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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In The Matter of Application of GULF POWER COMPANY for an increase in rates and charges.	DOCKET NO. 891345-EI HEARING EIGHTH DAY MORNING SESSION

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Pages 2788 through 2995

FPSC Hearing Room 106
Fletcher Building
101 E. Gaines Street
Tallahassee, Florida 32399

Wednesday, June 20, 1990

Met pursuant to adjournment at 8:35 a.m.

BEFORE: COMMISSIONER MICHAEL McK. WILSON, CHAIRMAN
COMMISSIONER GERALD L. GUNTER
COMMISSIONER THOMAS M. BEARD
COMMISSIONER BETTY EASLEY

APPEARANCES:

(As heretofore noted.)

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I N D E X

WITNESSES

Index Continued:

EXHIBITS

Number:		Identified	Admitted
361	Through 380 (Pollock)	2794	

P R O C E E D I N G S

(Hearing reconvened at 8:35 a.m.)

MR. McWHIRTER: Mr. Chairman, our first witness today is Mr. Pollock. You have not been previously sworn, I don't believe.

WITNESS POLLOCK: No.

CHAIRMAN WILSON: Would you raise your right hand, please?

(Witness Pollock sworn.)

JEFFRY POLLOCK

was called as a witness on behalf of the Industrial Intervenors, Air Products and Chemicals, Inc., American Cyanamid Company, Champion International Corporation, Exxon Company, U.S.A., Monsanto Company, Stone Container Corporation, having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. McWHIRTER:

Q Mr. Pollock, as I understand it, you've previously filed testimony in this case, is that right?

A Yes.

Q And you had some corrections in that testimony. We have furnished the reporter with a copy of a revised edition and this morning on your dais you will see pages with corrected copy.

Would you point out to the Commission what the changes were in the testimony, please?

A Yes, I will. On the direct testimony at Page 16, I inserted a clarification because of some confusion that arised during interpretation of that particular passage. And specifically on Line 18 of that page, which reads, "The EP and REP methods, however, would assign," and the old version said, "twice." The corrected version says, "about 1.5 times as much car," and then the parenthetical "(twice the 'excess' capital cost.) to the second customer."

And the other change is in the exhibit book, and specifically Schedule 2 has been revised. The calculation of the per unit capital cost assigned to the various classes under the Company's version of the refined equivalent peaker method was calculated incorrectly, and also omitted from the schedule was the rate SS, standby service, class data. And those have been corrected, and the rate SS class data added to the schedule. Specifically, the correction had to do with the fact that under the Company's version of the refined equivalent peaker, the demand costs were allocated on a 12 coincident peak basis. Consequently, it's appropriate to calculate the per unit plant costs on the basis of per unit of 12 coincident peak demand.

There are two other corrections that need to be made to the exhibit that are not contained in the additional sheets which were distributed. These are minor, however. Let me point them out. Schedule 3, Line 2, right now says, "Effective Forced Outage Rate." The correct term should be "Equivalent Forced Outage Rate."

Schedule 4, at the very bottom of the page in the footnote, the very last line says, "where FOR," which is forced outage rates, "of a peaker equals" and the number was mistyped. Instead of "30%," it should be "50%."

The other change which was in your handout is Schedule 8, Page 1. The presentation on that schedule was modified to include the rate SS class. There was some confusion about whether under the near coincident peak cost of service study, which I'm sponsoring, whether or not the standby service class was assigned any demand-related costs, and it turns out they were. It's just that the data was not shown on the schedule.

The last two changes are in the appendix book, specifically in Appendix C, specifically Page 6, Lines 23 and 24 have been revised to match the text -- the

text has been revised to match the table.
And similarly on Page 7, the text was changed to compare -- show the derivation of the operating cost to the GS/GST class.
And that's the extent of the changes.
MR. McWHIRTER: Mr. Chairman, I offer the testimony into evidence as though read and corrected.
CHAIRMAN WILSON: The prefiled testimony, as corrected, will be inserted into the record as though read.
(Exhibit Nos. 361 through 380 previously stipulated into the record.)

GULF POWER COMPANY

before the

Florida Public Service Commission

Docket No. 891345-EI

Testimony of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock, 12312 Olive Boulevard, St. Louis, Missouri.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and am a principal in the firm of Drazen-Brubaker & Associates, Inc., utility rate and economic consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This is summarized in Appendix A to the testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS DOCKET?

A I am appearing on behalf of the a group of Industrial Intervenors, as follows:

- Air Products and Chemicals, Inc.
- American Cyanamid Company
- Champion International Corporation
- Exxon Company, U.S.A.
- Monsanto Company
- Stone Container Corporation

These Intervenors are customers of Gulf Power Company. During 1989, these six companies purchased 978,000,000 kilowatthours, approximately 13% of Gulf's total retail sales. All six companies are served on Rate PXT. Several of the Intervenors also take service on Rate SS.

Q **WHAT ISSUES ARE YOU ADDRESSING?**

A I shall address various cost allocation and rate design issues, including:

(1) Production costing methodology;

(2) Transmission costing methodology;

(3) Classification of distribution capital costs;

(4) The distribution of the proposed base rate increase among the rate classes (i.e., rate spread); and

(5) The design of Rates PX/PXT and SS.

Q **ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR TESTIMONY?**

A I am submitting Exhibit JP-1 (361), consisting of seventeen schedules. The analysis presented in these schedules is based on Gulf's corrected and revised class cost-of-service study provided in response to Industrial Intervenors' Second Request for Production of Documents. This latest study incorporates the corrections to the original filed study (as provided in response to FEA's Second Set of Interrogatories, Question No. 16), and the "without migration" scenario.

Q WHAT OTHER MATERIALS ARE YOU SUBMITTING AT THIS TIME IN CONNECTION WITH YOUR COST-OF-SERVICE AND RATE DESIGN TESTIMONY?

A I am also submitting Appendices B and C to the testimony.

Appendix B is a narrative entitled "Cost-of-Service Determination Procedures." It provides an overview of the three basic phases of a rate case; a closer look at the various cost-of-service steps (i.e., functionalization, classification and allocation); and explains the reasons why the cost per kilowatthour is lower for industrial customers than for other customers.

Appendix C is a critique of the Equivalent Peaker (EP) methods of costing. Specifically, it addresses the lack of "fuel symmetry" with the original and revised EP methods and the implicit (and incorrect) assumption (in the original EP) that annual kWh sales determine the type of capacity to be installed.

Q IS THE FACT THAT YOUR TESTIMONY ADDRESSES COST ALLOCATION AND RATE DESIGN ISSUES AN ENDORSEMENT OF GULF'S CLAIMED $26.1 MILLION REVENUE DEFICIENCY?

A No.

COST ALLOCATION ISSUES

Q **BEFORE ADDRESSING THE VARIOUS COST ALLOCATION ISSUES, COULD YOU PLEASE EXPLAIN HOW A CLASS COST-OF-SERVICE STUDY IS PREPARED?**

A The basic procedure is simple, although the amount of detail can obscure this simplicity. In an allocated cost-of-service study, we identify the different types of cost (functionalization), determine their primary causative factors (classification), and then apportion each item of cost among the various rate classes (allocation). Adding up the individual pieces give the total cost for each class. A more detailed explanation is provided in Appendix B.

Q **IS THE COST-OF-SERVICE FRAMEWORK DESCRIBED IN APPENDIX B USED THROUGHOUT THE UTILITY INDUSTRY?**

A Yes. In fact, every logical cost analysis must use these procedures of functionalizing costs (into generation, transmission, distribution and so on), classifying them (into demand-related, energy-related and customer-related) and allocating them among classes. There can, of course, be differences in format, but the basic framework is always the same.

Q **DOES THE APPLICATION OF THESE GENERAL COSTING PRINCIPLES RESULT IN DIFFERENCES IN THE PER UNIT COST OF SERVING THE VARIOUS TYPES OF CUSTOMERS?**

A Yes. Large users are less costly to serve because of the differences in (1) load factor, (2) delivery voltage, and (3) size. Further, the process of delivering electricity to residences is more involved than the process of delivering electricity to industry, because it requires substantially more distribution plant to provide service at the point of consumption. Many industries, by comparison, provide their own (in-house) distribution facilities. The significance of these differences is that costs cannot simply be allocated on the basis of kilowatthours sold. The per unit cost is lower as service is taken at higher voltage levels and as customer size and load factor increase. Because large users tend to be served at higher voltages, consume more energy per location and use their capacity more efficiently (e.g., operate at a higher load factor) than small users, it follows that the per unit cost is also lower. This lower per unit cost justifies a lower per unit rate, a fact which is demonstrated on Page 14 of Appendix B (Table 5).

PRODUCTION COSTING METHODOLOGY

Q **WHAT ISSUES NEED TO BE ADDRESSED IN DETERMINING AN APPROPRIATE PRODUCTION COSTING METHODOLOGY?**

A Production costs can be separated into two major components: capital costs and operating costs.

Capital costs are related to the specific facilities that are used and useful in providing service at the point of consumption to satisfy the customers demand and energy requirements. They include:

- Return on investment;
- Fixed operation and maintenance (O&M) expenses;
- Depreciation expense; and
- Related income and other taxes (e.g., ad valorem, payroll, etc.).

Operating costs consist primarily of fuel and variable O&M expense. Unlike capital costs, operating costs generally vary with the amount of energy generated and sold.

An appropriate production costing methodology, thus, must consider how both capital and operating costs should be classified and then allocated to retail customer classes.

Q ONE THEORY OF PRODUCTION COSTING THAT HAS BEEN PROPOSED FROM TIME-TO-TIME IS BASED ON THE NOTION THAT AN APPROPRIATE METHODOLOGY SHOULD PARALLEL THE SYSTEM PLANNING PROCESS. IS THIS A VALID THEORY?

A Yes. Consistent with the principal of cost-causation, to the extent that production system planning criteria can be integrated into the cost classification and allocation process, it would result in an assignment of costs that would reflect the extent to which each class caused the utility to incur the cost. Because production system planners consider total (capital and operating) costs in evaluating capacity additions/retirements, etc., a production costing methodology must consider both capital and operating costs.

Q **HAVE ANY SUCH "SYSTEM PLANNING"-ORIENTED COSTING METHODS BEEN PRESENTED TO THIS COMMISSION?**

A Yes. Both the Equivalent Peaker (EP) and the Refined Equivalent Peaker (REP) methods purportedly emulate the utility system planning process.

These methods postulate that:

- Only the production capital costs equivalent to the cost of peaking capacity are demand-related; and

- The only justification for investing in more expensive types of generating capacity is to reduce fuel cost.

The above postulates are based on the theory of Capital Substitution (or CAPSUB). Under this theory, the utility is said to "substitute" capital investment for fuel cost--for example, by building a coal-fired base load plant instead of a combustion turbine peaking plant.

Q **HOW DOES THE EP METHOD ATTEMPT TO EMULATE THE PRODUCTION SYSTEM PLANNING PROCESS?**

A The EP method classifies production capital costs between demand and energy. The demand component is usually represented by the equivalent cost of peaking capacity. In other words, Gulf's generating capacity is revalued as though only peaking units were built instead of the various base load and intermediate units which actually exist. The *extra* capital costs (that is, the actual investment in excess of the cost of an equivalent amount of peaking capacity) are considered to be energy-related because they, allegedly, are incurred as a "tradeoff" for the lower cost of operating base load units.

Q **HOW ARE PRODUCTION CAPITAL COSTS ALLOCATED TO CLASSES UNDER THE EP METHOD?**

A In Gulf's response to Staff's first Set of Interrogatories, Item Nos. 1 and 2, demand-related production capital costs were allocated to classes using the Twelve Coincident Peak method. The remaining energy-related capital costs were allocated relative to "year-round" energy requirements.

Q **DOES THE EP METHOD ACCURATELY EMULATE THE PRODUCTION SYSTEM PLANNING PROCESS?**

A No. At best, it is an oversimplification of the system planning process. In reality, planners are faced with the dual dimensions of (1) providing reliable service and (2) minimizing total cost. Because electric energy cannot be stored in large quantities for any significant length of time, providing reliable service requires construction of sufficient generating capacity to meet the projected system peak demands and to provide an adequate reserve margin. This will ensure that whenever a consumer flips the switch an electric light or air conditioner will operate. Consumers often take it for granted that electricity will be instantaneously available whenever and at whatever rate of usage and quantity they demand.

Cost minimization is the requirement that the utility provide the service at the lowest overall cost. The utility strives to install the mix of generating capacity (i.e., base, intermediate and peaking) that, along with the existing generation, yields the lowest total cost. **In other words, the economic choice between a base load plant and a peaking plant must consider both capital costs and operating costs, and therefore is a function of average *total* costs.**

The capital cost of peaking plants is lower than the capital cost of base load plants, but the operating costs of peaking plants are higher than the operating costs of base load plants. Moreover, when the hours of use are considered, the capital cost per kilowatthour for the base load plant is usually less than the capital cost per kilowatthour for the peaking plant. Of course, since the fuel costs of base load plants are generally lower than the fuel costs of peaking plants, the overall cost per kilowatthour for base load plants is also less than the overall cost per kilowatthour for peaking plants.

System planners, therefore, must consider both capital costs and operating costs in light of the expected capacity factor of a new plant. **The fact that base load plants typically have lower fuel costs than peaking plants does not mean that the investment in base load plants is made strictly to achieve lower fuel costs.** Investment in a base load plant would be made to achieve lower total costs, of which capital costs <u>and</u> operating costs are the primary ingredients.

Q ARE THERE ANY OTHER FACTORS, BESIDES THE ECONOMIC TRADE-OFFS, THAT CAN AFFECT UTILITY INVESTMENT DECISIONS?

A Yes. For example, the decision can be affected by the existing generation mix, the availability of a suitable site for the plant, environmental restrictions, access to an ample supply of cooling water, the ability to obtain transmission rights of way, system stability, licensing, government and other regulatory restrictions (i.e., Fuel Use Act), fuel supply, fuel diversification, access to facilities to transport fuel to the plant, political priorities, etc.

Q ARE THERE OTHER REASONS--BESIDES THE CAPITAL/OPERATING COST TRADE-OFFS--FOR INSTALLING PEAKING PLANTS?

A Yes. One reason would be to provide the ability to ride through short-term peaks without starting-up additional base load units. Peaking capacity can be a source of emergency power in the event of large and unexpected forced outages, and it is available to provide start-up power for base load units. Further, the ability to place peaking units in service with a short lead time would enable a utility to meet unexpected increases in peak load. Each of these reasons were substantial in a publication entitled <u>Gas Turbine Electric Plant Construction Cost and Annual Production Expenses</u>--1978:

> "In recent years there has been a relatively rapid increase in the use of gas turbines for electric power generation. The northeast power failure of November 1965 provided the initial impetus for the present extensive use of gas turbines for a variety of

electric power generation requirements. A relatively common deficiency uncovered by the northeast failure was the lack of emergency power for start-up, continued operation, and safe shut down of steam electric generating units during power failures, and for the subsequent restarting of the units when system power is not available. Also, because of the short lead time for manufacture and installation of gas turbines, many electric utilities have installed substantial amounts of such capacity to offset delays in the completion of desired generation, and to meet unexpected increases in load. Too, many systems which have traditionally increased capacity by installing efficient base load units are finding that overall system economy can sometimes be improved by including low cost peaking units in their generating capacity expansion programs."

