Bend Outage Management Department. Refueling Outage RF-6 lasted just under 40 days.

61. The only NRC-cited violation that affected the outage was a mispositioned fuel bundle, which caused 7.8 hours of delay.

62. The most useful benchmark for this issue is the 49-day industry-median outage length for BWRs in the relevant time period.

63. The RF-6 duration of 39.8 days is well under the relevant industry median of 49 days.

64. The mispositioned fuel bundle raises heightened concern because it (along with other errors) triggered an NRC violation and a meeting with the NRC.

65. Deleted.

66. As to the entry into Refueling Outage RF-6 related to the second recirculation pump trip, EGS' actions were not imprudent, for the same reasons cited above regarding Forced Outage FO-95-01.

67. The turbine vibration was not an instance of imprudence and does not warrant a disallowance.

Nuclear Unit Forced Outage FO-96-01

68. On June 6, 1996, the River Bend plant experienced a rapid decrease in turbine load along with a rapid increase in reactor power and pressure. To be safe and to allow for investigation, the operators manually scrammed the reactor. The outage lasted about 8.9 days. The EGS investigators determined that reactor pressure had risen because one of the turbine stop valves and the intercept valves had closed, due to failure of two redundant power supplies, which failure was attributed to an overvoltage condition and a

defective blocking diode in one power supply, which then apparently prevented the other power supply from picking up the load.

69. No reasonable quality assurance program would have detected the defective diode that caused the power supply failure.

70. After replacing the defective part, the power supplies again worked correctly. The defective diode was not discoverable despite a reasonable level of quality assurance at both the power supply vendor's facility and at River Bend. Thus EGS was not imprudent with respect to the power supply failure, and no disallowance is appropriate.

71. EGS was not imprudent with respect to the air handler fan bearings faulty installation and repair work which extended Forced Outage FO-96-01; thus, no disallowance is appropriate.

Nuclear Fuel: 1977 Uranium Sale

72. In June 1977, EGS' predecessor Gulf States Utilities, Inc. (GSU) sold about 500,000 pounds of uranium concentrate to Florida Power & Light Company. GSU credited the profit to its shareholders.

73. GSU sold the uranium to gain an immediate source of cash and to have more flexibility in the timing of GSU's next uranium financing.

74. The 1977 uranium sale was litigated in GSU's last fuel reconciliation case.

74A. No portion of the original cost of or carrying charges for the uranium concentrate were ever placed in rate base and ratepayers never bore the burdens or risks associated with this item.

Nuclear Fuel: Lease Interest

75. In February 1989, GSU entered into a nuclear fuel lease with River Bend Fuel Services, Inc. (RBFS), a corporation whose sole purpose is to acquire nuclear fuel, process the fuel (via conversion, enrichment, and fabrication), and lease the fuel to EGS for use at the River Bend station. RBFS finances the acquisition and processing of nuclear fuel through the issuance of intermediate term notes and through loans from certain financial lending institutions.

76. All the information Mr. Hubbard needed to review the 1989 notes and propose a disallowance was available in previous dockets, and Mr. Hubbard did not need the amortization breakdown to review the 1989 notes and propose a disallowance.

76A. The evidence in the record does not support any disallowance of nuclear fuel lease costs.

Nuclear Fuel: Engineering Services

77. Engineering services accounted for $772,623 (2.2 percent) of EGS' eligible nuclear fuel expenses in this reconciliation period. Those expenses were related to nuclear fuel in process and to batch numbers 5-9.

78. The engineering services expenses for batches 7 and 8 were much higher (about 1000 percent higher) than for batches 6 and 9.

79. EGS presented no additional explanation or extraneous documentary evidence for its unsubstantiated conclusory assertion that batches 6 and 9 had a very low percentage of their overall costs charged to in-house design.

80. EGS' claim that it changed accounting methods during batch 9 to achieve Entergy system uniformity was an unsubstantiated conclusory assertion without extraneous documentary evidence or additional explanation. It also fails to explain why the cost for batch 6 was so relatively low.

81. EGS has failed to satisfy its burden of proof to show that $693,380 of its nuclear fuel engineering services expenses were prudently incurred, and that amount should therefore be disallowed.

Wheeling Revenues and Account 565 Expenses

82. EGS requested a good cause exception to the fuel rule's requirement that wheeling revenues and Account 565 expenses be included in eligible fuel expenses. As determined by the Commission in *Application of Southwestern Electric Power Company For Reconciliation of Fuel Costs, Surcharges of Fuel Cost Under-Recoveries, and Related Relief*, Docket No. 17460 (May 17, 1998) (SWEPCO), these expenses and revenues are not eligible fuel expenses. Thus, wheeling revenues and Account 565 expenses are not treated as reconcilable for this reconciliation period.

82A. EGS showed that, during the last rate case (Docket No. 12852), its wheeling (company service) expenses were placed in base rates. To now subtract wheeling (company service and access service) revenues from the fuel factor calculation (without adding wheeling expenses) would therefore be a double dip against EGS (*i.e.*, EGS would be treated as if it had received payment from not only wheeling customers but also retail customers -- virtually double the amount of wheeling revenues it actually received) unless base rates were simultaneously adjusted to exclude wheeling expenses. That simultaneous adjustment would require the onerous, time-consuming modification of the cost-of-service studies and allocation factors from the last rate case in order to set new base rates coincident with the implementation of the Phase I interim fuel factor. Inconsistent regulatory treatment (the double dip) would be unfair, and an onerous simultaneous retroactive base rate adjustment would be unwise; this third argument therefore strongly tends to show good cause for an exception as to the fuel reconciliation. (SFoF 18).

82B. Therefore, as to the fuel reconciliation, EGS' wheeling revenues and Account 565 expenses are not eligible fuel expenses. (SFoF 19).

82C. Cities failed to show good cause to deviate from the fuel rule so as to treat MSS-1 expenses as reconcilable, because: (1) MSS-1 expenses do not include any fuel expense component; and (2) elimination of regulatory lag does not justify expanding the scope of the fuel rule to include MSS-1 expenses, because regulatory lag affects all non-reconcilable (base rate) expenses, and MSS-1 expenses have not been shown to differ from any other non-reconcilable expense so as to justify reconcilable treatment. (SFoF 20).

Purchased Power Expenses

83. EGS requested reconciliation of and showed that it prudently incurred purchased power costs of $199,521,206.48.

84. EGS' $199,521,206.48 in purchased power and affiliate expenses were reasonable and necessary, and the prices charged by its supplying affiliates were reasonable and necessary and no higher than the prices charged by the supplying affiliate to its other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items.

Calculation of Surcharge and Interest Collection

85. EGS' cumulative fuel under-recovery balance as of June 30, 1996 was $48,308,092 (including interest and the remaining underrecovery balance (including interest) for the Docket No. 15102 reconciliation period). After reducing the amount shown above to reflect (1) the disallowances in Docket No. 15102, (2) the surcharge of the remaining underrecovery balance from Docket No. 15102, and (3) the disallowances in this docket, the underrecovery balance, if surcharged in one month (August 1998 assumed), as required by P.U.C. SUBST. R. 23.23(b)(3)(C), is $32,507,222 ($28,620,522 principal plus $3,886,700 interest).

86. Because the significant base rate reductions in this case, it is appropriate to use the total surcharge amount to offset a portion of the base rate refunds during the Historical Refund Period for the fixed fuel factor customers.

87. It is not appropriate to adopt EGS' proposal that the surcharge either: (a) not incorporate interest due beyond the start of the surcharge period; or (b) if surcharge period interest must be included in the surcharge, then only incorporate interest for the first 11 of the 12 surcharge months.

Disallowances and Non-Fixed Fuel Factor Customers

88. In EGS' last fuel reconciliation case (Docket No. 15102), the Commission ordered EGS to allocate a portion of certain disallowances to EGS' Texas Non-Fixed Fuel Factor (NFFF) customers.

89. General Counsel and EGS have asked the Commission to reverse or decline to follow its Docket No. 15102 decision to allocate disallowance refunds to NFFF customers.

90. Certain EGS customers specifically requested the rate structure of certain NFFF rates and participated in the development of the rate structure of certain NFFF rates.

91. NFFF customers have only recently requested inclusion in the disallowance refund distribution pool.

92. Certain NFFF customers (including EAPS customers) can choose not to accept power in those hours when they learn the price of power is high.

93. NFFF customers' exclusion from disallowances benefits was balanced or outweighed by the significant overall rate reductions offered by NFFF rates.

