTEM NET GENERATION	1.6872	1.6006	(0.0134)	(0.8)	1.6872	1.6006	(0.0134)	(0.8)
21a	FUEL RELATED TRANSACTIONS	-	-	-	-	-	-	-	-
22	FUEL COST OF POWER SOLD	2.4693	2.0424	0.4169	20.4	2.4693	2.0424	0.4169	20.4
23	FUEL COST OF PURCHASED POWER	2.2288	1.8534	0.3754	20.3	2.2288	1.8534	0.3754	20.3
23a	DEMAND & NON FUEL COST OF PURCHASED POWER	-	-	-	-	-	-	-	-
23b	ENERGY PAYMENTS TO QUALIFYING FACILITIES	1.7349	1.7701	(0.0352)	(2.0)	1.7349	1.7701	(0.0352)	(2.0)
24	ENERGY COST OF ECONOMY PURCHASES	1.7038	2.1471	(0.4433)	(20.8)	1.7038	2.1471	(0.4433)	(20.8)
25	TOTAL FUEL & NET POWER TRANSACTIONS	1.6426	1.7316	(0.0889)	(6.1)	1.6426	1.7316	(0.0889)	(6.1)

Florida Power & Light Company
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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIVALENT AVAILABILITY FACTOR (%)	NET OUTPUT FACTOR (%)	AVERAGE NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (MMBTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (\$)	FUEL COST PER KWH (¢/KWH)	COST OF FUEL (\$/UNIT)
1	CAPE CANAVERAL # 1	367	230,680	84.3	95.9	83.7	9,292	#6 OIL	336,232 BBLs	6.374	2,143,270	4,173,531	1.8092	12.41
2	# 1		556					OAS	5,462 MCP	1.000	5,462	11,496	2.0876	2.10
3	# 2	367	152,776	39.9	69.5	77.9	9,588	#6 OIL	229,087 BBLs	6.374	1,460,201	2,843,408	1.8612	12.41
4	# 2		816					GAS	12,506 MCP	1.000	12,506	26,321	3.2256	2.10
5	FT. MYERS # 1	137	70,671	67.7	84.2	80.8	10,147	#6 OIL	113,103 BBLs	6.340	717,073	1,398,480	1.9789	12.36
6	# 2	367	156,302	65.0	72.5	84.9	9,396	#6 OIL	231,635 BBLs	6.340	1,468,546	2,864,088	1.8324	12.36
7	LAUDERDALE # 4	391	0	90.1	100.0	93.2	7,708	#2 OIL	0 BBLs	0.000	0	0	0.0000	0.00
8	# 4		273,411					GAS	2,107,316 MCP	1.000	2,107,316	4,435,196	1.6322	2.10
9	# 5	391	(24)	91.3	98.7	92.9	7,848	#2 OIL	49 BBLs	5.617	275	1,399	0.0000	28.95
10	# 5		256,189					GAS	2,010,204 MCP	1.000	2,010,204	4,230,808	1.6514	2.10
11	MANATEE # 1	783	298,766	51.2	75.1	67.8	9,849	#6 OIL	463,000 BBLs	6.368	2,948,384	6,044,523	2.0232	13.06
12	# 2	783	411,116	70.8	96.1	71.3	9,788	#6 OIL	631,910 BBLs	6.368	4,024,003	8,249,678	2.0067	13.06
13	MARTIN # 1	783	228,042	43.0	97.3	53.2	10,296	#6 OIL	364,759 BBLs	6.413	2,339,199	5,642,542	2.4743	15.47
	# 1		17,862					OAS	192,602 MCP	1.000	192,602	405,363	2.2694	2.10
	# 2	783	100,397	20.4	96.8	43.3	10,287	#6 OIL	159,980 BBLs	6.413	1,023,952	2,474,768	2.4601	15.47
	# 2		3,011					OAS	39,897 MCP	1.000	39,897	83,970	2.7888	2.10
	# 3	426	0	87.5	88.1	86.3	7,169	#2 OIL	0 BBLs	0.000	0	0	0.0000	0.00
	# 3		272,152					OAS	1,951,187 MCP	1.000	1,951,187	4,106,998	1.9089	2.10
	# 4	426	0	92.1	100.0	96.9	10,505	#2 OIL	0 BBLs	0.000	0	0	0.0000	0.00
	# 4		176,127					OAS	1,284,443 MCP	1.000	1,284,443	2,691,203	1.5280	2.10
21	PT EVERGLADES # 1	204	113,623	75.2	99.6	76.7	10,061	#6 OIL	178,035 BBLs	6.413	1,142,095	2,293,933	2.0207	12.90
22	# 1		781					OAS	8,972 MCP	1.000	8,972	18,883	2.4178	2.10
23	# 2	204	49,828	28.8	38.2	77.4	10,162	#6 OIL	78,773 BBLs	6.413	505,329	1,015,834	2.0367	12.90
24	# 2		(100)					GAS	0 MCP	1.000	0	0	0.0000	0.00
25	# 3	367	164,636	66.6	79.4	87.3	9,661	#6 OIL	246,964 BBLs	6.413	1,584,274	3,184,839	1.9345	12.90
26	# 3		5,958					GAS	44,554 MCP	1.000	44,554	93,771	2.3692	2.10
27	# 4	367	79,062	21.6	25.4	83.2	9,640	#6 OIL	118,581 BBLs	6.413	760,697	1,529,316	1.9542	12.90
28	# 4		(142)					OAS	104 MCP	1.000	104	219	0.0000	2.11

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)		
	PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIVALENT AVAILABILITY FACTOR (%)	NET OUTPUT FACTOR (%)	AVERAGE NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (MMBTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (¢)	FUEL COST PER KWH (¢/KWH)	COST OF FUEL (¢/BRT)		
1	RIVIERA	#3	272	(218)	0.0	0.0	81.8	0	#6 OIL	0	BBLs	0.000	0	0.0000	0.00	
2		#3		(218)					GAS	0	MCF	1.000	0	0.0000	0.00	
3		#4	272	136,870	66.3	75.3	87.1	9,806	#6 OIL	209,970	BBLs	6.382	1,340,029	2,496,711	1.8241	11.89
4		#4		(67)					GAS	1,467	MCF	1.000	1,467	3,088	0.0000	2.10
5	SANFORD	#3	137	15,393	9.7	26.4	67.0	10,618	#6 OIL	25,674	BBLs	6.306	161,900	302,965	1.9682	11.80
		#3		(146)					GAS	0	MCF	1.000	0	0	0.0000	0.00
6		#4	362	182,962	68.3	100.0	75.2	9,898	#6 OIL	287,176	BBLs	6.306	1,810,932	3,388,814	1.8522	11.80
		#4		0					GAS	0	MCF	1.000	0	0	0.0000	0.00
		#4		0					ORIM	0	TONS	0.000	0	0	0.0000	0.00
7		#5	362	210,823	78.6	100.0	79.6	9,896	#6 OIL	330,831	BBLs	6.306	2,086,220	3,903,964	1.8518	11.80
11	TURKEY POINT	#1	387	181,964	57.3	72.4	85.4	9,321	#6 OIL	265,092	BBLs	6.391	1,694,203	3,397,692	1.8672	12.82
12		#1		686					GAS	8,230	MCF	1.000	8,230	17,363	2.3310	2.10
13		#2	367	161,730	66.2	88.7	80.0	9,813	#6 OIL	247,792	BBLs	6.391	1,583,639	3,175,958	1.9635	12.82
14		#2		4,845					GAS	51,109	MCF	1.000	51,109	107,567	2.2202	2.10
15	CUTLER	#5	67	0	0.0	0.0	0.0	0	#6 OIL	0	BBLs	0.000	0	0	0.0000	0.00
16		#5		0					GAS	0	MCF	1.000	0	0	0.0000	0.00
17		#6	140	0	0.0	0.0	0.0	0	#6 OIL	0	BBLs	0.000	0	0	0.0000	0.00
18		#6		0					GAS	0	MCF	1.000	0	0	0.0000	0.00
19	FT MYERS	1-12	365	9	0.0	100.0	0.0	14,222	#2 OIL	22	BBLs	5.829	128	636	7.0667	28.91
20	LAUDERDALE	1-12	364	48	0.1	100.0	19.6	16,879	#2 OIL	125	BBLs	5.779	723	3,555	7.4083	28.44
21		11-12		184					GAS	3,194	MCF	1.000	3,194	6,722	3.6533	2.10
22		13-24	364	18	0.2	100.0	87.6	16,919	#2 OIL	83	BBLs	5.779	480	2,380	13.1111	28.43
23		13-24		574					GAS	9,536	MCF	1.000	9,536	20,870	3.4965	2.10
24	EVERGLADES	1-12	364	78	0.4	63.2	60.5	18,308	#2 OIL	270	BBLs	5.762	1,556	7,679	9.8449	28.44
25		1-12		966					GAS	17,558	MCF	1.000	17,558	36,954	3.8235	2.10

