Florida Power & Light Company, Docket Nos. ER93- 465-000 and ER93-922-000

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Florida Power & Light Company, Docket Nos. ER93- 465-000 and ER93-922-000

Order on Policy Issues

(Issued February 24, 1994)

Before Commissioners: Elizabeth Anne Moler, Chair; Vicky A. Bailey, James J. Hoecker, William L. Massey, and Donald F. Santa, Jr.

I. Introduction

On September 24, 1993, the Commission issued an order in this proceeding accepting for filing, suspending, and setting for hearing a comprehensive restructuring of Florida Power & Light Company's (FPL) existing tariffs. *Florida Power & Light Company,* 64 FERC ¶61,361 (1993), *reh'g pending* (September 24 Order). Due to the complexity and magnitude of FPL's filing, however, the Commission stated that it would issue a supplemental order to address seven generic pricing issues raised by FPL which did not require a trial-type, evidentiary hearing. We address these issues in this order.

II. Background

On March 19, 1993, as completed on July 26, 1993, FPL made an extensive and comprehensive rate filing designed to completely overhaul its existing tariffs with all of its existing Florida customers. After initial review, the Commission accepted FPL's proposed rates for filing, suspended those rates for five months to become effective February 26, 1994, subject to refund, and set certain aspects of FPL's filing for trial-type, evidentiary hearing. [1] The Commission also found that FPL's filing raised several pricing policy issues which did not require a trial-type, evidentiary hearing. These issues are:

(1) whether transmission customers should be prohibited from charging an assignee a higher price than the amount originally paid by the transmission customer to the utility;

(2) whether a utility should be permitted to compute a rate for firm transmission opportunity costs equal to the higher of embedded or opportunity costs on an *hourly*--as opposed to life of the transaction--basis;

(3) whether a utility should be permitted to eliminate the expansion cost cap required by *New England Power Company,* 61 FERC ¶61,009 (1992), *reh'g pending,* for short-term transactions if construction is not a feasible option;

(4) whether a utility can withhold consent from partial requirements customers to resell energy purchased under the utility's tariff to other entities pursuant to any economy sale, coordination sale or similar transaction unless the utility's incremental cost in that hour is expected to be equal to or less than the energy charge under the tariff; and, if not, whether this is an efficient allocation of resources;

(5) the circumstances, if any, under which a utility may depart from the standard set forth in *Southern Company Services, Inc.,* 61 FERC ¶61,339 (1992), *appeal pending,* No. 93-1165 (D.C. Cir. Filed Feb. 11, 1993), for calculating the appropriate divisor to use in developing non-customer-specific rates;

(6) the circumstances, if any, under which a utility may depart from the standard set forth in *Jersey Central Power & Light Company et al.,* 38 FERC ¶61,275, *reh'g denied,* 40 FERC ¶61,236 (1987), and develop hourly rates to reflect the potential for full hours utilization; and

(7) the circumstances, if any, under which a utility may depart from the requirement set forth in *Indiana Michigan Electric Company et al.,* 10 FERC ¶61,295 (1980), that utilities must develop demand and energy charges on a consistent basis.

However, the Commission also found that "[g]iven the breath of FPL's filing and the interventions, and the limited amount of time available in which to act on FPL's filing, the Commission [could not] address [in the September 24 Order] each of these important issues in the detail that they deserve." [2]

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III. Discussion

Issue 1: *Transmission Resale Price Cap*

A. *Background*

Section 13.1 of FPL's proposed long-term transmission tariff restricts the price for the resale of transmission services. FPL argues that it is not fair to allow customers to earn profits by reselling a service at a rate that would exceed a just and reasonable level. [3] If resale rates are not limited, argues FPL, customers could earn scarcity rents that FPL is prohibited from earning by regulation. FPL asserts that limiting resale rates is consistent with open-access transmission tariffs accepted by the Commission. FPL also states that the Commission does not allow natural gas pipeline capacity to be resold at rates in excess of the maximum regulated rate. [4]

Seminole Electric Cooperative, Inc. (Seminole) argued that a price cap on the reseller not to exceed the charges for firm transmission service under the tariff is an unjust and unreasonable constraint on the provision of transmission services. [5]

B. *Discussion*

The Commission historically has placed price caps on transmission services supplied by public utilities because these utilities have been found to have market power in transmission services. This market power gives utilities the ability to restrict the quantity of service they provide and thereby drive up prices and create monopoly rents. Transmitting utilities may have the incentive to restrict transmission capacity in order to protect current high-cost generation assets, or future assets, from competition. [6] If they provide additional transmission capacity, this expands the market and puts their high-cost assets at risk. It can also displace their generation sales and thereby prevent them from building local generation to enhance rate base. [7] The Commission checks this potential exercise of market power through price regulation that prevents utilities from profiting from restricting service.