94. Certain NFFF rates do not in fact include a "fuel" expense.

95. NFFF rates do not include a "fuel factor," despite the name "non-fixed fuel factor," because the NFFF energy charges do not "pass costs through" to the NFFF customers, but only approximate fuel expenses, and therefore the "fuel" portion of the energy charge is not reconcilable.

96. NFFF expenses and revenues should not be included in fuel-reconciliation calculations. NFFF customers should not participate in reconciliation disallowances.

Interim Fuel Factor

96A. The portions of EGS' application and testimony regarding its proposed interim revision to the fixed fuel factor are not reasonably comprehensible -- *i.e.*, the lack of useful summaries, calculations, and tables made the application unnecessarily difficult to evaluate. (SFoF 1).

96B. EGS failed to supplement its application so as to provide the interim fuel factor eligible fuel expense components of purchased power expenses and off-system sales revenues for the months of March-June 1998. (SFoF 2).

96C. EGS' slowness in providing discovery responses aggravated the difficulty of evaluating the application. (SFoF 3).

96D. EGS' proposed interim fuel factor would have been in effect for such a short period of time that its consideration and implementation would be an inappropriate use of Commission resources and could needlessly complicate later Commission determinations. (SFoF 4).

Final Fuel Factor

Nuclear Fuel Costs

96E. EGS' nuclear fuel expense estimate, as modified by General Counsel, was based on ambitious operating assumptions, such as 30-day outages every 18 months and a 95% capacity factor between refueling outages, along with dollar considerations such as the level and book value of existing inventories, financing costs, spent fuel disposal fees, decommissioning and decontamination fees, and anticipated contract and market prices associated with procurement of uranium concentrates, conversion, enrichment, and fabrication. (SFoF 5).

96F. EGS' and General Counsel's nuclear fuel estimate of $30,874,211 is the most reasonable proposal, because it better indicates EGS' likely expenses than does Cities' benchmark. (SFoF 6).

Good Cause Exception for Wheeling Revenues and Account 565 Expenses

96G. EGS asked to be excused from the fuel rule's P.U.C. SUBST. R. 23.23(b)(2)(B) requirement that "eligible fuel expenses" include expenses recorded in Account 565 of the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts and revenues from wheeling transactions (comprising revenues from Access Service and Company Service). (SFoF 7).

96H. In the fuel reconciliation period for this case, the only items recorded by EGS in Account 565 are transmission equalization expenses paid pursuant to Service Schedule MSS-2 of the Entergy Service Agreement (ESA). Under the MSS-2 expense/revenue formula, EGS and other "short" (*i.e.*, relatively transmission-deficient) Entergy operating companies (EOCs) effectively pay into a pool from which the "long" (*i.e.*, relatively transmission-plentiful) EOCs draw; this formula is intended to equitably distribute the ownership costs of certain transmission facilities (mostly high-voltage (230 kV)) in the Entergy System. (SFoF 8).

96I. "Access service" is transmission service provided by the Entergy System (not EGS) to wholesale customers under an open access transmission tariff filed with the FERC. Access service revenues are received at the Entergy System level and are allocated to the various Entergy operating companies in proportion to each company's load. In the fuel reconciliation period, EGS received about $2.6 million in access service revenues on a total company basis. (SFoF 9).

96J. "Company service" is transmission service provided by EGS (not the Entergy System) to several wholesale customers which have been directly connected to EGS' transmission system for many years; current customers include Cajun Electric Power Cooperative, Inc., Sam Rayburn G&T, Inc., Sam Rayburn Municipal Power Agency, Lafayette Utility System, and Louisiana Energy and Power Authority. In the fuel reconciliation period, EGS received about $33.5 million in adjusted company service revenues. (SFoF 10).

96K. EGS' evidence that these expenses/revenues are demand-related and are not variable shows that they are not eligible fuel expenses under the reasoning in SEPCO. (SFoF 11).

96L. Deleted. (SFoF 12).

96M. Therefore, as to the final fuel factor, EGS' wheeling revenues and Account 565 expenses are not eligible fuel expenses as determined by the Commission in SWEPCO and should not be treated as reconcilable fuel expenses. (SFoF 13).

96N. The FERC has approved the relevant parts of the ESA as amended to reflect the inclusion of EGS. In Opinion No. 385, the FERC expressly accepted an amendment to the ESA which added Gulf States to the ESA as an operating subsidiary. EGS' MSS-2 expenses are therefore mandated by the FERC. (SFoF 14).

Good Cause Exception for MSS-1 Expenses

96O. Cities asked the Commission to disallow most of (if not all of) EGS' MSS-1 expenses, whether from base rates, where EGS has proposed their inclusion, or from the reconcilable fuel expenses used to calculate the fixed fuel factor, or else to grant a good cause exception to the fuel rule for EGS' MSS-1 expenses in order to eliminate the regulatory lag from timing differences between a FERC ordered revision in the System Agreement and a PUCT decision in a subsequent EGS base rate case. (SFoF 15).

96P. Cities failed to show good cause to deviate from the fuel rule so as to treat MSS-1 expenses as reconcilable, because: (1) MSS-1 expenses do not include any fuel expense component; and (2) elimination of regulatory lag does not justify expanding the scope of the fuel rule to include MSS-1 expenses, because regulatory lag affects all non-reconcilable (base rate) expenses, and MSS-1 expenses have not been shown to differ from any other non-reconcilable expense so as to justify reconcilable treatment. (SFoF 16).

Calculation of the Final Fuel Factor

96Q. The appropriate Texas retail fixed fuel factor is shown on Commission Schedule KP-Fuel/1. (SFoF 17).

Revenue Requirements

Invested Capital

97. EGS' appropriate level of invested capital is reflected in Commission Schedule IV.

Capital Additions

98. Capital addition costs for maintaining the River Bend Nuclear plant during the test year were within the range of costs experienced at the plant in prior years.

99. All capital additions expenditures are directly billed, not allocated, from Entergy Operations, Inc. (EOI) to EGS.

100. Capital additions to the River Bend plant during the test year in the amount of $11.8 million benefited ratepayers; the costs are reasonable and necessary and no higher than EOI would charge to other nuclear affiliates for the same or similar service.

101. EGS' capital additions expenditure for its fossil generation plant during the test year in the amount of $11,411,305 is an appropriate increase to rate base.

102. EGS' requested $2,134,558,000 represents an appropriate level of transmission and distribution (T&D) plant in rate base.

Accumulated Depreciation

103. EGS' appropriate level of accumulated depreciation is reflected in Commission Schedule IV. Accumulated depreciation reflects denial of EGS' request to include certain plant in rate base as plant held for future use (PHFU) as well as treatment of the gain on Neches 7.

Gain on Neches 7

104. The gain on Neches 7 in the amount of $8,719,000 should be amortized over a five-year period beginning June 1996, with a true-up established beginning with the rate year of the November 1998 rate case.

Accumulated Deferred Federal Income Taxes (ADIT)

105. A one-time accounting change related to the last 11 days of 1992 increased Entergy's revenues to the benefit of its shareholders. Therefore, ADIT related to those unbilled revenues should not be included in rate base.

106. EGS included $44,089,867 in net operating losses (NOLs) in rate base. As discussed at §V.D.2. of the PFD, this amount should be removed from rate base.

107. Accumulated deferred income tax related to alternative minimum taxes (AMT) in the amount of $38,965,455 should be removed from rate base as discussed at §V.D.3. of the PFD.

108. River Bend Unit 2 cancellation costs are not included in rate base. Therefore the ADIT associated with this canceled plant is not included in rate base.

109. Accumulated deferred income tax should be increased for the accrual adjustment posted after test-year end to adjust the Company's 1995 tax accrual to the 1995 tax return.

110. EGS' appropriate ADIT is reflected on Commission Schedule IV.

Plant Held for Future Use

111. EGS does not have a definite plan to return Neches Station Units 4, 5, 6 and 8 and Louisiana Station 2, Units 7, 8, and 9 to used and useful status within ten years in order to justify requiring ratepayers to begin paying for these plants in rate base as PHFU.

112. EGS' plan for these plants recognizes that they would be used only about ten percent of their capacity and only during peak times. Such minimal use should be considered in an integrated resource plan (IRP) proceeding to determine whether it is a reasonable alternative to another power source or is economically justified.

