BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Calculation of gains and appropriate regulatory treatment for non-separated wholesale energy sales by investor-owned electric utilities.	DOCKET NO. 010283-EI ORDER NO. PSC-01-2371-FOF-EI ISSUED: December 7, 2001

The following Commissioners participated in the disposition of this matter:

E. LEON JACOBS, JR., Chairman
LILA A. JABER
BRAULIO L. BAEZ

APPEARANCES:

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On behalf of Florida Power Corporation (FPC).

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On behalf of Florida Power & Light Company (FPL).

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On behalf of Gulf Power Company (Gulf).

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On behalf of Tampa Electric Company (TECO).

VICKI GORDON KAUFMAN, ESQUIRE, McWhirter Reeves Davidson Decker Kaufman Arnold & Steen, P.A., 117 South Gadsden Street, Tallahassee, FL 32301 and JOHN W. McWHIRTER, JR., ESQUIRE, McWhirter Reeves Davidson Decker Kaufman Arnold & Steen, P. A., 400 North Tampa Street, Suite 2450, Tampa, FL 33601-3350
On behalf of Florida Industrial Power Users Group (FIPUG).

STEPHEN C. BURGESS, ESQUIRE, Office of Public Counsel (OPC), 111 West Madison Street, #812, Tallahassee, FL 32399
On behalf of the Citizens of the State of Florida (OPC).

WM. COCHRAN KEATING IV, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Commission Staff (Staff).

ORDER CONCERNING CALCULATION OF GAINS AND APPROPRIATE REGULATORY TREATMENT FOR NON-SEPARATED WHOLESALE ENERGY SALES BY INVESTOR-OWNED ELECTRIC UTILITIES AND IMPLEMENTATION METHODOLOGY FOR SHAREHOLDER INCENTIVE MECHANISM

BY THE COMMISSION:

I. CASE BACKGROUND

In part III of Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, in Docket No. 991779-EI ("Order No. 00-1744"), this Commission approved, as proposed agency action, a method for calculating gains on non-separated wholesale power sales and the appropriate regulatory treatment of the revenues and expenses associated with those sales. The Florida Industrial Power Users Group ("FIPUG") and Gulf Power Company ("Gulf"), by separate petitions, protested specific and separate portions of the action proposed in part III of Order No. 00-1744. Hence, we set FIPUG's and Gulf's petitions for hearing by Order No. PSC-01-0084-FOF-EI, issued January 10, 2001, in Docket No. 991779-EI.

Pursuant to these petitions, we conducted an evidentiary hearing in this docket on August 31, 2001. Florida Power Corporation ("FPC"), Florida Power & Light Company ("FPL"), Tampa Electric Company ("TECO"), Gulf, FIPUG, and the Office of Public Counsel ("OPC") participated as parties in this proceeding. Jurisdiction over this matter is vested in this Commission through the provisions of Chapter 366, Florida Statutes, including Sections 366.04, 366.05, and 366.06, Florida Statutes.

II. ANALYSIS AND FINDINGS

A. APPROPRIATE REGULATORY TREATMENT FOR SO_2 EMISSION ALLOWANCES ASSOCIATED WITH NON-SEPARATED WHOLESALE ENERGY SALES

In its petition, Gulf sought an exception to Item 2 of Part III of Order No. 00-1744 concerning the regulatory treatment of SO_2 emission allowances related to non-separated wholesale energy sales. Specifically, that portion of Order No. 00-1744 states:

> Except for FPC, each [investor-owned electric utility] shall credit its environmental cost recovery clause for an amount equal to the incremental SO_2 emission allowance cost of generating the energy for each such sale. FPC, because it does not have an environmental cost recovery clause, shall credit this cost to its fuel and purchased power cost recovery clause[.]

Although Gulf agreed with this regulatory treatment in principle, Gulf asserted that the amount of this credit is very small for Gulf and that it is less burdensome for Gulf, from an administrative perspective, to credit an amount equal to the SO_2 emission allowance costs incurred to make a non-separated wholesale energy sale to Gulf's fuel and purchased power cost recovery clause ("fuel clause"), instead of its environmental cost recovery clause ("ECRC").

At the Prehearing Conference in this docket, the parties reached a stipulation on this matter, which is proposed for our approval. The stipulation states:

> For non-separated wholesale energy sales that contain an SO_2 emission allowance component, that portion of the sales price associated with the SO_2 emission allowance should be credited to either the fuel and purchased power cost recovery clause or the environmental cost recovery clause.

