Progress Energy

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September 12, 2003

Ms. Blanca S. Bayó, Director
Division of the Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 030001-EI

Dear Ms. Bayó:

Enclosed for filing in the subject docket on behalf of Progress Energy Florida, Inc., formerly Florida Power Corporation, are an original and 15 copies of the direct testimony of Javier Portuondo, Pamela R. Murphy, and Michael F. Jacob.

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

Very truly yours,

James A. McGee

JAM/scc
Enclosure

cc: Parties of record

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PROGRESS ENERGY FLORIDA

DOCKET NO. 030001-EI

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the direct testimony of Javier Portuondo, Pamela R. Murphy, and Michael F. Jacob has been furnished to the following individuals by regular U.S. Mail the 12th day of September, 2003:

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PROGRESS ENERGY FLORIDA

DOCKET NO. 030001-EI

Levelized Fuel and Capacity Cost Recovery Factors
January through December 2004

DIRECT TESTIMONY OF
JAVIER PORTUONDO

Q. Please state your name and business address.

A. My name is Javier Portuondo. My business address is Post Office Box 14042, St. Petersburg, Florida 33733.

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

A. I am employed by Progress Energy Service Company, LLC, in the capacity of Director, Regulatory Services - Florida.

Q. Have your duties and responsibilities remained the same since your testimony was last filed in this docket?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present for Commission approval the levelized fuel and capacity cost factors of Progress Energy Florida (Progress Energy or the Company) for the period of January through December 2004. In addition, I will address Staff preliminary Issue 13D regarding the Company's market price proxy for waterborne coal transportation, including a detailed discussion of the circumstances that led to the Commission's adoption of the market proxy mechanism. I will then address Staff Issues 13A, 13B and 13C regarding ongoing Commission practices for the treatment of certain costs related to Progress Fuels Corporation, Issue 13E regarding Progress Energy's purchase of synthetic coal in 2002, and a new matter of which Staff has recently advised the Company regarding the treatment of Progress Fuel's FOB Barge coal purchases in 2002. Finally, I will address an issue raised by the Company in an attempt to resolve any uncertainty that may exists regarding the appropriate baseline O&M expenses to be used in determining recoverable incremental costs in this proceeding.

Q. Do you have an exhibit to your testimony?

A. Yes. I have prepared an exhibit attached to my prepared testimony consisting of Parts A through F and the Commission's minimum filing requirements for these proceedings, Schedules E1 through E10 and H1, which contain the Company's levelized fuel cost factors and the supporting data. Parts A through C contain the assumptions which support the Company's cost projections, Part D contains the Company's capacity cost recovery factors and supporting data, Part E contains the calculation of recoverable depreciation expense and return on capital associated with Progress Energy's new Hines Unit 2 in accordance with the rate case stipulation and settlement approved by the Commission in April 2002, and

Part F contains a graphic depiction of the Company's incremental cost evaluation process.

FUEL COST RECOVERY

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

A. Schedule E1, page 1 of the "E" Schedules in my exhibit, shows the calculation of the Company's basic fuel cost factor of 3.453 ¢/kWh (before metering voltage adjustments). The basic factor consists of a fuel cost for the projection period of 2.90246 ¢/kWh (adjusted for jurisdictional losses), a GPIF reward of 0.00714 ¢/kWh, and an estimated prior period true-up of 0.54052 ¢/kWh.

Utilizing this basic factor, Schedule E1-D shows the calculation and supporting data for the Company's final levelized fuel cost factors for service received at secondary, primary, and transmission metering voltage levels. To perform this calculation, effective jurisdictional sales at the secondary level are calculated by applying 1% and 2% metering reduction factors to primary and transmission sales, respectively (forecasted at meter level). This is consistent with the methodology used in the development of the capacity cost recovery factors. The final fuel cost factor for residential service is 3.458 ¢/kWh.

Schedule E1-E develops the Time Of Use (TOU) multipliers of 1.310 On-peak and 0.865 Off-peak. The multipliers are then applied to the levelized fuel cost factors for each metering voltage level, which results in the final TOU fuel factors for application to customer bills during the projection period.

Q. What is the change in the fuel factor for the projection period from the fuel factor currently in effect?

A. The projected average fuel factor for 2004 of 3.453 ¢/kWh is an increase of 0.717 ¢/kWh, or 26.2%, from the 2003 midcourse fuel factor of 2.736 ¢/kWh.

Q. Please explain the reasons for the increase.

A. The increase is primarily driven by the recovery of the projected 2003 true-up balance of $210.4 million. Also contributing to the higher fuel factor is an increase in the projected fuel cost of oil and natural gas, as well as a slight increase due to recovery of actual energy costs, since the regulatory asset associated with the 1997 buyout of the Tiger Bay purchase power agreements (PPAs) has been fully amortized. In 2004, Tiger Bay will be treated as a company owned generating facility rather than a contractual cogenerator. Partially offsetting this increase is a reduction in coal prices and higher nuclear generation due to no refueling outage scheduled for 2004.

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

A. Line 4 shows the recovery of the costs associated with conversion of combustion turbine units to burn natural gas instead of distillate oil ($124,000), the annual payment to the Department of Energy for the decommissioning and decontamination of their enrichment facilities ($1,743,831), and the recovery of the depreciation and return associated with Hines Unit 2 ($42,589,716). These fuel cost adjustments total $44,457,547.

Q. Is the cost of purchasing emission allowances still included in Schedule E1, line 4, "Adjustments to Fuel Cost"?

A. No. Beginning in 2004, the cost of emission allowances will be recovered through the Environmental Cost Recovery Clause (ECRC). Order No. PSC-95-0450-FOF-EI in Docket No. 950001-EI allowed emission allowances to be recovered through the Fuel and Purchased Power Cost Recovery Clause if a utility was not participating in an ECRC. Progress Energy began utilizing the ECRC on January 1, 2003 and received Commission approval to move emission allowances to that clause in 2004.

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

A. Line 6 includes energy costs for the purchase of 60 MWs from Tampa Electric Company and the purchase of 414 MWs under a Unit Power Sales (UPS) agreement with the Southern Company. The capacity payments associated with the UPS contract are based on the original contract of 400 MWs. The additional 14 MWs are the result of revised SERC ratings for the five units involved in the unit power purchase, providing a benefit to Progress Energy in the form of reduced costs per kW. Both of these contracts have been approved for cost recovery by the Commission. The capacity costs associated with these purchases are included in the capacity cost recovery factor.

Q. What is included in Schedule E1, line 8, "Energy Cost of Economy Purchases"?

A. Line 8 consists primarily of economy purchases from within or outside the state. Line 8 also includes energy costs for purchases from Seminole Electric Cooperative, Inc. (SECI) for load following, and off-peak hydroelectric purchases from the Southeast Electric Power Agency (SEPA). The SECI contract is an ongoing contract under which the Company purchases energy from SECI at 95% of its avoided fuel cost. Purchases from SEPA are on an as-available basis. There are no capacity payments associated with either of these purchases. Other purchases may have non-fuel charges, but since such purchases are made only if the total cost of the purchase is lower than the Company's cost to generate the energy, it is appropriate to recover the associated non-fuel costs through the fuel adjustment clause rather than the capacity cost recovery clause. Such non-fuel charges, if any, are reported on line 10.

Q. How was the Gain on Other Power Sales, shown on Schedule E-1, Line 15a, developed?

A. Progress Energy estimates the total gain on non-separated sales during 2004 to be $4,584,880, which is below the three-year rolling average for such sales of $8,239,266 by $3,654,386. Based on the sharing mechanism approved by the Commission in Docket No. 991779-EI, the total gain will be distributed to customers.

Q. How was Progress Energy's three-year rolling average gain on economy sales determined?

A. The three-year rolling average of $8,239,266 is based on calendar years 2001 through 2003, and was calculated in accordance with Order No. PSC-00-1744-PAA-EI, issued September 26, 2000 in Docket 991779-EI.

Q. Why has the depreciation expense and return on capital associated with Hines Unit 2 been included in the Adjustments to Fuel Cost entry you described earlier?

A. The stipulation approved by the Commission in April 2002 for Progress Energy's base rate review proceeding (Docket No. 000824-EI) provides that the Company will be allowed the opportunity to recover the depreciation expenses and return on capital for its new Hines Unit 2 through the fuel clause beginning with the unit's commercial operation through the end of 2005, subject to the limitation that the costs of Hines Unit 2 recovered over this period may not exceed the cumulative fuel savings provided by the unit over the same period. Because Hines Unit 2 is scheduled to begin commercial operation in December 2003, these two cost components of the unit for 2004 have been included in the projection period for recovery in accordance with the stipulation. Part E of my exhibit shows the calculation of the depreciation expense and return on capital associated with Hines Unit 2.

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

A. Progress Energy has several wholesale contracts with Seminole, some of which represent Seminole's own firm resources, and others that provide for the sale of supplemental energy to supply the portion of their load in excess of Seminole's own resources, 1528 MW in 2004. The fuel costs charged to Seminole for supplemental sales are calculated on a "stratified" basis, in a manner which recovers the higher cost of intermediate/peaking generation used to provide the energy. New contracts for fixed amounts of intermediate and peaking capacity began in January of 2000. While those sales are not necessarily priced at average cost, Progress Energy is crediting average fuel cost of the appropriate stratification (intermediate or peaking) in accordance with Order No. PSC-97-0262-FOF-EI. The fuel costs of wholesale sales are normally included in the total cost of fuel and net power transactions used to calculate the average system cost per kWh for fuel adjustment purposes. However, since the fuel costs of the stratified sales are not recovered on an average system cost basis, an adjustment has been made to remove these costs and the related kWh sales from the fuel adjustment calculation in the same manner that interchange sales are removed from the calculation. This adjustment is necessary to avoid an over-recovery by the Company which would result from the treatment of these fuel costs on an average system cost basis in this proceeding, while actually recovering the costs from these customers on a higher, stratified cost basis.

Line 17 also includes the fuel cost of sales made to the City of Tallahassee in accordance with Order No. PSC-99-1741-PAA-EI. The stratified sales shown on Schedule E6 include 100,140 MWh, of which 93% is priced at average nuclear fuel cost, the balance at an estimated incremental cost of $25 per MWh. Other transactions included on Line 17 are the 50 MW sale to Florida Power & Light and a 15 MW sale to the City of Homestead.

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

A. The cost per million BTU of the nuclear fuel which will be in the reactor during the projection period (Cycle 14) was developed from the unamortized investment cost of the fuel in the reactor. Cycle 14 consists of several "batches" of fuel assemblies which are separately accounted for throughout their life in several fuel cycles. The cost for each batch is determined from the actual cost incurred by the Company, which is audited and reviewed by the Commission's field auditors. The expected available energy from each batch over its life is developed from an evaluation of various fuel management schemes and estimated fuel cycle lengths. From this information, a cost per unit of energy (cents per million BTU) is calculated for each batch. However, since the rate of energy consumption is not uniform among the individual fuel assemblies and batches within the reactor core, an estimate of consumption within each batch must be made to properly weigh the batch unit costs in calculating a composite unit cost for the overall fuel cycle.

Q. How was the rate of energy consumption for each batch within Cycle 14 estimated for the upcoming projection period?

A. The consumption rate of each batch has been estimated by utilizing a core physics computer program which simulates reactor operations over the projection period. When this consumption pattern is applied to the individual batch costs, the resultant composite cost of Cycle 14 is $.35 per million BTU.

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

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

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

A. The system sales forecast is made by the forecasting section of the Financial Planning & Regulatory Services Department using the most recent data available. The forecast used for this projection period was prepared in June 2003.

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

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

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

A. The fuel price forecast was made by the Regulated Commercial Operations Department based on forecast assumptions for residual (#6) oil, distillate (#2) oil, natural gas, and coal. The assumptions for the projection period are shown in Part B of my exhibit. The forecasted prices for each fuel type are shown in Part C.

CAPACITY COST RECOVERY

Q. How was the Capacity Cost Recovery factor developed?

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

Sheet 1: Projected Capacity Payments. This schedule contains system capacity payments for UPS, TECO and QF purchases. The retail portion of the capacity payments is calculated using separation factors from the Company's most recent Jurisdictional Separation Study available at the time this filing was prepared.

Sheet 2: Estimated/Actual True-Up. This schedule presents the actual ending true-up balance as of July, 2003 and re-forecasts the over/(under) recovery balances for the next five months to obtain an ending balance for the current period. This estimated/actual balance of $3,309,148 is then carried forward to Sheet 1, to be refunded during the January through December, 2004 period.

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

Sheet 4: Calculation of 12 CP and Annual Average Demand. The calculation of average 12 CP and annual average demand is based on 2003 load research data and the delivery efficiencies on Sheet 3.

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

Q. Please explain the decrease in the CCR factor for the projection period compared to the CCR factor currently in effect.

A. The projected average retail CCR factor of 0.77482 ¢/kWh is 13.6% lower than the 2003 mid-course factor of 0.89702 ¢/kWh. The decrease is primarily due to the elimination of the capacity payments associated with the buyout of the Tiger Bay PPAs, since the regulatory asset has been fully amortized. Partially offsetting this decrease is the annual contractual escalation in capacity payments.

Q. Has Progress Energy included incremental security charges in the 2004 projected capacity amount?

A. Yes. The Company has included $4,644,108 related to incremental security charges for 2004.

Q. What additional internal and/or external security initiatives have taken place or are anticipated to take place that will impact Progress Energy's request for recovery through the Capacity Cost Recovery Clause in 2004?

A. On April 29, 2003, the U.S. Nuclear Regulatory Commission (NRC) issued three orders intended to strengthen protection requirements for nuclear reactors (Design Basis Threat or DBT), limit working hours for security personnel, and improve training for guards. Licensees must submit revised DBT plans to the Commission for review and approval by April 29, 2004 and implement by October 29, 2004. Progress Energy is currently assessing this risk. The Company is also assessing the impact of limiting guard working hours and enhancing training. Licensees must start implementation immediately and must complete by October 29, 2004. The estimated cost of these NRC requirements is included in the total recoverable amount above. The NRC has also increased its annual license fee partly to cover the costs of making plants safe from terror attacks.

In addition to the NRC orders, the Coast Guard, Department of Homeland Security (DHS) issued on July 1, 2003 a series of interim rules to promulgate maritime security requirements mandated by the Maritime Transportation Security Act of 2002. The six interim rules consist of: Implementation of National Maritime Security Initiatives, Area Maritime Security, Vessel Security, Facility Security, Outer Continental Shelf Facility Security, and Automatic Identification System. The final rule is expected to be issued before November 25, 2003. The rule is expected to impact the following sites: Bartow Plant, Anclote Plant, Crystal River Complex, Higgins Plant, and Bayboro Station. These sites are expected to require such things as additional security officers, additional gates, and closed circuit television (CCTV) systems. The timing of this rule's issuance has not allowed Progress Energy enough time to thoroughly quantify the financial impact of its implementation. Therefore we have not included an estimate of the implementation cost but rather will include the actual cost incurred as part of the Company's Actual True-up filing. The costs will be accounted for in accordance with Order PSC-02-1761-FOF-EI, which states on page 10 that:

> "(B)ecause of the extraordinary nature of the costs in question and the unique circumstances under which they arose, we find that these costs do not clearly fall within the classification of 'items which traditionally and historically would be recovered through base rates'."

> . . . Because these costs are extraordinary, these costs shall be treated as current year expenses. Further, we require that these expenses be separately accounted to enhance our staff's ability to audit them."

WATERBORNE COAL TRANSPORTATION

Q. Before addressing Staff Issue 13D regarding Progress Energy's market price proxy, please describe the background of waterborne coal transportation to the Company's Crystal River plant site and its regulation by the Commission?

A. The origin of the current arrangement for waterborne transportation of coal to the Crystal River plant site took place in 1976. At that time the Company, then Florida Power Corporation (FPC), had two units at the Crystal River site that had been previously converted from coal to oil and were then in the process of being converted back to coal. These units, Crystal River 1 and 2, had a combined capacity of approximately 750 MW and would require about 2 million tons of coal annually. At the same time, FPC was in the design and pre-construction stages of two new coal-fired units, Crystal River 4 and 5, with a combined capacity of approximately 1,450 MW and annual coal requirements of nearly 4 million tons per year.

Faced with the need to arrange for the procurement and delivery of up to 6 million tons of coal a year starting almost from scratch, the Company elected a strategy aimed at securing a greater degree of control over the costs and reliability of its long-term coal supply and transportation needs than it could obtain as simply a purchaser of these services subject to the vagaries of an uncertain market. Under this strategy, the Company would acquire business expertise and ownership leverage through capital investment in partnerships with organizations experienced in the various segments of the coal supply and transportation business, particularly those segments lacking a competitive market. However, it would have been problematic for FPC to engage in such a business venture itself due to serious legal and tax impediments associated with multi-state operations and asset ownership and other key aspects of the strategy's business plan.

As a result, Electric Fuels Corporation (EFC), the predecessor of Progress Fuels Corporation (PFC), was formed in March 1976 as a wholly-owned subsidiary of FPC to carry out this long-term strategy for supplying the coal requirements of the Crystal River plant site.

Q. How did EFC implement this strategy with respect to waterborne coal transportation?

A. The most critical implementation issues were the absence of competitive markets in two key segments of the waterborne transportation route; (1) the storage and transloading of coal from river barges to Gulf barges at the mouth of the Mississippi River, and (2) the trans-Gulf transportation of coal to the Crystal River plant site. Neither segment had facilities with sufficient capacity to handle the approximately 2 million tons of waterborne coal annually that EFC needed to deliver to the Crystal River site (the requirements of the site remaining after maximum rail deliveries). This meant that a long-term commitment would have to be made for the construction of additional facilities to increase tonnage capacity in both segments. EFC chose to make that commitment through an ownership interest in the facilities, rather than entering into long-term contracts with third-party owners of the new facilities.

With respect to the river-to-Gulf transloading segment, EFC acquired a one-third ownership interest with two other experienced partners in International Marine Terminals (IMT), which began the construction of a new transloading and storage terminal on the Mississippi River approximately 60 miles south of New Orleans. In a similar vein, EFC acquired a 65% ownership interest in a partnership with Dixie Carriers, an experienced operator of ocean-going carrier vessels, for the transportation of coal to the Crystal River plant site. Since no carrier vessels capable of navigating the site's shallow, narrow channel were available, specially designed ocean-going tug-barge units had to be constructed by the partnership, Dixie Fuels Limited (DFL).

In addition to its investment in these two major undertakings, EFC also acquired ownership interests in several smaller upriver terminals, where coal delivered from the mines is loaded onto river barges. Due to the limited availability of upriver terminal capacity, these investments allowed EFC to obtain priority at existing terminals and to develop additional capacity by constructing new terminals. Since sufficient capacity existed at the time in the upriver mine-to-river (or "short-haul") transportation segment and the river barge transportation segment, EFC contracted with third-party suppliers of those services.

Q. What was the regulatory response of the Commission to the coal procurement and transportation responsibilities the Company placed with EFC?

A. As I indicated earlier, but for the legal and tax consequences it faced in 1976 (and still faces), the Company could have implemented its coal procurement and transportation strategy itself, through an internal operating division or department. Functionally, however, EFC served in much the same capacity and was indirectly regulated by the Commission in a similar manner. I use the term "indirectly regulated" because even though the Commission had no regulatory authority over EFC itself, the Commission had more than ample authority over the coal procurement and transportation costs the Company was allowed to recover through its fuel clause. And since FPC chose to pursue its strategy through an affiliate solely for business considerations, it supported the Commission's treatment of EFC in a utility-like manner.

Under this regulatory treatment, FPC was allowed to recover EFC's prudently incurred costs to procure and deliver coal to the Company, including a utility rate of return on its capital investment IMT and DFL. In return, any profits EFC earned from these investments would be returned to the Company and credited to the cost of coal charged to its customers. For example, because of its ownership interest in DFL, EFC receives 65% of DFL's profits. However, under the Commission's regulatory treatment, EFC would also earn a rate of return on its capital investment in DFL. Therefore, EFC would credit its DFL profits dollar-for-dollar against the cost of coal charged to the Company and, ultimately, its customers.

Q. How did this regulatory treatment of EFC work over time?

A. Initially, quite well. By 1986, however, several concerns about the continued use of this regulatory treatment, then referred to as "cost-plus" pricing, led the Commission to initiate an investigation into the matter (Docket No. 860001-EI-G). The investigation continued for nearly three years and included several hearings covering various aspects of EFC's operation. The following quotation from the Commission's final order concluding the investigation, although somewhat lengthy, best summarizes its findings and policy determinations, and also sets the stage for the currently pending issue regarding PFC's waterborne transportation market proxy mechanism:

> "[W]e believe and find that a change from cost-plus pricing is warranted. While we believe that the current system has been generally successful in allowing only reasonable and prudent cost to be passed through the utilities' fuel adjustment clauses, we believe that it has been administratively costly, caused unnecessary regulatory tension, and left the lingering suspicion that it has resulted in higher costs to the utility's customers. Implicit in cost-plus pricing is the requirement that one is capable of conducting a cost-of-service analysis of a business to determine that its expenses are both necessary and reasonable. This is a methodology that is demanded for monopoly utility services, and which usually proves to be complex, expensive and time consuming. It is a methodology which requires a high degree of familiarity with the capital requirements and expenses necessitated by the operation of the business being reviewed. Cost-

of-service analysis of affiliated operations places additional demands upon the regulatory agency in terms of time, expense and acquiring additional expertise. All come at some additional cost that must eventually be borne by the ratepayer, either in his role as customer or as a taxpayer. Furthermore, there seems to be no end to the types of affiliate business that we are expected to become sufficiently familiar with so that we might judge that reasonableness of their cost on a cost-of-services basis.

"Considering the many advantages offered by a market pricing system, we, as a policy matter, shall require its adoption for all affiliate fuel transactions for which a comparable market price may be found or constructed.

"In concluding, we note the following: (1) from the record in this case, we are convinced that market prices can be established for the affiliate coal; (2) market prices for the transportation-related services should be established if possible, but if not, methodologies for reasonably allocating the cost should be suggested; [and] (3) cost-of-service methodologies should be avoided, if possible; ... ." (Order No. 20604, issued January 13, 1989 in Docket No. 860001-EI-G.)

Q. With respect to the Commission's finding that "market prices for the transportation-related services should be established if possible," was a market price for EFC's waterborne transportation service eventually established pursuant to this finding?

A. In a strict sense, no. Unlike the situation with coal purchased by EFC from an affiliated supplier for which a market pricing mechanism was approved, the Commission recognized that comparable prices could not be found for some of the waterborne transportation services purchased by EFC from affiliates. In fact, this is the very reason EFC purchased these services from affiliates. As I described earlier, a market for river-to-Gulf transloading services and trans-Gulf transportation services to the Crystal River plant site did not exist at the time EFC was formed. That remained the situation when Order No. 20604 was issued, as it does today. This is particularly problematic with respect to the trans-Gulf transportation services provided by DFL's tug-barge units, which had to be custom made because of the unique and hazardous channel to the Crystal River plant site. There simply are no other vessels with the capacity to meet the waterborne coal requirements of the site that are capable of safely traversing the site's shallow, narrow channel.

Nonetheless, it was clear to the Company that the Commission expected an alternative to cost-plus pricing for EFC's waterborne transportation, even if a true market pricing mechanism could not be established. To this end, the Company began a series of negotiations with Staff, Public Counsel and FIPUG which ultimately led to the development of a pricing mechanism that the parties considered to be a reasonable alternative, or proxy, for a true market pricing mechanism. This alternative, referred to as a "market price proxy", was presented to the Commission at the August 1993 fuel adjustment hearing as a stipulated issue and was approved by Order No. PSC-93-1331-FOF-EI, issued September 13, 1993 in Docket No. 930001-EI.

Q. Please describe the market price proxy approved by the Commission?

The market price proxy became effective as of January 1993, and consists of a base price and a composite index used to escalate or de-escalate the base price annually. The base price of $23.00 per ton was derived from EFC's actual 1992 costs incurred for waterborne transportation services in delivering coal to the Crystal River plant site. The base price would then be adjusted as of January 1st each subsequent year using a composite index that consists of five individually weighted indices commonly used to adjust contract prices in the transportation services business. The total weighting of these indices is set at 90%, with 10% of the base price remaining fixed. In addition, the market proxy price may be adjusted for increases or decreases in EFC's waterborne transportation costs which result from governmental impositions on its transportation suppliers not in effect as of December 31, 1992.

Established and adjusted in this manner, the market proxy price is then paid to EFC in lieu of any payment for the costs it incurs to obtain waterborne transportation services in any of the five waterborne transportation segments; *i.e.*, short haul transportation to the upriver terminal, upriver storage and loading onto river barges, river barge transportation, storage and transloading from river barges to Gulf barges, and trans-Gulf transportation to the Crystal River plant site. In addition, EFC will no longer receive a return on its investment in IMT or DFL. In other words, compared to the price it will be paid under the market proxy mechanism, EFC will receive the benefit of any cost reductions it can achieve in providing waterborne transportation services to the Company, and it will incur the risk of any cost increases beyond its control, including the risk of catastrophic loss such as the loss of a DFL vessel at sea.

