BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO 891345-EI

REBUTTAL TESTIMONY
OF
M. T. O'SHEASY

Gulf Power

GULF POWER COMPANY
Before the Florida Public Service Commission
Rebuttal Testimony of
Michael T. O'Sheasy
In Support of Rate Relief
Docket No. 891345-EI
Date of Filing May 21, 1990

Q. **Mr. O'Sheasy, have you previously submitted testimony in this proceeding?**

A. Yes. I submitted prefiled direct testimony in this proceeding in support of the filed rates for Gulf Power Company.

Q. **Have you reviewed the testimony and exhibits of the witnesses intervening in this proceeding?**

A. Yes.

Q. **What is the purpose of this rebuttal testimony?**

A. It is to address the following cost of service subjects raised by the witnesses for the intervenors in this proceeding:

(1) Customer/Demand Classification of Distribution Accounts

(2) Proper Production Allocation for Gulf Power Company

(3) Equivalent Peaker (EP) and Refined Equivalent Peaker (REP)

(4) Allocation of Lines Investment

(5) Allocation of Plant Scherer

(6) Voltage Differentiated Rates
(7) Transformation Discounts.

CUSTOMER/DEMAND CLASSIFICATION

Q. On Page 36 of Mr. Pollock's testimony, he states that he believes that the Commission should examine the customer-demand classification issue. Do you agree that a more representative costing analysis would recognize more customer related costs in distribution accounts?

A. Yes. As stated on page 21 of my prefiled testimony, our position is that the Minimum Distribution System is includable for ascertaining customer related cost. This is logical from a cost causative perspective.

Q. Why do you believe that it is logical from a cost-causative perspective?

A. There is a customer related portion of distribution investment required to serve customers independent of their anticipated demand and energy requirements. The mere fact that they wish to become a customer of Gulf Power forces a certain minimal amount of equipment to be there available to serve. Distribution facilities, including poles, conductors, and transformers, are required regardless of the Company's expectations regarding load. A part of the customer component is the theoretical minimum distribution system that would be required to serve customers. The NARUC Electric Cost Allocation Manual not only recognizes a customer related portion of distribution costs, but devotes an entire chapter to a discussion of the separation of the customer related portion from the demand related portion.

Q. What would you recommend in this issue in order to define more accurately the cost to serve Gulf's customers?

A. I recommend that we adopt the customer/demand classification factors that were recommended in Gulf's 1984 retail filing. In fact, I believe that a more current analysis would still produce quite similar results. These factors would be applied in the following manner:

FERC Account	Description	Customer %	Demand %
364	Poles	46.1%	53.9%
365	Overhead Conductors	13.8%	86.2%
366	Underground Conduits	13.8%	86.2%
367	Underground Conductors	13.8%	86.2%
368	Line Transformers	34.2%	65.8%
369	Services	100.0%	0%
370	Meters	100.0%	0%

PROPER PRODUCTION ALLOCATION FOR GULF POWER COMPANY

Q. Mr. Pollock states in his testimony that a seasonal peaking allocator would be more appropriate for Gulf than the 12-MCP and 1/13 Energy which you utilized. Why did you choose 12-MCP and 1/13 Energy?

A. It was the required methodology stated in FPSC's Final Order from Gulf's last rate case. As stated in my testimony, we felt that this method was appropriate because the results of this technique did not diverge dramatically from results of concepts which we believe more appropriate. Also, it is the methodology upon which current rates are based and has been so since 1981. Gulf's customers are therefore familiar with the price signal which it sends. Since the majority of this allocator is 12-MCP, it matches up nicely with the FERC's preference for 12-MCP and the fact that Gulf's IIC payments and credits are dependent upon its monthly peak. Finally, it recognizes the impact of scheduled maintenance performed in non-peak months.

Q. Is Mr. Pollock's "Near Peak" procedure appropriate for Gulf Power Company?

A. No, although Gulf's costs are sensitive to the seasons. His methodology is much too restrictive an interpretation for Gulf's load shape, as even his results show. Mr.

Pollock's 71-hour allocation contains specified hours found in only two summer months. Certainly there are other months of the year when Gulf is in a "peaking mode." Mr. Pollock's own Schedules 5 and 7 indicate that throughout the years 1984 through 1989 there are at least four to five different critical summertime months. In addition, Mr. Haskins' Exhibit No. 6 further supports the importance to Gulf of four summer months during 1987 and 1988.

