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BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO 891345-EI

REBUTTAL TESTIMONY
AND EXHIBITS
OF
J. L. HASKINS

Gulf Power

<u>GULF POWER COMPANY</u>

Before the Florida Public Service Commission
Rebuttal Testimony of
Jack L. Haskins
In Support of Rate Relief
Docket No. 891345-EI
Date of Filing: May 21, 1990

Q. Mr. Haskins, have you previously submitted testimony in this proceeding?

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

Q. Have you prepared an exhibit that contains information to which you will refer to in your testimony?

A. Yes.

Counsel: We ask that Mr. Haskins' Exhibit (JLH-2) comprised of eight Schedules be marked for identification as Exhibit No. _____.

Q. Do you have any corrections or additions to the testimony and exhibits you have previously filed?

A. Yes. We have revised my Schedules 1, 2, and 5 as shown in my prefiled direct testimony based on the results of the revised cost of service study and rate design as submitted in Industrial Intervenor's Second Set of Interrogatories, Nos. 12 and 13, and Industrial Intervenor's Second Request for Production of

Documents, No. 27. These three schedules, "Analysis of Proposed Revenue by Rate 12 Months Ending December 1990," "Rates of Return by Rate Class," and "Average Cost of Localized Investment" are shown as Schedules 1, 2, and 3, respectively, in my exhibit to this testimony. For convenience, we are referring to the revised study as the "No Migration" study.

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

A. Yes.

Q. Do the subjects addressed in the testimony of Scheffel Wright, Jeffry Pollock, Dr. Charles Johnson, and Tom Kisla fall in your area of responsibility?

A. Yes. In addition to addressing various aspects of their testimony, my rebuttal testimony will also address some of the issues raised by intervenors, Staff, and Gulf Power Company.

Q. How did you develop the proposed customer charges?

A. The unit costs from Mr. O'Sheasy's cost of service study were used as the starting point in selecting the various customer charges. The subsequent development of the proposed charges is discussed fully in my prefiled direct testimony on pages 7-11. No other testimony supporting any other charges has been submitted by any party in these proceedings other than Mr. Wright, who stated that the customer charges should be cost based.

Q. How did you determine the proposed standard demand charges?

A. Again, the first consideration was the demand unit cost from Mr. O'Sheasy's cost of service study. The subsequent development of the proposed charges is discussed in my direct testimony beginning on page 14. With the exception of Dr. Johnson's LP/LPT rates, no other witness has offered testimony supporting any other demand charges for standard rates GSD, LP, or PX.

Q. How did you determine the demand charges which are included in Gulf's proposed TOU rates?

A. As stated in my direct testimony on pages 18-20, the Load Factor Methodology that has been used and approved in our last three rate cases was the methodology chosen to design the demand charges for the TOU rates.

Q. What is this "Load Factor Methodology"?

A. This methodology is described extensively in my direct testimony which includes an example. This methodology utilizes the lower of class or system load factors to allocate revenues between on-peak and maximum demand charges. It provides a substantial incentive for customers to control their load so that their maximum demand coincides as little as possible with their peak period demand or vice-versa.

Q. Has any other party proposed a different method for determining TOU demand charges?

A. Yes. Witness Wright has proposed a method that would recover only a portion of distribution costs from the maximum demand charge. This charge would use the customer's highest measured demand occurring during the current or previous "ratchet period" of one to two years. Mr. Wright's proposal is essentially a proposal for a Local Facilities Charge for all demand metered customers. We appreciate his support in that regard since we are proposing a type of Local Facilities Charge for LP/LPT and PX/PXT customers. However, I do not believe his proposal is appropriate for a maximum demand charge. A customer who is able to shift most of his load off-peak could end up being subsidized by other customers since the maximum demand charge would not recover any production or transmission costs. Even if all usage is off-peak, there would still be some production and transmission costs incurred. Mr. Wright's proposal is a brief theoretical discussion, which has no regard for the effect implementation of his proposal might have on the affected customers. In fact, he cannot evaluate this effect because he has proposed no rates. The Staff has proposed the same methodology, without supporting testimony.

Further, when Mr. Wright's proposal is combined with his proposal on page 35 of his testimony to re-impose mandatory TOU rates, it could be devastating to those customers that simply cannot move demand from the on-peak period to the off-peak period.

Dr. Johnson's proposed LPT rate maintains the same ratios as Gulf's; however, his charges have to be higher to offset the much larger transformer ownership and metering voltage discounts that he is proposing.

Q. Are there any other views expressed in Mr. Wright's testimony and accompanying exhibits that cause you concern?

A. Yes. While we agree with Mr. Wright that costs do vary by the time of day and the time of year, we believe that time-of-use rates should be optional and not mandatory for all customers. In Gulf's 1982 rate case, a three commissioner panel imposed mandatory TOU rates on all of Gulf's large customers with demand over 2000 KW. A different three commissioner panel supported our views on mandatory TOU rates in Gulf's 1984 rate case and reversed the previous panel's decision. In this and other matters that affect their lives and business, electric customers expect fairness and equity. They also expect and deserve consistency of rates and regulations so that they can plan for the future with confidence. This consistency, or gradualism where change is necessary, is a basic principle that permeates all of Gulf's proposed rates. We see no concern for this principle in the proposals of Mr. Wright, although he purports to represent the citizens of the State of Florida.

Q. Since Gulf's methodology and Mr. Wright's are different in the area of TOU demand and energy charges, would you elaborate more on Gulf's TOU rate design methodology?

A. Yes. Each TOU rate was designed to be revenue neutral with its standard rate counterpart; that is, the TOU rates were designed to recover the proposed revenue for the class assuming all customers were on the TOU rate in lieu of the standard rate. The Load Factor Methodology was then used to calculate the TOU energy prices for rates RST and GST. It takes total energy related revenue and splits it into on-peak and off-peak energy related revenues. Total energy related revenue for rates RST and GST is just the total class revenue requirement less the revenues related to customer charges. After applying the class load factor, on-peak and off-peak energy related revenues are then divided by the number of on-peak and off-peak energy related billing determinants to obtain the energy prices.

The Load Factor Methodology was used to split the standard demand price, which was selected based on the demand unit cost from Mr. O'Sheasy's cost of service study and the resulting demand charge we proposed to maintain, into on-peak demand and maximum demand components. Then, for the LP/LPT rate a minimum off-peak energy charge of $0.00300 per kwh was selected to assure recovery of all non-fuel energy costs, and for the PXT rate an off-peak energy charge of $0.00260 per kwh was selected for the same reason. Through the iteration process, the off-peak energy charge for rate LPT was refined to $0.00303. The remaining revenue for LPT and PXT was used to develop the on-peak kilowatt hour charge.