The Commission recognizes that, as a general matter, price caps on the resale of transmission can distort price signals and reduce the efficiency of secondary markets. However, transmission remains a natural monopoly and, under the circumstances of this case, the Commission continues to believe that a resale price cap for transmission services is appropriate in order to prevent the exercise of market power. The Commission is concerned that a customer of FPL could contract for large quantities of transmission service and then attempt to exploit shortages in transmission. The best way we currently know to ensure against such exploitation by resellers is to establish, as a condition to the transmission service FPL is providing, a resale price cap at the price (and not higher) at which FPL first sold the transmission service. This will give resellers flexibility to market their transmission capacity when they do not need it and protect ratepayers from paying prices which could, in some circumstances, reflect monopoly rents.

Issue 2: *Should Opportunity Costs Be Calculated on an Hourly, as Opposed to Life-of-the-Transaction, Basis?*

A. *Background*

FPL proposes to charge the higher of embedded or opportunity costs based on an hourly calculation--i.e., in hours when opportunity costs are higher than an equivalent hourly embedded cost charge (the monthly charge divided by the 730 hours in the month), FPL will charge the opportunity costs. In *New England Power Company, et al.,* 61 FERC ¶61,009 (1992) (*NEPCO*), *reh'g pending,* the Commission rejected the same proposal because it did not result in the lowest reasonable rate which held native load harmless. The Commission therefore directed NEPCO to compute the higher of embedded cost or opportunity cost over the entire transaction period rather than hourly and developed a cumulative comparison

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method that would allow NEPCO to ensure that, at all times during the transaction period, NEPCO would recover the higher of embedded cost or opportunity cost incurred to date. [8]

FPL argues that, notwithstanding the Commission's action in *NEPCO,* FPL should be allowed to adopt the hourly comparison method. In support, FPL argues that firm transmission services are provided on an hourly basis and opportunity costs are incurred on an hourly basis and, therefore, pricing on the basis of the transaction period will not send the proper price signals to transmission customers. FPL provides an example where a power producer has no incentive to avoid a constrained transmission corridor because the opportunity costs over the transaction period ($9.9 million) are less than the embedded cost rate over the transaction period ($10 million). [9] FPL also argues that under the transaction period approach, FPL will not be fully compensated because it will either: (1) recover its embedded cost and, therefore, it will not recover its opportunity costs; or (2) recover its opportunity costs and, therefore, no contribution to its embedded costs. Finally, FPL argues that native-load customers pay both embedded costs and opportunity costs and, therefore, transmission customers should as well.

B. *Discussion*

The Commission believes that FPL has provided no compelling arguments to adopt an hourly comparison of opportunity and embedded costs. As discussed in *NEPCO,* this type of pricing would allow a charge that is virtually as high as an "and" price. [10] While the Commission may ultimately wish to consider something other than full transaction comparisons in the future, [11] we see no reason, and FPL has offered none, to depart from our existing pricing policy at this time. We respond to each of FPL's arguments below.

FPL argues that firm transmission services are scheduled on an hourly basis and opportunity costs are incurred on an hourly basis and, therefore, pricing on the basis of the transaction period will not send the proper price signals to transmission customers. FPL provides an example in which a power producer has no incentive to avoid a constrained transmission corridor because the opportunity costs over the transaction period are less than the embedded cost rate over the transaction period. This example, however, is internally inconsistent with FPL's stated need to rely on real-time price signals, because the example has nothing to do with real-time price signals. As FPL's example shows, decisions about long-term transactions are made on the basis of the costs to be incurred over the *entire* transaction period. Such decisions cannot be revisited on a real time basis.

Moreover, while the level of opportunity costs over a transaction period will be affected by the number of hours that the system is constrained, the decision to expand will be made on the basis of opportunity costs incurred over the transaction period, not on the basis of transaction costs incurred in any particular hour. In this respect, FPL's pricing is inherently discriminatory. This is because FPL, when evaluating costs for its own use of its transmission system, compares opportunity costs over an entire transaction period to the cost of expansion, and presumably expands when the net present value of the sum of opportunity costs exceeds the cost to build. FPL does not make hourly comparisons; it makes transaction comparisons. Yet FPL would force transmission customers into hourly comparisons which raise the price well above what FPL implicitly charges itself and result in the transmission customers being forced into paying for an expansion prematurely. Accordingly, FPL's statement of the obvious--that energy associated with firm transmission services (like all electric energy) is scheduled on a hourly basis--provides no basis to allow FPL to adopt the hourly comparison method. The relevant fact is that while these services, as all services, are scheduled on an hourly basis, they are not contracted for, or evaluated on, an hourly basis.

Moreover, FPL's example in support of its proposal to compute opportunity costs on an hourly basis, *supra* p. 5, was rejected by the Commission in *Public Service Electric & Gas Company,* 62 FERC ¶61,014, *reh'g denied,* 63 FERC ¶61,200 (1993), *appeal pending,* No. 93-1411 (D.C. Cir. Filed June 23, 1993). There, the company argued that, when embedded cost transmission rates exceed the incremental expansion costs, the customer has no price signal or incentive to locate its generation facilities so as to minimize incremental transmission costs. The Commission determined that the customer's indifference to the incremental costs (opportunity costs or expansion costs) occurred under the Commission's current pricing policy

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only when the incremental costs were below the embedded costs, [12] and that the solution to this problem is to remove the embedded cost floor, not to permit the utility to charge a rate higher than embedded costs. [13] Accordingly, the solution to the problem raised in FPL's hypothetical is for FPL to remove the embedded cost floor.