Q **DOES THE OBSERVATION THAT THE CAPITAL COST OF NEW BASE LOAD UNITS MAY BE HIGHER THAN THE CAPITAL COST OF PEAKING CAPACITY NECESSARILY MEAN THAT THESE HIGHER COSTS WERE INCURRED TO SAVE OPERATING COSTS?**

A No. The fact that the capital cost of new base load units, in retrospect, may turn out to be significantly more expensive than the capital cost of a peaking unit does not necessarily mean that these higher costs were incurred to save operating costs. The differences in capital cost that we now observe are relatively recent phenomenon, resulting from a variety of factors that have little to do with the inherent economics of generating plants. For example, the Plant Daniel Units were installed in 1977 and 1981, respectively, at an average cost of $374 per kW. According to the EPRI _Technical Assessment Guide_, dated May, 1982, a combustion turbine plant could have been built in 1980 at an installed cost of over $200 per kW. Thus, the cost differential between coal and peaking units used to be less than $200 per kW. Today, the cost differential may be more than $1,000 per kW. In particular, many base load plants completed in recent years have shown higher capital costs because of delays and cost overruns that had nothing do to with the objective of obtaining lower cost energy. Therefore, it is wrong to assume that observed differences in capital costs are always the result of conscious decisions to spend more per kW in order to achieve lower operating costs.

Q **DO THE EP AND REP METHODS ALLOCATE THE SAME MIX OF CAPACITY (I.E., A SLICE-OF-THE SYSTEM) TO EACH RATE CLASS?**

A No. The EP method allocates a large portion of production capital costs on year-round energy. This assigns a larger portion of base load plant (and a correspondingly smaller portion of peaking plant) to high load factor customers. Customers with low load factors, conversely, are allocated a smaller portion of base load plant and a large portion of peaking plant.

Q **UNDER THE EP AND REP METHODS, IS THERE ANY ATTEMPT TO REALLOCATE PRODUCTION OPERATING COSTS CONSISTENT WITH THE ASSUMED CAPITAL/OPERATING COST TRADEOFFS IMPLICIT IN CLASSIFYING PRODUCTION CAPITAL COSTS UNDER THE EP AND REP METHODS?**

A No. Typically, and in the response to Staff's First Set of Interrogatories, operating costs--of which fuel is a primary component--are allocated to the classes in a traditional manner; that is, based on "year-round" energy requirements. This is tantamount to assuming that each rate class is served from the same mix of base load and peaking energy. Thus, from an operating cost perspective, each class is allocated a "slice-of-the system."

Because the EP and REP methods differentiate between the capacity mix but not the energy mix required to serve both high and low load factor customers, both fail to appropriately recognize the tradeoffs between capital costs and operating costs. This flaw is often referred to as the "Fuel Symmetry" problem.

Q **IF CUSTOMER CLASSES ARE ASSUMED TO BE SERVED FROM A DIFFERENT CAPACITY MIX, DOES IT ALSO FOLLOW THAT THE ENERGY MIX MUST ALSO BE DIFFERENT?**

A Yes. Appendix C demonstrates that differences in the capacity mix also imply differences in the energy mix. The lowest cost system to serve to Rate PX/PXT class, for example, would consist of 94% base load capacity and 99.8% base load energy. The optimum total Company base load capacity and generation mix would be 71% and 96.1%, respectively.

Q **WHAT IS THE SIGNIFICANCE OF THE DIFFERENCES BETWEEN THE OPTIMUM CAPACITY AND ENERGY MIX TO SERVE THE VARIOUS RATE CLASSES?**

A The significance is that if a lower load factor class is to be assigned below-average production capital costs (expressed on a per kW basis) because of the lower mix of base load capacity required to serve this class, then it should also be assigned above-average production operating costs (expressed on a per kWh basis) to reflect the larger share of peaking energy associated with the greater assignment of peaking capacity. Similarly, if a high load factor class is to be assigned above-average capital costs (because of the larger share of base load capacity required to serve this class) then it follows that this class should also be assigned a below-average operating cost to recognize the relatively larger share of base load energy providing service to this class.

Q **DO EITHER THE EP OR REP METHODS RECOGNIZE THE DIFFERENCES IN THE PER UNIT OPERATING COSTS TO SERVE THE VARIOUS CUSTOMER CLASSES CAUSED BY THE CORRESPONDING DIFFERENCES IN THE GENERATION CAPACITY MIX?**

A No. The EP and REP methods are simply a procedure for allocating production capital costs. Operating costs are allocated on a "slice-of-the system" approach. A "slice-of-the system" approach, however, assumes that all classes are served from the same mix of technologies. In other words, there is no difference between the generation mix to serve high and low load factor customers. Neither method, consequently, is consistent with the stated rationale and philosophy underlying the allocation of production capital costs, the result of which is to assign a different capacity mix to serve high and low load factor customers.

To give an analogy, suppose that two different customers are required to rent a fleet of cars and that there are two types of cars. One type has a high fixed charge per day and gets many miles to the gallon (analogous to a base load plant), while the other type has a low fixed charge per day but gets poor mileage (analogous to a peaking plant). Both the EP and REP methods argue that a customer who drives his/her car only a few miles a day (a low load factor customer) should be allocated more gas-guzzlers and fewer of the more efficient cars, with the opposite type of allocation for the customer that will put in many miles per day (a high load factor customer). While recognizing that the low load factor customer will pay a lower per day charge for his/her car than the higher load factor customer, neither the EP nor the REP methods recognize that the lower load factor customer should also incur a higher fuel cost per mile driven then the higher load factor customer.

Q IS THERE A SECOND MAJOR CONCEPTUAL FLAW WITH THE EP METHOD?

A Yes. When a utility determines the type of generating capacity it will install in order to minimize costs, it will examine how many hours the new unit can be expected to run. If the unit is expected to run beyond a certain point, called the break-even point, it is more economical to install base load capacity rather than peaking capacity. In other words, once the break-even threshold is reached, additional energy use (and the fuel cost savings resulting therefrom) would not affect the investment decision.

The conceptual flaw with the EP method, therefore, is the assumption that all hours of the year cause a utility to incur the extra capital costs of installing a base load unit. This is at odds with the planning process. <u>All</u> production from a plant is not the critical factor in deciding which type of capacity to install. Once a plant is expected to run beyond the break-even point, all additional generation is irrelevant to the investment. Therefore, load duration may influence capital investment decisions, but only up to a precisely determined point. It would be an abandonment of the logic underlying the EP method to allocate a major portion of production capital costs to all 8,760 hours per year.

Consider again the analogy with the cars that get different miles per gallon. Suppose that the break-even point were 100 miles; that is, the high mileage car has a lower total cost per mile if operated more than 100 miles. If one customer were to drive the car 200 miles and the second customer were to drive the car 400 miles, both customers would choose the same car--the more efficient one. The EP and REP methods, however, would assign about 1.5 times as much car (twice the "excess" capital cost) to the second customer.

Q **DOESN'T THE SECOND CUSTOMER GET TWICE AS MUCH BENEFIT FROM THE INCREASED FUEL EFFICIENCY AS THE FIRST CUSTOMER?**

A That is true, but an appropriate allocation method should be based on <u>cost-causation</u>, not benefit. Consider for instance, the example of the two rental car customers that I mentioned previously.

Despite the difference in benefits received, both customers would pay the same dollar per day charge.

Q DOES THE REP METHOD ALSO SUFFER FROM THE SAME LEAP OF LOGIC?

A No. A critical difference between the EP and REP methods is that, unlike the EP method, the REP method allocates the extra capital costs relative to each class' contribution to only the break-even hours. According to Gulf's response to the Staff Interrogatory No. 2, the break-even point was 1,430 hours.

Q ARE YOU SAYING THAT THE REP METHOD AS PRESENTED IN THE RESPONSE TO THE STAFF'S INTERROGATORY APPROPRIATELY REFLECTS PRODUCTION SYSTEM PLANNING CRITERIA?

A No, it is a decided improvement, but there are still several serious conceptual flaws in the REP method as presented in Gulf's response to the Staff Interrogatory.

First, the 12CP method was used to allocate the demand-related capital costs. As I shall demonstrate later, the 12CP method is inappropriate for the Gulf Power system because it sends the wrong price signals to customers. Further, as demonstrated in Exhibit JP-1 (361), Schedule 1, it is inconsistent with the allocation of the extra (nondemand-related) production capital cost.

Q PLEASE EXPLAIN THE INCONSISTENCY.

A Exhibit JP-1 (361), Schedule 1, is Gulf's total system load duration curve for the test year. The load duration curve is shown by the blue line. Also shown are the highest 1,430 hours (the red-shaded area) and the occurrence of each of the twelve monthly system peak demands (the black squares and vertical lines). During the test year, five of the monthly peaks would occur beyond the 1,430 hour break-even point derived by Gulf. Thus, Schedule 1 clearly demonstrates that demand-related capital costs (which are related to peaking capacity) would be allocated relative to loads occurring beyond the break-even threshold. This is inconsistent with the definition of cost-causation under the REP method because the loads beyond the 1,430 break-even threshold neither cause Gulf to install peaking capacity, nor do they cause the Company to invest in base load generating capacity. It was previously demonstrated, in Appendix C, that the loads up to the break-even point would, at most, affect the type of generating capacity that is most cost-effective in providing service. Further, Gulf could not satisfy its projected 1,743 MW summer peak demand if it only had 1,362 MW (i.e., the average of the twelve monthly peak demands) of installed capacity. The amount of capacity required to maintain reliable service, thus, is a function of the system peak, and not the 12 P, demand.

Q **WHAT IS THE SECOND REMAINING FLAW WITH THE REP METHOD?**

A As I previously testified, the REP method is incomplete because it--like the EP--fails to carry the capital/operating cost tradeoffs through to their logical conclusion. Under the REP method, higher load factor customer classes are allocated above-average capital costs, while lower load factor customer classes are allocated below-average capital costs. This is shown in Exhibit JP-1 (362), Schedule 2, Columns 1 through 4. However, as also shown in this schedule, in Columns 5 through 8, both high load factor and low load factor customer classes are allocated *average* operating costs. In other words, the REP method "de-averages" the allocation of capital costs (by assigning a larger share of expensive base load capacity to high load factor customers), but it fails to similarly "de-average" the allocation of operating costs (so as to assign to high load factor customers a larger share of the lower fuel costs of that expensive capacity). As demonstrated in Appendix C, the failure to also "de-average" the operating costs is contrary to the Capital Substitution theory on which both the EP and REP methods are founded.

Q **ARE THERE ANY OTHER PROBLEMS WITH THE REP METHOD?**

A Yes. The REP method assumes that a utility relying solely on peaking capacity to serve its peak demands would install the same amount of capacity as a utility that typically employs a mix of base load and peaking capacity to provide continuous service during the peak period. In other words, 1 kW of peaking capacity is assuming to be equivalent to 1 kW of base load capacity.

Q IS IT REASONABLE TO ASSUME THAT 1 KW OF PEAKING CAPACITY WOULD BE EQUIVALENT TO 1 KW OF BASE LOAD CAPACITY?

A No. This assumption fails to take into account the reality that there is a wide difference in reliability between base load coal-fired units and those generating technologies that are typically used as peaking capacity.

To illustrate, Exhibit JP-1 (363), Schedule 3, is a comparison of the forced outage rates between base load coal-fired units and various types of peaking capacity. The data comes from the National Electric Reliability Council's Report entitled "Generation Availability Report." The reliability statistics shown are for the years 1984 through 1988.

Comparing the forced outage rates (FOR), base load coal-fired plants had an average forced outage rate of 6.9%. By contrast, the corresponding FORs for jet engines, gas turbines and diesel were 31.6%, 53.5% and 56.4%, respectively.

Gulf has had even worse experience with its Smith A combustion turbine. In five of the six years, this unit has operated between 1982 and 1989, Smith A had an FOR that exceeded 54%.

Given the substantially higher forced outage rates of peaking technologies, it follows that a utility would have to install considerably more peaking capacity to produce the same level of reliability of a utility system comprised of primarily base load capacity. In other words, there is no equivalence in the equivalent peaker.

Q IS THE EP METHOD PRONE TO THE SAME PROBLEM?

A Yes. The EP method also makes the same assumption that 1 kW of peaking capacity is equivalent to 1 kW of base load capacity.

Q HOW CAN THE EQUIVALENCE BE RESTORED TO THE EP AND REP METHODS?

A One approach would be to use a loss of load probability (LOLP) analysis to determine the amount of peaking capacity that would be required to provide the same degree of reliability as Gulf's existing system during the peak hours.

A more simplified approach would be to calculate the expected amount of capacity available at the time of the system peak based on the forced outage rate of the various generating technologies.

Q PLEASE EXPLAIN.

A Gulf presently has 2,134.5 MW of generating capacity. Assuming that, on average, Gulf's units each had a 6% forced outage rate, then the expected amount of capacity available at the time of the system peak would be 2,006.4 MW [2,134.5 MW x (100% - 6%)].

Now let's assume that all 2,134.5 MW of capacity were replaced by a series of 39.4 MW peaking units having a 50% forced outage rate. Based on this very realistic assumption, each unit could be expected to generate 19.7 MW [39.4 MW x (100% - 50%)] at the time of the system peak. Therefore, to obtain the equivalent amount of capacity as Gulf's existing system, it would have to install nearly 102 peaking units (2,006.4 MW ÷ 19.7 MW), or 4,012.8 MW of peaking capacity. Assuming an average cost of peaking capacity of $162 per kW (which is based on Gulf's response to Staff Interrogatory No. 1), the 4,012.8 MW of equivalent peaking capacity would cost about $650 million. Gulf's actual embedded cost of peaking capacity is $4.2 million. Therefore, the total cost of an equivalent amount of peaking capacity would be $654 million, or about 87% of Gulf's embedded production plant investment. (If Plant Scherer 3 were removed from the analysis, the ratio would be even higher.)

Thus, in this simplified illustration, at least 87%, rather than 45%, of Gulf's production investment should be classified to demand to restore the equivalence to the Equivalent Peaker method.

Q **WHAT WOULD BE THE CORRESPONDING RATIO UNDER THE REP METHOD?**

A Applying a similar approach to Gulf's response to Staff Interrogatory No. 1, Page 4, would result in classifying 77% of Production Plant to demand (instead of only 40% in the interrogatory response). This result is derived in Exhibit JP-1 (364), Schedule 4.

TRANSMISSION COSTING METHODOLOGY

Q SHOULD TRANSMISSION CAPITAL COSTS BE CLASSIFIED TO DEMAND?

A Yes. In order to maintain nearly continuous service, a utility must have sufficient transmission capacity to meet the projected peak demand. Unlike production plant, however, there is no choice between different technologies (i.e., peaking versus base load units, etc.). The cost of a transmission line or substation is not affected by whether it is used to connect a base load plant or a combustion turbine to the system. Similarly, the utility will typically have a significant capital investment in the switchyard facilities and associated protective equipment just to connect the generating station to the transmission grid. The need for these facilities not only is independent of the type of fuel burned in the generating plant, but it is independent of the plant location.

