Before the

Florida Public Service Commission

Docket No. 891345-EI

GULF POWER COMPANY

Appendices of

JEFFRY POLLOCK

On behalf of:

AIR PRODUCTS AND CHEMICALS, INC.
AMERICAN CYANAMID COMPANY
CHAMPION INTERNATIONAL CORPORATION
EXXON COMPANY, U.S.A.
MONSANTO COMPANY
STONE CONTAINER CORPORATION

Project 5095
May 1990

Drazen-Brubaker & Associates, Inc.
St. Louis, Missouri 63141-0110

APPENDIX A

Qualifications 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 STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I am a graduate of Washington University. I hold the degrees of Bachelor of Science in Electrical Engineering and Master of Business Administration. At various times prior to graduation, I worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L. K. Comstock & Company. While at McDonnell Douglas, I analyzed the direct operating cost of commercial aircraft. Upon graduation, in June, 1975, I joined the firm of Drazen-Brubaker & Associates, Inc. My work consists of preparation of financial and economic studies related to electric and gas utilities, including revenue requirements, cost-of-service studies, rate design, site evaluations and service contracts. I am also responsible for the development of seminars on utility regulation.

I have testified before the regulatory commissions of Alabama, Arizona, Delaware, Florida, Georgia, Illinois, Iowa, Louisiana, Minnesota, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas and Washington. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Bonneville Power Administration, and the U.S. Federal District Court.

The firm of Drazen-Brubaker & Associates, Inc. was incorporated in 1972 and has assumed the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. In the last five years, our firm has participated in more than 700 rate cases in forty states and Canada.

The firm provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. In addition, we have also prepared depreciation and feasibility studies relating to utility service. In all these cases, it was necessary to analyze the utility's operating and financial records, including property records, depreciation studies, revenues, expenses and taxes. We also assist in the negotiation of contracts for utility service for large users and present seminars on utility regulation.

In general, we are engaged in regulatory consulting, economic studies and contract negotiation.

APPENDIX B

COST-OF-SERVICE DETERMINATION PROCEDURES

Overview - Rate Case Phases

There are three basic phases to a rate case. These phases are the *revenue requirement* phase, the *cost allocation* phase, and the *rate design* phase.

In the *revenue requirement* phase, the objective is to determine the total amount of money that the utility may collect from all of its customers in total. In general, a utility is entitled to recover its prudently incurred expenses, including labor, fuel, materials and supplies and taxes, plus sufficient income to cover interest expense and construction requirements.

In the *cost allocation* phase, the objective is to determine what proportion of the utility's total revenue requirements should be recovered from each customer class. As an aid to this determination. cost-of-service studies are usually performed to determine the portions of the total costs that are incurred to serve each customer class. Allocation factors are used to allocate costs which are not directly assignable to a particular class. The allocation factors used should reflect the extent to which each class causes the utility to incur costs for each item being allocated. (To achieve this goal, numerous allocation factors must be constructed.) The cost-of-service study identifies the cost responsibility of the class and provides the foundation for revenue allocation and rate design. For many regulators, cost-based rates are an expressed goal.

While many commissions are moving toward cost-based rates, it may require, as in the case of Gulf Power Company, gradual movement.

In the *rate design* phase, the objective is to determine how the class revenue requirement should be recovered from the individual ratepayers. While movement toward a cost-based allocation of revenues to classes eliminates subsidies between customer classes, proper rate design eliminates subsidies between customers within the class.

A Closer Look at Cost-of-Service Issues

Although people often think of electricity simply in terms of kilowatthours, a utility actually provides a multi-dimensional service and incurs many different types of cost in providing that service. Contrary to the claim that "a kilowatthour is a kilowatthour" and that industry shouldn't buy them any cheaper than homeowners, two customers using the same number of kilowatthours may impose quite different costs on the utility. The cost justifications for these per kilowatthour differences are described in more detail below in the discussion of cost-of-service issues.

A class cost-of-service study contains three steps:

(1) **Functionalization**--identifying the different types of cost;

(2) **Classification**--determining their primary causative factors; and

(3) **Allocation**--apportioning each item of cost among the various classes.

Functionalization

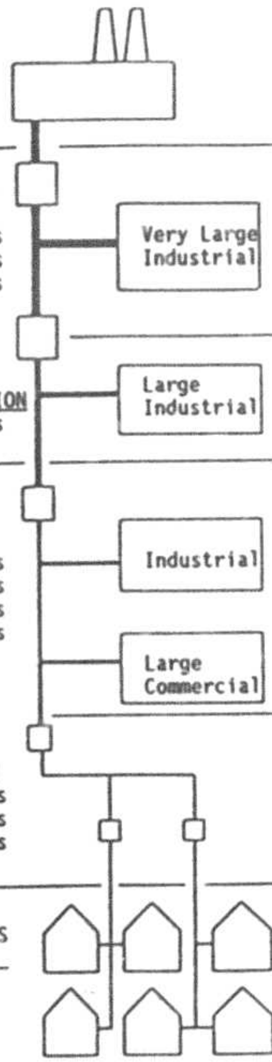
In this first step, costs are categorized into specific function production, transmission, distribution and general. Examine a non-electric commodity, for example, bananas. Many bananas sold in the United States are grown in Honduras, where they sell for about 5¢ a pound. Honduran growers represent the "production" phase of the banana market. To make the bananas available in Pensacola, they must be transported from the production site to the bulk distribution centers in this country. This transportation from Honduras is the "transmission" phase. The cost of transmission must be added to the original production cost of 5¢ a pound. Finally, the bananas are distributed to neighborhood stores, which adds more costs of transporting and handling as well as the store's own costs of light, heat, produce, personnel and rent. Shoppers can now purchase as many or as few bananas as they desire at their convenience. This stage represents the "distribution" phase. During the transmission and distribution phases, there are losses from spoilage and damage in handling. These "line losses" represent an additional cost which must be recovered in the final price. Finally, there are general costs associated with insurance, taxes and personnel that must be recovered in the price of bananas. The price paid at the store, for example, 40¢ per pound, must cover the costs of production, transmission, distribution and general expense. The store price is higher than the price at the dock, because it includes the <u>service</u> of having it available in convenient amounts and locations. If we chose to expend the time and resources, we could buy the bananas from the wholesale distributor or the importer at the dock. By foregoing the convenience, we could purchase the bananas at a lower price.

