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APPLICATION OF ENTERGY GULF STATES, INC. FOR AUTHORITY TO CHANGE RATES AND TO RECONCILE FUEL COSTS	§ § § § §	**BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS**

REDACTED VERSION

REBUTTAL TESTIMONY

OF

CLARENCE JOHNSON

ON BEHALF OF THE

OFFICE OF PUBLIC UTILITY COUNSEL

APRIL 18, 2008

1410

SOAH DOCKET NO. 473-08-0334
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REBUTTAL TESTIMONY OF CLARENCE JOHNSON
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REBUTTAL TESTIMONY OF CLARENCE JOHNSON

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Clarence Johnson. My business address is 1701 North Congress Avenue, Suite 9-180, Austin, Texas 78701.

Q. PLEASE STATE YOUR CURRENT EMPLOYMENT.

A. I am employed as a Regulatory Analyst for the Office of Public Utility Counsel ("OPC" or "Office").

Q. ARE YOU THE SAME CLARENCE JOHNSON WHO PREVIOUSLY TESTIFIED IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE SUBJECT OF YOUR TESTIMONY?

A. My testimony rebuts intervenor testimony filed by Wal-Mart witness Al-Jabir, TIEC witness Pollock, and state agencies witness Peveto.

II. PRODUCTION PLANT ALLOCATION

Q. DOES ANY INTERVENOR WITNESS ADDRESS THE PRODUCTION PLANT ALLOCATION METHOD?

A. Yes. Mr. Al-Jabir, on behalf of Wal-Mart Stores endorses the Average & Excess, A&E/4CP method. My testimony recommended rejection of that method, and adoption of the Average & Peak method, A&P/4CP. As I showed in my initial testimony, A&E/4CP is nearly identical to allocating on a straight 4CP basis, which Mr. Al-Jabir says he would prefer anyway. A&P/4CP, which I proposed allocates a proportion of plant costs equal to average hourly use on an energy basis and the remainder of production plant cost on demand during the 4 coincident peak hours.

Q. MR. AL-JABIR STATES THAT A&E/4CP ALLOCATES PART OF PRODUCTION PLANT ON THE BASIS OF AVERAGE DEMAND. DOES THAT MEAN A&E/4CP IS SIMILAR TO AVERAGE & PEAK?

A. No. The results of Average & Excess/4CP reflect no effective allocation on the basis of average hourly demand. This is in contrast to A&P which allocates on the basis of average demand, an amount which is equal to the proportionate relationship between system average demand and system peak demand. Mr. Al-Jabir provides a simple diagram to illustrate A&E/4CP (Al-Jabir at 14). However, if numbers are inserted into Mr. Al-Jabir's example, it becomes evident that the method is the same as allocating costs on a peak demand basis. Exhibit R-1 demonstrates the equivalence between A&E/4CP and 4CP, based upon Mr. Al-Jabir's illustration. My numerical example is consistent with Mr. Al-Jabir's assumptions.

Q. MR. AL-JABIR ASSERTS THAT 4CP IS THE PROPER COST CAUSATIVE FACTOR BECAUSE "GROWTH IN UTILITY SYSTEM PEAK DEMAND IS THE TRIGGER FOR UTILITY GENERATION ADDITIONS." DO YOU DISAGREE?

A. Yes. System peak demand is only one part of the input to the Company's generation planning process. The system energy use throughout the year drives total production costs and is a critical input to selecting resource options. As stated by EGSI in its system planning summary:

> The following three figures compare EGSI' existing resources with expected loads for the year 2008. These figures depict the annual load as a load duration curve, which presents the percentage of the hours during a year in which the load exceeds an array of values, and displays the hourly loads during a year by hour versus the capability by type of role that it is capable of serving...
>
> As a general matter, the Company's supply planning objective is to maintain the appropriate level of reliability at the lowest reasonable cost. The resource planning process must first assess the inventory of viable alternatives. A viable alternative is defined as any incremental supply solution that provides incremental capacity and satisfies the known constraints. The alternatives that are considered include the most promising generation alternatives, and where applicable, may also include transmission and combination (generation and transmission) alternatives. In order to evaluate the viable alternatives against one another, the costs and benefits of each are weighed. The cost of each potential incremental supply alternative is estimated based on the fixed and variable cost of developing and operating the resource at each potential site. The benefit of each potential incremental supply alternative is estimated based on the reliability impact in conjunction with the production cost savings. The total production cost based on the costs and benefits over the life of the supply resource are aggregated and the least costly alternatives that satisfy reliability criteria are pursued.[1]

Significantly, EGSI's system planners evaluate the adequacy of generation reserves based upon comparing the load duration curve throughout the year to hourly supply. In addition, the supply side decision is made on the basis of total costs (demand plus energy).