* INCLUDES CRANKING DIESELS

** EXCLUDES CRANKING DIESELS

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	PLANT/UNIT	NET CAPABILITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIVALENT AVAILABILITY FACTOR (%)	NET OUTPUT FACTOR (%)	AVERAGE NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (MMBTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST (¢)	FUEL COST PER KWH (¢/KWH)	COST OF FUEL (\$/UNIT)	
42	PUTNAM	# 1	239	0	17.3	67.5	51.1	10,087	#6 OIL	0 BBLs	0.000	0	0.0000	0.00	
		# 1		0				#2 OIL	347 BBLs	5.828	2,022	12,433	0.0000	35.83	
		# 1		25,812				GAS	258,350 MCF	1.000	258,350	543,740	2.1065	2.10	
		# 2	239	0	31.8	94.6	76.8	9,259	#6 OIL	0 BBLs	0.000	0	0.0000	0.00	
		# 2		0				#2 OIL	353 BBLs	5.828	2,057	12,648	0.0000	35.83	
		# 2		65,950				GAS	608,601 MCF	1.000	608,601	1,280,902	1.9422	2.10	
7	ST JOHNS (1)	# 1	(A) 125	(B) 86,665	97.6	98.2	97.4	(B) 9,301	(C) COAL	34,781 TONS	23.674	823,405	1,362,893	1.5726	39.18
8		# 1	(A)	(B) 48				(B) #2 OIL	(C) 78 BBLs	5.830	455	1,855	3.8646	23.78	
9		# 2	(A) 125	(B) 56,193	63.7	66.1	93.5	(B) 9,738	(C) COAL	21,872 TONS	25.018	547,194	857,054	1.5252	39.18
10		# 2	(A)	(B) 443				(B) #2 OIL	(C) 740 BBLs	5.830	4,314	17,990	3.9707	23.77	
11	SCHERER	# 4	416	217,717	71.9	100.0	71.9	9,728	COAL	124,899 TONS	16.958	2,118,037	3,694,528	1.6969	29.58
12		# 4		20				#2 OIL	33 BBLs	5.817	192	714	3.5700	21.64	
13	TURKEY POINT	# 3	666	85,989	7.8	10.4	83.7	11,566	NUCLEAR	994,531 MMBTU	---	994,531	594,951	0.6919	0.60
14		# 4	666	303,436	101.7	100.0	101.7	11,068	NUCLEAR	5,571,928 MMBTU	---	5,571,928	2,792,590	0.5547	0.50
15	ST LUCIE	# 1	839	500,419	89.7	90.3	98.2	11,029	NUCLEAR	5,518,916 MMBTU	---	5,518,916	2,887,685	0.5771	0.52
16		# 2	714	(9,666)	2.3	9.9	39.6	0	NUCLEAR	74,817 MMBTU	---	74,817	4,526	0.0000	0.06
17															
18															
19															
20	SYSTEM TOTALS	15,198	5,490,243	----	----	----	9,667	----	4,520,714 BBLs	----	53,072,307	88,758,294	1.6167	----	
21			* Exclude 101,051 Mwh (Martin 4) of ice energy which was capitalized.						8,615,312 MCF						
22	*** EXCLUDES PARTICIPANTS								181,552 TONS	COAL					
23	*** INCLUDES PARTICIPANTS								0 TONS	ORIMULSION					
24	(1) CALCULATED ON CALENDAR MONTH PERIOD. OTHER DATA IS FISCAL.								12,160,192 MMBTU	NUCLEAR					

(A) FPL SHARE. (B) CALCULATED ON GENERATION RECEIVED NET OF LINE LOSSES. (C) #2 OIL - PREVIOUSLY REPORTED AS PART OF COAL.

COSTS BY FUEL TYPE

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE		ACTUAL	ESTIMATED	DIFFERENCE	
				AMOUNT	%			AMOUNT	%
1 PURCHASES		***** HEAVY OIL *****							
2	UNITS (BBL)	6,956,719	2,794,000	2,162,719	77.4	6,956,719	2,794,000	2,162,719	77.4
3	UNIT COST (\$/BBL)	12.0728	16.3507	1.4779-	10.3-	12.0728	16.3507	1.4779-	10.3-
4	AMOUNT (\$)	63,006,041	40,095,000	23,710,051	59.1	63,006,041	40,095,000	23,710,051	59.1
5 BURNED		***** HEAVY OIL *****							
6	UNITS (BBL)	6,520,225	2,493,141	2,027,084	81.3	6,520,225	2,493,141	2,027,084	81.3
7	UNIT COST (\$/BBL)	12.9046	13.7371	.8325-	6.1-	12.9046	13.7371	.8325-	6.1-
8	AMOUNT (\$)	50,331,092	34,240,403	26,083,409	70.3	50,331,092	34,240,403	26,083,409	70.3
9 ENDING INVENTORY		***** HEAVY OIL *****							
10	UNITS (BBL)	3,974,826	4,212,012	237,186-	5.6-	3,974,826	4,212,012	237,186-	5.6-
11	UNIT COST (\$/BBL)	13.1450	14.3910	1,2460-	8.7-	13.1450	14.3910	1,2460-	8.7-
12	AMOUNT (\$)	52,249,050	60,615,190	8,366,140-	13.8-	52,249,050	60,615,190	8,366,140-	13.8-
13	OTHER USAGE (\$)	232,114-				232,114-			
14	DAYS SUPPLY	27							
15 PURCHASES		***** LIGHT OIL *****							
16	UNITS (BBL)	6,777	0	6,777	100.0	6,777	0	6,777	100.0
17	UNIT COST (\$/BBL)	26.0703	.0000	26.0703	100.0	26.0703	.0000	26.0703	100.0
18	AMOUNT (\$)	182,100	0	182,100	100.0	182,100	0	182,100	100.0
19 BURNED		***** LIGHT OIL *****							
20	UNITS (BBL)	2,414	2,002	412	20.6	2,414	2,002	412	20.6
21	UNIT COST (\$/BBL)	28.2800	28.8851	.6051-	2.1-	28.2800	28.8851	.6051-	2.1-
22	AMOUNT (\$)	68,268	57,828	10,440	18.1	68,268	57,828	10,440	18.1
23 ENDING INVENTORY		***** LIGHT OIL *****							
24	UNITS (BBL)	246,572	150,218	96,354	64.1	246,572	150,218	96,354	64.1
25	UNIT COST (\$/BBL)	29.7465	31.0502	1,3037-	4.2-	29.7465	31.0502	1,3037-	4.2-
26	AMOUNT (\$)	7,334,647	4,664,305	2,670,342	57.3	7,334,647	4,664,305	2,670,342	57.3
27	OTHER USAGE (\$)								
28	DAYS SUPPLY								
29 PURCHASES		***** COAL *****							
30	UNITS (TON)	203,000	172,000	31,000	10.4	203,000	172,000	31,000	10.4
31	UNIT COST (\$/TON)	34.5200	43.6791	9,1591-	20.9-	34.5200	43.6791	9,1591-	20.9-
32	AMOUNT (\$)	7,030,194	7,512,810	482,616-	6.6-	7,030,194	7,512,810	482,616-	6.6-
33 BURNED		***** COAL *****							
34	UNITS (TON)	181,952	173,972	7,980	4.4	181,952	173,972	7,980	4.4
35	UNIT COST (\$/TON)	32.5773	43.5460	10,9675-	25.2-	32.5773	43.5460	10,9675-	25.2-
36	AMOUNT (\$)	5,914,675	7,575,572	1,661,097-	21.9-	5,914,675	7,575,572	1,661,097-	21.9-
37 ENDING INVENTORY		***** COAL *****							
38	UNITS (TON)	230,521	264,337	33,816-	12.8-	230,521	264,337	33,816-	12.8-
39	UNIT COST (\$/TON)	38.2028	43.9628	5,7600-	13.1-	38.2028	43.9628	5,7600-	13.1-
40	AMOUNT (\$)	8,806,546	11,620,988	2,814,442-	24.2-	8,806,546	11,620,988	2,814,442-	24.2-
41	OTHER USAGE (\$)								
42	DAYS SUPPLY								
43 BURNED		***** GAS *****							
44	UNITS (MCF)	8,615,312	9,496,734	881,422-	9.3-	8,615,312	9,496,734	881,422-	9.3-
45	UNIT COST (\$/MCF)	2.1033	2.3055	.2022-	8.8-	2.1033	2.3055	.2022-	8.8-
46	AMOUNT (\$)	18,120,234	21,894,696	3,774,462-	17.2-	18,120,234	21,894,696	3,774,462-	17.2-
47 BURNED		***** NUCLEAR *****							
48	UNITS (MMBTU)	12,160,192	13,285,736	1,125,544-	8.5-	12,160,192	13,285,736	1,125,544-	8.5-
49	UNIT COST (\$/MMBTU)	.5164	.4795	.0369	7.7	.5164	.4795	.0369	7.7
50	AMOUNT (\$)	6,279,752	6,370,036	90,284-	1.4-	6,279,752	6,370,036	90,284-	1.4-
51 BURNED		***** CRACKED *****							
52	UNITS (TON)	0	0	0	100.0	0	0	0	100.0
53	UNIT COST (\$/TON)	.0000	.0000	.0000	100.0	.0000	.0000	.0000	100.0
54	AMOUNT (\$)	0	0	0	100.0	0	0	0	100.0
55 BURNED		***** PROPANE *****							
56	UNITS (GAL)	3,152	100	3,052	100.0	3,152	100	3,052	100.0
57	UNIT COST (\$/GAL)	.7586	1.0000	.2414-	24.1-	.7586	1.0000	.2414-	24.1-
58	AMOUNT (\$)	2,391	100	2,291	100.0	2,391	100	2,291	100.0

LINES 9 & 23 EXCLUDE 2,000 BARRELS, \$(41,281) CURRENT MONTH AND 2,000 BARRELS, \$(41,281) PERIOD-TO-DATE.

LINE 50 EXCLUDES NUCLEAR DISPOSAL COST OF 1,000,804 CURRENT MONTH AND 1,000,804 PERIOD-TO-DATE.