Q. With that background, please address Staff Issue 13D: Should the Commission modify or eliminate the method for calculating Progress Energy Florida's market price proxy for waterborne coal transportation that was established in Order No. PSC-93-1331-FOF-EI, issued September 13, 1993, in Docket No. 930001-EI?

A. I am not aware of any reason put forward by Staff or a party regarding a flaw or deficiency in the market proxy mechanism or a change of circumstances since the mechanism was approved by the Commission that would suggest it should be modified or eliminated. Nor am I aware of any reason to believe the mechanism has not performed reasonably in approximating the market price of waterborne coal transportation to the Crystal River plant site. To the contrary, when the market price proxy is measured against the benefits and objectives of market pricing articulated by the Commission in Order No. 20604 and quoted earlier in my testimony, I believe this consensus proposal developed jointly by the Company, Staff and other parties has served its intended purpose well. Moreover, the basis for the market price proxy remains conceptually sound. According to the Bureau of Labor Statistics (BLS), indices of the kind used in the market proxy mechanism are typically the basis for contract escalation. The indices used to escalate the market proxy base price are focused on the economic conditions that would reasonably and logically result in increases to the base price over time; and therefore result in an escalated price that fairly tracks these economic conditions, which the BLS quantified in the development of these indices.

In short, absent compelling reasons for change that have not yet been provided, the market price proxy developed to comply with the policy requirements of Order No. 20604, and which met the satisfaction of the Commission, Staff, the parties, and the Company, should remain in effect.

OTHER ISSUES

Q. Has Progress Energy confirmed the validity of the methodology used to determine the equity component of Progress Fuels Corporation's capital structure for calendar year 2002? (Staff Issue 13A)

A. Yes. Progress Energy's Audit Services department has reviewed the analysis performed by PFC. The revenue requirements under a full utility-type regulatory treatment methodology using the actual average cost of debt and equity required to support the Company's regulated business was compared to revenues billed using an equity component based on 55% of net long-term assets (the "short cut method"). The analysis showed that for 2002, the short cut method resulted in revenue requirements which were $47,749, or 0.01%, higher than revenue requirements under the full utility-type regulatory treatment methodology. Progress Energy submits that this analysis confirms again the appropriateness and continued validity of the short cut method.

Q. Has Progress Energy properly calculated the market price true-up for coal purchases from Powell Mountain? (Staff Issue 13B)

A. Yes. The calculation has been made in accordance with the market pricing methodology approved by the Commission in Docket No. 860001-EI-G.

Q. Has Progress Energy properly calculated the 2002 price for waterborne transportation services provided by Progress Fuels Corporation? (Staff Issue 13C)

A. Yes. Progress Energy has performed its calculation of the 2002 waterborne transportation price under the same methodology as the previous calculations that have been approved by the Commission.

Q. Were Progress Energy Florida's purchases of synthetic coal during 2002 cost effective? (Staff Issue 13E)

A. Yes. Progress Energy's purchases of synthetic coal (synfuel) in 2002 were made under an arrangement that allowed these purchases to substitute for purchases that would have been required under a contract for regular compliance coal at a price $2.00 per ton higher than was paid for the synfuel purchases. This resulted in fuel savings of over $1.3 million.

Q. In consideration of Order No. PSC-93-1331-FOF-EI, in Docket No. 930001-EI, issued September 13, 1993, should the Commission make an adjustment to Progress Energy Florida's 2002 waterborne coal transportation costs to account for upriver costs from mine to barge

for coal commodity contracts which are quoted FOB Barge? (New Staff Issue)

A. No adjustment is needed, since the Company and PFC have scrupulously followed the letter and spirit of the waterborne market proxy with respect to FOB Barge coal purchases. The market proxy's base price was determined from the waterborne transportation costs of PFC (then Electric Fuels Corporation, or EFC) in 1992. In that year, 27.8% of EFC's upriver waterborne coal was purchased at an FOB Barge price. This means that for these purchases the upriver "short-haul" transportation costs were included in the commodity purchase price, and were not included in the market proxy's waterborne transportations costs.

To avoid any significant over or under-recovery of these short-haul costs under the market proxy, PFC has attempted to maintain approximately the same ratio of purchases at an FOB Barge price since the inception of the market proxy in 1993. Over the ten-year period through 2002, PFC's purchases at the FOB Barge price have averaged 24.5%, meaning PFC has under-recovered the short-haul costs reflected in the market proxy through 2002. In 2002 itself, PFC's upriver waterborne coal purchases were 1,774,617 tons, of which 504,288 tons were purchased at an FOB Barge price, or 28.4% of its total upriver purchases. This slight imprecision in the 2002 ratio compared to the 27.8% base year guideline is not only small compared to the 24.5% 10-year average or the 2001 ratio of 19.0%, but is particularly small considering the complexities of optimizing individual purchase quantities, scheduling constraints, and periodic adjustments to the Company's coal requirements that PFC must take into account throughout the course of any given year.

Q. At the outset of your testimony you indicated a desire on Progress Energy's part to resolve any uncertainty that currently exists regarding the appropriate baseline expenses to be used in determining recoverable incremental costs. Please explain what you mean by the term "baseline expenses" as it is used in the determination of incremental costs.

A. The need to determine incremental costs in this proceeding arises because from time to time the Commission, under long-established policy, authorizes the recovery of certain O&M expenses through the fuel adjustment clause rather than base rates. Typically, this occurs when O&M expenses for an activity related to the adjustment clause are in excess of those that existed when the utility's base rates were last set. A recent example of this is the Commission's decision to authorize recovery of post-9/11 power plant security costs. Before actual recovery can begin, however, the Commission must assure itself that any portion of these expenses which may be included in base rates is not recovered twice – once through base rates and again through the clause. Therefore, to determine the level of incremental O&M expenses recoverable through the clause, the necessary first step is to establish the amount, if any, of these expenses included in the utility's base rates. This amount is sometimes referred to as the utility's "baseline expenses."

Q. Why has Progress Energy raised an issue regarding the appropriate baseline expenses to be used in determining recoverable incremental costs?

A. In each instance where the recovery of incremental costs has been requested by the Company and approved by the Commission since the 2002 rate case settlement went into effect, the baseline O&M expenses used to determine the recoverable amount of the incremental costs have been derived from the MFRs in that proceeding. Progress Energy believes that using the 2002 MFRs for that purpose is entirely appropriate. However, the continued use of these MFRs to establish the Company's baseline expenses has surfaced as a potential issue in pending matters.

To the extent any uncertainty exists as to the appropriateness of using the 2002 MFRs as source of baseline expenses, Progress Energy desires to have it resolved, since the need to establish baseline expenses is an ongoing one. Dealing with this issue on a case-by-case basis each time the recovery of incremental costs is sought appears unwise and inefficient. This is particularly so when the underlying question is the same in each instance: What baseline expenses best reflect the level of O&M expenses included in base rates? If the Company's base rates are unchanged, the answer to this question should be the same each time it arises.

For this reason, I believe that all concerned would benefit from the establishment of a uniform approach for setting the baseline level of O&M expenses when determining recoverable incremental costs. Doing so will allow everyone to know in advance how incremental costs are to be treated, and thus avoid the need to continually deal with this question on a case-by-case basis.

Q. Does Progress Energy seek to recover any incremental costs in this proceeding today that have been calculated using baseline O&M expenses from the Company's 2002 MFRs?

A. Yes. Based on the Commissions decision authorizing recovery of post-9/11 power plant security costs, these costs have been included in Progress Energy's true-up balance and in its projections for 2004 submitted for Commission approval in this proceeding. The Company has calculated the amount of its recoverable incremental power plant security costs using baseline expenses derived from the 2002 MFRs, as I will explain in greater detail latter in my testimony.

Q. Why is the use of baseline expenses derived from the Company's 2002 rate case MFRs the appropriate way to determine recoverable incremental costs?

A. The 2002 MFRs have been and should continue to be used by Progress Energy to establish baseline O&M expenses when determining recoverable incremental costs because they most accurately reflect the level of expenses included in the Company's current base rates. Based on long standing practice, I think it is clear that the MFRs would have been used for this purposes had the 2002 rate case been resolved in the traditional manner, *i.e.*, by a Commission decision based on the evidentiary record from a lengthy adversarial hearing. However, the fact that the 2002 rate case was resolved through settlement – a resolution that all agree is far superior to contentious, inefficient and costly litigation – provides no basis for a different conclusion about the appropriateness of using fully developed, rate case quality expense data in subsequent incremental cost determinations.

The 2002 MFRs were extensively reviewed and evaluated through discovery and testimony by Staff and the parties to the settlement negotiations. As has been previously noted, the Commission conducted a full rate case in every sense, except for the final hearing that was superceded by a negotiated settlement. The MFRs were a product of that fully developed rate case process and, as such, they and the related discovery and testimony served as a foundation for negotiations that led to the settlement and for Staff and Commission review and approval of the settlement. The use of the MFRs for incremental cost purpose is not only appropriate for this reason, but also because there simply is no other credible alternative for establishing baseline O&M expenses that reflects the level of expenses in current rates.

To summarize, by establishing a uniform treatment for the way in which baseline O&M expenses are determined, the Commission will resolve any uncertainty that now exist, avoid the need to address the issue on an inefficient and potentially inconsistent case-by-case basis, and allow all concerned to know the rules of the game in advance. By establishing the use of the Company's 2002 MFRs as that uniform treatment, the Commission will have selected the best, if not only, source of baseline O&M expenses that reflects the level included in the Company's currently approved base rates, as it must to ensure against double recovery of these expenses.

Q. Please describe the evaluation process used by Progress Energy to determine the incremental costs it submits for recovery through the adjustment clauses.

A. The evaluation process used by Progress Energy incorporates the Commission's long standing practice for determining recoverable incremental costs by removing any O&M expenses associated with the project that were included in the MFRs from the rate proceeding that established the Company's current base rates. Therefore, from the time Progress Energy's current rates were approved at the conclusion of its 2002 rate proceeding, the Company has evaluated the incremental costs associated with all projects submitted for adjustment clause recovery, including the incremental costs currently before the Commission, by first examining the 2002 rate case MFRs to determine whether any of the project's costs have been included. If none are found, all project costs are eligible for further evaluation. Any costs that are found to have been included in the MFRs are excluded from the project's recoverable costs at that point.

After this initial review, the second step is to identify any specific project costs that, although not associated directly with the project in the MFRs, are reflected elsewhere in base rates,. This step is performed by determining whether the cost would be incurred regardless of the new project. The following list provides an example of how several project cost component are broken down for analysis in this step.

- Labor from positions that were part of the last set of MFRs:
    - Regular labor is not considered incremental since is would be incurred regardless of the new project or task.
    - Overtime labor is considered incremental as it results only from the need to complete this new project or task.
    - Regular and Overtime labor for net new positions are considered incremental if it results only from the need to complete this new project or task.
- Outside Contract Labor is considered incremental since the expenditure would not have been incurred were it not for the new project or task.
- Outside Professional Services are considered incremental since the expenditure would not have been incurred were it not for the new project or task.
- Materials and Supplies are considered incremental since the expenditure would not have been incurred were it not for the new project or task.
- Travel is considered incremental since the expenditure would not have been incurred were it not for the new project or task.

The third step is to determine whether the new project will create any offsetting O&M savings associated with related activities, in which case the savings are credited to the project or task to reduce its total cost. Part F of my exhibit is a decision tree that graphically depicts the Company's incremental cost evaluation process using its post-9/11 power plant security project as an example.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBITS TO THE TESTIMONY OF
JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS
JANUARY THROUGH DECEMBER 2004

PART A - SALES FORECAST ASSUMPTIONS

SALES FORECAST ASSUMPTIONS

1. This forecast of customers, sales and peak demand was developed for use in the 2004 budget and 2004 - 2008 five-year Business Plan. This forecast was prepared in June 2003.

2. Normal weather conditions are assumed over the forecast horizon. For kilowatt-hour sales projections normal weather is based on a historical thirty-year average of service area weighted billing month degree days. Seasonal peak demand projections are based on a thirty-year historical average of system-weighted temperatures at time of seasonal peak.

3. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida as published in "Florida Population Studies Bulletin No. 134 (January 2003) provide the basis for development of the customer forecast. State and national economic assumptions produced by Economy.Com in their national and Florida forecasts (Quarter 2, 2003) are also incorporated.

4. Within the Progress Energy Florida (PEF) service area the phosphate mining industry is the dominant sector in the industrial sales class. Six major customers accounted for 26% of the industrial class MWh sales in 2002. These energy intensive customers mine and process phosphate-based fertilizer products for the global marketplace. Both supply and demand conditions for their products are dictated by global conditions that include, but not limited to, foreign competition, national/international agricultural industry conditions, exchange-rate fluctuations, and international trade pacts. Load and energy consumption at the PEF-served mining or chemical processing sites depend heavily on plant operations which are heavily influenced by the state of these global conditions as well as local conditions. There has been excess mining capacity in the industry for the past few years due to weak farm commodity prices and a strong U.S exchange rate. Weak farm commodity prices lead to lower crop production, which results in less demand for fertilizer products. A strong U.S. currency results in U.S. fertilizer producers becoming less price competitive. Going forward, energy consumption is expected to bounce back in 2003-2004 but not to the levels experienced in the year 2000. The increase projected in 2003 is mainly due to the elimination of extended vacation shutdowns that held down 2002 results. A continued improvement into 2004 is based on a weaker U.S. dollar that will result in improved competitiveness of the Florida producer

5. Progress Energy Florida supplies load and energy service to wholesale customers on a "full", "partial" and "supplemental" requirement basis. Full requirements customers' demand and energy is assumed to grow at a rate that approximates their historical trend. Partial requirements customer load is assumed to reflect the current contractual obligations received by PEF as of May 31, 2003. The forecast of energy and demand to the partial requirements customers reflect the nature of the stratified load they have contracted for, plus their ability to receive dispatched energy from power marketers any time it is more economical for them to do so. Contracts for partial requirements service included in this forecast are with FMPA, the cities of New Smyrna Beach, Tallahassee and Homestead, Reedy Creek Utilities, Florida Power & Light and TECO. PEF's arrangement with Seminole Electric Cooperative, Inc. (SECI) is to serve "supplemental" service over and above stated levels they commit to supply themselves. SECI's projection of their system's requirements in the PEF control area has been incorporated into this forecast. This forecast also incorporates a 150 MW stratified intermediate demand firm power contract with SECI.

6. This forecast assumes that PEF will successfully renew all future franchise agreements.

7. This forecast incorporates demand and energy reductions from PEF'S dispatchable and non-dispatchable DSM programs required to meet the approved goals set by the Florida Public Service Commission.

8. Expected energy and demand reductions from self-service cogeneration are also included in this forecast. PEF will supply the supplemental load of self-service cogeneration customers. While FPC offers "standby" service to all cogeneration customers, the forecast does not assume an unplanned need for standby power.

9. This forecast assumes that the regulatory environment and the obligation to serve our retail customers will continue throughout the forecast horizon. The ability of wholesale customers to switch suppliers has ended the company's obligation to serve these customers beyond their contract life. As a result, the company does not plan for generation resources unless a long-term contract is in place. Current "all requirements" customers are assumed to not renew their contracts with PEF. Current "partial requirements" contracts are projected to terminate as terms reach their expiration date.

10. The economic outlook for this forecast calls for a gradual strengthening of national and State economic growth as the recovery from the 2001 recession takes hold and terrorism fears subside. While this forecast was developed without much sign of an improving economy, policies, such as a second round of federal income tax cuts and 50 year low in market interest rates coaxed by the Federal Reserve Board, have been put in place and are expected to increase consumption and investment.

Besides the extremely accommodative fiscal and monetary policies of federal government officials, the national economy will improve as the excesses of the "bubble" economy get worked off. Significant over-investment in the late 1990s resulted in excess capacity in several industries. This is now getting gradually worked into the improving economy and will stimulate the need for renewed investment. More reasonable returns on business investment will enable businesses to resume hiring.

Particular sectors of the economy that have been performing well include the housing industry and the individual consumer. Both have been credited with fueling the limited economic advances of the past year or two. The multi-generational low in interest rates and expansion of credit has stimulated an unprecedented level of housing construction. The record level of mortgage refinancing has acted to put added money in people's pockets, further stimulating demand.

While most signs point toward an improving economic environment, there are some risks that were considered in the development of this forecast. Market prices for energy, which rose significantly during the Gulf War II, have not fallen as far as expected and can act as a cap on economic growth. Fears of a shortage in supplies of natural gas has kept prices high and has placed increased burden on manufacturers who rely upon reasonably priced fuel as a major source of production.

An additional risk that was considered in this forecast involves the undesirable consequence of low interest rates. The return on income-producing investments, specifically CDs and money market accounts, have dropped markedly. This is important in the Florida economy where a greater share of residents are retirees relying on these type investments to generate income. Reports of considerable drop in disposable income for these people will curtail their ability to fuel the economy as they have in past years.

Growth in energy consumption is directly tied to the levels of economic activity in the State, nation and around the world, but demographic forces play a major role as well. Factors that influence in-migration rates to Florida impact residential customer growth, especially since the difference between births and deaths contribute little to Florida's growing population. Obviously, many factors influence the pace of in-migration to Florida but there is one broad, demographically created influence one can expect during the next few years. The University of Florida's latest population projection (January 2003) shows smaller annual increases in Florida population. This is due to the characteristics of the age cohorts reaching retirement age this decade. Those now reaching retirement age were born during the Great Depression, which was a period of very low birth rates. This is expected to temporarily hold down Florida population growth by reducing the numbers of retirees entering the State.

EXHIBITS TO THE TESTIMONY OF
JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS
JANUARY THROUGH DECEMBER 2004

PART B - FUEL PRICE FORECAST ASSUMPTIONS

Progress Energy Florida
Docket No. 030001-EI
Witness: J. Portuondo
Part B
Sheet 1 of 3

FUEL PRICE FORECAST ASSUMPTIONS

A. Residual Oil and Light Oil

The oil price forecast is based on expectations of normal weather and no radical changes in world energy markets (OPEC actions, governmental rule changes, etc.). Prices are based on expected contract structures, specifications, and market conditions during 2003 & 2004.

PEF Residual Fuel Oil (#6) and Distillate Fuel Oil (#2) prices were derived from EVA forecasts, and current market information.

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

B. Coal

Coal price projections are provided by Progress Fuels Corporation and represent an estimate of the price to Florida Power for coal delivered to the plant sites in accordance with the delivery schedules projected. The forecast is consistent with the coal supply and transportation agreements which Progress Fuels has, or expects to have, in place during 2003 & 2004 and estimated spot purchase volumes and prices for the period. It assumes environmental restrictions on coal quality remain in effect as per current permits: 2.1 lbs. per million BTU sulfur dioxide limit for Crystal River Units 1 and 2, and 1.2 lbs. per million BTU sulfur dioxide limit for Crystal River Units 4 and 5.

C. Natural Gas

The natural gas price forecast is based on the expectation of average weather conditions and a steady trend in supply and demand. Prices are based on expected contract structures and spot market purchases for 2003 & 2004. Gas supply prices were derived from the EVA.

Transportation costs for Florida Gas Transmission and Gulfstream pipeline firm transportation services are based on expected tariff rates. Interruptible transportation rates and availability are based on expected tariff rates and market conditions.

EXHIBITS TO THE TESTIMONY OF
JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS
JANUARY THROUGH DECEMBER 2004

PART C - FUEL PRICE FORECAST

FUEL PRICE FORECAST
#6 Fuel Oil

	1.0%		1.5%		2.5%	
Month	**$/barrel**	**$/MMBtu (1)**	**$/barrel**	**$/MMBtu (1)**	**$/barrel**	**$/MMBtu (1)**
Jan – Feb 2004	29.25	4.50	28.28	4.35	26.33	4.05
Mar 2004	28.60	4.40	27.63	4.25	25.68	3.95
Apr – Jun 2004	27.30	4.20	26.00	4.00	24.05	3.70
Jul 2004	27.63	4.25	26.33	4.05	24.38	3.75
Aug 2004	27.95	4.30	26.65	4.10	24.70	3.80
Sep 2004	28.28	4.35	26.98	4.15	25.03	3.85
Oct 2004	28.60	4.40	27.30	4.20	25.35	3.90
Nov 2004	28.93	4.45	27.63	4.25	25.68	3.95
Dec 2004	29.25	4.50	27.95	4.30	26.00	4.00

(1) 6.5 mmbtu/bbl

FUEL PRICE FORECAST
#2 Fuel Oil

Month	$/barrel	¢/gallon	$/MMBtu[1]
Jan - Apr 2004	37.70	89.76	6.50
May 2004	34.22	81.48	5.90
Jun 2004	31.90	75.95	5.50
Jul 2004	32.19	76.64	5.55
Aug 2004	32.48	77.33	5.60
Sep 2004	32.77	78.02	5.65
Oct 2004	34.80	82.86	6.00
Nov - Dec 2004	37.70	89.76	6.50

(1) 5.8 MMBtu/Bbl & 42 gallon/Bbl

FUEL PRICE FORECAST
Coal

	Crystal River 1 & 2			Crystal River 4 & 5		
Month	BTU/lb.	$/ton	$/MMBtu	BTU/lb.	$/ton	$/MMBtu
Jan 2004	12,633	51.72	2.047	12,520	57.24	2.286
Feb 2004	12,633	51.74	2.048	12,520	57.39	2.292
Mar 2004	12,633	51.74	2.048	12,520	57.27	2.287
Apr 2004	12,633	51.97	2.057	12,500	57.65	2.306
May 2004	12,626	51.64	2.045	12,519	57.11	2.281
Jun 2004	12,633	51.92	2.055	12,500	57.95	2.318
Jul 2004	12,626	51.72	2.048	12,519	57.16	2.283
Aug 2004	12,633	52.00	2.058	12,500	58.00	2.320
Sep 2004	12,626	51.72	2.048	12,519	57.14	2.282
Oct 2004	12,633	52.20	2.066	12,500	58.15	2.326
Nov 2004	12,626	51.79	2.051	12,519	57.19	2.284
Dec 2004	12,661	51.88	2.049	12,485	57.63	2.308

FUEL PRICE FORECAST
Natural Gas Supply [(1)]

Month	$/MMBtu
Jan 2004	6.57
Feb 2004	6.45
Mar 2004	6.17
Apr 2004	5.15
May 2004	4.92
Jun 2004	4.84
Jul 2004	4.92
Aug 2004	4.84
Sep 2004	4.78
Oct 2004	4.78
Nov 2004	5.34
Dec 2004	5.55

[(1)] Transport costs not included

EXHIBITS TO THE TESTIMONY OF
JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS
JANUARY THROUGH DECEMBER 2004

PART D - CAPACITY COST RECOVERY CALCULATIONS

PROGRESS ENERGY FLORIDA
CAPACITY COST RECOVERY CLAUSE
PROJECTED CAPACITY PAYMENTS
For the Year 2004

Progress Energy Florida
Docket 030001-EI
Witness J Portuondo
Part D
Sheet 1 of 5

	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Total
Base Production Level Capacity Charges:													
1 Payments to Qualifying Facilities	21,432,179	21,432,179	21,432,179	21,432,179	21,432,179	21,432,179	21,432,179	21,432,179	21,432,179	21,432,179	21,432,179	21,432,179	257,186,148
2 UPS Purchase (414 MW)	4,215,321	3,943,365	4,215,321	4,079,343	4,215,321	4,079,343	4,215,321	4,215,321	4,079,343	4,215,321	4,079,343	4,215,321	49,767,984
3 Incremental Security Costs	0	0	1,161,027	0	0	1,161,027	0	0	1,161,027	0	0	1,161,027	4,644,108
4 Subtotal - Base Level Capacity Charges	25,647,500	25,375,544	26,808,527	25,511,522	25,647,500	26,672,549	25,647,500	25,647,500	26,672,549	25,647,500	25,511,522	26,808,527	311,598,240
5 Base Production Jurisdictional %	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	
6 Base Jurisdictional Capacity Charges	24,610,572	24,349,611	25,724,658	24,480,091	24,610,572	25,594,178	24,610,572	24,610,572	25,594,178	24,610,572	24,480,091	25,724,658	299,000,323
Intermediate Production Level Capacity Charges													
7 TECO Power Purchase	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	6,792,000
8 Other Power Sales	0	0	0	0	0	0	0	0	0	0	0	0	0
9 Subtotal - Intermediate Level Capacity Charges	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	566,000	6,792,000
10 Intermediate Production Jurisdictional %	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	
11 Intermediate Jurisdictional Capacity Charges	490,009	490,009	490,009	490,009	490,009	490,009	490,009	490,009	490,009	490,009	490,009	490,009	5,880,106
Peaking Production Level Capacity Charges.													
12 Peaking Purchases - Yearly	0	0	0	0	0	0	0	0	0	0	0	0	0
13 Peaking Purchases - Summer Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
14 Peaking Purchases - Winter Peak	884,800	884,800	0	0	0	0	0	0	0	0	0	897,900	2,667,500
15 Subtotal - Peaking Level Capacity Charges	884,800	884,800	0	0	0	0	0	0	0	0	0	897,900	2,667,500
16 Peaking Production Jurisdictional %	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	
17 Peaking Jurisdictional Capacity Charges	659,725	659,725	0	0	0	0	0	0	0	0	0	669,492	1,988,941
18 Transmission Revenues from Economy Sales	(250,803)	(350,326)	(279,073)	(187,956)	(97,950)	(81,854)	(123,427)	(116,851)	(128,194)	(132,816)	(187,076)	(199,366)	(2,135,692)
19 Jurisdictional Capacity Payments (Lines 6 + 11 + 17 + 18)	25,509,502	25,149,018	25,935,594	24,782,144	25,002,630	26,002,333	24,977,153	24,983,729	25,955,993	24,967,764	24,783,024	26,684,793	304,733,679
20 Estimated/Actual True-Up Provision for the Period January through December 2003													(3,309,148)
21 Total (Sum of lines 19 & 20)													301,424,531
22 Revenue Tax Multiplier													1.00072
23 Total Recoverable Capacity Payments													301,641,556