[1] EGSI "Long Term Assessment 2006 Report to the PUCT," EGSI Response to TIEC Request No. 1-19.

Q. MR. AL-JABIR ASSERTS THAT A 4CP ALLOCATION SENDS A COST-BASED PRICE SIGNAL TO CLASSES. IS HE CORRECT?

A. No. The "signal" does not reflect the cost trade-offs in the planning process. In the case of EGS, the effect of A&E/4CP is both inequitable and a potentially misguided influence on the resource preferences of customer classes. The majority of EGSI's generating investment cost consists of River Bend, Nelson-6, and Big Cajun solid-fuel plants. Ratepayers are paying a high capital cost premium in order to receive the expense savings of coal and uranium fuel. With A&E/4CP as the production plant allocator, the large industrial customers (LIPS) receive 31% of the fuel cost savings from those plants but pay for only 21% of the capital investment. Residential users, on the other hand, pay for 46% of the capital costs but receive only 36% of the energy savings from nuclear and coal fuels.

This divergence between costs and benefits at the class level could create a rational incentive for residential customers to oppose fuel-saving baseload investments which are otherwise cost-effective for the system, or for industrial customers to prefer those capital-intensive investments when they are not the optimal choice for the system. Over the past 15 years, I have seen examples in which the actual generation investment option which is most beneficial for the system would not be cost effective at the customer class level for one or more customer classes if a peak demand method is used to allocate capacity cost. In some cases, the most cost-effective option is not cost-beneficial for the residential class, and in other cases, for the industrial class. Utilizing a capacity allocation method which effectively recognizes both demand and energy is likely to align class costs and benefits from a resource option with the cost and benefit results produced on a system basis.

Q. IS MR. AL-JABIR'S PREFERENCE FOR A 4CP ALLOCATION CONTRARY TO THE INCURRENCE OF SPECIFIC POWER PURCHASES IN THIS CASE?

A. Yes. Mr. Jabir's discussion of cost causation does not recognize the Entergy System Operating Agreement which results in a 12CP allocation of shared generation capacity reserve costs. EGSI's customers' usage during the peak hours of each month, not just the summer months, will cause a direct impact upon EGSI's revenue requirement. Mr. Pollock's testimony states that every kilowatt of demand added at the monthly peak in any month (not just the summer peak) will result in $2.50 to $3.00 of added MSS-1 costs to EGSI. Although Mr. Pollock applies this calculation to interruptible credits, the conclusion applies equally to the use of 12CP to allocate purchase power. For that reason, purchase power costs are appropriately allocated on a 12CP basis, rather than the A&E/4CP advocated by Mr. Al-Jabir.

III. CLASS REVENUE ASSIGNMENT

Q. DO THE PARTIES REFLECT DIFFERING POSITIONS ON HOW TO SPREAD ANY BASE REVENUE CHANGES?

A. Yes. Mr. Al-Jabir seeks a revenue spread based directly on the class cost of service results. Mr. Pollock (TIEC) and Ms. Peveto (state agencies) are in agreement with me that some form of rate moderation should be applied to the class cost of service results. However, each has a recommendation which is applied quite differently.

Q. PLEASE COMMENT ON MS. PEVETO'S RECOMMENDATION.

A. I am in agreement with her general observation that moderating adjustments are necessary when assigning base revenue responsibility to different customer classes. However, her recommendation that the lighting class base revenue percentage increase be fixed no higher than the system base revenue percentage increase is not easily supported as a rate moderation technique. Unless Ms. Peveto is recommending an across the board equal percentage increase, singling out lighting for such treatment doesn't make sense. Lighting is the class which produces the larges disparity from the cost study results; and if any class receives an above-average percent increase in base rates, it is difficult to argue that the lighting class should be exempted. However, as indicated by my initial testimony, the lighting class base revenue increase should be subject to moderation constraints in the same manner as similarly situated classes.