FPL also argues that under the transaction period approach, FPL will not be fully compensated because it will either: (1) recover its embedded cost and, therefore, it will not recover its opportunity costs; or (2) recover its opportunity costs and, therefore, receive no contribution to its embedded costs. However, this argument is not an attack on the hourly comparison method for computing "or" rates; rather, it is an attack on the Commission's current pricing model, which has been upheld by the D.C. Circuit. [14]

Finally, FPL argues that native-load customers pay both embedded costs and opportunity costs and, therefore, transmission customers should as well. While FPL is correct that native load pays opportunity costs as well as embedded costs, FPL's suggestion that native load pays the same rate that FPL proposes here is incorrect. No native-load customer pays both a pro rata share of embedded costs plus all of the opportunity costs that would not have been incurred but for that customer. Native-load customers pay a pro rata share of all system-wide costs, both embedded costs and opportunity costs. In *New England Power Company,* 65 FERC ¶61,153 (1993), the Commission determined that an embedded cost transmission rate can include a pro rata share of all costs, including opportunity costs. This would, of course, result in a much lower rate than that proposed by FPL because opportunity costs would be shared among all customers, native load and transmission.

Issue 3: *Short-Term Transmission Service Price Cap*

A. *Background*

Under the Commission's current pricing policy, in situations in which the system is constrained, a utility may charge opportunity costs up to the cost of expanding the system to remove the constraint. FPL proposes to charge opportunity costs without regard to the cost of expanding the system to remove the constraint--i.e., to remove the expansion cost cap--when a customer contracts for short-term firm transmission service under Tariff No. 2. [15] Short-term service is available for a maximum term of one year.

FPL maintains that it cannot foresee circumstances in which the construction of new transmission facilities would be feasible or economically rational in a one-year contract. FPL points to *Northeast Utilities Service Company,* [16] in which the Commission said that three years was generally the minimum period of time needed to construct even the most limited transmission upgrades. FPL further contends that the Commission has stated that the purpose of the expansion cost cap is to prevent a utility from restricting transmission capacity so as to collect charges in excess of costs, and to provide an incentive for the utility to expand its transmission system when the system is constrained. FPL argues that since it cannot build to relieve the constraint during a short-term agreement, all opportunity costs associated with providing service are legitimate costs and should be recovered. According to FPL, under these circumstances, opportunity cost prices are not monopoly rents; they are all legitimate scarcity rents. [17]

Florida Cities argue that scarcity rents have economic meaning and enhance efficiency only in competitive markets. According to Florida Cities, in competitive markets, temporary supply scarcities will cause prices to rise, thereby lowering demand and inducing additional supplies until the market is again balanced; conversely, excess supply will cause price to decline until demand rises sufficiently to absorb the remaining supply. However, Florida Cities argue that the instant market is not competitive because FPL is a transmission monopolist. Florida Cities claim that these are all monopoly rents, not scarcity rents. The rents FPL receives perform no market equilibrating function in this non-competitive market. Monopolists have no incentive to expand output when they receive extra rents. No other competing suppliers enter the market; therefore, there are no market forces to restrain prices. Florida Cities conclude that FPL should not be allowed to remove the expansion cost cap on opportunity costs in its short-term tariff. [18] Finally, Florida Cities argue that some transmission system expansions might be accomplished

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in less than one year and FPL should be encouraged to do so by being required to adhere to the cap to make these quick upgrades when the circumstances warrant them. Florida Cities also claim that if the short-term tariff has no expansion cost cap, customers will never be able to anticipate their potential liability, and that will chill economic transactions. [19]

Seminole discusses many shortcomings of opportunity cost rates as proposed by FPL, but does not deal with the specifics of opportunity cost prices in Tariff No. 2. [20]

B. *Discussion*

The Commission concludes that prices based on FPL's legitimate and verifiable opportunity costs for short-term transmission service should not be capped at expansion cost because there is no significant need for such a cap. The Commission believes that short-term transmission markets will be better ordered and more efficient if prices for short-term transmission services reflect full legitimate and verifiable opportunity costs. Opportunity costs provide the most efficient price signals in congested short-term transmission markets and will thus perform the capacity allocation function more effectively. Because opportunity costs, whether above or below expansion costs, are costs that are actually incurred by the transmitting utility, they also ensure that native-load customers are held harmless from the utility's provision of short-term transmission service to third parties. The Commission does not believe that the supply of new capacity will be strategically withheld for the purpose of driving up prices of short-term transmission service, given FPL's commitment to provide firm long-term service at cost-based prices.