Production, transmission and distribution of electricity are comparable to the banana example, except that in most cases a single company handles everything from production to bulk transmission to retail distribution. Each additional step down the line from production to delivery requires additional investment, additional expenses and results in some additional line losses. When you buy a kilowatthour at home, you're buying not only the energy itself but also the service of having it delivered right to your doorstep in convenient form. Those who buy at the bulk or wholesale level--like municipal customers or large industrial users--pay less because the utility avoids some of the expenses of transmission and distribution. (Actually, the expenses are borne by the customer who must invest in his own transformers and other equipment.)

The process of identifying the different levels of operation is called functionalization. The functionalization process is illustrated in Diagram 1. This diagram illustrates the level of costs incurred by the utility at each functional level.

THE PRODUCTION AND DELIVERY OF ELECTRICITY

INVESTMENT	EXPENSE	FUNCTION
$531,156	FUEL & PURCHASED POWER: $168,333 OTHER: 103,219	GENERATION
83,472	12,480	TRANSMISSION 765,000 Volts 345,000 Volts 138,000 Volts SUBTRANSMISSION 69,000 Volts
225,120	27,265	PRIMARY DISTRIBUTION 46,000 Volts 34,500 Volts 13,200 Volts 4,160 Volts SECONDARY DISTRIBUTION 480 Volts 240 Volts 120 Volts
83,811	36,897	SERVICE DROPS AND METERS CUSTOMER ACCOUNTS
923,559	348,194	TOTAL



Classification

The next step in cost analysis is the classification of functional expenses as demand-related, energy-related or customer-related. In this step we identify the primary causative factor (or factors) for each functional cost element.

Some costs are easily classified to demand-related, energy-related or customer-related. For example, the amount of fuel burned--and therefore the amount of fuel expense--is directly related to the amount of energy (number of kilowatthours) that customers use. Therefore, fuel expense is an energy-related cost. On the other hand, the amount of production plant capacity required is primarily determined by the peak rate of usage during the year. If the utility anticipates a peak demand of 2,000 megawatts--it must install enough generating capacity to meet that anticipated demand (plus some reserve for variations in load or capacity). There will be many hours during the day or during the year when not all of this generating capacity will be needed. Nevertheless, it must be in place to meet the peak demands on the system. Thus, production plant investment usually is considered demand-related. The costs associated with transmission are usually classified as demand-related, because the transmission system must have enough capacity to carry the highest load on the system.

The difference between demand-related and energy-related costs explains the fallacy of the argument that "a kilowatthour is a kilowatthour." For example, two customers who use the same amount of energy (kWh) annually may require different amounts of generating capacity. Customer

A's manufacturing plant operates 22 hours a day, 364 days a year at a nearly constant load of 1,000 kilowatts. He uses about 8,000,000 kilowatthours a year (1,000 kW x 364 x 22 = 8,000,000). Customer B's plant has a load of 4,000 kilowatts but operates only one 40-hour shift a week for 50 weeks each year. He also uses 8,000,000 kilowatthours (4,000 kW x 40 x 50 = 8,000,000). Both use the same number of kilowatthours, but for Customer B the utility must install four times as much generating capacity as for Customer A. The cost of serving Customer B is therefore much higher.

In general, a customer who has a high <u>load factor</u> (defined as the average rate of usage divided by the peak rate of usage) will be cheaper to serve per kWh than a customer with a low load factor. Consider the analogy of a rental car which costs $40/day and 40¢/mile. If Customer B drives only 20 miles a day, the average cost will be $2.40/mile. But for Customer A, who drives 200 miles a day, spreading the daily rental charge over the total mileage gives an average cost of 60¢/mile. For both customers, the fixed cost rate (daily charge) and variable cost rate (mileage charge) are identical, but the <u>average total</u> cost per mile will differ depending on how intensively the car is used. Likewise, the average cost per kilowatthour will depend on how intensively the generating plant is used. A low load factor indicates that the capacity is idle much of the time; a high load factor indicates a more steady rate of usage. Since industries generally have higher load factors than residential or general service customers, they are less costly to serve on a per-kilowatthour basis. Again, we can say that "a kilowatthour is a kilowatthour" as to energy content, but there may be a big difference in how much generating plant investment is required to convert the raw fuel into electrical energy.

The third major classification category is customer-related costs. Each residential customer requires a meter and service drop. Each user's meter must be read, recorded and billed and the revenues posted. These costs are much the same for each residential customer whether he or she uses 15 kilowatthours or 1,500 kilowatthours. The amount of such cost increases as the number of customers increases; hence, they are called "customer-related."