We approve this proposed stipulation for the following reasons. First, the treatment proposed is consistent with the regulatory treatment we approved in Item 2 of Part III of Order No. 00-1744. Second, a utility's ratepayers will not be affected by the choice of the fuel clause or ECRC, because the utility will allocate these revenues on an energy (kWh) basis whether the revenues are credited to the fuel clause or ECRC.

B. APPROPRIATE REGULATORY TREATMENT FOR THE COST OF FUEL AND PURCHASED POWER ASSOCIATED WITH NON-SEPARATED WHOLESALE ENERGY SALES

Item 1 of Part III of Order No. 00-1744 ("Item 1") provides for the following regulatory treatment:

> Each [investor-owned electric utility] shall credit its fuel and purchased power cost recovery clause for an amount equal to the incremental fuel cost of generating the energy for each such sale[.]

In its petition, FIPUG alleged that a utility's ratepayers are financially disadvantaged under this regulatory treatment when two conditions occur: (1) a utility is simultaneously purchasing and selling wholesale energy; and (2) the price of purchased power is more expensive than the last generating unit dispatched on a utility's system.

In an effort to neutralize this disadvantage, FIPUG, in its petition, proposed the following modification to Item 1:

> Each IOU shall credit its fuel and purchased power cost recovery clause for an amount equal to the incremental fuel cost of generating the energy for each such sale <u>or in the event wholesale power is purchased to replace the power sold, when the incremental cost of replacement purchased power is more than the applicable fuel cost factor, the clause or the buy-through customer for whom the replacement power is purchased shall be credited with the price difference</u>.

FIPUG's witness Kordecki stated that a utility's purchased power costs, when higher than the marginal generating costs of its units, must be included in the cost of a non-separated wholesale energy sale. Mr. Kordecki stated that when "purchased power is the highest cost power on the utility system, <u>it is</u> the incremental cost". He stated that when a utility properly estimates its marginal costs, any cross-subsidy between retail ratepayers and wholesale customers is minimized.

Mr. Kordecki also asserted that this Commission should take the following actions to neutralize a utility's ratepayers' risk when the previously referenced conditions apply: (1) mandate that each non-separated sale should be priced at the marginal cost of the sale; and (2) mandate that each utility adopt a cumulative profit pool for all non-separated sales.

Mr. Kordecki proposed a second modification to Item 1:

> Each utility shall credit its fuel and purchased power recovery clause for an amount equal to the incremental fuel cost of generating the energy for each such sale. In the event wholesale power is purchased to serve retail load while non-separated sales are being made, the highest cost fuel shall be allocated to the wholesale sale not to the purchase used to meet retail load.

However, on cross-examination, Mr. Kordecki stated that a utility should include short-term, but not long-term, firm power purchases when calculating the utility's incremental cost. Also, Mr. Kordecki opined that:

> the utilities [can] make very conservative must buy or firm purchases and then turn around and treat those as zero cost. And at that point sell on their increment which is lower than the cost of that purchase. At that point it gives a much larger gain.

FPC's witness Portuondo stated that "the incremental fuel cost of generating the energy", as that phrase is used in Item 1, should be broadly interpreted to include not only incremental cost of energy generated by a utility, but also the incremental cost of energy purchased by a utility from another entity. Mr. Portuondo believes this broad interpretation was intended by this Commission.

FPL's witness Dubin stated that she believes the treatment we approved in Item 1 is reasonable and appropriate. Ms. Dubin stated that this regulatory treatment "is consistent with well established practices whereby gains from non-separated wholesale power sales transactions have been flowed back to customers through the Fuel Cost Recovery Clause." Ms. Dubin also stated that this regulatory treatment matches the revenues and expenses associated with non-separated wholesale energy sales. Like Mr. Portuondo, Ms. Dubin interprets the phrase "incremental fuel cost" to include the cost of purchased power if a utility dispatches a purchased power resource to make a non-separated wholesale energy sale.