113. The costs surrounding return of these plants to rate base have not been subjected to a solicitation under PURA § 34.051, which requires that a resource solicitation be conducted under the utility's preliminary IRP. EGS has no preliminary IRP which would have taken into account such things as present and projected reduction in the demand for energy as a result of conservation and energy efficiency in various customer classes (PURA § 34.024(a)(2)); the amount and operational characteristics of additional capacity needed; the types of viable supply-side resources to meet that need; and the range of

probable costs and many other inquiries dictated by PURA § 34.024. EGS should engage in the IRP process and fulfill the requirements of PURA § 34.021-34.024 before the Neches and Louisiana plants are put in rate base as PHFU.

113A. Because of advancing competition in the wholesale market and recent amendments to state law, the Commission will not follow the PHFU standard or any standard that anticipates recovery of new or mothballed generation plant investment through rate base. Instead, utilities should be on notice that they should acquire new generation capacity from non-utility suppliers through the IRP process.

Cash Working Capital

114. EGS' appropriate level of cash working capital is reflected in Commission Schedule IV. Adjustments to EGS' requested cash working capital reasonably include:
   a. Recognizing vacation time as a separate component of payroll to account for the lag between when the employee earns the vacation time and when the Company pays for it in salary expense;
   b. Adjusting "Other O&M Expenses Over $100,000" and "$50,000 to $100,000" to recognize that the service date for medical costs is the date medical treatment was provided and the lag for Thrift Plan payments is based not on the employees' one-year employment period; and
   c. Adjusting SFAS 106 regarding OPEBs.

Fuel Inventories

115. A reasonable level of coal inventory is $8,902,457, which represents approximately a 35-day supply of coal at each plant: Nelson 6 (385 megawatts) and Big Cajun II, Unit 3 (227 megawatts).

116. EGS' natural gas inventory working capital allowance of $8,542,533 is reasonable.

117. A reasonable level of fuel oil working capital in rate base is $5,110,085.

117A An adjustment to remove $4,659,033 related to EGS' No. 6 fuel oil supply shall not be made because the record demonstrates that such fuel inventories may be used and useful. In this case, the existence of these fuel inventories supported a related disallowance of fuel expense because No. 6 fuel was not burned.

Materials and Supplies Inventories

118. A reasonable level of materials and supplies inventory is $88,527,930.

Deferred Sales Tax on Coal Cars

119. It is reasonable to include in rate base EGS' test-year-end balance of $291,000 as deferred sales tax or coal cars.

Property Insurance Reserve Balance

120. The reasonable and necessary reserve balance in rate base for property insurance should be ($15,572,000).

Other Adjustments to Invested Capital

121. Based on an amortization period ending January 31, 2000, the test year amortization expense for deferred financing costs would increase by $5,903,700, and amortization expense for property cancellation loss for River Bend 2 would decrease by $1,365,396, for a net increase in test year amortization of $4,538,304.

122. No expenditures necessary to produce cost savings related to the merger between EGS and Entergy Corporation should be reflected in rate base consistent with the decision to disallow all such costs.

123. From April 1994 through the end of the test year, June 30, 1996, EGS collected $36,205,679 on a total Company basis for post-retirement expenses other than pensions

(OPEBs). This amount should not be reduced by EGS' OPEB trust funds, as EGS has not had access to the funds with which to fund rate base.

124. The following are appropriate adjustments to EGS' request level of invested capital:

Account	13 Mo. Avg.	Adjustment	Total Level
Injuries and Damages	($5,543,000)	$643,000	($4,899,000)
Coal Car Maint. Reserve	($4,071,000)	($91,000)	($4,162,000)
Customer Deposits	($21,510,000)	($860,000)	($22,370,000)
Contractor Retainage	($455,000)	11,000	($444,000)

Cost of Capital

125. EGS' cost of capital should be based on a capital structure consisting of 48.06 percent long-term debt, 2.16 percent QUIPS, 6.52 percent preferred stock, and 43.26 percent common equity.

126. A reasonable cost of long-term debt is 8.51 percent and of preferred stock is 8.32 percent.

127. EGS' reasonable cost of quarterly income preferred securities (QUIPS) is its May 1997 embedded cost of 9.07 percent.

128. A reasonable return on equity for EGS is 11.7 percent.

128A. Based on the Commission's decision in *Entergy Gulf States, Inc. Service Quality Issues (Severed from Docket No. 16705),* Docket No. 18249, EGS' return on equity established in this docket (Docket No. 16705) is reduced by 60 basis points to 11.1 percent for the period June 1, 1996 through May 12, 1998. Also in accordance with Docket No. 18249, EGS' return on equity is reduced by 30 basis points from 11.7 percent to 11.4 percent from May 13, 1998 through the remainder of the period in which the rates subject to this docket are in effect.

129. EGS' cost of equity is properly determined by use of a multi-stage non-constant discounted cash flow (DCF) analysis, which is the most reliable model for projecting dividend payouts and future growth. To the extent a constant-growth DCF analysis captures investor expectations it has value. However, to the extent it projects market risk or diversity unchanged from historical fact, then it is less reliable than the multi-stage non-constant DCF analysis.

130. Relevant assumptions captured in the multi-stage DCF model are that investors expect electric utilities to be separated into regulated (largely the T&D) segments and unregulated (generation) segments; that the unregulated segment will be fully competitive in ten years, with a transition period between 2001 and 2006; and that investors expect each segment to grow at different rates, the unregulated segment being similar to that of a competitive enterprise. Such assumptions are legitimate when anticipating a move toward deregulation of the electric utility industry.

131. Utilities such as EGS will likely be configured so that 50 percent of their assets is generation and 50 percent T&D. Thus utilities will move toward, but not entirely replicate the risk and growth characteristics attendant to, Standard & Poors 500 firms.

132. Growth rates over the next five years are reasonably projected within a range of four percent to 5.25 percent, but are largely dependent on variables such as payout ratios and the effects of competition.

133. A risk premium calculation is an appropriate check on the DCF analysis, to assess the risks and long-term effects of deregulation on the utility industry.

134. Because all demand side management (DSM) expenses, ESI affiliate expenses, and EOI affiliate expenses not direct-billed are disallowed, it is not necessary to adjust cost of equity to account for these issues.

135. The appropriate weighted overall cost of capital for the period June 1, 1996 through May 12, 1998 is 9.63 percent. The appropriate weighted overall cost of capital for the period from May 13, 1998 through the remainder of the period in which the rates in this docket are in effect is 9.76 percent as reflected on Commission Schedule IV.

Cost of Service

136. EGS' reasonable and necessary cost of service, determined in accordance with this Order, is set forth in Commission Schedule I.

Operations and Maintenance Expense

137. EGS' reasonable and necessary operations and maintenance expense is set forth in Commission Schedule II.

Salaries and Wages

138. Due to declining employee rolls since test-year end and related declining costs, it is appropriate to use the most recent data evidenced in the record to calculate salary expense. A post-test-year adjustment should be made to bring payroll cost adjustments up to April 1997 levels. To capture all appropriate attendant impacts, that adjustment should include the adjustments made by EGS in its rebuttal testimony, with further changes as follows. A reduction should be made to salary expenses of $116,216 to disallow employee activity costs relating to non-business activities, such as employee picnics, parties, lunches, dinners, and awards because these activities provide no benefit to ratepayers and are not necessary to provide utility service. In addition, the labor costs associated with employee time spent during normal business hours on outside organizations that are unrelated to the provision of service to customers should be removed. Costs related to meter reading should reflect 19 readers, and contractor expense should be adjusted, all as discussed at §VII.A.1. of the PFD.

139. It is reasonable to include in cost of service $2,997,044 in incentive compensation paid during the test year.

139A. The amount of $441,000 associated with advertising to promote electricity usage should be disallowed as consistent with EGS' adjustments.

139B. The amount of $445,000 relating to a River Bend Outage accrual should be disallowed to be consistent with other EGS adjustments.

139C. The amount of $646,517 relating to ESI affiliate expenses should also be disallowed to be consistent with the determination that EGS has not met its burden of proof relating to ESI affiliate expenses.

140. EGS' base salaries are competitive with the market, as are the incentive payments. This variable portion of compensation thus expands and contracts with the degree to which employees attain the performance goals that have been established by the utility. Such payment plans could be valuable tools in managing budgets and at the same time evoking the best work from employees. EGS' total compensation package costs are reasonable when compared with other utilities.

141. The reasonable and necessary payroll expense for EGS is reflected in attached Commission Schedule II.

Employee Pensions and Benefits

142. Total electric pension expense should reflect a 3.5 percent assumed salary escalation factor, an eight percent discount rate, and an adjustment to reflect the declining employee levels through January 1997.

