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.; however, in the compliance proceeding, the rate design for these two schedules should be revised to ensure that the cross-over point at which the rates of these two classes equal is at approximately the 80% load factor point.

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, SUS, IHE, 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% demand charge credit. Five-minute customers receive a demand charge credit of 63 to 70%. And 30-minute customers receive a demand charge credit of 33-40%.

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% 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 as appropriate 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. Deleted.

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. To avoid imputation of "excess" credits to shareholders, and to avoid requiring firm customers to absorb the excess credits, it is appropriate to freeze the IS demand and energy charges at the levels in effect on the date before this Order becomes effective. This treatment will also ensure that IS customers pay their share of transmission and, where applicable, distribution costs.

267B. 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 a reasonable approximation 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 kW from $0.84 per kW;

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 kW should be substituted for the existing demand charge of $0.84 per kW, while the demand charge for off-peak maintenance should be $0.84 per kW;

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 kW for maintenance service, which is 33% greater than the off-peak rate of $.084 per kW, should be approved. This 33% 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 customer charge should be reduced from $10.95 to a minimum of $9.50 to bring the charge more in line with the cost.

273. At present, the GS Class consists of medium sized commercial customers (between 5 kW and 750 kW demands).

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

275. The energy charges for the GS and LGS rate classes should be decreased; the minimum demand for the LGS rate class should be reduced from 750 kW to 300 kW.

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 all classes of customers.

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 or, if that filing is extended, in a report to be filed in its November 1998 rate case. An SGS TOD tariff should be proposed as a new tariff offering.

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 and off-peak periods. 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 where on-peak is defined as 1:00 p.m. to 8:00 p.m.. Making the hours consistent is reasonable and 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. Deleted.

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% 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% for a recovery term of one year to 2.041% 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% 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 reasonable 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.

300A. The Company-proposed two new lighting rates within the Area Lighting Service Schedule ALS are reasonable. The Company-proposed revisions to the "sunset" provisions of the SSTS and EAPS tariffs are reasonable. The Company-proposed application and other wording changes to the Experimental Rider to Schedule RS for Good Cents Homes, Residential Street Lighting Service, Unmetered Service, Experimental Rider for Water Heating Service, Schedule SMC, and miscellaneous clarification wording changes to certain other tariffs are reasonable.

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%; 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%. 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%.

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% 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 costs that would otherwise have been expensed between River Bend's commercial in-service date and the effective date of the rates approved in the rate case in which River Bend was rate-based, Docket No. 7195, and related carrying costs..

337B. Now that costs and rates are declining, it is appropriate to accelerate the amortization of the AOD. To the extent that the amortization period of the River Bend regulatory asset avoided rate shock to ratepayers, sound policy requires that EGS' shareholders recover these costs on an accelerated basis now that costs are declining.

337C. Accelerated recovery of deferred River Bend costs will avoid additional and/or future stranded costs.

337D. Accelerated recovery of deferred River Bend related costs represents one approach to avoid potential stranded costs while balancing the interests of present and future customers and EGS' shareholders.

337E. EGS is entitled to receive additional revenue for the deficient deferred income taxes related to AOD due to a change in federal income tax rates. The deferred income taxes related to the AOD were based on a 34% federal income tax rate. The revenues EGS will receive due to the deficient deferred taxes will be taxed at the current rate of 35%. To reflect this one-percent difference, EGS should receive an additional $36,237 per month during the 36-month recovery period.

337F. The increase in revenues resulting from the acceleration of the AOD should be adjusted upward by 2.49% to reflect revenue related items such as bad debt expense and revenue taxes.

337G. Accelerated depreciation of the AOD will ameliorate intergenerational inequities.

338. Excessive accelerated recovery of River Bend costs could result in below market costs at the time of retail access.

339. Deleted.

Deferral of Transmission and Depreciation (T&D) Expense

340. Deleted.

341. Reducing the depreciation rate of EGS' distribution assets by $2.97 million per year and correspondingly increasing the depreciation rate of EGS' nuclear generation assets by the same amount (depreciation reclassification) would confuse EGS' nuclear generation and distribution assets and make policy-making more difficult if the law is to be changed to permit retail generation competition.

342. If allocation differences are not addressed, depreciation reclassification could produce unfair interclass effects because allocation factors for production and distribution plant differ. Residential and small businesses take power at lower voltage, hence they would pay a greater share of any distribution cost increase.