Q **DOES TRANSMISSION PLANT SERVE ANY OTHER FUNCTION BESIDES DELIVERING THE OUTPUT OF THE GENERATING PLANT INTO THE SYSTEM?**

A Yes. There are significant transmission facilities which interconnect Gulf with other utility systems. These interconnections help to improve system reliability by providing alternative transmission paths and by enabling Gulf to call upon the capacity resources of other utilities, either to provide the necessary operating reserves or to replace Gulf-owned generation during periods of scheduled and forced outages.

In summary, classifying transmission capital costs to demand is consistent with the realities of planning and operating a transmission system.

RECOMMENDED ALLOCATION OF PRODUCTION AND TRANSMISSION CAPITAL COSTS

Q **WHAT CRITERIA SHOULD BE USED TO DETERMINE AN APPROPRIATE DEMAND ALLOCATION METHOD?**

A The specific demand allocation method should reflect the load characteristics of the utility. If, for example, a utility has a high summer peak relative to the demands in other seasons, then the responsibility for production and transmission costs should be based on each customer class's contribution to that system peak (or peaks). If a utility has predominant peaks in both the summer and winter periods, then an appropriate allocation method would be based on the coincident demands during both the summer and winter peaks. For a utility having a relatively high load factor and/or nonseasonal load pattern, either the Twelve Coincident Peak or Average and Excess methods might be more appropriate.

Q **WHICH METHOD WOULD BE THE MOST APPROPRIATE FOR ALLOCATING PRODUCTION AND TRANSMISSION CAPITAL COSTS ON THE GULF SYSTEM?**

A A summer coincident peak method would be appropriate because--consistent with my analysis--it recognizes the predominant summer-peaking characteristic of the Gulf system. It also recognizes that the Southern Company--which is responsible for the joint development and coordination of electric operations, including decisions about scheduled maintenance outages--generally experiences its lowest reserve and capacity margins during the summer (peak) months. Thus, the demands imposed during the summer months determine the amount of capacity which must be installed to enable Gulf to provide nearly continuous service.

Q HAVE YOU ANALYZED GULF'S LOAD CHARACTERISTICS?

A Yes. Gulf is a summer-peaking utility, as shown in Exhibit JP-1 (365), Schedule 5.

Schedule 5, Page 1, shows the monthly peak demands as a percent of the annual system peak for the years 1984 through 1989. The monthly peaks are shown in blue. The peak months are denoted by the red/blue bars. The annual system peak is shown in red. Except for 1985 and the unusually cold winter of 1989, Gulf has had, and continues to have, a predominant summer peak. The summer peaks typically occur in the months June through September.

Gulf's predominant summer peak is further analyzed on Page 2 of Schedule 5. Page 2 shows the ratio of the annual system peak demand to the minimum monthly and average monthly peak. If the load pattern were nonseasonal, then these ratios would be close to 1.0. For Gulf, however, the maximum-to-minimum monthly peak has ranged from 1.47 to 1.83 times (Column 2). Similarly, the ratio of the maximum-to-average monthly peak has ranged from 1.18 to 1.29 times. Finally, Gulf's annual load factor (Column 4) has remained in the 50%-56% range. The predominant seasonal peak load characteristic coupled with a below-average load factor mean that the Twelve Coincident Peak (12CP) method of allocation--which virtually ignores seasonality--would be especially inappropriate for Gulf.

Q EARLIER, YOU TESTIFIED THAT THE SOUTHERN COMPANY IS RESPONSIBLE FOR THE JOINT DEVELOPMENT AND COORDINATION OF ELECTRIC OPERATIONS, INCLUDING THE DISPATCH OF GULF POWER'S GENERATING UNITS. DO GULF POWER AND THE SOUTHERN COMPANY HAVE SIMILAR LOAD PATTERNS?

A Yes, they do. Exhibit JP-1 (366), Schedule 6, is an analysis of the Southern Company monthly system peaks as a percent of the annual system peak. This analysis demonstrates that Southern's total system load pattern is also highly seasonal and that the annual system peak always occurs during the summer period. The peak demands during the nonsummer months are generally below 85% of the annual system peak. Further, based on the ratios presented on Page 2 of Schedule 6, it is apparent that the Southern system is even more predominantly summer-peaking than Gulf Power.

Q ARE THE DEMANDS DURING THE NONSUMMER MONTHS ALSO IMPORTANT BECAUSE OF THE NEED TO PERFORM SCHEDULED MAINTENANCE?

A In general, this proposition is not supported by the evidence. Exhibit JP-1 (367), Schedule 7, is an analysis of the monthly reserve margins of the Southern Company expressed as a percent of peak demand for the years 1984 through 1989. The reserves are shown in two ways: (1) before and (2) after planned and scheduled maintenance outages. The reserve margins before planned and scheduled maintenance outages are represented by the orange and blue bars. The orange portion of each bar denotes the portion of total reserve unavailable because of planned and scheduled maintenance outages.

The blue portion, therefore, represents the reserve margins after removing planned and scheduled maintenance outages.

The overall reserve margins (orange and blue bars) are demonstrably lower during the summer peak months, which are identified by the yellow line. Further, Southern schedules most of the planned and maintenance outages during the nonsummer period. This maximizes the availability of capacity during the more critical summer peak months.

Q **DOES THE FACT THAT THE BLUE BARS, ON OCCASION, ARE SMALLER DURING SELECTED NONSUMMER MONTHS MEAN THAT A SUMMER COINCIDENT PEAK METHOD IS NOT APPROPRIATE?**

A No, it does not. First, Southern has some discretion over the timing of these outages. It should be possible to coordinate planned outages with other Southeastern Electric Reliability Council (SERC) utilities. If a problem occurs, additional capacity could be made available from one of Southern's numerous interconnections. Second, because the SERC is also a summer-peaking system, other utilities are more likely to have surplus capacity during the nonsummer months than during the summer months.

Q **DO FORCED OUTAGES ALSO NEED TO BE TAKEN INTO ACCOUNT IN CONFIRMING THE APPROPRIATENESS OF A SUMMER COINCIDENT PEAK METHOD?**

A No, they do not. Unlike scheduled outages which are planned, forced outages are random events which generally occur when equipment malfunctions. The uncertainties of such outages and of the forecast load, coupled with the obligation to provide service upon demand, are precisely the reason why utilities must construct adequate generating capacity to meet the projected system peak and to provide an adequate reserve margin. Thus, no purpose would be served by measuring the reserve margins net of forced outages.

Q **SPECIFICALLY, WHAT DEMAND ALLOCATION METHOD ARE YOU RECOMMENDING IN THIS DOCKET?**

A I am recommending the "Near-Peak" method to allocate demand-related production and transmission capital costs. Under this method, demand cost responsibility is assigned to each customer class based on an average of the coincident peak demands during those hours when the system is "near" a peak. Thus, unlike the one, two, three and four CP methods, considerably more demand measurements are utilized in developing the allocation factors for each customer class.

Q **HOW ARE THE NEAR-PEAK DEMAND ALLOCATION FACTORS DERIVED?**

A The Near-Peak allocation factors were derived by summing the coincident demands of each customer class during those hours in which the total system demand was within 5% of the annual system peak. This is shown in Exhibit JP-1 (368), Schedule 8. (The hourly load data was provided in response to Industrial Intervenors' First Request for Production of Documents, Item No. 10.) As shown on Pages 2 and 3 of Schedule 8, there were 71 such occurrences during the test year which included the hours between 1:00 P.M. and 7:00 P.M. By contrast, the monthly peak demands (within 5% of the annual system peak) occurred at 5:00 P.M. By providing 71 measurements over a two-month period, the Near-Peak method covers a broader spectrum of hours than the other summer CP methods. This provides a more representative measurement of the coincident demands of the various classes during those hours when the system is in a "peaking mode." Further, because the allocation factors are not sensitive to the absolute timing of the monthly system peaks, the Near-Peak method would produce more stable results over time than would the other summer CP methods. Thus, it overcomes one of the frequent criticisms associated with peak responsibility allocation methods.

Q **WHAT IS THE BASIS FOR USING 5% AS THE THRESHOLD FOR DETERMINING WHEN THE SYSTEM IS NEAR THE PEAK?**

A It provides a more representative sample. Further, this is the period when system reliability is usually the most critical.

Q **ONE CRITICISM OF THE COINCIDENT PEAK METHOD IS THAT IT CREATES A "FREE RIDE" FOR OFF-PEAK LOADS, SUCH AS STREET LIGHTING. IS THIS A VALID REASON FOR REJECTING THIS METHOD?**

A No, it is not. Because costs are usually allocated to customer classes (and not to individual loads), it is unlikely that a CP method of allocation would create a free ride for any major firm customer class. Seldom is a class completely "on" during the off-peak hours and completely "off" during the on-peak hours. The only obvious exception would be the lighting classes. However, this is a small exception and, therefore, it should not control the selection of an appropriate demand cost allocation method to be applied to the remaining (and much larger) customer classes.

In summary, the Near-Peak method appropriately reflects cost-causation for Gulf, and it should be used to allocate both production and transmission capital costs.

Q SHOULD THE NEAR-PEAK METHOD BE APPLIED TO ALL PRODUCTION AND TRANSMISSION CAPITAL COSTS?

A Yes. Unless an explicit fuel symmetry adjustment were made to recognize the different energy mix implicit in classifying a portion of production capital cost to energy, my recommendation would be to use the near peak method to allocate all production and transmission capital costs. Further, my recommendation is consistent with the Commission's Fuel Adjustment mechanism in which each class pays the same average fuel cost. This procedure (i.e., classifying all production capital costs to demand and recovering average fuel costs) effectively assigns an identical mix of generation capacity and energy to each rate class. In essence, each class gets a "slice-of-the system" with respect to both capital and operating costs.

CRITIQUE OF THE 12CP METHOD

Q ARE THERE ANY OTHER PROBLEMS WITH USING THE 12CP METHOD TO ALLOCATE PRODUCTION DEMAND-RELATED CAPITAL COSTS?

A Yes, there are. 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 nonsummer period, the 12CP method is relatively insensitive to seasonal load shifts. As a result, the 12CP method could send the wrong price signal. To illustrate, Exhibit JP-1 (369), Schedule 9 is an illustration showing the impact of shifting load on the allocation factors derived under the 12CP method. For simplicity, it is assumed that the utility consists of two classes--Class "A" and Class "B". Both the utility and Class "A" are assumed to be summer-peaking. Class "B", by comparison, is assumed to have a constant demand throughout the year. Under the base case, the 12CP method would assign about 89% and 11% of capital costs to Class "A" and to Class "B", respectively.

Now let's assume that Class "B" shifts 10% (15 MW) of load from April to August. As a consequence, the utility becomes even more predominantly summer-peaking and may require additional capacity in order to maintain nearly continuous service. Despite the fact that Class "B" may be causing the need for additional capacity, the 12CP method allocates the same percentage of capital costs after the load shift as was allocated, under the base case, prior to the load shift. If the utility subsequently incurs higher capital costs, then these higher capital costs will be allocated, under the 12CP method, to both Class "A" and to Class "B" even though Class "B" caused the utility to incur these higher costs. This is further proof that the 12CP method is inappropriate for allocating demand-related capital costs, particularly for a utility system, like Gulf, which has a highly seasonal load pattern.

Q **WOULD THE USE OF THE 12CP METHOD BE JUSTIFIED BY THE FACT THAT THE CAPACITY EQUALIZATION CHARGES (OR CREDITS) UNDER THE INTERCOMPANY INTERCHANGE CONTRACT (IIC) ARE A FUNCTION OF THE MONTHLY PEAK DEMANDS OF THE FIVE SOUTHERN OPERATING COMPANIES, INCLUDING GULF?**

A No. First, it should be noted that the IIC is regulated by the Federal Energy Regulatory Commission (FERC). It would be inappropriate for the FERC (which regulates only a small portion of Gulf's operations) to dictate the manner in which production demand-related capital costs should be allocated among the retail customers classes subject to this Commission's jurisdiction.

Second, one of the main purposes of the IIC is to equalize <u>reserve</u> generating capacity among the five operating companies. By equalizing the reserves, the IIC maximizes the benefits derived from the joint planning and ownership of generating capacity.

Finally, it should be noted that the FERC does not allocate costs to "end-use" customer classes, as is the case with Gulf's class cost-of-service study in this Docket. Rather, the FERC uses a cost allocation method to provide a jurisdictional separation between retail and wholesale markets. Because the wholesale class typically consists of a mix of end-use customer groups, the results are usually much less sensitive to changes in the allocation method.

CLASSIFICATION AND ALLOCATION OF DISTRIBUTION CAPITAL COSTS

Q **HOW SHOULD DISTRIBUTION CAPITAL COSTS BE CLASSIFIED?**

A Distribution capital costs can be either demand-related and/or customer-related.

The primary purpose of the distribution system is to deliver power from the transmission grid to the customer, where it is eventually consumed. Certain investments (e.g., meters, service drops) must be made just to attach a customer to the system. These investments are customer-related. The remaining distribution investment is incurred to ensure that there is sufficient capacity to meet customer demands when they arise. This investment is demand-related.

Q **ARE CERTAIN DISTRIBUTION INVESTMENTS, OTHER THAN THE METER AND SERVICE DROP, ALSO CUSTOMER-RELATED?**

A Yes. A portion of the primary and secondary distribution network--poles, towers, fixtures, overhead lines, line transformers--is also customer-related. Classifying a portion of the distribution network as customer-related recognizes the reality that every utility must provide a path through which electricity can be delivered to each and every customer regardless of the peak demand or energy consumed. Further, that path must be in place if the utility is to meet its obligation to provide service upon demand.

If Gulf were to provide only a minimum amount of electric power to each customer, it would still have to construct nearly the same miles of line as is currently required to serve every customer. The poles, conductors and transformers would not need to be as large as they are now if every customer were supplied only a minimum level of service, but there is a definite limit to the size to which they could be reduced.

Q **HOW SHOULD THE CUSTOMER-RELATED PORTION OF THIS INVESTMENT BE DETERMINED?**

A This requires an engineering analysis. The customer-related portion is representative of the investment required simply to attach customers to the system, irrespective of their demand and energy requirements. Consider the diagram in Appendix B, Page 9. This shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A, a residential subdivision for example, is designed to serve the same load as the distribution feeder serving Class B, a large shopping center or small factory. Clearly, a much more extensive distribution system is required to attach a multitude of small customers than to attach a single larger customer, even though the total demand of each customer class is the same.

Q **IS IT COMMON PRACTICE TO CLASSIFY A PORTION OF THE DISTRIBUTION NETWORK AS CUSTOMER-RELATED?**

A Yes. Exhibit JP-1 (370), Schedule 10, demonstrates that this practice is widely recognized in the utility industry.

Page 1, for example, is an excerpt from the NARUC Cost Allocation manual, which shows the appropriateness of classifying a portion of the distribution network (i.e., Account Nos. 364 through 368) as customer-related.

Pages 2 through 4 are an excerpt from a survey conducted by Duke Power Company to evaluate the distribution costing practices used in the electric utility industry. This survey, which was based on responses received from 87 utilities, concluded that:

> "The accounts (364, 365, 366, 367, 368) which represent conductors and transformers investment are split approximately 70% demand and 30% customer. The remaining accounts (369, 370, 371, 373) are primarily customer-related."