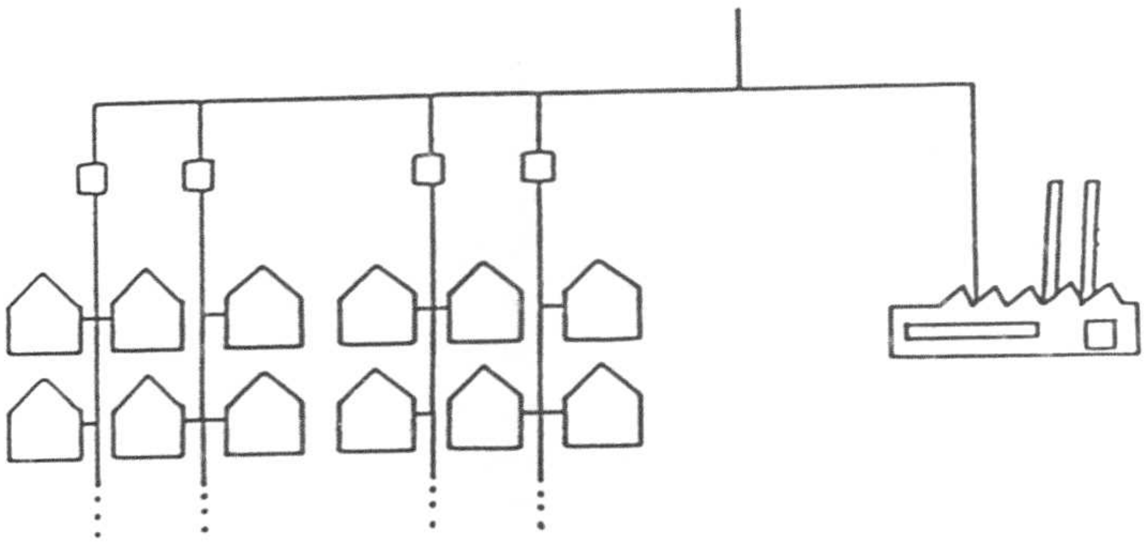
Also, a certain portion of the cost of the distribution system--poles, wires and transformers--is required simply to attach customers to the system, regardless of their demand or energy requirements. This minimum or "skeleton" distribution system may also be considered a customer-related cost since it depends primarily on the number of customers, rather than demand or energy usage.

The diagram on Page 9, for example, shows the distribution network for a utility with two customer classes, A and B. The physical distribution network necessary to attach Class A is designed to serve 12 customers, each with a 10-kilowatt load, having a total demand of 120 kW. This is the same total demand as is imposed by Class B, which consists of a single customer. Clearly, a much more extensive distribution system is required to attach the multitude of small customers (Class A), than to attach the single larger customer (Class B), even though the total demand of each customer class is the same.

Even though some additional customers can be attached without additional investment in some areas of the system, it is obvious that attaching a large number of customers requires investment in facilities, not only initially but on a continuing basis for maintenance and repair.

To the extent that the distribution system components must be sized to accommodate additional load beyond the minimum, the balance is a demand-related cost. Thus, the distribution system is classified as both demand-related and customer-related.

Classification of Distribution Investment



Total Demand = 120 kW

Class A

Total Demand = 120 kW

Class B

Allocation

The final step in the cost-of-service analysis is the allocation of the costs to the customer classes. Demand, energy and customer allocation factors are developed to apportion the costs among the customer classes. Each factor simply measures the customer class's contribution to the system total cost.

For example, we have already determined that the amount of fuel expense on the system is a function of the energy. In order to allocate this expense among classes, we must determine how much each class contributes to the total kWh consumption and we must recognize the line losses associated with transporting and distributing the kWh. These contributions, expressed in percentage terms, are then multiplied by the expense to determine how much expense should be attributed to each class. A sample calculation for Gulf is shown in Table 1.

TABLE 1

Energy Allocation Factor

Line	Rate Class	Energy Sold (MWh) (1)	Loss Expansion Factor (2)	Energy Generated (MWh) (3)	Allocation Factor (4)
1	RS/RST	3,330,638	1.0830	3,606,997	43.83%
2	GS/GST	211,052	1.0830	228,563	2.78
3	GSD/GSDT	1,731,710	1.0827	1,874,959	22.79
4	LP/LPT	1,383,390	1.0482	1,450,046	17.62
5	PX/PXT	983,828	1.0241	1,007,513	12.25
6	OS I, II & III	54,809	1.0830	59,357	0.72
7	Total	7,695,427		8,227,435	100.00%

Note that the GSD and LP classes are served at secondary, primary and subtransmission levels. All of the PX sales are made at the subtransmission level.

Similarly, meter reading expense is customer-related. Accordingly, we would allocate this cost among classes in proportion to the number of customers in each class. Because utilities recognize that industrial customers require more sophisticated and expensive meters and, therefore, somewhat more investment and expense, they commonly assign "weighting factors" so that a single industrial customer is regarded as equivalent to several residential customers.

Table 2 shows the construction of a weighted customer allocation factor. In this example, each GS and GSD customer is considered to be equivalent to 5 and 14.0 residential customers, respectively. Each LP and PX customer is considered to be equivalent to 38 and 86 residential customers, respectively.

Table 2

Weighted Customer Allocation Factor
Account 370 - Meters

Line	Rate Class	Customers (1)	Weighting Factor (2)	Weighted Customers (3)	Allocation Factor (4)
1	RS/RST	253,526	1.0	253,526	48.60%
2	GS/GST	21,975	5.3	115,401	22.12
3	GSD/GSDT	10,588	13.9	146,901	28.16
4	LP/LPT	140	38.1	5,327	1.02
5	PX/PXT	6	85.8	515	0.10
6	Total	286,235		521,670	100.00%

For demand-related costs, we construct an allocation factor by looking at the contribution of each class to the peak demands within 5% of the annual system peak (Near Peak). Table 3 shows the calculation of this factor for Gulf.

