State of Florida

Public Service Commission

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-M-E-M-O-R-A-N-D-U-M-

DATE: OCTOBER 25, 2001

TO: DIRECTOR, DIVISION OF THE COMMISSION CLERK & ADMINISTRATIVE SERVICES (BAYÓ)

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FROM: DIVISION OF SAFETY & ELECTRIC RELIABILITY (BOHRMANN, JDJ BREMAN, HARLOW)
DIVISION OF ECONOMIC REGULATION (REVELL)
DIVISION OF LEGAL SERVICES (C. KEATING) WCK RVE

RE: DOCKET NO. 010283-EI - CALCULATION OF GAINS AND APPROPRIATE REGULATORY TREATMENT FOR NON-SEPARATED WHOLESALE ENERGY SALES BY INVESTOR-OWNED ELECTRIC UTILITIES

AGENDA: 11/06/01 - REGULAR AGENDA - POST HEARING DECISION - PARTICIPATION IS LIMITED TO COMMISSIONERS AND STAFF

CRITICAL DATES: NONE

SPECIAL INSTRUCTIONS: NONE

FILE NAME AND LOCATION: S:\PSC\SER\WP\010283.RCM

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), the Commission approved, as a 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 or Gulf Power), by separate petitions, protested specific and separate portions of the action proposed by the Commission. Hence, the Commission set

FIPUG's and Gulf Power's petitions for hearing by Order No. PSC-01-0084-FOF-EI, in Docket No. 991779-EI, issued January 10, 2001.

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

DISCUSSION OF ISSUES

STIPULATED

ISSUE 1: What is the appropriate regulatory treatment for SO_2 emission allowances associated with non-separated wholesale energy sales?

RECOMMENDATION: Staff recommends that the Commission approve the stipulated language set forth below.

STAFF ANALYSIS: The parties stipulated to the following language at the pre-hearing in this docket:

> 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.

The Commission set forth the following regulatory treatment for SO_2 emission allowances associated with non-separated wholesale energy sales in Item 2 of Part III of Order No. 00-1744:

> Except for [Florida Power Corporation], 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. [Florida Power Corporation], because it does not have an environmental cost recovery clause, shall credit this cost to its fuel and purchased power cost recovery clause[.] (TR 89-90)

Although Gulf Power agreed with the Commission's regulatory treatment in principle, Gulf Power protested this portion of Order No. 00-1744 because it is less burdensome 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 Power's fuel clause, instead of its environmental cost recovery clause. (TR 90-91) This proposed stipulation would not affect Gulf Power's ratepayers because Gulf Power would allocate these revenues on an energy (kwh) basis, regardless if the revenues are credited to the fuel clause or environmental cost recovery clause. (TR 92)

Staff recommends that the Commission approve the proposed stipulated language for two reasons. First, the language is consistent with the Commission's regulatory treatment in Item 2 of Part III of Order No. 00-1744. Second, a utility's ratepayers are not affected because the utility would allocate these revenues on an energy (kwh) basis, whether the revenues are credited to the fuel clause or environmental cost recovery clause.

ISSUE 2: **What is the appropriate regulatory treatment for the cost of fuel and purchased power associated with non-separated wholesale energy sales?**

RECOMMENDATION: The Commission should require each investor-owned electric utility to credit its fuel and purchased power cost recovery clause with the incremental energy cost of generating or purchasing the energy used to make each non-separated wholesale energy transaction.

POSITIONS OF THE PARTIES

FPC: Item 1 in the PAA Order describes the appropriate treatment. However, if the Commission finds Item 1 should more clearly encompass the incremental cost of purchased power, a simple modification of Item 1 to that effect would be sufficient. FIPUG's proposed modification is inappropriate and should be rejected.

FPL: Consistent with Commission Order No. PSC-00-1744-PAA-EI in Docket No. 991779 dated September 26, 2000, which states, "Each IOU shall credit its fuel and purchased power cost recovery clause for an amount equal to incremental fuel cost of generating the energy for each such sale".

GULF: The fuel and purchased power cost recovery clause should be credited for an amount equal to the incremental fuel cost of generating the energy for non-separated wholesale energy sales.