143. EGS' reasonable and necessary pension expense through January 1997 is ($3,161,011). (*See* Revised PFD.)

144. Post-retirement benefits other than pension should be $8,800,267 for total electric. This includes a medical cost trend rate of 7.9 percent, an eight percent discount rate, and employee levels through January 1997. It is not reasonable to permit a utility to recover estimated costs that exceed by any large degree the actual costs experienced in the test year. The $8.8 million level of expense reasonably approximates EGS' test year OPEB expense.

Production Operation and Maintenance Expense

145. EGS included $136,327,381 in production O&M expense, of which $51,491,665 relates to fossil plants. Production O&M expense for its Big Cajun II Unit 3 plant should be $6,428,935, which amounts to a $5,921,024 reduction from EGS' requested O&M expense for this plant. Using EGS' revised figures based on the FERC Form 1 methodology achieves a reasonable total fossil plant O&M expense of $45,570,641.

Insurance Expense

146. EGS' reasonable insurance expense is $1,651,321 per year for current losses. With regard to current losses, EGS should accrue only enough each year to cover typical storm damage. (*See* Revised PFD.)

147. Any reduction to the reserve fund occurring after the test year should not be considered in this case because EGS did not prove a reasonable post-test-year level for its existing reserve fund or that the amount expended in 1997 to reduce the fund was prudent or appropriate. Reserve fund levels following the test year in this case can be addressed in EGS' November 1998 rate filing when all parties will have the opportunity to evaluate the reasonableness of changes to the insurance reserve fund.

Affiliate Expenses

148. Under PURA § 11.003(2), a utility's affiliates include any entity owning five percent or more of a utility and any entity in which the holding company has a five percent ownership interest. Accordingly, Entergy Service, Inc.(ESI) and Entergy Operations,

Inc., (EOI), subsidiaries of Entergy Corporation, are EGS affiliates. Entergy Services, Inc. provides numerous services ranging from administrative functions to providing fuel supplies to Entergy's various affiliates. Entergy Operations, Inc. is responsible for the management, operation, and support of the five nuclear generating units owned by the Entergy operating companies.

149. EGS provided evidence of ESI expenses based on the total of all expenses charged. Neither proof by an aggregate finding as to total expenses nor total expenses for that affiliate is viable in this docket--because so many services are provided by ESI, the quantity and diversity of these costs is enormous and involve thousands of items billed during the test-year period. For this reason, EGS must provide evidence of the reasonableness and necessity of its affiliate expense in strict compliance with Section 36.058 of PURA. That is, it must provide evidence supporting the reasonableness and necessity of these expenses by class of costs. It failed to do this.

150. Furthermore, independent evidence must be provided in order to meet the statutory requirement to develop findings of fact based on an item or class of items basis. EGS' direct case for ESI expenses in this docket includes no studies, no supporting evidence of non-duplication, no comparison to alternative providers, no evidence of costs to EGS on a stand-alone basis.

151. The evidence EGS provided in its direct case does not provide a means for the Commission to determine the reasonableness and necessity of ESI affiliate charges as required under PURA § 36.058. The Commission determined, on appeal of the Administrative Law Judge's Order Nos. 124, 143, and 144, that it is appropriate to direct judgment against the utility when its direct case fails to meet the required level of proof.

152. To determine the reasonableness of the ESI expenses, EGS directed the fact finder to the scope statements contained in EGS Ex. 91 at LEB-4c. Because those items are not arranged by class and no underlying evidence is included to support the reasonableness or

necessity of the items by class, the only way for the Commission to make an independent evaluation of these costs is by looking at each item. Because of the nature and volume of items, such evaluation is impossible. No evidence exists in the record to support findings for each affiliate item.

153. While it may be possible to find the reasonableness and necessity of certain limited items addressed in EGS' testimony regarding ESI affiliate expenses, most costs remain unaddressed on an individual or class of costs basis. Furthermore, ESI bills EGS at its costs of providing the service, but EGS did not evaluate whether the prices ESI charged to EGS were higher than the price it charged other Entergy subsidiaries for the same or similar service. Evidence indicating that ESI bills at its costs is generally not sufficient to show that all affiliates therefore are billed the same for similar services when there is no evidence regarding what ESI actually charge affiliates other than EGS.

154. EGS presented evidence regarding EOI direct (site-specific) O&M expenses and allocated O&M expenses. The direct O&M costs total over $100 million.

154A. The EOI direct (site-specific) O&M expenses where billed at EOI's costs of providing the service. Because EOI bills at its costs, from the record presented, it can be inferred that the prices charged EGS are not greater than the prices EOI charges other affiliates.

154B. The EOI direct (site-specific) costs can be viewed as a separate "class" of costs similar to the production costs category of expenses.

154C. River Bend's capacity factor improved significantly in 1995 bring River Bend close to the industry average, and production costs at River Bend are declining

154D. Cities bench-marking report supports the reasonableness of the EOI direct-billed expenses.

155. EGS has met its statutory burden pursuant to PURA § 36.058 as to a total of $79,188,990, which should be included in cost of service as EGS' 70 percent share of River Bend O&M direct-billed costs. To this amount, $4.8 million is added to correct an error of twice subtracting ESI indirect charges for River Bend operations, the resulting allowance being $83,979,591.

156. The Company failed to provide evidence that would permit it to meet the statutory standard with regard to EOI *allocated* affiliate O&M expenses. There is no evidence of the reasonableness and necessity of these allocations by class of costs, or by individual item. Therefore, all EOI allocated expenses should be disallowed.

Payments to Other Affiliates

157. In accordance with the discussion at §VII.A.6.e.i. of the PFD, test-year payments of $8,207,982 made under Service Schedule MSS-1 are reasonable and should be included in base rates.

158. EGS received services during the test year from Entergy Arkansas, Inc. costing $57,803, from Entergy Louisiana, Inc. costing $17,976, and from Entergy Mississippi, Inc. costing $8,175. They are billed directly, not allocated, to the receiving company. All services are billed at cost; none of the companies receives a profit; the costs are reasonable and necessary and satisfy the affiliate standard prescribed in PURA §36.058(c).

Outside Services

159. EGS included $42,277,529 for outside services in its cost of service, a portion of which was included in its payroll expense. Because of the test-year transition to contract services for billing and metering, these costs should remain as part of payroll expense. (*See* Revised PFD.)

Cost Savings Expenditures

160. EGS requests that it be permitted to recover $55,929,000 of cost savings expenditures (CSE) amortized over five years, or $11,186,000 per year. These costs were incurred from 1994 through the end of the test year primarily attributable to severance and retirement expenses which the Company spent in order to achieve savings related to the merger between Gulf States Utilities, Inc. and Entergy Corporation. The CSE are non-recurring expenses and, as such, should not be included in cost of service.

161. To the extent any merger savings have been realized to date, they have accrued solely to the benefit of shareholders, as they have yet to be reflected in rates.

PURA § 36.062 (PURA95 § 2.208(d)) Expenses

162. EGS demonstrated that it has removed all costs disallowed under PURA §36.062 from cost of service.

Rate Case Expenses

163. The Cities' rate case expenses incurred through November 1997 in the amount of $1,914,340.91 in connection with PUC Docket Nos. 16705, 17899, 18249, and 18290 are reasonable.

164. Pursuant to an agreement among the parties, Cities' rate case expenses will not be surcharged or included in cost of service in this proceeding or any future proceeding.

164A. At the Commission's open meeting on July 10, 1998, representatives of EGS committed orally on the record that the Company will not seek to recover its own rate case expenses in this proceeding or any future proceeding.

Regulatory Commission Expenses

165. The total reasonable regulatory commission expense to be included in cost of service is $5,633,304.

EPRI Dues

166. EGS included $2,283,547 in dues to the Electric Power Research Institute (EPRI) based on the test year. Because the 1997 dues are now known, the 1997 EPRI dues to be included in cost of service as a known and measurable change to test year are total dues of $1,526,621.

Edison Dues

167. The appropriate level of Edison Electric Institute dues included in cost of service is $172,347.

Other Organizational Dues

168. Removing legislative advocacy expenses related to chamber of commerce and other dues, results in a reasonable total of $50,986 for other business and organizational dues.

Payroll Deduction Costs

169. No incremental cost is associated with political action committee contributions that affects EGS' cost of service.

Interest on Customer Deposits

170. The appropriate interest on customer deposits is $1,200,449 based on applying the PUC-approved interest rate of six percent to the test-year-end deposits included in rate base, $8,194,176 for Texas, and five percent to the $14,175,951 Louisiana deposits. (*See* Revised PFD.)