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD (000)	KWH WHEELED FROM OTHER SYSTEMS (000)	KWH FROM OWN GENERATION (000)	cents/KWH		TOTAL \$ FOR FUEL ADJ. (5) x (6)(a)	TOTAL COST \$ (5) x (6)(b)
					(a) FUEL COST	(b) TOTAL COST		
ESTIMATED:								
	C, A, B, OS	69,475	0	69,475	2.430	3.300	1,668,240	2,282,672
	S	0	0	0	0.000	0.000	0	0
ST. LUCIE RELIABILITY		43,260	0	43,260	0.540	0.540	233,604	233,604
80% OF GAIN ON ECONOMY SALES							380,658	
TOTAL		112,735	0	112,735	1.705	2.241	2,302,502 *	2,526,276
ACTUAL:								
ECONOMY		139,527	0	139,527	2.344	3.094	3,270,051	4,316,469
FMPA (SL 1)		21,729	0	21,729	0.615	0.615	133,548	133,548
OUC (SL 1)		15,027	0	15,027	0.749	0.749	112,528	112,528
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		924	0	924	1.907	2.193	17,610	20,262
FT. PIERCE UTILITIES AUTHORITY	OS	6,876	0	6,876	2.219	2.797	152,579	192,289
UTILITY BOARD OF THE CITY OF KEY WEST	OS	3,698	0	3,698	2.423	3.023	89,609	111,797
CITY OF LAKE WORTH UTILITIES	OS	1,718	0	1,718	2.288	2.878	39,313	49,443
UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH	OS	345	0	345	2.299	2.908	7,931	10,031
OGLETHORPE POWER CORPORATION	OS	466	0	466	2.209	2.893	10,295	13,480
FLORIDA KEYS ELECTRIC COOPERATIVE		671	0	671	3.905	3.905	26,204	26,204
ECONOMY SUB-TOTAL		139,527	0	139,527	2.344	3.094	3,270,051	4,316,469
ST. LUCIE PARTICIPATION SUB-TOTAL		30,758	0	30,758	0.689	0.689	246,074	246,074
SALES EXCLUSIVE OF ECONOMY AND ST. LUCIE PARTICIPATION SUB-TOTAL		14,698	0	14,698	2.337	2.661	343,550	423,508
80% OF GAIN ON ECONOMY SALES (SEE SCHED A7a)							837,134	
TOTAL		190,981	0	190,981	2.021	2.611	4,696,809 *	4,986,049
CURRENT MONTH:								
DIFFERENCE		78,246	0	78,246	0.316	0.370	2,394,307	2,458,773
DIFFERENCE (%)		69.4	0.0	69.4	16.5	16.5	104.0	97.4
PERIOD TO DATE:								
ACTUAL		190,981	0	190,981	2.021	2.611	4,696,809	4,986,049
ESTIMATED		112,735	0	112,735	1.705	2.241	2,302,502	2,526,276
DIFFERENCE		78,246	0	78,246	0.316	0.370	2,394,307	2,458,773
DIFFERENCE (%)		69.4	0.0	69.4	16.5	16.5	104.0	97.4

* ONLY TOTAL \$ INCLUDES 80% OF GAIN ON ECONOMY SALES.

(1)	(2)	(3)	(4)		(5)		(6)
SOLD TO	TYPE & SCHEDULE	TOTAL KWH SOLD (000)	\$		cents/KWH		GAIN ON ECONOMY ENERGY SALES (4)(b) - (4)(a)
			(a) FUEL COST	(b) TOTAL COST	(a) FUEL COST	(b) TOTAL COST	
ESTIMATED:							
80% OF GAIN ON ECONOMY SALES	C	59,789	1,502,498	1,978,320	2.513	3.309	475,822
TOTAL		59,789	1,502,498	1,978,320	2.513	3.309	x .80 380,658
ACTUAL:							
FLORIDA MUNICIPAL POWER AGENCY	C	866	18,842	18,591	1.945	2.147	1,748
FLORIDA POWER CORPORATION	C	46,195	1,080,895	1,502,498	2.339	3.252	421,785
FT. PIERCE UTILITIES AUTHORITY	C	1,285	25,729	29,144	2.002	2.268	3,415
CITY OF GAINESVILLE	C	3,741	74,360	87,032	1.988	2.328	12,672
CITY OF HOMESTEAD	C	617	12,422	15,549	2.013	2.520	3,127
JACKSONVILLE ELECTRIC AUTHORITY	C	814	16,467	18,794	2.023	2.309	2,327
UTILITY BOARD OF THE CITY OF KEY WEST	C	1,434	28,953	36,083	1.880	2.518	8,130
KISSIMMEE UTILITY AUTHORITY	C	3,638	83,042	112,835	2.283	3.102	29,783
CITY OF LAKE WORTH UTILITIES	C	123	2,425	2,962	1.972	2.408	537
UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH	C	20	530	851	2.850	4.255	321
ORLANDO UTILITIES COMMISSION	C	8,768	166,893	169,441	1.901	2.161	22,748
REEDY CREEK IMPROVEMENT DISTRICT	C	1,850	38,373	42,320	1.988	2.288	5,947
SEMINOLE ELECTRIC COOPERATIVE, INC.	C	8,724	175,595	222,003	2.013	2.545	46,408
SOUTHERN COMPANIES	C	28,372	721,760	1,033,788	2.737	3.820	312,028
CITY OF ST. CLOUD	C	868	20,557	26,238	2.374	3.030	5,681
CITY OF STARKE	C	584	11,874	16,881	2.105	3.312	6,007
CITY OF TALLAHASSEE	C	340	7,287	8,208	2.143	2.414	819
TAMPA ELECTRIC COMPANY	C	1,193	25,873	39,340	2.188	3.298	13,467
CITY OF VERO BEACH	C	3,743	74,892	85,349	2.001	2.288	10,457
CITY OF GAINESVILLE	X	3,072	73,114	88,047	2.388	2.801	12,933
CITY OF HOMESTEAD	X	10,834	250,378	293,115	2.311	2.708	42,738
SEMINOLE ELECTRIC COOPERATIVE, INC.	X	531	12,797	14,821	2.410	2.810	2,124
UTILITY BOARD OF THE CITY OF KEY WEST	OS	5,658	144,333	177,985	2.551	3.148	33,652
CITY OF LAKE WORTH UTILITIES	OS	2,304	58,070	70,895	2.520	3.077	12,825
UTILITIES COMMISSION, CITY OF NEW SMYRNA BEACH	OS	100	2,619	3,179	2.619	3.179	500
CITY OF VERO BEACH	OS	5,875	148,373	180,630	2.525	3.075	32,257
SUB-TOTAL		139,527	3,270,051	4,316,469	2.344	3.094	1,046,418
80% OF GAIN ON ECONOMY SALES							x .80
TOTAL		139,527	3,270,051	4,316,469	2.344	3.094	837,134
CURRENT MONTH:							
DIFFERENCE		76,738	1,767,553	2,338,149	(0.169)	(0.215)	458,476
DIFFERENCE (%)		133.4	117.8	118.2	(0.7)	(0.5)	119.8
PERIOD TO DATE:							
ACTUAL		139,527	3,270,051	4,316,469	2.344	3.094	837,134
ESTIMATED		59,789	1,502,498	1,978,320	2.513	3.308	380,658
DIFFERENCE		79,738	1,767,553	2,338,149	(0.169)	(0.215)	458,476
DIFFERENCE (%)		133.4	117.8	118.2	(0.7)	(0.5)	119.8

PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASE)
FOR THE MONTH OF APRIL 1994

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	KWH FOR OTHER UTILITIES (000)	KWH FOR INTERRUPTIBLE (000)	KWH FOR FIRM (000)	cents/KWH		TOTAL \$ FOR FUEL ADJ. (6) x (7)(a) \$
						(a) FUEL COST	(b) TOTAL COST	
ESTIMATED:								
SOUTHERN COMPANIES (UPS & R)		849,939	0	0	849,939	1.962		16,672,740
ST. LUCIE RELIABILITY		8,883	0	0	8,883	0.540		52,288
SJRP		265,808	0	0	265,808	1.555		4,133,290
TOTAL		1,125,430	0	0	1,125,430	1.853		20,858,318
ACTUAL:								
SOUTHERN COMPANIES	UPS	287,973	0	0	287,973	2.153		6,200,968
SOUTHERN COMPANIES	R	311,764	0	0	311,764	1.950		6,080,412
PRIOR MONTH ADJUSTMENT		0	0	0	0			50
		599,737	0	0	599,737	2.048		12,281,130
FMPA (SL 2)		0	0	0	0	0.000		0
PRIOR MONTH ADJUSTMENT		0	0	0	0			0
		0	0	0	0	0.000		0
OUC (SL 2)		0	0	0	0	0.000		0
PRIOR MONTH ADJUSTMENT		0	0	0	0			0
		0	0	0	0	0.000		0
JACKSONVILLE ELECTRIC AUTHORITY	UPS	134,630	0	0	134,630	3.207		4,318,012
PRIOR MONTH ADJUSTMENT		0	0	0	0			(225,003)
		134,630	0	0	134,630	3.040		4,093,009
SEMINOLE ELECTRIC COOPERATIVE, INC. (UNSCHEDULED)		1,706	0	0	1,706	1.838		31,382
ST. LUCIE PARTICIPATION SUB-TOTAL								
		0	0	0	0	0.000		0
TOTAL		736,073	0	0	736,073	2.229		16,405,501
CURRENT MONTH DIFFERENCE		(389,357)	0	0	(389,357)	0.375		(4,452,817)
DIFFERENCE (%)		(34.6)	0.0	0.0	(34.6)	20.3		(21.3)
PERIOD TO DATE:								
ACTUAL		736,073	0	0	736,073	2.229		16,405,501
ESTIMATED		1,125,430	0	0	1,125,430	1.853		20,858,318
DIFFERENCE		(389,357)	0	0	(389,357)	0.375		(4,452,817)
DIFFERENCE (%)		(34.6)	0.0	0.0	(34.6)	20.3		(21.3)