TECO: Each IOU should 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. FIPUG's alternative would impose a disincentive to make these sales in order to benefit interruptible customers at the expense of all retail customers.

FIPUG: If there are any purchased power costs which are higher than the marginal costs of a utility's own units, such cost should be included in the cost of the wholesale sale. When purchased power cost is the highest cost power on the utility's system, it is the incremental cost.

OPC: The cost of non-separated wholesale sales should be removed from the retail cost recovery clause(s) on an incremental basis. For this purpose "incremental" should consider purchased power, as well as fuel burned.

STAFF ANALYSIS: In Order No. 00-1744, the Commission proposed the appropriate regulatory treatment for revenues and expenses associated with a utility's non-separated wholesale energy sales. In part, the Commission stated:

> 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 protest, FIPUG alleged that a utility's ratepayers are financially disadvantaged under the Commission's proposed regulatory treatment when two conditions occur:

1. A utility is simultaneously purchasing and selling wholesale energy; and

2. When the price of purchased power is more expensive than the last generating unit dispatched on a utility's system. (TR 164)

In an effort to neutralize this financial disadvantage when these two conditions apply, FIPUG proposed the following modification to Item 1 of Part III of Order No. 00-1744 in its protest:

> 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>. (TR 31)

FIPUG's witness Gerard J. 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. (TR 177)

Mr. Kordecki also stated that the Commission should take the following actions to neutralize a utility's ratepayers' risk when the previously referenced conditions apply. First, the Commission should mandate that "each non-separated sale should be priced at the marginal cost of the sale". Second, the Commission should mandate that each utility adopt a cumulative profit pool for all non-separated sales. (TR 180)

Mr. Kordecki proposed a second modification to Item 1 of Part III of Order No. 00-1744:

> 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. (TR 182)

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. (TR 192-193)

Florida Power's witness Javier Portuondo stated that "the incremental fuel cost of generating the energy" 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 the Commission's intent in Order No. 00-1744. (TR 30)

FPL's witness Korel M. Dubin believes that the Commission's treatment in Order No. 00-1744 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. (TR 63) Ms. Dubin also interprets "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. (TR 77, 82)

Tampa Electric Company's witness Lynn Brown stated that Tampa Electric 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. (TR 103-106) However, both Mr. Brown and Tampa Electric's witness J. Denise Jordan stated that Tampa Electric does not sell short-term or non-firm wholesale energy when Tampa Electric either interrupts its non-firm retail ratepayers or purchases "buy-through" energy on their behalf (TR 108, 110, 138-139). However, good engineering practices may require that some overlap occur occasionally (TR 139). When an interruption appears imminent or "buy through" purchases are required, Tampa Electric 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. (TR 108) Furthermore, when calculating the incremental fuel costs to credit to the fuel clause, Ms. Jordan does not believe that the Commission should consider the cost of purchased power in the event Tampa Electric is simultaneously purchasing power for retail ratepayers and selling short-term or non-firm wholesale energy. (TR 140-142)

A utility will sell wholesale energy on a short-term or non-firm basis on an as, if, and when available basis. (TR 140, 172-174, 179) By Order No. PSC-97-0262-FOF-EI (Order No. 97-0262), in Docket No. 970001-EI, issued March 11, 1997, the Commission stated that a non-separated wholesale energy sale has at least one of the following two characteristics: short-term (less than one year in duration) or non-firm. The Commission further stated its 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 (TR 45, 82). Staff believes 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. (TR 45, 82-83, 159) Thus, for non-separated wholesale energy sales, the utility should credit its fuel and purchased power cost recovery clause (fuel clause) for an amount equal to the incremental energy cost of <u>generating or purchasing</u> the energy used to make such sale. (TR 31, 170)

FPL's, Florida Power's, and Tampa Electric'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 <u>incremental</u> 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 <u>zero incremental costs</u>. (TR 44-47, 50, 66, 67, 76, 120, 130-132, 156-157, 185, 192, 225-226, 238-239)

Tampa Electric's witness Brown was asked how Tampa Electric 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 Tampa Electric would dispatch those resources in the following order: the $80/MWH firm purchased power agreement; the $25/MWH base load unit; and the $75/MWH combustion turbine. Also, Mr. Brown was asked to identify Tampa Electric's incremental costs if Tampa Electric 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. (TR 130-131)