PROGRESS ENERGY FLORIDA
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED / ACTUAL TRUE-UP
For the Year 2003

		Actual Jan-03	Actual Feb-03	Actual Mar-03	Actual Apr-03	Actual May-03	Actual Jun-03	Actual Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated Dec-03	Total 2003
	Base Production Level Capacity Charges:													
1	Payments to Qualifying Facilities	24,724,976	27,151,122	25,536,546	25,183,973	25,641,292	25,877,780	26,049,524	26,314,605	26,314,605	26,314,605	20,505,184	20,505,184	300,119,396
2	UPS Purchase (413 MW)	4,051,119	4,265,922	3,788,442	3,925,202	3,701,633	3,967,206	4,600,651	4,031,019	3,900,986	4,031,019	3,900,986	4,031,019	48,195,204
3	Incremental Security Costs	0	0	0	197,728	0	0	289,444	252,750	252,750	252,750	252,750	252,828	1,751,000
4	Subtotal - Base Level Capacity Charges	28,776,095	31,417,044	29,324,988	29,306,903	29,342,925	29,844,986	30,939,619	30,598,374	30,468,341	30,598,374	24,658,920	24,789,031	350,065,600
5	Base Production Jurisdictional %	95 957%	95 957%	95 957%	95 957%	95 957%	95 957%	95 957%	95.957%	95 957%	95 957%	95.957%	95 957%	95 957%
6	Base Level Jurisdictional Capacity Charges	27,612,677	30,146,853	28,139,379	28,122,025	28,156,591	28,638,353	29,688,730	29,361,282	29,236,506	29,361,282	23,661,960	23,786,810	335,912,448
	Intermediate Production Level Capacity Charges													
7	TECO Power Purchase	565,567	565,567	565,567	565,567	565,567	565,567	565,567	566,000	566,000	566,000	566,000	566,000	6,788,969
8	Capacity Sales	(3,593)	(3,245)	(3,593)	(3,477)	(3,593)	(3,477)	(3,593)	0	0	0	0	0	(24,571)
9	Subtotal - Intermediate Level Capacity Charges	561,974	562,322	561,974	562,090	561,974	562,090	561,974	566,000	566,000	566,000	566,000	566,000	6,764,398
10	Intermediate Production Jurisdictional %	86 574%	86 574%	86 574%	86 574%	86 574%	86 574%	86 574%	86 574%	86 574%	86 574%	86 574%	86 574%	86 574%
11	Intermediate Level Jurisdictional Capacity Charg	486,523	486,825	486,523	486,624	486,523	486,624	486,523	490,009	490,009	490,009	490,009	490,009	5,856,210
	Peaking Production Level Capacity Charges													
12	Peaking Purchases - Yearly	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Peaking Purchases - Summer Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Peaking Purchases - Winter Peak	1,034,801	1,084,800	0	0	0	0	0	0	0	0	0	884,800	3,004,401
15	Subtotal - Peaking Level Capacity Charges	1,034,801	1,084,800	0	0	0	0	0	0	0	0	0	884,800	3,004,401
16	Peaking Production Jurisdictional %	74 562%	74 562%	74 562%	74 562%	74 562%	74 562%	74 562%	74 562%	74 562%	74 562%	74 562%	74 562%	74 562%
17	Peaking Level Jurisdictional Capacity Charges	771,568	808,849	0	0	0	0	0	0	0	0	0	659,725	2,240,141
18	Transmission Revenues from Economy Sales	(361,936)	(835,914)	(182,755)	(113,525)	(48,143)	(26,384)	(13,938)	(92,398)	(96,091)	(79,991)	(152,485)	(177,352)	(2,180,912)
19	Jurisdictional Capacity Payments (Lines 6 + 11 + 17 + 18)	28,508,833	30,606,612	28,443,147	28,495,124	28,594,971	29,098,593	30,161,316	29,758,893	29,630,424	29,771,300	23,999,484	24,759,192	341,827,887
20	Capacity Cost Recovery Revenues	30,746,795	28,983,600	24,247,953	24,296,838	27,928,411	32,162,523	32,763,177	32,965,768	34,735,948	30,038,709	24,758,855	25,970,718	349,599,295
21	Prior Period True-Up Provision	(742,168)	(742,168)	(742,168)	(242,404)	(242,404)	(242,404)	(242,404)	(242,404)	(242,404)	(242,404)	(242,404)	(242,402)	(4,408,138)
22	Current Period Capacity Revenues (Lines 20+21)	30,004,627	28,241,432	23,505,785	24,054,434	27,686,007	31,920,119	32,520,773	32,723,364	34,493,544	29,796,305	24,516,451	25,728,316	345,191,157
23	Current Period Over/(Under) Rec (Lines 22-19)	1,495,794	(2,365,180)	(4,937,362)	(4,440,690)	(908,964)	2,821,526	2,359,457	2,964,471	4,863,120	25,005	516,967	969,124	3,363,270
24	Interest Provision for Month	(3,510)	(3,132)	(5,957)	(9,999)	(12,542)	(10,448)	(7,252)	(4,791)	(1,263)	1,020	1,457	2,296	(54,121)
25	Current Cycle Balance	1,492,284	(876,029)	(5,819,348)	(10,270,037)	(11,191,543)	(8,380,464)	(6,028,259)	(3,068,579)	1,793,279	1,819,304	2,337,728	3,309,148	3,309,148
26	Plus Prior Period Balance	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)
27	Plus. Cumulative True-Up Provision	742,168	1,484,336	2,226,504	2,468,908	2,711,312	2,953,716	3,196,120	3,438,524	3,680,928	3,923,332	4,165,736	4,408,138	4,408,138
28	End of Period Net True-Up (Lines 25+26+27)	(2,173,686)	(3,799,831)	(8,000,982)	(12,209,267)	(12,888,369)	(9,834,886)	(7,240,277)	(4,038,193)	1,066,069	1,334,498	2,095,326	3,309,148	3,309,148

PROGRESS ENERGY FLORIDA
DEVELOPMENT OF JURISDICTIONAL DELIVERY LOSS MULTIPLIERS
BASED ON ACTUAL CALENDAR YEAR 2002 DATA
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Energy Delivered				Energy Required @ Source			Jurisdictional
Class Loads	Sales Mwh	Unbilled Mwh	Total Mwh	% of Total	Delivery Efficiency	Mwh (3) / (5)	% of Total	Loss Multiplier
I. CLASS LOADS:								
A. RETAIL								
1. Transmission	452,297	(323)	451,974		0.9754000	463,373		
2. Distribution Primary	4,383,984	(3,125)	4,380,859		0.9654000	4,537,869		
3. Distribution Secondary	32,023,066	(22,815)	32,000,251		0.9358295	34,194,531		
Total Retail	36,859,347	(26,263)	36,833,084	92.13%	0.9397208	39,195,773	92.48%	1.0038
B. WHOLESALE								
1. Source Level	1,566,129	(7,455)	1,558,674		1.0000000	1,558,674		
2. Transmission	1,452,503	37,851	1,490,354		0.9754000	1,527,941		
3. Distribution Primary	94,972	517	95,489		0.9654000	98,911		
4. Distribution Secondary	-	-	0		0.9358295	0		
Total Wholesale	3,113,604	30,913	3,144,517	7.87%	0.9871260	3,185,526	7.52%	0.9556
Total Class Loads	39,972,951	4,650	39,977,601	100.00%	0.9432840	42,381,299	100.00%	1.0000
II. NON-CLASS LOADS								
1. Sepa	59,463	-	59,463		0.9754000	60,963		
2. Interchange	1,006,540	-	1,006,540		1.0000000	1,006,540		
3. Company Use	116,427	-	116,427		0.9358295	124,410		
Total Non-Class Loads	1,182,430	-	1,182,430		0.9920439	1,191,913		
Total System	41,155,381	4,650	41,160,031		0.9446178	43,573,212		

PROGRESS ENERGY FLORIDA
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF AVERAGE 12 CP AND ANNUAL AVERAGE DEMAND
For the Year 2004

Progress Energy Florida
Docket 030001-EI
Witness: J. Portuondo
Part D

Rate Class	(1) Mwh Sales @ Meter Level	(2) 12 CP Load Factor	(3) Average CP MW @ Meter Level (1)/8760hrs/(2)	(4) Delivery Efficiency Factor	(5) Average CP MW @ Source Level (3)/(4)	(6) Mwh Sales @ Meter Level	(7) Delivery Efficiency Factor	(8) Source Level Mwh (6)/(7)	(9) Annual Average Demand (8)/8760hrs
I. Residential Service	19,556,652	0.548	4,073.90	0.9358295	4,353.25	19,556,652	0.9358295	20,897,666	2,385.58
II. General Service Non-Demand									
Transmission	2,531	0.609	0.47	0.9754000	0.48	2,531	0.9754000	2,595	0.30
Primary	8,178	0.609	1.53	0.9654000	1.58	8,178	0.9654000	8,471	0.97
Secondary	1,321,155	0.609	247.65	0.9358295	264.63	1,321,155	0.9358295	1,411,748	161.16
Total Gen Serv Non-Demand	1,331,864		249.65		266.69	1,331,864		1,422,814	162.43
III. GS - 100% L.F.	82,245	1.000	9.39	0.9358295	10.03	82,245	0.9358295	87,885	10.03
IV. General Service Demand									
SS-1 - Transmission	10,688	3.733	0.33			10,688			
GSD-1 - Transmission	1,650	0.698	0.27			1,650			
Total Transmission	12,338		0.60	0.9754000	0.62	12,338	0.9754000	12,649	1.44
SS-1 - Primary	1,762	3.733	0.05			1,762			
GSD-1 - Primary	2,708,093	0.698	442.90			2,708,093			
Total Primary	2,709,855		442.95	0.9654000	458.83	2,709,855	0.9654000	2,806,976	320.43
GSD - Secondary	12,293,545	0.698	2,010.56	0.9358295	2,148.43	12,293,545	0.9358295	13,136,522	1,499.60
Total Gen Serv Demand	15,015,738		2,454.11		2,607.88	15,015,738		15,956,147	1,821.47
V. Curtailable Service									
CS - Primary	178,873	0.779	26.21			178,873			
SS-3 - Primary	2,618	0.480	0.62			2,618			
Total Primary	181,491		26.83	0.9654000	27.79	181,491	0.9654000	187,996	21.46
CS - Secondary	576	0.779	0.08	0.9358295	0.09	576	0.9358295	615	0.07
Total Curtailable Service	182,067		26.91		27.88	182,067		188,611	21.53
VI. Interruptible Service									
IS - Transmission	489,311	0.940	59.42			489,311			
SS-2 - Transmission	3,617	0.748	0.55			3,617			
Total Transmission	492,928		59.97	0.9754000	61.48	492,928	0.9754000	505,360	57.69
IS - Primary	1,766,528	0.940	214.53			1,766,528			
SS-2 - Primary	67,490	0.748	10.30			67,490			
Total Primary	1,834,018		224.83	0.9654000	232.89	1,834,018	0.9654000	1,899,749	216.87
IS - Secondary	129,878	0.940	15.77	0.9358295	16.85	129,878	0.9358295	138,784	15.84
Total Interruptible Service	2,456,824		300.57		311.22	2,456,824		2,543,893	290.40
VII. Lighting Service	305,074	4.650	7.49	0.9358295	8.00	305,074	0.9358295	325,993	37.21
Total Retail	**38,930,464**				**7,584.95**	**38,930,464**		**41,423,009**	**4,728.65**

PROGRESS ENERGY FLORIDA
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF CAPACITY COST RECOVERY FACTOR
For the Year 2004

	(1) Average 12 CP Demand Mw	(2) Average 12 CP Demand %	(3) Annual Average Demand Mw	(4) Annual Average Demand %	(5) 12/13 of 12 CP 12/13 * (2)	(6) 1/13 of Annual Demand 1/13 * (4)	(7) Demand Allocation (5) + (6)	(8) Dollar Allocation (7) * Total	(9) Effective Mwh's @ Secondary Level Year 2004	(10) Capacity Cost Recovery Factor (c/Kwh)
I. Residential Service	4,353.25	57.393%	2,385.58	50.450%	52.978%	3.881%	56.859%	171,510,372	19,556,652	**0.877**
II. General Service Non-Demand										
Transmission									2,480	**0.779**
Primary									8,096	**0.787**
Secondary									1,321,155	**0.795**
Total Gen Serv Non-Demand	266.69	3.516%	162.43	3.435%	3.246%	0.264%	3.510%	10,587,619	1,331,731	
III. GS - 100% L.F.	10.03	0.132%	10.03	0.212%	0.122%	0.016%	0.138%	416,265	82,245	**0.506**
IV. General Service Demand										
Transmission									12,091	**0.684**
Primary									2,682,756	**0.691**
Secondary									12,293,545	**0.698**
Total Gen Service Demand	2,607.88	34.382%	1,821.47	38.520%	31.737%	2.963%	34.700%	104,669,620	14,988,392	
V. Curtailable Service										
Transmission									0	**0.615**
Primary									179,676	**0.621**
Secondary									576	**0.628**
Total Curtailable Service	27.88	0.368%	21.53	0.455%	0.340%	0.035%	0.375%	1,131,156	180,252	
VI. Interruptible Service										
Transmission									483,069	**0.518**
Primary									1,815,678	**0.524**
Secondary									129,878	**0.529**
Total Interruptible Service	311.22	4.103%	290.40	6.141%	3.787%	0.472%	4.259%	12,846,914	2,428,625	
VII. Lighting Service	8.00	0.106%	37.21	0.787%	0.098%	0.061%	0.159%	479,610	305,074	**0.157**
Total Retail	**7,584.95**	**100.000%**	**4,728.65**	**100.000%**	**92.308%**	**7.692%**	**100.000%**	**301,641,556**	**38,872,971**	**0.77482**

EXHIBITS TO THE TESTIMONY OF
JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS
JANUARY THROUGH DECEMBER 2004

PART E - HINES UNIT 2 DEPRECIATION & RETURN CALCULATION

PROGRESS ENERGY FLORIDA
DOCKET NO. 030001-E1
WITNESS J PORTUONDO
PART E

HINES UNIT 2
SCHEDULE OF SYSTEM DEPRECIATION AND RETURN
FOR THE PERIOD OF JANUARY THROUGH DECEMBER 2004

	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1 BEGINNING BALANCE	$ 240,500,000	$ 240,500,000	$ 240,500,000	$ 240,500,000	$ 240,500,000	$ 240,500,000	$ 240,500,000	$ 240,500,000	$ 240,500,000	$ 240,500,000	$ 240,500,000	$ 240,500,000	$ 240,500,000
2 ADD INVESTMENT	-	-	-	-	-	-	-	-	-	-	-	-	-
3 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
4 ENDING BALANCE	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000
5													
6 AVERAGE BALANCE	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	240,500,000	
7 DEPRECIATION RATE	0 458333%	0 458333%	0 458333%	0 458333%	0 458333%	0 458333%	0 458333%	0.458333%	0 458333%	0 458333%	0 458333%	0 458333%	
8 DEPRECIATION EXPENSE	1,102,291	1,102,291	1,102,291	1,102,291	1,102,291	1,102,291	1,102,291	1,102,291	1,102,291	1,102,291	1,102,291	1,102,291	13,227,492
9 LESS RETIREMENTS	-	-	-	-	-	-	-	-	-	-	-	-	-
10 BEGINNING BALANCE DEPRECIATION	551,145	1,653,436	2,755,727	3,858,018	4,960,309	6,062,600	7,164,891	8,267,182	9,369,473	10,471,764	11,574,055	12,676,346	551,145
11 ENDING BALANCE DEPRECIATION	1,653,436	2,755,727	3,858,018	4,960,309	6,062,600	7,164,891	8,267,182	9,369,473	10,471,764	11,574,055	12,676,346	13,778,637	13,778,637
12													
13 ENDING NET INVESTMENT	$ 238,846,564	$ 237,744,273	$ 236,641,982	$ 235,539,691	$ 234,437,400	$ 233,335,109	$ 232,232,818	$ 231,130,527	$ 230,028,236	$ 228,925,945	$ 227,823,654	$ 226,721,363	$ 226,721,363
14													
15 AVERAGE INVESTMENT	$ 239,397,710	$ 238,295,419	$ 237,193,128	$ 236,090,837	$ 234,988,546	$ 233,886,255	$ 232,783,964	$ 231,681,673	$ 230,579,382	$ 229,477,091	$ 228,374,800	$ 227,272,509	
16 ALLOWED EQUITY RETURN	55083%	55083%	55083%	55083%	.55083%	55083%	55083%	55083%	55083%	55083%	55083%	55083%	
17 EQUITY COMPONENT AFTER-TAX	1,318,682	1,312,611	1,306,539	1,300,467	1,294,395	1,288,323	1,282,252	1,276,180	1,270,108	1,264,036	1,257,965	1,251,893	15,423,451
18 CONVERSION TO PRE-TAX	1.62800	1 62800	1 62800	1 62800	1 62800	1 62800	1 62800	1 62800	1 62800	1 62800	1 62800	1 62800	
19 EQUITY COMPONENT PRE-TAX	2,146,814	2,136,931	2,127,045	2,117,160	2,107,275	2,097,390	2,087,506	2,077,621	2,067,736	2,057,851	2,047,967	2,038,082	25,109,378
20													
21 ALLOWED DEBT RETURN	21417%	21417%	21417%	21417%	21417%	21417%	21417%	21417%	.21417%	.21417%	21417%	21417%	
22 DEBT COMPONENT	512,710	510,349	507,989	505,628	503,267	500,906	498,546	496,185	493,824	491,463	489,103	486,742	5,996,712
23													
24 TOTAL RETURN REQUIREMENTS	2,659,524	2,647,280	2,635,034	2,622,788	2,610,542	2,598,296	2,586,052	2,573,806	2,561,560	2,549,314	2,537,070	2,524,824	31,106,090
25													
26 TOTAL DEPRECIATION & RETURN	$ 3,761,815	$ 3,749,571	$ 3,737,325	$ 3,725,079	$ 3,712,833	$ 3,700,587	$ 3,688,343	$ 3,676,097	$ 3,663,851	$ 3,651,605	$ 3,639,361	$ 3,627,115	$ 44,333,582
27													
28 ESTIMATED FUEL SAVINGS	$ 2,784,000	$ 2,136,000	$ 15,000	$ 331,000	$ 2,332,000	$ 4,632,000	$ 5,051,000	$ 7,509,000	$ 4,547,000	$ 2,520,000	$ 1,657,000	$ 1,584,000	35,098,000
29 TOTAL DEPRECIATION & RETURN	$ 3,761,815	$ 3,749,571	$ 3,737,325	$ 3,725,079	$ 3,712,833	$ 3,700,587	$ 3,688,343	$ 3,676,097	$ 3,663,851	$ 3,651,605	$ 3,639,361	$ 3,627,115	$ 44,333,582
30 NET BENEFIT (COST) TO RATEPAYER	$ (977,815)	$ (1,613,571)	$ (3,722,325)	$ (3,394,079)	$ (1,380,833)	$ 931,413	$ 1,362,657	$ 3,832,903	$ 883,149	$ (1,131,605)	$ (1,982,361)	$ (2,043,115)	$ (9,235,582)

DEPRECIATION EXPENSE IS CALCULATED BASED UPON AN ANNUAL RATE OF 5 5%
RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 9 18% (EQUITY 6 61%, DEBT 2 57%).
RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY RATE OF 38 575%

EXHIBITS TO THE TESTIMONY OF
JAVIER PORTUONDO

LEVELIZED FUEL AND CAPACITY COST RECOVERY FACTORS
JANUARY THROUGH DECEMBER 2004

SCHEDULES E1 THROUGH E10 AND H1

PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

			DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation		1,002,316,024	36,127,393	2 77439
2.	Spent Nuclear Fuel Disposal Cost		6,222,543	6,655,126 *	0.09350
3.	Coal Car Investment		0	0	0 00000
4.	Adjustment to Fuel Cost		44,457,547	0	0.00000
5.	TOTAL COST OF GENERATED POWER		1,052,996,114	36,127,393	2.91468
6.	Energy Cost of Purchased Power (Excl. Econ & Cogens) (E7)		57,264,214	3,255,878	1.75879
7.	Energy Cost of Sch. C,X Economy Purchases (Broker) (E9)		0	0	0.00000
8.	Energy Cost of Economy Purchases (Non-Broker) (E9)		23,227,445	614,002	3.78296
9.	Energy Cost of Schedule E Economy Purchases (E9)		0	0	0.00000
10.	Capacity Cost of Economy Purchases (E9)		0	0 *	0.00000
11.	Payments to Qualifying Facilities (E8)		129,110,247	5,367,739	2.40530
12.	TOTAL COST OF PURCHASED POWER		209,601,906	9,237,619	2.26900
13.	TOTAL AVAILABLE KWH			45,365,012	
14.	Fuel Cost of Economy Sales	(E6)	0	0	0.00000
14a	Gain on Economy Sales - 80%	(E6)	0	0 *	0.00000
15.	Fuel Cost of Other Power Sales	(E6)	(38,411,259)	(1,144,002)	3.35762
15a.	Gain on Other Power Sales	(E6)	(4,584,880)	(1,144,002) *	0.40078
16.	Fuel Cost of Unit Power Sales	(E6)	0	0	0.00000
16a.	Gain on Unit Power Sales	(E6)	0	0	0.00000
17.	Fuel Cost of Stratified Sales	(E6)	(59,979,005)	(1,596,144)	3.75774
18.	TOTAL FUEL COST AND GAINS ON POWER SALES		(102,975,144)	(2,740,146)	3.75802
19.	Net Inadvertent Interchange			0	
20.	TOTAL FUEL AND NET POWER TRANSACTIONS		1,159,622,876	42,624,866	2.72053
21.	Net Unbilled		(1,397,401)	51,365	(0.00350)
22.	Company Use		3,917,565	(144,000)	0.00980
23.	T & D Losses		65,957,924	(2,424,450)	0.16445
24.	Adjusted System KWH Sales		1,159,622,876	40,107,781	2.89128
25.	Wholesale KWH Sales (Excluding Supplemental Sales)		(33,957,989)	(1,177,317)	2.88435
26.	Jurisdictional KWH Sales		1,125,664,887	38,930,464	2.89148
27.	Jurisdictional KWH Sales Adjusted for Line Losses x	1.0038	1,129,942,414	38,930,464	2.90246
28.	Prior Period True-Up (E1-B, Sheet 1)		210,426,260	38,930,464	0.54052
29.	Total Jurisdictional Fuel Cost		1,340,368,674	38,930,464	3.44298
30.	Revenue Tax Factor				1.00072
31.	Fuel Cost Adjusted for Taxes		1,341,333,739	38,930,464	3.44546
32.	GPIF		2,781,223	38,930,464	0.00714
33.	Fuel Factor Adjusted for taxes including GPIF		1,344,114,962	38,930,464	3.45260
34.	Total Fuel Cost Factor (rounded to the nearest .001 cents/ KWH)				3.453

* For Informational Purposes Only

PROGRESS ENERGY FLORIDA
CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

1.	ACTUAL OVER/(UNDER) RECOVERY JANUARY - DECEMBER 2002 (Schedule E1-B, Line 18 - Dec '03)	$ (31,685,712)	
2.	PROJECTED DECEMBER 2002 UNDER RECOVERY COLLECTED THROUGH DECEMBER 2003 (Schedule E1-B, Line 19 - Dec '03)	(6,091,854)	
3.	ESTIMATED OVER/(UNDER) RECOVERY JANUARY - DECEMBER 2003 (Schedule E1-B, Line 17, Dec '03)	(172,648,694)	
4.	TOTAL OVER/(UNDER) RECOVERY (Lines 1 through 3)	$ (210,426,260)	
5.	JURISDICTIONAL MWH SALES (Projected Period)	38,930,464	Mwh
6.	TRUE-UP FACTOR (Line 4 / Line 5 / 10)	0.54052	Cents/kwh

PROGRESS ENERGY FLORIDA
CALCULATION OF ESTIMATED TRUE-UP
REPROJECTED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2003

		ACTUALS	ESTIMATED					TOTAL
DESCRIPTION		Jan - Jul 03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	PERIOD
REVENUE								
1 Jurisdictional KWH Sales		21,577,779	3,677,676	3,875,158	3,351,132	2,762,109	2,897,305	38,141,159
2 Jurisdictional Fuel Factor (Pre-Tax)		2.561	2.734	2.734	2.734	2.734	2.734	
3 Total Jurisdictional Fuel Revenue		552,705,875	100,548,820	105,948,040	91,621,004	75,516,930	79,213,231	1,005,553,901
4 Less: True-Up Provision		7,511,070	(283,843)	(283,843)	(283,843)	(283,843)	(283,844)	6,091,854
5 Less: GPIF Provision		(354,700)	(50,671)	(50,671)	(50,671)	(50,671)	(50,673)	(608,057)
6 Less: Other		0	0	0	0	0	0	0
7 Net Fuel Revenue		559,862,245	100,214,306	105,613,526	91,286,490	75,182,416	78,878,714	1,011,037,698
FUEL EXPENSE								
8 Total Cost of Generated Power		585,623,059	122,144,688	104,321,963	93,152,863	62,403,112	78,630,097	1,046,275,782
9 Total Cost of Purchased Power		174,637,523	24,402,601	23,002,328	23,473,451	16,278,646	16,840,898	278,635,447
10 Total Cost of Power Sales		(68,819,249)	(10,497,900)	(10,898,496)	(8,863,313)	(9,354,396)	(8,663,430)	(117,096,784)
11 Total Fuel and Net Power		691,441,333	136,049,389	116,425,795	107,763,001	69,327,362	86,807,565	1,207,814,445
12 Jurisdictional Percentage		97.80%	97.29%	97.22%	96.97%	96.77%	97.26%	97.51%
13 Jurisdictional Loss Multiplier		1.0038	1.0038	1.0038	1.0038	1.0038	1.0038	1.0038
14 Jurisdictional Fuel Cost		678,756,565	132,865,428	113,619,277	104,894,874	67,343,023	84,749,868	1,182,229,034
COST RECOVERY								
15 Net Fuel Revenue Less Expense		(118,894,320)	(32,651,122)	(8,005,750)	(13,608,383)	7,839,393	(5,871,154)	
16 Interest Provision	(1)	(614,374)	(148,656)	(165,820)	(174,906)	(177,265)	(176,338)	
17 Current Cycle Balance		(119,508,694)	(152,308,471)	(160,480,042)	(174,263,331)	(166,601,203)	(172,648,694)	
18 Plus: Prior Period True-Up Balance		(31,685,712)	(31,685,712)	(31,685,712)	(31,685,712)	(31,685,712)	(31,685,712)	
19 Plus: Cumulative True-Up Provision		(7,511,070)	(7,227,227)	(6,943,384)	(6,659,541)	(6,375,698)	(6,091,854)	
20 Total Retail Balance		(158,705,476)	(191,221,410)	(199,109,138)	(212,608,584)	(204,662,613)	(210,426,260)	

(1) Interest for the August through December 2003 period calculated at the July 2003 monthly rate of .085%.