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	KWH FOR OTHER UTILITIES (000)	KWH FOR INTERRUPT- IBLE (000)	KWH FOR FIRM (000)	cents/KWH		TOTAL \$ FOR FUEL ADJ. (8) = (7)(9) \$
						(a) FUEL COST	(b) TOTAL COST	
ESTIMATED:								
QUALIFYING FACILITIES		385,420	0	0	385,420	1.770	1.770	0,822,211
TOTAL		385,420	0	0	385,420	1.770	1.770	0,822,211
ACTUAL:								
ROYSTER COMPANY		6,297	0	0	6,297	1.514	1.514	95,311
DOWNTOWN GOVERNMENT CENTER		9,799	0	0	9,799	2.102	2.102	205,889
BIO-ENERGY PARTNERS, INC.		7,468	0	0	7,468	1.950	1.950	148,317
SOLID WASTE AUTHORITY OF PALM BEACH COUNTY		21,498	0	0	21,498	1.834	1.834	351,233
TROPICANA PRODUCTS, INC.		1,101	0	0	1,101	1.828	1.828	20,124
FLORIDA CRUSHED STONE		78,694	0	0	78,694	1.731	1.731	1,362,237
BROWARD COUNTY RESOURCE RECOVERY - SOUTH SITE		38,307	0	0	38,307	2.241	2.241	858,543
BROWARD COUNTY RESOURCE RECOVERY - NORTH SITE		33,523	0	0	33,523	2.250	2.250	754,398
U. S. SUGAR CORPORATION - BRYANT		(1,217)	0	0	(1,217)	1.781	1.781	(21,437)
U. S. SUGAR CORPORATION - CLEWISTON		0	0	0	0	0.000	0.000	227
GEORGIA PACIFIC CORPORATION		(19)	0	0	(19)	(5.379)	(5.379)	1,022
CEDAR BAY GENERATING COMPANY		217,471	0	0	217,471	1.558	1.558	3,390,029

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
FOR THE MONTH OF APRIL 1994

SCHEDULE A8

(1)	(2)	(3)	(4)	(5)	(6)		(7)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	TRANS. COST cents/KWH	TOTAL \$ FOR FUEL ADJ. (3) x (4) \$	COST IF GENERATED		FUEL SAVINGS (6)(b) - (5) \$
					(a) cents/KWH	(b) \$	
ESTIMATED:							
FLORIDA	C	102	2.147	2,190	2.370	2,417	227
SOUTHERN COMPANY	C	0	0.000	0	0.000	0	0
TOTAL		102	2.147	2,190	2.370	2,417	227
ACTUAL:							
FLORIDA POWER CORPORATION	C	1,999	1.643	32,837	1.762	35,222	2,385
CITY OF GAINESVILLE	C	209	1.785	3,731	1.929	4,032	301
JACKSONVILLE ELECTRIC AUTHORITY	C	247	1.638	4,046	1.769	4,419	373
SEMINOLE ELECTRIC COOPERATIVE, INC.	C	1,659	1.653	27,423	1.812	30,068	2,645
TAMPA ELECTRIC COMPANY	C	9,583	1.785	171,055	1.941	185,995	14,940
OGLETHORPE POWER CORPORATION	OS	8,333	1.634	136,189	2.007	167,253	31,064
PRIOR MONTH'S ADJUSTMENT (SOUTHERN CO.)	C	0	0.000	0	0.000	0	(68)
FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		13,697	1.746	239,092	1.896	250,736	20,644
NON-FLORIDA ECONOMY/OS PURCHASES SUB-TOTAL		8,333	1.635	136,257	2.007	167,253	30,998
TOTAL		22,030	1.704	375,349	1.938	426,989	51,640
CURRENT MONTH:							
DIFFERENCE		21,928	(0.443)	373,150	(0.431)	424,572	51,413
DIFFERENCE (%)		21,498.0	(20.6)	17,039.2	(18.2)	17,568.1	22,648.9
PERIOD TO DATE:							
ACTUAL		22,030	1.704	375,349	1.938	426,989	51,640
ESTIMATED		102	2.147	2,190	2.370	2,417	227
DIFFERENCE		21,928	(0.443)	373,150	(0.431)	424,572	51,413
DIFFERENCE (%)		21,498.0	(20.6)	17,039.2	(18.2)	17,568.1	22,648.9

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE A10

05/13/94

ACTUAL UNSCHEDULED (IN ADVERTANT) INTERCHANGE
FOR THE PERIOD/MONTH OF: APRIL 1994

RECEIVED FROM
OR
DELIVERED TO

TOTAL KWH
EXCHANGED

SEE ATTACHED

INTERCHANGE FOR FISCAL MONTH OF APRIL, 1994

SCHEDULED INTERCHANGE (MWH)

	Receipts	Deliveries	Net
*SCS Southern Company Services	831,380	26,819	(804,561)
* Tampa Electric Company	16,807	1,731	(14,876)
* Florida Power Corporation	86,113	47,429	(38,684)
FMP Florida Municipal Power Agency	1,228	5,142	3,914
OUC Orlando Utilities Commission	0	48,800	48,800
JEA Jacksonville Electric Authority	362,967	4,881	(358,086)
JEA Loss Payback	743	0	(743)
VER City of Vero Beach	0	12,266	12,266
FTP Ft. Pierce Utilities Authority	0	15,216	15,216
LWU Lake Worth Utilities Authority	0	11,815	11,815
NSB Utl. Comm., City of New Smyrna Beach	0	2,656	2,656
HST City of Homestead	0	14,684	14,684
SEC Seminole Electric Cooperative, Inc.	1,695	20,318	18,623
SEC Loss Payback	72	0	(72)
SEC Inadvertent Payback	0	0	0
STK City of Starke	6	1,568	1,562
GVL City of Gainesville	76	38,867	38,891
ALC City of Alachua	0	93	93
CLW City of Clewiston	0	480	480
KIS Kissimmee Utility Authority	0	14,511	14,511
LAK City of Lakeland	0	0	0
STC City of St. Cloud	0	1,849	1,849
GCS City of Green Cove Springs	0	385	385
JBN City of Jacksonville Beach	0	2,309	2,309
KEY Utl. Board of the City of Key West	0	44,754	44,754
TAL City of Tallahassee	0	650	650
RCI Ready Creek Energy Services, Inc.	0	26,098	26,098
TOTAL SCHEDULED INTERCHANGE	1,300,887	342,721	(958,166)

ACTUAL INTERCHANGE (MWH)

FPC at Deland	0	17,465	17,465
FPC at Barboursville	0	0	0
FPC at Sumner	0	0	0
FPC at Forest	1,084	52,840	51,556
FPC at North Longwood	4	221,337	221,333
FPC at Sanford	0	51,000	51,000
* at Deland	31,045	0	(31,045)
* at Johnson	138,189	2	(138,187)
TEC at Marianna	66,730	1,563	(65,167)
TEC at Marianna #1	75,571	850	(74,721)
OUC at Indian River	30,828	26,711	(4,119)
FMP at Green Cove Springs #1	0	4,280	4,280
FMP at Green Cove Springs #2	0	4,821	4,821
FMP at Jacksonville Beach #1	0	9,429	9,429
FMP at Jacksonville Beach #2	0	9,546	9,546
FMP at Hendry	0	8,437	8,437
FMP at Jacksonville Beach #3	0	19,085	19,085
JEA at Switzerland	152,131	0	(152,131)
JEA at Duval #1	104,854	467	(104,187)
JEA at Duval #2	104,908	459	(104,449)
JEA at Normandy 115 kV	24,480	0	(24,480)
JEA at Eport	0	152,517	152,517
FTP at West	7,671	294	(7,377)
FTP at Midway	0	28,717	28,717
LWU at Hypociss	4	11,718	11,714
VER at West M	6,723	1,096	(5,626)
VER at West E	82	19,885	19,963
HST at Lucy	7,817	25,956	18,138
NSB at Smyrna V1	36	4,225	4,189
NSB at Smyrna V2	0	16,045	16,045
*SCS at Kingsland	11,694	18,142	6,748
*SCS at Hatch #1	434,150	66	(434,084)
*SCS at Hatch #2	568,721	0	(568,721)
SEC at Black Creek	519	221	(298)
SEC at Futaba	1,181	20	(1,161)
SEC at Rice #1	90,482	315	(90,097)
SEC at Rice #2	86,977	380	(86,597)
SEC at Lee	110,175	0	(110,175)
STK at Starke	0	4,480	4,480
GVL at Oorhaven	1,258	28,888	27,297
KEY at Marathon	0	48,157	48,157
Subtotal - Interchange Exchange	2,057,121	788,813	(1,268,308)
Transfers SCS/JEA	176,278	176,278	0
Transmission for others	93,871	93,782	(99)
Less Partial Requirements	0	27,492	27,492
Less SEC Load Replacement	338,228	0	(338,228)
TOTAL ACTUAL INTERCHANGE	1,448,638	491,261	(957,377)

INADVERTENT NET INTERCHANGE Received

*adjusted to Eastern Prevailing Time and includes Unit Power Sales

789

**RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1,000 KWH**

APRIL 1994	MAY 1994	JUNE 1994	JULY 1994	AUGUST 1994	SEPTEMBER 1994	AVERAGE PERIOD TO DATE
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ESTIMATED:

Base Rate Revenues (\$)	47.38					47.38
Fuel Recovery Factor (c/KWH)	1.498					1.498
Group Loss Multiplier	1.00161					1.00161
Fuel Recovery Revenues (\$)	15.00					15.00
Total Revenues (\$)	62.38					62.38

ACTUAL:

Base Rate Revenues (\$)	47.38					47.38
Fuel Recovery Factor (c/KWH)	1.508					1.508
Group Loss Multiplier	1.00161					1.001
Fuel Recovery Revenues (\$)	15.10					15.10
Total Revenues (\$)	62.48					62.48

DIFFERENCE

Base Rate Revenues (\$)	0					0
Fuel Adj Revenues (\$)	0.10					0.10
Total Revenues (\$)	0.10					0.10