Table 3

Demand Allocation Factor:
Production and Transmission

Line	Rate Class	Near Peak at Meter (MW) (1)	Loss Expansion Factor (2)	Near Peak at Generator (MW) (3)	Allocation Factor (4)
1	RS/RST	757	1.1141	843	51.59%
2	GS/GST	50	1.1141	56	3.43
3	GSD/GSDT	328	1.1137	365	22.34
4	LP/LPT	231	1.0836	250	15.30
5	PX/PXT	115	1.0325	119	7.28
6	OS I, II & III	1	1.1140	1	0.06
7	Total	1,482		1,634	100.00%

Making the Cost-of-Service Study--Summary

The cost-of-service procedure involves three steps:

(1) Functionalization -- Identify the different functional "levels" of the system;

(2) Classification -- Determine, for each functional type, the primary cause or causes of that cost being incurred;

(3) Allocation -- Calculate the class proportional responsibilities for each type of cost and spread the cost among classes.

Table 4 shows the results of a cost-of-service study in condensed, summary form. The revenues from each class can be calculated by taking the billing units times the current rate. The expenses for each class are allocated. Subtracting the expenses from the revenue gives the net operating income (also called return) from each class. Dividing this net operating income by the allocated rate base gives the rate of return (return on investment) for each class.

Table 4

Summary of Gulf Power Company's Cost-of-Service Study (Thousands of Dollars)

Line	Rate Class	Revenues (1)	Expenses (2)	Return (3)	Rate Base (4)	Rate of Return (5)
1	RS/RST	$135,989	$106,862	$29,127	$511,835	5.69%
2	GS/GST	15,452	10,659	4,793	35,982	13.32
3	GSD/GSDT	52,987	39,246	13,741	189,251	7.26
4	LP/LPT	29,810	22,536	7,274	114,693	6.34
5	PX/PXT	16,541	11,901	4,640	55,614	8.34
6	OS I, II & III	4,129	3,030	1,099	13,477	8.15
7	Total Retail	$254,908	$194,234	$60,674	$920,852	6.59%

This cost study shows two things. First, it shows that at present rates not all classes are equally profitable. In other words, some classes pay a portion of the costs incurred to serve other customer classes. Second, it provides the information from which we can calculate the necessary increase in revenues from each class to achieve cost-based revenues.

Table 5 shows each class's cost-based revenue requirement.

This amount is calculated by summing the required return (rate base times system rate of return) and expenses. Expressed on a cents per kWh basis, the residential class has an above-average cost per kWh and the PX class has a below-average cost per kWh.

Table 5

Class Revenue Requirement
Excluding Fuel and Conservation Costs
Near-Peak Method
(Millions of Dollars)

Line	Rate Class	Cost-Based Revenue (1)	Energy Sales (GWh) (2)	Cost per kWh (3)
1	RS/RST	$158.1	3,331	4.7¢
2	GS/GST	12.5	211	5.9
3	GSD/GSDT	56.3	1,732	3.3
4	LP/LPT	33.6	1,383	2.4
5	PX/PXT	16.6	984	1.7
6	OS I, II & III	4.4	55	8.0
7	Total Retail	$281.5	7,695	3.7¢

The reasons for these differences are: (1) load factor, (2) delivery voltage, and (3) size.

LP and PX customers have higher load factors, as shown in Schedule B-1. Consequently, the capital costs related to production and transmission are spread over a greater number of kilowatthours.

In addition, LP and PX customers take service at a higher voltage level, as shown in Schedule B-2. This means that they have fewer costs associated with lower voltage distribution. Nor does Gulf incur as many losses to serve LP and PX customers. As shown in Schedule B-3, Gulf must generate 108 kWh per 100 kWh sold to the residential class. By contrast, only 105 and 102 kWh need to be generated to sell 100 kWh to LP and PX customers, respectively.

Finally, the per capita sales to the LP and PX classes are also much greater than to the other classes. Gulf sells between 19,900,000 and 164,000,000 kilowatthours per LP and PX customer, respectively, but only 13,137 kilowatthours per residential customer, or between 1,500 and 12,500 times more per capita, as shown in Schedule B-4. The customer-related costs to serve the former are not 1,500 to 12,500 times the customer-related costs to serve the residential customer.

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Comparative Load Factors
(Year Ending December 31, 1990)

Line	Rate Class	Energy Required (MWh) (1)	Near-Peak Demand (MW) (2)	Load Factor (3)
1	RS/RST	3,606,997	843	49%
2	GS/GST	228,563	56	47
3	GSD/GSDT	1,874,959	365	59
4	LP/LPT	1,450,046	250	66
5	PX/PXT	1,007,513	119	97
6	OS I, II & III	59,357	1	N/M
7	Total Retail	8,227,435	1,634	57%

GULF POWER COMPANY

Percent of Sales by Incoming Voltage (Year Ending December 31, 1990)

Line	Rate Class	Secondary (1)	Primary (2)	Transmission/ Subtransmission (3)	Total (4)
1	RS/RST	100.00%	- %	- %	100.00%
2	GS/GST	99.99	0.01	-	100.00
3	GSD/GSDT	99.26	0.63	0.11	100.00
4	LP/LPT	26.38	37.51	36.11	100.00
5	PX/PXT	-	-	100.00	100.00
6	OS I, II & III	100.00	-	-	100.00%
7	Total Retail	73.81%	6.89%	19.30%	100.00%

GULF POWER COMPANY

Energy Losses
(Year Ending December 31, 1990)

Line	Rate Class	Energy Required (MWh) (1)	Energy Sold (MWh) (2)	Losses as a Percent of kWh Sales (3)	Generation per 100 kWh Sold (4)
1	Residential	3,606,997	3,330,638	8.3%	108
2	General Service	228,563	211,052	8.3	108
3	General Service - Demand	1,874,959	1,731,710	8.3	108
4	LP & LPT	1,450,046	1,383,390	4.8	105
5	PXT	1,007,513	983,828	2.4	102
6	OS	59,357	54,809	8.3	108
7	Total Retail	8,227,435	7,695,427	6.9%	107