343. Deleted.

344. Deleted.

345. Deleted.

True-Up Mechanism

346. Deleted.

347. Deleted.

348. Deleted.

349. Deleted.

Alternative Recovery Proposals

350. Commission-ordered divestiture is premature because the legislators may take action during the next session on electric utility competition, and no party has fully analyzed the requirements or implications of divestiture.

351. Deleted.

352. A lower ROE on the accelerated recovery of the AOD is not justified in this case because (1) the Commission is accepting the provisions of that a May 7, 1996 letter agreement between EGS and Cities that deals with interest collected on base rate-related items, (2) the AOD is being removed from rate base, and (3) the effect of the other ratemaking treatments adopted in this Order.

353. Deleted.

354. Deleted.

Allocation of ECOM

355. It is reasonable to use the same jurisdictional and interclass cost allocation cost methodologies approved in Phase III during the transition to competition because cost causation and fairness will still apply during the transition.

356. The unbundled cost studies in Phase IV were developed from the jurisdictional and Texas retail cost allocation studies presented in Phase III.

Effect of ECOM Recovery on Competition

357. Deleted.

358. Deleted.

Earnings Sharing Mechanisms

359. EGS' banded ROE proposal is unreasonable for the following reasons: a reasonable return on equity is 11.7% (prior to the *EGS Service Quality* adjustment), not the 12.75% recommended by EGS in its banded ROE; EGS' shareholders receive excess earnings, while the ratepayers see few benefits; the proposal encourages small efficiency gains because the shareholders keep all the profits, but significant gains are less profitable because half the savings are flowed to the ratepayers; and the banded ROE proposal violates the Stipulation and Agreement in Docket No. 11292 by eliminating rate reductions.

360. General Counsel's return cap is reasonable because it requires EGS to use any earnings that exceed the cap to reduce its ECOM. The return cap would apply only to EGS' costs of service that the General Counsel does not propose to include in the River Bend performance plan.

361. Deleted.

362. Deleted.

362A. While General Counsel's return cap proposal is reasonable, due to the fact that EGS is required to file a rate case in November 1998, a comprehensive proposal can be reviewed by the Commission at that time.

363. In EGS' next rate case a return cap can be useful in dealing with regulatory lag, so that the passage of time does not result in excessive earnings.

364. A return cap would give EGS an incentive to increase efficiencies so that more overearnings could be used to reduce ECOM.

365. In EGS next rate case a return cap will be a reasonable way of ensuring that the utility's return remains reasonable after it has been fixed by the Commission.

366. Deleted.

367. Generation facilities that are not included in EGS' rate base in this proceeding should not be considered in an overearnings calculation unless they have been approved by the Commission in an integrated resource plan. This definition would not include additional investment at existing generating facilities. The electric plant in service may not include annual capital additions to production plant in excess of 1.5% of EGS' net plant in service as of the date of approval of this order, unless EGS demonstrates that the additions are reasonable.

368. Deleted.

369. Deleted.

River Bend Performance Based Ratemaking (PBR)

370. PBR provides customers with a more predictable level of future revenue requirements; streamlines the ratemaking process; and provides ratepayers an opportunity to share in improved efficiencies.

371. Capital additions should not be part of the PBR plan because it is difficult to determine if EGS prudently managed the additions.

372. The Palo Verde standards should be disregarded in setting standards for River Bend because those standards are outdated and are not appropriate considering the improved performance of nuclear plants over the last decade.

373. It is reasonable to maintain the nuclear fuel costs in the fixed fuel factor because it is not necessary to transfer the fuel costs to base rates to provide an incentive to control River

Bend's fuel expense; the transfer of nuclear fuel to base rates without reconciliation could result in an unreconciled over collection when EGS reduces its fuel costs; and nuclear fuel has a variable cost component, making it more appropriate to be reconciled as part of the fuel factor.

Economic Viability of River Bend

374. Non-outage O&M personnel costs, property taxes, and certain A&G costs are unavoidable costs.

375. River Bend is economically viable because, after excluding the unavoidable costs, a market price of $26 per MWh in 1997 that escalates at 3% per year allows River Bend to cover its anticipated avoidable operating costs.

376. Deleted.

377. It is reasonable to continue to operate River Bend because River Bend does not emit pollutants such as NOx, SOx, and CO_2. River Bend provides customers with a more diverse fuel supply subject to less gas price volatility; and a shut down of River Bend would reduce the supply of electricity, which could increase electricity prices in the region.

Components of PBR Plans

378. The costs of owning and operating River Bend are divided into two categories: 1) the return on the rate base value of net plant-in-service and accounting order deferrals as of the end of the test year, June 30, 1996; and 2) the revenue requirement associated with the on-going operation and capital costs.