PROGRESS ENERGY FLORIDA
CALCULATION OF GENERATING PERFORMANCE INCENTIVE AND TRUE-UP ADJUSTMENT FACTORS

ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

1. TOTAL AMOUNT OF ADJUSTMENTS:		
A. Generating Performance Incentive Reward / (Penalty)	$ 2,781,223	
B. True-Up (Over) / Under Recovery	$ 210,426,260	
2. JURISDICTIONAL MWH SALES	38,930,464	Mwh
3. ADJUSTMENT FACTORS:		
A. Generating Performance Incentive Factor	0.00714	Cents/kwh
B. True-Up Factor	0.54052	Cents/kwh

PROGRESS ENERGY FLORIDA
CALCULATION OF LEVELIZED FUEL ADJUSTMENT FACTORS
(PROJECTED PERIOD)
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

1.	Period Jurisdictional Fuel Cost (E1, line 27)	$ 1,129,942,414	
2.	Prior Period True-Up (E1, line 28)	210,426,260	
3.	Other Adjustments	0	
4.	Regulatory Assessment Fee (E1, line 30)	965,065	
5.	Generating Performance Incentive Factor (GPIF) (E1, line 32)	2,781,223	
6.	Total Jurisdictional Fuel Cost (E1, line 33)	$ 1,344,114,962	
7.	Jurisdictional Sales (E1, line 26)	38,930,464	Mwh
8.	Jurisdictional Cost per Kwh Sold (Line 6 / Line 7 / 10)	3.453	Cents/kwh
9.	Effective Jurisdictional Sales (See Below)	38,872,971	Mwh

LEVELIZED FUEL FACTORS:

10.	Fuel Factor at Secondary Metering (Line 6 / Line 9 / 10)	**3.458**	Cents/kwh
11.	Fuel Factor at Primary Metering (Line 10 * 99%)	**3.423**	Cents/kwh
12.	Fuel Factor at Transmission Metering (Line 10 * 98%)	**3.389**	Cents/kwh

	JURISDICTIONAL SALES (MWH)	
METERING VOLTAGE:	METER	SECONDARY
Distribution Secondary	33,689,125	33,689,125
Distribution Primary	4,733,542	4,686,206
Transmission	507,797	497,640
Total	38,930,464	38,872,971

PROGRESS ENERGY FLORIDA
CALCULATION OF FINAL FUEL COST FACTORS
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

		(1)	(2)	(3)
			----------Time of Use----------	
		Levelized Factors	On-Peak Multiplier	Off-Peak Multiplier
Line:	Metering Voltage	Cents/Kwh	1.310	0.865
1.	Distribution Secondary	3.458	4.530	2.991
2.	Distribution Primary	3.423	4.484	2.961
3.	Transmission	3.389	4.440	2.931
4.	Lighting Service	3.279	--	--

Line 4 Calculated as secondary rate 3.458 * (18.7% * On-Peak Multiplier 1.310 + 81 3% * Off-Peak Multiplier 0.865).

DEVELOPMENT OF TIME OF USE MULTIPLIERS

	ON-PEAK PERIOD			OFF-PEAK PERIOD			TOTAL		
Mo/Yr	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)	System MWH Requirements	Marginal Cost	Average Marginal Cost (¢/kWh)
1/04	945,921	43,190,494	4.566	2,573,035	84,553,381	3 286	3,518,956	127,743,876	3.630
2/04	849,731	41,022,003	4.828	2,336,248	71,626,850	3.066	3,185,979	112,648,853	3.536
3/04	869,924	34,798,239	4.000	2,496,401	96,499,478	3.866	3,366,325	131,297,717	3 900
4/04	1,057,567	41,911,948	3 963	2,088,637	54,012,579	2.586	3,146,204	95,924,527	3 049
5/04	1,248,191	64,241,802	5.147	2,592,110	72,414,152	2.794	3,840,301	136,655,955	3 558
6/04	1,395,313	73,883,037	5.295	2,707,258	88,294,590	3.261	4,102,571	162,177,627	3.953
7/04	1,440,955	87,342,889	6.061	2,906,180	100,193,019	3.448	4,347,135	187,535,908	4 314
8/04	1,455,281	92,712,134	6.371	2,988,175	111,091,922	3.718	4,443,456	203,804,055	4.587
9/04	1,345,676	80,184,831	5.959	2,763,826	97,625,564	3.532	4,109,502	177,810,395	4.327
10/04	1,125,426	50,789,590	4.513	2,469,933	73,518,660	2.977	3,595,359	124,308,250	3.457
11/04	803,544	32,577,018	4.054	2,342,752	92,437,688	3.946	3,146,296	125,014,705	3.973
12/04	909,054	31,201,045	3.432	2,514,719	75,468,509	3.001	3,423,773	106,669,555	3.116
TOTAL	13,446,584	673,855,032	5.011	30,779,276	1,017,736,392	3.307	44,225,859	1,691,591,424	3 825

	ON-PEAK	OFF-PEAK	AVERAGE
MARGINAL FUEL COST WEIGHTING MULTIPLIER	1.310	0.865	1.000

PROGRESS ENERGY FLORIDA
DEVELOPMENT OF JURISDICTIONAL DELIVERY LOSS MULTIPLIERS
BASED ON ACTUAL CALENDAR YEAR 2002 DATA
FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Energy Delivered				Energy Required @ Source			
Class Loads	Sales Mwh	Unbilled Mwh	Total Mwh	% of Total	Delivery Efficiency	Mwh (3) / (5)	% of Total	Jurisdictional Loss Multiplier
I. CLASS LOADS:								
A. RETAIL								
1. Transmission	452,297	(323)	451,974		0.9754000	463,373		
2. Distribution Primary	4,383,984	(3,125)	4,380,859		0.9654000	4,537,869		
3. Distribution Secondary	32,023,066	(22,815)	32,000,251		0.9358295	34,194,531		
Total Retail	36,859,347	(26,263)	36,833,084	92.13%	0.9397208	39,195,773	92.48%	1.0038
B. WHOLESALE								
1. Source Level	1,566,129	(7,455)	1,558,674		1.0000000	1,558,674		
2. Transmission	1,452,503	37,851	1,490,354		0.9754000	1,527,941		
3. Distribution Primary	94,972	517	95,489		0.9654000	98,911		
4. Distribution Secondary	-	-	0		0.9358295	0		
Total Wholesale	3,113,604	30,913	3,144,517	7.87%	0.9871260	3,185,526	7.52%	0.9556
Total Class Loads	39,972,951	4,650	39,977,601	100.00%	0.9432840	42,381,299	100.00%	1.0000
II. NON-CLASS LOADS								
1. Sepa	59,463	-	59,463		0.9754000	60,963		
2. Interchange	1,006,540	-	1,006,540		1.0000000	1,006,540		
3. Company Use	116,427	-	116,427		0.9358295	124,410		
Total Non-Class Loads	1,182,430	-	1,182,430		0.9920439	1,191,913		
Total System	41,155,381	4,650	41,160,031		0.9446178	43,573,212		

PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

	DESCRIPTION		Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	TOTAL
1	Fuel Cost of System Net Generation		$85,684,876	$75,089,019	$73,505,675	$62,326,915	$82,871,842	$95,511,124	$105,900,813	$109,635,433	$97,550,544	$77,781,524	$66,752,080	$69,706,179	$1,002,316,024
1a	Nuclear Fuel Disposal Cost		532,395	498,370	532,395	515,337	521,623	504,910	521,623	521,623	504,910	521,623	515,337	532,395	6,222,543
1b	Adjustments to Fuel Cost		3,588,586	3,558,220	3,515,015	3,518,829	3,599,399	3,609,420	3,602,758	3,562,506	3,553,935	5,284,792	3,532,728	3,531,359	44,457,547
2	Fuel Cost of Power Sold		(4,500,558)	(6,098,788)	(4,409,896)	(3,221,760)	(1,810,146)	(1,600,379)	(2,446,255)	(2,315,904)	(2,575,050)	(2,454,468)	(3,507,315)	(3,470,740)	(38,411,259)
2a	Fuel Cost of Stratified Sales		(6,662,080)	(6,911,892)	(7,466,012)	(6,590,920)	(4,045,212)	(4,176,656)	(4,250,181)	(4,872,855)	(4,796,883)	(4,071,024)	(3,223,675)	(2,911,615)	(59,979,005)
2b	Gains on Power Sales		(296,268)	(451,804)	(376,757)	(299,490)	(238,552)	(369,367)	(568,352)	(560,799)	(664,687)	(231,112)	(300,342)	(227,350)	(4,584,880)
3	Energy Cost of Purchased Power		4,565,352	4,351,881	5,139,320	4,321,684	4,710,657	4,730,751	4,957,915	5,146,881	4,908,606	4,754,926	5,105,205	4,571,036	57,264,214
3a	Capacity Cost of Economy Purchases		-	-	-	-	-	-	-	-	-	-	-	-	-
3b	Payments to Qualifying Facilities		10,950,799	10,318,080	10,878,327	9,771,755	11,031,297	10,780,760	11,496,565	11,591,233	10,668,755	10,336,796	10,412,237	10,873,643	129,110,247
4	Energy Cost of Economy Purchases		1,630,437	1,088,738	966,210	2,117,154	2,696,412	3,097,076	3,417,188	2,678,890	2,210,637	1,829,812	837,493	657,398	23,227,445
5	Total Fuel & Net Power Transactions		$95,493,539	$81,441,824	$82,284,277	$72,459,504	$99,337,320	$112,087,639	$122,632,074	$125,387,008	$111,360,767	$93,752,870	$80,123,748	$83,262,305	$1,159,622,876
6	Adjusted System Sales	MWH	3,094,554	2,983,532	2,858,324	2,939,922	3,064,354	3,609,633	3,931,159	3,914,648	3,977,868	3,617,400	3,046,241	3,070,146	40,107,781
7	System Cost per KWH Sold	c/kwh	3 0858	2 7297	2 8787	2 4647	3 2417	3 1052	3 1195	3 2030	2 7994	2 5917	2 6302	2 7120	2 8913
7a	Jurisdictional Loss Multiplier	x	1 0038	1 0038	1 0038	1.0038	1 0038	1 0038	1 0038	1 0038	1 0038	1 0038	1 0038	1 0038	1 0038
7b	Jurisdictional Cost per KWH Sold	c/kwh	3 0976	2 7401	2 8897	2.4740	3 2540	3 1170	3 1313	3 2152	2 8102	2 6016	2 6402	2 7223	2 9025
8	Prior Period True-Up	c/kwh	0 5851	0 6073	0 6324	0.6139	0 5890	0 4997	0 4584	0 4608	0 4540	0 5000	0 5948	0 5883	0 5405
9	Total Jurisdictional Fuel Expense	c/kwh	3 6826	3 3474	3 5221	3.0879	3 8430	3 6168	3 5897	3 6760	3 2642	3 1016	3 2350	3 3106	3 4430
10	Revenue Tax Multiplier	x	1 00072	1 00072	1 00072	1 00072	1 00072	1 00072	1 00072	1 00072	1 00072	1 00072	1 00072	1 00072	1 00072
11	Fuel Cost Factor Adjusted for Taxes	c/kwh	3 6853	3 3498	3 5246	3 0901	3 8458	3 6194	3 5923	3 6786	3 2665	3 1038	3 2374	3 3129	3 4455
12	GPIF	c/kwh	0 0077	0 0080	0.0084	0 0081	0 0078	0 0066	0 0061	0 0061	0 0060	0 0066	0 0079	0 0078	0 0071
13	Total Fuel Cost Factor (rounded 001)	c/kwh	3 693	3 358	3 533	3 098	3 854	3 626	3.598	3 685	3 273	3 110	3 245	3 321	3 453

PROGRESS ENERGY FLORIDA
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

			Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Subtotal
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		21,442,563	17,274,481	17,937,160	12,398,471	21,106,723	26,127,235	116,286,632
2	LIGHT OIL		4,060,021	1,732,075	559,262	1,033,700	717,214	2,343,956	10,446,228
3	COAL		27,974,982	27,226,014	28,735,146	26,993,458	30,357,369	30,853,682	172,140,650
4	GAS		30,176,325	26,955,261	24,243,121	19,935,370	28,658,074	34,218,911	164,187,062
5	NUCLEAR		2,030,986	1,901,188	2,030,986	1,965,916	2,032,462	1,967,341	11,928,879
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	85,684,876	75,089,019	73,505,675	62,326,915	82,871,842	95,511,124	474,989,451
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		463,994	378,329	403,507	295,952	494,129	609,987	2,645,898
9	LIGHT OIL		46,244	21,032	8,198	13,122	10,945	32,310	131,851
10	COAL		1,323,918	1,286,876	1,351,064	1,265,711	1,442,185	1,449,384	8,119,138
11	GAS		479,574	437,029	424,375	395,688	581,107	717,796	3,035,569
12	NUCLEAR		569,406	533,016	569,406	551,163	557,886	540,011	3,320,888
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	2,883,136	2,656,282	2,756,550	2,521,636	3,086,252	3,349,488	17,253,344
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	744,889	602,877	643,066	473,296	794,025	985,432	4,243,585
16	LIGHT OIL	BBL	104,371	44,642	14,393	26,628	20,311	71,053	281,397
17	COAL	TON	506,514	491,506	514,331	482,538	550,623	553,141	3,098,653
18	GAS	MCF	3,953,251	3,542,390	3,279,926	3,100,077	4,737,122	5,909,205	24,521,971
19	NUCLEAR	MMBTU	5,802,817	5,431,966	5,802,817	5,616,902	5,807,035	5,620,974	34,082,511
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		4,841,778	3,918,700	4,179,929	3,076,427	5,161,161	6,405,307	27,583,302
22	LIGHT OIL		605,349	258,923	83,480	154,442	117,803	412,105	1,632,103
23	COAL		12,732,483	12,354,695	12,923,300	12,126,744	13,841,147	13,904,294	77,882,664
24	GAS		3,953,251	3,542,390	3,279,926	3,100,077	4,737,122	5,909,205	24,521,971
25	NUCLEAR		5,802,817	5,431,966	5,802,817	5,616,902	5,807,035	5,620,974	34,082,511
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	27,935,678	25,506,674	26,269,453	24,074,592	29,664,268	32,251,886	165,702,551
	GENERATION MIX (% MWH)								
28	HEAVY OIL		16.09%	14.24%	14.64%	11.74%	16.01%	18.21%	15.34%
29	LIGHT OIL		1.60%	0.79%	0.30%	0.52%	0.36%	0.97%	0.76%
30	COAL		45.92%	48.45%	49.01%	50.19%	46.73%	43.27%	47 06%
31	GAS		16.63%	16.45%	15.40%	15.69%	18.83%	21.43%	17.59%
32	NUCLEAR		19.75%	20.07%	20.66%	21.86%	18.08%	16.12%	19.25%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0 00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	28.79	28.65	27.89	26.20	26.58	26.51	27.40
36	LIGHT OIL	$/BBL	38.90	38.80	38.86	38.82	35.31	32.99	37.12
37	COAL	$/TON	55.23	55.39	55.87	55.94	55.13	55.78	55.55
38	GAS	$/MCF	7.63	7.61	7.39	6.43	6.05	5.79	6.70
39	NUCLEAR	$/MMBTU	0.35	0.35	0.35	0.35	0.35	0.35	0.35
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		4.43	4.41	4.29	4.03	4.09	4.08	4.22
42	LIGHT OIL		6.71	6.69	6.70	6.69	6.09	5.69	6.40
43	COAL		2.20	2.20	2.22	2.23	2.19	2.22	2 21
44	GAS		7.63	7.61	7.39	6.43	6.05	5.79	6.70
45	NUCLEAR		0.35	0.35	0.35	0.35	0.35	0.35	0.35
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	3.07	2.94	2.80	2.59	2.79	2.96	2.87
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,435	10,358	10,359	10,395	10,445	10,501	10,425
49	LIGHT OIL		13,090	12,311	10,183	11,770	10,763	12,755	12,378
50	COAL		9,617	9,601	9,565	9,581	9,597	9,593	9,592
51	GAS		8,243	8,106	7,729	7,835	8,152	8,232	8,078
52	NUCLEAR		10,191	10,191	10,191	10,191	10,409	10,409	10,263
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	9,689	9,602	9,530	9,547	9,612	9,629	9,604
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		4.62	4.57	4.45	4.19	4.27	4.28	4.39
56	LIGHT OIL		8.78	8.24	6.82	7.88	6.55	7.25	7.92
57	COAL		2.11	2.12	2.13	2.13	2.10	2.13	2.12
58	GAS		6.29	6.17	5.71	5.04	4.93	4.77	5.41
59	NUCLEAR		0.36	0.36	0.36	0.36	0.36	0.36	0.36
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0 00
61	TOTAL	C/KWH	2.97	2.83	2.67	2.47	2.69	2.85	2.75

PROGRESS ENERGY FLORIDA
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

			Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Total
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		28,268,771	29,490,518	26,010,718	20,752,338	21,398,781	13,222,680	255,430,438
2	LIGHT OIL		4,920,932	4,372,006	2,749,798	1,285,321	654,723	1,030,222	25,459,231
3	COAL		31,523,648	32,736,112	31,061,750	27,668,463	22,795,812	31,711,098	349,637,535
4	GAS		39,154,999	41,004,334	35,760,937	26,042,939	19,936,848	21,711,193	347,798,311
5	NUCLEAR		2,032,462	2,032,462	1,967,341	2,032,462	1,965,916	2,030,986	23,990,509
6	OTHER		0	0	0	0	0	0	0
7	TOTAL	$	105,900,813	109,635,433	97,550,544	77,781,524	66,752,080	69,706,179	1,002,316,024
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		654,627	677,257	589,074	460,957	478,958	293,981	5,800,752
9	LIGHT OIL		64,085	57,197	36,045	17,289	9,037	13,324	328,828
10	COAL		1,498,566	1,537,711	1,476,750	1,299,127	1,090,592	1,495,007	16,516,891
11	GAS		795,455	850,281	769,840	577,092	387,679	409,880	6,825,796
12	NUCLEAR		557,886	557,886	540,011	557,886	551,163	569,406	6,655,126
13	OTHER		0	0	0	0	0	0	0
14	TOTAL	MWH	3,570,619	3,680,332	3,411,720	2,912,351	2,517,429	2,781,598	36,127,393
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	1,053,074	1,084,290	945,840	744,965	762,151	468,418	9,302,323
16	LIGHT OIL	BBL	147,829	130,256	81,022	35,791	16,839	26,522	719,655
17	COAL	TON	570,974	586,103	562,622	496,344	418,143	570,078	6,302,916
18	GAS	MCF	6,721,041	7,192,502	6,293,047	4,515,215	3,037,721	3,235,980	55,517,478
19	NUCLEAR	MMBTU	5,807,035	5,807,035	5,620,974	5,807,035	5,616,902	5,802,817	68,544,310
20	OTHER	BBL	0	0	0	0	0	0	0
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		6,844,980	7,047,882	6,147,962	4,842,273	4,953,983	3,044,718	60,465,100
22	LIGHT OIL		857,406	755,487	469,928	207,586	97,666	153,825	4,174,002
23	COAL		14,352,531	14,732,724	14,142,475	12,478,795	10,516,557	14,329,429	158,435,174
24	GAS		6,721,041	7,192,502	6,293,047	4,515,215	3,037,721	3,235,980	55,517,478
25	NUCLEAR		5,807,035	5,807,035	5,620,974	5,807,035	5,616,902	5,802,817	68,544,310
26	OTHER		0	0	0	0	0	0	0
27	TOTAL	MMBTU	34,582,994	35,535,630	32,674,388	27,850,904	24,222,829	26,566,768	347,136,065
	GENERATION MIX (% MWH)								
28	HEAVY OIL		18.33%	18.40%	17.27%	15.83%	19.03%	10.57%	16.06%
29	LIGHT OIL		1.80%	1.55%	1.06%	0.59%	0.36%	0.48%	0.91%
30	COAL		41.97%	41.78%	43.29%	44.61%	43.32%	53.75%	45.72%
31	GAS		22.28%	23.10%	22.57%	19.82%	15.40%	14.74%	18.89%
32	NUCLEAR		15.62%	15.16%	15.83%	19.16%	21.89%	20.47%	18.42%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	26.84	27.20	27.50	27.86	28.08	28.23	27.46
36	LIGHT OIL	$/BBL	33.29	33.56	33.94	35.91	38.88	38.84	35.38
37	COAL	$/TON	55.21	55.85	55.21	55.74	54.52	55.63	55.47
38	GAS	$/MCF	5.83	5.70	5.68	5.77	6.56	6.71	6.26
39	NUCLEAR	$/MMBTU	0.35	0.35	0.35	0.35	0.35	0.35	0.35
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		4.13	4.18	4.23	4.29	4.32	4.34	4.22
42	LIGHT OIL		5.74	5.79	5.85	6.19	6.70	6.70	6.10
43	COAL		2.20	2.22	2.20	2.22	2.17	2.21	2.21
44	GAS		5.83	5.70	5.68	5.77	6.56	6.71	6.27
45	NUCLEAR		0.35	0.35	0.35	0.35	0.35	0.35	0.35
46	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
47	TOTAL	$/MMBTU	3.06	3.09	2.99	2.79	2.76	2.62	2.89
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,456	10,407	10,437	10,505	10,343	10,357	10,424
49	LIGHT OIL		13,379	13,209	13,037	12,007	10,807	11,545	12,694
50	COAL		9,578	9,581	9,577	9,606	9,643	9,585	9,592
51	GAS		8,449	8,459	8,174	7,824	7,836	7,895	8,133
52	NUCLEAR		10,409	10,409	10,409	10,409	10,191	10,191	10,299
53	OTHER		0	0	0	0	0	0	0
54	TOTAL	BTU/KWH	9,685	9,656	9,577	9,563	9,622	9,551	9,609
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		4.32	4.35	4.42	4.50	4.47	4.50	4.40
56	LIGHT OIL		7.68	7.64	7.63	7.43	7.24	7.73	7.74
57	COAL		2.10	2.13	2.10	2.13	2.09	2.12	2.12
58	GAS		4.92	4.82	4.65	4.51	5.14	5.30	5.10
59	NUCLEAR		0.36	0.36	0.36	0.36	0.36	0.36	0.36
60	OTHER		0.00	0.00	0.00	0.00	0.00	0.00	0.00
61	TOTAL	C/KWH	2.97	2.98	2.86	2.67	2.65	2.51	2.77