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Kilowatthours Sold
per Customer
(Year Ending December 31, 1990)

Line	Rate Class	Energy Sold (MWh) (1)	Number of Customers (2)	Annual Sales per Customer (3)
1	RS/RST	3,330,638	253,526	13,137
2	GS/GST	211,052	21,975	9,604
3	GSD/GSDT	1,731,710	10,588	163,554
4	LP/LPT	1,383,390	140	9,881,357
5	PX/PXT	983,826	6	163,971,333

APPENDIX C

ILLUSTRATIONS OF TWO OF THE CONCEPTUAL FLAWS WITH THE EP AND REP METHODS

Q **WHAT IS THE PURPOSE OF APPENDIX C?**

A The purpose of Appendix C is to illustrate two of the conceptual flaws with both the EP and REP methods. As discussed beginning on Page 7 of the direct testimony, the two methods allocate more production capital costs to higher load factor rate classes than under a "slice of the system" approach. The rationale behind this approach is that utilities, allegedly, incur the higher capital costs of installing and operating base load units solely to save fuel costs.

Even if one would accept this proposition (which is a gross oversimplification of the utility planning process), both the EP and REP methods remain fatally flawed.

First, there is no attempt to reallocate production operating costs in a manner consistent with the assumed capital/operating cost trade-offs implicit in both methods. In other words, each class continues to get a "slice of the system" as far as operating costs are concerned. This is wrong because, as far as capital costs are concerned, each class is assigned a different mix of technologies. Consistency and logic demand that if each rate class is assigned a difference capacity mix, then the allocation of operating costs should also reflect a different energy mix. This flaw of the EP and REP methods is often referred to as the "Fuel Symmetry" problem.

The second conceptual flaw is the assumption that all kilowatt-hours throughout the year cause the higher capital investment typically associated with modern base load units. There is no empirical evidence, however, to support the assumption that capital investment decisions are related to annual kWh sales. As demonstrated below, it is only the hours of the load duration curve up to the break-even threshold that would cause *extra* base load capital costs to be incurred. Therefore, it would a giant leap of logic--not to mention a flagrant violation of the principal of cost-causation--to allocate these *extra* capital cost to year-round energy, as is the case under the EP method.

1. <u>FUEL SYMMETRY PROBLEM</u>

Q CAN YOU ILLUSTRATE HOW THE RECOGNITION OF THE CAPITAL/OPERATING COST TRADE-OFFS WOULD RESULT IN ALLOCATING <u>BOTH</u> BELOW-AVERAGE CAPITAL COSTS AND ABOVE-AVERAGE OPERATING COSTS TO A LOW LOAD FACTOR CUSTOMER CLASS?

A Yes. This symmetrical relationship can be demonstrated using a "Lowest Cost System" (LCS) model. The LCS is the generation system that explicitly takes into account the trade-off between capital costs and operating costs of different technologies in order to minimize the total cost of serving a given load. In other words, the LCS model explicitly recognizes the capital substitution effect. To demonstrate this effect, I have constructed an LCS for the total Gulf and an LCS for each of the major rate classes. By comparing the per-unit capital and operating costs of each class, it is possible to demonstrate that an appropriate recognition of the production cost trade-off should result in allocating above-average capital costs and below-average operating costs to a high load factor load and vice-versa for a low load factor load.

Q HOW WAS THE "LOWEST COST SYSTEM" DEVELOPED?

A To simplify the analysis, I assumed that the total cost to construct and operate base load and peaking capacity is equivalent at 1,430 hours' use. In other words, 1,430 hours' use is assumed to be the break-even threshold between base load and peaking capacity. If the unit is expected to run for less than 1,430 hours, the lower "up front" capital cost of the peaking unit makes this technology more economical. If the unit is expected to run more than 1,430 hours per year, then the base load unit would be more economical. The assumed capital and operating costs for each technology are as follows:

Table 1

Production Cost Trade-Offs
1,430 Hour Break-Even Threshold

Technology	Capital Cost (kW)	Operating Cost (kWh)
Base Load	$126.09	2.076¢
Peaking	$ 44.36	7.790¢

At 1,430 hours' use, the two technologies would have the same total production cost:

Table 2

Total Production Cost
At 1,430 Hours' Use

Base Load:	\$126.09/kW + (1,430 hours x 2.076¢/kWh)	= \$156
Peaking:	\$ 44.36/kW + (1,430 hours x 7.790¢/kWh)	= \$156

Q WHAT IS THE NEXT STEP FOR DERIVING THE LCS?

A The next step is to look at the load duration curve (LDC) and determine the optimal amount of base and peaking capacity. Schedule C-1 shows a representative load duration curve for the total Gulf system. Schedule C-2 shows the LDCs by customer class. On each LDC, I have marked the break-even threshold (at 1,430 hours). The optimum capacity mix and the optimum generation mix are shown in Schedules C-3 and C-4. By definition, the optimal amount of base load capacity is the point on the vertical axis that intersects the LDC at the break-even threshold.