379. The revenue requirement is divided into two subcategories: 1) O&M expenses, including A&G, fuel costs, and the return of and on future capital additions (PBR costs); and 2) expenses associated with decommissioning, property taxes, insurance, low-level radioactive waste disposal, and contra-allowance for funds used during construction

(exogenous costs). Exogenous costs will be recovered through traditional ratemaking methods.

Capacity Factor

380. River Bend achieved a 97.6% capacity factor in 1995 (a non-outage year) and an 83.23% capacity factor in 1996 (an outage year).

381. Currently, 48% of U.S. nuclear plants meet or exceed a three-year capacity factor average of 81%.

382. River Bend's most recent three-year average was 79.9% (1994-1996).

383. Three-year averaging would allow periods of poor performance to be offset by periods of superior performance.

384. A three-year rolling average target capacity factor of 81% with a deadband range of 78% to 86% is a reasonable performance standard for River Bend.

385. It is reasonable for EGS to report River Bend's three-year capacity factor through the prior year. On January 30 of each year, EGS shall file a report showing the three-year capacity factor, as well as the capacity factor, outages, and purchased power costs occurring each month during the prior calendar year. If River Bend has operated below the target capacity factor range, then a downward adjustment to EGS' ROE will be made. The adjustment will equal the difference between the actual cost of nuclear fuel and the alternative energy rate. If EGS operates at above the upper target capacity factor range, then an upward adjustment to the ROE will be made. If River Bend operates above the 86% target capacity factor range, then EGS' ROE will be adjusted upward in an amount equal to half the difference between nuclear fuel cost and the alternative energy rate. All adjustments to the ROE shall be calculated in a separate deferred account and assessed in EGS' fuel reconciliation proceeding.

386. Deleted.

387. Based on the most recent figures, it is reasonable to assume that EGS will achieve a capacity factor over the next several years between 78% to 86%, depending on factors such as refueling.

388. The deadband for purposes of measuring a reward or penalty should be 78% to 86%, 5 percentage points above and 3 percentage points below the targeted capacity factor of 81%. The three-year rolling average target capacity factor of 81% will be compared to EGS' actual three-year rolling average capacity factor to determine the reward or penalty.

389. If EGS operates at better than 86% capacity factor, then it will receive a ROE increase of 50% of the avoided fuel costs. If EGS operates below 78% capacity factor, it will receive an ROE decrease of 100% of the additional fuel costs.

390. The Nuclear Regulatory Commission (NRC) recommends against performance standards for nuclear facilities that sharply penalize short term under-performance. It suggests deadbands, which would avoid penalties for mild under-performance, banking of rewards, and other measures to avoid sharp penalization.

391. A three-year average capacity factor performance standard would avoid sharp penalty thresholds, otherwise avoid penalizing short-term under-performance, and adequately address the NRC's concerns.

392. Performance standards with explicit penalties and rewards are useful in protecting consumers from inadequate performance of utility facilities, in providing an incentive for superior performance of such facilities, in giving utilities a reason to continually assess the economic viability of generating assets, and in preparing utilities for more competitive markets.

393. Deleted.

394. Deleted.

395. If River Bend operates above 86%, it will have already provided less expensive electricity than in the past.

396. It is reasonable to assign 100% of the penalties to EGS because EGS has traditionally not performed at the level of the other Entergy plants (Arkansas One, Grand Gulf, and Waterford); therefore, assigning 100% of the penalty to EGS will provide a significant incentive to obtain a three-year rolling average capacity factor above 81%.

397. NRC guidelines caution against use of systematic assessment of licensee performance scores in economic incentive programs.

398. The rolling three-year capacity factor of 81% (86 to 78% deadband) protects the ratepayers from poor performance, provides an incentive for superior performance, gives EGS incentive to continually evaluate the economic viability of generating assets, and prepares EGS for a more competitive market.

399. The three-year rolling average capacity factor of 81% accounts for River Bend's improved performance, accounts for River Bend's past performance, sets a reasonable and obtainable goal, and provides sufficient funds to operate the plant.

Nuclear Fuel Costs

400. EGS' nuclear fuel expenses include: 1) the cost of the nuclear fuel consumed (amortization); 2) the lease or financing cost of the fuel remaining in the core; 3) the fees paid to the United States Department of Energy (DOE) for the spent fuel disposal fee; and 4) the fees paid to the DOE for the enrichment decontamination and decommissioning fee (D&D fee).

401. It is reasonable to exclude the spent fuel fee and the D&D fee from the PBR proposal because the costs cannot be controlled by EGS.