Merger Tracker

171. In Docket No. 11292, EGS and most parties to that docket agreed on a merger stipulation that resolved all issues in the merger case. Included in that stipulation was a "merger tracker" that established a base line against which to gauge the merger-related savings EGS would experience during the years following the merger with Entergy. Under the

stipulation, there is to be a 50/50 sharing of savings between shareholders and ratepayers. The tracker also contains a mechanism or methodology for calculating those savings. The appropriate level of shareholder savings to be applied in this rate proceeding is $28,793,500.

172. Paragraph six of the Docket No. 11292 merger stipulation requires that the shareholders' portion be reduced by $2.6 million in years four through eight. The meaning of paragraph six "years four through eight" refers to the rate years established in paragraph nine of the stipulation.

173. If this docket results in a rate reduction, then EGS has guaranteed that rates will be effective beginning in June 1996. In that case, year four (1997) would be six months from that time, and only about four-fifths of the rate period would fall in year four or after. It is therefore appropriate to discount the $2.6 million by 20 percent as a credit to the shareholders savings. The investors' share of non-fuel O&M savings should be reduced by $2.08 million under paragraph six.

174. To calculate merger savings, it is necessary to use the calendar year rather than the test year because FERC Form 1 is prepared on an annual basis only and is audited by Independent Auditors. Any other time period would not tie to a FERC Form 1 and would not have the assurance of being audited. Furthermore, FERC Form No. 1 for 1996 reflects the employee reductions used to determine cost savings in this docket and, consequently, ensures that the matching principle is being applied consistently. Accordingly, calendar year 1996 results most closely in the amount of savings contemplated by Appendix 2 to the stipulation.

175. Paragraph four of Appendix 2 of the merger stipulation requires normalization of any significant abnormal item or out-of-period adjustments with an impact greater than $1,000,000. However, not all cost of service disallowances are appropriately incorporated into the savings tracker calculation. Appendix 2 does not require that the

tracker be adjusted to match a particular cost of service approved by the Commission in a rate case. It is specifically tied to the FERC Form No. 1, not to the Commission's final order.

176. Based on Findings of Fact Nos. 171 through 175, 50 percent of merger-related savings as calculated under the merger tracker mechanism, based on calendar year 1996, is $30,873,500, less stipulation paragraph 6 shareholder deduction--$2,600,000 - 20 percent $2,080,000--leaving $28,793,500 to be added back to cost of service as the shareholders' portion of merger savings.

Non-Reconcilable Fuel and Purchased Power Expenses

177. It is reasonable to include non-reconcilable coal, gas, and purchased power expenses in the amount of $4,853,684 in cost of service.

Decommissioning Expense

178. The cost to decommission the River Bend plant, adjusted for a ten percent ceiling value for contingencies, will be $385.2 million. EGS' 70 percent share of this amount is $269,640,000.

179. Based on the Commission's previous adoption of low level radioactive waste disposal costs at 7.5 percent, the fact that River Bend specific inflation factor has been very low in the past several years, and the fact that decommissioning does escalate at a rate higher than general inflation, a 4.81 percent escalation rate is reasonable.

180. An 11.47 percent trust equity return and overall 6.6 percent return for the trust fund results from the most reasonable assessment of return projections.

181. Total company annual decommissioning expense of $8,551,000 is EGS' reasonable and necessary share of River Bend decommissioning costs as evaluated in PFD §VII.B.

Depreciation Rates and Expense

182. The total reasonable depreciation expense for EGS is stated on Commission Schedule I.

Production Plant

183. Because EGS has no specific plan to retire any generating unit soon, it is reasonable to assume that the units will be retired in the middle of the year, because they may, in fact, be retired at any time during the year.

184. The retirement dates for planning purposes should be used for depreciation purposes, as well. The River Bend license expiration date of August 29, 2025 should be used as the retirement date for that plant. For EGS' other generating units, the remaining lives contained in General Counsel Exhibit 34 (González errata) at Attachment CFG-G should be used, except that the remaining lives for Nelson Unit 3, Sabine Unit 3, and Willow Glen Unit 1 should be based on a June 30, 2007 retirement date to be consistent with EGS' plan not to retire these units before 2007. (*See* Revised PFD.)

185. It is reasonable and commensurate with Commission practice to include a negative five percent net salvage value for production plants. A negative five percent terminal net salvage value is a conservative amount that is appropriate given the current uncertainty about future events related to deregulation. Account 310 should be set at zero percent net salvage.

186. The depreciation rate for EGS' nuclear plant should be 2.639 percent, which was calculated using test-year-end (6/30/96) balances. The non-nuclear production plant depreciation rates should also be calculated using test-year-end balances instead of the 12/31/95 balances used in EGS' depreciation study, because use of the more recent test-year-end balances is preferable for setting prospective rates and accounts for any interim retirements and additions that actually occurred between 12/31/95 and 6/30/96. (*See* Revised PFD.)

Mass Property--T&D and General Plant

187. The reasonable depreciation expense for EGS' Transmission, Distribution, and General plant is reflected in Commission Schedule I.

188. The equal life group (ELG) methodology for calculating depreciation rates is theoretically more accurate than the average life group (ALG) method; however, this is only true where there is enough information available to predict with some degree of certainty how a life (mortality) curve might look in the future.

189. The debate over ELG and ALG is not an either/or dialogue but rather should be viewed as a continuum and must be balanced.

190. In accordance with the discussion at §VII.C.1.b. of the PFD, Staff's proposed depreciation rates, which include application of both the ALG and ELG methodologies, should be used for the mass property accounts.

Amortization Expense

191. EGS' reasonable and necessary amortization expense to provide service is reflected on Commission Schedule I. The amortization expense is calculated using June 1, 1996 as the beginning date and May 31, 1999 as the assumed ending date.

Taxes Other Than Income Taxes

192. EGS' reasonable and necessary payroll taxes are based on the payroll expense approved in this case and are reflected in Commission Schedule III.

193. Texas gross receipts taxes based on the total revenue requirement approved in this case are reflected in Commission Schedule III.

194. EGS' Texas franchise tax was adjusted to reflect a June 1994 Texas franchise tax refund and is calculated based on net taxable earned surplus by applying an effective rate to the

revenue requirement approved in this docket. The tax is reasonable and necessary as reflected in Commission Schedule III. (*See* Revised PFD)

195. EGS' reasonable and necessary ad valorem tax adjusted based on disallowance for PHFU is reflected in Commission Schedule III.

Federal Income Taxes

196. It is reasonable to include a consolidated tax savings (CTS) adjustment in cost of service, because Entergy's non-regulated affiliates benefit from their relationship with profitable utilities in the Entergy group, and because it is beneficial to EGS' ratepayers to share in the tax savings realized on a consolidated basis.

197. EGS' share of the CTS is properly based on a hypothetical stand-alone calculation where all affects of disallowed plant are disregarded. EGS' net operating losses (NOLs) would have been fully utilized in 1995 had there been no abeyed River Bend tax deductions.

198. The CTS adjustment is based on a two-year period, 1994 and 1995. As set forth in PFD §VII.E.1., the appropriate amount of CTS adjustment is ($877,030).

199. Because it did not provide the *without* abeyed River Bend calculation, to ensure that all effects of the abeyance and disallowances related to the plant are captured, the Company should amortize the excess deferred federal income tax, including the $64 million write-off of excess deferred federal income tax, over the remaining life of the depreciable River Bend plant. This is an annual amortization of ($2,166,126).

200. It is appropriate, as an equitable treatment and as a matter of law, to disregard all effects of the abeyed portion of River Bend on an EGS total company basis. Therefore, it is reasonable that EGS' investment tax credits (ITCs) should be amortized in the amount of ($6,707,000). This excludes ITCs generated by the abeyed and disallowed River Bend expenditures and includes both utilized and unutilized ITCs.

Request for Good Cause Exception to P.U.C. Subst. R. 23.23(b)(2)(B)(vi)(II) (Wheeling Expenses and Revenues)

207. EGS' wheeling revenues and expenses are not eligible fuel expenses and should be included in base rates in accordance with the principles in Docket No. 17460. Therefore, EGS' wheeling revenues and expenses should be included in the revenue requirement beginning with the effective date of rates in this proceeding.

Treatment of SO_2 Allowance Sales

208. Revenues from sale of SO_2 allowances are to be recorded in FERC Account 254 ordered in EGS' last fuel reconciliation proceeding. Therefore, EGS should remove the $46,950 in SO_2 emission revenues from FERC Account 411.8 - Gains from Disposition of Allowances - and record them in FERC Suspense Account 254.