For example, referring to Schedule C-1, the total Gulf load would be served most economically by 71% base load capacity--which will be operated for more than 1,430 hours per year--and 29% peaking capacity --which will be operated for less than 1,430 hours per year. The optimum capacity mix by customer class would be as follows:

Table 3

Optimum Capacity Mix
Derived From the LCS Model

Customer Class	Base Load	Peaking
RS/RST	60%	40%
GS/GST	53	47
GSD/GSDT	72	28
LP/LPT	72	28
PX/PXT	94	6
OS I, II & III	88	12
Total Company	**71%**	**29%**

The average capital cost to serve each class would be the product of: (1) the assumed base load and peaking capital costs from Table 1 and (2) the capacity mix from Table 3 as follows:

Table 4

Production Capital Cost
Derived From the LCS Model

Customer Class	Cost	Relative Cost
RS/RST	$ 93/kW	91%
GS/GST	87/kW	86
GSD/GSDT	103/kW	101
LP/LPT	103/kW	101
PX/PXT	121/kW	119
OS I, II & III	116/kW	114
Total Company	**$102/kW**	**100%**

For example, the RS/RST capital cost would be derived as follows:

$$\$126.09 \times 60\% + \$44.36 \times 40\% = \$93/\text{kW}$$

This demonstrates that, on a stand-alone basis, the average capital cost to provide service is below the system average for residential customers and above the system average for industrial customers.

Q **IF THE OPTIMUM CAPACITY MIX DIFFERS BETWEEN THE VARIOUS RATE CLASSES, WOULD THE OPTIMUM GENERATION MIX ALSO BE DIFFERENT?**

A Yes. As shown below, residential customers would require relatively less base load energy and more peaking energy while the opposite would be true for industrial customers.

Table 5

Optimum Generation Mix
Derived From the LCS Model

Customer Class	Base Load	Peaking
RS/RST	96.13%	3.87%
GS/GST	93.94	6.06
GSD/GSDT	97.46	2.54
LP/LPT	98.58	1.42
PX/PXT	99.82	0.18
OS I, II & III	96.80	3.20
Total Company	**96.12%**	**3.88%**

Translating these differences into average production operating costs, it becomes evident that the average operating cost to provide service would be higher than the system average for a residential customer and lower than the system average for an industrial customer:

Table 6

Production Operating Cost
Derived from the LCS Model

Customer Class	Total Cost	Relative Cost
RS/RST	$22.97/MWh	100%
GS/GST	24.22/MWh	105
GSD/GSDT	22.21/MWh	95
LP/LPT	21.57/MWh	94
PX/PXT	20.86/MWh	91
OS I, II & III	22.59/MWh	98
Total Company	**$22.98/MWh**	**100%**

The derivation of the RS/RST operating cost, for example, would be as follows:

$$\$20.76 \times 96.13\% + \$77.90 \times 3.87\% = \$22.97/\text{MWh}$$

To summarize, the LCS model confirms the expectation that there is a symmetrical relationship between the allocation of capital and fuel costs; that is, a low load factor class which is allocated below-average capital costs under a CAPSUB-based method should also be allocated above-average operating costs. Higher load factor customers, by contrast, who are allocated above-average capital costs should be allocated below-average operating costs.

Q IS THE "FUEL SYMMETRY" CONCEPT VALID EVEN IF THERE IS NOT A SIGNIFICANT FUEL COST DIFFERENTIAL BETWEEN DIFFERENT TYPES OF GENERATING CAPACITY?

A The entire CAPSUB theory rests on the assumption that the fuel cost differences between base load and peaking units cause the utility to incur the extra capital costs usually associated with a base load unit. If such differentials no longer exist, then one has to seriously question the validity of the CAPSUB theory. Either there is or is not a trade-off. If the trade-off only works one way as CAPSUB proponents advocate, then it should be obvious that CAPSUB is nothing more than an excuse to shift more capital costs onto high load factor customer classes.

Studies that I have made of various utility planning decisions invariably show that oil and natural gas prices were expected to escalate much more rapidly than nuclear, coal or lignite, even assuming that ample supplies of oil and natural gas were available. (Natural gas curtailments, the Arab oil embargo and the Fuel Use Act virtually eliminated these fuels from consideration.) The important point is not what fuel costs are today, but what they were projected to be over the life-cycle of the base load unit when the decision to build the unit was made. Viewed from this perspective, it can be shown that a base load unit would be more economical over its useful life than a peaking unit, even if the former operated only 1,430 hours per year.

2. CAPITAL INVESTMENT DECISIONS ARE <u>NOT RELATED TO ANNUAL KWH SALES</u>

Q **DO ANNUAL KWH SALES AFFECT THE DECISION TO INVEST IN A PARTICULAR TYPE OF GENERATING CAPACITY?**

A No. The break-even point--that is, the hours of use at which the total cost of base load and peaking units are equivalent--typically occurs between 1,000 and 2,000 hours per year. Below the break-even point, a peaking unit would be more economical than a base load unit. Beyond the break-even point, a base load unit would be the more economical choice. Whether additional capacity would be operated 1,000, 2,000, 4,000 or even 100 hours beyond the break-even point would, therefore, be irrelevant. In other words, once the break-even threshold is reached, additional energy use (and the fuel cost savings resulting therefrom) has no impact on the investment decision. Therefore, load duration may influence capital investment decisions, but only up to a point. It would be logically incorrect to jump from this conclusion to a method in which production capital costs are allocated to all 8,760 hours per year.

Q **WHAT EMPIRICAL EVIDENCE DO YOU HAVE THAT YEAR-ROUND ENERGY CONSUMPTION DOES NOT DRIVE UTILITY INVESTMENT DECISIONS?**

A Recall that CAPSUB advocates typically proclaim that if a utility only had to meet its peak demand, then it would need to install only peaking units. Based on the total Gulf LCS analysis described earlier, the cost to serve the on-peak period (defined as the shaded area under the load duration curve to the left of the break-even point--Schedule C-1) entirely with peaking units would be $240 million, as shown in Table 7 below.