402. Annual cost targets for River Bend's nuclear fuel should be based on the prudently incurred costs of the fuel currently in the core, the fuel that is in-process, and the projected costs of nuclear fuel, financing, and inflation.

403. If EGS meets the annual cost targets for nuclear fuel, the cost of the fuel for that year will automatically reconcile during the following fuel reconciliation proceeding. If EGS does not meet the annual cost targets for nuclear fuel, the difference in fuel cost over the target that year will be disallowed. The disallowance will be applied to the fuel under/over collection until the next fuel reconciliation period.

404. The reasonable nuclear fuel cost targets for the amortization and lease interest portion only are:

YEAR	TARGET($/MWh)
7/1/96-12/31/97	$6.15
1998	$5.25
1999	$5.60
2000	$5.57
2001	$5.27
2002	$5.65

405. It is appropriate to calculate the nuclear fuel targets by averaging the projected fuel costs under favorable and unfavorable conditions using EGS' forecast and the Staff's forecast for 1997 through 1999. For 2000-2002, the targets are based on the Staff's projections only.

406. It is not reasonable to base EGS' nuclear fuel cost targets based on industry standards because River Bend's fuel costs for the reloads that were placed in the core prior to July 1995 were found to be reasonable in Docket No. 15102; use of industry averages does not

recognize the higher cost of fabrication incurred by the BWRs; the use of an average fuel cost does not account for the difference in the cost of leasing and ownership; and it is inappropriate to consider the fuel cost of Entergy's other nuclear plants because those plants have benefited through economies of scale from the nuclear fuel purchases made by the System Fuels, Inc., an Entergy subsidiary.

Non-fuel Operating Costs

407. It is reasonable to exclude non-fuel operating costs (O&M expenses, A&G expenses, and capital additions) as part of the fuel PBR plan because the onset of deregulation provides a sufficient incentive to reduce operating costs; the Commission can account for operating costs savings through cost of service regulation; EGS has reduced its operating costs over the last two years and will likely continue to do so with retail competition pending; and EGS' O&M targets are significantly higher than the nuclear industry median for 1996.

Replacement Power Costs

408. The alternative energy rate will be the average price of gas reported in transactions on the New York Mercantile Exchange (NYMEX) as the settle price as that price is reported on the final day of trading for contracts to be delivered during each of the twelve operational months that the reward or penalty is to be determined.

409. The alternative energy rate is reasonable for purposes of the PBR because it is objectively determined and readily ascertainable; the alternative energy rate is not subject to the control of Entergy; the alternative energy rate is subject to the usual market and other pricing pressures that impact a fossil-fuel supply and the choice of gas as the replacement fuel is reasonable given that gas-fired plants will typically make up shortfalls in base load generation.

410. A heat rate of 10,400 Btu/kWh is high in comparison to newer technology, but is nevertheless reasonable because it approximates the average heat rate of gas fired plants serving Texas.

411. The NYMEX (Henry Hub) Index should be the value used in determining the alternative energy rate.

Implementation of PBR Plans

412. Long-term measures more accurately reflect River Bend's performance because: 1) refueling outages will bias short-term measure; 2) short-term measures provide an incentive to operate a plant through a high demand period when the plant should be shut down; and 3) the NRC policy focuses on the long-term goal of reliability and operational safety.

413. Although the calculation will be made annually, it is reasonable to require EGS to keep monthly records of River Bend's performance, outages, and of monthly purchased power costs.

413A. The PBR plan prescribed in this Order shall apply to River Bend's operation effective July 1, 1996.

Force Majeure Provisions

414. The reasonable force majeure provisions for EGS' nuclear fuel PBR are:

- The performance standard shall be terminated on January 1 following a three-year period where the River Bend capacity factor falls below 50%. Thereafter, the operational performance of River bend will be subject to a prudence review in a fuel reconciliation proceeding. River Bend performance during the period when the standard was in effect will not be subject to the prudence review.
- The performance standards would be set aside if River Bend could not perform due to civil unrest, natural catastrophes, or industry-wide shut downs imposed by legislative or regulatory bodies to protect EGS from matters beyond its control.

415. It is unreasonable to allow the Company to terminate the fuel PBR plan if the nuclear fuel costs exceed the target by more than 25% because controlling fuel costs is the major component under the PBR plan.

416. Force majeure provisions should not provide EGS a risk-free way out of its obligations to perform well.

Compatibility with Merger Savings Tracker

417. Because non-fuel O&M is not part of the PBR plan, the merger related non-fuel O&M savings provision will remain the same, giving ratepayers 50% of the savings.