Mr. Wright discusses an alternate methodology for determining energy charges, but again, does not express any concern for the effect his proposals may have on the customers he purports to represent. He has done no calculation, produced no costs, and offered no rates as alternatives to the Company's rates that were filed on December 15, 1989.

Q. On page 53 of Mr. Pollock's testimony, he refers to a revised Company proposal for the PX minimum bill provision. Where did the Company propose this revision?

A. In error, Mr. Pollock has included some language that was proposed in response to an interrogatory in the withdrawn rate case, Docket No. 881167-EI. The revised proposals for the PX and PXT minimum bill provisions are shown in the Company's response to Interrogatory No. 144 of Staff's Eighth Set of Interrogatories in this Docket No. 891345-EI.

Q. Mr. Pollock states that the proposed PX minimum KW charge penalizes a PX customer with a monthly load factor of less than 75 percent even though the applicability section of the rate only requires an annual load factor of 75 percent. Would you agree with this statement?

A. Yes. We do agree with this statement regarding our original filed tariff. However, this situation has been corrected in our revised language for the PX/PXT minimum bill provisions as shown in the response to Interrogatory No. 144 (prices adjusted pursuant to No Migration study) of Staff's Eighth Set of Interrogatories and is shown below:

PX: Minimum Monthly Bill - In the event the customer's annual load factor for the current and preceding eleven months is less than 75 percent and in consideration of the readiness of the Company to furnish such service, the minimum monthly bill shall not be less than the customer charge plus $10.390 per KW of billing demand and the local facilities charge, if applicable.

PXT: Minimum Monthly Bill - In the event the customer's annual load factor for the current and preceding eleven months is less than 75 percent and in consideration of the readiness of the Company to furnish such service, the minimum monthly bill shall not be less than the customer charge plus $10.347 per KW of maximum billing demand and the local facilities charge, if applicable.

Q. Mr. Pollock recommends having a minimum annual billing demand charge with a true up provision. What are your thoughts about this alternative for the PX/PXT minimum bill provisions?

A. First, we agree with Mr. Pollock, as already stated, that a customer should not be penalized if his monthly load factor is less than 75 percent as long as his annual load factor is 75 percent or more. Further, we believe the PX/PXT minimum bills should be designed in such a way that the CED bill (includes customer, energy, and demand charges) would normally be more as long as the 75 percent annual load factor is maintained. Using the revised PXT rate and Mr. Pollock's methodology, an annual minimum bill demand charge of $124.16 per maximum annual on-peak KW was developed as shown below:

($10.347/kw)(12 months) = $124.16

This charge was then applied to the six PXT customers' billing determinants. As shown on my Schedule 4, Mr. Pollock's minimum annual billing demand charge would result in four of the six PXT customers paying less on the CED bill than their minimum annual charges, even though all six customers have annual load factors of 75 percent or more. However, Gulf's PXT minimum bill would be less than the CED bill. This difference in the relationship of the minimum bill to the CED bill when comparing Gulf's and

Mr. Pollock's methodologies is because Mr. Pollock uses the highest on-peak demand for the year and we use the customer's monthly maximum billing demand to calculate the minimum bill.

Because this is such a small class and the bills are reviewed monthly by customer accounting and marketing personnel, any customer who is consistently not meeting the annual load factor requirement can be readily identified and appropriate steps can be taken to place the customer on the appropriate rate. Let me emphasize again that if the annual load factor requirement is met, we do not choose to penalize a customer with a minimum bill in a month just because his load factor for that month is less than 75 percent.

Q. **Mr. Wright states that Gulf's proposed minimum bill provision for the demand metered rates allows non-fuel energy and fuel charges to be used in the calculation of the minimum bill. If this is not correct, please explain how the minimum bill is calculated.**

A. The proposed minimum bill provisions of all demand metered rates considers only the customer charge, demand charge, and local facilities charge, if applicable. This amount is then compared to the normal CED bill, and the customer pays the larger of the two. Whether the customer pays the minimum bill or the regular bill is irrelevant as far as the fuel charge because in either case the customer pays the same fuel charge. Further, if the customer is caught by the minimum bill provision, he would not pay the non-fuel energy charge. For clarification, my Schedule 5 shows an example of how a minimum bill for rate GSD would be calculated.

Q. The applicability clause of the three demand classes (GSD/GSDT, LP/LPT, and PX/PXT) is stated in terms of the amount of KW demand for which the customer contracts. Is this an appropriate basis for determining applicability?

A. Yes. This will especially be appropriate if the proposed Local Facilities Charge for rates LP, LPT, PX, and PXT is approved. Further, for a new customer you would have no actual demand upon which to base a contract or to determine which rate would be applicable. Thus, without a contract capacity, you would have no meaningful contract. We acknowledge that many of the LP or LPT customers listed on our response to Interrogatory No. 115 of Staff's Eighth Set of Interrogatories either do not have contracts, or their contract capacity is not consistent with their actual maximum demand. However, presently there is little reason to keep the contract capacity and actual maximum demand close as long as the substation is not overloaded and the customer is still on the proper rate, because the contract kw has no effect on the customer's bill. After the approval of the requested Local Facilities Charge, Gulf will initiate a review and possible revision of existing LP/LPT and PX/PXT contracts and the signing of appropriate new contracts with those LP/LPT customers who presently do not have a signed contract.

Q. The Local Facilities Charge that the Company has proposed for LP/LPT and PX/PXT customers would be applicable when the customer's highest billing demand for standard rates and highest maximum billing demand for TOU rates in the current and previous eleven months is less than 80 percent of the Capacity Required to be Maintained as specified in the Standard Form of Contract for Electric Power. The charge would be applied to all kw in excess of the billing kw necessary to reach 80 percent of the Capacity Required to be Maintained. Is it appropriate to base this charge on contract demand instead of actual demand?

A. Yes. As stated in response to the previous question, it may not be appropriate now with the existing LP/LPT contracts, but it will be appropriate if the Local Facilities Charge is approved. At that time all contracts will be reviewed or initiated to assure that the contract capacity represents the customer's actual demand requirement. If the charge was based on actual demand and we had a situation where facilities had been constructed to serve a particular load, then a customer would be under no obligation to pay for those facilities should he for some reason not use the load as contracted. This proposed Local Facilities Charge will protect other customers from having to subsidize these customers who on a temporary or permanent basis reduce their load or shut down completely. Such a customer would be obligated to pay at least the minimum monthly bill, which includes the Local Facilities Charge, if applicable, for the duration of the contract.