TECO's witness Brown stated that TECO does make simultaneous long-term firm capacity and energy purchases and short-term or non-firm wholesale energy sales to provide reliable, cost-effective service to its ratepayers. Both Mr. Brown and TECO's witness Jordan stated that TECO does not sell short-term or non-firm wholesale energy when it either interrupts its non-firm retail ratepayers or purchases "buy-through" energy on their behalf. However, these witnesses indicated that good engineering practices may require that some overlap to occur occasionally. Mr. Brown stated that when an interruption appears imminent or "buy through" purchases are required, TECO will either "ramp out" of existing short-term or non-firm wholesale energy sales as quickly as good engineering practices mandate or purchase replacement power to continue the energy sale. Furthermore, when calculating the incremental fuel costs to credit to the fuel clause, Ms. Jordan stated that she does not believe this Commission should consider the cost of purchased power in the event TECO is simultaneously purchasing power for retail ratepayers and selling short-term or non-firm wholesale energy.

We note that utilities sell wholesale energy on a short-term or non-firm basis on an as, if, and when available basis. By Order No. PSC-97-0262-FOF-EI ("Order No. 97-0262"), issued March 11, 1997, in Docket No. 970001-EI, we stated that a non-separated wholesale energy sale has at least one of the following two characteristics: (1) it is short-term (less than one year in duration); or (2) it is non-firm. We further stated our policy regarding non-separated wholesale energy sales on page 2 in Order No. 97-0262 as follows:

> Because non-separated sales are sporadic, a utility does not commit long-term capacity to the wholesale customer. Non-separable sales are not assigned cost responsibility through a separation process, therefore the retail ratepayer supports all of the investment that is used to make the sale.

The source of the energy for these non-separated wholesale energy sales is the next megawatt ("MW") that a utility dispatches on its system after the utility meets its native load. We find that the energy cost of that next MW is the incremental energy cost of making the non-separated wholesale energy sale, whether the utility generated or purchased the next MW. Thus, for non-separated wholesale energy sales, we find that each investor-owned electric utility shall credit its fuel clause for an amount equal to the incremental energy cost of <u>generating or purchasing</u> the energy used to make such sale.

FPC's, FPL's, and TECO's witnesses discussed how a utility dispatches its resources to meet its native load. According to these witnesses, a utility dispatches its resources in ascending order of each resource's incremental costs. These resources may be a generating unit on the utility's system or a purchased power agreement with another utility or non-utility generator. For purposes of economic dispatch, a utility does not distinguish between its utility-owned resources and resources owned by another entity. However, in general, a utility will dispatch a firm, long-term, "must-take" purchased power resource before its generating units because this resource has zero incremental costs.

TECO's witness Brown was asked during cross-examination how TECO would dispatch an $80/MWH firm purchased power agreement for 100 MW, a $75/MWH combustion turbine unit, and a $25/MWH base load unit. Mr. Brown testified that TECO would dispatch those resources in the following order: (1) the $80/MWH firm purchased power agreement; (2) the $25/MWH base load unit; and (3) the $75/MWH combustion turbine. Also, Mr. Brown was asked to identify TECO's incremental costs if TECO could fulfill its native load obligations with the firm purchase power agreement and part of its base load unit. Under that scenario, Mr. Brown stated that Tampa Electric's incremental cost is $25/MWH, which is the incremental cost of the base load unit. Furthermore, Mr. Brown testified that if this Commission mandated TECO to calculate its incremental cost as the highest-priced resource on its system (the $80/MWH firm purchase in the scenario presented), TECO's ratepayers could be harmed. Mr. Brown stated that TECO's system would not operate at an optimal level because TECO would make fewer short-term or non-firm wholesale energy sales. Further, TECO would credit a smaller amount of gains from these wholesale energy sales to ratepayers through its fuel clause.

We find that FIPUG's proposed modification to Item 1 of Part III of Order No. 00-1744 is neither reasonable nor appropriate. First, as Mr. Portuondo indicates, FIPUG's proposed modification may cause a utility to identify inaccurately the next resource a utility would dispatch to sell short-term or non-firm wholesale energy. Under FIPUG's proposed modification, a utility would identify the resource with the highest average cost as its system incremental resource. We agree with the utilities' assertion, as set forth above, that the resource with the highest average cost is not always a utility's incremental resource. Second, FIPUG's proposed modification compares a possibly mis-identified incremental cost of a wholesale energy sale to the weighted-average cost of fuel and net power transactions the utility dispatched to meet its load. Mr. Kordecki conceded that this comparison is not appropriate. Finally, if this possibly mis-identified incremental cost of a wholesale energy sale is greater than the utility's weighted-average fuel cost recovery factor, then the utility would only credit the difference to the fuel clause. If we were to adopt FIPUG's proposal, we believe the utilities should credit the entire incremental cost to the fuel clause. In summary, FIPUG's proposed modification does not consistently identify a utility's true incremental cost of a short-term or non-firm wholesale energy sale.