As FPL points out, the purpose of the Commission's expansion cost price cap is to encourage a transmission owner to expand capacity to meet market demand. With the price cap, a transmission owner cannot profit by restricting supply. The only argument for imposing an expansion cost price cap on short-term service prices in situations where the utility offers firm long-term transmission service would be to encourage FPL to expand transmission capacity in anticipation of short-term transmission needs. However, only if FPL correctly anticipates short-term needs will it recover its costs. If the company builds more capacity than is needed for the short-term market, its shareholders and/or native-load customers will pay the costs of the excess capacity. If the company builds too little capacity to meet short-term demands, its tariff service obligation will force it to provide service at a price that could be less than actual opportunity costs. Accordingly, either its shareholders and/or its native-load customers will pick up the cost if it builds too much or too little capacity for the short-term market.

For the reasons discussed, the Commission will allow FPL to set rates for short-term, [21] firm transmission services at the higher of its embedded or opportunity costs without an expansion cost cap. The rates, in effect, will be capped at the higher of FPL's legitimate and verifiable opportunity costs or its embedded costs.

The Commission also believes that a resale price cap is appropriate for short-term firm, transmission service. As discussed in the section addressing long-term transmission service, the Commission believes that this is the best way to insure against exploitation by resellers. Accordingly, we will also impose, as a condition to the transmission service FPL is providing, a resale price cap at the price (and not higher) at which FPL first sold the transmission service. A short-term resale price cap will protect customers from paying prices which could, in some circumstances, reflect monopoly rents.

Issue 4: *Energy Resale Restrictions*

A. *Background*

FPL proposes to preclude its partial requirement (PR) customers from reselling the energy they purchased from FPL during any hour in which FPL's incremental cost in the hour is more than the energy charge paid by the PR customer to FPL--i.e., in any hour in which FPL's incremental costs exceed its incremental PR revenues. FPL argues that this energy resale restriction is required to prevent uneconomic, inefficient and irrational transactions from occurring on the Florida Coordinating Group (FCG) Broker. [22] Because the Broker matches trades on the basis of the highest incremental cost to the lowest decremental cost

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during any hour, FPL claims that it is necessary to restrict the resale of energy, which FPL sells at average embedded costs, in order to ensure that FPL is never required to use high cost resources to displace another utility's lower cost resource. [23]

FPL states that section 23 of Rate Schedule PR includes a small, well-defined limitation on resale when FPL's incremental fuel cost exceeds either its projected on-peak or off-peak fuel charge. [24] FPL states that the FCG Broker pairs the lowest incremental cost resource with the highest decremental cost resource and makes successive transactions on the same basis. If a PR customer quotes his average cost PR power on the Broker and a sale is made, this will result in FPL's production of additional power at FPL's incremental cost. If FPL's incremental cost is above its average cost, the Broker will achieve the wrong "match" of incremental and decremental costs. Such a match would not reduce operating costs in Florida as much as would occur if the proper match were made and could actually increase operating costs in the state. [25]

FPL argues that its resale restriction is narrowly drawn. FPL will consent to resale in any hour when its incremental cost for the affected power is expected to be equal to or less than the incremental revenue received under the PR Rate Schedule. FPL argues that in *Gulf States Utilities Company,* 5 FERC ¶61,066 (1978), the Commission refused to accept resale restrictions because it wanted to increase competition to the benefit of consumers. Here, FPL proposes a restriction that prevents inefficient trades that increase costs to consumers. [26] Therefore, FPL maintains its proposed restriction is pro-competitive.

Florida Cities criticize FPL's restriction on resale of PR power on the grounds that it is contrary to established Commission policy, FPL's Nuclear Regulatory Commission (NRC) License Conditions and competitive conduct. Florida Cities point out that FPL makes profits on every hour of PR service it sells and there is no justification for denying others the right to operate in wholesale markets. [27]

B. *Discussion*

The Commission will order FPL to remove the tariff provision that restricts sales by its PR customers in the economy energy market when FPL's incremental production costs exceed its incremental revenues. As discussed below, the restriction is overly broad and fails to discriminate between efficient and inefficient trades on the Florida Broker.

FPL is correct that the resale of power, which it sells at average, embedded costs, could result in inefficient trades on the Broker. For example, consider a case in which PR customers purchase energy from FPL at 6 mills. If FPL's incremental resource cost is 12 mills per kWh and the highest cost resource used on the Broker is 10 mills, it is not efficient for PR customers to resell power purchased from FPL on the Broker because FPL's resource would displace a lower cost resource. The problem with the restriction is that it is misdirected and too broad. Whether a resale of PR power on the Broker is efficient or inefficient does not depend on the difference between FPL's incremental production cost and its incremental PR sales revenue, but depends instead on the relationship of FPL's incremental cost and the highest cost resource sold on the Broker.

As demonstrated in the above example, when FPL's incremental resource has higher operating costs than the highest cost resource used by the Broker in an hour, resale by PR customers is likely to be inefficient. But when FPL's incremental resource has lower operating costs than the highest cost resource used by the Florida Broker in an hour, resale by PR customers is efficient. For example, consider again a case in which PR customers purchase energy from FPL at 6 mills. If FPL's incremental resource cost is 8 mills per kWh and the Florida Broker's highest cost resource displaced is 10 mills, it is efficient for PR customers to sell on the Broker. In both this example and the prior one, FPL's incremental cost is greater than its average price for PR energy, but FPL's proposed restriction would prohibit both resales, even though the second example is efficient. The proposed restriction does not discriminate

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between efficient and inefficient trades, [28] Therefore, it should be removed.