DIFFERENCE (%)

Base Rate Revenues	0					0
Fuel Adj Revenues	0.67					0.67
Total Revenues	0.16					0.16

CURRENT MONTH				PERIOD TO DATE			
ACTUAL	ESTIMATED	DIFFERENCE		ACTUAL	ESTIMATED	DIFFERENCE	
		AMOUNT	%			AMOUNT	%

KWH SALES (000)

1	Residential	2,760,704	2,496,239	264,465	10.6%	2,760,704	2,496,239	264,465	10.6%
2	Commercial	2,491,088	2,241,799	249,289	11.1%	2,491,088	2,241,799	249,289	11.1%
3	Industrial	308,622	345,433	(36,811)	-10.7%	308,622	345,433	(36,811)	-10.7%
4	Street & Highway Lighting	27,656	28,172	(516)	-1.8%	27,656	28,172	(516)	-1.8%
5	Other Sales to Public Authority	43,227	46,929	(3,702)	-7.9%	43,227	46,929	(3,702)	-7.9%
5A	Railways & Railroads	6,609	6,307	302	4.8%	6,609	6,307	302	4.8%
7	Total Jurisdictional Sales	5,637,907	5,164,879	473,028	9.2%	5,637,906	5,164,879	473,027	9.2%
8	Sales for Resale	97,823	65,730	32,093	48.8%	97,823	65,730	32,093	48.8%
9	Total Sales	5,735,730	5,230,609	505,121	9.7%	5,735,729	5,230,609	505,120	9.7%

NUMBER OF CUSTOMERS*

10	Residential	3,043,543	3,054,553	(11,010)	-0.4%	3,043,543	3,054,553	(11,010)	-0.4%
11	Commercial	365,207	370,325	(5,118)	-1.4%	365,207	370,325	(5,118)	-1.4%
12	Industrial	15,394	15,189	205	1.3%	15,394	15,189	205	1.3%
13	Street & Highway Lighting	2,304	2,487	(183)	-7.4%	2,304	2,487	(183)	-7.4%
14	Other Sales to Public Authority	298	297	1	0.3%	298	297	1	0.3%
14A	Railways & Railroads	23	23	0	0.0%	23	23	0	0.0%
16	Total Jurisdictional Customers	3,426,769	3,442,874	(16,105)	-0.5%	3,426,769	3,442,874	(16,105)	-0.5%
17	Sales for Resale	12	12	0	0.0%	12	12	0	0.0%
18	Total Customers	3,426,781	3,442,886	(16,105)	-0.5%	3,426,781	3,442,886	(16,105)	-0.5%

KWH USE PER CUSTOMER

19	Residential	907	817	90	11.0%	907	817	90	11.0%
20	Commercial	6,821	6,054	767	12.7%	6,821	6,054	767	12.7%
21	Industrial	20,048	22,742	(2,694)	-11.8%	20,048	22,742	(2,694)	-11.8%
22	Street & Highway Lighting	12,003	11,328	676	6.0%	12,003	11,328	676	6.0%
23	Other Sales to Public Authority	145,057	158,010	(12,953)	-8.2%	145,057	158,010	(12,953)	-8.2%
23A	Railways & Railroads	287,348	274,195	13,152	4.8%	287,348	274,195	13,152	4.8%
25	Total Jurisdictional Use Per Customer	1,645	1,500	145	9.7%	1,645	1,500	145	9.7%
26	Sales for Resale	8,151,917	5,477,500	2,674,417	48.8%	8,151,917	5,477,500	2,674,417	48.8%
27	Total Use Per Customer	1,674	1,519	155	10.2%	1,674	1,519	155	10.2%

SCHEDULE A13

SPENT FUEL DISPOSAL COSTS

APRIL 1994

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE		ACTUAL	ESTIMATED	DIFFERENCE	
				AMOUNT	%			AMOUNT	%
ST LUCIE 1									
	Amortization of								
1	Fuel Burned	0	0	0		0	0	0	
	Fuel Burned								
2	During Month	459,535	535,000	(75,465)	-14.1%	459,535	535,000	(75,465)	-14.1%
ST LUCIE 2									
	Fuel Burned								
3	During Month	0	119,000	(119,000)	-100.0%	0	119,000	(119,000)	-100.0%
TURKEY POINT 3									
	Amortization of								
4	Fuel Burned	0	0	0		0	0	0	
	Fuel Burned								
5	During Month	78,964	0	78,964		78,964	0	78,964	
TURKEY POINT 4									
	Fuel Burned								
6	During Month	462,305	426,000	36,305	8.5%	462,305	426,000	36,305	8.5%
7	TOTAL	1,000,804	1,080,000	(79,196)	-7.3%	1,000,804	1,080,000	(79,196)	-7.3%

AMOUNTS MAY NOT TIE TO OTHER SCHEDULES DUE TO ROUNDING

EFFECTIVE JANUARY 1994 THIS SCHEDULE EXCLUDES ALL DOE CREDITS.

APPENDIX IV
CAPACITY COST RECOVERY

BTB - 7
DOCKET NO 940001-EI
FPL WITNESS: B.T. BIRKETT
EXHIBIT _____
PAGES 1-8
JUNE 27, 1994

**APPENDIX IV
CAPACITY COST RECOVERY**

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FLORIDA POWER & LIGHT
PROJECTED CAPACITY PAYMENTS
FOR OCTOBER 1994 - MARCH 1995

	PROJECTED						
	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH	TOTAL
1. CAPACITY PAYMENTS TO NON-COGENERATORS	\$21,031,976	\$21,031,976	\$21,031,976	\$21,032,850	\$21,032,850	\$21,032,850	\$126,194,478
2. CAPACITY PAYMENTS TO COGENERATORS	\$11,892,156	\$11,881,903	\$11,801,850	\$12,519,965	\$12,520,169	\$12,745,374	\$73,431,219
3. REVENUES FROM CAPACITY SALES	<u>\$51,890</u>	<u>\$59,880</u>	<u>\$16,920</u>	<u>\$31,008</u>	<u>\$87,088</u>	<u>\$167,209</u>	<u>\$474,015</u>
4. SYSTEM TOTAL (Lines 1 + 2 - 3)	\$32,852,334	\$32,823,899	\$32,876,696	\$33,521,807	\$33,485,931	\$33,611,015	\$199,151,882
5. JURISDICTIONAL % *							97.87555%
6. JURISDICTIONALIZED CAPACITY PAYMENTS							\$184,820,804
7. LESS SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET							\$28,472,766
8. FINAL TRUE-UP OCT 1993 - MARCH 1994 \$8,570,760 Overrecovery			EST / ACT TRUE-UP APRIL 1994 - SEPT 1994 \$8,210,692 Overrecovery				\$16,761,361
9. TOTAL (Lines 6 - 7 - 8)							\$149,858,647
10. REVENUE TAX MULTIPLIER							1.01609
11. TOTAL RECOVERABLE CAPACITY PAYMENTS							<u>\$152,074,763</u>

*CALCULATION OF JURISDICTIONAL %

	AVG 12 CP	%
FPSC	12992	97.87555%
FERC	282	2.12445%
TOTAL	<u>13274</u>	<u>100.00000%</u>

NOTE: BASED ON 1993 ACTUAL DATA

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
OCTOBER 1994 THROUGH MARCH 1995

Rate Class	(1) AVG 12 CP Load Factor at Meter (%)	(2) Projected Sales at Meter (kwh)	(3) Projected AVG 12 CP at Meter (kW)	(4) Demand Loss Expansion Factor	(5) Energy Loss Expansion Factor	(6) Projected Sales at Generation (kwh)	(7) Projected AVG 12 CP at Generation (kW)	(8) Percentage of Sales at Generation (%)	(9) Percentage of Demand at Generation (%)
RS1	60.222%	17,326,577,684	6,588,762	1.098852931	1.072653616	18,586,416,206	7,204,866	52.08895%	58.46217%
GS1	68.684%	2,152,496,365	715,506	1.098852931	1.072653616	2,308,883,009	784,804	6.47205%	6.47684%
QSD1	79.091%	7,780,242,450	2,245,808	1.098768487	1.07265454	8,344,974,880	2,463,241	23.39187%	20.32889%
OS2	112.125%	6,572,082	1,948	1.068062788	1.049677128	10,047,598	2,078	0.02818%	0.01715%
QSLD1/CS1	83.973%	3,306,716,334	898,777	1.095333673	1.071360018	3,541,614,447	984,461	9.92753%	8.12470%
QSLD2/CS2	89.963%	851,030,542	215,877	1.089411561	1.066266755	808,574,544	235,288	2.54123%	1.94182%
QSLD3/CS3	93.423%	418,580,781	101,808	1.037953652	1.028561922	428,489,394	105,672	1.20110%	0.87211%
ISST1D	70.680%	953,878	308	1.098852931	1.072653616	1,023,288	338	0.00287%	0.00279%
SST1T	101.212%	35,706,470	8,054	1.037953652	1.028561922	38,726,287	8,380	0.10284%	0.06889%
SST1D	126.750%	12,408,681	2,236	1.082362375	1.061081741	13,168,825	2,419	0.03691%	0.01996%
CHLC D/CHLC G	97.784%	708,933,706	185,625	1.091550450	1.087883820	757,128,586	180,679	2.12232%	1.49113%
CHLC T	99.844%	460,130,868	105,217	1.037953652	1.028561922	473,273,090	108,210	1.32664%	0.90130%
MET	74.148%	37,552,782	11,563	1.086062788	1.049677128	39,418,275	12,327	0.11049%	0.10173%
OL1/SL1	289.907%	183,905,772	14,483	1.098852931	1.072653616	197,267,191	15,888	0.55296%	0.13111%
SL2	100.005%	28,594,545	8,528	1.098852931	1.072653616	30,672,042	7,160	0.08588%	0.06808%
TOTAL		33,310,414,000	11,062,599			35,674,875,460	12,118,888	100.00%	100.00%

(1) AVG 12 CP load factor based on actual 1993 calendar data.