Q **HAS GULF CLASSIFIED ANY DISTRIBUTION CAPITAL COSTS, OTHER THAN THE METER AND SERVICE DROP, AS CUSTOMER-RELATED?**

A Yes. Only 16.4% of Account 365 (overhead conductors) was classified as customer-related. Although Gulf's witness, Mr. O'Sheasy, agrees that some portion of other distribution capital costs are also customer-related, he has classified them to demand to reduce the controversy surrounding the various cost allocation/rate design issues (Testimony at Pages 21 and 22). While I concur with Mr.

O'Sheasy that revenue sensitive issues are important. I do not agree with his recommendation to limit the discussion of controversial cost-of-service allocation methodologies. This Commission has not seriously considered cost allocation methodologies since the Tampa Electric rate case, in 1985. If the highly controversial EP method is to be addressed in this Docket, then the classification of distribution capital costs should also be revisited.

Q **DO YOU HAVE A SPECIFIC RECOMMENDATION TO OFFER AT THIS TIME?**

A Yes. The Commission should instruct Gulf to conduct a study examining alternative methods of classifying distribution capital costs. The two most frequently used methods are the minimize size distribution system and the zero intercept method. A third alternative would be to quantify the labor component of primary and secondary distribution investment. The labor-related portion of the installed cost would be a conservative proxy for that portion of the investment in distribution plant which would have to be made just to connect customers to the system, irrespective of actual demand and energy consumption. The analysis should be conducted by FERC account for each method. A copy of the study should be filed with the Commission and distributed to all parties prior to Gulf's next general rate case. This should provide the Commission and all parties an objective basis for evaluating the merits of each method.

REVISED COST-OF-SERVICE STUDIES

Q HAVE YOU REVISED THE CLASS COST-OF-SERVICE STUDIES TO REFLECT YOUR VARIOUS COST ALLOCATION RECOMMENDATIONS?

A Yes, I have. Exhibit JP-1 (371), Schedule 11, is a summary of the class cost-of-service study based on the Near-Peak method, which I am recommending, rather than Gulf's proposed 12CP method. Specifically, I have revised the Level 1, 2 and 3 retail demand allocation factors by substituting the near-peak demands shown in Schedule 8 for the 12CP demands used by Gulf. All production and transmission capital costs were classified to demand. In all other respects, the revised cost-of-service study is identical to the Company's.

Q WOULD YOU PLEASE SUMMARIZE THE RESULTS OF YOUR RECOMMENDED CLASS COST-OF-SERVICE STUDY?

A Yes. The results at present rates, based on Gulf's claimed revenue requirement, are as follows:

Summary of Cost-of-Service Study Results at Present Rates
Near-Peak Method

Line	Rate Class	Rate of Return (1)	Relative Rate of Return (2)	Interclass Subsidy* (Millions) (3)
1	RS/RST	5.95%	90	$(5.4)
2	GS/GST	12.21	185	3.5
3	GSD/GSDT	6.49	98	(0.3)
4	LP/LPT	5.93	90	(1.3)
5	PX/PXT	9.95	151	2.7
6	OS I & II	8.50	129	0.4
7	OS III	25.29	383	0.2
8	SS	11.07	168	0.2

*A negative subsidy means that a class is being subsidized.

A positive subsidy means that a class is providing a subsidy.

Under the Near Peak method, the residential class rate of return is 26 basis points higher than in Gulf's 12CP & 1/13th Aug cost-of-service study.

Q WOULD YOU PLEASE EXPLAIN THE TERMS "RATE OF RETURN," "RELATIVE RATE OF RETURN" AND "SUBSIDY?"

A Rate of return is the ratio of: (1) operating income (i.e., operating revenues less allocated operating expenses and (2) allocated rate base (i.e., net plant in service, working capital, etc.). If a class is providing revenues sufficient to recover its cost of service, it will have a rate of return equal to the total Gulf return.

The relative rate of return (RROR) is the ratio of the class rate of return to the total Gulf rate of return. An RROR above 100 means that a class is providing a rate of return higher than the system average, while an RROR below 100 indicates that a class is providing a below-system average rate of return.

The subsidy measures the difference between the revenues required from each class and the revenues actually recovered. A negative amount indicates that a class is being subsidized each year (i.e., revenues are below cost), while a positive amount indicates that a class is providing a subsidy each year (i.e., revenues are above cost).

Q **EARLIER, YOU TESTIFIED THAT THE REP METHOD, WHICH GULF RERAN IN RESPONSE TO COMMISSION STAFF INTERROGATORY NO. 2, WAS FLAWED BECAUSE THE 12CP METHOD WAS USED TO ALLOCATE DEMAND-RELATED CAPITAL COSTS AND BECAUSE THE STUDY FAILED TO RECOGNIZE FUEL SYMMETRY. IS THAT CORRECT?**

A Yes.

Q **CAN YOU ILLUSTRATE HOW THE REP COST STUDY COULD BE CORRECTED TO TAKE INTO ACCOUNT YOUR TWO CRITICISMS?**

A Yes. First, 77% of production capital costs should be classified to demand, consistent with the much lower FOR's of peaking capacity.

Second, all production and transmission demand-related costs should be allocated using the Near-Peak method. Third, an explicit fuel symmetry adjustment should be made to appropriately recognize the production capital/operating cost tradeoffs on which both the EP and REP methods are founded.

Q HOW SHOULD THE FUEL SYMMETRY ADJUSTMENT BE MADE?

A The recommended fuel symmetry adjustment is derived in Exhibit JP-1 ( ), Schedule 12, Column 4. The specific adjustment should be made to the energy-related O&M expenses remaining after recoverable fuel and purchased costs have been removed. For example, the residential class energy-related O&M expenses should be increased by $865,000, while the Rate LP/LPT class O&M expenses should be decreased by $490,000.

Q HOW WAS THE FUEL SYMMETRY ADJUSTMENT DERIVED?

A As shown on Page 1 of Schedule 12, the fuel symmetry adjustment is the difference between the percent of total operating costs (Column 1) and Gulf's energy allocation factor (Column 2) multiplied by $168.3 million. The latter represents the costs recoverable under the Fuel and Purchased Power Cost Adjustment Clause for the test year which were removed from the analysis.

Q HOW WAS THE PERCENT OF TOTAL OPERATING COSTS DETERMINED FOR EACH RATE CLASS?

A This determination is shown on Page 2 of Schedule 12. The percent of total operating costs (Column 6) is derived by first summing the allocated peak and base period operating costs (i.e., Column 2 + Column 4) and expressing the result (Column 5) as a percent of total retail, excluding Rate SS. The allocated peak period operating costs shown in Column 2 are the product of Total Company peak period operating costs (Line 8) and the percentage of peak period loads contributed by each rate class (Column 1). Similarly, the allocated base period operating cost (Column 4) is the product of Total Company base period operating costs (Line 8) and the percentage of loads contributed by each rate class during the base period (Column 3).

Q **HOW WERE THE TOTAL COMPANY PEAK AND BASE PERIOD OPERATING COSTS DERIVED?**

A This is shown on Page 3 of Schedule 12. Column 1 shows the energy generated from peaking and base load capacity segregated between the peak period and base period.

The peak period energy was derived from an analysis of Gulf's system load shape (Appendix C, Schedule C-1) adjusted for the test year. Specifically, the total peak period energy requirement is the cumulative load during the first 1,430 hours, or 2,087.8 GWh. (Recall that 1,430 hours was derived by Gulf in response to Staff Interrogatory No. 2, and it represents the break-even threshold between peaking and base load technologies.) The base period energy consists of all of the remaining load beyond the 1,430-hour break-even threshold.

Referring to Appendix C, Schedule C-1, the load at 1,430 hours is approximately 71% of the projected system peak, or 1,229 MW, as shown in Schedule C-3. As explained in Appendix C, 1,229 MW is the amount of base load capacity consistent with providing electricity at the lowest total cost. The remaining 514 of Gulf's peak period load would be economically served from peaking capacity.

Peak period energy, thus, is generated from both peaking and base load capacity. The energy generated from base load capacity would be the product of the amount of base load capacity, 1,229 MW, and 1,430 hours, or 1,757.5 GWh. The remaining 330.3 GWh of peak period energy would be generated from peaking capacity. All of the base load energy would be generated from base load capacity.

The operating cost assigned to each time period are derived in Column 3. Column 3 is the product of Column 1 (generation by capacity type) and Column 2 (per unit operating cost by capacity type). (The per unit operating costs by capacity type were derived by Gulf Power in response to Staff Interrogatory No. 1, Pages 5 and 6.)

Q ARE THE PEAK AND BASE PERIOD ALLOCATION FACTORS DERIVED?

A They were derived from an analysis of the rate class hourly loads during the peak period. The results of this analysis are shown in Schedule 12, Page 4, Column 1. The peak period allocation factor (Column 2) is the peak period energy (Column 1) expressed as a percentage of Total Company peak period energy use.

Base period energy use (Column 4) is the difference between annual energy use (Column 3) and peak period energy use (Column 1). The corresponding base period allocation factors, thus, are derived by expressing the base period energy use (Column 4) as a percentage of Total Company base period energy use.

Q **WHY WAS RATE SS EXCLUDED FROM THE FUEL SYMMETRY ANALYSIS?**

A Rate SS is not a typical cost-of-service class and there is not sufficient representative hourly data to determine the Rate SS peak period demands.

Q **WHY IS RATE SS NOT A TYPICAL COST-OF-SERVICE CLASS?**

A Unlike the other classes, the Rate SS class coincident demands are based on the expectation that 10% of the Standby Service Contract Capacity will occur during peak hours. This assumption was based on the Commission's Order in Docket No. 850673-EU--Generic Investigation of Standby Rates for Electric Utilities. The Rate SS class' coincident demands for the test year are projected to be much lower than 10% of the Standby Service Contract Capacity. In some years, however, the Rate SS coincident demands may exceed 10% of the expected Standby Service Contract Capacity. Therefore, as Mr. O'Sheasy testifies, it is appropriate to use the expected Rate SS class loads to provide a more stable cost allocation from one rate case to the next. (Later in my testimony, I shall comment on the reasonableness of the 10% assumption.)

Q HAVE YOU RERUN THE COST-OF-SERVICE STUDY BASED ON A CORRECTED VERSION OF THE REFINED EQUIVALENT PEAKER METHOD?

A Yes. The revised study is shown in Exhibit JP-1 (373), Schedule 13. This study incorporates the same two corrections identified previously. The results can be summarized as follows:

Summary of Cost-of-Service Study Results at Present Rates
Corrected Refined Equivalent Peaker Method

Line	Rate Class	Rate of Return (1)	Relative Rate of Return (2)	Interclass Subsidy* (Millions) (3)
1	RS/RST	5.90%	89	$(5.7)
2	GS/GST	12.30	186	3.5
3	GSD/GSDT	6.43	97	(0.5)
4	LP/LPT	6.27	95	(0.6)
5	PX/PXT	9.52	144	2.5
6	OS I & II	8.60	130	0.4
7	OS III	25.76	390	0.2
8	SS	12.31	187	0.2

*A negative subsidy means that a class is being subsidized.

A positive subsidy means that a class is providing a subsidy.

Q ARE THE CORRECTED REP COST STUDY RESULTS MATERIALLY DIFFERENT FROM THE RESULTS OF THE NEAR-PEAK COST-OF-SERVICE STUDY?

A No. Actually, with the exception of Rate SS, the results are quite similar, as shown below:

Summary of Cost-of-Service Study Results at Present Rates Between the Near Peak Method and the Corrected Refined Equivalent Peaker Method

	Rate of Return		Relative Rate of Return	
Rate Class	Near Peak (1)	Corrected REP (2)	Near Peak (3)	Corrected REP (4)
RS/RST	5.95%	5.90%	90	89
GS/GST	12.21	12.30	185	186
GSD/GSDT	6.49	6.43	98	97
LP/LPT	5.93	6.27	90	95
PX/PXT	9.95	9.52	151	144
OS I & II	8.50	8.60	129	130
OS III	25.29	25.76	383	390
SS	11.07	12.31	168	187

In both instances, the residential class rate of return is higher than under Gulf's proposed cost-of-service study.

RATE SPREAD ISSUES

Q **IF THE COMMISSION APPROVES A PERMANENT BASE RATE INCREASE FOR GULF, WHAT FACTORS SHOULD BE CONSIDERED IN DETERMINING AN EQUITABLE SPREAD OF THAT INCREASE?**

A Although other factors may be considered, such as gradualism, rate continuity, ease of administration, customer acceptance and simplicity, primary emphasis should be placed on the cost of providing service to determine the revenue requirements from each class and from each customer within a class. The basic reasons for adhering to the cost-of-service principle throughout the rate spread and rate design phases are *equity*, *engineering efficiency* (cost-minimization), *stability* and *conservation*.

Rates which reflect primarily cost-of-service considerations are *equitable* because each customer pays what it costs the utility to serve him, no more and no less. If rates are not based on costs, then some customers must pay part of the costs of providing service to other customers, which is inequitable.

With respect to *engineering efficiency*, when rates are designed so that demand and energy charges are properly reflected in the rate structure, the utility has an incentive to construct the most economical mix of plants, and customers are provided with the proper incentive to minimize their costs, which will in turn minimize the costs to the utility.

When rates are closely tied to cost, the utility's *earnings are stabilized* because changes in customer use patterns would result in parallel changes in revenues and expenses. Cost-based rates also provide a more stable basis for determining future levels of power costs. If rates are based, instead, on vague social policies, it becomes much more difficult to translate expected utility-wide cost changes into changes in the rates charged to particular customer classes. This added element of uncertainty will lessen the attractiveness of industrial expansion either by new or existing industries. To the extent that rates do not reflect costs, multi-plant firms will be encouraged to shift production from high energy cost plants to lower energy cost plants in order to remain competitive. Such a shifting of production would reduce employment and the overall contribution of the manufacturing concern to the state and local economy. This would, in turn, be self-defeating to the presumed beneficiaries of below-cost electric rates.

Finally, by providing balanced price signals against which to make consumption decisions, cost-based rates encourage *conservation* (of both capacity and energy), which is properly defined as the avoidance of wasteful or inefficient use (and not just less use). If rates are not based on costs, then the choices are distorted.

Q HOW IS GULF PROPOSING TO SPREAD THE INCREASE AMONG THE RATE CLASSES?

A Gulf's proposed base revenue distribution, as modified by the new class cost-of-service study, is shown in Exhibit JP-1 (374), Schedule 14. Specifically, Gulf is proposing an above-average percent increase to the residential, Rate LP/LPT and Rate SS classes, while the remaining classes would either receive below-average increases, no increase or a rate decrease.

Q **IS GULF'S PROPOSED BASE REVENUE DISTRIBUTION CONSISTENT WITH THE OBJECTIVE OF MOVING RATES CLOSER TO COST?**

A Yes. However, this conclusion is based on Gulf's flawed class cost-of-service study.