We disagree with witness Kordecki's statement that when "purchased power is the highest cost power on the utility system, it is the incremental cost." Regardless of its total or average cost, the utility's incremental cost of a "must-take" purchased power agreement is zero. If the energy from a purchased power agreement is not the last resource that a utility dispatches on its system, then the cost of that purchased power agreement is not the incremental cost of the wholesale energy sale.

We also disagree with witness Kordecki's opinion that a utility should include short-term, but not long-term, firm power purchases when calculating the utility's incremental cost. As stated above, we find that the energy cost of the next MW a utility dispatches on its system is the incremental energy cost of making the non-separated wholesale energy sale.

In addition, we disagree with witness Kordecki's statement that a utility can "make very conservative must buy or firm purchases and then turn around and treat those as zero cost." Mr. Kordecki does not provide any evidence to support this assertion.

Furthermore, this Commission will review a firm, long-term purchased power contract if the contract requires the construction of a generating unit subject to the Florida Electrical Power Plant Siting Act. Pursuant to Chapter 403.519, Florida Statutes, and Rules 25-22.080 and 25.22.081, Florida Administrative Code, we review these contracts in a determination of need proceeding. In such a proceeding, we consider whether the power provided by such a contract is needed by the purchasing utility, as well as whether the power is the least-cost option. In addition, when an investor-owned electric utility and a qualifying facility execute a negotiated contract, the utility submits the negotiated contract with this Commission for approval prior to or concurrent with the utility's request for cost recovery. We evaluate the cost-effectiveness of each negotiated contract based on the criteria set forth in Rule 25-17.0832(2) and (3), Florida Administrative Code. Finally, as provided by Order No. 6357, issued November 26, 1974, and Order No. 7890, issued July 6, 1977, each investor-owned electric utility seeks recovery of costs associated with all other purchased power contracts during the annual evidentiary hearings in the fuel clause docket. At these hearings, purchased power contracts, among other things, are routinely reviewed for prudence.

C. APPROPRIATE REGULATORY TREATMENT FOR THE OPERATION AND MAINTENANCE (O&M) EXPENSES ASSOCIATED WITH NON-SEPARATED WHOLESALE ENERGY SALES

Item 3 of Part III of Order No. 00-1744 ("Item 3") provides for the following regulatory treatment:

> Each [investor-owned electric utility] shall credit its operating revenues for an amount equal to the incremental operating and maintenance (O&M) cost of generating the energy for each such sale.

In its petition, FIPUG argued that this regulatory treatment should be modified to the following: "credit the fuel and purchased power clause with any O&M costs charged to the clause and operating revenues with any costs charged to base rate expenses." In support of this position, FIPUG's witness Kordecki stated:

> O&M costs are hard to quantify; it is even more difficult to identify O&M expenses that are not already being collected in the utility's base rates. All O&M expenses

> charged to a wholesale transaction should be credited back 100% to the appropriate clause(s) unless a utility supports the charge as a cost which is incremental to any present costs being collected by the utility in its base rates. If a cost is truly incremental, it may be appropriate to charge the sales with the cost and credit the utility's operating revenues. The utility carries a heavy burden of proof that a cost is incremental before any credit to operating revenues should occur . . .. All O&M costs assigned to non-separated sales should be treated as a cost and credited back to the fuel and/or capacity clause.

FPC's witness Portuondo stated that FPC estimates, but does not directly track, the amount of incremental O&M costs from each non-separated wholesale energy sale based on a formula. FPC deducts this estimated amount from the revenues received from the wholesale customer, and credits this amount to its operating revenues. Mr. Portuondo asserted that this revenue offsets the actual incremental O&M costs that are charged to the utility's operating expenses.