Table 7

Total On-Peak* Production Cost Assuming that Service Were Supplied Entirely from Peaking Units

Description	Formula	Total Gulf System Cost (Millions)
Capital Cost	= System Peak x Cp	= $ 77.3
	= 1,743 MW x $44.36/kW	
Operating Cost	= On-Peak Energy x Op	= 162.7
	= 2,087,776.0 MWh x $.0779/kWh	
Total On-Peak Cost		= $240.0

Where: Cp = Capital Cost of a Peaking Unit
Op = Operating Cost of a Peaking Unit

*Highest 1,430 hours of load

However, this is equivalent to the total production capital cost and the on-peak operating cost of an optimal generation system (consisting of both base load and peaking capacity) derived in the LCS analysis of the total Gulf system depicted in Table 8.

Table 8

Total On-Peak* Production Cost
Derived from LCS Model
Total Gulf System

Description	Formula	Cost (Millions)
Capital Cost:		
Peak-Related	= 1,743 x $44.36/kW	= $ 77.3
Base-Related	= 1,229 x ($126.09/kW-$44.36/kW)	= 100.5
Total Capital Cost		= $177.8
Operating Cost:		
Peaking	= 330,246 MWh x $.0779/kWh	= 25.7
Base Load**	= 1,757,530 MWh x $.02076/kWh	= 36.5
Total Operating Cost		= $ 62.2
Total On-Peak Cost		= $240.0

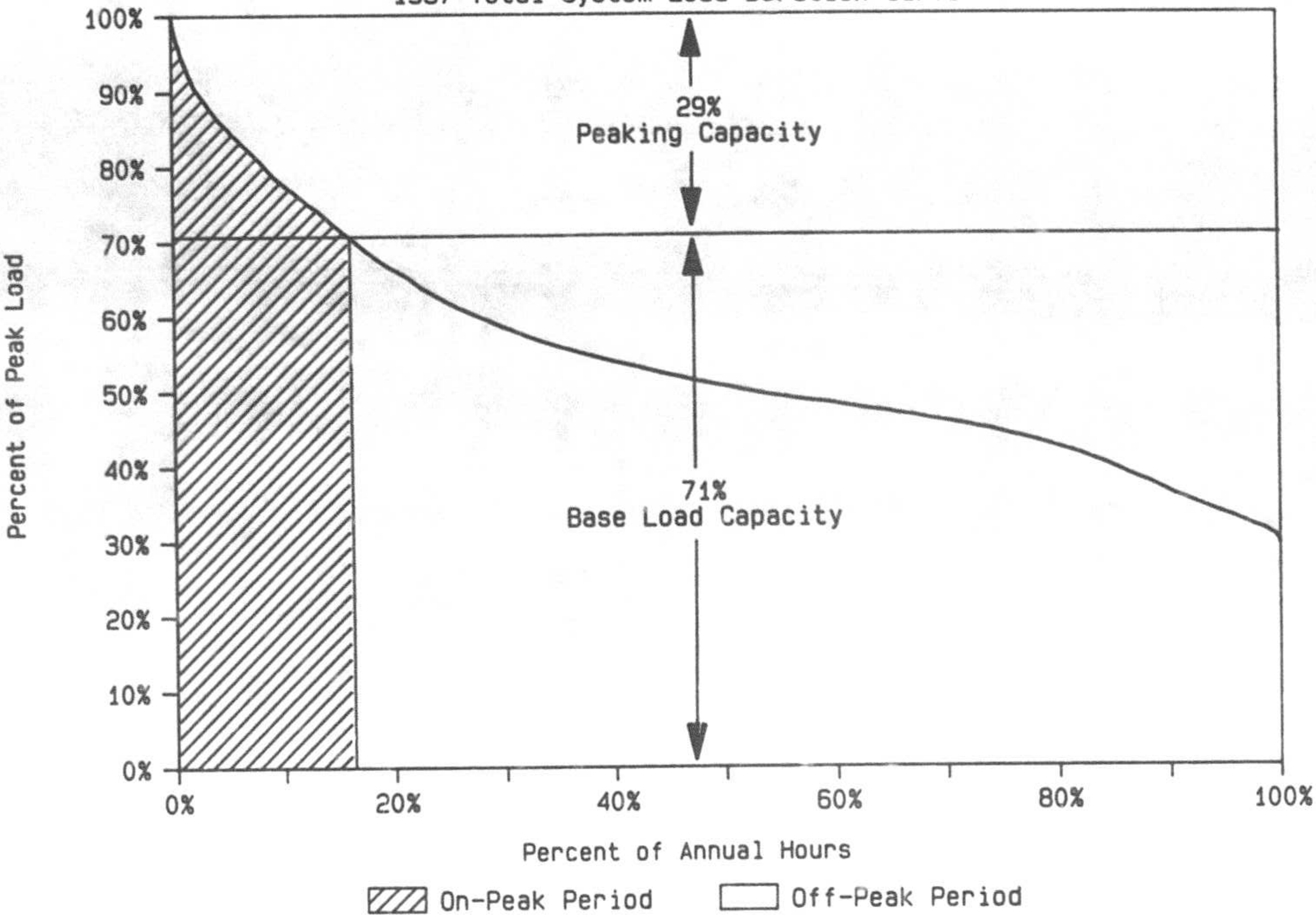
* Highest 1,430 hours of load
** 1,229 MW x 1,430 hours

In other words, at 1,430 hours of use, the extra base load capital costs are completely paid for. Thus, it would not be appropriate to allocate capital costs to all 8,760 hours (i.e., on an energy basis) because the lions share of these hours (beyond the break-even threshold) did not cause the utility to build a base load unit. Doing so not only would understate the cost to provide service to on-peak hours, but it would violate the principle of cost-causation.