(2) Projected kwh sales for the period October 1994 through March 1995

(3) Calculated: Col(2)/(8760 hours/2 * Col(1)), 8760 hours/2 = hours over 8 mos.

(4) Based on 1993 demand losses.

(5) Based on 1993 energy losses.

(6) Col(2) * Col(5).

(7) Col(3) * Col(4).

(8) Col(6) / total for Col(6)

(9) Col(7) / total for Col(7)

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
OCTOBER 1994 THROUGH MARCH 1995

Rate Class	(1) Percentage of Sales at Generation (%)	(2) Percentage of Demand at Generation (%)	(3) Energy Related Cost (1)	(4) Demand Related Cost (1)	(5) Total Capacity Costs (1)	(6) Projected Sales at Meter (kwh)	(7) Billing KW Load Factor (%)	(8) Projected Billed KW at Meter (kw)	(9) Capacity Recovery Factor (\$/kw)	(10) Capacity Recovery Factor (\$/kwh)
RS1	52.09695%	59.46217%	\$6,094,333	\$83,471,046	\$89,565,379	17,326,577,684	-	-	-	0.00517
GS1	6.47205%	6.47684%	\$757,104	\$9,082,116	\$9,849,220	2,152,486,385	-	-	-	0.00458
GSD1	23.39187%	20.32899%	\$2,736,386	\$28,537,170	\$31,273,556	7,780,242,450	48.09679%	18,450,862	1.69	-
DS2	0.02818%	0.01715%	\$3,294	\$24,075	\$27,369	9,572,082	-	-	-	0.00286
GSLO1/CS1	9.92753%	8.12470%	\$1,161,326	\$11,405,188	\$12,566,516	3,305,718,334	63.34186%	7,149,113	1.76	-
GSLO2/CS2	2.54123%	1.94182%	\$297,275	\$2,725,863	\$3,023,138	851,030,542	68.61320%	1,689,083	1.78	-
GSLO3/CS3	1.20110%	0.67211%	\$140,505	\$1,224,235	\$1,364,744	418,590,781	73.40974%	777,380	1.76	-
ISST1D	0.00287%	0.00279%	\$336	\$3,917	\$4,253	953,978	31.27366%	4,179	**	-
SST1T	0.10294%	0.06899%	\$12,042	\$88,846	\$100,888	35,705,470	11.76175%	415,853	**	-
SST1D	0.03691%	0.01986%	\$4,318	\$28,019	\$32,337	12,408,681	33.90571%	50,134	**	-
CILC D/CILC G	2.12232%	1.49113%	\$246,270	\$2,093,189	\$2,341,469	708,933,708	69.80658%	1,391,190	1.68	-
CILC T	1.32664%	0.80130%	\$155,191	\$1,265,215	\$1,420,406	480,130,868	71.06085%	887,009	1.60	-
MET	0.11049%	0.10173%	\$12,925	\$142,805	\$155,730	37,552,762	60.80894%	84,878	1.83	-
OL1/SL1	0.55296%	0.13111%	\$64,688	\$184,046	\$248,734	183,905,772	-	-	-	0.00135
SL2	0.08598%	0.05909%	\$10,058	\$82,849	\$93,007	28,594,545	-	-	-	0.00325
TOTAL			\$11,698,060	\$140,376,723	\$152,074,783	33,310,414,000		30,909,681		

Note: There are currently no customers taking service on Schedule ISST1(T). Should any customer begin taking service on this schedule during the period, they will be billed using the ISST(D) Factor.

(1) Obtained from Document No. 2

(2) Obtained from Document No. 2

(3) (Total Capacity Costs/13) * Col (1)

(4) (Total Capacity Costs/13 * 12) * Col (2)

(5) Col (3) + Col (4)

(6) Projected kwh sales for the period October 1994 through March 1995

(7) (1993 kWh sales / 8760 hours) / (avg customer NCP / 8760 hours)

(8) Col (6) / ((7) * 730) For GSD-1, only 83,265% of KW are billed due to 10 KW exemption

(9) Col (5) / (8)

(10) Col (5) / (6)

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Reservation	
Demand =	(Total col 5) / (Doc 2, Total col 7) / (10) (Doc 2, col 4)
Charge (RDC)	6 months
Sum of Daily	
Demand =	(Total col 5) / (Doc 2, Total col 7) / (21 onpeak days) (Doc 2, col 4)
Charge (SDD)	6 months
CAPACITY RECOVERY FACTOR	
	RDC SDD
	** (1/kw) ** (1/kw)
ISST1 (D)	00.23 00.11
SST1 (T)	00.22 00.10
SST1 (D)	00.23 00.11

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1994

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL	ACTUAL	REVISED PROJECTIONS	REVISED PROJECTIONS	REVISED PROJECTIONS	REVISED PROJECTIONS	
	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	TOTAL
1. Unit Power (UPS) Capacity Charges	\$19,015,668	\$17,435,335	\$14,052,876	\$14,052,876	\$14,052,876	\$14,052,876	\$92,682,507
2. SJRPP Capacity Charges	7,645,947	6,472,392	7,068,300	7,068,300	7,068,300	7,068,300	42,391,539
3. Qualifying Facilities (QF) Capacity Charges	12,401,465	12,085,181	11,883,188	11,882,929	11,882,670	11,882,413	72,017,846
4. Short-term Capacity Purchases	0	0	0	0	0	0	0
5. Revenues from Capacity Sales	(79,956)	80	(125,210)	(612,527)	(402,609)	(79,140)	(1,299,362)
6. Total Company Capacity Charges	38,983,124	36,012,988	32,879,154	32,391,578	32,601,237	32,924,449	205,792,530
7. Jurisdictional Separation Factor (a)	98.59840%	98.59840%	98.59840%	98.59840%	98.59840%	98.59840%	n/a
8. Jurisdictional Capacity Charges	38,436,736	35,508,230	32,418,320	31,937,578	32,144,298	32,462,980	202,908,142
9. Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(28,672,796)
10. Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	\$33,691,270	\$30,762,764	\$27,672,854	\$27,192,112	\$27,398,832	\$27,717,514	\$174,435,346
11. Capacity Cost Recovery Revenues (Net of Revenue Taxes)	\$27,336,568	\$29,706,835	\$30,635,184	\$34,556,981	\$36,067,322	\$35,193,760	\$193,465,629
12. Prior Period True-up Provision	(1,805,339)	(1,805,339)	(1,805,339)	(1,805,339)	(1,805,339)	(1,805,338)	(10,832,033)
13. Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	\$25,531,229	\$27,901,496	\$28,829,845	\$32,751,642	\$34,261,983	\$33,388,402	\$182,664,596
14. True-up Provision for Month - Over/(Under) Recovery (Line 13 - Line 10)	(\$8,160,041)	(\$2,861,268)	\$1,156,991	\$5,559,530	\$6,863,151	\$5,670,888	\$8,229,250
15. Interest Provision for Month (c)	(17,200)	(25,317)	(29,914)	(11,262)	17,825	47,219	(18,649)
16. True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(10,832,033)	(17,203,935)	(18,285,180)	(15,352,765)	(7,999,158)	687,157	(10,832,033)
17. Deferred True-up - Over/(Under) Recovery	8,570,760	8,570,760	8,570,760	8,570,760	8,570,760	8,570,760	8,570,760
18. Prior Period True-up Provision - Collected/(Refunded) this Month	1,805,339	1,805,339	1,805,339	1,805,339	1,805,339	1,805,338	10,832,033
19. End of Period True-up - Over/(Under) Recovery (Sum of Lines 14 through 18)	(\$8,633,175)	(\$9,714,420)	(\$6,782,005)	\$571,602	\$9,257,917	\$16,781,362	\$16,781,362

Notes: (a) See B. T. Birkett's Testimony, Appendix IV, Page 3, Line 5, Docket No. 940001-EI, filed Jan. 18, 1994
(b) See B. T. Birkett's Testimony, Appendix IV, Page 3, Line 7, Docket No. 940001-EI, filed Jan. 18, 1994
(c) The interest provision for May was adjusted by \$6,213 to reflect interest from October 1993 through April 1994 related to an error in the capacity charges recovered for October 1993.
(d) Columns and rows may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL INTEREST PROVISION
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1994

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	ACTUAL	ACTUAL	REVISED	REVISED	REVISED	REVISED	
	APRIL	MAY	PROJECTIONS	PROJECTIONS	PROJECTIONS	PROJECTIONS	TOTAL
			JUNE	JULY	AUGUST	SEPTEMBER	
1. Beginning True-up Amount	(\$2,261,273)	(\$8,633,175)	(\$9,714,420)	(\$6,782,005)	\$571,602	\$9,257,917	n/a
2. Ending True-up Amount Before Interest	(8,615,975)	(9,689,104)	(6,752,090)	582,864	9,240,092	16,734,143	n/a
3. Total Beginning & Ending True-up Amount (Lines 1+2)	(10,877,268)	(18,322,279)	(16,466,511)	(6,199,141)	9,811,694	25,992,060	n/a
4. Average True-up Amount (50 % of Line 3)	(\$5,438,626)	(\$9,161,139)	(\$8,233,255)	(\$3,099,570)	\$4,905,847	\$12,996,030	n/a
5. Interest Rate - First day of Reporting Business Month	0.03690	0.03900	0.04360	0.04360	0.04360	0.04360	n/a
6. Interest Rate - First day of Subsequent Business Month	0.03900	0.04360	0.04360	0.04360	0.04360	0.04360	n/a
7. Total Interest Rate (Lines 5+6)	0.07590000	0.08260000	0.08720000	0.08720000	0.08720000	0.08720000	n/a
8. Average Interest Rate (50 % of Line 7)	0.03795000	0.04130000	0.04360000	0.04360000	0.04360000	0.04360000	n/a
9. Monthly Average Interest Rate (1/12 of Line 8)	0.00316250	0.00344167	0.00363333	0.00363333	0.00363333	0.00363333	n/a
10. Interest Provision for the Month (Line 4 X Line 9)	(\$17,200)	(\$31,530)	(\$29,914)	(\$11,262)	\$17,825	\$47,219	(\$26,862)