Furthermore, Mr. Brown testified that if the Commission mandated Tampa Electric to calculate its incremental cost as the highest-priced resource on its system, Tampa Electric's ratepayers would be harmed. With an $80/MWH incremental cost, Tampa Electric's system would not operate at an optimal level as Tampa Electric would make fewer short-term or non-firm wholesale energy sales. Also, Tampa Electric would credit a smaller amount of gains from these wholesale energy sales to ratepayers through its fuel clause. (TR 132)

Staff believes that FIPUG's proposed modification to Item 1 of Part III of Order No. 00-1744 is neither reasonable nor appropriate for three reasons. 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. The record reflects that the resource with the highest average cost is not always a utility's incremental resource. (TR 44-47, 50, 66, 67, 76, 120, 130-132, 156-157, 185, 192, 225-226, 238-239) Second, FIPUG's proposed modification compares a possibly mis-identified incremental cost of a wholesale energy sale to the <u>weighted-average</u> cost of fuel and net power transactions the utility dispatched to meet its load. (TR 33) Mr. Kordecki concedes that this comparison is not appropriate. (TR 197) 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 the Commission did adopt FIPUG's proposal, staff believes that the utility 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. (TR 32-35)

Staff disagrees with FIPUG's witness Kordecki's statement that when "purchased power is the highest cost power on the utility system, <u>it is</u> the incremental cost." (TR 177) The record shows that, regardless of its total or average cost, the utility's <u>incremental cost</u> 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 <u>is not</u> the incremental cost of the wholesale energy sale. (TR 50, 67)

Also, staff disagrees 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. Staff believes 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. (TR 45, 82-83, 159)

Furthermore, staff disagrees 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." (TR 192-193) Mr. Kordecki does not provide any evidence to support this assertion. Furthermore, the Commission reviews a utility's 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 Chapters 403.501 through 403.517, Florida Statutes. Pursuant to Chapter 403.519, Florida Statutes and Rule 25-22.080-.081, Florida Administrative Code, these contracts are reviewed by the Commission in a determination of need proceeding. In this proceeding, the Commission determines 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.

Also, when a utility and a qualifying facility execute a negotiated contract, the utility submits the negotiated contract with the Commission for approval prior to or concurrent with the utility's request for cost recovery. The Commission evaluates the cost effectiveness of each negotiated contract with the criteria set forth in Rule 25-17.0832(2)-(3), Florida Administrative Code.

As provided by Order No. 6357, issued November 26, 1974, and Order No. 7890, issued July 6, 1977, each utility seeks recovery of costs associated with all other purchased power contracts during the annual evidentiary hearings in the fuel clause docket. If FIPUG believes that its interests are affected because a utility has entered into a firm, long-term contract that is not cost effective, then FIPUG may seek to intervene in the appropriate docket.

ISSUE 3: What is the appropriate regulatory treatment for the operation and maintenance (O&M) expenses associated with non-separated wholesale energy sales?

RECOMMENDATION: The Commission should require each utility to credit its operating revenues for an amount equal to its recognized incremental operating and maintenance (O&M) cost of generating the energy that the utility has sold in each non-separated wholesale energy transaction.

POSITIONS OF THE PARTIES

FPC: Item 3 in the PAA Order describes the appropriate treatment. Variable O&M expense and related revenues associated with non-separated wholesale sales are base rate items and should therefore be excluded from the calculation of the gain on non-separated wholesale energy sales.

FPL: Consistent with Commission Order No. PSC-00-1744-PAA-EI in Docket No. 991779 dated September 26, 2000, which states, "Each IOU 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".

GULF: Operating revenues should be credited for an amount equal to the incremental O&M expenses related to generating the energy for non-separated wholesale energy sales.

TECO: Each IOU should credit its operating revenues for an amount equal to the incremental O&M cost of generating the energy for each such sale. The only evidence of record supports the Commission's reaffirmation of this regulatory treatment, as originally proposed in Order No. 00-1744.