While the resale of power purchased at average cost rates could lead to some inefficient transactions, FPL's solution, prohibiting a whole class of transactions, is not appropriate. FPL's concern stems from the fact that the prices in FPL's Schedule PR may not reflect FPL's incremental costs. The resale of power need not be prohibited in order to address this concern. The price signals themselves could be improved in ways that would promote efficient resource use without imposing overly broad restrictions that prevent both efficient and inefficient trading. [29] Consequently, the Commission rejects FPL's proposed remedy as too broad.

Issue 5: *Divisor for Transmission Rates*

A. *Background*

FPL's transmission rate formula develops a rate by dividing its transmission costs by the sum of: (1) the average of its 12 monthly system peaks exclusive of wholesale and transmission customers; and (2) the billing demands of its wholesale and transmission customers (either noncoincident peaks or contract demands). In the September 24 Order, the Commission noted that, in *Southern Company Services, Inc.,* 61 FERC ¶61,339 (1992) (*Southern*), the Commission had determined that the appropriate divisor for this type of rate was the annual system peak as a proxy for the transmission system's capability. [30]

FPL argues that its proposal is reasonable because, unlike *Southern* which involved the use of a divisor equal to the average of 12 monthly peaks, FPL adjusted the peak to eliminate wholesale and transmission customers' coincident peaks and to add their billing determinants. FPL concludes that this adjustment ensures that there is a consistency between the rate design and the customers' billing determinants. FPL also states that its approach is appropriate because, if it had done a customer-specific rate, it would have allocated costs using the customers' contract demands, consistent with the Commission's decision in *Central Power & Light Company,* Opinion No. 326, 47 FERC ¶61,339 (1989) (*Central*). FPL concludes that it recovers the same revenues under its formula as it would under a customer-specific rate where costs were allocated on the basis of contract demands.

B. *Discussion*

FPL's arguments have no merit. FPL's first argument was addressed in *AEP.* There the Commission explained that using a divisor equal to the sum of: (1) the average of the 12 monthly native-load coincident peaks; and (2) the transmission customers' billing determinants is merely a slightly modified version of a non-customer-specific rate that the Commission has consistently rejected. The Commission emphasized that utilities have two rate options: (1) a customer-specific rate that allocates the utility's total transmission revenue requirement to customers based upon the customers' contribution to the 12 monthly peaks and dividing that revenue requirement by the customers' billing determinants; or (2) a non-customer-specific rate that divides the utility's total transmission revenue requirement by the annual system peak as a proxy for capability. [31]

FPL's second argument is clearly off point. What FPL would do if it designed a customer-specific rate is irrelevant. FPL may revise its formula to do customer-specific rates, consistent with the option afforded in *AEP.* The issue presented here is how to develop a rate that is not customer specific. Having chosen a rate that is not customer specific, any arguments as to how FPL would allocate costs for a cus-tomer-specific

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rate method are simply irrelevant. [32]

Consistent with *AEP,* FPL must revise its formula to use its annual system peak as the divisor. This finding, of course, is without prejudice to FPL filing a customer-specific rate in a new proceeding under section 205 of the FPA if it chooses.

Issue 6: *Hourly Rate Development for Interchange Service*

A. *Background*

Under Service Schedule AF, FPL will provide emergency interchange service for up to 24 hours. The proposed rate is the highest of: (1) 100 mills/kWh; (2) the daily capacity and energy charges for Schedule BF (maintenance outage service); or (3) a formula that computes an hourly charge by dividing the annual fixed and variable costs of FPL's gas turbine (GT) generating units by the output of the GT units and adding to that figure FPL's standard hourly transmission rate. In the September 24 Order, the Commission noted that FPL's proposal (under (3) above) to develop the production component of the hourly charge by dividing fixed GT production costs by the output of the GT units departed from the standard set forth in *Jersey Central Power & Light Company, et al.,* 38 FERC ¶61,275, *reh'g denied,* 40 FERC ¶61,236 (1987) (*Jersey Central*). In *Jersey Central,* the Commission required the hourly charge to be computed by dividing the annual fixed costs by 8,760 to reflect the potential for full hours' utilization. FPL argues that its proposal, while contrary to *Jersey Central,* is reasonable because (1) its present emergency rates are developed by dividing the fixed O & M component by the unit's annual output and FPL's instant proposal simply extends that method to all fixed costs, (2) the Commission recognized in *Indiana Michigan Power Company,* 44 FERC ¶61,313 (1988) (*IMPC*), that it may be appropriate to design rates for emergency service differently than ordinary coordination rates, and (3) failure to use the actual plant output would result in FPL's under-recovering its GT costs.