Q. The current GSD/GSDT and LP/LPT rate schedules have sections on the determination of billing demand that require that a certain minimum demand be charged if the customer does not actually use this minimum demand in the current or previous eleven months. Is this

minimum demand provision appropriate for customers who opt for a higher rate class?

A. My answer to this question is a qualified no. While this might be a workable scenario, we do not have demand type meters on the majority of our GS/GST customers and thus do not readily know how many GS/GST customers would benefit from such a change. If this information were available and the bills associated with these GS/GST customers who might cross over could be compared with the GSD/GSDT costs, then this provision might have merit. Results of our initial analyses indicate that the GSD rate becomes cheaper than the GS rate as kw increases and also as load factor improves. At the proposed level of GS energy prices, these breakeven points are too low for reasonable implementation. However, if this relationship changes significantly as a result of other decisions in this case, then such a change may be workable; and if so, the Company would like to see it approved. Likewise, if this change is implemented for rates LP/LPT, we would need to redesign the rates to account for the change in the minimum demand provisions of the rate and the lost revenue that could result from any crossovers.

Q. The Company presently has seasonal rates for the RS and GS rate classes. Should seasonal rates be retained for RS and GS?

A. Yes. Gulf has offered seasonal RS and GS rates since 1962. We have been a summer peaking utility since the installation of air conditioning in the early 1950's. This trend is expected to continue into the foreseeable future. In fact, Gulf has had only two annual peaks occur in the winter season since the early 1950's. The primary purpose of seasonal rates is to reduce the growth of summer peak demand and to keep this differential from getting any worse. A secondary purpose is to improve the utilization of system resources. Seasonal rates historically have provided the customer a price signal with the effect of slowing the rate of growth in summer peak demand by minimizing the customer's use of electricity during the Company's peak period. Seasonal rates are simply time-differentiated rates based on an annual system load shape, much as daily TOU rates are based on daily system load shapes.

Q. Since Gulf still supports seasonal rates for rates RS and GS, why were seasonal demand rates not proposed?

A. We simply did not want to introduce the additional complexity of seasonal rates for those classes in this filing. Instead, we chose to just try to retain the seasonal rates we had on RS and GS and improve the differential we had on GS.

Q. If seasonal rates for RS and GS are continued, how should the rates be designed?

A. We propose to simply retain the same ratio of summer price to winter price as in the present RS rate and to apply this same ratio for the GS seasonal differential.

Q. Dr. Johnson proposed a different set of LP/LPT rates, transformer ownership discounts, and metering voltage discounts. Would Dr. Johnson's proposed charges and discounts produce the same revenue as Gulf's?

A. No. Dr. Johnson's rates would allow Gulf to collect $856,289.34 more in revenue than our original LP/LPT revenue target of $34,421,500 when rates are run in competition. I do not believe this would be allowed by the Commission. On the other hand, the ten LP/LPT FEA customers that he represents would generate $156,708.60 less in revenue than Gulf's original proposed rates. The remaining LP/LPT customers would be required to make up this deficit.

Q. In Dr. Johnson's testimony, he addresses transformer ownership discounts--specifically for rates LP and LPT. What is the purpose of transformer ownership discounts?

A. Some customers provide their own transformation. The transformer ownership discount is utilized to give these customers credit for transformation costs that are not incurred by the Company in order to serve these customers.

Q. In what component of the demand rate does Gulf charge the transformation costs to customers?

A. The demand charge component includes costs associated with all of the transformation necessary to provide service from the production plant down to the secondary distribution level. Thus, any customer providing his own transformation and taking service at a voltage level higher than secondary should be credited for those transformation costs not required to serve him. In other words, the Company returns that portion of the demand charge related to transformation to those customers to whom it does not apply.

Q. Gulf's present transmission transformer ownership discount is \$.70/KW/month, and the present primary transformer ownership discount is \$.25/KW/month. What do these prices represent?

A. These discounts are recognized as the amounts needed to account for the difference in the secondary tariff price and the rates associated with different voltage deliveries. The \$.25/KW/month primary discount was approved by the Commission in Gulf's 1981 rate case, Docket No. 810136-EU, Order No. 10557. Between Gulf's 1981 and 1982 rate cases, the \$.70/KW/month transmission discount was approved. Then both discounts were retained in the 1982 rate case, Docket No. 820150-EU, Order No. 11498. In both rate cases, the approved discounts were determined by the Commission and were not the ones proposed by Gulf.

Q. Why does the tariff for the demand rates provide a metering voltage discount in addition to a transformer ownership discount?

A. The transformer ownership discount gives the customer credit for transformation costs not required to serve that customer; however, it does not recognize the reduction in line and transformation losses as a result of the customer taking service above the secondary distribution level. The metering voltage discount does recognize this reduction in losses. A customer providing his own transformation and taking service at the primary voltage level would receive a primary transformer ownership discount of $.25/KW/month and an additional metering voltage discount of 1 percent of the energy charge and 1 percent of the demand charge under present rates. Likewise, a customer providing his own transformation and taking service at the transmission voltage level would receive a transmission transformer ownership discount of $.70/KW/month and an additional metering voltage discount of 2 percent of the energy charge and 2 percent of the demand charge under present rates.

Q. Is it appropriate to increase or decrease transformer ownership discounts at the same percentage as rates vary from unit costs?

A. Yes. If demand rates are set at unit cost from the cost of service study, then transformer ownership discounts should be set at their unit costs. However, if the demand rates do not fully recover the unit costs, then transformer ownership discounts should bear the same ratio to their unit costs as the demand charge does to its unit cost.

Q. Is it appropriate to increase transformer ownership discounts at the same percentage as rates increase?

A. No. An increase in a specific rate does not lead to the conclusion that differences between voltage classifications should increase accordingly. Overall costs at the corresponding levels may have increased or prices may be simply set closer to costs than under previous rates.

Q. Does Gulf support retaining the present transformer ownership and metering voltage discounts?

A. The Company proposes that the transformer ownership and metering voltage discounts, as developed in the Company's responses to Interrogatory Nos. 110, 111, and 113 of Staff's Eighth Set of Interrogatories, be approved after adjusting the transformer ownership discounts for the variance of demand charges from unit cost.

Q. Should the SS and ISS rate schedules have provisions for both transformer ownership and metering voltage discounts? If so, should the level of the discounts be set equal to the otherwise applicable rate schedule?