Q. What is your opinion on Mr. Pollock's statement "besides failing to adequately recognize the seasonal load characteristics of the Gulf Power and Southern Company systems and the fact that Southern schedules most of its outages during the non-summer period, the 12CP method is relatively insensitive to seasonal load shifts. As a result, the 12CP method could send the wrong price signal?"

A. His point that the 12CP method is relatively insensitive to seasonal load shifts is true, but many allocation methods would appear "relatively insensitive to seasonal load shifts" when compared with the ultra-sensitive "Near Peak" method whereby any load shifts from two specific summer months to any of ten other months would result in complete disappearance of any cost responsibility.

Q. Do you agree with Mr. Pollock's statement that the "Near-Peak" method would produce more stable results over time than would the <u>other summer CP methods</u>?

A. This could possibly be true when compared to strictly "summer" coincident peak methods. Mr. Pollock has not produced any data that shows it to be more stable than 12-MCP, however. In fact, many proponents of 12-MCP applaud the fact that for most major rates, the 12-MCP does indeed produce relatively stable results over time. Also, one must remember that while stable results are important, also very important is the assignment of cost to those customers who caused the cost to be incurred. To avoid associating cost responsibility to customers who may have demanded service from Gulf during any one of ten months other than July and August would be inequitable and incorrect.

Q. What is your opinion on Mr. Pollock's stated basis for using 5 percent as the threshold since, "this is the period when system reliability is usually the most critical"?

A. First of all, I question why the 5 percent figure was chosen. What is the magic of 5 percent that justifies it to define this specific time frame as most critical? Secondly, the highest 71 hours are contained in July and

August, but Schedule 7 reveals four out of six years where some other monthly reserve margins after planned/scheduled maintenance were at or below the reserve margins for July and August.

Q. **Of the demand allocation methodologies proposed for allocating generation cost in this case, which do you recommend?**

A. I recommend an allocator approximating the 12-MCP. The purpose of a cost of service study is to allocate "embedded" cost upon those factors that caused them to be incurred, and, under these conditions, determine the cost to serve. In order to do so, we must consider why these costs were incurred. We must recognize that a generating plant will service Gulf Power Company's customers over 30 years into the future.

This study is not a marginal cost study. It is not a customer specific cost study. It is an analysis based upon the "embedded" cost as defined by our industry and allocated upon the causation of each of those costs. The result is an <u>average</u> embedded cost study reflecting the cost responsibility of an average customer within the respective rate.

After this task has been completed, the rate designer can be handed the inputs upon which he can fulfill his responsibility. He will then take the average embedded cost to serve the average customer within a rate class and mold a price for specific customer groups which will appropriately reflect cost and satisfy other goals and objectives, while working within prevailing constraints for the time frame to which these rates will apply. For instance, the price signal which the rate artist provides Gulf's customers must consider that we want to minimize the cost to serve Gulf's customers over all future years. This goal could then justify rates that will alter Gulf's load shape, thereby producing a more efficient process.

The point here is that the selection of a costing methodology should be dependent upon cost causation and should mirror the system in place to service Gulf's customers. It should not be a methodology selected to achieve goals or objectives conditioned by economic, societal, political, regulatory, and other constraints -- this is the responsibility of the rate designer; in this case, Gulf's witness Haskins.

EQUIVALENT PEAKER AND REFINED EQUIVALENT PEAKER

Q. With that in mind, what do you think about the Equivalent Peaker concept and the Refined Equivalent Peaker concept?

A. Both Equivalent Peaker concepts contain serious flaws which prevent them from justifying departure from the tried and tested methodology proposed by Gulf in this rate case. They depend upon the proposition that additional production plant costs result from the utility's attempt to minimize total cost after factoring in running cost. They assume that serving peak loads only, with no consideration for running cost, would warrant a peaking type plant. Accordingly the difference in equivalent peaking cost and total cost is related to running time and should therefore be allocated upon KWH.

These concepts do embody considerations which must be made when planning a system to serve projected load at a minimum cost. There is no doubt that, if a projected load shape revealed a need to build plant, one criteria for alternative plant selection would be to minimize total cost by considering capital cost, running cost, and projected plant utilization. However, the ultimate decision of what to build is far too complex to simplify into a mere trade-off of operating cost versus fixed cost. Gulf's witness Mr. Howell will elaborate on some of these other considerations, but there is no doubt that governmental regulations, legal and societal constraints, availability of capital, plant location parameters including fuel delivery problems, current plant mix and the potential dangers of total commitment to one type of fuel all play a role in the decision making process.