B. *Discussion*

The Commission finds no merit to any of FPL's arguments. FPL's present emergency rates are indeed developed improperly by dividing fixed O & M costs by the unit's output, but those rates do not reflect any other fixed production costs (return, income taxes, or depreciation), nor any fixed transmission costs. The Commission has allowed FPL and others to include defective rate treatments in their formula rates when it had reason to believe that the results of the formula would produce reasonable results because of the exclusion of other appropriate costs. [33] Here, FPL intends to include all costs in the formula and there is no cushion of excluded costs to offset an excessive production component.

FPL's second argument is disingenuous. In *IMPC,* the Commission approved a non-cost-based rate for emergency service in order to discourage excessive reliance on the emergency service. The Commission approved the rate expressing concern that such disincentive rates be set at the lowest reasonable level that would discourage inappropriate requests for emergency service because a rate set too high could be exploitative and exorbitant. Here, FPL has already adopted the same 100 mill/kWh non-cost-based minimum approved in *IMPC* and

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has provided no basis to consider any other type of disincentive or non-cost-based rate that would exceed 100 mills/kWh.

FPL's final argument is that it will not recover its costs unless the GT fixed costs are spread across actual output of the GT units. FPL provides an example in which its GT units operate, on average, 5% of the hours in a year (438 hours). Of this amount, 40% of the energy is used to make emergency interchange sales (175 hours) and 60% is used for FPL's own needs (263 hours). FPL argues that if it develops an hourly charge on the basis of net generation, emergency interchange customers would properly pay 40% of the fixed costs because they would have purchased 40% of the annual output. FPL states that, if it designs its rates as prescribed by *Jersey Central,* emergency interchange customers would pay only 2% of the fixed costs (175 hours of service billed/8760 hours in the year). FPL's explanation, however, assumes that the GT units are useless during the 8,322 hours per year that the GT units are idle, and this is not the case. During those remaining 8,322 hours, FPL relies on the GT units to provide reserves for its native load or to sell peaking *capacity* to other wholesale customers who may never request that energy be generated from such capacity. [34] It is entirely appropriate for FPL's native-load customers and wholesale customers purchasing peaking capacity to pay the fixed costs of the GT units during those idle periods. To the extent FPL is concerned that a rate based on the cost of the GT units, computed as prescribed in *Jersey Central,* is too low to discourage excessive reliance, FPL's proposal to adopt a non-cost-based minimum (*e.g.,* the 100 mill/kWh minimum) as a disincentive should resolve FPL's concerns.

Because none of the arguments advanced by FPL provide a basis for departing from the Commission's consistent requirement that the production component of hourly rates be developed by dividing annual fixed costs by 8,760 hours per year, FPL is hereby directed to revise its formula accordingly. [35]

Issue 7: *Consistency Between Demand and Energy Charges*

A. *Background*

FPL's coordination rates consist of: (1) an energy charge equal to 110% of FPL's incremental cost; and (2) a demand charge computed using a formula which reflects FPL's average system production costs, excluding nuclear. In the September 24 Order, the Commission noted that this departed from the requirements set forth in *Indiana and Michigan Electric Company, et al.,* 10 FERC ¶61,295 (1980) (*Indiana Michigan*), which requires consistency between demand and energy charges. In *Indiana Michigan,*the Commission stated:

> [The energy charges] are generally based on replacement fuel costs of the units actually used to provide the service. Native load requirements would generally be met by the large base-load capacity recently added to the system whereas the units providing [this service] would generally consist of the older, less-efficient units. Logic would dictate utilizing the capital costs associated with such units for the purpose of intersystem pricing when energy charges are based on the cost of the actual units utilized.[[36]]

Because the utilities in *Indiana Michigan* elected to price energy on the basis of the fuel cost of the generating units incrementally dispatched to provide the services, the Commission required that the demand charges reflect the fixed costs of the same generating units weighted on the basis of relative expected use. In contrast, while FPL employs the same incremental energy pricing as in *Indiana Michigan,* it bases its demand charges on average non-nuclear generation fixed costs.

In support of its proposal, FPL states that: (1) its existing coordination rates, while stated rates rather than formula rates, are designed in this manner; (2) in developing the composite rate ceiling for the *Western Systems Power Pool,* 55 FERC ¶61,099, *reh'g denied,* 55 FERC ¶61,495 (1991) (*WSPP*), the Commission developed a cost for each member reflecting the average cost of the units expected to be used to price energy, not weighted according to relative expected use; and (3) *Indiana Michigan* is not on point because the Commission did not state that utilities must develop all coordination rates by weighting fixed costs on the basis of relative energy pricing, but only accepted a proposal tendered by several utilities with respect to fuel conservation rates.