Q **WOULD GULF'S PROPOSED BASE REVENUE DISTRIBUTION REDUCE THE INTERCLASS SUBSIDIES OF ALL RATE CLASSES BASED ON YOUR RECOMMENDED COST-OF-SERVICE STUDY?**

A No, not in all cases, as shown in Exhibit JP-1 ( ), Schedule 15, and in the chart below:

Summary of Interclass Subsidies at Present and Proposed Rates Near-Peak Method (Millions)

Rate Class	Present Rates (1)	Proposed Rates (2)	Movement Toward Cost (3)
RS/RST	$(5.4)	$(2.1)	60%
GS/GST	3.5	2.4	31%
GSD/GSDT	(0.3)	(1.3)	No
LP/LPT	(1.3)	(0.9)	30%
PX/PXT	2.7	1.3	54%
OS I & II	0.4	0.2	52%
OS III	0.2	0.1	42%
SS	0.2	0.3	No

Specifically, the Rate GSD/GSDT and Rate SS subsidies would increase.

Q IF THE COMMISSION WERE TO AWARD GULF A PERMANENT BASF REVENUE INCREASE, HOW SHOULD THAT INCREASE BE SPREAD AMONG THE CLASSES?

A My recommendation, which is based on Gulf's claimed revenue deficiency, is presented in Exhibit JP-1 (576), Schedule 16. It is based on the results of the Near-Peak cost-of-service study (Schedule 11).

Q WHAT IS THE BASIS FOR YOUR RECOMMENDED REVENUE DISTRIBUTION SHOWN IN SCHEDULE 16?

A The objective was to move all rate classes about half the way closer to cost of service by reducing the interclass subsidies at present rates by about 50%. This result is illustrated in Exhibit JP-1

(377), Schedule 17. In most instances, the interclass subsidies under the recommended allocation (Column 6) would be about 50% lower than the corresponding subsidies at present rates (Column 5). An exception was to Rate SS which would recover no increase under my recommendation. The subsidy provided by the Rate SS class would be 30% smaller.

Q **UNDER YOUR RECOMMENDATION, CERTAIN RATE CLASSES WOULD RECEIVE SIGNIFICANTLY BELOW-AVERAGE INCREASES, WHILE OTHERS WOULD RECEIVE RATE DECREASES. MIGHT THIS SEND THE WRONG PRICE SIGNALS TO THESE CUSTOMERS?**

A No, I do not believe so. The reason for the significantly below-average increases and the rate decreases for certain rate classes is the fact that their respective rates of return are significantly above the system average. Given the significant disparity between the revenue/cost relationships of certain rate classes, the only way to move them meaningfully closer to cost in this Docket would be to assign either below-average percent increases or a rate decrease. I must emphasize, however, that moving only one-half of the way to cost, as per my recommendation, is only a very modest step in the right direction.

Q **WOULD YOUR RECOMMENDATION DIFFER IF IT HAD BEEN BASED ON THE CORRECTED REP METHOD?**

A No. Because of the similarity of the results between the Near-Peak and Corrected REP studies, my recommendation would not be materially different if the latter method were adopted.

Q **IF THE COMMISSION WERE TO AWARD GULF A SMALLER BASE REVENUE INCREASE THAN IT IS PROPOSING, HOW SHOULD THAT LOWER INCREASE BE ALLOCATED AMONG THE RATE CLASSES?**

A My recommendation would be to apply the same approach--that is, to reduce the subsidies of all rate classes by at least one-half based on the results of an approved cost-of-service study. The latter would take into account all of the Commission-approved adjustments to Gulf's proposed rate base, revenues and operating expenses, and it would be based on the approved cost allocation methodology. This process, by definition, warrants thorough review by the Commission, the Staff and all parties to the case.

RATE DESIGN ISSUES

Q WHAT RATE DESIGN ISSUES ARE YOU ADDRESSING?

A I shall address the design of Rate Schedules PX/PXT and SS.

RATE PX/PXT

Q WHAT CHANGES ARE BEING PROPOSED FOR RATE SCHEDULE PX?

A Gulf is proposing to decrease the customer charge, increase the demand charge and reduce the energy charge.

Q DO YOU AGREE WITH GULF'S PROPOSED CHANGES IN THE DEMAND AND ENERGY CHARGES?

A Yes. The proposed reduction in the Rate PX energy charge, from $5.21 to $4.45/MWh, is consistent with the results of the unit cost study, which shows that the average nonfuel variable costs are about $1.9/MWh. (The nonfuel energy unit cost, which also includes some fixed costs, is $3.27/MWh under Gulf's revised class cost-of-service study.) Even with the proposed $0.76/MWh reduction, the proposed Rate PX energy charge would continue to be above cost. The Company's proposal recognizes gradualism, and it should, therefore, be adopted.

Q DO YOU HAVE ANY COMMENTS WITH RESPECT TO THE PROPOSED ON AND OFF-PEAK ENERGY CHARGES IN RATE PXT?

A Gulf is proposing to decrease the on-peak energy charge and to increase the off-peak charge. On balance, however, the revenues collected through the energy charge would be lower. This is consistent with the unit cost study results. Further, I would note that there is no significant difference in the correlation coefficients between PX customers' contributions to the twelve monthly coincident peak demands and either billing demand or on-peak kWh to support the retention of a high on-peak energy charge. (I am not suggesting that the correlation coefficient analysis is even relevant to the issue of determining an appropriate rate design)

Q **WHAT OTHER CHANGES IS GULF PROPOSING FOR RATE PX?**

A Gulf is also proposing to change the Minimum Monthly Bill. Under its revised proposal, the Minimum Monthly Bill:

> "Shall not be less than the Customer Charge plus:
>
> (a) Highest demand for the current month or previous eleven or
>
> (b) The contract capacity whichever is greater or
>
> $10.686 per kW of Billing Demand and the Local Facilities Charge, if applicable." (As Gulf's response to Staff's Third Set of Interrogatories, Item No. 48.)

The proposed $10.686 minimum bill is equivalent to the demand and energy charge at a 75% <u>monthly</u> load factor.

Q **HOW WOULD THE PROPOSED MINIMUM MONTHLY BILL REQUIRE RATE PX CUSTOMERS TO OPERATE AT LEAST A 75% MONTHLY LOAD FACTOR?**

A The proposed $10.686 per kW charge is equivalent to the proposed $8.25 per kW demand charge and the proposed 0.445¢ per kWh energy charge at a 75% load factor, as illustrated below:

Rate PX Minimum Monthly Bill

Line	Description	Amount
1	Total	$10.686
2	Demand Charge	8.250
3	Minimum Energy Charge	$ 2.436
4	Proposed Energy Charge	0.445¢
	Minimum Hours' Use	
5	(Line 3 ÷ Line 4 x 100)	547
	Minimum Monthly Load Factor	
6	(Line 5 ÷ 730)	75%

Q **IS GULF'S PROPOSED $10.686 PER KW MINIMUM CHARGE APPROPRIATE?**

A No. As written, the proposed Minimum Monthly Bill would penalize a PX customer for operating below a 75% minimum monthly load factor even if the customer's annual load factor exceeded 75%.

Q **HOW IS THE ANNUAL LOAD FACTOR RELEVANT?**

A The Applicability criterion in both the present and proposed PX/PXT rates states:

> "Applicable for three-phase lighting and power service to any customer contracting for not less than 7,500 kilowatts (kW), with *an annual load factor* of not less than seventy-five percent (75%)." Haskins, Schedule No. 3, Page 11. (Emphasis added)

A PX/PXT customer, thus, could still qualify for the rate even though the monthly load factor may be below 75% load factor in a particular month. The Commission, therefore, should reject the way in which this portion of the proposed Monthly Minimum Bill is written.

Q DOES THE PROPOSED RATE PXT ALSO INCLUDE A SIMILAR MINIMUM MONTHLY BILL PROVISION?

A Yes. The proposed Rate PXT Minimum Monthly Bill would be $10.648 per kW of Maximum Billing Demand, according to Gulf's Response to Staff's Eighth Set of Interrogatories, Item No. 124. The $10.648 per kW charge is also based on the assumption that a PXT customer should operate at a 75% monthly load factor.

Q HOW SHOULD THE 75% ANNUAL LOAD FACTOR REQUIREMENT OF RATES PX AND PXT BE ENFORCED?

A Consistent with the Applicability paragraph, Rate PX/PXT customers should be subject to a minimum annual billing demand charge.

For example, using Gulf's proposed Rate PX demand and energy charges of $8.25/kW and 0.445¢/kWh, respectively, a minimum annual billing demand charge would be $128.24 per kW ($10.686 x 12). The minimum annual bill, thus, would be $128.24 per kW times the highest billing demand occurring in the current or previous 11 billing months. This would provide a true-up in the event that a customer's annual load factor were to fall below the 75% minimum required.

Q SHOULD THE RATE PXT MINIMUM ANNUAL BILLING DEMAND CHARGE BE SIMILARLY CALCULATED?

A Yes. However, consistent with encouraging customers to minimize on-peak demands, the minimum should be based on the maximum on-peak demand during the current and previous 11 months, rather than the maximum demand, in either on or off-peak hours, as Gulf is proposing.

RATE SS

Q HAVE YOU REVIEWED GULF'S PROPOSED STANDBY SERVICE RATE (RATE SS)?

A Yes.

Q MR. HASKINS, TESTIFYING FOR GULF POWER COMPANY, STATES (ON PAGE 22) THAT "STANDBY RATE ORDER 17159 IS VERY SPECIFIC ABOUT THE DESIGN OF EACH RATE COMPONENT OF THE STANDBY SERVICE RATE." ARE YOU FAMILIAR WITH ORDER NO. 17159?

A Yes.

Q DOES GULF'S PROPOSED RATE SS COMPLY WITH THAT ORDER?

A No. In my opinion, neither the proposed $1.08 per kW reservation charge nor the 0.344¢/kWh energy charge fully comply with the provisions of that Order.

Q PLEASE EXPLAIN.

A Pages 12 through 15 of Order No. 17159 describe the parameters that were to be used to design an <u>initial</u> standby rate for purposes of the Commission's Generic Investigation. The design of present Rate SS, for example, was based on the full demand-related production and transmission unit cost per coincident peak kilowatt of demand and the energy-related production unit cost per kilowatthour based on the cost-of-service study used for rate-making purposes in Gulf's last general rate case.

Q WHY WAS A "SYSTEM AVERAGE" COSTING APPROACH USED IN DOCKET NO. 850673-EU TO DESIGN RATE SS?

A This "system average" costing approach was necessary because the standby service customers were not treated as a separate class in Gulf's last rate case.

Q DOES THIS MEAN THAT THE SAME APPROACH MUST BE USED FOR DETERMINING THE RESERVATION AND ENERGY CHARGES IN A GENERAL RATE CASE?

A No. In fact, the Commission was very specific in ordering each utility to treat standby customers as a separate customer class and be assigned costs consistent with the appropriate data in the new cost-of-service study, in each utility's next rate case.

Q HAS GULF TREATED RATE SS CUSTOMERS AS A SEPARATE CUSTOMER CLASS IN ITS COST-OF-SERVICE STUDY?

A Yes.

Q WERE THE RESERVATION AND ENERGY CHARGES DERIVED FROM THE COSTS ALLOCATED TO THE RATE SS CLASS?

A No. As explained earlier, Gulf used "system-average" costing. This is also evident from the fact that Gulf is proposing a 17.1% base rate increase to Rate SS--which is 1.6 times the system average--even though this class is already providing a substantially above-average rate of return at present rates. Consequently, the Rate SS class would move farther from cost, in violation of this Commission's long-standing practice of moving all rate classes closer to cost of service.

Q HOW SHOULD THE RATE SS RESERVATION AND NONFUEL ENERGY CHARGES BE SET?

A The nonfuel energy charges in Rate SS should be identical to the corresponding nonfuel energy charges in the otherwise applicable full requirements tariff. Rate SS customers who are also taking supplementary power on Rate PXT, for example, should pay the Rate PXT nonfuel energy charges.

This approach is necessary because not all of the Rate SS customers take standby service at the same delivery voltage, nor do all of these customers purchase supplementary power on the same rate schedule.

The remaining nonfuel revenue requirement--not otherwise recovered in the customer, local facilities and nonfuel energy charges--should be recovered through the reservation charge consistent with the Commission's long-standing policy of moving all rate classes closer to cost of service. My recommended base revenue distribution, for example, would not assign any increase to the Rate SS class, as shown in Schedule 16. This is appropriate because, as shown in Schedule 17, the class would move closer to cost of service, consistent with Commission policy.

Q **ARE THERE ANY OTHER ISSUES YOU WISH TO ADDRESS CONCERNING RATE SS?**

A Yes. These issues concern:

- The assumption that Rate SS customers would impose 10% of their Standby Service Contract Capacity during system peak periods;
- The 23-month demand ratchet; and
- The calculation of the Daily Standby Service kW.

Q **WHAT IS THE ORIGIN OF THE 10% FACTOR BEING USED TO ESTABLISH THE COINCIDENT DEMANDS OF THE RATE SS CLASS?**

A The Commission Order in Docket No. 850673-EU states on Page 13, that:

> "The reservation charge is to be calculated by multiplying *an assumed 10 percent forced outage rate* for SGCs' generators times the utility system's unit cost per coincident peak kilowatt (CPKW) for demand-related production and transmission (P&T) functions." (Emphasis added)

Thus, 10% was the assumed forced outage rate (FOR) of the SGC's.

Q SHOULD THE 10% FOR ASSUMPTION BE CARRIED FORWARD INDEFINITELY?

A No. The Order clearly states that the 10% FOR was an assumption. To assure that the approved standby rates would continue to be fair and cost-based, the Commission also ordered the utilities and the SGCs:

> "to undertake such data collection and reporting activities as are necessary to permit analysis of the load and usage characteristics of back-up, maintenance and supplemental electric service." (Order No. 17159, Page 22)

Specifically, each utility was to collect and report certain specified data for its standby customers, including:

- Billing data,
- Load, coincidence and load factor data,
- Customer Generation and availability data, and
- Additional data deemed necessary for proper cost-of-service analyses and rate design.

Q HAS GULF PERFORMED ANY SUCH ANALYSES OF THE CHARACTERISTICS OF ITS SGCs FOR PURPOSES OF THIS CASE?

A No. Gulf continues to use the 10% forced outage rate assumption to allocate demand-related capital costs and to design the proposed Rate SS reservation charge.

Q IS THERE ANY EVIDENCE THAT THE FORCED OUTAGE RATE OF GULF'S SGCs IS DIFFERENT FROM THE 10% ASSUMPTION?

A Yes. In response to Monsanto's First Set of Interrogatories, Item No. 11, Gulf supplied data necessary to calculate the FOR's of three of its four SGCs. While the proprietary nature of the response prevents full disclosure of the results, my analysis indicates that the FORs of the three SGCs were all significantly below 10%, in the 1% to 4% range.

Q **ISN'T IT UNUSUAL FOR SGCs TO HAVE FORCED OUTAGE RATES CONSIDERABLY BELOW 10%?**

A No. An analysis of the SGCs in the Houston Lighting & Power Company service territory, for example, revealed a composite equivalent FOR of only 3%. I am also aware of other similar experiences, but these other experiences cannot be disclosed for confidentiality reasons.

Q **SHOULD A DIFFERENT FORCED OUTAGE RATE, OTHER THAN 10%, BE ASSURED FOR PURPOSES OF DETERMINING THE COINCIDENT DEMANDS AND THE RESERVATION CHARGE FOR THE RATE SS CLASS IN THIS DOCKET?**

A No. This would not be necessary because the Rate SS class is already providing a substantially above-average rate of return at present rates. Also, one SGC refused to disclose the necessary information to calculate the FOR.