A. The SS and ISS rate schedules should provide for metering voltage discounts only, and the metering voltage discount should be applied to only the SS/ISS energy charges pursuant to the Commission's Order No. 17159 which states on page 15:

> The rate structure for backup and maintenance power service shall include a non-fuel energy charge set equal to the system energy unit cost, i.e., the total energy-related costs of the utility divided by total energy sales, with appropriate adjustments to reflect different line losses at different service voltage levels, if applicable.

Q. Should Gulf's proposed revisions to the language of the customer charge on the standby service rate schedules (SS and ISS) be approved?

A. No. As a result of the discussions with Staff, we agree that the wording of the customer charge section of the tariff needs to be revised in order to be in complete compliance with Order No. 17159. Shown below is a proposed revision to the customer charge section of the SS and ISS tariffs:

> <u>Customer Charge</u>
> A customer will pay a Standby Service customer charge of $25.00 plus the LP/LPT customer charge except for those customers taking supplementary service on rate PX/PXT. These customers will pay

the $25.00 Standby Service customer charge plus the PX/PXT customer charge.

Q. Should Gulf's proposed change in the definition of the capacity used to determine the applicable local facilities and fuel charges on the standby service rate schedules (SS and ISS) be approved?

A. No. Since this rate case was filed, we have worked with Staff on several revisions to the SS tariff. We now have a better understanding of how to apply the Local Facilities Charge for rate schedules SS and ISS. Even our present criteria for selecting the appropriate Local Facilities is not adequate because of an interpretation problem with capacities of 500 kw or more. This present inadequacy does not affect our current customers but may affect future standby customers and needs to be adjusted. Shown below is revised language for this charge:

<u>Local Facilities Charge</u> -

a. For those customers who have contracted for standby service capacity not less than 100 kw nor more than 499kw - $1.60/kw of BC.
b. For those customers who have contracted for standby service capacity not less than 500 kw - $1.35/kw of BC.
c. For those customers who have contracted for standby service capacity not less than 7500 kw and are taking supplementary service under the PX/PXT rate - $0.64/kw of BC.

In regard to fuel charges, shown below is revised language for that charge which will conform to the proposed Local Facilities Charge language shown above:

> Fuel Charges - Fuel charges as shown below will be applied to all Standby Service kwh:
>
> a. For those customers who have contracted for standby service capacity not less than 100 kw nor more than 499 kw, the fuel cost for rate schedules GSD/GSDT as shown on Sheet 6.15 will be applied.
>
> b. For those customers who have contracted for standby service capacity not less than 500 kw, the fuel cost for rate schedules LP/LPT as shown on Sheet 6.15 will be applied.
>
> c. For those customers who have contracted for standby service capacity not less than 7500 kw and are taking supplementary service under the PX/PXT rate, the fuel cost for rate schedules PX/PXT as shown on Sheet 6.15 will be applied.

Q. Should the proposed paragraph on the monthly charges for supplementary service on the SS and ISS rate schedule be approved?

A. Our reason for including the second sentence in that proposal was to clarify that a customer who contracts for 0 KW supplementary and uses only standby service must still pay the LP/LPT customer charge in addition to the $25.00 Standby Service customer charge. This condition affects only one of our present customers. Too much time and energy has already been consumed on the wording of this one paragraph. Thus, we will accept without further discussion whatever wording the Commission deems appropriate.

Q. Should the Interruptible Standby Service (ISS) tariff language be revised to comply with the final proposed Standby Service (SS) language if applicable?

A. Yes.

Q. In Dr. Johnson's testimony, he also supports fuel costs differentiated within a rate schedule by voltage level for LP and LPT rates. Has this change to the fuel cost adjustment ever been considered?

A. Yes. This subject has been addressed by the Commission in the past. However, Order No. 10289, Docket No. 810001-EU, page 3, states:

> Having reviewed the various retail class line loss allocation factors, we conclude that utilization of every factor is unnecessarily confusing. Certain customer classes of each utility have similar line loss factors, and those classes should be subject to the same multiplier.

Thus, for simplicity of design, application, and administration, the Commission has ordered that each class of fuel costs should represent the average voltage level losses for those customers. The purpose of the four rate groups is to serve as a proxy for voltage level. In any event, fuel cost recovery rate design is not a proper subject for these hearings on base rates.

Q. Are there any views expressed in the testimony and accompanying exhibits of Mr. Kisla that cause you concern?

A. Yes. It is noted that Mr. Kisla in his Table II for both the winter and summer scenarios shows the supplementary MW's for the four scenarios incorrectly. We need to emphasize that the contract for supplementary service gives the customer the option of using up to his contract capacity, but this capacity is not a substitute for standby service capacity. The supplementary service for the scenarios A and B would be 10.0 MW and for scenarios C and D would be 14.0 MW. The extra 5.0 MW in the winter and the 1.0 MW in the summer should be included as standby service as shown in the revised portion of the table on my Schedule 6.

Q. Mr. Pollock and Mr. Kisla both agree that a seasonal type of customer could be charged more standby demand than actually taken certain times of the year. Do you agree?

A. We understand their concern. It is certainly not the intention of the tariff to penalize customers with seasonal variations in their generation. We suggest that a modification be made in the formula and language as shown on Standby Service tariff sheet no.

6.30. This revision, as shown on my Schedule 7, would adjust the "maximum totalized customer generation output occurring in any interval between the end of the prior outage and the beginning of the current outage" portion of the formula for seasonal variation in generation output. In order for us to apply this adjustment to customers with seasonal generation, we would need any such customers to annually provide us a monthly schedule that would state what this monthly adjustment (kw) should be. For example, using the revised table in my Schedule 6 and a seasonal reduction of 4 MW from the winter to the summer season, if the maximum customer generation since the last outage occurred during a winter month with generation of 32 megawatts and the current outage is in a summer month (scenario C), then 32 MW - 4 MW - 14 MW - 5.5 MW = 8.5 MW standby service which is the same as if the maximum generation since the last outage occurred during a summer month with no seasonal adjustment in generation output. By properly utilizing the formula, a customer should never be charged for more standby service than that customer actually takes.

Q. Are there any other problem areas in Mr. Kisla's testimony?

A. Yes. In comparing his scenarios to the tariff at the bottom of his Table II, Mr. Kisla incorrectly stated the MAX for scenarios C and D at 32 MW. It should be 28 MW as shown in the "Summer Hot" column of Mr. Kisla's Table II. This correction would result in standby service of 8.5 MW and 14.0 MW in lieu of the incorrect amounts of 12.5 MW and 18.0 MW.

Q. Mr. Kisla has stated that subtracting the actual standby used results in a 5 MW discrepancy for each scenario. Do you agree with this statement?