Rate Design

209. EGS' cost allocation and rate design proposals reflect changes stemming from the merger of Entergy Corporation and Gulf States Utilities Company. EGS used a cost allocation methodology different from GSU's prior cases. The Company also proposed structural changes to its tariffs and has unbundled its rates in preparation for competition. The Company proposes no overall base rate increase.

210. The Company should use weighted billing cycle data for each day of the month to match exactly weather and sales.

211. EGS' weather adjustment for the commercial classes is unreasonable because the Company did not use a uniform method of weather adjustment.

212. An adjustment based on number of customers and weather should be made to demand. Although energy sales and peak demands are not necessarily affected by weather in the same degree, there is also no indication that the difference is substantial. It would be inconsistent to allow EGS to adjust revenues for weather but not demand.

213. EGS' adjustments to the Residential Service (RS), Small General Service (SGS), and General Service (GS) classes based on the number of customers at the end of the test year, the several reclassification adjustments caused by customer transfers between classes, and the miscellaneous adjustments are reasonable.

214. The 12 Coincident Peak (CP) values used by EGS should be replaced with the actual 12 CP, average (54,092 kw).

215. The CP method allocates costs on the basis of system peak. This method assumes that the system-peak drives all production capacity-related costs and assigns costs to customer classes based on each class' relative contribution to the system coincident peak demand.

216. The 12CP method is based on the twelve monthly peaks of EGS' various jurisdictions, thus reflecting, to a degree, the kWh load patterns of EGS' jurisdictions.

217. The use of the 12 CP method reasonably allocates production capacity-related and transmission capacity-related costs at the jurisdictional level.

217A. Special-rate revenue (for LQF, SMQ, MSS, and EAPS) should be directly assigned to the jurisdiction of origin. This will preclude a $396,000 subsidy from Texas to Louisiana.

218. Wheeling expenses should be accorded base rate treatment. Wheeling revenues should be treated as base rate revenues.

219. The wheeling classes should be included as separate classes in the cost of service studies.

220. Deleted.

221. The continued use of the A&E 4CP allocator is the most reasonable methodology for allocating production and transmission plant among classes. The A&E 4CP allocator sufficiently recognizes customer demand and energy requirements and assigns cost responsibility to peak and off-peak users. It best recognizes the contribution of both peak demand and the pattern of capacity use throughout the year.

222. The A&E 4CP method is also preferable because it is devoid of any double counting problem.

223. The Company's methodology for allocating distribution plant is the most reasonable because distribution substation and primary line costs are localized in nature, that is, they are designed and constructed to handle loads close to the point of ultimate use. The Company used the simultaneous peak load of each customer class Maximum Diversified Demand (MDD) as the basis for allocating those costs.

224. Current cost of services studies are not based on geographical differences. Classes are not divided based on geography, and industrial sites are not self-sufficient islands. The use of city streets and property enables EGS to have an integrated utility system from which all ratepayers benefit.

225. EGS' allocation of local gross receipt and franchise taxes to the classes based on total rate schedule revenues is reasonable.

226. The decommissioning expense does not vary with the amount of energy the plant consumes or produces. The costs are fixed and do not vary with the level of generation.

227. The allocation of decommissioning expense to both the Texas jurisdictional and class levels on the basis of production capacity-related costs is reasonable.

228. The Company allocates Cash Working Capital and other non-investor-supplied capital that serves as a general source of funds by a composite factor that recognizes that CWC is fungible, which is reasonable.

228A EOI expense should be allocated consistent with the Commission's-approved rate design allocation in this docket.

229. Synchronizing fuel revenues and expenses in the compliance cost of service study by using the rate-year fuel expense and fuel revenues will ensure compliance with P.U.C. SUBST. R. 23.23(b)(2)(D)(i)(I), and will ensure the proper calculation of any allocation factor based on measures of cost including fuel and purchased power expenses.

230. The FERC staff method used by the Company to classify production non-fuel O&M expense is a reasonable method and produces reasonable results.

231. Just as it may seem unfair to have the industrial customers absorb the bad debts of a few individuals, it is just as unfair to have the great majority of dutiful residential ratepayers pay those debts. The passing on of such costs to others is generally factored into the cost of doing business. It is a cost that is better absorbed by the many. Therefore, uncollectible expense should be allocated at both the jurisdictional and class levels on the basis of jurisdictional and class operating revenues.

232. Because there is no apparent relationship between the Customer service expense and the meter investment allocator, and because use of the meter investment allocator creates a large discrepancy between the cost of serving residential and large industrial customers that is not adequately justified, the Company's allocation method is reasonable. The Company's weighted relationship is reasonable enough to capture the additional meter reading and customer service reading expenses required by the different classes.

233. The Company's allocation of Customer Sales Expense based on total adjusted production, transmission, and distribution, and Information Expense as customer-related are reasonable because one expense serves a marketing function, the other customer information.

234. The Company's proposed distribution depreciation expense adjustment between Texas and Louisiana is reasonable.

235. Revenue-related taxes are derived based on total company revenue; therefore, allocation of such taxes to both Texas retail and wholesale customers is appropriate.

236. General Counsel's adjustment to customer deposits based on use of the average of 12 months of jurisdictional data is reasonable.

237. The allocation of customer deposits based on the composite factor is reasonable.

238. The allocation of CTOC reserves on the basis of the high-voltage transmission demand-related allocation factor is reasonable because CTOC costs are related to use of a portion of the Cajun high voltage transmission facilities.

239. Facilities charges are revenues that the Company receives from specific customers for installing substation and related facilities. These revenues should be classified as distribution demand-related and be allocated in the same general manner as the costs of the associated investment--the Texas distribution substation demand-primary factors.

240. Plant investment, accumulated depreciation, and depreciation expense associated with laboratory equipment should be allocated on the same basis, which is adjusted production, transmission and distribution plant.

241. Customer advances, ADIT, and ADITC are a general source of funds of non-investor supplied capital, which is appropriately allocated on the same basis as similar rate base items, such as CWC, that is, according to a composite factor that consists of all rate base items other than those identified as sources of non-investor capital.

242. An additional adjustment of $476,000 to the total reconcilable fuel expense is necessary to reconcile the mismatch caused by the Company's use of different allocators in the Rate Design phase and the Fuel phase concerning reconcilable fuel expense. In its jurisdictional cost of service study, EGS allocated reconcilable fuel expense based on a test-year energy allocator, while in the fuel phase, EGS allocated reconcilable fuel expenses on the basis of a rate-year energy allocator. The recommended $476,000 allocation adjustment is required to ensure that reconcilable fuel expenses are allocated consistently with General Counsel's recommendation in the Fuel phase.

243. EGS's "other operating revenue" in its cost of service study should be reduced by $183,928 for a miscellaneous adjustment. This adjustment is based on the charges including Draw Draft/Levelized Billing, Meter Testing Charge, and Non-Sufficient Funds Charge.

244. It is not reasonable to combine the LPS and HLFS classes for purposes of the cost of service study.

245. It is appropriate to move all firm customer classes to unity rate of return. In moving all classes to unity, no firm class would receive an increase under its proposed revenue distribution. The percentage revenue decreases relative to the system average decrease are reflected on the Commission Schedule KS-J1.

246. Under all of the cost of service studies, the SGS and General Service (GS) classes have been paying more than their fair share of cost of service, entitling them to a greater decrease in rates.

247. EGS agrees to the revenue imputation for the SUS and IHE rates.

248. The EAPS rate is sufficiently different and apart from firm service so that it should not be considered a discounted firm service rate. The sale of power under the EAPS rate is like a commodity transaction. The rate contemplates that the customer will not rely on the Company for service. The Company reserves the right to discontinue the service at its discretion. EAPS rate is not a discount rate, and there should be no imputation of revenue to the Company.

249. The EEDS and SSTS tariffs were devised when the River Bend nuclear plant was added to rate base. The two rates were discounted because of GSU's excess capacity. They were designed to retain and expand load.

250. The SSTS rate is not a lower quality of service.

251. There is no evidence indicating that SSTS is excluded from resource planning.

252. The EEDS and SSTS rates are discount rates.

253. EGS provides interruptible service under its Schedule IS tariff, which is available to customers taking service under the HLFS and LPS rates. The Company offers no-notice, 5-minute notice, and 30-minute notice under the tariff. No-notice customers receive a 100 percent demand charge discount. Five-minute customers receive a demand charge discount of 63 to 70 percent. And 30-minute customers receive a demand charge discount of 33-40 percent.