As required in Order No. 17159, Gulf should already be collecting and analyzing the load characteristics and reliability of each SGC. This analysis, which is based on actual experience, should be utilized in the class cost-of-service study in Gulf's next rate case.

Q WHAT IS THE 23-MONTH RATCHET TO WHICH YOU REFER?

A The billing demand used in applying the reservation charge

> "will be the greater of the Standby Service Capacity (kW) in accordance with the Contract for Standby Service or the Maximum Standby Service (kW) taken in the current and twenty-three (23) previous service months." (Section No. VI, First Revised Sheet No. 6.31)

Thus, if a customer were to contract for 7.5 MW of standby service capacity, but the maximum daily standby demand were 13 MW, the customer would be charged for the extra 5.5 MW for the current and the subsequent 23 months. At $.98 per kW, this would translate into about $124,000 in additional reservation costs.

Q ISN'T THAT PROPER BECAUSE THE UTILITY HAS TO STAND READY TO PROVIDE THE EXTRA STANDBY CAPACITY WHEN THE CUSTOMER DEMANDS IT?

A It would not be proper under all circumstances. Although standby power is used intermittently, when an SGC experiences either a forced or scheduled outage of his/her generating equipment, not all of these outages are random in nature.

Q PLEASE EXPLAIN.

A Certain maintenance outages, for example, may occur only infrequently--once every three to five years--at the SGC's discretion. These outages are similar to the ones that Gulf Power incurs to make extensive repairs on a boiler or to rebuild a turbine generator. Such extended outages would have to be scheduled in advance to enable Gulf to obtain the labor and material required to perform the necessary maintenance. Also, each outage would have to be coordinated with Gulf's sister operating companies to ensure that such outages do not create a capacity deficit on The Southern system.

Q **CAN AN SGC ALSO PRE-SCHEDULE SUCH UNIT MAINTENANCE OUTAGES?**

A Yes. There is no fundamental difference between a utility and an SGC as regards the need to schedule maintenance outages well in advance.

Q **IS THERE ANY INCENTIVE FOR AN SGC TO PRE-SCHEDULE A MAINTENANCE OUTAGE UNDER GULF'S PRESENT RATE SS?**

A No. For pricing purposes, no distinction is made whatsoever between back-up and maintenance outages. This is despite the fact that back-up power is often more random in nature--because forced outages are rather unpredictable--while maintenance outages can typically be pre-scheduled in advance.

Q **DOES THE COMMISSION'S STANDBY RATE ORDER PROHIBIT A UTILITY FROM DIFFERENTIATING BETWEEN BACK-UP AND MAINTENANCE POWER?**

A No. The Order does not preclude a utility from offering for a discount on, or forgiveness of, demand-related production plant charges if the customers schedules maintenance in advance with the utility to provide "useful coordination" (Order No. 17159, Page 10). Therefore, waiving the 23-month demand ratchet for such maintenance outages would not be contrary to the Commission's standby rate order.

Q **DIDN'T THE COMMISSION FIND, IN DOCKET NO. 850673-EU, THAT BACK-UP AND MAINTENANCE POWER WERE NOT SUFFICIENTLY DIFFERENT FROM EACH OTHER TO WARRANT SEPARATE COST-BASED RATES?**

A Yes. However, the rationale for this finding was that it was difficult to distinguish between back-up and maintenance power because the utility must provide the same level of replacement power regardless of whether the customer's generator is out for scheduled maintenance or has been forced out.

Although the same level of service may be required to provide both back-up and maintenance power, clearly an SGC that is able to usefully coordinate a maintenance outage with a utility can be distinguished from a SGC that may require back-up power on a moment's notice. In the former case, the utility can plan well ahead to provide the necessary capacity when it is needed. If the utility knows in advance that sufficient capacity is not available in the amount requested during the planned maintenance outage, it would not have an obligation to provide the service. (The SGC and the Utility would then have to determine when adequate capacity would be available before a commitment could be firmed-up.) In the case of back-up power, by contrast, the utility must stand ready to meet the additional back-up power demand whenever it may be imposed.

Because a maintenance outage that an SGC is required to schedule well in advance and in full coordination with the utility represents a different quality of service, a lower rate would be cost justified. At a minimum, the 23-month ratchet should not apply under these circumstances.

Q **DID THE COMMISSION MANDATE THE 23-MONTH RATCHET?**

A No. On Page 21 of Order No. 17159, the Commission stated:

> "To discourage initial misrepresentation of maximum standby power demand levels, the utilities *may* incorporate into their tariffs "ratchet" provisions that increase the contract demand for up to 24 months following an outage during which the customer's *back-up demand* exceeded his contractually specified maximum back-up demand. Alternatively, the utilities may propose other appropriate penalties instead of a ratchet provision." (Emphasis added)

Not only was the 23-month ratchet not mandated, Gulf was given the discretion to develop alternatives to the ratchet that may be appropriate to prevent misrepresentation of the maximum standby power demand levels.

Q **HAVE YOU REVIEWED THE TESTIMONY OF MR. TOM KISLA ON BEHALF OF STONE CONTAINER CORPORATION?**

A Yes.

Q **ARE THE CIRCUMSTANCES DESCRIBED IN MR. KISLA'S TESTIMONY REGARDING MAINTENANCE OF THE 18 MW TURBINE RELEVANT TO YOUR DISCUSSION OF THE 23-MONTH RATCHET?**

A Yes.

Q **MR. KISLA ALSO SUGGESTS THAT STONE BE ALLOWED TO PURCHASE ADDITIONAL CAPACITY AND ENERGY ON THE SUPPLEMENTAL ENERGY (SE) RIDER UNDER CERTAIN CIRCUMSTANCES. WOULD SUCH ADDITIONAL PURCHASES CAUSE OTHER RATEPAYERS TO SUBSIDIZE STONE?**

A No. With minor modification, the SE Rider would be an appropriate vehicle to enable Gulf Power Company to sell additional capacity and energy when the opportunity arises.

Q **WHAT MODIFICATION WOULD HAVE TO BE MADE TO THE SE RIDER?**

A In order that the ratepayers do not subsidize these additional opportunity purchases, the Rider should be modified to enable Gulf to terminate an SE period on as little as 30-minutes notice if it is necessary to avoid contributing to the monthly Southern system territorial peak. The 30-minute notice of curtailment provision would enable Gulf to exclude the SE demand in determining the Capacity Equalization Charges under the Intercompany Interchange Contract. This provision is described more fully in Gulf's response to Staff's 3rd Set of Interrogatories, Item No. 69. I would further note that both Alabama Power and Georgia Power are presently able to exclude their respective interruptible loads from the IIC under similar circumstances.

Q WOULD USING THE SE RIDER IN THE MANNER DESCRIBED BY MR. KISLA BE IN VIOLATION OF THE TERMS AND CONDITIONS OF THE STANDBY SERVICE RATE?

A No. As I understand Mr. Kisla's testimony, he is not asking for the opportunity to use SE as a substitute for normal back-up and maintenance power requirements. Rather, the SE Rider would be used to displace available, but less economical generation. Because this would afford Gulf the opportunity increase electric sales when adequate, cost-effective capacity and energy are readily available, the additional revenues generated from such sales would benefit Gulf's other ratepayers.

Q MR. KISLA ALSO CRITICIZES THE CALCULATION OF THE DAILY STANDBY SERVICE KW. WHAT IS THE PROBLEM WITH THE CALCULATION?

A The starting point for calculating the Daily Standby Service kW is the SGC's maximum totalized generation output since the most recent outage but prior to the current outage. Because Stone is required to generate more during the cold winter months than is the normally the case at other times, Stone could be charged for more standby power than is actually used (TK Exhibit 1, Page 2).

Q DO OTHER UTILITIES USE THE SAME FORMULA TO CALCULATE DAILY STANDBY SERVICE KW?

A No. Florida Power Corporation, for example, calculates Daily Standby Power on either the amount of load ordinarily supplied by customer's generation or a specified amount of self-service generating capability.

Q **DOES THE COMMISSION STANDBY RATE ORDER ADDRESS THIS ISSUE?**

A Yes. The Order requires a utility to "diligently analyze the customer's generator operation and power usage *for the period immediately preceding an outage.*" The Order goes on to state that this analysis "should enable the identification of back-up power taken to replace the customer's *normal* generation and supplemental power taken in excess of *normal* generation." (Order No. 17159, Page 21, emphasis added.)

Q **DOES GULF'S METHODOLOGY FOR CALCULATING DAILY STANDBY SERVICE KW COMPLY WITH THE ORDER?**

A No. The Order refers to power usage for the period immediately preceding an outage, whereas Gulf's calculation of daily standby service kW considers the maximum generator output during the entire period following a prior outage. For an SGC, this period could be as long as several months.

More importantly, as Mr. Kisla demonstrates, the highest generator output since the most recent outage may have little relevance in determining the actual amount of standby power being taken. In my opinion, the Commission intended for a utility to determine, as closely as practicable, the actual amount of standby power taken.

Q **HOW SHOULD THE DAILY STANDBY SERVICE KW BE CALCULATED?**

A I see nothing wrong with Mr. Kisla's suggestion that the amount of standby power be equal to the difference between the maximum metered demand during an outage period and the corresponding maximum demand in a non-outage period, during the current billing month. Not only is this approach simpler to use, it would more closely reflect the actual amount of standby power used.

Q **WOULD FPC'S FORMULA FOR CALCULATING STANDBY POWER ALSO BE AN ACCEPTABLE ALTERNATIVE?**

A Yes, the FPC formula could be an acceptable alternative if it were possible to seasonally differentiate between the amount of load ordinarily supplied by customer's generation. Seasonal differentiation would more accurately charge the customer for the amount of standby power being purchased to replace the capacity formerly being supplied by the customer's own generation. If more generation capacity is used during the winter months, then the Daily Standby Power kW should reflect this higher capacity when an outage occurs, minus the amount of load reduction as a result of the outage.

Q **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A Yes, it does.

Q (By Mr. McWhirter) Mr. Pollock, give us a summary of your testimony, if you will, sir.

A First of all, I want to apologize for the length of this testimony. It's really not my custom to put in 62 plus pages of testimony with appendices and tables, but as I hope you'll appreciate, the subject matter which I'm testifying on today is a very complicated subject and it's not explained in one or two pages, but what I'm going to try to do in the summary is boil down my testimony into two parts.

Part one is a part that I will call a "Tail of Two Costing Theories." There are basically two costing theories being discussed in the testimony. There is a "slice-of-the-system" costing methodology and the energy or load duration costing methodology. I think there are a number of similarities and there are also a number of differences, but let me try to focus on the "slice-of-the-system" methodologies first.

The "slice-of-the-system" methodologies encompass many of the so-called traditional demand allocation methods that you often see in rate cases. For example, in this case, the Company is proposing to use a 12 coincident peak method. That methodology basically assigns production plant and transmission plant investment on the basis of the highest demand of each customer class at the time of each of the 12 monthly peaks. It's a method, as the Company points out, that is frequently used at the FERC for jurisdictional separations, and it also has a tendency of ignoring seasonal differentials.

The other traditional or "slice-of-the-system" approach being used in this case is the one which I'm recommending, the near-coincident peak method.

Now back in the past before the days of computers, many utilities measured demand responsibility in relation to the contribution to the annual system peak. I believe this Company used to use the contribution to the five-day peak.

What I'm doing is a variation of that theme and saying, taking a look at the hours within which the system peak demand was within -- was within 5% of the annual system peak, which basically averages the coincident demands of each class when the system is near a peak or in a peaking mode. And that's, as I said, a variation of the one or five-day system peak and the purpose is is to try to provide a more representative sampling of class contributions when the system is in a peaking mode.

Now, what have the 12 CP in the near peak methods have in common as "slice-of-the-system" approaches?

The basic fundamental concept of a "slice-of-the-system" approach is the assumption that each customer class is served from the same mix of technologies. That is, each class receives an allocation -- same average capital cost per kilowatt of peak demand, and similarly they are allocated the same average operating cost per kilowatt hour consumed.

The emphasis of a "slice-of-the-system" method is usually on system reliability because this is the most realistic and most important planning consideration that utilities use in determining the amount of capacity required to maintain reliable service. Simply put, the peak demand determines how large and how much capacity the Utility must install in order to maintain continuous service and fulfill its obligations to ratepayers.

So goes the "slice-of-the-system" approach. What are the energy or load duration approaches?

Well, these approaches -- well, I've said the "slice-of-the-system" approaches encompass many of the traditional methods. The energy and load duration approaches similarly are not all that new. In fact, they have been debated for many, many years along with the so-called traditional "slice-of-the-system" approaches. In the 1920s and '30s you had the Lauriol (phonetic) method, the average and access method. In the '70s and '80s you had the probability of deficiency, probability of dispatch, average and peak, peaker, equivalent peaker, refined equivalent peaker, and now corrected refined equivalent peaker.

The assumptions of the load duration approaches are a little different from the "slice-of-the-system". They recognize reliability but they also attempt to recognize cost minimization; the fact that utilities will employ a mix of technologies to serve its total load, that each type of technology has different characteristics in terms of capital costs and operating costs. And further, that that mix is a function of load duration. Since different customer classes have different load durations composite, therefore, the different classes should be assigned a different mix of generating technologies.

So you see, in contrast with the "slice-of-the-system" approach, which assumes that each class is allocated the same mix of technologies, the assumptions behind the energy or load duration approaches takes it one step further and says there are differences in generation mix to serve different customer classes. Because of a high load factor class is posited to be more likely to require more capital intensive units like baseload plants, an energy or load duration approach typically assigns higher than average capital costs to high load factor classes.

I believe that consistent application of that approach should also result in assigning or allocating lower or below average operating costs per kilowatt hour basis. The problem that we have in this case, however, is that the load duration approach being used in the form of the equivalent peaker, and even the refined equivalent peaker, fails to assign below average operating costs to the classes who are allocated above average capital costs.

Consequently, I've recommended an adjustment to the Refined Equivalent Peaker Cost Study filed in this case in reponse to a Staff interrogatory to recognize fuel symmetry. To put it simply, fuel symmetry says if a class is to be assigned above average capital costs per unit of demand, it should similarly be assigned below average operating costs per unit of energy.

I gave an anology in my testimony of a car rental agency where you have a choice of two types of cars to rent: A very cheap gas guzzler, which is expensive to run, or a very expensive fuel efficient car which is very cheap to run.

If by economic analysis says I drive enough to justify driving the fuel efficient car, I expect not only to pay the higher daily charge of the more fuel efficient car, I would also expect to pay the lower mileage charge associated with that more fuel efficient car. And so is the fuel assymetry adjustment designed to match the costs of the higher capital costs of plant used to serve high load factor customers with the lower operating costs.

The second flaw in the load duration approaches is the assumption that the entire load duration curve causes a utility to incur higher baseload capital costs. Unfortunately, that fails to recognize the reality that when you look over the life cycle of different technologies you find that the cost of a peaking unit and the total cost of a baseload unit tend to be equivalent between 1,000 and 2,000 hours of use. In other words, it's only the fuel cost savings in the 1,000 to 2,000 hours of use that would cause a utility to incur the higher capital costs usually associated with baseload capacity. And, therefore, in contrast with the equivalent peaker method which allocates the energy-related production investment to all hours of the year, cost causation suggests in the analysis of the breakeven points between different technologies suggest that you should only assign those costs to the hours of the year up to the breakeven point between baseload and peaking technologies. This is, in fact, the genesis of the refined equivalent peaker method and is held consistently through in the corrected refined equivalent peaker method which I've sponsored.