Q. PLEASE COMMENT ON MR. POLLOCK'S RECOMMENDATION.

A. Mr. Pollock sets a relatively high threshold (175% of system average increase) for rate moderation. As a result, only one class (lighting) qualifies for moderation. Mr. Pollock also fails to establish a floor level or minimum percentage increase for classes with relative rate of return above 1.0. This approach benefits the LGS and LIPS classes, which he represents. In my view, a more appropriate moderation scheme would use lower maximum percentages and include a floor (such as 50% of the system average percentage increase).

Mr. Pollock's almost non-existent approach to moderating class revenue increases for industrial classes stands in contrast to his pleas for special rate moderation treatment applied to industrial customers on Riders SSTS and IS.

IV. INTERRUPTIBLE RATES

Q. WHAT IS THE POSITION OF TIEC WITNESS MR. POLLOCK WITH RESPECT TO INTERRUPTIBLE RATES?

A. The PUC's order in Docket No. 16705 requires EGSI to terminate its existing interruptible service (IS) tariffs and replace them with a market based interruptible program. Mr. Pollock opposes both the termination of the IS tariffs and the EGSI replacement programs, market value call option (MVCO) and market value energy (MVE).

Q. DO YOU AGREE WITH MR. POLLOCK'S RECOMMENDATION?

A. No. The conditions which led the Commission to order the termination of IS have not changed. Interruptibility is a resource which should compete with other supply-side resource options available to EGSI. Market-based methods continue to be the most accurate means of determining the value of interruptibility. The Commission's concern that IS may serve as a load retention rate rather than a DSM program is best addressed by carrying out the Docket No. 16705 order.

Q. MR. POLLOCK ASSERTS THAT THE EGSI CLASS COST OF SERVICE STUDY SHOULD NOT ALLOCATE ANY PRODUCTION CAPACITY COSTS TO THE INTERRUPTIBLE CLASS BECAUSE INTERRUPTIBLE DEMANDS ARE EXCLUDED FROM THE PLANNING PROCESS. DO YOU AGREE WITH THIS CONCLUSION?

A. No. First, Mr. Pollock incorrectly states that EGSI allocates production capacity costs to the IS class. EGSI allocates no costs to the IS class because EGSI proposes to terminate the tariff. Second, even if the IS class is included in the cost of service study, it is appropriate to allocate production costs to the class. As discussed in Sec. II of this testimony, total system energy use (including interruptible customers' consumption) is also a key input to the resource planning process. Interruptible customers tend to have high load factors and their consumption tilts the capacity resource selection process towards baseload generation options. Typically baseload options, such as coal-fired capacity, are as much as four times more costly to install than peaking capacity. Thus a large portion of production capacity costs are driven by energy use. And IS customers are major contributors to system energy use.

Q. DO YOU AGREE WITH MR. POLLOCK'S CLAIM THAT THE COMMISSION REQUIRED TERMINATION OF THE INTERRUPTIBLE TARIFF BECAUSE RETAIL OPEN ACCESS WAS EXPECTED TO OCCUR IN THE NEAR FUTURE?

A. No. Nothing in the Docket No. 16705 order supports that view. This argument appears to be "revisionist history," in an attempt to create a basis for changing the order in Docket No. 16705. The PUC initiated the process of phasing out existing interruptible tariffs in CPL's 1996 rate case, Docket No. 14965. At that time, whether retail open access legislation would ever be enacted was unknown, and the Commission processed the Docket No. 14965 rate case as if the Company would continue to be regulated.

The Commission ordered termination of the IS rate because a market valuation of interruptible credits is superior to a litigated administrative determination. The Commission's order in CPL's integrated resource planning docket sets out the preference for market determinations:[2]

> While there is general agreement that interruptible loads can benefit the utility system, there is significant disagreement regarding the cost of such service, and the design of interruptible tariffs...
>
> Interruptible service is a demand-side resource or DSM resource under Commission rules. One means of determining the value of

[2] *Joint Application of CPL, WTU, and SWEPCO for Approval of Preliminary IRP,* Order Requesting Briefing on Threshold Issues, Docket No. 16995. (Footnotes omitted)

> interruptible loads as a resource is through competitive bidding. In such an approach, customers with the capability to offer load interruption as a resource would bid against other resources. The Commission has used this approach once in its consideration of a Notice of Intent application for new generating capacity.

In Docket No. 16995, the Commission stated that "all other utilities in Texas...are on notice of the new Commission policy regarding interruptible resources and determination of the value of interruptibility in the market."[3]

Although the IRP statutory provisions were repealed, the Commission could order EGSI to undertake solicitations for interruptible contracts. That would be reasonable approach, in my opinion.