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jan-04

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	789	569,406	97.0		100.0	10,191	NUCLEAR	5,802,817	MMBTU	1.00	5,802,817	2,030,986	0.36
2	ANCLOTE	1	522	143,239	36.9		40.1	10,237	HEAVY OIL	225,590	BBLS	6.50	1,466,338	6,592,880	4.60
3	ANCLOTE	1		0				0	GAS	0	MCF	1.00	0	0	0.00
4	ANCLOTE	2	522	131,393	33.8		39.8	10,125	HEAVY OIL	204,670	BBLS	6.50	1,330,354	5,981,477	4.55
5	ANCLOTE	2		0				0	GAS	0	MCF	1.00	0	0	0.00
6	BARTOW	1	123	40,488	44.2		54.6	10,569	HEAVY OIL	65,833	BBLS	6.50	427,918	1,775,200	4.38
7	BARTOW	2	121	43,060	47.8		51.4	10,700	HEAVY OIL	70,883	BBLS	6.50	460,742	1,911,370	4.44
8	BARTOW	3	208	62,132	40.1		44.1	10,150	HEAVY OIL	97,022	BBLS	6.50	630,640	2,616,185	4.21
9	BARTOW	3		0				0	GAS	0	MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	383	209,535	73.5		78.8	9,825	COAL	81,694	TONS	25.20	2,058,681	4,230,100	2.02
11	CRYSTAL RIVER	2	491	277,821	76.1		82.8	9,815	COAL	108,207	TONS	25.20	2,726,813	5,602,952	2.02
12	CRYSTAL RIVER	4	735	414,776	75.8		79.3	9,550	COAL	157,813	TONS	25.10	3,961,111	9,042,695	2.18
13	CRYSTAL RIVER	5	732	421,786	77.4		80.8	9,450	COAL	158,800	TONS	25.10	3,985,878	9,099,235	2.16
14	SUWANNEE	1	33	9,989	40.7		52.8	12,813	HEAVY OIL	19,691	BBLS	6.50	127,989	588,848	5.89
15	SUWANNEE	1		0				0	GAS	0	MCF	1.00	0	0	0.00
16	SUWANNEE	2	32	9,663	40.6		56.5	12,534	HEAVY OIL	18,633	BBLS	6.50	121,116	557,227	5.77
17	SUWANNEE	2		0				0	GAS	0	MCF	1.00	0	0	0.00
18	SUWANNEE	3	81	24,030	39.9		55.3	11,514	HEAVY OIL	42,566	BBLS	6.50	276,681	1,419,376	5.91
19	SUWANNEE	3		0				0	GAS	0	MCF	1.00	0	0	0.00
20	AVON PARK	1-2	64	268	0.6		26.2	16,500	LIGHT OIL	762	BBLS	5.80	4,422	30,114	11.24
21	BARTOW	1-4	219	2,471	2.3		52.4	16,450	LIGHT OIL	7,008	BBLS	5.80	40,648	269,496	10.91
22	BARTOW	1-4		1,345				16,800	GAS	22,596	MCF	1.00	22,596	166,984	12.42
23	BAYBORO	1-4	232	7,314	4.2		72.5	13,412	LIGHT OIL	16,913	BBLS	5.80	98,095	650,372	8.89
24	DEBARY	1-10	762	8,074	3.5		66.8	13,430	LIGHT OIL	18,695	BBLS	5.80	108,434	737,350	9.13
25	DEBARY	1-10		12,043				13,551	GAS	163,195	MCF	1.00	163,195	1,206,009	10.01
26	HIGGINS	1-4	134	255	0.5		46.8	17,075	LIGHT OIL	751	BBLS	5.80	4,354	29,216	11.46
27	HIGGINS	1-4		215				16,850	GAS	3,623	MCF	1.00	3,623	26,772	12.45
28	HINES	1-2	1,111	296,330	35.8		31.3	7,240	GAS	2,145,429	MCF	1.00	2,145,429	15,854,722	5.35
29	HINES	1-2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
30	INT CITY	1-14	1,206	13,436	6.3		51.1	13,186	LIGHT OIL	30,546	BBLS	5.80	177,167	1,181,705	8.80
31	INT CITY	1-14		42,866				13,100	GAS	561,545	MCF	1.00	561,545	4,149,815	9.68
32	RIO PINAR	1	16	92	0.8		71.9	16,912	LIGHT OIL	268	BBLS	5.80	1,556	10,440	11.35
33	SUWANNEE	1-3	201	5,627	3.8		73.0	13,918	LIGHT OIL	13,503	BBLS	5.80	78,317	530,203	9.42
34	SUWANNEE	1-3		0				0	GAS	0	MCF	1.00	0	0	0.00
35	TIGER BAY	1	223	97,615	58.8		61.3	7,750	GAS	756,516	MCF	1.00	756,516	2,700,763	2.77
36	TURNER	1-4	194	1,499	1.0		62.6	15,450	LIGHT OIL	3,993	BBLS	5.80	23,160	156,790	10.46
37	UNIV OF FLA.	1	41	29,160	95.6		99.6	10,300	GAS	300,348	MCF	1.00	300,348	1,869,572	6.41
38	OTHER - START UP		-	7,208	-		-	9,600	LIGHT OIL	11,930	BBLS	5.80	69,197	464,334	6.44
39	OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	-	-	-	-	4,201,688	-
40	TOTAL		9,175	2,883,136				9,689					27,935,678	85,684,876	2.97

SCHEDULE E4

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Feb-04

(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	789	533,016	100 5		100 0	10,191	NUCLEAR	5,431,966 MMBTU	1 00	5,431,966	1,901,188	0 36
2 ANCLOTE	1	522	128,075	36 5		37 9	10,284	HEAVY OIL	202,634 BBLS	6 50	1,317,123	5,921,989	4 62
3 ANCLOTE	1		0				0	GAS	0 MCF	1 00	0	0	0 00
4 ANCLOTE	2	522	127,793	36 4		37 3	10,193	HEAVY OIL	200,399 BBLS	6 50	1,302,594	5,856,663	4 58
5 ANCLOTE	2		0				0	GAS	0 MCF	1 00	0	0	0 00
6 BARTOW	1	123	34,635	41 9		57 3	10,585	HEAVY OIL	56,402 BBLS	6 50	366,611	1,520,874	4 39
7 BARTOW	2	121	32,149	39 5		52 9	10,725	HEAVY OIL	53,046 BBLS	6 50	344,798	1,430,381	4.45
8 BARTOW	3	208	44,100	31 6		48 2	10,201	HEAVY OIL	69,210 BBLS	6 50	449,864	1,866,244	4 23
9 BARTOW	3		0				0	GAS	0 MCF	1 00	0	0	0 00
10 CRYSTAL RIVER	1	383	185,901	72 2		84 1	9,855	COAL	72,701 TONS	25 20	1,832,054	3,765,890	2 03
11 CRYSTAL RIVER	2	491	272,657	82.6		86 0	9,819	COAL	106,239 TONS	25 20	2,677,219	5,503,173	2 02
12 CRYSTAL RIVER	4	735	414,774	84 0		84 7	9,478	COAL	156,623 TONS	25 10	3,931,228	8,997,970	2 17
13 CRYSTAL RIVER	5	732	413,544	84 1		84 7	9,465	COAL	155,944 TONS	25 10	3,914,194	8,958,982	2 17
14 SUWANNEE	1	33	1,843	8 3		58 2	12,697	HEAVY OIL	3,600 BBLS	6 50	23,401	107,661	5 84
15 SUWANNEE	1		0				0	GAS	0 MCF	1 00	0	0	0 00
16 SUWANNEE	2	32	2,379	11 1		63 5	12,495	HEAVY OIL	4,573 BBLS	6 50	29,726	136,761	5.75
17 SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0 00
18 SUWANNEE	3	81	7,355	13 5		60.5	11,500	HEAVY OIL	13,013 BBLS	6 50	84,583	433,908	5 90
19 SUWANNEE	3		0				0	GAS	0 MCF	1 00	0	0	0 00
20 AVON PARK	1-2	64	25	0 1		15 6	16,500	LIGHT OIL	71 BBLS	5 80	413	2,809	11 24
21 BARTOW	1-4	219	312	1 0		45 4	16,875	LIGHT OIL	908 BBLS	5 80	5,265	34,907	11 19
22 BARTOW	1-4		1,180				16,682	GAS	19,685 MCF	1 00	19,685	142,518	12 08
23 BAYBORO	1-4	232	4,302	2 8		65 6	13,441	LIGHT OIL	9,970 BBLS	5 80	57,823	383,368	8 91
24 DEBARY	1-10	762	599	2 2		66 2	13,787	LIGHT OIL	1,424 BBLS	5 80	8,258	56,157	9 38
25 DEBARY	1-10		10,608				13,438	GAS	142,550 MCF	1 00	142,550	1,032,064	9 73
26 HIGGINS	1-4	134	73	0 2		14 9	16,850	LIGHT OIL	212 BBLS	5 80	1,230	8,254	11 31
27 HIGGINS	1-4		132				16,675	GAS	2,201 MCF	1 00	2,201	15,936	12 07
28 HINES	1-2	1,111	282,393	37 8		31 5	7,300	GAS	2,061,469 MCF	1 00	2,061,469	14,925,035	5 29
29 HINES	1-2		0				0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
30 INT CITY	1-14	1,206	6,380	3 8		48 4	13,150	LIGHT OIL	14,465 BBLS	5 80	83,897	559,593	8 77
31 INT CITY	1-14		24,358				13,271	GAS	323,255 MCF	1 00	323,255	2,340,366	9 61
32 RIO PINAR	1	16	0	0 0		0 0	0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
33 SUWANNEE	1-3	201	2,220	1 6		57.1	13,946	LIGHT OIL	5,338 BBLS	5 80	30,960	209,600	9 44
34 SUWANNEE	1-3		0				0	GAS	0 MCF	1 00	0	0	0 00
35 TIGER BAY	1	223	90,343	60 3		60 6	7,800	GAS	704,675 MCF	1.00	704,675	2,515,691	2 78
36 TURNER	1-4	194	480	0 4		61 9	15,257	LIGHT OIL	1,263 BBLS	5 80	7,323	49,579	10 33
37 UNIV OF FLA.	1	41	28,015	101 7		99 9	10,300	GAS	288,555 MCF	1 00	288,555	1,864,135	6 65
38 OTHER - START UP		-	6,641	-	-	-	9,600	LIGHT OIL	10,992 BBLS	5 80	63,754	427,809	6 44
39 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	- -	-	-	4,119,516	-
40 TOTAL		9,175	2,656,282				9,602				25,506,674	75,089,019	2 83

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Mar-04

(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	789	569,406	97.0		100.0	10,191	NUCLEAR	5,802,817	MMBTU	1.00	5,802,817	2,030,986	0.36
2 ANCLOTE	1	522	138,873	35.8		52.0	10,210	HEAVY OIL	218,137	BBLS	6.50	1,417,893	6,233,277	4.49
3 ANCLOTE	1		0				0	GAS	0	MCF	1.00	0	0	0.00
4 ANCLOTE	2	522	98,589	25.4		29.9	10,225	HEAVY OIL	155,088	BBLS	6.50	1,008,073	4,431,642	4.50
5 ANCLOTE	2		0				0	GAS	0	MCF	1.00	0	0	0.00
6 BARTOW	1	123	48,953	53.5		63.0	10,507	HEAVY OIL	79,131	BBLS	6.50	514,349	2,082,323	4.25
7 BARTOW	2	121	33,630	37.4		56.5	10,688	HEAVY OIL	55,298	BBLS	6.50	359,437	1,455,169	4.33
8 BARTOW	3	208	64,703	41.8		66.2	10,163	HEAVY OIL	101,166	BBLS	6.50	657,577	2,662,174	4.11
9 BARTOW	3		0				0	GAS	0	MCF	1.00	0	0	0.00
10 CRYSTAL RIVER	1	383	39,964	14.0		92.3	9,850	COAL	15,621	TONS	25.20	393,645	809,160	2.02
11 CRYSTAL RIVER	2	491	308,879	84.6		91.2	9,812	COAL	120,267	TONS	25.20	3,030,721	6,229,815	2.02
12 CRYSTAL RIVER	4	735	510,830	93.4		97.6	9,472	COAL	192,772	TONS	25.10	4,838,582	11,051,629	2.16
13 CRYSTAL RIVER	5	732	491,391	90.2		94.5	9,484	COAL	185,671	TONS	25.10	4,660,352	10,644,542	2.17
14 SUWANNEE	1	33	4,250	17.3		47.3	12,625	HEAVY OIL	8,255	BBLS	6.50	53,656	241,494	5.68
15 SUWANNEE	1		0				0	GAS	0	MCF	1.00	0	0	0.00
16 SUWANNEE	2	32	2,827	11.9		51.4	12,504	HEAVY OIL	5,438	BBLS	6.50	35,349	159,097	5.63
17 SUWANNEE	2		0				0	GAS	0	MCF	1.00	0	0	0.00
18 SUWANNEE	3	81	11,682	19.4		52.3	11,436	HEAVY OIL	20,553	BBLS	6.50	133,595	671,985	5.75
19 SUWANNEE	3		0					GAS	0	MCF	1.00	0	0	0.00
20 AVON PARK	1-2	64	0	0.0		0.0	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
21 BARTOW	1-4	219	0	0.1		27.4	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
22 BARTOW	1-4		195				16,736	GAS	3,264	MCF	1.00	3,264	22,975	11.78
23 BAYBORO	1-4	232	567	0.3		61.1	13,397	LIGHT OIL	1,310	BBLS	5.80	7,596	50,362	8.88
24 DEBARY	1-10	762	0	0.0		60.8	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
25 DEBARY	1-10		3,982				13,274	GAS	52,857	MCF	1.00	52,857	372,114	9.34
26 HIGGINS	1-4	134	0	0.0		14.9	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
27 HIGGINS	1-4		55				16,845	GAS	926	MCF	1.00	926	6,522	11.86
28 HINES	1-2	1,111	288,923	35.0		28.5	7,229	GAS	2,088,624	MCF	1.00	2,088,624	14,703,916	5.09
29 HINES	1-2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
30 INT CITY	1-14	1,206	680	0.7		41.5	13,086	LIGHT OIL	1,534	BBLS	5.80	8,898	59,353	8.73
31 INT CITY	1-14		5,474				13,350	GAS	73,078	MCF	1.00	73,078	514,468	9.40
32 RIO PINAR	1	16	0	0.0		0.0	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
33 SUWANNEE	1-3	201	60	0.0		44.8	13,870	LIGHT OIL	143	BBLS	5.80	832	5,634	9.39
34 SUWANNEE	1-3		0				0	GAS	0	MCF	1.00	0	0	0.00
35 TIGER BAY	1	223	95,513	57.6		60.0	7,850	GAS	749,777	MCF	1.00	749,777	2,676,704	2.80
36 TURNER	1-4	194	0	0.0		0.0	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
37 UNIV OF FLA.	1	41	30,233	99.1		99.9	10,300	GAS	311,400	MCF	1.00	311,400	1,942,255	6.42
38 OTHER - START UP		-	6,891	-	-	-	9,600	LIGHT OIL	11,406	BBLS	5.80	66,154	443,913	6.44
39 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	-	4,004,166	-
40 TOTAL		9,175	2,756,550				9,530					26,269,453	73,505,675	2.67

SCHEDULE E4

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Apr-04

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	789	551,163	97 0		100 0	10,191	NUCLEAR	5,616,902 MMBTU	1 00	5,616,902	1,965,916	0 36
2	ANCLOTE	1	522	99,473	26 5		35 0	10,255	HEAVY OIL	156,938 BBLS	6 50	1,020,096	4,228,689	4 25
3	ANCLOTE	1		0				0	GAS	0 MCF	1 00	0	0	0 00
4	ANCLOTE	2	522	60,504	16 1		30 2	10,195	HEAVY OIL	94,898 BBLS	6 50	616,838	2,557,032	4 23
5	ANCLOTE	2		0				0	GAS	0 MCF	1 00	0	0	0 00
6	BARTOW	1	123	38,098	43 0		48 9	10,512	HEAVY OIL	61,613 BBLS	6 50	400,486	1,520,923	3 99
7	BARTOW	2	121	27,163	31 2		53 2	10,657	HEAVY OIL	44,535 BBLS	6 50	289,476	1,099,341	4 05
8	BARTOW	3	208	54,205	36 2		48 4	10,146	HEAVY OIL	84,610 BBLS	6 50	549,964	2,088,594	3 85
9	BARTOW	3		0	0 0			0	GAS	0 MCF	1 00	0	0	0 00
10	CRYSTAL RIVER	1	383	99,373	36 0		85 1	9,837	COAL	38,791 TONS	25 20	977,532	2,018,294	2 03
11	CRYSTAL RIVER	2	491	286,268	81 0		87 3	9,818	COAL	111,531 TONS	25 20	2,810,579	5,802,954	2 03
12	CRYSTAL RIVER	4	735	452,103	85 4		89 7	9,456	COAL	170,322 TONS	25 10	4,275,086	9,829,291	2 17
13	CRYSTAL RIVER	5	732	427,967	81 2		84 7	9,495	COAL	161,894 TONS	25 10	4,063,547	9,342,919	2 18
14	SUWANNEE	1	33	4,109	17.3		53 4	12,710	HEAVY OIL	8,035 BBLS	6 50	52,225	221,958	5 40
15	SUWANNEE	1		0				0	GAS	0 MCF	1 00	0	0	0.00
16	SUWANNEE	2	32	4,084	17 7		55 0	12,549	HEAVY OIL	7,885 BBLS	6 50	51,250	217,813	5 33
17	SUWANNEE	2		0				0	GAS	0 MCF	1 00	0	0	0 00
18	SUWANNEE	3	81	8,316	14 3		53 8	11,555	HEAVY OIL	14,783 BBLS	6 50	96,091	464,121	5 58
19	SUWANNEE	3		0				0	GAS	0 MCF	1 00	0	0	0 00
20	AVON PARK	1-2	64	110	0 2		57 3	16,788	LIGHT OIL	318 BBLS	5 80	1,847	12,576	11 43
21	BARTOW	1-4	219	302	1 2		58 4	16,455	LIGHT OIL	857 BBLS	5 80	4,969	32,947	10 91
22	BARTOW	1-4		1,616				16,814	GAS	27,171 MCF	1 00	27,171	148,356	9 18
23	BAYBORO	1-4	232	2,565	1 5		69 1	13,376	LIGHT OIL	5,915 BBLS	5 80	34,309	227,472	8 87
24	DEBARY	1-10	762	663	1 5		70 3	13,596	LIGHT OIL	1,554 BBLS	5 80	9,014	61,296	9 25
25	DEBARY	1-10		7,377				13,435	GAS	99,110 MCF	1 00	99,110	541,141	7 34
26	HIGGINS	1-4	134	0	0 0		51 4	0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
27	HIGGINS	1-4		448				16,732	GAS	7,496 MCF	1.00	7,496	40,928	9 14
28	HINES	1-2	1,111	305,693	38 2		30 8	7,237	GAS	2,212,300 MCF	1 00	2,212,300	12,079,159	3 95
29	HINES	1-2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0 00
30	INT CITY	1-14	1,206	2,322	2 0		48 0	13,378	LIGHT OIL	5,356 BBLS	5 80	31,064	207,195	8 92
31	INT CITY	1-14		15,061				13,193	GAS	198,700 MCF	1 00	198,700	1,084,901	7 20
32	RIO PINAR	1	16	0	0 0		0 0	0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
33	SUWANNEE	1-3	201	303	0 5		61 9	13,770	LIGHT OIL	719 BBLS	5 80	4,172	28,247	9 32
34	SUWANNEE	1-3		485				13,932	GAS	6,757 MCF	1 00	6,757	36,893	7 61
35	TIGER BAY	1	223	49,404	30 8		60 0	7,850	GAS	387,821 MCF	1 00	387,821	1,384,522	2 80
36	TURNER	1-4	194	553	0 4		50 3	15,457	LIGHT OIL	1,474 BBLS	5 80	8,548	57,868	10 46
37	UNIV OF FLA.	1	41	15,604	52 9		99 9	10,300	GAS	160,721 MCF	1 00	160,721	652,538	4 18
38	OTHER - START UP		-	6,304	-	-	-	9,600	LIGHT OIL	10,434 BBLS	5 80	60,518	406,099	6 44
39	OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	- -	-	-	3,966,932	-
40	TOTAL		9,175	2,521,636				9,547				24,074,592	62,326,915	2 47

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: May-04

(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1 CRYS RIV NUC	3	773	557,886	97 0		100 0	10,409	NUCLEAR	5,807,035 MMBTU	1 00	5,807,035	2,032,462	0 36
2 ANCLOTE	1	498	158,267	42 7		46 3	10,269	HEAVY OIL	250,038 BBLS	6 50	1,625,244	6,737,261	4 26
3 ANCLOTE	1		0				0	GAS	0 MCF	1 00	0	0	0 00
4 ANCLOTE	2	495	133,287	36 2		49 1	10,156	HEAVY OIL	208,256 BBLS	6 50	1,353,663	5,611,453	4 21
5 ANCLOTE	2		0				0	GAS	0 MCF	1 00	0	0	0 00
6 BARTOW	1	121	47,411	52.7		59 3	10,530	HEAVY OIL	76,806 BBLS	6 50	499,238	1,895,952	4 00
7 BARTOW	2	119	39,032	44 1		56 9	10,640	HEAVY OIL	63,892 BBLS	6 50	415,300	1,577,183	4 04
8 BARTOW	3	204	64,797	42 7		55 1	10,123	HEAVY OIL	100,914 BBLS	6 50	655,940	2,491,058	3 84
9 BARTOW	3		0				0	GAS	0 MCF	1 00	0	0	0 00
10 CRYSTAL RIVER	1	379	229,344	81 3		86 8	9,860	COAL	89,735 TONS	25 20	2,261,332	4,639,320	2 02
11 CRYSTAL RIVER	2	486	296,101	81 9		88 8	9,816	COAL	115,338 TONS	25 20	2,906,527	5,962,995	2 01
12 CRYSTAL RIVER	4	720	463,721	86 6		90 5	9,462	COAL	174,810 TONS	25 10	4,387,728	9,993,881	2 16
13 CRYSTAL RIVER	5	717	453,019	84 9		88 6	9,460	COAL	170,739 TONS	25 10	4,285,560	9,761,173	2 15
14 SUWANNEE	1	32	10,356	43 5		51 9	12,752	HEAVY OIL	20,317 BBLS	6 50	132,060	561,254	5 42
15 SUWANNEE	1		0				0	GAS	0 MCF	1 00	0	0	0 00
16 SUWANNEE	2	31	11,707	50 8		52 2	12,440	HEAVY OIL	22,405 BBLS	6 50	145,635	618,949	5 29
17 SUWANNEE	2		0				0	GAS	0 MCF	1 00	0	0	0 00
18 SUWANNEE	3	80	29,272	49 2		52 3	11,413	HEAVY OIL	51,397 BBLS	6 50	334,081	1,613,613	5 51
19 SUWANNEE	3		0				0	GAS	0 MCF	1 00	0	0	0 00
20 AVON PARK	1-2	52	20	0 1		19 2	16,650	LIGHT OIL	57 BBLS	5 80	333	2,068	10 34
21 BARTOW	1-4	187	0	0 5		44 0	0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
22 BARTOW	1-4		638				16,870	GAS	10,763 MCF	1 00	10,763	56,614	8 87
23 BAYBORO	1-4	184	1,623	1 2		65 3	13,638	LIGHT OIL	3,816 BBLS	5 80	22,134	133,471	8 22
24 DEBARY	1-10	667	0	0 0		51 2	0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
25 DEBARY	1-10		14,605				13,554	GAS	197,956 MCF	1 00	197,956	1,041,249	7 13
26 HIGGINS	1-4	122	0	0 0		34 9	0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
27 HIGGINS	1-4		213				16,822	GAS	3,583 MCF	1 00	3,583	18,847	8 85
28 HINES	1-2	998	398,769	53 7		34 6	7,424	GAS	2,960,461 MCF	1 00	2,960,461	15,572,025	3 91
29 HINES	1-2		0				0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
30 INT CITY	1-14	1,041	1,586	5 0		40 0	13,406	LIGHT OIL	3,666 BBLS	5 80	21,262	129,060	8 14
31 INT CITY	1-14		37,472				13,284	GAS	497,778 MCF	1 00	497,778	2,618,313	6 99
32 RIO PINAR	1	13	0	0 0		0 0	0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
33 SUWANNEE	1-3	164	0	0 0		0 0	0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
34 SUWANNEE	1-3		0				0	GAS	0 MCF	1 00	0	0	0 00
35 TIGER BAY	1	207	103,595	67 3		70 1	7,729	GAS	800,686 MCF	1 00	800,686	2,858,448	2 76
36 TURNER	1-4	154	0	0 0		0 0	0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
37 UNIV OF FLA.	1	35	25,815	99.1		99 9	10,300	GAS	265,895 MCF	1 00	265,895	1,123,605	4 35
38 OTHER - START UP		-	7,716	-	-	-	9,600	LIGHT OIL	12,771 BBLS	5 80	74,074	452,615	5 87
39 OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	- -	-	-	5,368,973	-
40 TOTAL		8,479	3,086,252				9,612				29,664,268	82,871,842	2 69