Q. What failings do you see in the Equivalent Peaker concept in addition to the over simplification of the system planning process that is discussed by Mr. Howell?

A. When the decision was being made, the costs of peaking units versus base units were not necessarily the same peaking versus base relationships which we observe today. To discount embedded cost to constant dollars is an attempt in the right direction, but may not reflect what the original costs were. For example, one must determine whether the discount rates are appropriates, or whether something was added after initial construction which could not have been anticipated, such as scrubbers. Also, the differential in oil cost and coal cost has not always been constant. In fact, oil fired plants were at one time the least cost option.

If you do accept the breakeven analysis between a peaker and a base unit, why allocate the incremental costs upon 8,760 hours of energy? Only the hours up to the breakeven point were important in the decision. Past the breakeven point, no matter how far, the decision has been made and would not be altered no matter how the plant utilization improved. To allocate these incremental capital costs upon all hours would not track cost causation.

The costs of reserving a peaker (i.e., its reliability) may not be the same as those of a base unit. The presumptions of EP, REP, and 12-MCP and 1/13 are that reserve costs are identical. However, because EP and REP differentiate the cost of peakers and base units for allocation purposes, unlike 12-MCP and 1/13, this fact requires a review of this reserving question.

Q. What do you feel about the statement that there may well be a long run marginal generating plant cost of off-peak energy use in which the EP method "will embody an appropriate reflection"?

A. First of all, we are not allocating long run marginal cost -- we are allocating average embedded cost. Secondly, if there is some long term marginal generating cost of off-peak energy use, I do not see where EP quantifies this cost, and therefore, reflects it. It simply appears to make a contribution towards it, which may be over or under the true cost. Also, what if the utility has no long run marginal generating cost of off-peak energy use? No one has said or proven that there is long run marginal generating cost of off-peak energy use for Gulf Power Company. In this instance, costs would be allocated to hours where none actually existed.

In addition, we would be indicating to our customers that off-peak KWH growth is bad since we would be allocating fixed cost on a KWH basis whereas we did not under Gulf's present and proposed methodology. Correspondingly, we would be telling our customers that peaking growth is not nearly as bad as we once thought since those costs would now be transferred to some degree from peaking periods to off-peak periods. Over time, our customers will react accordingly. System load factors could easily deteriorate, creating a need for more C.T.'s and fewer base load units in Florida. This may or may not be the trend which is in the best interest of Gulf's customers.

Q. Are there also flaws in the Refined Equivalent Peaker concept?

A. Yes. This approach attempts to correct a major criticism of the Equivalent Peaker method by only allocating the incremental plant cost upon energy up to the breakeven point between a peaker and a base unit. This, in theory, is a logical enhancement. However, this in itself presents a major problem:

<u>How do you determine the breakeven point?</u>

The methodology used by Mr. William Slusser, Jr. of Florida Power Corporation in Docket No. 870220-EI and my submitted response to Interrogatory No. 2 of Staff's First Set of Interrogatories in this docket, discounts embedded net plant costs of coal units and C.T.'s to current costs in order to match up with today's current running cost; the breakeven point then falls out. Besides the question of selecting the appropriate discount rate, the volatility of fuel (running) cost creates a problem. It has been said that in the long run, coal cost may track oil cost. However, it is most difficult to determine the correct cost to enter when examining the current cost environment. Many of the workpapers supporting the Company's response to Interrogatory No. 2 were completed in November of 1988 based on then prevailing oil and coal prices. Consider the impact that the Valdez oil spill has caused on oil prices; this effect may be temporary, but also there may be some lasting influence much like the '73 Arab Oil Embargo.

The point to be made here is that the need to choose a proper discount rate as well as volatility of fuel prices will cause the breakeven point to jump around dramatically. I have seen the hours of breakeven jump from 900 hours in some studies to 3000 hours in others. The impact on the hours selected and resultant allocator may cause significant swings in implied cost responsibility. The end result may be an unstable rate design process requiring continuous rate adjustments.

The EP approach bases its energy/demand split upon levelized gross investment. The Refined EP method bases its energy/demand split upon levelized net plant. One results in a 45 percent demand portion while the other produces a 40 percent demand. It is not perfectly clear which figure is correct.