FIPUG: The Commission should not permit double collection of costs. No O&M costs collected from wholesale customers should be kept by the utility when those costs are already part of base rates. No revenue recovered as O&M costs should be considered part of the gain but should be flowed back to ratepayers.

OPC: They should be excluded from the calculation of the gain on wholesale sales for fuel adjustment purposes. This treatment does not affect the utilities' motivation to place wholesale sales, [TR-79, 158] removes the difficult issue of identifying what is truly "incremental O&M," and increases the gain available to retail customers through fuel adjustment.

STAFF ANALYSIS: In Order No. 00-1744, the Commission proposed the appropriate regulatory treatment for revenues and expenses associated with a utility's non-separated wholesale energy sales. In part, the Commission stated:

> 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. (TR 62, 164, 180)

In its protest, FIPUG stated 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." (TR 164) 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. (TR 180-182)

Mr. Portuondo stated that Florida Power estimates, but not directly tracks, the amount of incremental O&M costs from each non-separated wholesale energy sale based on a formula. Florida Power deducts this estimated amount from the revenues received from the wholesale customer, and credits this amount to its operating revenues. This revenue offsets the actual incremental O&M costs that are charged to the utility's operating expenses. (TR 38-43)

FPL's witness Dubin, believes that the Commission's treatment as described in Order No. 00-1744 is reasonable and appropriate. Ms. Dubin stated that this regulatory treatment matches the revenues and expenses associated with non-separated wholesale energy sales. (TR 63) Furthermore, 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. (EXH 2) Ms. Dubin stated that FPL would recover O&M costs from FPL's base load or cycling units through FPL's retail base rates. (TR 67-70) Staff believes 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. (TR 170-171)

Tampa Electric's witness Jordan, believes that the Commission's treatment in Order No. 00-1744 is reasonable and appropriate, because this revenue offsets the actual incremental O&M costs that are charged to the utility's operating expenses. Tampa Electric estimates its incremental O&M costs based upon historical accounting and operations data. Tampa Electric charges actual O&M costs to its operating expenses, not its fuel clause. In 2000, Tampa Electric charged approximately $3.4 million for actual O&M costs to operating expenses. (TR 138, 142, 146, EXH 2)

For non-separated wholesale energy sales, staff believes that the utility should credit its operating revenues for an amount equal to its recognized incremental O&M costs incurred to make such sale. (TR 63, 138, 142) With this regulatory treatment, Mr. Kordecki implies that a utility would recover its incremental O&M costs of a non-separated wholesale energy sale twice - once through its base rates and again from the wholesale energy customer. (TR 180-181) The evidentiary record 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. (TR 38, 42) Crediting an amount equal to these incremental O&M costs to operating revenues would not result in a double recovery of these costs. (TR 48, 75, 157) 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. (TR 38-43, 63, 138, 142, 146)

By Order No. 14546, in Docket No. 850001-EI-B, issued July 8, 1985, the Commission delineated between costs which are more appropriate for fuel clause recovery and costs which are more appropriate for base rate recovery. On page 5 of that Order, the Commission stated, in 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.

The record shows that Florida Power and Tampa Electric have matched revenues with costs and record these revenues and costs consistent with Order No. 14546. (TR 38, 145, EXH 2) No party had 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, staff believes that each utility should 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 and be consistent with Order No. 14546. (TR 68)

ISSUE 4: **How should the Commission implement Part II of Order No. PSC-00-1744-PAA-EI, in Docket No. 991779-EI, issued September 26, 2000, concerning the application of incentives to wholesale energy sales?**

RECOMMENDATION: The shareholder incentive mechanism approved in Order No. PSC-00-1744-PAA-EI should be implemented as set forth in Staff's memorandum to the parties dated September 20, 2000. Consistent with the parties' agreement previously approved by the Commission by Order No. PSC-00-2385-FOF-EI, in Docket No. 000001-EI, issued December 12, 2000, this methodology should be made effective as of January 1, 2001.

POSITIONS OF THE PARTIES

FPC: Part II of the order should be implemented in a manner consistent with Exhibit No. 3, Staff's memorandum dated September 20, 2000.