A. No. As previously stated, for the winter scenarios Mr. Kisla counted 5 MW as supplementary service, and for the summer scenarios counted 1 MW as supplementary service when in actuality these are standby service MW's.

Q. Mr. Kisla has recommended calculating the daily standby service demand by taking the difference between the highest on-peak readings in each day of an outage and the highest on-peak reading during a non outage period of the same billing period. What is your opinion of this method?

A. First, this method would not work if a customer took supplementary service with the SE rider applied. Use of SE would inflate the customer's normal usage pattern and cause the customer to pay less for standby than actually taken. In addition, because outages can extend beyond one billing period, you may not be able to select the two readings in the same billing period. Further, considerable thought and time have been spent on the present wording of the determination of standby service (kw) rendered section of the SS tariff utilizing input from Commission Staff, Company employees, and our customers. We were striving for a method that would make the calculation of standby service demand more exact and eliminate any guesswork. We believe that, with our previously proposed inclusion of an adjustment for seasonal variation in generation output, that this method will work well. We did, however, calculate the standby service demand for the four scenarios in Mr. Kisla's Table II using his methodology. With this set of variables, the standby service calculated per the tariff, modified as I have proposed, and per Mr. Kisla's methodology are the same as shown on my Schedule 8 including the correction I discussed on page 26.

Q. Why did Gulf choose the customer's highest generation output since the end of the previous outage and the beginning of the current outage in the formula instead of the customer's normal generation?

A. First, we were trying to remedy a problem that developed with the wording on the standby service demand determination section of the tariff when the SS tariff was revised February 1, 1990. Our goal, as stated previously, was to come up with a methodology that would make the determination of the daily standby service demand a much easier and more exact task. The previous method of selecting the generation in the second prior interval was at times a hindrance to the customer. Normally, if the customer experiences an outage, it may not be immediate but demand may ramp up for several demand intervals. Thus by just comparing the second prior interval, this would not necessarily be the customer's "normal generation." We also believed that using a so-called "normal generation demand" was not specific enough. Thus we chose to use the maximum generation since the last outage as the so-called "normal generation." We believe this is more representative of the customer's normal generation. The inclusion of the new adjustment for seasonal variation in generation output in the formula will take care of any seasonal types of variation in generation.

Q. Mr. Kisla, as well as Mr. Pollock suggested that standby customers be allowed to purchase as-available energy under the SE rider in lieu of standby service. What are Gulf's thoughts on this alternative?

A. If the Commission did not require that a customer take service under the SS rate if his total generating capability (1) exceeds 100 KW, (2) supplies at least 20 percent of this total electrical load, and (3) is operated for other than emergency and test purposes, then the SE rider might be an option for the customer. However, since that is not the case, and in order to be in compliance with the Commission's standby service Order No. 17159, any backup or maintenance service as defined by that order must be billed under the applicable standby service rate. Further, Order No. 17159 states on page 17:

> . . . standby customers shall not be permitted to take backup or maintenance power on the otherwise applicable full requirements rate schedule.

Thus, maintenance power must be billed under the standby service rate as required by the standby service order. In addition, according to the applicability section of the SE rider, this rider can only be applied to full requirements customers on the LP, LPT, PX, or PXT rate.

Q. Mr. Pollock, as well as Mr. Kisla, recommends a different treatment of backup and maintenance power as far as establishing a ratchet for determination of the standby service demand to be used in the calculation of the local facilities charge and reservation charge. He refers to page 21 of order no. 17159 and implies that the ratchet refers only to backup power. Would Gulf raise the contract KW if the customer's maintenance demand exceeded his standby service contract demand?

A. Yes. The beginning of that paragraph in Order No. 17159 states that the initial contract demand represents the maximum backup or maintenance demand that the customer expects to impose on the utility. Because the initial contract is based on backup or maintenance, any change in either type of service need would warrant a change in the contract capacity. Further, on page 5 of order no. 17159 it states:

> While we find that the expected load characteristics of both backup and maintenance power are sufficiently different from standard services to warrant separate rate schedules, <u>we cannot, based upon the record in this case, find that backup and maintenance power are sufficiently different from each other to warrant separate</u>

> cost-based rates. In theory, if maintenance power service can be scheduled to avoid a utility's peaks, it should not be assigned any cost responsibility for demand related production and bulk transmission costs. However, there are several factors that may make it difficult or impossible to distinguish between backup and maintenance power. FPC witness William Slusser testified that backup and maintenance are difficult to distinguish from the utility's perspective because the utility must provide the same level of replacement power regardless of whether the customers' generator is out for scheduled maintenance or has been forced out. Mr. Slusser added that customers with more than one generator may simultaneously experience forced and scheduled outages. He testified that he found it difficult to distinguish any difference in the standby cost impact of the two.
>
> We find Mr. Slusser's testimony to be persuasive. In a cost-of-service analysis using a 12 CP allocator to allocate demand-related costs, the cost responsibility will be the same for 10 MW of maintenance power taken for a full month as for 10 MW of backup power taken intermittently but only during one monthly peak hour of the year. (emphasis added)

Q. Mr. Pollock proposed a different method of calculating the non-fuel energy charge and reservation charge. Did the Company follow the guidelines established in standby rate Order No. 17159 in calculating these charges? If so, is there any reason for not deviating from this method?

A. Yes. The final Order states that "the public interest will best be served by requiring a uniform approach to cost allocation and rate design for standby services." That uniform approach for the design of all standby service rate components is spelled out very specifically in the Order.

Q. Why did the Company increase the SS rate class by more than 1.5 times the overall system average percentage rate change?

A. As stated in my prefiled testimony, the SS rate was designed per the rate design procedures specified in Order No. 17159 in the standby rate docket.

Q. Mr. Pollock suggests using a different forced outage rate in the design of the reservation charge and daily demand charge. Would this be appropriate?

A. Again, the Commission insisted on a uniform approach to rate design in the State. Thus, since the Order specified using a forced outage rate of 10 percent in the design of the reservation charge and daily demand charges, we chose not to use a different forced outage rate. In addition, Mr. Pollock appears to contradict himself since he is supporting a different forced outage rate for rate design purposes; and yet for the Cost-of-Service Study, he recommends using the 10 percent forced outage rate.

Q. Should Gulf revise the forecasted KW for the customer who experienced an outage of his generation capacity and took back-up power from Gulf but was not billed on the SS rate?