254. EGS serves fourteen interruptible customers. Eight customers take service under LPS, six take under HLFS. The fourteen customers contract for approximately 207 MW of

interruptible load, which represents approximately 28 percent of the combined HLFS and LPS total class loads of 743.7 MW.

255. During the test year the interruptible customers saved $10.8 million off the firm rates.

256. Firm customers benefit from interruptible service with the deferral or avoidance of additional capacity, and because the revenues received from interruptible customers reduce the revenue requirements of firm customers.

257. Since the approval of Schedule IS in 1988, there have been only two service interruptions, which occurred on August 17 and 18, 1995, lasting a total of 10-11 hours.

258. EGS' actual practice is to continue to serve interruptible customers as long as the Company has capacity to and is able to provide service; the rate was designed with the expectation that interruptions would be infrequent.

259. EGS' policies do not place a high priority on interrupting IS customers.

260. Historically, EGS did not curtail IS customers to enhance system economics.

260A. As a matter of policy, interruptible service should be employed to the maximum extent possible to improve system reliability and enhance system economics.

261. EGS' actual interruption policy limits the alleged benefit of interruptible power, so that interruptible service is equivalent to firm service.

262. EGS will not need additional capacity until 2004. This projection includes interruptible capacity. EGS will need capacity earlier if IS is not included in the projection.

263. The unbundled transmission and distribution cost for IS customers is $580,963832,595. The T&D cost shall be applied to IS customers effective June 1, 1996, with the unbundled transmission-related costs allocated solely to transmission voltage IS customers.

264. Interruptible demands are counted and that demands in all months directly affect EGS' System Agreement payments.

265. There is no evidence that the IS demand charges were ever designed to recover transmission and distribution costs.

266. Actual usage is the more appropriate determination for costs.

267. Interruptible service is not properly priced and the amount of load under interruptible contracts may be too large. The existing IS tariffs shall be eliminated three years after the effective date of this order and replaced with contracts for interruptible resources.

267A. The appropriate size and price of the interruptible resource beginning three years after the effective date of this order are matters that shall be determined as part of EGS' IRP process. The recommendation of the ALJ with respect to pricing interruptible service (reduce the discount by $4.5 million) is reasonable in this regard, but may be updated as appropriate. EGS shall propose a method for sizing and pricing interruptible resources in its preliminary integrated resource plan filing in September 1998.

268. During the test year, revenues from the energy charges did not recover their necessary costs so that SMQ revenues were insufficient to cover the cost of service for this rate class.

269. EGS' proposed SMQ rate should be adjusted as follows:

a) The current monthly load charge should be increased to $1.12 per kWh from $0.84 per kWh;

b) Both qualifying and non-qualifying facilities should be eligible for service under the SMQ rate;

c) An on-peak maintenance demand charge of $1.12 per kWh should be substituted for the existing demand charge of $0.84 per kWh, while the demand charge for off-peak maintenance should be $0.84 per kWh;

d) The minimum standby service should remain at one year;

e) Supplemental power should continue to be based on the HLFS demand and energy charges;

f) The summer and winter on-peak and off-peak hours in existing rate SMQ should be retained; and

g) The existing SMQ fuel charge provision should be retained.

270. An on-peak rate of $1.12 per kWh for maintenance service, which is 33 percent greater than the off-peak rate of $.084 per KWh, should be approved. This 33 percent differential is consistent with the intent of the off-peak provisions of the existing HLFS tariff.

271. It is not reasonable to base the rate on the maximum amount of service contracted by the standby customers. Although standby customers may be buying a different kind of service, it cannot be shown that they are buying the maximum amount of their contract.

272. The SGS charge should be reduced from $10.95 to a minimum of $9.50 to bring the charge more in line with the cost.

273. The GS Class consists of medium sized commercial customers (between 5 kWh and 750 kWh demands).

274. The Large General Service Rate Class (LGS) consists of large-sized commercial customers with 750 kWh minimum demand.

275. Deleted.

276. Deleted.

277. Rider RS is an income-tested waiver of the customer service charge for eligible low-income senior citizens. It is reasonable that the lost revenues of Rider RS be recovered from the members of the residential class.

278. EGS currently has Time of Day (TOD) rates for five of its seven standard rate classes, including the RS, GS, LGS, LPS, and HLFS customers.

279. The Company's current TOD rates were not sufficiently promoted in the past.

280. Elimination of the LPS and HLFS TOD rates is not appropriate at this time.

281. EGS should address the promotion of its existing TOD rates as part of its preliminary integrated resource plan filing in September 1998. An SGS TOD tariff should be proposed as part of EGS' next rate case.

282. The Company should combine the Low-Income/Low Use (LILU) Rider with a comprehensive educational effort, to educate low income customers about energy conservation.

283. EGS proposes an optional Pipeline Pumping Service (PPS) rider to Schedule LPS and HLFS (Schedule PPS) for pipeline pumping station customers. The optional rider modifies the LPS and HLFS rate schedules to change the definition of the on-peak period from May 15 through October 15 to May 1 through September 30. The proposal also

shifts the hours of the on-peak period from 8:00 a.m. through 10:00 p.m. to 11:00 a.m. through 9:00 p.m. The modification requires the customers to commit to a minimum four-year term. This proposal is in response to customer request and will enhance operating flexibility for pipelines that operate pumping stations.

284. EGS' Texas on-peak hours do not match those of EGS' Louisiana tariff. Making the hours consistent will allow the pipeline companies to coordinate dispatch flows better.

285. Proposed Schedule PPS is a reasonable option for pipeline pumping customers and should be approved.

286. The changes to the current Rate Schedule MES, the Miscellaneous Electric Services Tariff, which establishes fees for various services, including returned checks are reasonable.

287. EGS proposes a new Premium Lighting Service (PLS) tariff to offer customers more lighting choices in response to requests for new and diverse lighting services and products , such as increased lumens per wattage, better color retention and special lenses, which cannot be provided under the current lighting tariffs.

288. The proposed Schedule PLS is a formula-based pricing mechanism that will be used to develop a rate for any new lighting service. The formula rate will take into account the estimated cost of installing and maintaining a new lighting service offering over its estimated useful life.

289. EGS proposes a regulatory process for adding service to Schedule PLS. Attachment A to the tariff will list each service offering and its price. Under the Company's proposal, EGS may provide a new premium lighting service by filing with the Commission a revision to Attachment A with supporting documentation and workpapers. The new service offering

would be effective 90 days from the date of filing, or on the proposed effective date, unless suspended by the Commission for 60 days.

290. The proposed PLS tariff should be approved because it provides for increased lighting services to meet customer lighting choices.

291. EGS proposes replacing its existing Facilities Charge Tariff with the Additional Facilities Charge (Rider AFC), which offers more payment options for customers requesting additional facilities. Rider AFC is a monthly rental charge paid by a customer when EGS installs facilities that would not normally be supplied, such as line extensions, transformers, or dual feeds.

292. Under the Rider AFC, customers will have two options. Option A is virtually identical to the current tariff. A monthly charge based on the monthly rate is applied to the installed cost of the facilities, continuing until the customer no longer wants the facilities. The proposed rate of 1.64 percent is the same as the current rate. Current customers will be given a one-time opportunity to switch to Option B rates.

293. Option B has two rates--the Recovery Term Rate and Post-Term Rate. Both rates apply to the installed cost of the facilities, including the cost of materials, plus labor, transportation, stores, taxes, engineering, and general expenses.

294. The Recovery Term Rate will apply over a specific recovery term ranging from one to ten years, determined by the customer. This rate is designed to recover continuing non-capital ownership costs, such as property tax, insurance, operation and maintenance expense, and the return on investment over the recovery term. The rate varies from 9.954 percent for a recovery term of one year to 2.041 percent for a recovery term of ten years.

295. The Post-Term Rate applies upon the completion of the recovery term and continues until the customer no longer requires the additional facilities. It is set at .508 percent and is

designed to recover non-capital ownership costs, that is, the Recovery Term Rate exclusive of the return on investment.

296. Although basing rates on cost of service is a primary rate design goal, it is not the only one. Revised options A and B should be approved because the rate is a voluntary one which appears to be based on a cost that the market will bear.

297. The Company is requesting a good cause exception to P.U.C. SUBST. R. 23.47(d), which provides that a customer may have one meter test performed for free every four years. EGS has not stated an adequate basis for a good cause exception. The cost of meter testing is apparently well beyond what the rule currently allows. EGS' situation is no different from any other utility; therefore, its request for a good cause exception should be denied.