The logic underpinning the Refined EP may assume an optimization based upon certain planning parameters. Because of the lumpiness of plant additions, it is rare that any utility will always maintain an optimal mix for the current load shape. As Mr. Howell states in his testimony, "the philosophy of optimum generation mix did not become widespread until the 70's," when most of Gulf's current generation had been either constructed or committed.

Does it then make sense to allocate actual embedded dollars upon a few theoretically presumed optimal parameters?

By levelizing embedded capacity cost into today's constant dollars to synchronize with current running cost, we are attempting to replicate the parameters which the planner faced. However, the current day fixed cost/variable cost relationship for peakers versus base units is <u>not</u> necessarily the same factors which the system planner observed when he constructed Plant Daniel in the late 70's or Plant Smith in the mid 60's. The reason that we rolled forward the capacity cost to match up with current fuel cost is that we are not sure of the exact fuel considerations anticipated at the time of construction, nor are we certain that these costs are relevant because of the dramatic changes in oil prices since then. Therefore, we chose current day costs as a proxy, but they are only a proxy at best. As a result, we are allocating embedded dollars on a current cost calculation which may or may not be appropriate.

Is there an inherent inconsistency in logic if one assumes capital substitution theory in determining base rates but average running cost allocation in fuel recovery? Capital Substitution theory appears to suggest that, after considering the running cost of a peaker versus a base unit and the resultant breakeven point has been passed, a base unit will be chosen and operated: in other words, subsequent hours after the justification point will have load requirements satisfied through the running cost of base units. It seems inconsistent then to associate any peaker fuel cost to hours past the breakeven point; unfortunately, the average fuel clause methodology would do so. Therefore, it does seem as if some type of adjustment is appropriate. However, is is not clear exactly what type of adjustment would be fair and equitable, especially since Gulf is essentially all coal fired. It does appear, however, that EP requires more of an adjustment than REP merely because EP allocates fuel savings capital cost to hours in the off-peak that should not receive any.

The basis upon which the demand defined portion of REP (and EP) is allocated must be examined carefully. In response to Interrogatories No. 1 and No. 2 of Staff's First Set in this docket, it was done upon the 12-MCP's. However, some of these 12-MCP's fall outside the highest 1430 hours. It seems illogical then to allocate cost defined to be serving demand requirements only, upon hours not even necessary to justify the incremental "fuel savings" investment cost. However, the real answer might be to capture the highest 1430 hours from a reliability standpoint, such as LOLP or EUE, which might possibly contain all of the 12-MCP's.

<u>In which component of rates do you place the incremental cost allocated upon hours up to the breakeven point?</u>

It seems as if it should be the energy component. The analyst must still decide whether to place these costs in the annual energy rate or in a seasonal rate.

Q. **Could you summarize your position on generation cost allocation?**

A. Gulf's generation costs occur throughout the year. There are four methodologies presented in this case: 12-MCP and 1/13, Near Peak, Equivalent Peaker, and Refined Equivalent Peaker. Of these choices, the method which is most appropriate for Gulf, considering Gulf's load shape and other considerations previously mentioned, is definitely 12-MCP and 1/13. This method is the most sound and will continue to provide the stable, consistent price signals to which Gulf's customers are accustomed and which they expect to see. The 12-MCP methodology is a widely used and accepted methodology throughout our industry. The other methods are either inappropriate (Near Peak) or possess far too many flaws to warrant a departure from the current methodology.

Q. **If a choice had to be made between Equivalent Peaker and Refined Equivalent Peaker, which alternative should be chosen?**

A. Before answering this, let me point out a few implementation problems. First, both of these concepts are relatively new. As a result their stability and acceptability is still suspect. Obviously in order to become accepted, any new concept must be subjected to careful analysis and review. However, this is not the time to test a new cost-of-service methodology on Gulf's customers, given the other major issues in this case.

In fact, even if one of these procedures were required, some type of adjustment period would only be fair to Gulf's customers. Gulf's customers have been told through price signals for over 50 years that they should flatten their load shape, increase KWH usage in off-peak times and reduce peak KW. Either of these two techniques, especially the Equivalent Peaker method, would tell Gulf' customers that KWH growth is bad and there will be more allocation of cost as a result, while KW growth isn't so bad after all. Even if this is justifiable due to an evolution in our dynamic utility system and the costing models that attempt to track it, our customers cannot be expected to adapt overnight. They, over the years, have purchased equipment to match the price signals we have sent them. They would be sorely shocked by an immediate adoption of Equivalent Peaker.