Q. MR. POLLOCK CLAIMS THAT A MARKET FOR INTERRUPTIBILITY WOULD NOT EXIST WITHOUT RETAIL OPEN ACCESS. IS THAT CORRECT?

A. No. The fact that the Commission ordered all source DSM solicitations for interruptible providers in the CSW IRP case and required the development of market-based programs by EGSI, demonstrates the Commission's belief that market methods are viable outside of retail open access. The Company's obligation, enforceable by the Commission, is to acquire generation resources at the lowest reasonable cost for its monopoly customers. Market based bidding methods are likely to reveal the lowest cost providers of interruptibility. Mr. Pollock's real concern seems to be that bidding approaches will produce credits which are "least cost."

[3] Docket No. 16995, *Ibidem.*, Order on Certified Issues at 3.

Q. WHY HAS THE COMMISSION NOT CARRIED OUT THE TERMINATION OF THE INTERRUPTIBLE RATE?

A. The Commission order in Docket No. 20150 makes clear that the statutory rate freeze prevented implementation of the termination order:[4]

> With respect to EGS' IS tariff, the Commission also determines that S.B. 7 supercedes the Commission's directive in Docket No. 16705 to phase out the IS tariff. Specifically, S.B. 7 § 39.052 freezes the utility's retail base rate tariffs in effect on September 1, 1999. This precludes action on NSST's contention that EGS should file a market-based interruptible tariff. Because EGS will keep its current tariff in place until the rate freeze period ends in 2002, NSST's desire for certainty about IS rates is alleviated.

Subsequently the rate freeze was extended until the current rate proceeding.

Q. MR. POLLOCK CITES THE COMMISSION'S SUPPORT FOR THE ERCOT "LOAD ACTING AS A RESOURCE" (LARS) PROGRAM AS GROUNDS FOR KEEPING THE INTERRUPTIBLE TARIFF. IS THAT A VALID REASON?

A. No. The Commission's support for the ERCOT LARS program is consistent with the order in Docket No. 16705, which required the existing IS rate to be replaced with a market-based approach to demand-side response. LARS is a market-based system which treats demand response on an equivalent basis with supply-side resources.

[4] *Application of EGSI for Base Rate Increase*, Docket No. 20150, Final Order (1999).

Q. DO YOU PERCEIVE THE EGSI PROPOSED CALL OPTION PROGRAMS TO BE A REASONABLE RESPONSE TO THE REQUIREMENT FOR PROPOSING A MARKET-BASED INTERRUPTIBLE PROGRAM?

A. Yes. The program appears to provide flexible bidding for firm power customers who can provide interruptible benefits. Undoubtedly the programs can be improved. I have no objection to Mr. Pollock's recommendation that the program should have more transparency with respect to the Company's decision to accept particular bids. In addition, as mentioned previously, the Company should be encouraged to engage in "low bid" solicitations for interruptible contracts.

Q. DO YOU CONCUR WITH THE INTERRUPTIBLE RATE CREDITS PROPOSED BY MR. POLLOCK?

A. No. The rate credit would continue to be excessive.

Q. HOW DOES MR. POLLOCK STRUCTURE THE PROPOSED CREDITS?

A. He utilizes three types of IS rates: No notice, 5-minute notice, and 30-minute notice. Mr. Pollock's basis for developing the credit amounts involve calculations of a MSS-1 System Agreement benefit and operating reserve benefits associated with no notice and 5-minute interruptions.

Q. DO YOU AGREE WITH MR. POLLOCK'S CALCULATION OF OPERATING RESERVE BENEFITS?

A. No. The calculated credits are based upon flawed premises and the credit amounts are excessive.

Q. WHY IS THE $2.00 CREDIT FOR SPINNING RESERVE BENEFITS UNREASONABLE?

A. The IS load does not qualify as spinning reserve. EGSI follows the SPP criteria for spinning reserves, and SPP only permits generating units to provide spinning reserves.[5] Obviously a credit cannot be provided for spinning reserve benefits if interruptible load does not qualify as spinning reserves.