298. EGS currently charges $5.00 for a check returned due to insufficient funds. It is unreasonable to charge $12.00 based on the comparison with other Texas utilities and other institutions.

299. EGS' request to modify its Terms and Conditions of Electric Service to discontinue the practice of providing self-contained meter sockets without charge is reasonable.

300. The proposal for a $1.00 monthly credit for customers to pay their bill by draw draft is reasonable and should be adopted.

Competitive Issues

EGS' Plans

301. EGS filed its initial and supplemental application as the Original Transition to Competition Plan (Original Plan), which is EGS' preferred plan. EGS developed the Alternative Transition to Competition Plan (Alternative Plan) in its rebuttal case to address concerns raised by the other parties.

302. EGS' Original Plan caps base rates at existing levels during the transition period; establishes performance targets for the on-going River Bend nuclear fuel costs; develops a banded rate of return with a midpoint of 12.75 percent; accelerates the recovery of the investment in River Bend; applies a one-way, market-based true up at the end of the transition period if EGS' generation costs are below market value at the end of the transition period; and provides retail choice at the end of the seven-year transition period.

303. The Alternative Plan provides base rate reductions; establishes performance targets for on-going River Bend nuclear fuel costs; implements a return cap with excess earnings dedicated to recovery of stranded investment; accelerates recovery of River Bend costs; applies a two-way true-up and a non-bypassable charge for the recovery of stranded costs; and provides retail choice by January 1, 2002.

304. The Original and Alternative Plans offer new tariffs as EGS enters the competitive environment. The Company further proposes to unbundle its rates into four components: generation, transmission, distribution/customer service, and a Universal Service Cost (USC) rider.

305. The parties, other than EGS, that participated in the Competitive Issues Phase are: General Counsel, Cities, OPC, TIEC, NSST, Enron Capital & Trade Resources (Enron), HLFCCG, and LII (collectively, Phase IV Intervening Parties).

306. The Phase IV Intervening Parties reject EGS' proposal to recover excess costs over market (ECOM) on an accelerated basis. The other aspects of EGS' application, such as the performance-based standards and the new competitive tariffs, are either rejected by the Phase IV Intervening Parties or are significantly modified.

Timing of Retail Competition

307. January 1, 2002 date is a reasonable date for retail access for the following reasons: it allows EGS sufficient time to modify its System Agreement and to make other necessary changes that may be ordered by the Legislature during the 1999 session; it allows EGS sufficient time to educate its customers about retail choice; it allows EGS adequate time to modify any existing tariffs and to implement any new competitive tariffs; and it also allows EGS time to implement any pilot programs during the transition.

Required Statutory Changes and Regulatory Approvals

308. Among the regulatory approvals and statutory modifications that will be necessary for a successful transition are: PURA will need to be modified to incorporate supplier certification requirements; rates and services will need to be unbundled; any legislation approved in 1999 will have to be incorporated into EGS' plan; and the Federal Energy Regulatory Commission (FERC) will have to approve an Independent System Operator (ISO), Regional Power Exchange (RPX), transmission tariffs, and changes to the System Agreement.

ECOM Policy

309. ECOM is EGS' present value sunk costs that would become unrecoverable in a competitive market.

310. Stranded costs are the costs that a utility cannot recover through competitive sales once there is actually competition.

311. While the magnitude of ECOM can be estimated now, EGS' investment will not become stranded until its customers have access to market-priced alternatives. The portion of ECOM that ultimately becomes stranded will depend upon changes in the market price of electricity; the speed with which markets become effectively competitive; tax implications of restructuring; regulatory actions taken prior to the introduction of a broad competitive market that accelerate the recovery of ECOM; and the actions of the utility,

the Legislature, and the Commission relating to electric industry restructuring. Other factors may also affect the portion of ECOM that ultimately becomes stranded.

312. To appropriately balance the interests of the ratepayers and the shareholders, it is necessary to determine whether EGS will have significant stranded costs that will be unrecoverable in a competitive market that warrants accelerated recovery of ECOM now.

313. If EGS does not have significant stranded cost exposure, then EGS should not be allowed accelerated recovery of River Bend costs. If EGS does have significant stranded cost exposure, it should be allowed to accelerate recovery of a portion of its ECOM.

ECOM Estimations

314. In Project No. 15001, the Commission issued an order initiating an investigation to determine the magnitude of generation ECOM for electric power utilities in Texas. It directed the utilities to use a specific methodology (the 15001 ECOM method) developed by the Commission' Office of Policy Development. The Commission has determined that the 15001 ECOM method is a reasonable and an appropriate method for quantifying ECOM.

315. The Commission approved the 15001 ECOM Model on April 24, 1996.

316. The 15001 ECOM Model estimates the after-tax net present value of the change in revenue that a utility would experience as a result of selling electricity at market prices rather than at regulated prices.

317. The 15001 ECOM Model requires that certain variables be selected such as the market price for electricity, efficiency adjustment factor, and competitive market scenario.

318. The 15001 ECOM method reasonably uses the lost net revenue method (LNR method) of calculating ECOM. The LNR method reasonably assumes that an assets value is equal to

the net present value of the difference between the revenues expected to be generated from the asset and its cash expenses.

319. As long as owners of existing generation capacity keep their average prices below long run marginal cost (LRMC), no new competitor could profitably build a generation facility and sell power at retail.

320. It is reasonable to assume that the price for power in a competitive retail generation market will include a five percent adder for long-term contracts and fuel diversity and a $1 per MWh adder for ancillary services escalated at three percent per year. Effectively, these adders assume that consumers will pay EGS and other current utility generators more for the power they produce than they will pay new competitive generators who cannot offer long term contracts, fuel diversity, and ancillary services.

321. ECOM is independent of market outcomes and market structure but depends upon the start date at which ECOM is estimated.

322. The vast majority of EGS' ECOM is related to its investment in River Bend.

323. Different estimates of future market prices, gas prices, and other factors are likely to affect the ECOM estimates.

324. Deleted.

325. There is a high level of uncertainty in estimating future market prices and the scope and timing of future competition.

326. Administrative estimates of ECOM often can be overstated, and the over-estimation is only discovered upon a sale of the generation facilities.

327. The 15001 ECOM Model is designed so that long-run market prices reflect all costs of new units in the market. The Model assumes that there would be more than one new unit built once LRMC are included in the Model. Because these units will not all come on line in the first year, the Model assumes a three percent increase in the fixed capital costs over time to ensure that the LRMC for each year equal the market price for a plant constructed in the same year.

328. All fixed and variable costs attributable to an incremental unit combine to define the LRMC or the long-run market price.

329. A proper calculation of the LRMC and the analysis of the return on equity an investor could achieve should account for all operating costs, which escalate over time.

330. Deleted.

330A. EGS' ECOM is significantly in excess of $45.2 million.

ECOM Mitigation

331. EGS can mitigate ECOM by selling generation facilities; improving efficiency; increasing productivity; looking for off-system sales opportunities; and reducing operating costs.

331A. Accelerated depreciation of deferred regulatory assets related to River Bend will benefit future customers by lowering the amount of future production plant rate base on EGS' system and, in the event of retail competition, the likelihood of lower charges to recover potentially stranded costs.

Rate Cap

332. Deleted.

333. Deleted.

334. Sales growth during the transition period could be 2.1 percent. This is a reasonable but conservative estimate based on the sales growth for EGS over the last three years (1994-1996), which was 3.99 percent.

335. State space methodology (sales are determined by past behavior) has been approved by the Commission in Docket Nos. 7512 and 7437 and is a reasonable method for forecasting electricity sales.

336. The Commission's 1996 Statewide Electrical Energy Plan for Texas estimates the average growth rate for electricity sales of large electric utilities to be approximately 2.6 percent per year between 1995 and 2005.

Accelerated Recovery

337. EGS proposes to recover $397 million in River Bend costs on an accelerated basis. EGS proposes to fund the recovery through a combination of four sources: the continuation of straight-line depreciation and amortization of accounting order deferrals; the dedication of estimated growth in base revenue; the dedication of the decline in the River Bend revenue requirements over the transition period; and the temporary deferral of the annual transmission and distribution depreciation accrual.

337A. EGS has a regulatory asset in the form of an accounting order deferral (AOD) that consists of deferred River Bend costs incurred after River Bend became operational but before River Bend entered rate base.

337B. To the extent that deferred River Bend costs are regulatory assets created by Commission order to avoid rate shock to ratepayers, sound policy requires that EGS' shareholders recover these costs on an accelerated basis now that costs are declining.