NOTE: Columns and rows may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL VARIANCES
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1994

	(1)	(2)	(3)	(4)
	ESTIMATED/ ACTUAL	ORIGINAL PROJECTIONS (a)	VARIANCE (1)-(2)	PERCENTAGE CHANGE (3)/(2)
1. Unit Power (UPS) Capacity Charges	\$92,682,507	\$95,876,672	(\$3,194,165)	-3.33%
2. SJRPP Capacity Charges	42,391,539	42,357,000	34,539	0.08%
3. Qualifying Facilities (QF) Capacity Charges	72,017,846	71,267,829	750,017	1.05%
4. Short-term Capacity Purchases	0	0	0	n/a
5. Revenues from Capacity Sales	(1,299,362)	(1,985,963)	686,601	-34.57%
6. Total Company Capacity Charges	205,792,530	207,515,538	(1,723,008)	-0.83%
7. Jurisdictional Separation Factor	98.59840%	98.59840%	0.00%	0.00%
8. Jurisdictional Capacity Charges	202,908,142	204,607,000	(1,698,858)	-0.83%
9. Capacity related amounts included in Base Rates (FPSC Portion Only)	(28,472,796)	(28,472,796)	0	0.00%
10. Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	\$174,435,346	\$176,134,204	(\$1,698,858)	-0.96%
11. Capacity Cost Recovery Revenues (Net of Revenue Taxes)	\$193,496,629	\$186,966,237	\$6,530,392	3.49%
12. Prior Period True-up Provision	(10,832,033)	(10,832,033)	0	n/a
13. Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	\$182,664,596	\$176,134,204	\$6,530,392	3.71%
14. True-up Provision - Over/(Under) Recovery (Line 12 - Line 9)	\$8,229,250	\$0	\$8,229,250	n/a
15. Interest Provision	(18,649)	0	(18,649)	n/a
16. True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(10,832,033)	(10,832,033)	0	0.00%
17. Deferred True-up - Over/(Under) Recovery	8,570,760	0	8,570,760	n/a
18. Prior Period True-up Provision - Collected/(Refunded)	10,832,033	10,832,033	0	0.00%
19. End of Period True-up - Over/(Under) Recovery (Sum of Lines 13 through 17)	\$16,781,362	\$0	\$16,781,362	n/a

Notes: (a) See Appendix IV, page 3, filed January 18, 1994, in Docket No. 940001-EI, and approved at the March 1994 hearings.

APPENDIX V
OIL BACKOUT RECOVERY

BTB - 8
DOCKET NO 940001-EI
FPL WITNESS: B.T. BIRKETT
EXHIBIT _____
PAGES 1-12
JUNE 27, 1994

**APPENDIX V
OIL BACKOUT COST RECOVERY**

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5	Jurisdictional kWh Sales Projected Period	B. T. Birkett
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7	Jurisdictional kWh Sales Estimated/Actual Period	B. T. Birkett
8	Estimated/Actual Period	B. T. Birkett
9	Interest Provision Estimated/Actual Period	B. T. Birkett
10	True-Up Variances Estimated/Actual Period	B. T. Birkett
11	Revenue Requirements Estimated/Actual Period	B. T. Birkett
12	Jurisdictional kWh Sales Estimated/Actual Period	B. T. Birkett

FLORIDA POWER & LIGHT COMPANY
OIL BACKOUT COST RECOVERY CLAUSE
DERIVATION OF OIL-BACKOUT COST RECOVERY FACTOR
PROJECTED FOR THE PERIOD OCTOBER 1994 THROUGH MARCH 1995

Line No.

1	Total Cost Recovery		
2	(Page 4, Line 7)	\$	4,253,037
3			
4	Total kWh Sales		
5	(Page 5, Line 3)		33,756,241,000
6			
7	Cost in cents per kWh		0.0126
8			
9	End of Period True-up		
10	Over/(Under) recovery		
11	(Page 8, Line 12)	\$	508,252
12			
13	Retail kWh Sales		
14	(Page 5, Line 1)		33,310,414,000
15			
16	Cost in cents per kWh		0.0015
17			
18	Total Cost		
19	(Line 7 - Line 16) in cents per kWh		0.0111
20			
21	Revenue Tax Factor		1.01609
22			
23	Oil-Backout Factor		
24	Adjusted for Taxes		
25	(Line 19 x Line 21) in cents per kWh		0.0113
26			
27			
28	Oil-Backout Factor		
29	Rounded to Nearest		
30	.001 cents/kWh		0.011

FLORIDA POWER & LIGHT COMPANY
OIL BACKOUT COST RECOVERY CLAUSE
REVENUE REQUIREMENTS
PROJECTED FOR APRIL THROUGH SEPTEMBER 1994

		(1) <u>October</u>	(2) <u>November</u>	(3) <u>December</u>	(4) <u>January</u>	(5) <u>February</u>	(6) <u>March</u>	(7) <u>Total</u>
1.	Straight Line Depreciation (a)	\$ 0	0	0	0	0	0	0
2.	Return on Investment (b)	\$ 355,075	350,484	345,905	341,330	336,761	332,183	2,061,739
3.	Taxes Other Than Income Taxes	\$ 230,750	230,750	230,750	230,750	230,750	230,750	1,384,500
4.	Income Taxes - Current	\$ (408,788)	(408,783)	(409,769)	(410,578)	(413,162)	(414,297)	(2,465,377)
5.	Deferred Income Taxes	\$ 500,996	499,591	499,142	498,525	499,613	499,308	2,997,175
6.	O & M Expenses	\$ 50,000	50,000	50,000	45,000	40,000	40,000	275,000
7.	Total Revenue Requirements (Lines 1+2+3+4+5+6)	\$ 728,033	722,042	716,028	705,027	693,963	687,944	4,253,037

(a) Straight-line depreciation is zero since the capital investment for the project was fully recovered in October 1989.

(b) Includes return on equity of 12.0%.

NOTE: Columns and rows may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
OIL BACKOUT COST RECOVERY CLAUSE
JURISDICTIONAL KWH SALES
PROJECTED FOR OCTOBER 1994 THROUGH MARCH 1995

		(1) <u>October</u>	(2) <u>November</u>	(3) <u>December</u>	(4) <u>January</u>	(5) <u>February</u>	(6) <u>March</u>	(7) <u>Total</u>
1.	Jurisdictional Sales	kWh 5,603,617,000	5,661,410,000	5,436,896,000	5,481,658,000	5,052,473,000	5,074,360,000	33,310,414,000
2.	Sales for Resale	kWh 107,332,000	75,887,000	67,929,000	61,620,000	67,954,000	65,105,000	445,827,000
3.	Total Sales	kWh 6,710,949,000	5,737,297,000	5,504,825,000	5,543,278,000	5,120,427,000	5,139,465,000	33,756,241,000
4.	Jurisdictional Portion of Total kWh Sales (Line 1 / Line 3)	0.98400643	0.98677304	0.98766010	0.98888383	0.98672884	0.98733234	--

NOTE: Columns above may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
OIL BACKOUT COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL REVENUE REQUIREMENTS
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1994

	Actual			Estimated					
	(1) April	(2) May	(3) Sub-total	(4) June	(5) July	(6) August	(7) September	(8) Sub-total	(9) Total
1. Straight Line Depreciation	\$ 0	0	0	0	0	0	0	0	0
2. Return on Investment	\$ 383,488	378,880	762,368	374,268	369,682	355,087	360,487	1,469,524	2,231,892
3. Taxes Other Than Income Taxes	\$ 230,750	230,750	461,500	230,750	230,750	230,750	230,750	923,000	1,394,500
4. ITC Amortization	\$ 0	0	0	0	0	0	0	0	0
5. Income Taxes - Current	\$ (400,685)	(402,723)	(803,407)	(401,146)	(403,524)	(405,633)	(407,654)	(1,617,957)	(2,421,365)
6. ITC Generated	\$ 0	0	0	0	0	0	0	0	0
7. Deferred Income Taxes	\$ 501,608	502,165	1,003,773	499,247	500,136	500,765	501,307	2,001,455	3,005,128
8. Seminole Credits	\$ 0	0	0	0	0	0	0	0	0
9. O & M Expenses	\$ 26,472	33,186	59,658	38,000	38,000	50,000	50,000	176,000	235,658
10. Total Revenue Requirements (Lines 1+2+3+4+5+6+7+8+9)	\$ 741,634	742,259	1,483,892	741,118	735,044	740,969	731,890	2,952,022	4,435,914

* Columns and rows may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
OIL BACKOUT COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL JURISDICTIONAL KWH SALES
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1994

		Actual			Estimated						
		(1) <u>April</u>	(2) <u>May</u>	(3) <u>Sub-total</u>	(4) <u>June</u>	(5) <u>July</u>	(6) <u>August</u>	(7) <u>September</u>	(8) <u>Sub-total</u>	(9) <u>Total</u>	
1. Jurisdictional Sales	kWh	5,637,907,154	5,876,127,271	11,514,034,425	6,238,083,000	7,036,858,000	7,344,201,000	7,168,318,000	27,785,260,000	39,299,294,425	
2. Sales for Resale	kWh	5,637,907,154	109,448,678	208,097,824	79,261,000	102,105,000	115,929,000	120,998,000	418,293,000	626,390,924	
3. Total Sales	kWh	5,736,556,500	5,985,575,849	11,722,132,249	6,317,344,000	7,138,963,000	7,460,130,000	7,289,316,000	28,203,553,000	39,925,685,349	
4. Jurisdictional Portion of Total kWh Sales (Line 1 / Line 3)		0.98280339	0.98171461	--	0.98745343	0.98569710	0.98446019	0.98339608	--	--	

* Columns and rows may not add due to rounding.