None of the arguments advanced by FPL have merit. It is true that FPL supported its existing coordination demand charges on the basis of average non-nuclear generation fixed

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costs; however, those demand charges include no transmission costs other than O & M. As explained above, FPL is well aware that the Commission evaluates the rate level, not the costing methodology used by the filing utility. Given FPL's election to price energy on the basis of the fuel costs of the generating units incrementally dispatched to provide the service, the Commission has consistently evaluated FPL's coordination demand charges on the basis of the fixed costs of those same generating units, weighted by likely participation, and including all transmission costs. Now, FPL proposes a formula rate that will operate without review and which will include all transmission costs. The only way to be sure that the formula produces reasonable results is to revise it to reflect the cost of the units used to price energy, weighted on relative use. [37]

FPL's reliance on *WSPP* is misplaced. In *WSPP,* the Commission rejected a market rate proposal but allowed the arrangement to go forward under cost-based ceiling rates. The Commission calculated the ceilings in the order rejecting the market-based rates. FPL apparently believes that the Commission developed a fixed production cost for each member reflecting the average costs of the member's units without weighting to reflect the likelihood that the units would be used to price energy. This is not true. The Commission analyzed each member's resources and loads and developed a composite WSPP demand charge ceiling reflecting the generating unit on each public-utility member's system most likely to be used by that member to price incremental cost energy.

Finally, FPL's suggestion that *Indiana Michigan* is not on point is ill-premised. In the 14 years since *Indiana Michigan* was issued, the Commission has steadfastly required formula rates' demand and energy charges reflect the cost of the same generating resources. [38] The fact that there are only a few orders in which the issue is discussed is testimony to the universal compliance with that requirement by other public utilities.

FPL is ordered to revise its formula rate to reflect the fixed costs of the generating units that are reflected in the incremental cost energy charge, weighted on relative use. Alternatively, FPL may revise the energy charge to reflect average non-nuclear variable costs. Either alternative would reflect the consistency required by *Indiana Michigan* and subsequent cases.

The Commission orders:

FPL is hereby directed to revise its filing in this proceeding to reflect the discussion contained in the body of this order, and to make a compliance filing within 15 days of the date of this order.

-- Footnotes --

[61,523]

[1] 64 FERC at p. 63,486.

[2] *Id.* at pp. 63,485-86.

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[3] *See* FPL September 8, 1993 Answer at p. 70.

[4] The Commission caps the rate for the resale of gas pipeline transportation capacity at the maximum just and reasonable rate the pipeline is allowed to charge. *See Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol and Order Denying Rehearing in Part, Granting Rehearing in Part, and Clarifying Order No. 636* [*FERC Statutes and Regulations* ¶30,939], Order No. 636-A, 57 Fed. Reg. 36128 (August 12, 1992), *FERC Statutes and Regulations* ¶30,950, at p. 30,560 (1992), *appeal pending, Atlanta Gas Light v. FERC,* No. 92-8782 (11th Cir. Filed December 4, 1992)(Pipeline must allocate released capacity to the shipper offering the highest rate, not over the maximum rate).

[5] Seminole August 24, 1993 Protest at pp. 207-208.

[6] *See, e.g., Northeast Utilities Service Company (Re Public Service Company of New Hampshire),* Opinion No. 364, 56 FERC ¶61,269, at p. 62,010 (1991), *order on reh'g,* Opinion No. 364-A, 58 FERC ¶61,070 (1992), *aff'd in part, Northeast Utilities Service Company v. FERC,* 993 F.2d 937 (1st Cir. 1993).

[7] Restricting transmission service can take many forms. When a system is being used at capacity and additional service is desired, not building new capacity is a way of withholding or restricting service. The local utility is usually singularly situated in that only it can provide additional capacity at a reasonable cost. One way the utility can withhold service is by simply not aggressively pursuing new transmission capacity additions.

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[8] 61 FERC at pp. 61,069-70.

[9] *See* FPL March 19, 1993 Transmittal Letter at p. 35 and n.9.

[10] *See Pennsylvania Electric Company v. FERC,* 11 F.3d 207 (D.C. Cir. 1993).

[11] The Commission currently is comprehensively evaluating its transmission pricing policies. *See Inquiry Concerning the Commission's Pricing Policy for Transmission Service Provided by Public Utilities Under the Federal Power Act, FERC Statutes and Regulations* ¶35,024, 58 Fed. Reg. 36400 (1993).

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[12] Under the current pricing policy, the utility can charge the higher of embedded or incremental costs.

[13] 63 FERC at pp. 62,549-550.

[14] *Supra* n.10.

[15] *See* Amended Filing, July 26, 1993, Volume 5, Part 2 of 3, "Transmission Tariffs" at p. 21.

[16] 62 FERC ¶61,294, at pp. 62,917-18 (1993).

[17] *See* Amended Filing, July 26, 1993, Volume 2(a), Testimony of William C. Locke, Jr., at pp. 19-20.

[18] Florida Cities August 24, 1993 Amended Protest, Volume 1, at pp. 116-118.

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[19] Tampa also argues that removing the expansion cost cap on opportunity cost rates "will have a chilling effect on the competitive nature of the Florida bulk power market." Tampa August 19, 1993, Protest at p. 43.

[20] *See* Seminole August 24, 1993 Protest at pp. 175-178, 188-196.

[21] As noted, FPL's tariff defines short-term as one year or less.