A. No. The 7959 KW was not reported as standby service by the customer. This KW is Gulf's current best estimate of what we now believe could have been reported by the customer as standby in September of 1989 had they had a better understanding of when an outage should be reported. The estimate was prepared as my Late Filed Exhibit No. 15 to my deposition by the Staff in this docket. We do not believe it is appropriate to backbill the customer based on the 7959 KW nor do we intend to change their BC from the present BC of 7500 KW. In the revised cost of service study and the revised rate design, we used the new contract KW's of 3000 KW in February 1990 and 7500 KW beginning March 1990 in our forecast. We believe forecasting 7959 SS KW would be overstating the forecast as the Company has contracted for only 7500 KW at the present time. We believe the customer will limit its standby to no more 7500 KW in the future. In fact, its max SS has been no more than 7500 KW since the one time occurrence of 7959 KW eight months ago.

Q. Has Gulf complied with Order No. 17568, Docket No. 850102-EI, by making the SE Rider customers a separate rate class in this rate case?

A. During a preliminary conference regarding the MFR's before filing our withdrawn case, Docket No. 881167-EI, a verbal agreement between the Company and the then Bureau Chief of Electric Rates was reached not to separate the SE customers from the others in their respective rate classes because SE is an optional rider applied to other rate classes and not a separate rate class in itself. This is the same treatment given to customers in the residential class taking the optional levelized billing rider and for customers on all of the optional TOU rates. The Company has relied on this very reasonable agreement.

Nevertheless, on May 9, 1990, as a part of Staff's Thirteenth Set of Interrogatories, Mr. O'Sheasy has been requested to redo the cost of service study making several changes. One such change is to make the SE Rider customers a separate rate class. We will file the Company's study in response to these interrogatories as soon as practicable.

Q. Why is Gulf opposed to making the SE Schedule a rate and not an optional rider?

A. Because it would disrupt the standard rate classes and destroy the SE rider. LP/LPT and PX/PXT customers opting for the rider would be grouped together. The Company has no obligation under the optional rider to declare SE periods, and the customer can go off the rider at any time. This would not be the case if it was changed to a separate rate schedule. If customers could not freely leave the rider, we would almost certainly have to state a minimum for the number and duration of SE periods that would be declared.

Q. With SE remaining a rider, how should rates be designed?

A. Billing determinants for customers opting for the SE rider should be combined with non SE customers' billing determinants for rate design purposes. This is the procedure used in designing Gulf's proposed rates. This issue related to Rider SE was introduced by the Staff, but no testimony has been offered to support a position.

Q. How were Gulf's proposed service charges derived?

A. The proposed service charges were selected based on our cost studies shown in MFR Schedule No. E-10.

Q. What are the appropriate service charges to be collected by Gulf Power Company?

A. The following are the Company's proposed service charges:

Initial Connection	$20.00
Investigation Charge	55.00
Temporary Service Pole	60.00

All other service charges remain at current levels.

Q. Staff has taken the position that four of the service charges should be less than Gulf's proposed charges. Can you tell us why your proposed charges are appropriate?

A. In designing our proposed rates as well as our proposed service charges, basic rate making philosophies of simplicity of design, application, and administration were utilized. For these reasons, Gulf supports our proposed service charges in lieu of Staff's. For example, we have proposed to allow two different types of reconnection charges to remain unchanged at $16.00. The Staff proposes to increase one by $1.60 and reduce the other by $1.50 to move them closer to costs. We believe this is needless tinkering with the rates. One of our objectives has been to keep all of these prices at whole dollar amounts. The Staff would have us reduce our proposed initial service charge by $.25. The effect of this change on total retail jurisdictional revenue is less than $200 per month!

Q. You have reviewed Mr. Pollock's testimony and accompanying exhibits. Are there any other areas of his testimony that you would like to address?

A. Yes. We disagree with Mr. Pollock's method of allocating the revenue increase among the various rate classes by moving all rate classes an arbitrary one half of the way closer to the unit costs in the cost of service study. He must revert to this method of severely limiting the movement of customers on his proposed rates because of the drastic distortion his cost method introduces relative to the method used by the Company and approved by the Commission in the Company's past several rate cases. Without this limitation, Mr. Pollock would be requesting a $1,323,000 rate reduction for his clients.

Q. What method does Gulf use to allocate the revenue increase among the various rate classes?

A. The cost of service study for present rates served as the starting point for allocating the increase among the classes. From there, the proposed $26,295,000 revenue increase was spread in a manner that caused the rate of return for each class to move closer to the retail system average rate of return at the proposed revenue level. The exception is the revenue from the SS class, which resulted from the use of rate design procedures specified in Order No. 17159 in the standby rate docket. In compliance with this Commission's previously stated guideline that no class should receive an increase or decrease greater than 1.5 times the overall system average percent increase, the decrease in the OS-III class was restrained. Gulf's allocation method gives proper recognition to the impact the increases will have on each class, Commission precedent, previous rate case treatment of the various classes, as well as Mr. O'Sheasy's cost of service study.

Q. **In Mr. Wright's testimony, he advocates setting GS rates equal to RS rates. Would Gulf consider setting the GS rates equal to the RS rates as well as GST rates equal to RST rates?**

A. Yes. Both groups are served by non-demand meters, and their load factors are quite close. Combining the two groups of customers would result in an energy charge unit cost of $0.0034789 per KWH and a customer charge unit cost of $10.45 under proposed rates. These charges remain fairly close to the proposed RS unit costs of $0.0034472 per KWH and a $9.71 customer charge; however, they represent a substantial decrease in GS unit costs under proposed rates and would help to eliminate the subsidy problem that exists with both rates.

Q. If it is not appropriate to assume that customers on present rates would remain on the same rate when proposed rates become effective, explain why this is not the case.

A. This would not be an appropriate rate design assumption. Let me explain Gulf's rate design process. First we produce rates designed using the forecasted billing determinants for each rate class. Next, with our rate design computer program, we run the forecasted customer billing determinants against these preliminary rates and also run the preliminary rates in competition with other rates to assure that each customer is on the most economical rate for that customer; assuring, of course, that all qualifications or restrictions of the rate are met. Through this process the Company is able then to do any necessary fine tuning of the rates through successive iterations in order to get as close as possible to the proposed revenue target. If we did not check for crossovers (competition runs), we would not recover the proposed revenue because those customers crossing to a different rate would be paying lower prices and thus not producing the revenue that was originally intended.

Q. Once an increase is granted, would it be appropriate to allow the Company to redesign the rates to recover the approved revenue, run the rates in competition, and go through the same iteration process as was done in the original filing of the case and the revised portion of this case?