SCHEDULE E4

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jun-04

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	773	540,011	97.0		100 0	10,409	NUCLEAR	5,620,974	MMBTU	1 00	5,620,974	1,967,341	0 36
2	ANCLOTE	1	498	179,454	50 0		52 7	10,281	HEAVY OIL	283,841	BBLS	6 50	1,844,967	7,648,096	4 26
3	ANCLOTE	1		0				0	GAS	0	MCF	1 00	0	0	0 00
4	ANCLOTE	2	495	187,284	52 5		54 4	10,296	HEAVY OIL	296,658	BBLS	6 50	1,928,276	7,993,446	4 27
5	ANCLOTE	2		0				0	GAS	0	MCF	1 00	0	0	0 00
6	BARTOW	1	121	50,156	57 6		64 8	10,606	HEAVY OIL	81,839	BBLS	6 50	531,955	2,020,200	4 03
7	BARTOW	2	119	51,685	60 3		61 6	10,740	HEAVY OIL	85,400	BBLS	6 50	555,097	2,108,087	4 08
8	BARTOW	3	204	88,135	60 0		65 5	10,244	HEAVY OIL	138,901	BBLS	6 50	902,855	3,428,765	3 89
9	BARTOW	3		0				0	GAS	0	MCF	1 00	0	0	0 00
10	CRYSTAL RIVER	1	379	232,039	85 0		90 7	9,848	COAL	90,679	TONS	25 20	2,285,120	4,713,514	2 03
11	CRYSTAL RIVER	2	486	292,605	83 6		90 1	9,815	COAL	113,965	TONS	25 20	2,871,918	5,923,901	2 02
12	CRYSTAL RIVER	4	720	470,168	90 7		94 8	9,468	COAL	177,353	TONS	25 10	4,451,551	10,288,225	2 19
13	CRYSTAL RIVER	5	717	454,572	88 1		91 9	9,450	COAL	171,144	TONS	25 10	4,295,705	9,928,043	2 18
14	SUWANNEE	1	32	11,818	51 3		53 6	12,726	HEAVY OIL	23,138	BBLS	6 50	150,396	639,182	5 41
15	SUWANNEE	1		0				0	GAS	0	MCF	1 00	0	0	0 00
16	SUWANNEE	2	31	11,782	52 8		55 1	12,549	HEAVY OIL	22,747	BBLS	6 50	147,852	628,372	5 33
17	SUWANNEE	2		0				0	GAS	0	MCF	1 00	0	0	0 00
18	SUWANNEE	3	80	29,673	51 5		55 0	11,590	HEAVY OIL	52,909	BBLS	6 50	343,910	1,661,086	5 60
19	SUWANNEE	3		0				0	GAS	0	MCF	1 00	0	0	0 00
20	AVON PARK	1-2	52	215	0 6		19 2	16,854	LIGHT OIL	625	BBLS	5 80	3,624	21,053	9 79
21	BARTOW	1-4	187	1,226	4 2		49 2	16,387	LIGHT OIL	3,464	BBLS	5 80	20,090	113,109	9 23
22	BARTOW	1-4		4,427				16,835	GAS	74,529	MCF	1 00	74,529	380,841	8 60
23	BAYBORO	1-4	184	10,002	7 5		73 5	13,655	LIGHT OIL	23,548	BBLS	5 80	136,577	768,930	7 69
24	DEBARY	1-10	667	3,030	6 2		63 7	13,794	LIGHT OIL	7,206	BBLS	5 80	41,796	242,416	8 00
25	DEBARY	1-10		26,524				13,421	GAS	355,979	MCF	1 00	355,979	1,819,051	6 86
26	HIGGINS	1-4	122	101	1 3		26 3	17,129	LIGHT OIL	298	BBLS	5 80	1,730	9,878	9 78
27	HIGGINS	1-4		1,079				16,834	GAS	18,164	MCF	1 00	18,164	92,817	8 60
28	HINES	1-2	998	494,354	68 8		35 6	7,250	GAS	3,584,067	MCF	1 00	3,584,067	18,314,580	3 70
29	HINES	1-2		0				0	LIGHT OIL	0	BBLS	5 80	0	0	0 00
30	INT CITY	1-14	898	6,241	10 4		47 9	13,550	LIGHT OIL	14,580	BBLS	5 80	84,566	479,487	7 68
31	INT CITY	1-14		60,691				13,246	GAS	803,913	MCF	1 00	803,913	4,107,995	6 77
32	RIO PINAR	1	13	0	0 0		0 0	0	LIGHT OIL	0	BBLS	5 80	0	0	0 00
33	SUWANNEE	1-3	164	3,121	2 6		60 1	13,884	LIGHT OIL	7,471	BBLS	5 80	43,332	250,025	8 01
34	SUWANNEE	1-3		0				0	GAS	0	MCF	1 00	0	0	0 00
35	TIGER BAY	1	207	105,742	70 9		71 5	7,710	GAS	815,271	MCF	1 00	815,271	2,910,517	2 75
36	TURNER	1-4	154	0	0 0		0 0	0	LIGHT OIL	0	BBLS	5 80	0	0	0 00
37	UNIV OF FLA.	1	35	24,979	99 1		100 0	10,300	GAS	257,284	MCF	1 00	257,284	989,720	3 96
38	OTHER - START UP		-	8,374	-	-	-	9,600	LIGHT OIL	13,860	BBLS	5 80	80,390	459,057	5 48
39	OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	-	5,603,390	-
40	TOTAL		8,336	3,349,488				9,629					32,251,886	95,511,124	2 85

SCHEDULE E4

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Jul-04

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	773	557,886	97.0		100.0	10,409	NUCLEAR	5,807,035	MMBTU	1.00	5,807,035	2,032,462	0.36
2	ANCLOTE	1	498	188,867	51.0		53.2	10,251	HEAVY OIL	297,858	BBLS	6.50	1,936,076	8,124,071	4.30
3	ANCLOTE	1		0				0	GAS	0	MCF	1.00	0	0	0.00
4	ANCLOTE	2	495	203,752	55.3		57.1	10,220	HEAVY OIL	320,361	BBLS	6.50	2,082,345	8,737,842	4.29
5	ANCLOTE	2		0				0	GAS	0	MCF	1.00	0	0	0.00
6	BARTOW	1	121	54,350	60.4		68.0	10,543	HEAVY OIL	88,156	BBLS	6.50	573,012	2,205,215	4.06
7	BARTOW	2	119	56,247	63.5		64.3	10,650	HEAVY OIL	92,159	BBLS	6.50	599,031	2,305,346	4.10
8	BARTOW	3	204	93,772	61.8		67.8	10,220	HEAVY OIL	147,438	BBLS	6.50	958,350	3,688,172	3.93
9	BARTOW	3		0				0	GAS	0	MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	379	239,961	85.1		90.8	9,810	COAL	93,413	TONS	25.20	2,354,017	4,836,945	2.02
11	CRYSTAL RIVER	2	486	301,879	83.5		90.0	9,810	COAL	117,517	TONS	25.20	2,961,433	6,085,040	2.02
12	CRYSTAL RIVER	4	720	487,939	91.1		95.2	9,438	COAL	183,473	TONS	25.10	4,605,168	10,498,316	2.15
13	CRYSTAL RIVER	5	717	468,787	87.9		91.7	9,454	COAL	176,570	TONS	25.10	4,431,912	10,103,347	2.16
14	SUWANNEE	1	32	12,925	54.3		56.1	12,771	HEAVY OIL	25,395	BBLS	6.50	165,065	709,907	5.49
15	SUWANNEE	1		0				0	GAS	0	MCF	1.00	0	0	0.00
16	SUWANNEE	2	31	12,852	55.7		57.3	12,606	HEAVY OIL	24,925	BBLS	6.50	162,012	696,778	5.42
17	SUWANNEE	2		0				0	GAS	0	MCF	1.00	0	0	0.00
18	SUWANNEE	3	80	31,862	53.5		57.1	11,584	HEAVY OIL	56,783	BBLS	6.50	369,089	1,801,440	5.65
19	SUWANNEE	3		0				0	GAS	0	MCF	1.00	0	0	0.00
20	AVON PARK	1-2	52	650	1.7		31.3	16,560	LIGHT OIL	1,856	BBLS	5.80	10,764	63,077	9.70
21	BARTOW	1-4	187	3,288	7.0		53.3	16,649	LIGHT OIL	9,438	BBLS	5.80	54,742	310,934	9.46
22	BARTOW	1-4		6,486				16,431	GAS	106,571	MCF	1.00	106,571	549,909	8.48
23	BAYBORO	1-4	184	18,789	13.7		76.2	13,533	LIGHT OIL	43,840	BBLS	5.80	254,272	1,444,262	7.69
24	DEBARY	1-10	667	6,843	8.7		69.4	13,998	LIGHT OIL	16,515	BBLS	5.80	95,788	560,362	8.19
25	DEBARY	1-10		36,137				13,414	GAS	484,742	MCF	1.00	484,742	2,501,267	6.92
26	HIGGINS	1-4	122	975	3.4		37.8	16,833	LIGHT OIL	2,830	BBLS	5.80	16,412	94,534	9.70
27	HIGGINS	1-4		2,152				16,716	GAS	35,973	MCF	1.00	35,973	185,620	8.63
28	HINES	1-2	998	526,111	70.9		36.7	7,220	GAS	3,798,521	MCF	1.00	3,798,521	19,600,371	3.73
29	HINES	1-2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
30	INT CITY	1-14	898	14,456	15.2		51.2	13,480	LIGHT OIL	33,598	BBLS	5.80	194,867	1,114,639	7.71
31	INT CITY	1-14		86,871				13,218	GAS	1,148,261	MCF	1.00	1,148,261	5,925,026	6.82
32	RIO PINAR	1	13	92	1.0		88.5	16,987	LIGHT OIL	269	BBLS	5.80	1,563	9,032	9.82
33	SUWANNEE	1-3	164	8,445	6.9		65.5	13,980	LIGHT OIL	20,355	BBLS	5.80	118,061	683,533	8.09
34	SUWANNEE	1-3		0				0	GAS	0	MCF	1.00	0	0	0.00
35	TIGER BAY	1	207	111,883	72.6		75.7	7,875	GAS	881,079	MCF	1.00	881,079	3,145,451	2.81
36	TURNER	1-4	154	1,620	1.4		77.0	15,579	LIGHT OIL	4,351	BBLS	5.80	25,238	146,902	9.07
37	UNIV OF FLA.	1	35	25,815	99.1		99.9	10,300	GAS	265,895	MCF	1.00	265,895	1,147,016	4.44
38	OTHER - START UP		-	8,927	-	-	-	9,600	LIGHT OIL	14,776	BBLS	5.80	85,699	493,657	5.53
39	OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	-	6,100,340	-
40	TOTAL		8,336	3,570,619				9,685					34,582,994	105,900,813	2.97

SCHEDULE E4

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Aug-04

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	773	557,886	97.0		100.0	10,409	NUCLEAR	5,807,035 MMBTU	1.00	5,807,035	2,032,462	0.36
2	ANCLOTE	1	498	198,801	53.7		56.0	10,217	HEAVY OIL	312,485 BBLS	6.50	2,031,150	8,623,012	4.34
3	ANCLOTE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
4	ANCLOTE	2	495	214,332	58.2		60.1	10,181	HEAVY OIL	335,710 BBLS	6.50	2,182,114	9,263,914	4.32
5	ANCLOTE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
6	BARTOW	1	121	47,245	52.5		70.6	10,585	HEAVY OIL	76,937 BBLS	6.50	500,088	1,949,190	4.13
7	BARTOW	2	119	56,357	63.7		64.3	10,618	HEAVY OIL	92,061 BBLS	6.50	598,399	2,332,374	4.14
8	BARTOW	3	204	99,335	65.4		71.9	10,134	HEAVY OIL	154,871 BBLS	6.50	1,006,661	3,923,654	3.95
9	BARTOW	3		0				0	GAS	0 MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	379	246,846	87.5		93.4	9,828	COAL	96,270 TONS	25.20	2,426,002	5,011,813	2.03
11	CRYSTAL RIVER	2	486	306,061	84.6		91.3	9,817	COAL	119,230 TONS	25.20	3,004,601	6,207,124	2.03
12	CRYSTAL RIVER	4	720	501,467	93.6		97.8	9,454	COAL	188,879 TONS	25.10	4,740,869	10,966,329	2.19
13	CRYSTAL RIVER	5	717	483,337	90.6		94.5	9,437	COAL	181,723 TONS	25.10	4,561,251	10,550,847	2.18
14	SUWANNEE	1	32	13,445	56.5		59.8	12,699	HEAVY OIL	26,267 BBLS	6.50	170,738	742,711	5.52
15	SUWANNEE	1		0				0	GAS	0 MCF	1.00	0	0	0.00
16	SUWANNEE	2	31	13,635	59.1		60.6	12,504	HEAVY OIL	26,230 BBLS	6.50	170,492	741,640	5.44
17	SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0.00
18	SUWANNEE	3	80	34,107	57.3		60.7	11,383	HEAVY OIL	59,729 BBLS	6.50	388,240	1,914,023	5.61
19	SUWANNEE	3		0				0	GAS	0 MCF	1.00	0	0	0.00
20	AVON PARK	1-2	52	295	0.8		19.2	16,660	LIGHT OIL	847 BBLS	5.80	4,915	29,046	9.85
21	BARTOW	1-4	187	2,291	6.2		52.2	16,750	LIGHT OIL	6,616 BBLS	5.80	38,374	219,884	9.60
22	BARTOW	1-4		6,401				16,350	GAS	104,656 MCF	1.00	104,656	529,561	8.27
23	BAYBORO	1-4	184	16,575	12.1		75.4	13,633	LIGHT OIL	38,960 BBLS	5.80	225,967	1,294,791	7.81
24	DEBARY	1-10	667	5,086	8.9		69.3	13,850	LIGHT OIL	12,145 BBLS	5.80	70,441	415,602	8.17
25	DEBARY	1-10		38,943				13,416	GAS	522,459 MCF	1.00	522,459	2,643,644	6.79
26	HIGGINS	1-4	122	225	2.8		32.5	16,850	LIGHT OIL	654 BBLS	5.80	3,791	22,027	9.79
27	HIGGINS	1-4		2,283				16,540	GAS	37,761 MCF	1.00	37,761	191,070	8.37
28	HINES	1-2	998	567,485	76.4		39.1	7,259	GAS	4,119,374 MCF	1.00	4,119,374	20,844,030	3.67
29	HINES	1-2		0				0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
30	INT CITY	1-14	898	13,939	16.0		52.4	13,450	LIGHT OIL	32,324 BBLS	5.80	187,480	1,081,757	7.76
31	INT CITY	1-14		92,820				13,288	GAS	1,233,392 MCF	1.00	1,233,392	6,240,964	6.72
32	RIO PINAR	1	13	0	0.0		0.0	0	LIGHT OIL	0 BBLS	5.80	0	0	0.00
33	SUWANNEE	1-3	164	8,808	7.2		62.2	14,100	LIGHT OIL	21,413 BBLS	5.80	124,193	725,243	8.23
34	SUWANNEE	1-3		0				0	GAS	0 MCF	1.00	0	0	0.00
35	TIGER BAY	1	207	116,534	75.7		78.8	7,800	GAS	908,965 MCF	1.00	908,965	3,245,006	2.78
36	TURNER	1-4	154	777	0.7		79.7	15,440	LIGHT OIL	2,068 BBLS	5.80	11,997	70,430	9.06
37	UNIV OF FLA.	1	35	25,815	99.1		99.9	10,300	GAS	265,895 MCF	1.00	265,895	1,115,426	4.32
38	OTHER - START UP		-	9,201	-	-	-	9,600	LIGHT OIL	15,229 BBLS	5.80	88,330	513,225	5.58
39	OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	- -	-	-	6,194,632	-
40	TOTAL		8,336	3,680,332				9,656				35,535,630	109,635,433	2.98

SCHEDULE E4

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Sep-04

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)		(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)		FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	773	540,011	97.0		99.9	10,409	NUCLEAR	5,620,974	MMBTU	1.00	5,620,974	1,967,341	0.36
2	ANCLOTE	1	498	169,503	47.3		49.3	10,275	HEAVY OIL	267,945	BBLS	6.50	1,741,643	7,482,368	4.41
3	ANCLOTE	1		0				0	GAS	0	MCF	1.00	0	0	0.00
4	ANCLOTE	2	495	179,218	50.3		51.9	10,155	HEAVY OIL	279,994	BBLS	6.50	1,819,959	7,818,823	4.36
5	ANCLOTE	2		0				0	GAS	0	MCF	1.00	0	0	0.00
6	BARTOW	1	121	47,328	54.3		65.1	10,584	HEAVY OIL	77,065	BBLS	6.50	500,920	1,977,862	4.18
7	BARTOW	2	119	48,686	56.8		57.6	10,626	HEAVY OIL	79,590	BBLS	6.50	517,337	2,042,687	4.20
8	BARTOW	3	204	90,973	61.9		68.3	10,181	HEAVY OIL	142,492	BBLS	6.50	926,196	3,657,050	4.02
9	BARTOW	3		0				0	GAS	0	MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	379	235,690	86.4		92.1	9,837	COAL	92,003	TONS	25.20	2,318,483	4,763,930	2.02
11	CRYSTAL RIVER	2	486	294,618	84.2		90.7	9,809	COAL	114,679	TONS	25.20	2,889,908	5,938,073	2.02
12	CRYSTAL RIVER	4	720	482,934	93.2		97.4	9,447	COAL	181,764	TONS	25.10	4,562,277	10,396,903	2.15
13	CRYSTAL RIVER	5	717	463,508	89.8		93.7	9,432	COAL	174,176	TONS	25.10	4,371,807	9,962,844	2.15
14	SUWANNEE	1	32	12,192	52.9		55.2	12,692	HEAVY OIL	23,806	BBLS	6.50	154,741	680,979	5.59
15	SUWANNEE	1		0				0	GAS	0	MCF	1.00	0	0	0.00
16	SUWANNEE	2	31	10,464	46.9		57.5	12,442	HEAVY OIL	20,030	BBLS	6.50	130,193	572,950	5.48
17	SUWANNEE	2		0				0	GAS	0	MCF	1.00	0	0	0.00
18	SUWANNEE	3	80	30,710	53.3		56.5	11,624	HEAVY OIL	54,919	BBLS	6.50	356,973	1,778,000	5.79
19	SUWANNEE	3		0				0	GAS	0	MCF	1.00	0	0	0.00
20	AVON PARK	1-2	52	337	0.9		34.1	16,878	LIGHT OIL	981	BBLS	5.80	5,688	33,900	10.06
21	BARTOW	1-4	187	2,127	4.0		62.9	16,650	LIGHT OIL	6,106	BBLS	5.80	35,415	204,696	9.62
22	BARTOW	1-4		3,312				16,312	GAS	54,025	MCF	1.00	54,025	270,667	8.17
23	BAYBORO	1-4	184	7,195	5.4		78.2	13,554	LIGHT OIL	16,814	BBLS	5.80	97,521	563,672	7.83
24	DEBARY	1-10	667	4,968	7.0		80.2	13,709	LIGHT OIL	11,742	BBLS	5.80	68,106	405,233	8.16
25	DEBARY	1-10		28,842				13,150	GAS	379,272	MCF	1.00	379,272	1,900,154	6.59
26	HIGGINS	1-4	122	687	1.6		43.5	16,950	LIGHT OIL	2,008	BBLS	5.80	11,645	68,238	9.93
27	HIGGINS	1-4		719				16,556	GAS	11,904	MCF	1.00	11,904	59,638	8.29
28	HINES	1-2	998	539,558	75.1		38.5	7,261	GAS	3,917,731	MCF	1.00	3,917,731	19,627,830	3.64
29	HINES	1-2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
30	INT CITY	1-14	898	6,081	10.7		57.0	13,450	LIGHT OIL	14,102	BBLS	5.80	81,789	476,015	7.83
31	INT CITY	1-14		62,897				13,100	GAS	823,951	MCF	1.00	823,951	4,127,993	6.56
32	RIO PINAR	1	13	82	0.9		90.1	17,150	LIGHT OIL	242	BBLS	5.80	1,406	8,268	10.08
33	SUWANNEE	1-3	164	4,797	4.1		69.6	13,950	LIGHT OIL	11,538	BBLS	5.80	66,918	394,125	8.22
34	SUWANNEE	1-3		0				0	GAS	0	MCF	1.00	0	0	0.00
35	TIGER BAY	1	207	109,533	73.5		76.6	7,750	GAS	848,881	MCF	1.00	848,881	3,030,504	2.77
36	TURNER	1-4	154	1,242	1.1		71.2	15,750	LIGHT OIL	3,373	BBLS	5.80	19,562	115,818	9.33
37	UNIV OF FLA.	1	35	24,979	99.1		100.0	10,300	GAS	257,284	MCF	1.00	257,284	1,063,991	4.26
38	OTHER - START UP		-	8,529	-	-	-	9,600	LIGHT OIL	14,117	BBLS	5.80	81,878	479,836	5.63
39	OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	-	5,680,158	-
40	TOTAL		8,336	3,411,720				9,577					32,674,388	97,550,544	2.86

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Oct-04

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	773	557,886	97.0		100.0	10,409	NUCLEAR	5,807,035	MMBTU	1.00	5,807,035	2,032,462	0.36
2	ANCLOTE	1	498	126,098	34.0		37.3	10,250	HEAVY OIL	198,847	BBLS	6.50	1,292,505	5,616,429	4.45
3	ANCLOTE	1		0				0	GAS	0	MCF	1.00	0	0	0.00
4	ANCLOTE	2	495	137,187	37.3		38.4	10,216	HEAVY OIL	215,616	BBLS	6.50	1,401,502	6,090,067	4.44
5	ANCLOTE	2		0				0	GAS	0	MCF	1.00	0	0	0.00
6	BARTOW	1	121	36,331	40.4		53.4	10,606	HEAVY OIL	59,281	BBLS	6.50	385,327	1,540,417	4.24
7	BARTOW	2	119	40,497	45.7		47.3	10,770	HEAVY OIL	67,100	BBLS	6.50	436,153	1,743,604	4.31
8	BARTOW	3	204	72,323	47.7		52.0	10,222	HEAVY OIL	113,736	BBLS	6.50	739,286	2,955,437	4.09
9	BARTOW	3		0				0	GAS	0	MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	379	231,681	82.2		87.7	9,839	COAL	90,457	TONS	25.20	2,279,509	4,727,268	2.04
11	CRYSTAL RIVER	2	486	296,250	81.9		88.3	9,800	COAL	115,208	TONS	25.20	2,903,250	6,020,788	2.03
12	CRYSTAL RIVER	4	720	314,997	58.8		86.6	9,466	COAL	118,795	TONS	25.10	2,981,762	6,915,073	2.20
13	CRYSTAL RIVER	5	717	456,199	85.5		89.2	9,457	COAL	171,883	TONS	25.10	4,314,274	10,005,334	2.19
14	SUWANNEE	1	32	10,862	45.6		49.3	12,834	HEAVY OIL	21,447	BBLS	6.50	139,403	620,343	5.71
15	SUWANNEE	1		0				0	GAS	0	MCF	1.00	0	0	0.00
16	SUWANNEE	2	31	9,287	40.3		51.8	12,604	HEAVY OIL	18,008	BBLS	6.50	117,053	520,887	5.61
17	SUWANNEE	2		0				0	GAS	0	MCF	1.00	0	0	0.00
18	SUWANNEE	3	80	28,372	47.7		50.5	11,668	HEAVY OIL	50,930	BBLS	6.50	331,044	1,665,154	5.87
19	SUWANNEE	3		0				0	GAS	0	MCF	1.00	0	0	0.00
20	AVON PARK	1-2	52	95	0.2		60.9	16,920	LIGHT OIL	277	BBLS	5.80	1,607	10,143	10.68
21	BARTOW	1-4	187	275	1.3		54.3	16,852	LIGHT OIL	799	BBLS	5.80	4,634	28,408	10.33
22	BARTOW	1-4		1,554				16,750	GAS	26,030	MCF	1.00	26,030	129,106	8.31
23	BAYBORO	1-4	184	2,736	2.0		70.0	13,686	LIGHT OIL	6,456	BBLS	5.80	37,445	229,537	8.39
24	DEBARY	1-10	667	698	1.5		64.6	13,825	LIGHT OIL	1,664	BBLS	5.80	9,650	60,794	8.71
25	DEBARY	1-10		6,587				13,650	GAS	89,913	MCF	1.00	89,913	445,966	6.77
26	HIGGINS	1-4	122	15	0.3		41.9	16,834	LIGHT OIL	44	BBLS	5.80	253	1,568	10.45
27	HIGGINS	1-4		228				16,612	GAS	3,788	MCF	1.00	3,788	18,786	8.24
28	HINES	1-2	998	461,479	62.2		37.9	7,282	GAS	3,360,490	MCF	1.00	3,360,490	16,668,031	3.61
29	HINES	1-2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
30	INT CITY	1-14	1,041	4,327	3.8		48.2	13,434	LIGHT OIL	10,022	BBLS	5.80	58,129	358,655	8.29
31	INT CITY	1-14		24,844				13,021	GAS	323,494	MCF	1.00	323,494	1,604,529	6.46
32	RIO PINAR	1	13	0	0.0		0.0	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
33	SUWANNEE	1-3	164	1,702	1.4		57.7	13,792	LIGHT OIL	4,047	BBLS	5.80	23,474	146,470	8.61
34	SUWANNEE	1-3		0				0	GAS	0	MCF	1.00	0	0	0.00
35	TIGER BAY	1	207	56,585	36.7		69.7	7,875	GAS	445,607	MCF	1.00	445,607	1,590,817	2.81
36	TURNER	1-4	154	160	0.1		77.9	15,606	LIGHT OIL	431	BBLS	5.80	2,497	15,658	9.79
37	UNIV OF FLA.	1	35	25,815	99.1		99.9	10,300	GAS	265,895	MCF	1.00	265,895	1,108,837	4.30
38	OTHER - START UP		-	7,281	-	-	-	9,600	LIGHT OIL	12,051	BBLS	5.80	69,898	434,088	5.96
39	OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	-	4,476,867	-
40	TOTAL		8,479	2,912,351				9,563					27,850,904	77,781,524	2.67