Schedule C-1

GULF POWER COMPANY

1987 Total System Load Duration Curve

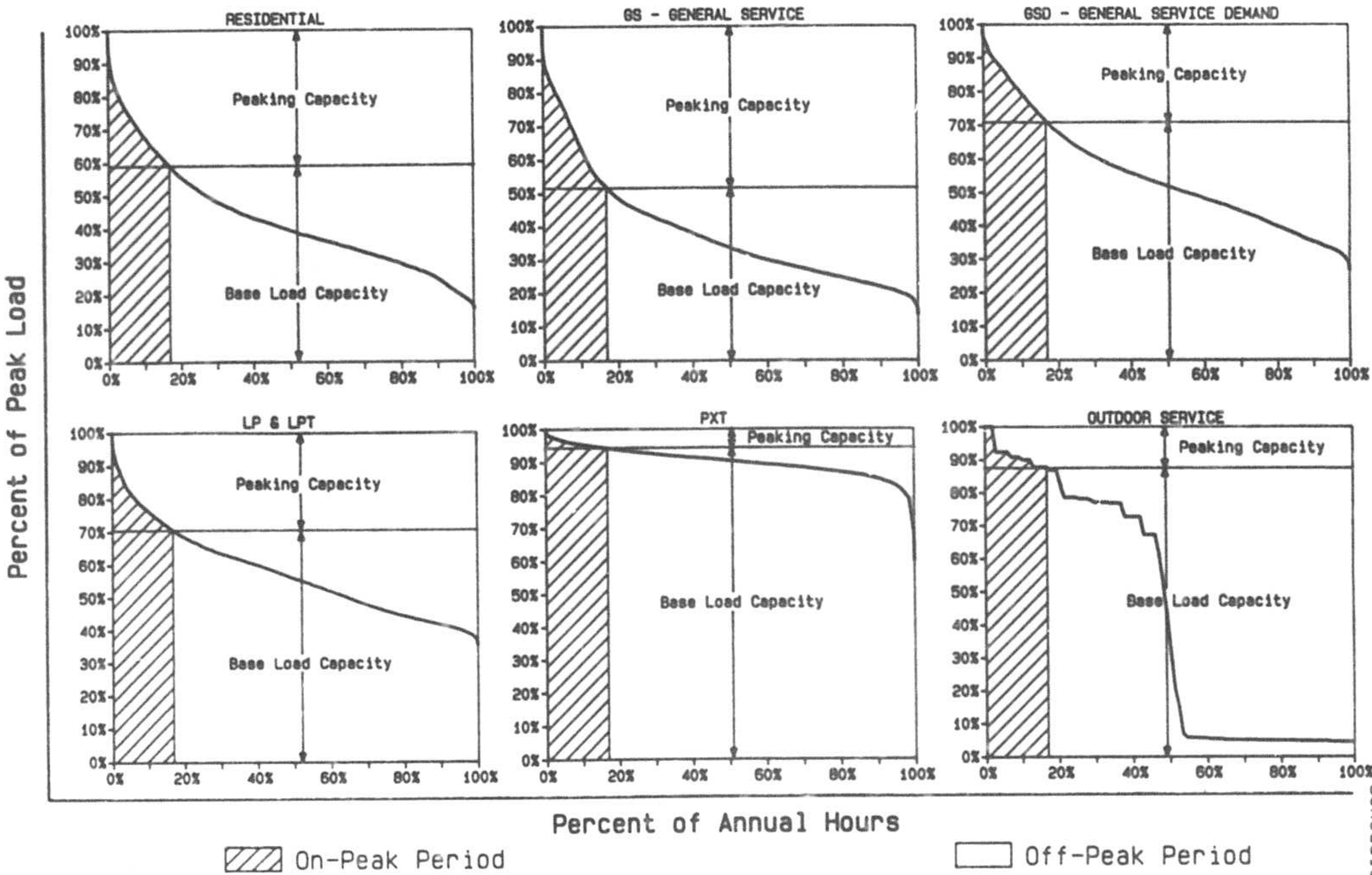


Schedule C-1

Schedule C-2

GULF POWER COMPANY

1987 Load Duration Curves



Schedule C-2

GULF POWER COMPANY

Lowest Cost System Capacity Mix by Customer Class
Assuming "Stand-Alone" Service
Year Ending December 31, 1990

		Capacity			Percent Capacity Mix		
Line	Customer Class	Base Load (MW) (1)	Peaking (MW) (2)	Total (MW) (3)	Base Load (4)	Peaking (5)	Total (6)
1	RS/RST	590	395	985	60%	40%	100%
2	GS/GST	38	34	72	53	47	100
3	GSD/GSDT	291	114	405	72	28	100
4	LP/LPT	219	84	303	72	28	100
5	PX/PXT	121	7	129	94	6	100
6	OS I, II & III	13	2	15	88	12	100
7	Gulf Power System	1,229	514	1,743	71%	29%	100%

GULF POWER COMPANY

Lowest Cost System Generation Mix by Customer Class
Assuming "Stand-Alone" Service
Year Ending December 31, 1990

Line	Customer Class	Energy Requirements: Base Load (MWh) (1)	Energy Requirements: Peaking (MWh) (2)	Energy Requirements: Total (MWh) (3)	Generation Mix: Base Load (4)	Generation Mix: Peaking (5)	Generation Mix: Total (6)
1	RS/RST	3,467,243	139,754	3,606,997	96.13%	3.87%	100%
2	GS/GST	214,704	13,859	228,563	93.94	6.06	100
3	GSD/GSDT	1,827,280	47,679	1,874,959	97.46	2.54	100
4	LP/LPT	1,429,432	20,615	1,450,046	98.58	1.42	100
5	PX/PXT	1,005,750	1,673	1,007,513	99.82	0.18	100
6	OS I, II & III	57,458	1,899	59,357	96.80	3.20	100
7	Gulf Power System	8,176,666	330,246	8,506,912	96.12%	3.88%	100%