A. Yes. If not allowed this opportunity because of the customer crossovers I just discussed, the Company would not collect the full amount of the granted revenue increase as intended by the Commission in its decision.

Prior to the 1984 rate case, the Commission has always allowed Gulf to go through this iteration process. However, the final implementation of rates in that case was delayed seven days because of this issue. We hope by discussing this issue now, the Commission will understand the need for the Company to participate in this part of the rate design process, so that we will not experience the same needless delay when final rates in this case are implemented.

Q. How should the revenue shortfall, if any, be recovered in order to properly recognize crossovers between rates?

A. First, let me explain in more detail how the iteration process works. If, for example, the revenue target for rate class GSD/GSDT was $50,000,000 and after running the proposed rates against the forecasted customer billing determinants, the GSD/GSDT rate class only produced $44,000,000 in proposed revenue due to crossovers to cheaper rates, then it would be necessary to fine tune the GSD/GSDT proposed rates to recover the adjusted $6,000,000 revenue shortfall (the adjustment results from accounting for any revisions to rates that the crossovers are billed under) from the customers who would remain on the GSD/GSDT rates. Using this methodology, the original GSD/GSDT customers would produce the total revenue target of $50,000,000 as originally intended. This same methodology should be used for all demand rate classes in order to recover any revenue shortfall that results from crossovers between rates or classes. For the non-demand rate classes (RS/RST and GS/GST) this methodology would not be necessary because the only crossovers we are able to predict are those which occur within the class if a TOU customer crosses over to the standard rate.

A thorough review of each customer's usage is done during this iteration and crossover process to assure that customers are on the appropriate rate schedule under proposed rates. After the rate case, any customers that would benefit significantly by crossing over to another applicable rate schedule would be notified and given the opportunity to change rates.

Q. Should the Company's rates for street and outdoor lights be approved?

A. Yes. No other party has filed testimony regarding Gulf's street and outdoor light rates. Nevertheless, the Staff has taken some unsupported positions in their preliminary list of issues.

Q. Is it appropriate to eliminate the general provisions pertaining to replacement of lighting systems on the Outdoor Service Schedule (OS)?

A. Yes. Gulf proposes to eliminate such a provision from the tariff altogether. This would allow proper price signals to encourage replacement of these old mercury vapor fixtures. An issue has been raised in this proceeding seeking a revised provision dealing with the replacement of a mercury vapor fixture with a high pressure sodium fixture. This would impede the replacement process which Gulf hopes to encourage with the proposed rate design for the lighting services. We believe most customers will be unwilling to pay the undepreciated cost of the fixture and the cost of removal in order to get the more efficient sodium vapor fixture. Customers will soon realize they can avoid this payment simply by telling us to take down the mercury vapor light one day and then call back later and request a new sodium vapor light. Because two trips will be required, this will double the Company's removal and installation expense.

Q. **Should recreational lighting customers that currently take service under OS-III be transferred to OS-IV?**

A. Yes. These type customers consist of baseball parks, football and soccer fields, and tennis courts which are only used during portions of night-time hours. Since these customers' load characteristics differ from OS-III and OS-II, they should not receive service under those sections. Customers receiving service under OS-III have a continuous load characteristic. OS-II loads are photo-cell or time-clock controlled and remain on during the entire period of darkness, whereas recreational lighting loads are on at random times during the early part of the night. I do not support moving a group of customers with varying usage characteristics into a group with very homogeneous usage characteristics.

Q. Should recreational lighting customers that currently take service under OS-III be transferred to the GS or GS-D rate?

A. No. These recreational lighting customers have a load characteristic which peaks at a different time than the coincident peak or system peak of GSD or GS customers. This difference shows that these customers should not have the same demand allocated cost as the GSD or GS rates.

Q. Does this conclude your rebuttal testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 891345-EI

Before me the undersigned authority, personally appeared Jack L. Haskins, who being first duly sworn, deposes and says that he/she is the Manager of Rates and Regulatory Matters and Assistant Secretary of Gulf Power Company and that the foregoing is true and correct to the best of his/her knowledge, information and belief.

Jack L. Haskins

Sworn to and subscribed before me this 11th day of May, 1990.

Candace Klinglesmith
Notary Public, State of Florida at Large

My Commission Expires: MY COMMISSION EXPIRES MAY 18, 1991

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891345-EI

ANALYSIS OF PROPOSED REVENUE BY RATE

12 MONTHS ENDING DECEMBER, 1990

(NO MIGRATION)

LINE NO.	RATE SCHEDULE	PROPOSED REVENUE INCREASE	ADDITIONAL REVENUE FROM SERVICE CHARGES			PROPOSED INCREASE AFTER ADJUSTMENTS	INCREASED UNBILLED REVENUE	ADJUSTED REVENUE RATE DESIGN TARGET INCREASE
			INITIAL SERVICE	TEMPORARY SERVICE	INVESTIGATION FEE			
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)(a)	(9)(b)
1	RS/RST	$17,538,000	$25,496	$0	$21,425	$17,491,079	$39,795	$17,451,284
2	GS/GST	$0	$4,720	$42,036	$275	$(47,031)	$(144)	$(46,887)
3	GSD/GSDT	$4,757,000	$1,260	$0	$125	$4,755,615	$10,700	$4,744,915
4	LP/LPT	$3,735,000	$0	$0	$0	$3,735,000	$11,108	$3,723,892
5	PX/PXT	$0	$0	$0	$0	$0	$0	$0
6	OSI & II	$186,000	$0	$0	$0	$186,000	$592	$185,408
7	OSIII	$(53,000)	$0	$0	$0	$(53,000)	$(157)	$(52,843)
8	SS	$132,000	$0	$0	$0	$132,000	$0	$132,000
		$26,295,000	$31,476	$42,036	$21,825	$26,199,663	$61,894	$26,137,769

(a) Column 7 - Column 9
(b) Column 7/(1 + (Present Unbilled Base Revenue/Present Billed Base Revenue))

Schedule 1

Schedule 2

891345-EI (NO MIGRATION)
RATES OF RETURN BY RATE CLASS

	Present		Proposed	
Rate Class	R.O.R.(%)	Index	R.O.R.(%)	Index
RS/RST	5.69	0.86	7.79	0.93
GS/GST	13.32	2.02	13.32	1.60
GSD/GSDT	7.26	1.10	8.80	1.06
LP/LPT	6.34	0.96	8.34	1.00
PX/PXT	8.34	1.26	8.34	1.00
OSI & II	7.45	1.13	8.34	1.00
OSIII	21.95	3.33	17.00	2.04
SS	10.09	1.53	12.94	1.55
TOTAL RETAIL	6.60	1.00	8.34	1.00

Schedule 3

Average Cost of
Localized Investment

891345-EI (NO MIGRATION)

Rate Class GSD/GSDT

$$\frac{\$12,347,000*}{7,696,772\text{KW}} = \$1.60\ /\text{KW}$$

Rate Class LP/LPT

$$\frac{\$5,028,000*}{3,730,465\text{KW}} = \$1.35\ /\text{KW}$$

Rate Class PX/PXT

$$\frac{\$1,061,000*}{1,651,152\text{KW}} = \$0.64\ /\text{KW}$$

*Revised Schedule 8 (Witness: O'Sheasy)

NOTE: The KW's used in the above calculations are based on 100% ratcheted KW's for the class in order to be consistent with Standby Rate Order No. 17159.