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Nov-04

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)		(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	789	551,163	97.0		99.9	10,191	NUCLEAR	5,616,902	MMBTU	1.00	5,616,902	1,965,916	0.36
2	ANCLOTE	1	522	161,867	43.1		56.0	10,213	HEAVY OIL	254,330	BBLS	6.50	1,653,148	7,267,491	4.49
3	ANCLOTE	1		0				0	GAS	0	MCF	1.00	0	0	0.00
4	ANCLOTE	2	522	163,987	43.6		46.3	10,178	HEAVY OIL	256,778	BBLS	6.50	1,669,060	7,337,443	4.47
5	ANCLOTE	2		0				0	GAS	0	MCF	1.00	0	0	0.00
6	BARTOW	1	123	52,153	58.9		73.5	10,545	HEAVY OIL	84,608	BBLS	6.50	549,953	2,226,465	4.27
7	BARTOW	2	121	30,444	34.9		75.6	10,662	HEAVY OIL	49,938	BBLS	6.50	324,594	1,314,106	4.32
8	BARTOW	3	208	49,205	32.9		73.2	10,198	HEAVY OIL	77,199	BBLS	6.50	501,793	2,031,488	4.13
9	BARTOW	3		0				0	GAS	0	MCF	1.00	0	0	0.00
10	CRYSTAL RIVER	1	383	243,604	88.3		94.4	9,823	COAL	94,957	TONS	25.20	2,392,922	4,923,532	2.02
11	CRYSTAL RIVER	2	491	299,595	84.7		91.3	9,815	COAL	116,687	TONS	25.20	2,940,525	6,050,247	2.02
12	CRYSTAL RIVER	4	735	65,469	12.4		96.8	9,474	COAL	24,711	TONS	25.10	620,253	1,414,721	2.16
13	CRYSTAL RIVER	5	732	481,924	91.4		95.4	9,468	COAL	181,787	TONS	25.10	4,562,856	10,407,312	2.16
14	SUWANNEE	1	33	5,077	21.4		47.3	12,638	HEAVY OIL	9,871	BBLS	6.50	64,163	288,783	5.69
15	SUWANNEE	1		0				0	GAS	0	MCF	1.00	0	0	0.00
16	SUWANNEE	2	32	5,358	23.3		49.1	12,488	HEAVY OIL	10,294	BBLS	6.50	66,911	301,150	5.62
17	SUWANNEE	2		0				0	GAS	0	MCF	1.00	0	0	0.00
18	SUWANNEE	3	81	10,867	18.6		48.3	11,444	HEAVY OIL	19,133	BBLS	6.50	124,362	631,854	5.81
19	SUWANNEE	3		0				0	GAS	0	MCF	1.00	0	0	0.00
20	AVON PARK	1-2	64	42	0.1		21.9	16,453	LIGHT OIL	119	BBLS	5.80	691	4,706	11.20
21	BARTOW	1-4	219	30	0.0		27.4	16,575	LIGHT OIL	86	BBLS	5.80	497	3,297	10.99
22	BARTOW	1-4		0				0	GAS	0	MCF	1.00	0	0	0.00
23	BAYBORO	1-4	232	664	0.4		52.0	13,445	LIGHT OIL	1,539	BBLS	5.80	8,927	59,189	8.91
24	DEBARY	1-10	762	250	0.5		295.8	13,840	LIGHT OIL	597	BBLS	5.80	3,460	23,528	9.41
25	DEBARY	1-10		2,455				13,445	GAS	33,007	MCF	1.00	33,007	199,695	8.13
26	HIGGINS	1-4	134	0	0.0		27.6	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
27	HIGGINS	1-4		120				16,635	GAS	1,996	MCF	1.00	1,996	12,077	10.06
28	HINES	1-2	1,111	245,743	30.7		29.0	7,299	GAS	1,793,678	MCF	1.00	1,793,678	10,851,753	4.42
29	HINES	1-2		0				0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
30	INT CITY	1-14	1,206	1,100	1.2		49.9	13,106	LIGHT OIL	2,486	BBLS	5.80	14,417	96,159	8.74
31	INT CITY	1-14		9,553				13,180	GAS	125,909	MCF	1.00	125,909	761,747	7.97
32	RIO PINAR	1	16	0	0.0		0.0	0	LIGHT OIL	0	BBLS	5.80	0	0	0.00
33	SUWANNEE	1-3	201	577	0.4		47.8	13,865	LIGHT OIL	1,379	BBLS	5.80	8,000	53,918	9.34
34	SUWANNEE	1-3		0				0	GAS	0	MCF	1.00	0	0	0.00
35	TIGER BAY	1	223	100,551	62.6		65.3	7,775	GAS	781,784	MCF	1.00	781,784	2,790,969	2.78
36	TURNER	1-4	194	80	0.1		61.9	15,640	LIGHT OIL	216	BBLS	5.80	1,251	8,471	10.59
37	UNIV OF FLA.	1	41	29,257	99.1		99.9	10,300	GAS	301,347	MCF	1.00	301,347	1,603,150	5.48
38	OTHER - START UP		-	6,294	-	-	-	9,600	LIGHT OIL	10,418	BBLS	5.80	60,422	405,455	6.44
39	OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	-	-	-	-	3,717,457	-
40	TOTAL		9,175	2,517,429				9,622					24,222,829	66,752,080	2.65

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE MONTH OF: Dec-04

	(A)		(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	PLANT/UNIT		NET CAPACITY (MW)	NET GENERATION (MWH)	CAPACITY FACTOR (%)	EQUIV AVAIL FACTOR (%)	OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MMBTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	789	569,406	97 0		100 0	10,191	NUCLEAR	5,802,817 MMBTU	1 00	5,802,817	2,030,986	0 36
2	ANCLOTE	1	522	89,424	23 0		36 0	10,267	HEAVY OIL	141,249 BBLS	6 50	918,116	4,081,380	4 56
3	ANCLOTE	1		0				0	GAS	0 MCF	1 00	0	0	0 00
4	ANCLOTE	2	522	103,890	26 8		29 8	10,264	HEAVY OIL	164,050 BBLS	6 50	1,066,327	4,740,233	4 56
5	ANCLOTE	2		0				0	GAS	0 MCF	1 00	0	0	0 00
6	BARTOW	1	123	29,044	31 7		49 5	10,593	HEAVY OIL	47,333 BBLS	6 50	307,663	1,260,709	4 34
7	BARTOW	2	121	16,061	17 8		56 0	10,728	HEAVY OIL	26,508 BBLS	6 50	172,302	706,042	4 40
8	BARTOW	3	208	48,568	31 4		49 0	10,178	HEAVY OIL	76,050 BBLS	6 50	494,325	2,025,592	4 17
9	BARTOW	3		0				0	GAS	0 MCF	1 00	0	0	0 00
10	CRYSTAL RIVER	1	383	221,695	77 8		85 8	9,835	COAL	86,523 TONS	25 20	2,180,370	4,493,986	2 03
11	CRYSTAL RIVER	2	491	303,313	83 0		89 5	9,814	COAL	118,124 TONS	25 20	2,976,714	6,135,338	2 02
12	CRYSTAL RIVER	4	735	501,954	91 8		96 3	9,457	COAL	189,123 TONS	25 10	4,746,979	10,910,487	2 17
13	CRYSTAL RIVER	5	732	468,045	85 9		89 7	9,455	COAL	176,309 TONS	25 10	4,425,365	10,171,288	2 17
14	SUWANNEE	1	33	2,627	10 7		54 5	12,791	HEAVY OIL	5,170 BBLS	6.50	33,602	152,889	5 82
15	SUWANNEE	1		0				0	GAS	0 MCF	1 00	0	0	0 00
16	SUWANNEE	2	32	1,760	7.4		65 5	12,623	HEAVY OIL	3,418 BBLS	6 50	22,216	101,085	5 74
17	SUWANNEE	2		0				0	GAS	0 MCF	1.00	0	0	0 00
18	SUWANNEE	3	81	2,607	4 3		59 6	11,571	HEAVY OIL	4,641 BBLS	6 50	30,166	154,750	5 94
19	SUWANNEE	3		0				0	GAS	0 MCF	1 00	0	0	0 00
20	AVON PARK	1-2	64	40	0 1		15 6	16,793	LIGHT OIL	116 BBLS	5 80	672	4,574	11 44
21	BARTOW	1-4	219	154	0.4		41 1	16,767	LIGHT OIL	445 BBLS	5 80	2,582	17,119	11 12
22	BARTOW	1-4		499				16,450	GAS	8,209 MCF	1 00	8,209	51,303	10 28
23	BAYBORO	1-4	232	1,409	0 8		56 5	13,565	LIGHT OIL	3,295 BBLS	5 80	19,113	126,720	8 99
24	DEBARY	1-10	944	362	0 7		47 3	13,686	LIGHT OIL	854 BBLS	5 80	4,954	33,689	9 31
25	DEBARY	1-10		4,462				13,438	GAS	59,960 MCF	1 00	59,960	374,752	8 40
26	HIGGINS	1-4	134	20	0 2		24 5	17,129	LIGHT OIL	59 BBLS	5 80	343	2,299	11 49
27	HIGGINS	1-4		210				16,834	GAS	3,535 MCF	1 00	3,535	22,095	10 52
28	HINES	1-2	1,111	266,353	32 2		28 5	7,276	GAS	1,937,984 MCF	1.00	1,937,984	12,112,403	4 55
29	HINES	1-2		0				0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
30	INT CITY	1-14	1,206	2,876	1 7		45 6	13,189	LIGHT OIL	6,540 BBLS	5 80	37,932	253,004	8 80
31	INT CITY	1-14		11,973				13,124	GAS	157,134 MCF	1 00	157,134	982,085	8 20
32	RIO PINAR	1	16	0	0 0		0 0	0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
33	SUWANNEE	1-3	201	1,229	0 8		57 3	13,943	LIGHT OIL	2,954 BBLS	5 80	17,136	115,490	9 40
34	SUWANNEE	1-3		0				0	GAS	0 MCF	1 00	0	0	0 00
35	TIGER BAY	1	223	96,150	58 0		60 4	7,881	GAS	757,758 MCF	1 00	757,758	2,705,197	2 81
36	TURNER	1-4	194	280	0 2		61 9	15,484	LIGHT OIL	748 BBLS	5 80	4,336	29,354	10 48
37	UNIV OF FLA.	1	41	30,233	99 1		99 9	10,300	GAS	311,400 MCF	1 00	311,400	1,706,249	5 64
38	OTHER - START UP		-	6,954	-	-	-	9,600	LIGHT OIL	11,510 BBLS	5 80	66,758	447,972	6 44
39	OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP.	- -	-	-	3,757,109	-
40	TOTAL		9,357	2,781,598				9,551				26,566,768	69,706,179	2 51

SCHEDULE E4

PROGRESS ENERGY FLORIDA
SYSTEM NET GENERATION AND FUEL COST
ESTIMATED FOR THE PERIOD OF: Jan-04 THROUGH Dec-04

	(A) PLANT/UNIT		(B) NET CAPACITY (MW)	(C) NET GENERATION (MWH)	(D) CAPACITY FACTOR (%)	(E) EQUIV AVAIL FACTOR (%)	(F) OUTPUT FACTOR (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (C/KWH)
1	CRYS RIV NUC	3	781	6,655,126	97 3	0 0	100 0	10,299	NUCLEAR	68,544,310 MMBTU	1 00	68,544,310	23,990,509	0 36
2	ANCLOTE	1	510	1,781,941	39 9	0 0	46 1	10,250	HEAVY OIL	2,809,892 BBLS	6 50	18,264,297	78,556,943	4 41
3	ANCLOTE	1		0				0	GAS	0 MCF	1 00	0	0	0 00
4	ANCLOTE	2	509	1,741,216	39.1	0 0	44 2	10,200	HEAVY OIL	2,732,478 BBLS	6 50	17,761,105	76 420,035	4 39
5	ANCLOTE	2		0				0	GAS	0 MCF	1 00	0	0	0 00
6	BARTOW	1	122	526,192	49 2	0 0	60 8	10,562	HEAVY OIL	855,003 BBLS	6 50	5,557,520	21,975,329	4 18
7	BARTOW	2	120	475,011	45 2	0 0	57 7	10,679	HEAVY OIL	780,410 BBLS	6.50	5,072,667	20,025,692	4 22
8	BARTOW	3	206	832,248	46 1	0 0	59 0	10,181	HEAVY OIL	1,303,608 BBLS	6 50	8,473,450	33,434,413	4 02
9	BARTOW	3		0				0	GAS	0 MCF	1 00	0	0	0 00
10	CRYSTAL RIVER	1	381	2,415,633	72 4	0 0	88 4	9,836	COAL	942,844 TONS	25 20	23,759,669	48,933,750	2 03
11	CRYSTAL RIVER	2	489	3,536,047	82 6	0 0	89 0	9,813	COAL	1,376,992 TONS	25 20	34,700,208	71,462,397	2 02
12	CRYSTAL RIVER	4	728	5,081,132	79 7	0 0	91 9	9,467	COAL	1,916,438 TONS	25 10	48,102,594	110,305,521	2 17
13	CRYSTAL RIVER	5	725	5,484,079	86 4	0 0	90 0	9,459	COAL	2,066,642 TONS	25 10	51,872,703	118,935,866	2 17
14	SUWANNEE	1	33	99,493	34 9	0 0	53 2	12,739	HEAVY OIL	194,991 BBLS	6 50	1,267,439	5,556,009	5 58
15	SUWANNEE	1		0				0	GAS	0 MCF	1 00	0	0	0 00
16	SUWANNEE	2	32	95,798	34 7	0 0	55 2	12,524	HEAVY OIL	184,586 BBLS	6 50	1,199,806	5,252,709	5 48
17	SUWANNEE	2		0				0	GAS	0 MCF	1 00	0	0	0 00
18	SUWANNEE	3	81	248,853	35 3	0 0	54 8	11,528	HEAVY OIL	441,356 BBLS	6 50	2,868,817	14,209,310	5 71
19	SUWANNEE	3		0				0	GAS	0 MCF	1 00	0	0	0 00
20	AVON PARK	1-2	58	2,097	0 4	0 0	25 2	16,678	LIGHT OIL	6,030 BBLS	5 80	34,975	214,066	10 21
21	BARTOW	1-4	203	12,476	2 3	0 0	50 1	16,609	LIGHT OIL	35,727 BBLS	5 80	207,217	1,234,798	9 90
22	BARTOW	1-4		27,653				16,544	GAS	457,499 MCF	1 00	457,499	2,448,834	8 86
23	BAYBORO	1-4	208	73,741	4 0	0 0	68 1	13,558	LIGHT OIL	172,376 BBLS	5 80	999,781	5,932,146	8 04
24	DEBARY	1-10	730	30,573	3 5	0 0	64 0	13,734	LIGHT OIL	72,397 BBLS	5 80	419,902	2,596,427	8 49
25	DEBARY	1-10		192,565				13,403	GAS	2,581,001 MCF	1 00	2,581,001	14,077,107	7 31
26	HIGGINS	1-4	128	2,351	0 9	0 0	33 0	16,911	LIGHT OIL	6,855 BBLS	5 80	39,757	236,014	10 04
27	HIGGINS	1-4		7,854				16,673	GAS	130,950 MCF	1 00	130,950	691,108	8 80
28	HINES	1-2	1,055	4,673,191	50 6	0 0	33 8	7,271	GAS	33,980,129 MCF	1 00	33,980,129	191,153,854	4 09
29	HINES	1-2		0				0	LIGHT OIL	0 BBLS	5 80	0	0	0 00
30	INT CITY	1-14	1,076	73,424	5 8	0 0	59 1	13,367	LIGHT OIL	169,218 BBLS	5 80	981,467	5,996,620	8 17
31	INT CITY	1-14		474,880				13,204	GAS	6,270,408 MCF	1 00	6,270,408	34,458,202	7 26
32	RIO PINAR	1	15	266	0 2	0 0	79 8	17,011	LIGHT OIL	780 BBLS	5 80	4,525	27,740	10 43
33	SUWANNEE	1-3	183	36,889	2 3	0 0	60 6	13,972	LIGHT OIL	88,861 BBLS	5 80	515,395	3,142,488	8 52
34	SUWANNEE	1-3		485				13,932	GAS	6,757 MCF	1 00	6,757	36,893	7 61
35	TIGER BAY	1	215	1,133,448	60 2	0 0	67 5	7,798	GAS	8,838,820 MCF	1 00	8,838,820	31,554,588	2 78
36	TURNER	1-4	174	6,691	0 4	0 0	66 7	15,530	LIGHT OIL	17,916 BBLS	5 80	103,911	650,871	9 73
37	UNIV OF FLA	1	38	315,720	94 8	0 0	99 5	10,300	GAS	3,251,916 MCF	1 00	3,251,916	16,186,493	5 13
38	OTHER - START UP		-	90,320	-	-	-	9,600	LIGHT OIL	149,495 BBLS	5 80	867,072	5,428,061	6 01
39	OTHER - GAS TRANSP.		-	0	-	-	-	-	GAS TRANSP	- -	-	-	57,191,231	-
40	TOTAL		8,795	36,127,393				9,609				347,136,065	1,002,316,024	2 77

PROGRESS ENERGY FLORIDA
INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

	HEAVY OIL		Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Subtotal
1	PURCHASES:								
2	UNITS	BBL	744,889	602,877	643,066	473,296	794,025	985,432	4,243,585
3	UNIT COST	$/BBL	28.79	28.65	27.89	26.20	26.58	26.51	27.40
4	AMOUNT	$	21,442,563	17,274,481	17,937,160	12,398,471	21,106,723	26,127,235	116,286,632
5	BURNED:								
6	UNITS	BBL	744,889	602,877	643,066	473,296	794,025	985,432	4,243,585
7	UNIT COST	$/BBL	28.79	28.65	27.89	26.20	26.58	26.51	27.40
8	AMOUNT	$	21,442,563	17,274,481	17,937,160	12,398,471	21,106,723	26,127,235	116,286,632
9	ENDING INVENTORY:								
10	UNITS	BBL	800,000	800,000	800,000	800,000	800,000	800,000	
11	UNIT COST	$/BBL	28.79	28.65	27.89	26.20	26.58	26.51	
12	AMOUNT	$	23,029,040	22,922,720	22,314,560	20,956,800	21,265,520	21,210,800	
13	DAYS SUPPLY:		33	37	39	51	31	24	
	LIGHT OIL								
14	PURCHASES:								
15	UNITS	BBL	104,371	44,642	14,393	26,628	20,311	71,053	281,397
16	UNIT COST	$/BBL	38.90	38.80	38.86	38.82	35.31	32.99	37.12
17	AMOUNT	$	4,060,021	1,732,075	559,262	1,033,700	717,214	2,343,956	10,446,228
18	BURNED:								
19	UNITS	BBL	104,371	44,642	14,393	26,628	20,311	71,053	281,397
20	UNIT COST	$/BBL	38.90	38.80	38.86	38.82	35.31	32.99	37.12
21	AMOUNT	$	4,060,021	1,732,075	559,262	1,033,700	717,214	2,343,956	10,446,228
22	ENDING INVENTORY:								
23	UNITS	BBL	550,000	550,000	550,000	550,000	550,000	550,000	
24	UNIT COST	$/BBL	38.90	38.80	38.86	38.82	35.31	32.99	
25	AMOUNT	$	21,395,000	21,340,000	21,373,000	21,351,000	19,420,500	18,144,500	
26	DAYS SUPPLY:		163	345	1185	620	839	232	
	COAL								
27	PURCHASES:								
28	UNITS	TON	506,514	491,506	514,331	482,538	550,623	553,141	3,098,653
29	UNIT COST	$/TON	55.23	55.39	55.87	55.94	55.13	55.78	55.55
30	AMOUNT	$	27,974,982	27,226,014	28,735,146	26,993,458	30,357,369	30,853,682	172,140,650
31	BURNED:								
32	UNITS	TON	506,514	491,506	514,331	482,538	550,623	553,141	3,098,653
33	UNIT COST	$/TON	55.23	55.39	55.87	55.94	55.13	55.78	55.55
34	AMOUNT	$	27,974,982	27,226,014	28,735,146	26,993,458	30,357,369	30,853,682	172,140,650
35	ENDING INVENTORY:								
36	UNITS	TON	550,000	550,000	550,000	550,000	550,000	550,000	
37	UNIT COST	$/TON	55.23	55.39	55.87	55.94	55.13	55.78	
38	AMOUNT	$	30,376,775	30,466,150	30,727,950	30,767,275	30,323,040	30,678,505	
39	DAYS SUPPLY:		34	31	33	34	31	30	
	GAS								
40	BURNED:								
41	UNITS	MCF	3,953,251	3,542,390	3,279,926	3,100,077	4,737,122	5,909,205	24,521,971
42	UNIT COST	$/MCF	7.63	7.61	7.39	6.43	6.05	5.79	6.70
43	AMOUNT	$	30,176,325	26,955,261	24,243,121	19,935,370	28,658,074	34,218,911	164,187,062
	NUCLEAR								
44	BURNED:								
45	UNITS	MMBTU	5,802,817	5,431,966	5,802,817	5,616,902	5,807,035	5,620,974	34,082,511
46	UNIT COST	$/MMBTU	0.35	0.35	0.35	0.35	0.35	0.35	0.35
47	AMOUNT	$	2,030,986	1,901,188	2,030,986	1,965,916	2,032,462	1,967,341	11,928,879