Q. DO YOU AGREE WITH MR. POLLOCK'S CALCULATION OF OPERATING BENEFITS FOR 5-MINUTE NOTICE IS SERVICE?

A. No. The relevant time frame for providing ready reserves is 15 minutes, according the EGSI.[6] Mr. Pollock uses the differential in cost between a "quick start" aero-derivative gas turbines and a standard gas-fired combustion turbine to arrive at a credit of $2.57. However, Mr. Pollock has provided no evidence that standard heavy duty CTs cannot be started within the 15-minute time frame required for ready reserves.[7] Indeed the ability to provide operating reserves is one reason for installing combustion turbines. Although aero-derivate gas turbines may have quicker starting capability, the advantage may be unnecessary for ready reserve purposes.

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[5] EGSI Response to TIEC Request No. 4-23.

[6] *Ibidem.*

[7] GE recently provided modifications to the widely used 7FA CT to enable those units to achieve starts in 7 minutes.

Q. IS IT APPROPRIATE TO SUM <u>BOTH</u> OPERATING RESERVE CREDITS TOGETHER FOR "NO NOTICE" SERVICE?

A. No. Summing the credits is duplicative. The same resource should get paid for offering one ancillary service at a time.

Q. IS MR. POLLOCK'S USE OF MSS-1 SYSTEM AGREEMENT COSTS TO QUANTIFY A $2.50 CREDIT INCONSISTENT WITH PREVIOUS POSITIONS HE HAS ESPOUSED?

A. Yes. Previously, FERC included interruptible loads in the MSS-1 calculation. As a result, the IS load had the opposite impact on MSS-1 payments (*i.e.*, increased payments). In Docket No. 16705, Mr. Pollock stated that the System Agreement "is not relevant to the issue of the appropriate costing and pricing of interruptible service for Texas retail customers whose rates are regulated by the PUC."[8] Responding to an argument that the IS rate should be designed to recover the MSS-1 costs which IS load causes. Mr. Pollock stated:[9]

> It would be inappropriate for the FERC (which regulates only a small portion of EGS' operations) to dictate the rate design policy applicable to retail customers under tariffs subject to PUC jurisdiction.

[8] Cross-Rebuttal Testimony of Jeffry Pollock at 22-33 (excerpt attached as Exhibit R-2).
[9] *Ibidem.*

Q. IF MR. POLLOCK'S CALCULATION OF INTERRUPTIBLE RESERVE BENEFITS UNDER MSS-1 WERE TO BE ADOPTED, SHOULD A CORRESPONDING CHANGE BE MADE IN THE ALLOCATION OF SYSTEM AGREEMENT PURCHASE POWER COSTS IN THE EGSI CLASS COST OF SERVICE STUDY?

A. Yes. As noted in my initial testimony, purchase power should be allocated on a 12CP basis, in part because MSS-1 system agreement costs are incurred based upon the 12 monthly peak hours. Recognizing the MSS-1 12CP reduction to IS rates without reflecting the equivalent cost allocation impact for firm loads would be unfair and contradictory.

Q. WHY IS THE OPERATING RESERVE CREDIT EXCESSIVE?

A. In addition to the reasons provided previously, the credits amount should be capped by the price of available short term purchases of power. As a practical matter, interruptible rates are not a "least cost" resource if the cost of the credits exceed short term power purchase options.

Q. IF THE COMMISSION WERE TO ADOPT A CREDIT BASED ON MR. POLLOCK'S RECOMMENDATION, WHAT SHOULD BE THE MAXIMUM CREDIT?

A. EGSI system planners assume short term CT purchase power capacity costs of [redacted]/kw per month.[10] This equates to a billing demand credit of [redacted]. If the IS rate is continued (contrary to my recommendation) any credit amount for no

[10] EGSI Response to OPC Request No. 20-3 (Highly Sensitive and Confidential)

notice or 5-minute notice IS over and above the credit for MSS-1 reserves should be limited to the system planning assumption for short term purchases above. Failure to cap the credit in this manner would be contrary to the concept of a market-based valuation.

V. EAPS AND SSTS

Q. DOES MR. POLLOCK MAKE A RECOMMENDATION WITH RESPECT TO SUPPLEMENTAL SHORT TERM SERVICE (SSTS)?

A. Yes. The Company has proposed termination of the discounted SSTS rider. Mr. Pollock says that this action would cause "rate shock" and argues that the discount should be phased out.

Q. WHAT WAS THE PUC ACTION WITH RESPECT TO SSTS IN DOCKET NO. 16705?

A. The Commission concluded that SSTS is a discounted rate which is subject to revenue imputation (*i.e.,* cost of discount borne by EGSI shareholders).