**FLORIDA POWER & LIGHT COMPANY
OIL BACKOUT COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1994**

	Actual (1) <u>April</u>	(2) <u>May</u>	(3) <u>Sub-total</u>	(4) <u>June</u>	(5) <u>July</u>	Estimated (6) <u>August</u>	(7) <u>September</u>	(8) <u>Sub-total</u>	(9) <u>Total</u>
1. Oil Backout Cost Recovery Revenue (Net of Revenue Taxes) \$	666,676	690,779	1,387,455	736,718	831,030	867,350	846,342	3,281,440	4,668,895
2. Adjustment not Applicable to this Period (Prior True-up) \$	(9,579)	(9,579)	(19,158)	(9,579)	(9,579)	(9,579)	(9,580)	(38,317)	(57,475)
3. Oil Backout Revenue Applicable to this Period \$	687,097	681,200	1,368,297	727,139	821,451	857,771	836,762	3,243,123	4,611,420
4. Oil Backout Cost Recovery Authorized (Page 6, Line 10) \$	741,634	742,259	1,483,892	741,118	735,044	740,969	734,890	2,952,022	4,435,914
5. Jurisdictional Portion of Total kWh Sales (Page 7, Line 4)	0.98280339	0.98171461	--	0.98745343	0.98669710	0.98446019	0.98339608	--	--
6. Jurisdictional Oil Backout Cost Recovery Authorized (Line 4X5) \$	728,880	728,686	1,457,566	731,820	724,531	729,454	722,688	2,908,493	4,366,059
7. True-up Provision for Month Over/(Under) Recovery (Lines 3-6) \$	(41,783)	(47,486)	(89,269)	(4,681)	96,920	128,317	114,074	334,630	245,361
8. Interest Provision for Month (Page 9, Line 10) \$	583	516	1,099	486	690	1,137	1,616	3,929	5,028
9. True-up & Interest Provision Beginning of Month - Over/(Under) Recovery \$	(57,475)	(89,096)	(57,475)	(126,487)	(121,103)	(13,914)	125,119	(126,487)	(57,475)
10. Deferred True-up Beginning of Period Over/(Under) Recovery \$	257,863	257,863	257,863	257,863	257,863	257,863	257,863	257,863	257,863
11. Prior Period True-up Provision - Collected/(Refunded) this month \$	9,579	9,579	19,158	9,579	9,579	9,579	9,580	38,317	57,475
12. End of period True-up - Over/(Under) Recovery (Lines 7+8+9+10+11) \$	168,767	131,376	131,376	136,760	243,949	382,982	508,252	508,252	508,252

* Columns and rows may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
OIL BACKOUT COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL INTEREST PROVISION
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1994

		Actual			Estimated					
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		<u>April</u>	<u>May</u>	<u>Sub-total</u>	<u>June</u>	<u>July</u>	<u>August</u>	<u>September</u>	<u>Sub-total</u>	<u>Total</u>
1. Beginning True-up Amount	\$	200,388	168,767	369,155	131,376	136,760	243,949	382,982	895,067	1,264,222
2. Ending True-up Amount Before Interest	\$	168,184	130,860	299,044	136,274	243,259	381,845	506,636	1,268,014	1,567,058
3. Total Beginning & Ending True-up Amount (Lines 1+2)	\$	368,572	299,627	668,199	267,650	380,019	625,794	889,618	2,163,081	2,831,280
4. Average True-up Amount (50 % of Line 3)	\$	184,286	149,814	334,100	133,825	190,010	312,897	444,809	1,081,541	1,415,640
5. Interest Rate - First day of Reporting Business Month		0.03690	0.03900	--	0.04360	0.04360	0.04360	0.04360	--	--
6. Interest Rate - First day of Subsequent Business Month		0.03900	0.04360	--	0.04360	0.04360	0.04360	0.04360	--	--
7. Total Interest Rate (Lines 5+6)		0.0759	0.0826	--	0.0872	0.0872	0.0872	0.0872	--	--
8. Average Interest Rate (50 % of Line 7)		0.03795000	0.04130000	--	0.04360000	0.04360000	0.04360000	0.04360000	--	--
9. Monthly Average Interest Rate (1/12 of Line 8)		0.00316250	0.00344167	--	0.00363333	0.00363333	0.00363333	0.00363333	--	--
10. Interest Provision (Line 4 X Line 9)	\$	583	518	1,099	486	690	1,137	1,618	3,929	5,028

* Columns and rows may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
OIL BACKOUT COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP VARIANCES
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1994

	(1)	(2)	(3)	(4)	(5)
	Estimated/Actual June 1994	Projections January 1994	Difference (1)-(2)	Percent Difference (3)/(2)	Variance Explanation
1. Oil-Backout Cost Recovery Revenue (Net of Revenue Taxes)	\$ 4,668,895	4,475,649	193,246	4.32%	
2. Adjustment not Applicable to this Period (Prior True-up)	\$ (57,475)	(57,475)	0	0.00%	
3. Oil-Backout Revenue Applicable to this Period	\$ 4,611,420	4,418,174	193,246	4.37%	(A)
4. Oil-Backout Cost Recovery Authorized	\$ 4,435,914	4,482,462	(46,548)	-1.04%	(B)
5. Jurisdictional Portion of Total kWh Sales	\$ --	--	--	n/a	
6. Jurisdictional Oil-Backout Cost Recovery Authorized	\$ 4,366,059	4,418,174	(52,115)	-1.18%	
7. True-up Provision for Month Over/(Under) Collection (Lines 3-6)	\$ 245,361	0	245,361	n/a	(C)
8. Interest Provision for Month	\$ 5,028	0	5,028	n/a	
9. True-up & Interest Provision Beginning of Month	\$ (57,475)	(57,475)	0	0.00%	
10. Deferred True-up Beginning of Period	\$ 257,863	0	257,863	n/a	(D)
11. True-up Collected (Refunded)	\$ 57,475	57,475	0	0.00%	
12. End of Period - Net True-up (Lines 7+8+9+10+11)	\$ 508,252	0	508,252	n/a	

* Columns and rows may not add due to rounding.

VARIANCE EXPLANATIONS:

(A) ~~The increase is due to higher~~ than originally projected jurisdictional kWh sales, which is explained on page 12.
"Calculation of Estimated/Actual kWh Sales Variances."

(B) The decrease is due primarily to the decreases in Return on Investment and O&M Expenses, as explained on page 11.
"Calculation of Estimated/Actual Revenue Requirement Variances."

(C) The difference is a direct result of the variances explained in (A) and (B) above. The combined effect of higher than originally projected revenues and lower than originally projected authorized cost recovery result in an estimated/actual overrecovery for the six month period.

(D) This is the overrecovery which was deferred from the period October 1993 through March 1994. The explanation for this overrecovery was provided in the Final True-up testimony filed May 1994.

FLORIDA POWER & LIGHT COMPANY
OIL BACKOUT COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL REVENUE REQUIREMENT VARIANCES
FOR THE PERIOD APRIL THROUGH SEPTEMBER 1994

	(1)	(2)	(3)	(4)	(5)
	Estimated/Actual June 1994	Original Projection January 1994	Difference (1)-(2)	Percent Difference (3) / (2)	Variance Explanation
1. Straight Line Depreciation	\$ 0	0	0	0.00%	
2. Return on Investment	\$ 2,231,892	2,266,718	(34,826)	-1.54%	(A)
3. Taxes Other than Income Taxes	\$ 1,384,500	1,384,500	0	0.00%	
4. Income Taxes-Current	\$ (2,421,365)	(2,416,147)	(5,218)	0.22%	
5. Deferred Income Taxes	\$ 3,005,228	3,000,391	4,837	0.16%	
6. O & M Expenses	\$ 235,658	247,000	(11,342)	-4.59%	(B)
7. Total Revenue Requirements (Lines 1+2+3+4+5+6)	\$ 4,435,913	4,482,462	(46,549)	-1.04%	

NOTE: Columns and rows may not add due to rounding.

(A) The decrease is due to the update of the capital structure used to develop the cost rates. The updated figures resulted in lower cost rates.

(B) The decrease is due to a significant decrease in substation maintenance due to new maintenance practices.

FLORIDA POWER & LIGHT COMPANY
OIL BACKOUT COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL KWH SALES VARIANCES
FOR THE PERIOD APRIL 1994 THROUGH SEPTEMBER 1994

		(1) Estimated/Actual <u>June 1994</u>	(2) Original Projection <u>January 1994</u>	(3) Difference <u>(1)-(2)</u>	(4) Percent Difference <u>(3) / (2)</u>	(5) Variance <u>Explanation</u>
1. Jurisdictional Sales	kWh	39,299,294.425	38,036,086.000	1,263,208.425	3.32%	(A)
2. Sales for Resale	kWh	<u>626,390,924</u>	<u>553,458,000</u>	<u>72,932,924</u>	13.18%	
3. Total Sales	kWh	<u>39,925,685.349</u>	<u>38,589,544.000</u>	<u>1,336,141.349</u>	3.46%	

NOTE: Columns and rows may not add due to rounding.

VARIANCE EXPLANATION:

(A) The increase in kWh sales is primarily due to above normal weather and higher than projected economic growth for the period.