FPL's witness Dubin stated that the regulatory treatment approved in Item 3 matches the revenues and expenses associated with non-separated wholesale energy sales. Ms. Dubin further stated that FPL only calculates incremental O&M costs when the source of a short-term or non-firm wholesale energy is one of FPL's gas (or combustion) turbine units. FPL estimates the incremental O&M costs from these sales made from gas turbine units at approximately $15.00 per megawatt-hour (MWH) based on historical accounting and engineering data. Prior to Order No. 00-1744, FPL credited its fuel clause to offset these incremental O&M costs. In 2000, FPL credited approximately $950,000 to its fuel clause to offset incremental O&M costs. Ms. Dubin stated that FPL would recover O&M costs from FPL's base load or cycling units through FPL's retail base rates. We believe this regulatory treatment is consistent with Mr. Kordecki's testimony regarding the recognition and treatment of incremental O&M costs from short-term or non-firm wholesale energy sales.

TECO's witness Jordan stated that the regulatory treatment approved in Item 3 is reasonable and appropriate because the revenues associated with non-separated wholesale energy sales offset the actual incremental O&M costs that are charged to the utility's operating expenses. TECO estimates its incremental O&M costs based upon historical accounting and operations data. TECO charges actual O&M costs to its operating expenses, not its fuel clause. In 2000, TECO charged approximately $3.4 million for actual O&M costs to operating expenses.

For non-separated wholesale energy sales, we find that each investor-owned electric utility shall credit its operating revenues for an amount equal to its recognized incremental O&M costs incurred to make such sales. Under this regulatory treatment, Mr. Kordecki implies that a utility would recover the incremental O&M costs of its non-separated wholesale energy sale twice - once through its base rates and again from the wholesale energy customer. We find that the record of this proceeding does not support this implication. When a utility incurs incremental O&M costs to make a non-separated wholesale energy sale, the utility recovers those costs once - from the wholesale energy customer. Crediting an amount equal to these incremental O&M costs to operating revenues would not result in a double recovery of these costs. When a utility credits its operating revenues with the amount equal to the incremental O&M costs incurred to make a short-term or non-firm wholesale energy sale, the utility is matching the revenues with the expenses incurred to make such sale.

By Order No. 14546, issued July 8, 1985, in Docket No. 850001-EI-B, this Commission distinguished those costs that are appropriate for fuel clause recovery from those costs that are appropriate for base rate recovery. On page 5 of that Order, the Commission stated, in pertinent part:

> The following types of fossil fuel-related costs are more appropriately considered in the computation of base rates:
>
> Operations and maintenance expenses at generating plants or system storage facilities. This includes unloading and fuel handling costs at the generating plant or storage facility.

We find that the record shows that FPC and TECO have matched revenues with costs and recorded these revenues and costs consistent with Order No. 14546. No party implied that FPL's ratepayers were financially worse off because FPL credited an amount equal to its incremental O&M costs to its fuel clause, instead of its operating revenues. However, to be consistent with Order No. 14546, we find that each investor-owned electric utility shall credit its operating revenues for an amount equal to its recognized incremental O&M costs incurred to make a non-separated wholesale energy sale to match base rate revenues with costs.

D. IMPLEMENTATION OF PART II OF ORDER NO. 00-1744

In Part II of Order No. PSC-00-1744, we ordered that each investor-owned electric utility may retain, as an incentive, 20 percent of the gains from eligible non-separated wholesale energy sales once the utility meets an established, annual threshold level for such sales. Following this decision, the parties and our staff met on September 12, 2000, to discuss how the decision should be implemented. During this meeting, staff proposed a methodology by which the decision could be implemented. That methodology was reduced to writing and distributed by memorandum dated September 20, 2000. An issue concerning the appropriate implementation methodology was raised in Docket No. 000001-EI, but the parties agreed to defer the issue to be addressed in this docket, with the understanding that the methodology ultimately approved would be made effective as of January 1, 2001. We approved this agreement, among other matters, in Order No. PSC-00-2385-FOF-EI, issued December 12, 200, in Docket No. 000001-EI.

In FPL witness Dubin's testimony in this docket, she proposed that the methodology to be used to implement Part II of Order No. 00-1744 be the methodology described in the September 20, 2000, memorandum. TECO witness Jordan testified that TECO agrees with the methodology proposed by Ms. Dubin. Gulf also indicated that it agrees with the methodology proposed by Ms. Dubin. The methodology proposed by Ms. Dubin provides a procedure under which the filing schedule and true-up mechanism used for the fuel docket is used in implementing the incentive mechanism approved in Part II of Order No. 00-1744, as follows:

1. In its Actual/Estimated True-Up filing and testimony in the fuel docket, each utility shall include an estimated value of gains on eligible non-separated wholesale energy sales for the current calendar year based on actual and estimated data;