There are other flaws with the equivalent peaker method, but to try to keep this thing short, my testimony describes how some of these flaws can be corrected. I have just discussed two of them, allocating the energy-related investment to the break-even point, which Gulf determines in this case to be 1430 hours; to allocate or recognize fuel symmetry, that is to say, to associate higher capital costs and lower fuel costs to high load factor classes, lower capital costs and higher fuel costs to low load factor classes.

In addition, because of the fact that the 12-CP method falls outside of the break-even point range as indicated in my exhibit -- in other words, five of the 12 months occur beyond 1430 hours, which is determined as the break-even point -- it's my position that that methods is not compatible in connection with the use under the refined equivalent peaker method. Consequently, I have used the near-peak method to allocate the demand-related cost.

In short, when you make these corrections and do the cost of service study as I have done in my exhibit, you come to the conclusion that the cost of service study results on a per-class basis, under the load duration approach of allocation, does not differ significantly from from the corresponding results under the slice-of-the-system approaches. Therefore, it's my position there's nothing fundamentally wrong with the slice-of-the-system approach that has been used for many, many years.

The second part of my testimony is, I guess you could characterize it, is what's good for the goose is good for the gander. The Commission has done an outstanding job over the years in moving all rate classes closer to cost of service. And in this case, the Industrial Intervenors believe that that pattern should continue. We also believe that that pattern should continue for all classes.

In this case, the standby class, which is shown as a separate cost of service class by order of the Commission in the generic investigation of standby rates, would be allocated a 17.1% increase, which is

163% of the average 10.5% based rate increase the Company is seeking in this case. Not only does that exceed the gradualism constraint normally applied in these cases, which is 1.5 times, but the gradualism constraint is normally applied only when a class is providing a rate of return below the system average.

In this case, Gulf's cost of service study and the cost studies which I am sponsoring show that the standby class is providing a substantially above-average rate of return of present rates, a relative rate of return of 153% versus 100% system average.

At proposed rates, this would be increased to 155. In other words, the rate is moving away from and not closer to cost. And we feel that the standby class ought to be assigned revenue responsibility in a way to move it closer to a unity rate of return or 100 relative rate of return.

I also address in my testimony several issues regarding the design of the standby rate. These touch on the same issues which Mr. Kisla testified on.

Basically, they cover the derivation of the daily standby capacity service charge and two other issues which, in my opinion, would treat self-generating customers on a more or less level playing field with the utilities.

With respect to the daily standby charge, I support Mr. Kisla's comments that the daily standby capacity charge billing demand should be based upon the difference between the highest demand imposed on the system in the month during an outage period and the corresponding highest demand imposed on the Utility during the month, during a non-outage period. Not only is this simpler than the existing methodology, it avoids the seasonality penalty caused by the fact that standby power requirements are determined based upon generation output during some previous interval since the last outage. It also measures the actual standby capacity used and imposed on a system in relation to the supplementary demand.

With respect to the other two issues, it's our position that the ability to coordinate scheduled maintenance outages is a factor which should be recognized in the standby service rate, but for the 23-month ratchet. Extended outages can be planned well in advance in time to occur when the Utility has surplus capacity. As Mr. Kisla indicated, these outages occur infrequently, just as utilities take their generating units down periodically for major maintenance. The service is provided or can be provided only when capacity is available and then it's provided with a known quantity and in a known duration.

So there is nothing unknown about it. It is a service that will only occur when capacity is available and will occur in a fixed time and a fixed duration. Therefore, it's a lower quality of service than backup power, which can occur instantaneously for any length, any duration.

We feel that waiving the 23 months ratchet makes sense because it recognizes the lower quality of service being provided and also recognizes the fact that it provides incentive for the customer; it provides additional revenues for the Company in a way that minimizes the additional cost to the customer. In short, it's a win-win proposition.

The other recommendation we're making is a clarification on whether or not customers with self-generation can use supplemental energy rate to displace less economical generation. In concept, this is no different than economy purchases by utilities where they back off of their less efficient units and buy economy sales on the spot market.

We feel that this approach would not cause any extra costs on the Utility; in fact, to the contrary, it will provide the Utility with more revenues than would otherwise be the case. And as a safeguard, we are willing to stipulate that the SE rate for this type of application be curtailed on 30 minutes notice so that it does not cause any additional cost responsibility or cost to be assigned to Gulf Power through The Southern Company or company interchange contract.

With that, that concludes my summary.

MR. McWHIRTER: Tender the witness.

CHAIRMAN WILSON: Let me ask you a question while we're real fresh with what you just said about displacing self-generation with supplemental energy when supplemental energy is less expensive.

What happens now if you do that, using, I guess, Stone Container as an example? What happens now if they were to do that, engage in that kind of thing?

WITNESS POLLOCK: It's not clear. Because when they're only allowed to use the supplemental energy at times when they cannot -- well, they cannot use the SE rate if their units are down or out for any reason.

CHAIRMAN WILSON: So they can't do that now?

WITNESS POLLOCK: It's my position that it's ambiguous. I think the Company feels that they can do it. But when you take a generating unit down, that could be construed as -- that replacement power could be construed as standby power and perhaps billable under the standby rate.

What we're saying is, if you take the unit down for maintenance or you take the unit down because it's forced down, that's clearly a situation where you would be billed under the standby rates. But what's different here is if you take the unit down for economic reasons, it's not clear from the rules and the tariff that that, too, doesn't fall under the standby category.

CHAIRMAN WILSON: Which aren't clear, the rules or the tariff, or both?

WITNESS POLLOCK: Well, I think I'm referring primarily to the tariff and the definitions of backup and maintenance power in the tariff.

CHAIRMAN WILSON: Okay.

COMMISSIONER GUNTER: How do you handle the situation, though, and it's one that we have to grapple with. How do you handle a situation when you would have someone that would self-generate 100% of their requirements and the time period drops along for six months, just kind of rocks along. It's my understanding that the utilities are required to provide for those cogenerators backup maintenance.

Aren't there three categories in the law, the types of services the utility must provide to cogenerators?

WITNESS POLLOCK: Yes, that's right.

COMMISSIONER GUNTER: If, in fact, that standby rate is not used, then who pays for the capital investment of the facilities that are required to be there to satisfy their needs, should they need that power?

WITNESS POLLOCK: If they are on a standby contract --

COMMISSIONER GUNTER: Yeah.

WITNESS POLLOCK: -- then they will pay a reservation charge that reflects the cost of capacity that is standing ready to provide backup and maintenance service when it's needed.

COMMISSIONER GUNTER: Okay.

WITNESS POLLOCK: If they're not on a standby rate, then they're not -- perhaps, at that point, they're not entitled to standby power.

COMMISSIONER GUNTER: I understand. But then philosophically, if that cogenerator, not for any other reason other than economics, decides and has the ability to move on and off the system, and that requirement still be there over a 12-month time period, and they just move on and off? Sort of like some folks do that as the price of No. 6 oil and gas gets a little bit out of whack. You know, they'll switch back and forth, whatever is to their economic advantage.

How do you make sure, if you have the supplemental rate, in this instance how do you make sure that you have full recovery over the entire year of standby and/or supplemental, as I understood your testimony? How do you make sure that there's no subsidy from other classes of customers to that individual customer?

WITNESS POLLOCK: That's a good question. And if the customer is going to remain interconnected with the utility, an assumption --

COMMISSIONER GUNTER: Yeah.

WITNESS POLLOCK: And that customer has some ability to impose power requirements that are not related to backup or maintenance, this is strictly economic displacement, it's not clear to me that the standby rate would apply under those circumstances. The customer would be billed under the supplementary rate for whatever minimum demand that customer imposes. And if there are separately-stated local facility charges to recover the cost of the local transmission distribution equipment required to connect the customer to that system, it seems to me the contract would read something like, "Regardless of what your demand is on the utility, you're going to pay for those costs because we have got to maintain that equipment."

COMMISSIONER GUNTER: Well, you understand our dilemma?

WITNESS POLLOCK: Yes.

COMMISSIONER GUNTER: Is trying to make sure that the cogenerator, regardless, that the other ratepayers -- you know, it's taken a while, but we're moving closer and closer to parity. And then some utilities have had more rate cases than other ones. We're probably too close to call as to whether we're over or under, at least by the time of the last case.

But if you can, theoretically, get to parity, then that's a very ticklish issue to me is to try and keep everybody at parity so there's no subsidy from one class of customers to another, or even customers within the same class subsidizing others, where the issue of standby and maintenance power requirements exist.

And I'm not sure when I read your testimony, I'm not sure I find that answer in your recommendation about the stand-by -- I mean the supplemental, the SE portion. I'm not sure that I find my answer there.

WITNESS POLLOCK: Well --

COMMISSIONER GUNTER: I understand it's an economic -- hell, if I had on your hat, I understand exactly where you're coming from, but having it on mine, I'm not sure that's clear. Maybe we can clear it up on cross examination.

WITNESS POLLOCK: I agree. It's definitely a moving target. I think though, the circumstances that apply here suggest that there is no subsidy because the customer in question is picking up the costs of the facilities under the normal rate schedule.

COMMISSIONER GUNTER: I understand. But it's your recommendation that it not continue in that in that fashion?

WITNESS POLLOCK: No, it's not. That wouldn't change. What would change is here is an opportunity for this customer to displace less economical generation. This customer, in order to maintain the profile that it has for the test period, has to generate more steam that is not physically used in the process as a result of using more expensive form of generation.

What this customer would like to be able -- and this customer is willing to do it. And you saw the charts last night, we suggest this customer has a very good ability to control his loads. And those are the costs and those are the load which cause those costs, and he's paying for the costs associated with that pattern. What this customer is saying, "Look, what's the point of generating ineffiently with condensing energy -- condensing-type generation if the utility has cheaper energy available? We'll take that cheaper energy when it's available and back off of our own generation; therefore, we save costs -- 'we' meaning the company -- the utility gets more revenues."

COMMISSIONER BEARD: This would, in essence, not be firm then?

WITNESS POLLOCK: That's correct. It would not be a firm sale. It would be an economy sale.

COMMISSIONER BEARD: The inverse of the as-available to cogenerator sales to the utility, you would now have as-available from the utility to the cogenerator?

WITNESS POLLOCK: Yes, just the same as economy sales between utilities.

COMMISSIONER GUNTER: Would you propose they still pay the standby rate, just the standby portion, and then have the economy sales?

WITNESS POLLOCK: The economy sale, yes, I would. The standby rate would be based upon whatever contract demand they agreed to or set in the way of standby power. What this would be would be something in addition to that.

COMMISSIONER GUNTER: So to put it in a different term, the reservation charge for that capacity would continue and then the rate that would be charged would be something akin to an economy energy sale, in addition to the standby reservation charge that would go on?

WITNESS POLLOCK: That's essentially correct. The standby rate reservation charge would continue for the amount of contract capacity a customer agreed to. This capacity could be on top of that standby capacity, but again, it's only provided when it's available, when it's economical.

COMMISSIONER GUNTER: I understand.

COMMISSIONER BEARD: How does the utility distinguish between the times that when you're on standby and the times when you're taking economy sales, for lack of a better term?

WITNESS POLLOCK: Well, the way to do it would be to work with the customer and to have the customer demonstrate and communicate with the utility the fact that they would like to take this particular generation off-line because it's less economical, not because it's going down for operational reasons or because of maintenance, or because of a forced outage.

COMMISSIONER BEARD: Let's carry this hypothetical a step further. You work -- the cogenerator works with the Utility, demonstrates economics, and brings the unit down for economic reasons, performs maintenance while it's down, the logical thing to do, it just happens to be down for economic reasons, we'll perform maintenance at the same time. How do you charge for it?

(Pause)

WITNESS POLLOCK: Well, if a customer performs maintenance on that unit at that time, that customer is taking a risk that if the supplemental energy becomes unavailable on 30 minutes' notice, that he's going to have to bring that generation back up in 30 minutes, and given that risk, I really doubt whether a customer would undertake any major maintenance on a unit in that circumstance.

COMMISSIONER BEARD: Well, okay, carry my hypothetical a step further. The customer takes the risk on 30 minutes' notice. How much notice is it that the customer has to give for standby?

WITNESS POLLOCK: I don't believe there's any notice requirement. I think they have to notify the utility within a certain period of time after an outage occurs.

COMMISSIONER BEARD: Well, okay. So I take the risk as a customer, economic, number one, I understand that. I go ahead and do some maintenance while it's down. There's a risk associated with that, and 30 minutes' notice from the utility says, "In 30 minutes we're not going to have the supplemental energy for you." Okay. In 30 minutes I want standby. Is that a feasible scenario?

WITNESS POLLOCK: It certainly is. And what would happen is if they take more than their contracted standby power because they can't replace that generation with something else or back off of their load, then that would tend to ratchet up their standby capacity reservation and they would pay the higher reservation charge and local facilities charges associated with that higher standby demand.

COMMISSIONER BEARD: Surely there would be some mitigation of risk, though.

WITNESS POLLOCK: It certainly would be very risky.

COMMISSIONER BEARD: No, I'm saying that the ability to switch from supplemental to standby mitigates to some degree that risk.

WITNESS POLLOCK: Well, maybe it's not as clear-cut as that because when you say "back off your generation," you're never really backing it off full. Utilities never shut down their units, they simply back them off to a level where they can continue to operate. So if a customer responded that way, there could be no major maintenance done. I guess there are a lot of -- there's certainly a lot of possibilities, and I sure don't --

COMMISSIONER BEARD: I'm trying to explore and understand.

WITNESS POLLOCK: I certainly haven't explored every one of them.

COMMISSIONER BEARD: Okay.

COMMISSIONER GUNTER: Mr. Stone, have you got any questions?

MR. STONE: No questions.

CROSS EXAMINATION

BY MR. BURGESS:

Q Mr. Pollock, is it correct that when a utility determines the type of generating capacity that it intends to install to minimize costs, that the utility is going to consider how many hours the new unit is expected to run?

A Yes.

Q Is this any different than saying -- or does this lead then to the conclusion that the energy loads

in those hours that
the unit is expected to run determines the type of unit that will be built?

A Yes, it can be different. The fact that a utility might decide that it needs a unit for 500 hours a year, or 2,000 hours a year, in itself has not defined what caused you to actually build that unit in terms of the ecnomics.

Q To build that type of unit?

A That's correct.

Q Does it not follow that the energy loads in those hours that you expect the unit to be serving would determine, or be a determining factor in the type of unit that would be constructed?

A Again, not necessarily. It would depend upon the economics of building that unit versus some alternative and what hours -- at what point you justify one alternative or another. The fact that a unit may operate 7,000 hours a year has no bearing on what hours caused the utility to construct that unit.

Q I see. When you say the "alternatives," you're speaking then -- what you're saying is some other alternative form of production may operate different times and present a different pattern of cost for the utility to consider in minimizing the total cost?

A Well, it's not a case of operating at different times. The generation planner will look at different options to serve the same need and determine from that which is the least costly.