However, if one had to choose between EP versus Refined EP, the best or least undesirable alternative would be Refined EP. It presents fewer flaws than the EP. However, the filed REP study should be re-examined to determine the correct demand allocator for the equivalent peaking cost and the question of a possible fuel cost adjustment should be researched.

ALLOCATION OF INVESTMENT IN LINES

Q. On page 32 of Public Counsel's witness Scheffel Wright's testimony, he states "the company should estimate the rate base value of primary and higher voltage-level conductor that functions as dedicated distribution facilities, or as a higher voltage service drop, and directly assign these estimated amounts to the classes that include the customers who are served by these facilities." Do you agree?

A. No. To examine this question more clearly, we must visualize Gulf's electrical delivery system whereby there is a network of interconnecting lines transmitting electricity around the system at predetermined, reliable voltage levels. From this network, taps branch off to serve load centers. As a result, all related customers are allocated an average portion of the network and taps according to the loads they place on the system.

Account 369-Services contains secondary service drops which must be installed to serve a customer at a secondary distribution no matter what his load requirements. It is, therefore, allocated upon number of customers. Line investment cost found within other FERC accounts is sized according to anticipated load requirements and, therefore, allocated upon demand. Gulf has never assigned line investment cost to specific customers. Some of the primary reasons are:

1. It would be very difficult to determine the line investment specifically serving one particular customer. Some very large customers might prove traceable but, if one accepted this methodology for a few large customers, it would only be equitable to do so for smaller customers. These smaller customers would be most onerous to trace.
2. If one did assign so called "dedicated taps," one would have to first determine the total investment in taps, segregate it from investment in networks and then remove dedicated ones leaving "common taps." The common taps would then be allocated to common customers only. To do otherwise would risk associating taps with these dedicated customers twice, once through the assignment process and second, through the allocation process.
3. A further delineation of load flow would prove necessary. The load from customers served by common taps would be placed into a demand allocator for the cost of common taps. Then, the load for these common customers must be combined with the load from

customers using dedicated taps in order to produce an allocator for the common network.

4. A tap serving one customer today may serve two or more customers tomorrow. Gulf does not generally incur large investments in lines designed to specifically serve one customer over the entire life of the line. What originally began as a line serving one customer may have new customers added to the line. Also, the line may become a closed loop which would serve many more customers. Given these possibilities, an annual review of dedicated taps would be required.

5. Where does the dedicated tap begin? Can this beginning point change as customers are added?

6. Not only would the accounting and load flows segregation be most difficult, but the cost of service model could require extensive revisions.

7. All the required effort would result in insignificant effects on the cost-of-service results. It is estimated that only 2 percent to 4 percent of lines investment would prove to be dedicated at a particular point in time. Due to the difficulty of ascertaining the specific cost of these facilities and the required annual updates, it is not certain that the results of the cost of service study would

be any more accurate at any decimal level even if one could perform this most difficult task. Mr. Howell discusses the system planning aspects of direct assignment of taps and gives a real example of why Mr. Wright's concept of dedicated taps is not appropriate for a utility such as Gulf.

ALLOCATION OF PLANT SCHERER

Q. Do you agree with Dr. Johnson's statement that Plant Scherer should be considered a surcharge?

A. No. I do not. Plant Scherer is definitely considered a production resource during the 1990 test period for the reasons fully explained by Messers. Parsons, Scarbrough, and Howell. As such, its allocation on a production allocator is entirely appropriate.

Q. If it were to be considered a surcharge, should it be allocated upon revenues?

A. No. It should not. If it were deemed appropriate to consider it as a surcharge, the basic reason that it would be so placed is that it would become used and useful as generating resource in the future. When it then did become an acknowledged production resource in the future, surely it would receive a production type of allocation.

Although it is not entirely clear, I presume Dr. Johnson is advocating the isolation of Plant Scherer's cost and the allocation of this cost in the cost of service study upon revenues. A revenue allocation, however, is actually an indirect allocation result of the cost of all services which have been allocated upon the direct allocators of KWH, KW, and number of customers. This revenue allocation result involves all functions of the utility: Production, Transmission, Distribution, Customer Accounting, and Customer Assistance. Plant Scherer is a production plant and to utilize an allocator also influenced by transmission, distribution, customer accounting, and customer assistance is illogical and certainly not cost based.