[22] The FCG Broker is a trade mechanism for economy energy transactions in peninsular Florida. It is operated by Tampa Electric Company for the FCG. The Broker now has 20 members. Every generating utility in Florida is a member except Gulf Power. For hourly economy, utilities make offers each hour of how much capacity they want to buy or sell and specify the incremental or decremental running costs associated with the various capacity blocks. This information is posted on the Broker's electronic bulletin board (EBB). The Broker's computer then matches trades on the basis of highest decremental cost to lowest incremental cost to maximize savings. Matched trades are priced on a split savings basis. The matched trades and their prices are also displayed on the EBB. Individual members have established bilateral transmission contracts to ensure that there are contract paths for all possible economy energy trades.

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[23] *See* Filing of March 19, 1993 “Volume I--Transmittal Letter and Notice of Filing” at pp. 50-51.

[24] *See* Amended Filing, July 26, 1993, Volume 2(a), Testimony of William C. Locke, Jr. at pp. 35-36.

[25] *See* Amended Filing, July 26, 1993, Volume 2(c), Testimony of Joseph P. Stepenovitch at pp. 17-18.

[26] FPL April 27, 1993, Answer at pp. 171-173.

[27] Florida Cities August 24, 1993, Protest, Volume I at pp. 171-173.

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[28] Moreover, FPL’s concern with inefficiencies in its PR rate design is also rather selective. The potential for PR customers to make inefficient decisions is not limited to resale markets. For example, PR customers who have their own generating resources make comparisons between the cost of dispatching their own generators and the cost of purchases under the PR tariffs. As long as decisions are based on a comparison of incremental costs and average PR prices, inefficient decisions can be made.

[29] For example, FPL is free to propose and support marginal-cost rate designs.

[30] As we explained in*Southern:*

[W]hen utilities are developing customer-specific, per unit charges, they do so by dividing the customer-specific, allocated revenue requirement (i.e., that customer’s share of the total revenue requirement) by that customer’s billing determinants. The choice of what to use as the denominator is a comparatively simple question of mathematics--it must be the customer’s billing determinants.

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While this description reflects a typical rate design, it is not uncommon for a utility to develop transmission rates that are not customer-specific--by dividing its total company transmission-related revenue requirement by its transmission system’s capability. This rate design yields a per unit cost or rate for the full capability of the utility’s transmission system. The resulting rate produces reasonable results when customer are billed on the basis of reservations or contract demand.

61 FERC at pp. 62,337-338; *Accord American Electric Power Service Corporation,* 64 FERC ¶61,279, at pp. 62,976-77 (1993) (AEP), *reh’g pending.*

[31] *Id.*at p. 62,977.

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[32] FPL has also mischaracterized *Central* as standing for the proposition that, when developing customer-specific rates, utilities may allocate costs to wholesale and transmission customers on the basis of contract demands rather than coincident demands. In *Central,* the Commission explained that its consistent practice is to allocate costs on the basis of coincident demands. The Commission departed from that practice in *Central* based on the unique facts presented in that case. Central’s customer had operated its system to place no coincident demands on Central resulting in a demand allocator of zero. The Commission rejected a demand allocator of zero primarily on equity grounds. The Commission also noted that there was evidence on the record that Central used the customer’s contract demands for planning purposes. Finally, the Commission noted that Central used its facilities to provide operating reserves for the customer’s loads even when the customer was not purchasing power from Central. *Id.* at pp. 62,165-167. Very simply, the unique facts present in *Central* are not present here.

[33] FPL is well aware of the Commission’s practice at looking at overall formula rate results. *See Florida Power & Light Company,* 24 FERC ¶61,171 (1983), where the Commission explained that it had allowed FPL to use an excessive return on equity (19%) in a formula rate for coordination services because the formula rate did not recover any transmission costs except transmission operation & maintenance (O & M). The Commission found that the formula produced reasonable results when

tested against FPL's overall costs (production and transmission) together with an appropriate equity return. *Id.* at pp. 61,407-08. *See also Southern Company Services, Inc.,* 62 FERC ¶61,072 (1993), in which the Commission explained that it had allowed an excessive transmission component in a formula rate for sales made to FPL and other utilities because the production component was set below the level the Commission would have allowed. The Commission found that the formula produced a reasonable rate when it tested the overall formula results (production and transmission) against Southern Companies' overall costs. *Id.* at pp. 61,347-48.

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[34] A customer could purchase such capacity to meet its operating reserve requirements but actually not need any energy to meet its customers' load.

[35] The Commission has also allowed utilities to develop hourly rates on the basis of the peak hours in the year rather than all hours in the year; however, the Commission requires that the daily hourly charge revenues be capped at the daily rate. FPL is aware of this option because it developed the transmission component of the charge on the peak hour basis with a daily cap.

[36] 10 FERC at p. 61,591.

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[37] In *Illinois Power Company,* 57 FERC ¶61,213, at p. 61,699 (1991), the Commission clarified that many pricing structures are acceptable, *e.g.,* specific unit prices, average system costs, or the cost of the incremental unit on the system, as long as energy and demand charges are developed consistently.

[38] *See Southern Company Services, Inc.,* 62 FERC ¶61,072, at p. 61,348 (1993); *United Illuminating Company,* 61 FERC ¶61,027, at p. 61,151 and n.16 (1992); *Illinois Power Company,* 57 FERC ¶61,213, at p. 61,699 (1991).