2. In its Projection filing in the fuel docket, each utility shall include a forecasted value of gains on eligible non-separated wholesale energy sales for the next calendar year;

3. Each utility shall compare its forecasted value of gains from eligible sales for the next calendar year to an estimated three-year moving average of such gains. This estimated three-year moving average, or estimated benchmark, will be based on actual gains from eligible sales for each of the previous two calendar years and the estimated gains from eligible sales for the current calendar year. This comparison will be one of numerous inputs that each utility will use to calculate its levelized fuel cost recovery factor for the next calendar year;

4. In its Final True-Up filing in the fuel docket in the next calendar year (typically in April), each utility shall indicate its actual gains on eligible non-separated wholesale energy sales for the previous calendar year. Each utility will then re-calculate its three-year moving average based on the actual gains from eligible sales for each of the previous three years to establish an actual benchmark.

5. Each utility shall record its actual gains from eligible non-separated wholesale energy sales on its Schedule A-6 filed monthly with the Commission. When these actual gains are equal to or less than the utility's actual benchmark, the utility shall credit 100 percent of these gains to its ratepayers through its fuel and purchased power cost recovery clause. When these actual gains are greater than the utility's actual benchmark, the utility shall credit 80 percent of the gains above the benchmark to its ratepayers through its fuel clause. The utility shall credit the remaining 20 percent to its shareholders;

6. Each utility shall reflect any differences between its actual and forecasted gains from eligible sales through its monthly true-up calculations in Schedule A-2;

7. The first estimated benchmark for gains on eligible non-separated wholesale energy sales shall be established at the November 2000 fuel hearing for purposes of calculating a levelized fuel cost recovery factor for 2001. The shareholder

incentive shall apply to actual gains on eligible sales made over the actual benchmark for 2001. On a going-forward basis, the difference between actual and forecasted gains on eligible sales shall be "trued-up" at each fuel hearing.

FIPUG's witness Kordecki objected to step 3 of this methodology. Mr. Kordecki stated that he believes a utility should not estimate gains for the third year of the three-year moving average when calculating the threshold for eligible non-separated wholesale energy sales.

We do not share this concern. This Commission sets a prospective, annual fuel factor each November in the fuel clause docket comprised of countless inputs based partly on historical, actual data and partly on future, estimated data. Using the above-stated methodology to implement our decision in Part II of Order No. 00-1744 is consistent with the filing schedule and true-up mechanism used for the fuel docket. This methodology proposes that a utility file specific information regarding non-separated wholesale energy sales as accurately and timely as any other input to the utility's fuel factor.

We find that the methodology set forth above will allow us to receive and process data regarding gains on eligible non-separated wholesale energy sales efficiently through the filing schedule and true-up mechanism already in place for the fuel docket. Thus, we approve this methodology. Consistent with the parties' agreement previously approved in Order No. PSC-00-2385-FOF-EI, this methodology is deemed effective as of January 1, 2001.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that for investor-owned electric utilities' non-separated wholesale energy sales that contain an SO_2 emission allowance component, that portion of the sales price associated with the SO_2 emission allowance shall be credited to either the fuel and purchased power cost recovery clause or the environmental cost recovery clause. It is further

ORDERED that for non-separated wholesale energy sales, each investor-owned electric utility shall credit its fuel and purchased power cost recovery clause for an amount equal to the incremental energy cost of generating or purchasing the energy used to make such sales, as set forth in the body of this Order. It is further

ORDERED that for non-separated wholesale energy sales, each investor-owned electric utility shall credit its operating revenues for an amount equal to its recognized incremental O&M costs incurred to make such sales, as set forth in the body of this Order. It is further

ORDERED that Part II of Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, establishing a shareholder incentive mechanism for investor-owned electric utilities' non-separated wholesale energy sales, shall be implemented using the methodology set forth in the body of this Order, which is deemed effective as of January 1, 2001.

By ORDER of the Florida Public Service Commission this 7th day of December, 2001.

BLANCA S. BAYÓ, Director
Division of the Commission Clerk
and Administrative Services

By: Kay Flynn
Kay Flynn, Chief
Bureau of Records and Hearing
Services

(S E A L)

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of the Commission Clerk and Administrative Services, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/or wastewater utility by filing a notice of appeal with the Director, Division of the Commission Clerk and Administrative Services and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.