In addition, a cost-benefit inequity would result. If Plant Scherer were allocated in its early, more expensive years upon revenues, and during its cheaper, depreciated years upon a production allocator when its resource benefits were being enjoyed, we would have customers who were strongly affected by transmission, distribution, customer accounting, and customer assistance, paying for Plant Scherer but failing to enjoy commensurate benefits of the cheaper resource cost when it was deemed used and useful due to the same customers' smaller sensitivity to pure production allocation. To create this cost-benefit inequity would be incongruous and senseless. Plant Scherer is a production plant today, tomorrow, and until it is retired.

VOLTAGE DIFFERENTIATED RATES

Q. What is your opinion on voltage differentiated rates?

A. I do not disagree with the theoretical concept of voltage differentiated rates. In fact, Gulf currently has voltage differentiated rates and is proposing a cost based transformation discount in this docket.

Q. Do you concur with Dr. Johnson's voltage differentiated rates?

A. I do believe that if possible they should be cost based. Unfortunately, Dr. Johnson's procedure is not cost based in terms of unit cost. It would produce a discount, but that discount could be above or below what the true cost based discount should be.

Q. Can you elaborate further on this distinction between Dr. Johnson's procedure and a pure unit cost method?

A. His procedure appears to depend upon a factor which contains two ingredients: (1) The numerator represents his cost of serving the customers as they exist in the rate class from the uppermost voltage level down through the voltage level in question, and (2) the denominator reflects the total cost to serve all customers as they exist in the rate class, or as he terms it on his direct testimony, page 18, line 13, the average cost of LP/LPT service. So, in effect what we are dealing with is the cost of serving various loads at different voltage levels which is somewhat different from the cost of serving the same load at two different service levels. In order to base a discount on pure unit cost, one needs to determine the cost to serve a KW at level 5 and the cost to serve that same KW at level 2. The difference can then be used to accurately develop the discount.

Q. What is your recommendation?

A. If this Commission decides to implement voltage level differentiated rates for LP/LPT, implementation should be based upon a cumulative unit cost analysis which properly considers the cost differentials involved in serving separate voltage levels.

TRANSFORMATION DISCOUNTS

Q. Do you agree with Dr. Johnson that a transformation discount is warranted?

A. There is nothing wrong with a transformation discount where customers have purchased their own transformers. However, if one is advocating voltage differentiated rates, as he apparently is, one should not also give a transformation discount. This would provide a credit twice for the avoided transformation cost, since the discount would already have been embedded in the discounted voltage differentiated rates in this instance.

Q. Is there a discount developed in this rate proceeding that reflects the cost to Gulf Power Company of transformation equipment?

A. Yes. Gulf's responses to Interrogatories No. 110 and No. 111 of Staff's Eighth Set in this docket provide a discount for transformation cost. These discounts by rate class and by voltage level for customer owned transformation are shown below:

	Primary	Transmission
GSD/GSDT	$0.35/KW	$0.41/KW
LP/LPT	$0.42/KW	$0.52/KW
PX/PXT	N/A	$0.11/KW

In addition, in Interrogatory No. 113 of Staff's Eighth Set the following discounts were developed for metering voltage discounts to account for the reduction in line and transformation losses as a result of the customer taking service above the secondary distribution level. These discounts by rate class and by voltage level for customer owned transformation are shown below:

GSD/GSDT & LP/LPT	Primary	Transmission
Energy Discount	.82%	1.8313%
Demand Discount	1.26%	2.632%
PX/PXT		
Demand Discount		1.35531%
Energy Discount		1.00312%

Q. Does this conclude your rebuttal testimony?

A. Yes. It does.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 891345-EI

Before me the undersigned authority, personally appeared Michael T. O'Sheasy, who being first duly sworn, deposes and says that he/she is the Senior Engineer of Gulf Power Company and that the foregoing is true and correct to the best of his/her knowledge, information and belief.

Michael T. O'Sheasy

Sworn to and subscribed before me this 10th day of May, 1990.

Caralyn S. Phillips
Notary Public, State of Florida at Large

My Commission Expires: Notary Public, Dekalb County, Georgia
My Commission Expires Jan. 20, 1991