Q. DO YOU AGREE WITH THE TERMINATION OF RIDER SSTS?

A. Yes. This rate was initiated as an "experimental" rate for "short term service" but has continued in existence for over 20 years. The term "short term" obviously has become a misnomer. The rate was developed in response to temporary excess capacity on the GSU system and the prospect of load loss due to co-generation. GSU's initial testimony requesting approval of the rate states:[11]

> Schedule SSTS (Supplemental Short Term Service) is a schedule that will allow existing customers to receive a discounted rate on any additional load of 5,000 KW or greater. The discounted rate will vary on a month-to-month basis depending on the cost of fuel and purchased power. This schedule is experimental and will only be available in years when Gulf States has a 25 percent or greater reserve margin.

The extreme excess capacity problem of the late 1980's no longer provides a justification for this tariff.

Q. IF MR. POLLOCK'S SSTS RECOMMENDATION IS ADOPTED, WHAT IS THE IMPACT ON EGSI?

A. The rate is a discounted rate pursuant to PURA § 36.007, and the cost of the discount may not be allocated to other customers, as required by § 36.007(d). The only alternative treatment is to assign the loss to the LIPS class.

Q. DOES MR. POLLOCK DISAGREE WITH THE COMPANY'S PROPOSED INCREASE IN THE EAPS RATE?

A. Yes. Mr. Pollock opposes the Company's pricing change for EAPS. In particular, he opposes the Company's requirement that EAPS customers submit bids for obtaining EAPS power.

[11] Pre-filed Testimony of Edward Loggins, at 80-81, *Application of Gulf States Utilities Co. for a Rate Increase*, Docket No. 6525 (1986).

Q. DO YOU AGREE WITH MR. POLLOCK'S VIEW THAT THE EAPS RATE WOULD NOT BE "JUST AND REASONABLE" TO EAPS USERS?

A. No. EAPS is available only to cogenerators in EGSI's service territory. Costs are not allocated to EAPS; instead a minimal "margin" over incremental energy costs is collected from the rate. Although EAPS is a retail rate, the rate has been characterized by the PUC as more analogous to a price for supplying power in the wholesale market. EAPS customers do not pay any costs of the recently approved riders, hurricane reconstruction cost recovery and the interim purchased capacity rider, even though EAPS users benefit from such costs. For that reason, EAPS is under-priced rather than over-priced. Given that EAPS is a competitive pricing mechanism, and taking into account the under-pricing of fixed cost recovery under the current EAPS tariff, I have no objection to the Company's attempt at increasing the margin received from these sales through the implementation of competitive bidding. Any increases in fixed cost recovery from EAPS would reduce fuel costs which must be recovered from other customers of EGSI.

VI. PUBLIC BENEFITS RIDER

Q. HAVE INTERVENOR WITNESSES ADDRESSED THE PUBLIC BENEFIT RIDER WHICH WOULD PROVIDE LOW INCOME ENERGY ASSISTANCE?

A. Yes. Several witnesses, including Ms. Peveto and Mr. Al-Jabir, oppose the creation of this rider.

Q. DO YOU HAVE A RECOMMENDATION IN THE EVENT THAT THE LOW INCOME ASSISTANCE FUNDING PROGRAM IS NOT APPROVED?

A. Yes. If the rider is rejected, I recommend continuation of the current low income rate discounts within the residential rate design. The costs of the discounts should be allocated among customer classes in the same manner as ordered in Docket No. 16705. The Company proposed to discontinue the existing rate discounts in order to fund the new rider. If the rider is not adopted, the existing discounts should be continued.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit R-1

Exhibit R-1

The following example illustrates the equivalence of A&E and CP allocators, based upon the illustration at page 14 of Mr. Al-Jabir's testimony.

Class	**Average Demand**	**Peak Demand**	**Excess Demand**
A	50 kW	125 kW	75 kW
B	50 kW	50 kW	0 kW
Total	100 kW	175 kW	75 kW

Load Factor = 100/175 = 57.14%

The ratio of total average demand to total peak demand, the system load factor, is 57.14%. Under A&E the product of the system load factor and total capacity cost, i.e., approximately 57.14% of total capacity cost, is allocated to classes based on class contribution to average demand.