Q Do you know, speaking specifically with Gulf and Southern Company and their generation expansion plans, to your knowledge have they ever constructed a facility that was not the most economic choice?

A I haven't reviewed their plans with the idea of determining whether or not their generation mix was prudent.

Q So the answer is "no," but you couldn't say one way or the other?

A No, I can't.

Q Are you at all familiar with genreration expansion planning concept, in a general sense?

A Yes, I am.

Q Is one of the steps in generation planning, generation expansion planning, the technology screening step?

A That is a step, yes.

Q And in the technology screening step, does it produce an output that is a list of select generating technology alternatives that are candidates, so to speak, for future additions?

A Yes.

Q And then further, this particular step would then involve itself in some type of program that internally generates a large number of scheduled unit additions and measures the cost of each alternative?

A That's right. The expansion plan will look over a fair number of years, 15 to 20 to 30 years, and it's not just looking at one unit being added; it's looking at a series of units being added at certain periods of time and comparing those scenarios against each other to determine which one meets both the reliability requirements and does so in the lowest-cost fasion.

Q And in that process, though, each of the scenarios, as you described, each one of those would meet the reliability and load requirement, is that right?

A To varying degrees, yes.

Q And then the choice from that point is which produces is the lowest total cost?

A The choice would be one which prevents the least amount of risk, which means provides an acceptable degree of reliability at the lowest cost. It's not just simply picking the lowest one; it's picking the least risky one that meets all the criteria.

Q So then would I be correct in understanding that cost then is not the determining factor; that it's a question of risk and meeting all the criteria?

A Well, cost is a major factor, yes. I wouldn't necessarily say it's a determining factor. Reliability is also a very major factor, too, and I think that is the first step in the planning process is to look at the system reliability and plan for it according, and then develop a scenario that meets the reliability criterion with the lowest amount of cost and the least amount of risk.

Q Okay. I must have gotten off track a little bit. Technology screening is one of the steps in the generation expansion planning, is that correct?

A Yes, it is.

Q Okay. And when you talked about meeting the reliability criteria, I had thought that that was an earlier step than the technology screening.

A It generally is, yes.

Q Okay.

A First you have to have a need before you can look at alternatives for meeting that need.

Q Okay. So meeting the reliability

requirements is an earlier step generally than the technology screening?

A Yes.

Q Okay. And in the technology screening you gather a number of varying scenarios, all of which meet the reliability criteria, is that correct?

A Let me clarify that. Essentially it is, but technology screening can occur independent of your expansion plan. Once you determine the need, you look at different technologies that are available to meet that need. That can be considered the technology screening. You consider which technologies are feasible within the time frame that your need exists. In other words, see if you can look at new types of generation, like fluidized bed boilers, for example, make a determination of whether or not that technology is feasible within the time frame that it's needed. And if the assumption is that it is or will be feasible, then that could be included in the expansion plan scenarios.

Q Okay.

A So the screen is kind of a step before you get to the point where you look at alternative expansion plans and compare the revenue requirements.

Q Okay. So then you have a number of

alternative expansion plans presumably if you've done things correctly, each one of which will meet the reliability and load requirements?

A Yes.

Q Okay. And then the planners will measure the cost of each of those scenarios? Am I correct in that understanding?

A Yes, it is; yes, they will.

Q And then that's a total cost for each scenario in all of the years for which the scenario applies, is that correct?

A It's a total cost of the expansion units as well as the cost or the effect on the existing system. In other words, the variable that gets added to all of this is the fact that you have got to see how the expansion units will interrelate with the existing mix. So you look at the total effect on the existing system and the total incremental effect of the expansion system and develop scenarios which try to minimize that total cost.

Q And the total cost is normally or always brought back to a current net worth for purposes of comparison one to another?

A Yes. (Pause)

Q And my final question, along these lines to see, I guess to refine my understanding somewhat of this particular area is the present net worth then has two basic components, is that correct?

A It would depend on how --

Q Okay. Let me read the two sentences that follow that in Gulf's Generation or Southern Electric System's Generation Expansion Plan. This present net worth of revenue requirements has two components. One is the cost of future capital additions required. The other is the production cost of serving all the load in all the years of the study.

A Yes, I would expect that you're looking at basically those two types of costs.

Q Okay. So you don't have any quarrel with the way it's presented in this study, with the description of the total cost for comparison purposes as it's presented in this study?

A No, I don't.

Q Or at least as I read that particular section.

A I have no quarrel with that, no.

Q Does that then lead to the conclusion that all of Southern System's energy loads are included in the economic analysis that determine what the economic choice ends up being for the particular production scenario, or generation expansion scenario?

A I would accept that as a matter of fact that the loads are all included.

Q I'm going to read you a statement that I'll represent to you is from the Generation Expansion Planning Studies documents submitted by FCG in 890004, and ask you if it rings true as far as your experience and expertise would judge it.

"A new baseload unit to be economic must produce operating savings in the total system that are larger than its capital costs compared to intermediate and peaking options. This will usually occur when the new baseload unit is highly utilized without significantly lowering the utilization of existing baseload capacity."

A I would accept that, yes.

Q Would you think that a baseload unit is considered highly utilized, as that term is used in the FCG study, if it ran 1,430 hours a year?

A I think the expectation would be -- it would run considerably more hours than that -- that it would not, 1,430 hours in itself would not be considered highly utilized.

Q Do you have a notion as to, or did you make a calculation to determine what percent of the year that the 1,430 hours represents?

A It represents less than 20% of the total hours.

Q Do you have any idea as to what is normally considered to be the -- an average baseload unit running time for a year?

A It varies. Depending on the type of baseload units and the need. But baseload units can operate at capacity factors as low as 45 to 50%, as high as 85 to 90%.

Q Which is substantially above the breakeven point of 1,430 hours that's been calculated at least for purposes of using the refined equivalent peaker method.

A It's certainly greater in that that's exactly the point that I was making earlier in your earlier question was the fact that expected usage and cost causation are two different things. You expect to use a baseload plant more than the breakeven point, otherwise you wouldn't build it. But compared to the alternative, it's the breakeven point in those hours which cause you to build the baseload plant instead of the alternative.

Q Will you tell me just generally how the break-even point is calculated; theoretically, what that break-even point represents?

A What the break-even point represents is a life cycle. It's a comparison of a life cycle cost of two alternative technologies. So one will take a look at the capital cost of, let's say, building a peaking unit and the corresponding operating costs; make assumptions about the first year-costs, the escalation of those costs over 30 or 40 years.

And likewise do the same thing with respect to a new baseload unit; look at the first year capital cost and operating costs and escalate those costs, you expect the cost of fuel and labor to escalate, and then compare the present value revenue requirements of those streams over the corresponding 35- or 40-year time period. And at the point where the hours use yields the same total revenue requirement for each technology represents the breakeven point.

So, again, to give a little easier example, if I had a choice of running two types of cars and one cost me $60 a day to rent and it cost 30 cents a mile, and the other car costs $30 a day, at 60 cents a mile, my breakeven point would be 100 miles. So if I drive more than 100 miles I'm going to choose the $60 car instead of the $30 car.

Whether I drive 200 miles -- if I expect to drive 200 miles, that extra 100 miles is not going to affect my decision one bit because anything above 100 is going to convince me that I should pay for the $60 car.

Q In the concept of the break-even point, does the 1,430 hours represent the highest demand hours of the year?

A Yes, it does.

Q A utility wouldn't build a baseload unit if it was only for the purpose of serving during the highest 1,430 hours of the year, is that correct?

A Well, conceivably they could justify it. I doubt seriously if they would do it, if that was their obligation. I think the problem is the utility has to look at their obligation and the cost, the likely cost of fulfilling that obligation.

Q I see. And you conceivably they could justify it. That's basically -- that's a fallout of the breakeven point analysis, Is that correct?

A Exactly, yes.

Q But taking it as a fallout of that analysis -- strike that beginning and let me try this approach.

Do you know where the highest demand 1,430 hours of the year would fall?

A Generally speaking, in the summer for this utility.

Q They would all fall in the summer?

A Not necessarily all, but primarily, yes. There is a secondary winter demand that conceivably could fall into that highest 1,430 hours.

Q Okay. And we're talking about individual hours. Isn't there -- even if there is a summer peak demand, aren't there individual hours in the winter on given days that would exceed the demand of a -- some summer day that occurs during the, say, the highest peak month?

A I'm sorry, I lost your train of thought.

Q Okay. Let's take a high demand day in the summer time, then when you are -- isn't it correct that even for that particular day, when you go to the lower demand portion of that day, and compared that to perhaps the higher demand portion of a winter day, that a particular hour in that winter day could exceed the demand in a lower portion of the summer day?

A That's certainly conceivable, the 1,430 hours. It looks at the highest 1,430 irrespective of whether they occur in the summer, the winter, the spring or the fall. It's not the highest 1,430 summer hours, it's the highest 1,430 system demand hours.

Q Okay. So it's not like the highest 1,400 continuous hours or even 700 continuous hours and then 730 more continuous hours?

A Oh, that's correct, it's not. It's taking -- the actual load shape of Gulf Power, which measures the hourly loads in descending order beginning with the peak hour descending to other hours.

Q Okay.

A It's not a consecutive time period by any means.

Q So if we were to try to take that 1,430 hours and actually identify them, actually identify which hours they are, 7 p.m. of July 28th, et cetera, we would be plucking hours -- by the time it was all over, we'd be plucking hours from all over the calendar, wouldn't we?

A That's conceivable. I'm not sure what the purpose of doing that would be.

Q I'm trying to find out. But if conceivable, it's not only conceivable, it's likely, is it not?

A I'd say so, yes.

Q Well, wouldn't that mean, then, if one were to say, "Well, a baseload unit is built just to serve those highest 1430 hours," that conceptually, we'd be talking about cranking it up to serve one hour in a particular month, and then it would come back down and

then go up for another week at some point, and then
come back down, just to meet those 1430 hours?

A Well, no. Because if we're talking about
just those 1430 hours, we're saying, "Hey, we're not
concerned about anything else." I mean the reality is
you don't just, the reality is that if you want to look
at consecutive hours, you could do that. They build
the baseload plant so it can operate continuously.

And the hope, the expectation, is that it
would operate continuously. What caused you to build
the baseload plant, though, is the function for the
need for liability and the economics. These are the
alternatives. If you were only looking at 1430 hours,
if that was the only load that the utility had to
serve, by definition those hours would be consecutive.

So I guess by the constraints of your
question, the 1430 hours would occur by definition on
consecutive times or consecutive periods. Because that
would be the only period you would be looking at.

The fact of the matter is the utility has the
load duration curve and they expect, if they can past
the 1430 hour hurdle, regardless of whether the day is
in the 1430 hours or not, that the economics will
justify the baseload unit.

Q But if you're saying now -- as I understand it, what you're saying is that break-even number demonstrates that it is perhaps most economical to use baseload to serve anything above 1430 hours on a consecutive basis? I mean, that's what the break-even number then demonstrates, as I understand your explanation?

A If you restrict yourself just to that part of the load duration curve and said if they had nothing else to serve, forget about everything else, what I was saying was, by definition those would be consecutive days, and yes, they could justify building that kind of unit if they expected that that's all they would -- that the alternative would be equally as expensive.

Q Then doesn't that mean that the break-even number of hours, 1430, does not demonstrate that it would be more cost beneficial or more cost effective to build a baseload unit to serve the actual, if you were only going to serve the actual 1430 peak demand hours of a year? (Pause)

A I'm not sure I understand the connection. If the baseload unit --

Q Do you understand the question?

A I guess I don't. I don't see what -- the actual 1430 highest peak hours of the year, that's one thing.

Q Okay. Let's say, let's start with the actual highest 1430 peak demand hours in a year on Gulf's system. And you know, as we discussed, that they would likely be, if you actually took the highest 1430 and started with the highest being 1 and ran to 1430, by the time you had identified each one, you would be all over the calendar at various times?

A You could be, yes.

Q Likely would be?

A Certainly. If you're planning for 8,760 hours, then yes, by definition, the 1430 are not going to occur simultaneously.

Q All right. And if a utility were to be required to meet demand in those hours -- exclusively. I'm talking about strictly on a theoretical bases, strictly to explore theory. If a utility were to be required to meet those 1430 hours only, they likely wouldn't choose as the most economical choice a baseload unit, is that correct?

A Probably not, because of the cycling required.

Q Okay.

A And when you do the economic analysis, you're not looking at the baseload plant in a cycling mode and comparing that with a peaking unit, you're comparing it with a peaking unit and a baseload plant in its normal mode.

Q And so you agree that, if it's only to meet those 1430 identified peak hours, it wouldn't be cost effective to use baseload, you would go to peaking? So wouldn't that mean that for a baseload to be more cost effective, it's because of times other than the identifiable 1430 highest peak hours?

A That's the assumption that you're going to operate a baseload plant at a relatively steady state.

Q So that basically then takes, for cost justification of the baseload over the peaking unit, requires consideration of some of the non-1430 highest peak hours of a given year, is that correct?

A Not, no, in consideration only in the sense that the reality is that the unit is going to operate. And I maintain the fact that the unit operates in those hours does not necessarily equate with cause or reason why you built that unit vis-a-vis the other unit.

Q Doesn't this demonstrate, then, to you that if one were to -- that the 1430 highest peak demand hours of the year, by themselves, do not dictate a baseload unit as a preferable choice over a peaking unit?

A Well, again, if you're just looking at the

1430 hours, irrespective of the other hours of the year that you expect the baseload unit to operate, no, the Utility would certainly not build the baseload unit.

Q And isn't that the theory upon which the break-even analysis calculates 1430 hours as its break-even point?

A Not really. The theory is that, looking at the alternative in building the peaking unit, it simply isn't economical to run a peaking unit beyond 1430 hours, therefore, I'm going to build a baseload unit.

If you have a demand that's going to be more than 1430 hours, you know that you've got the load duration curve, you're not going to just serve loads in those 1430 hours, you're going to serve loads beyond those 1430 hours. Remember, the break-even point defines the point of indifference, it doesn't define the point as more economical. It's the fact that past the break-even point, you're now, you've chosen the more economical alternative.

Q Back to the load, to the non-1430 hours as a consideration?

A It's a consideration, not necessarily a causation. If all we were concerned about was serving 1430 hours, then there would probably be no consideration of different technologies to serve the load economically.

Q We would just be talking about peaking, at that point?

A We would be talking about anything that could do the job in that. But you wouldn't necessarily look at different technologies or do technology screens as systems planners do.

Similarly, if you only look at the hours after the 1430 hours, you have no longer a concern with the need for capacity, there is no capital substitution because the load curve is flatter in that period, and again, there is no technology screen.

Q Is there an average availability factor for baseload coal-fired units?

A The statistics have been calculated as to what the reliability of baseload units are, yes.

Q Would it be fair to say it's somewhere in the low 80% range?

A Depending on which type of unit you're talking about.

Q Let's go to, let's talk about Gulf's units. Then we're talking in the high 80% range, aren't we?

A I accept that.

Q With a 100% load factor load, let's suppose a 100% load factor load and you have, say, 89%

reliability factor. That would mean that, for the other 11% of the time, you'd have to have some type of reserve system, is that correct?

A Yes. You would. (Pause)

MR. BURGESS: Mr. Pollock, thank you very much, that's all I have.

(Transcript follows in sequence in Volume XX.)

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