FPL: In Order No. PSC-00-1744-PAA-EI the Commission decided to allow the utilities to split (80% to customers and 20% to shareholders) any gains on non-separated wholesale power sales that exceed a threshold based on a three-year average of gains. Consistent with our position presented in the Fuel Docket, FPL believes that the Commission's decision should be implemented by using the methodology proposed by Staff in their memorandum dated September 20, 2000. Staff proposes that the first two and one half years used in the calculation of the average would be the actual gains for those years and the final six months would be estimated. This data is to be supplied with the utilities' fuel projection filings. Later, the threshold of gains on off system sales is to be updated with actual gains for the balance of the third year and filed as part of the fuel true up testimony. Gains on sales are to be measured against this three-year average threshold. FPL believes this approach is appropriate.

GULF: Gulf agrees with the implementation methodology set forth in the Commission Staff's September 20, 2000 memorandum issued in Docket No. 000001-EI.

TECO: The Commission should approve the implementation methodology set forth in the Commission Staff's September 20, 2000 memorandum issued in Docket No. 000001-EI (identified as Exhibit 3 in this proceeding[)]. No reasonable criticism of that methodology and no reasonable alternative to that methodology have been offered by any party.

FIPUG: The Commission should ensure that the clarifications set out in Issue Nos. 2 and 3 above are included in the incentive calculation so that the calculation is made uniformly and fairly.

OPC: The benchmark should be based exclusively on historic data. Additionally, the initial three-year average should act as a perpetual floor of expectation, such that no future rewards should not be granted unless the gains exceed the original three-year average benchmark, as well as the rolling average.

STAFF ANALYSIS: By Order No. PSC-00-1744-PAA-EI, in Docket No. 991779-EI, issued September 26, 2000, the Commission ordered that a utility may keep 20 percent of the gain from eligible non-separated wholesale energy sales once the utility had met its annual threshold. The parties in Docket No. 991779-EI met with staff on September 12, 2000, to discuss how the Commission should implement its most recent decision in that docket. During this meeting, staff proposed the timing in which each utility should file specific information with the Commission and the parties.

FPL's witness Dubin proposed a methodology for implementing Part II of Order No. 00-1744 as the methodology that staff described in its September 20, 2000, memorandum to the parties. (TR 64, 76-81) Ms. Jordan, Tampa Electric's witness, testified that Tampa Electric agrees with the methodology set forth in the memorandum. (TR 142) Gulf Power agrees with the methodology set forth in the memorandum. (TR 85) The proposed methodology is as follows:

1. In its Actual/Estimated True-Up filing and testimony, each utility shall include an estimated value of gains on eligible non-separated wholesale energy sales for the current calendar year (2000) based on actual and estimated data;

2. In its Projection filing, each utility shall include a forecasted value of gains on eligible non-separated wholesale energy sales for the next calendar year (2001);

3. Each utility shall compare its forecasted value of gains from eligible sales for the next calendar year (2001) 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 (1998 and 1999) and the estimated gains from eligible sales for the current calendar year (2000). 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 (2001);

4. In its April True-Up filing in the next calendar year (2001), each utility shall indicate its actual gains on eligible non-separated wholesale energy sales for the previous calendar year (2000). 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 (1998, 1999, and 2000) 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 (fuel 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.

Staff memorialized this proposal in its September 20, 2000, memorandum to the parties. (EXH 3, 4)

FIPUG's witness Kordecki, objects to step 3 of the methodology that staff proposed in its September 20, 2000, memorandum to the parties to implement Part II of Order No. 00-1744. Mr. Kordecki believes that 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. (TR 196)

Staff disagrees with Mr. Kordecki's comment that 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. (TR 196) As indicated by Order No. PSC-00-2385-FOF-EI, in Docket No. 000001-EI, issued December 12, 2000, the Commission sets a prospective 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. Staff agrees with FPL's witness Dubin that the September 20, 2000 memorandum is a reasonable methodology for implementing the Commission's decision in Order No. 00-1744. (TR 64, 76-81) This methodology proposes that a utility file specific information regarding non-separated wholesale energy sales as accurate and timely as any other input to the utility's fuel factor. (EXH 3, 4)

No other party made any objections to the methodology set forth in the September 20, 2000, memorandum. This methodology will allow the Commission 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, the Commission should approve this methodology.