The remainder of cost (42.86%) is allocated in proportion to class contribution to excess demand. Thus, the A&E allocators for classes A and B are:

$$A = 57.14\% \text{ X } \frac{50}{100} + 42.86\% \text{ X } \frac{75}{75} = .2857 + .4286 = 71.43\%$$

$$B = 57.14\% \text{ X } \frac{50}{100} + 42.86\% \text{ X } \frac{0}{75} = .2857 + 0 = 28.57\%$$

Although a portion of capacity cost appears to be attributed to energy, A&E is mathematically equivalent to a CP allocation. In the above example, the CP allocators are 125 ÷ 175 = 71.43% and 50 ÷ 200 = 28.57% for classes A and B, respectively.

Exhibit R-2

ENTERGY GULF STATES, INC

Before the
State Office of Administrative Hearings

SOAH Docket No. 473-96-2285
PUC Docket No. 16705

RATE DESIGN PHASE

Rebuttal Testimony of Jeffry Pollock

INTRODUCTION

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Jeffry Pollock, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q **DID YOU PREVIOUSLY FILE DIRECT TESTIMONY ON BEHALF OF THE TEXAS INDUSTRIAL ENERGY CONSUMERS IN THE RATE DESIGN PHASE OF THIS PROCEEDING?**

A Yes.

Q **WHAT ISSUES ARE YOU ADDRESSING IN YOUR REBUTTAL TESTIMONY IN THE RATE DESIGN PHASE?**

A I shall respond to certain recommendations made by Steven Andersen on behalf of Certain Cities (Cities), Clarence Johnson and Aarne Hartikka on behalf of the Office of

Q SHOULD DR. ANDERSEN'S RECOMMENDATIONS BE ADOPTED?

A No. First, Dr. Andersen's reliance on the System Agreement is misplaced. The System Agreement, which is subject to FERC regulation, is not relevant to the issue of the appropriate costing and pricing of interruptible service for Texas retail customers whose rates are regulated by the PUC. Second, Dr. Andersen's bottom-up analysis of the fixed cost recovery of no-notice interruptible customers is based on a false assumption that the out-of-pocket cost to provide no-notice interruptible service should be based on the average cost of gas generation.[14]

Q WHY DO YOU CONTEND THAT THE ENTERGY SYSTEM AGREEMENT IS NOT RELEVANT TO THE COSTING AND PRICING OF INTERRUPTIBLE SERVICE?

A First, as previously noted, the System Agreement is regulated by the FERC. It would be inappropriate for the FERC (which regulates only a small portion of EGS' operations) to dictate the rate design policy applicable to retail customers under tariffs subject to PUC jurisdiction.

Second, one of the main purposes of the System Agreement is to equalize reserve generation capacity among the five Entergy Operating Companies (OPCOs). By equalizing the reserves, the System Agreement maximizes the benefits derived from the

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analysis of the fixed cost contribution on Pages 54 and 55 of his testimony only applies to no-notice interruptible load. No analysis was provided of the fixed cost contribution made by noticed interruptible service.

[14]Id. at Page 54.

joint planning, ownership and operation of generation capacity. Thus, although EGS is incurring explicit costs under the System Agreement that were not being incurred prior to the GSU-Entergy merger, these costs should be more than offset by the corresponding merger benefits. The GSU-Entergy merger would not have been approved without a demonstration that GSU's customers would benefit from lower costs.

If interruptible load is causing EGS to incur a cost under the System Agreement, it must be shown that these costs are incremental; that is, they would not be incurred in any form in the absence of the Agreement. Neither Dr. Andersen nor Mr. Johnson have demonstrated that the costs EGS is incurring under Schedules MSS-1 or MSS-2 of the System Agreement would not have otherwise been incurred by EGS. For example, by purchasing capacity under Schedule MSS-1, EGS avoids the need to invest in new generation capacity or to purchase power from non-affiliated companies to maintain adequate reserves. Similarly, EGS may not need to incur additional transmission investment or operating expense in order to maintain reliability. Thus, to the extent that the System Agreement is a substitute for costs which EGS would have otherwise incurred as a stand-alone company, it would not be fair to characterize them as incremental costs.

Finally, the System Agreement is merely an accounting mechanism which is designed to equalize the benefits and costs associated with interconnected operation and joint planning. No costs are incurred by Entergy shareholders because of the Agreement since the transfer payments among the affiliates net to zero. The existence of transfer payments does not fundamentally alter how system resources are planned. In other words, if Entergy as a system does not incur capacity costs to serve interruptible load, then it follows that all of the OPCOs, including EGS, would not incur capacity costs to serve interruptible load.