Schedule 4

EFFECT OF MR. POLLOCK'S
PROPOSED MINIMUM ANNUAL BILLING DEMAND CHARGE

	Gulf's Annual PXT Bill	Gulf's Minimum PXT Bill	Pollock's Minimum Annual Bill
Customer 1	$1,812,136	$1,783,751	$1,853,472
Customer 2	2,004,737	1,940,260	2,174,674
Customer 3	1,170,701	1,127,606	1,295,497
Customer 4	2,194,811	2,081,310	2,114,953
Customer 5	1,696,399	1,645,277	1,850,119
Customer 6	7,488,355	7,210,913	7,394,608

Schedule 5

GSD MINIMUM BILL VS GSD

CED BILL

	Minimum Bill		CED Bill
Customer Charge	$ 40.00		$ 40.00
Demand Charge 30 KW @ $4.52/KW	135.60		135.60
Energy Charge 500 KWH @ $0.01427/KWH	0.00		7.14
Primary Discounts 30 KW @ $0.25/KW	0.00		(7.50)
30 KW @ $4.52/KW @ 1%	0.00		(1.36)
500 KWH @ $0.01427/KWH @ 1%	0.00		(0.07)
Minimum Bill	$175.60	Subtotal	$173.81
Fuel Charge 500 KWH @ $0.02466/KWH		12.33	12.33
ECCR 500 KWH @ $0.00007/KWH		0.04	0.04
		$187.97	$186.18

NOTE: The customer would be billed the minimum bill of $175.60 plus the applicable fuel and ECCR charges since the minimum bill is more than the comparable CED bill of $173.81.

Schedule 6

Revision of Mr. Kisla's Table II

	Winter Cold	Winter Outage A	Winter Outage B	Summer Hot	Summer Outage C	Summer Outage D
Turbine Output	19.0	0.0	0.0	17.0	0.0	0.0
Turbine Output	9.0	10.5	10.5	7.0	10.0	10.0
Turbine Output	4.0	4.0	4.0	4.0	4.0	4.0
Self Gen	32.0	14.5	14.5	28.0	14.0	14.0
Supplementary	10.0	10.0*	10.0*	14.0	14.0*	14.0*
Standby	0.0	12.5*	17.5*	0.0	8.5*	14.0*
Reduce Load	0.0	5.0	0.0	0.0	5.5	0.0
Sum of Factor	42.0	42.0	42.0	42.0	42.0	42.0

*These numbers are the ones that were shown incorrectly on Mr. Kisla's Table II.

Determination of Standby Service (KW) Rendered:

The amount of standby service (KW) taken by the customer shall be determined in the following manner:

Within three (3) days of an outage of the customer's generating equipment, the Customer will notify the Company that such outage has occurred, will specify the amounts (KW) of Standby Service, if any, expected to be taken, and give an estimate of the expected duration of that outage. Within three (3) days after normal operations are restored, the Customer will notify the Company that operations are back to normal and Standby Service, if taken, is no longer required. On the day after the last day of each billing period, the customer will provide the Company a written report specifying (1) the beginning date and time of each outage, (2) the ending date and time of each outage, (3) the daily maximum amount (KW) of Standby Service, if any, taken during each outage of the billing period, and (4) the daily on-peak period load reduction (KW) that is a direct result of the customer's generation outage. If the Standby Service taken on a particular day occurs during an on-peak period as well as an off-peak period, then the daily maximum amount (KW) of Standby Service will be shown separately for each on-peak period and off-peak period. The information from this written report in combination with the Company's metered data will be applied to the formula shown below to determine the amount of daily Standby Service (KW) taken by the customer during designated peak hours for each day during the outage. Provided, however, that at no time will the amount (KW) of daily Standby Service being taken by the Customer exceed the difference between the maximum totalized Customer generation output (KW) occurring in any interval between the end of the prior outage and the beginning of the current outage (adjusted for seasonal variation in generation output, if applicable) and the minimum totalized Customer generation output (KW) occurring in any interval during the daily on-peak period of the current outage, and shall not exceed the total service (KW) being supplied by the Company.

Daily Standby Service (KW) =

Maximum totalized customer generation output occurring in any interval between the end of the prior outage and the beginning of the current outage (adjusted for seasonal variation in generation output, if applicable) .

Minus the Customer's daily generation output (KW) occurring during the on-peak period of the current outage.(1)

Minus the daily on-peak period load reduction (KW) that is a direct result of the Customer's current generation outage.(1)

All amounts (KW) of service supplied by the Company during such outage in excess of the amounts (KW) of Standby Service are to be treated as actual measured demand in the Determination of Billing Demand of the Rate Schedule established for Supplementary Service. In no event, shall Customer's demand (KW) billed as Standby Service also be billed as Supplementary Service.

(1) The customer's daily generation output (KW) and daily on-peak period load reduction (KW) that are used in the formula must occur during the same 15 minute interval as the daily Standby Service (KW) that is used for billing purposes.

Schedule 8

KISLA'S METHOD

	Highest Usage(1)		Lowest Usage(2)		
Scenario A	22.5	-	10.0	=	12.5 MW SS
Scenario B	27.5	-	10.0	=	17.5 MW SS
Scenario C	22.5	-	14.0	=	8.5 MW SS
Scenario D	28.0	-	14.0	=	14.0 MW SS

GULF'S METHOD USING FORMULA

Scenario A	32.0 - 0.0 - 14.5 - 5.0	=	12.5 MW SS
Scenario B	32.0 - 0.0 - 14.5 - 0.0	=	17.5 MW SS
Scenario C	28.0 - 0.0 - 14.0 - 5.5	=	8.5 MW SS
Scenario D	28.0 - 0.0 - 14.0 - 0.0	=	14.0 MW SS

(1) Supplementary plus standby
(2) Supplementary only