PROGRESS ENERGY FLORIDA
INVENTORY ANALYSIS
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

			Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Total
	HEAVY OIL								
1	PURCHASES:								
2	UNITS	BBL	1,053,074	1,084,290	945,840	744,965	762,151	468,418	9,302,323
3	UNIT COST	$/BBL	26.84	27.20	27.50	27.86	28.08	28.23	27.46
4	AMOUNT	$	28,268,771	29,490,518	26,010,718	20,752,338	21,398,781	13,222,680	255,430,438
5	BURNED:								
6	UNITS	BBL	1,053,074	1,084,290	945,840	744,965	762,151	468,418	9,302,323
7	UNIT COST	$/BBL	26.84	27.20	27.50	27.86	28.08	28.23	27.46
8	AMOUNT	$	28,268,771	29,490,518	26,010,718	20,752,338	21,398,781	13,222,680	255,430,438
9	ENDING INVENTORY:								
10	UNITS	BBL	800,000	800,000	800,000	800,000	800,000	800,000	
11	UNIT COST	$/BBL	26.84	27.20	27.50	27.86	28.08	28.23	
12	AMOUNT	$	21,475,280	21,758,400	22,000,080	22,285,440	22,461,440	22,582,720	
13	DAYS SUPPLY:		24	23	25	33	31	53	
	LIGHT OIL								
14	PURCHASES:								
15	UNITS	BBL	147,829	130,256	81,022	35,791	16,839	26,522	719,655
16	UNIT COST	$/BBL	33.29	33.56	33.94	35.91	38.88	38.84	35.38
17	AMOUNT	$	4,920,932	4,372,006	2,749,798	1,285,321	654,723	1,030,222	25,459,231
18	BURNED:								
19	UNITS	BBL	147,829	130,256	81,022	35,791	16,839	26,522	719,655
20	UNIT COST	$/BBL	33.29	33.56	33.94	35.91	38.88	38.84	35.38
21	AMOUNT	$	4,920,932	4,372,006	2,749,798	1,285,321	654,723	1,030,222	25,459,231
22	ENDING INVENTORY:								
23	UNITS	BBL	550,000	550,000	550,000	550,000	550,000	550,000	
24	UNIT COST	$/BBL	33.29	33.56	33.94	35.91	38.88	38.84	
25	AMOUNT	$	18,309,500	18,458,000	18,667,000	19,750,500	21,384,000	21,362,000	
26	DAYS SUPPLY:		115	131	204	476	980	643	
	COAL								
27	PURCHASES:								
28	UNITS	TON	570,974	586,103	562,622	496,344	418,143	570,078	6,302,916
29	UNIT COST	$/TON	55.21	55.85	55.21	55.74	54.52	55.63	55.47
30	AMOUNT	$	31,523,648	32,736,112	31,061,750	27,668,463	22,795,812	31,711,098	349,637,535
31	BURNED:								
32	UNITS	TON	570,974	586,103	562,622	496,344	418,143	570,078	6,302,916
33	UNIT COST	$/TON	55.21	55.85	55.21	55.74	54.52	55.63	55.47
34	AMOUNT	$	31,523,648	32,736,112	31,061,750	27,668,463	22,795,812	31,711,098	349,637,535
35	ENDING INVENTORY:								
36	UNITS	TON	550,000	550,000	550,000	550,000	550,000	550,000	
37	UNIT COST	$/TON	55.21	55.85	55.21	55.74	54.52	55.63	
38	AMOUNT	$	30,365,665	30,719,645	30,364,895	30,659,530	29,984,240	30,594,245	
39	DAYS SUPPLY:		30	29	29	34	39	30	
	GAS								
40	BURNED:								
41	UNITS	MCF	6,721,041	7,192,502	6,293,047	4,515,215	3,037,721	3,235,980	55,517,478
42	UNIT COST	$/MCF	5.83	5.70	5.68	5.77	6.56	6.71	6.26
43	AMOUNT	$	39,154,999	41,004,334	35,760,937	26,042,939	19,936,848	21,711,193	347,798,311
	NUCLEAR								
44	BURNED:								
45	UNITS	MMBTU	5,807,035	5,807,035	5,620,974	5,807,035	5,616,902	5,802,817	68,544,310
46	UNIT COST	$/MMBTU	0.35	0.35	0.35	0.35	0.35	0.35	0.35
47	AMOUNT	$	2,032,462	2,032,462	1,967,341	2,032,462	1,965,916	2,030,986	23,990,509

PROGRESS ENERGY FLORIDA
FUEL COST OF POWER SOLD
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

(1) MONTH	(2) SOLD TO	(3) TYPE & SCHED	(4) TOTAL KWH SOLD	(5) KWH WHEELED FROM OTHER SYSTEMS	(6) KWH FROM OWN GENERATION	(7) C/KWH (A) FUEL COST	(7) C/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJ (6) x (7)(A)	(9) TOTAL COST $ (6) x (7)(B)	(10) REFUNDABLE GAIN ON POWER SALES $
Jan-04	ECONSALE	--	134,345,000		134,345,000	3.350	3.571	4,500,558	4,796,826	296,268
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	166,552,000		166,552,000	4.000	4.000	6,662,080	6,662,080	0
	TOTAL		300,897,000		300,897,000	3.710	3.808	11,162,638	11,458,906	296,268
Feb-04	ECONSALE	--	187,655,000		187,655,000	3.250	3.491	6,098,788	6,550,592	451,804
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	177,228,000		177,228,000	3.900	3.900	6,911,892	6,911,892	0
	TOTAL		364,883,000		364,883,000	3.566	3.690	13,010,680	13,462,484	451,804
Mar-04	ECONSALE	--	149,488,000		149,488,000	2.950	3.202	4,409,896	4,786,653	376,757
	ECONOMY	C	0		0	0.000	0 000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	196,474,000		196,474,000	3.800	3.800	7,466,012	7,466,012	0
	TOTAL		345,962,000		345,962,000	3.433	3.542	11,875,908	12,252,665	376,757
Apr-04	ECONSALE	--	100,680,000		100,680,000	3.200	3.497	3,221,760	3,521,250	299,490
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	188,312,000		188,312,000	3.500	3.500	6,590,920	6,590,920	0
	TOTAL		288,992,000		288,992,000	3.395	3.499	9,812,680	10,112,170	299,490
May-04	ECONSALE	--	52,468,000		52,468,000	3.450	3.905	1,810,146	2,048,698	238,552
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	112,367,000		112,367,000	3.600	3.600	4,045,212	4,045,212	0
	TOTAL		164,835,000		164,835,000	3.552	3.697	5,855,358	6,093,910	238,552
Jun-04	ECONSALE	--	43,846,000		43,846,000	3.650	4.492	1,600,379	1,969,746	369,367
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	109,912,000		109,912,000	3.800	3.800	4,176,656	4,176,656	0
	TOTAL		153,758,000		153,758,000	3.757	3.997	5,777,035	6,146,402	369,367

PROGRESS ENERGY FLORIDA
FUEL COST OF POWER SOLD
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
MONTH	SOLD TO	TYPE & SCHED	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (6) x (7)(A)	TOTAL COST $ (6) x (7)(B)	REFUNDABLE GAIN ON POWER SALES $
Jul-04	ECONSALE	--	66,115,000		66,115,000	3.700	4.560	2,446,255	3,014,607	568,352
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	108,979,000		108,979,000	3.900	3.900	4,250,181	4,250,181	0
	TOTAL		175,094,000		175,094,000	3.824	4.149	6,696,436	7,264,788	568,352
Aug-04	ECONSALE	--	62,592,000		62,592,000	3.700	4.596	2,315,904	2,876,703	560,799
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	124,945,000		124,945,000	3.900	3.900	4,872,855	4,872,855	0
	TOTAL		187,537,000		187,537,000	3.833	4.132	7,188,759	7,749,558	560,799
Sep-04	ECONSALE	--	68,668,000		68,668,000	3.750	4.718	2,575,050	3,239,737	664,687
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0 000	0.000	0	0	0
	STRATIFIED	--	122,997,000		122,997,000	3.900	3 900	4,796,883	4,796,883	0
	TOTAL		191,665,000		191,665,000	3.846	4.193	7,371,933	8,036,620	664,687
Oct-04	ECONSALE	--	71,144,000		71,144,000	3.450	3.775	2,454,468	2,685,580	231,112
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	113,084,000		113,084,000	3.600	3.600	4,071,024	4,071,024	0
	TOTAL		184,228,000		184,228,000	3.542	3.668	6,525,492	6,756,604	231,112
Nov-04	ECONSALE	--	100,209,000		100,209,000	3.500	3.800	3,507,315	3,807,657	300,342
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	92,105,000		92,105,000	3.500	3.500	3,223,675	3,223,675	0
	TOTAL		192,314,000		192,314,000	3.500	3.656	6,730,990	7,031,332	300,342
Dec-04	ECONSALE	--	106,792,000		106,792,000	3.250	3.463	3,470,740	3,698,090	227,350
	ECONOMY	C	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	83,189,000		83,189,000	3.500	3.500	2,911,615	2,911,615	0
	TOTAL		189,981,000		189,981,000	3.359	3.479	6,382,355	6,609,705	227,350
Jan-04	ECONSALE	--	1,144,002,000		1,144,002,000	3.358	3.758	38,411,259	42,996,139	4,584,880
THRU	ECONOMY	C	0		0	0.000	0.000	0	0	0
Dec-04	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	SALE OTHER	--	0		0	0.000	0.000	0	0	0
	STRATIFIED	--	1,596,144,000		1,596,144,000	3.758	3.758	59,979,005	59,979,005	0
	TOTAL		2,740,146,000		2,740,146,000	3.591	3.758	98,390,264	102,975,144	4,584,880

PROGRESS ENERGY FLORIDA
PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGEN PURCHASES)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jan-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	20,783,000			20,783,000	3.550	3.550	737,797
	UPS PURCHASE	UPS	246,939,000			246,939,000	1.550	1.550	3,827,555
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		267,722,000	0	0	267,722,000	1.705	1.705	4,565,352
Feb-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	21,805,000			21,805,000	3.550	3.550	774,078
	UPS PURCHASE	UPS	230,826,000			230,826,000	1.550	1.550	3,577,803
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		252,631,000	0	0	252,631,000	1.723	1.723	4,351,881
Mar-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	36,921,000			36,921,000	3.550	3.550	1,310,696
	UPS PURCHASE	UPS	247,008,000			247,008,000	1.550	1.550	3,828,624
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		283,929,000	0	0	283,929,000	1.810	1.810	5,139,320
Apr-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	17,368,000			17,368,000	3.550	3.550	616,564
	UPS PURCHASE	UPS	239,040,000			239,040,000	1.550	1 550	3,705,120
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		256,408,000	0	0	256,408,000	1.685	1.685	4,321,684
May-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	24,846,000			24,846,000	3.550	3.550	882,033
	UPS PURCHASE	UPS	247,008,000			247,008,000	1.550	1.550	3,828,624
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		271,854,000	0	0	271,854,000	1.733	1.733	4,710,657
Jun-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	28,891,000			28,891,000	3.550	3.550	1,025,631
	UPS PURCHASE	UPS	239,040,000			239,040,000	1.550	1.550	3,705,120
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		267,931,000	0	0	267,931,000	1.766	1.766	4,730,751

PROGRESS ENERGY FLORIDA
PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGEN PURCHASES)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

(1) MONTH	(2) NAME OF PURCHASE	(3) TYPE & SCHEDULE	(4) TOTAL KWH PURCHASED	(5) KWH FOR OTHER UTILITIES	(6) KWH FOR INTERRUPTIBLE	(7) KWH FOR FIRM	(8) C/KWH (A) FUEL COST	(8) C/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jul-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	31,811,000			31,811,000	3.550	3.550	1,129,291
	UPS PURCHASE	UPS	247,008,000			247,008,000	1.550	1.550	3,828,624
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		278,819,000	0	0	278,819,000	1.778	1.778	4,957,915
Aug-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	37,134,000			37,134,000	3.550	3.550	1,318,257
	UPS PURCHASE	UPS	247,008,000			247,008,000	1.550	1.550	3,828,624
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		284,142,000	0	0	284,142,000	1.811	1.811	5,146,881
Sep-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	33,901,000			33,901,000	3 550	3.550	1,203,486
	UPS PURCHASE	UPS	239,040,000			239,040,000	1.550	1.550	3,705,120
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		272,941,000	0	0	272,941,000	1.798	1.798	4,908,606
Oct-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	26,093,000			26,093,000	3.550	3.550	926,302
	UPS PURCHASE	UPS	247,008,000			247,008,000	1.550	1.550	3,828,624
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		273,101,000	0	0	273,101,000	1.741	1.741	4,754,926
Nov-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	39,439,000			39,439,000	3.550	3.550	1,400,085
	UPS PURCHASE	UPS	239,040,000			239,040,000	1.550	1.550	3,705,120
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		278,479,000	0	0	278,479,000	1.833	1.833	5,105,205
Dec-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	20,913,000			20,913,000	3.550	3.550	742,412
	UPS PURCHASE	UPS	247,008,000			247,008,000	1.550	1.550	3,828,624
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		267,921,000	0	0	267,921,000	1.706	1.706	4,571,036
Jan-04	EMERGENCY	A&B	0			0	0.000	0.000	0
THRU	TECO	--	339,905,000			339,905,000	3.550	3.550	12,066,632
Dec-04	UPS PURCHASE	UPS	2,915,973,000			2,915,973,000	1.550	1.550	45,197,582
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		3,255,878,000	0	0	3,255,878,000	1.759	1.759	57,264,214

PROGRESS ENERGY FLORIDA
ENERGY PAYMENT TO QUALIFYING FACILITIES
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	C/KWH (A) ENERGY COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(A)
Jan-04	QUAL. FACILITIES	COGEN	461,536,000			461,536,000	2.373	7.166	10,950,799
Feb-04	QUAL. FACILITIES	COGEN	436,163,000			436,163,000	2.366	7.159	10,318,080
Mar-04	QUAL. FACILITIES	COGEN	450,876,000			450,876,000	2.413	7 207	10,878,327
Apr-04	QUAL. FACILITIES	COGEN	413,852,000			413,852,000	2.361	7.155	9,771,755
May-04	QUAL. FACILITIES	COGEN	461,786,000			461,786,000	2.389	7.183	11,031,297
Jun-04	QUAL. FACILITIES	COGEN	446,500,000			446,500,000	2.415	7.208	10,780,760
Jul-04	QUAL. FACILITIES	COGEN	472,169,000			472,169,000	2.435	7.229	11,496,565
Aug-04	QUAL. FACILITIES	COGEN	473,752,000			473,752,000	2.447	7.240	11,591,233
Sep-04	QUAL. FACILITIES	COGEN	435,988,000			435,988,000	2.447	7.241	10,668,755
Oct-04	QUAL. FACILITIES	COGEN	429,510,000			429,510,000	2.407	7.200	10,336,796
Nov-04	QUAL. FACILITIES	COGEN	427,651,000			427,651,000	2.435	7.229	10,412,237
Dec-04	QUAL. FACILITIES	COGEN	457,956,000			457,956,000	2.374	7.168	10,873,643
TOTAL	QUAL. FACILITIES	COGEN	5,367,739,000			5,367,739,000	2.405	7.199	129,110,247

PROGRESS ENERGY FLORIDA
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

(1) MONTH	(2) PURCHASE	(3) TYPE & SCHED	(4) TOTAL KWH PURCHASED	(5) TRANSACTION COST ENERGY COST C/KWH	(6) TRANSACTION COST TOTAL COST C/KWH	(7) TOTAL $ FOR FUEL ADJ (4) x (5)	(8) COST IF GENERATED (A) C/KWH	(8) COST IF GENERATED (B) $	(9) FUEL SAVINGS (8)(B) - (7)
Jan-04	ECONPURCH	--	42,349,000	3.850	3.850	1,630,437	4.600	1,948,054	317,617
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		42,349,000	3.850	3.850	1,630,437	4.600	1,948,054	317,617
Feb-04	ECONPURCH	--	28,651,000	3.800	3 800	1,088,738	4.600	1,317,946	229,208
	OTHER	--	0	0.000	0 000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		28,651,000	3 800	3.800	1,088,738	4.600	1,317,946	229,208
Mar-04	ECONPURCH	--	24,461,000	3.950	3.950	966,210	4.700	1,149,667	183,457
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		24,461,000	3.950	3.950	966,210	4.700	1,149,667	183,457
Apr-04	ECONPURCH	--	54,991,000	3 850	3.850	2,117,154	4.500	2,474,595	357,441
	OTHER	--	0	0 000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		54,991,000	3.850	3.850	2,117,154	4.500	2,474,595	357,441
May-04	ECONPURCH	--	72,876,000	3.700	3.700	2,696,412	4.600	3,352,296	655,884
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		72,876,000	3.700	3.700	2,696,412	4.600	3,352,296	655,884
Jun-04	ECONPURCH	--	81,502,000	3.800	3.800	3,097,076	4.700	3,830,594	733,518
	OTHER	--	0	0 000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		81,502,000	3.800	3.800	3,097,076	4.700	3,830,594	733,518

PROGRESS ENERGY FLORIDA
ECONOMY ENERGY PURCHASES
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				TRANSACTION COST		TOTAL $	COST IF GENERATED		
MONTH	PURCHASE	TYPE & SCHED	TOTAL KWH PURCHASED	ENERGY COST C/KWH	TOTAL COST C/KWH	FOR FUEL ADJ (4) x (5)	(A) C/KWH	(B) $	FUEL SAVINGS (8)(B) - (7)
Jul-04	ECONPURCH	--	91,125,000	3.750	3.750	3,417,188	4 900	4,465,125	1,047,937
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		91,125,000	3.750	3.750	3,417,188	4.900	4,465,125	1,047,937
Aug-04	ECONPURCH	--	67,820,000	3.950	3.950	2,678,890	5.100	3,458,820	779,930
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		67,820,000	3.950	3.950	2,678,890	5.100	3,458,820	779,930
Sep-04	ECONPURCH	--	56,683,000	3.900	3.900	2,210,637	4.900	2,777,467	566,830
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		56,683,000	3.900	3.900	2,210,637	4.900	2,777,467	566,830
Oct-04	ECONPURCH	--	51,544,000	3.550	3.550	1,829,812	4.300	2,216,392	386,580
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		51,544,000	3.550	3.550	1,829,812	4.300	2,216,392	386,580
Nov-04	ECONPURCH	--	22,945,000	3.650	3.650	837,493	4.300	986,635	149,142
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		22,945,000	3.650	3.650	837,493	4.300	986,635	149,142
Dec-04	ECONPURCH	--	19,055,000	3.450	3.450	657,398	4.200	800,310	142,912
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		19,055,000	3.450	3.450	657,398	4.200	800,310	142,912
Jan-04	ECONPURCH	--	614,002,000	3.783	3.783	23,227,445	4 687	28,777,901	5,550,456
THRU	OTHER	--	0	0.000	0.000	0	0.000	0	0
Dec-04	OTHER	--	0	0.000	0.000	0	0.000	0	0
	TOTAL		614,002,000	3.783	3.783	23,227,445	4.687	28,777,901	5,550,456

PROGRESS ENERGY FLORIDA
FUEL AND PURCHASED POWER COST RECOVERY CLAUSE
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

	DESCRIPTION		Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Period Average	Prior Residential Bill (a)	Jan-04 vs. Prior
1	Base Rate Revenues	($)	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	41.18	0.00
2	Fuel Recovery Factor	(c/kwh)	3.453	3.453	3.453	3.453	3.453	3.453	3.453	3.453	3.453	3.453	3.453	3.453	3.453	2.736	
3	Fuel Cost Recovery Revenues	($)	34.58	34.58	34.58	34.58	34.58	34.58	34.58	34.58	34.58	34.58	34.58	34.58	34.58	27.41	7.17
4	Capacity Cost Recovery Revenues	($)	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	8.77	11.00	-2.23
5	Energy Conservation Cost Revenues (b)	($)	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.79	1.89	-0.10
6	Environmental Cost Recovery Revenues	($)	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.14	0.47
7	Gross Receipt Taxes	($)	2.23	2.23	2.23	2.23	2.23	2.23	2.23	2.23	2.23	2.23	2.23	2.23	2.23	2.09	0.14
8	Total Revenues	($)	89.16	89.16	89.16	89.16	89.16	89.16	89.16	89.16	89.16	89.16	89.16	89.16	89.16	83.71	5.45

(a) Actual Residential Billing for December 2003.

(b) This is a preliminary number, the Energy Conservation Clause is not due to be filed until 9/26/03.

PROGRESS ENERGY FLORIDA
GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

			2001	2002	2003	2004	2002 vs. 2001	2003 vs. 2002	2004 vs. 2003
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL		213,961,876	221,008,292	289,619,546	255,430,438	3.3%	31.0%	-11.8%
2	LIGHT OIL		53,999,426	52,447,821	51,960,491	25,459,231	-2.9%	-0.9%	-51.0%
3	COAL		287,596,087	322,518,187	368,606,595	349,637,535	12.1%	14.3%	-5.1%
4	GAS		235,028,653	237,581,107	320,873,704	347,798,311	1.1%	35.1%	8.4%
5	NUCLEAR		20,430,020	22,334,715	22,616,582	23,990,509	9.3%	1.3%	6.1%
6	OTHER		0	0	0	0	0.0%	0.0%	0.0%
7	TOTAL	$	811,016,062	855,890,122	1,053,676,918	1,002,316,024	5.5%	23.1%	-4.9%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL		6,097,609	6,261,481	6,705,217	5,800,752	2.7%	7.1%	-13.5%
9	LIGHT OIL		635,027	683,473	624,341	328,828	7.6%	-8.7%	-47.3%
10	COAL		14,164,779	14,406,461	16,416,102	16,516,891	1.7%	13.9%	0.6%
11	GAS		5,763,274	6,429,397	5,413,606	6,825,796	11.6%	-15.8%	26.1%
12	NUCLEAR		5,978,766	6,700,267	6,159,850	6,655,126	12.1%	-8.1%	8.0%
13	OTHER		0	0	0	0	0.0%	0.0%	0.0%
14	TOTAL	MWH	32,639,455	34,481,079	35,319,116	36,127,393	5.6%	2.4%	2.3%
	UNITS OF FUEL BURNED								
15	HEAVY OIL	BBL	9,725,543	9,850,631	10,664,930	9,302,323	1.3%	8.3%	-12.8%
16	LIGHT OIL	BBL	1,429,740	1,547,027	1,440,062	719,655	8.2%	-6.9%	-50.0%
17	COAL	TON	5,449,229	5,564,857	6,352,728	6,302,916	2.1%	14.2%	-0.8%
18	GAS	MCF	49,833,191	56,163,957	47,133,864	55,517,478	12.7%	-16.1%	17.8%
19	NUCLEAR	MMBTU	61,584,668	68,947,790	63,418,478	68,544,310	12.0%	-8.0%	8.1%
20	OTHER	BBL	0	0	0	0	0.0%	0.0%	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL		62,806,026	64,868,317	69,786,947	60,465,100	3.3%	7.6%	-13.4%
22	LIGHT OIL		8,285,452	8,977,691	8,355,432	4,174,002	8.4%	-6.9%	-50.0%
23	COAL		134,617,335	138,370,054	158,173,574	158,435,174	2.8%	14.3%	0.2%
24	GAS		51,975,761	58,186,575	48,481,386	55,517,478	11.9%	-16.7%	14.5%
25	NUCLEAR		61,584,668	68,947,790	63,418,478	68,544,310	12.0%	-8.0%	8.1%
26	OTHER		0	0	0		0.0%	0.0%	0.0%
27	TOTAL	MMBTU	319,269,242	339,350,427	348,215,817	347,136,064	6.3%	2.6%	-0.3%
	GENERATION MIX (% MWH)								
28	HEAVY OIL		18.68%	18.16%	18.99%	16.06%	-2.7%	4.4%	-15.3%
29	LIGHT OIL		1.95%	1.98%	1.77%	0.91%	0.0%	-10.1%	-50.9%
30	COAL		43.40%	41.78%	46.48%	45.72%	-3.7%	11.2%	-1.7%
31	GAS		17.66%	18.65%	15.33%	18.89%	5.7%	-17.7%	23.5%
32	NUCLEAR		18.32%	19.43%	17.44%	18.42%	6.0%	-10.3%	5.7%
33	OTHER		0.00%	0.00%	0.00%	0.00%	0.0%	0.0%	0.0%
34	TOTAL	%	100.00%	100.00%	100.00%	100.00%	0.0%	0.0%	0.0%
	FUEL COST PER UNIT								
35	HEAVY OIL	$/BBL	22.00	22.44	27.16	27.46	2.0%	21.0%	1.1%
36	LIGHT OIL	$/BBL	37.77	33.90	36.08	35.38	-10.2%	6.4%	-2.0%
37	COAL	$/TON	52.78	57.96	58.02	55.47	9.8%	0.1%	-4.4%
38	GAS	$/MCF	4.72	4.23	6.81	6.26	-10.3%	60.9%	-8.0%
39	NUCLEAR	$/MMBTU	0.33	0.32	0.36	0.35	-2.4%	10.2%	-2.0%
40	OTHER	$/BBL	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL		3.41	3.41	4.15	4.22	0.0%	21.8%	1.8%
42	LIGHT OIL		6.52	5.84	6.22	6.10	-10.4%	6.5%	-1.9%
43	COAL		2.14	2.33	2.33	2.21	9.1%	0.0%	-5.3%
44	GAS		4.52	4.08	6.62	6.27	-9.7%	62.1%	-5.3%
45	NUCLEAR		0.33	0.32	0.36	0.35	-2.4%	10.2%	-2.0%
46	OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47	TOTAL	$/MMBTU	2.54	2.52	3.03	2.89	-0.7%	20.0%	-4.6%
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL		10,300	10,360	10,408	10,424	0.6%	0.5%	0.2%
49	LIGHT OIL		13,047	13,135	13,383	12,694	0.7%	1.9%	-5.2%
50	COAL		9,504	9,605	9,635	9,592	1.1%	0.3%	-0.4%
51	GAS		9,018	9,050	8,955	8,133	0.4%	-1.0%	-9.2%
52	NUCLEAR		10,301	10,290	10,295	10,299	-0.1%	0.1%	0.0%
53	OTHER		0	0	0	0	0.0%	0.0%	0.0%
54	TOTAL	BTU/KWH	9,782	9,842	9,859	9,609	0.6%	0.2%	-2.5%
	GENERATED FUEL COST PER KWH (C/KWH)								
55	HEAVY OIL		3.51	3.53	4.32	4.40	0.6%	22.4%	1.9%
56	LIGHT OIL		8.50	7.67	8.32	7.74	-9.8%	8.5%	-7.0%
57	COAL		2.03	2.24	2.25	2.12	10.2%	0.3%	-5.7%
58	GAS		4.08	3.70	5.93	5.10	-9.4%	60.4%	-14.0%
59	NUCLEAR		0.34	0.33	0.37	0.36	-2.3%	10.2%	-1.9%
60	OTHER		0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61	TOTAL	C/KWH	2.48	2.48	2.98	2.77	-0.1%	20.2%	-7.0%

Incremental Cost Evaluation Decision Tree for Progress Energy's Post-9/11 Plant Security Upgrade Project.