418. River Bend fuel PBR plan does not violate the Stipulation and Agreement in Docket No. 11292 regarding fuel expenses because the ratepayers will still receive the benefit of all the fuel cost savings through the reconciliation proceeding.

Return on Equity During Transition Period

419. Deleted.

Functional Unbundling of Generation, Transmission, and Distribution

420. Functional unbundling identifies and separates the functional costs of a utility's retail rates.

421. It is reasonable to unbundle the Texas retail rate class cost of service into four categories: generation, transmission, distribution, and customer service.

422. The functional unbundling of rates is reasonable because it provides a way of monitoring predatory pricing of competitive services, reduces the possibility of monopoly services subsidizing competitive services, and identifies the costs associated with the different functions.

423. General Counsel's unbundled cost of service study methodology is reasonable. The Phase IV unbundled cost of service study should be adjusted for the revenue requirement, rate design, cost allocation, and other decisions made elsewhere in the PFD.

424. It is reasonable for EGS to unbundle its distribution and customer services into three categories: basic, non-basic, and competitive.

425. Deleted.

426. Deleted.

427. Including a Universal Service Cost (USC) charge as part of an unbundled rate would create customer confusion in that the law may never change to permit a less regulated environment.

428. Deleted.

429. Deleted.

430. EGS is compensated for any risk associated with competition in its ROE.

431. Because EGS cannot currently calculate exact load, the exact amount of ECOM, or the number of customers that will leave the system, it is unnecessary at this time to impose a USC charge.

432. EGS' rates should not be unbundled to include a USC charge designed to fully recover EGS' ECOM.

433. The USC charge in its current form discriminates between customers.

434. The USC charge imposes a heavier burden on industrial customers by discouraging cogeneration.

435. The USC charge economically prohibits certain customers from constructing cogeneration, thus enhancing EGS' market power.

436. Deleted.

437. It is premature to display unbundled rates on the customers' bills pending final resolution of the Commission's rulemaking proceedings that address such unbundling issues.

438 Deleted.

New Services and Pricing Initiatives

439. Deleted.

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456. The following components of the Employment and Economic Service Schedule (EEDS) are reasonable: the minimum threshold for applicability of the rider shall be ten permanent jobs; and certain types of commercial customers would be eligible such as military installations, correctional facilities, distribution centers/warehouses, headquarters of international or multi-state corporations, large research facilities, and large computer/data processing centers.

457. By expanding the type of customer that is eligible for the EEDS, EGS has more of an opportunity to achieve the goals of an economic development rate, which includes creating higher levels of employment, expanding the income base, and spreading fixed utility costs over a larger customer base.

458. In a competitive market there will be a variety of service and price arrangements targeted to low-income and fixed-income customers.

459. EGS' NUS plan provides a procedure for the addition, unbundling, or elimination of activities, services, products, and pricing options by EGS.

460. Although the NUS tariff states that the new or unbundled service must exceed the cost to provide such service, EGS does not provide details on how its incremental costs will be calculated. Therefore, it is reasonable, as part of the compliance filing for this proceeding, for EGS to provide additional details on how the incremental costs will be calculated in accordance with PURA § 36.007.

461. To allow for more adequate review, it is reasonable for EGS to revise the tariff to state that an NUS filing will be approved within 90 days unless a party determines that it needs to be docketed, and if docketed, the traditional suspension period for tariff review will apply.

462. It is not necessary at this time to limit the term of NUS services to a maximum of one year.

463. Deleted.

464. More research needs to be conducted to evaluate the role of an ESR in a competitive market.

465. A pilot aggregate billing program is a meaningful step towards competition. The program should address the problems such as the cost of the program, how the dollars would be allocated to each class of customers, a proposed implementation date, and what entity would handle customer service inquiries.

465A. The Commission declines to address retail pilot programs at this time.

Structure of the Bulk Power Market

466. EGS will have certain advantages when competition arrives such as name recognition, knowledge of customer usage, and diversified mix of customers with a diversified mix of generation resources.

467. Mandatory divestiture is not reasonable at this time because the details of that divestiture have not been explored; past decisions to divest have been voluntary; divestiture may not be the most beneficial for ratepayers; a reliable market power study was not conducted as part of this docket that shows that it is necessary for EGS to divest; divestiture must account for EGS' customers in Louisiana; the provider of last resort issue has not been resolved; an effective competitor could be eliminated; and divestiture may not be an appropriate way to value all of EGS' generating assets.

468. A code of conduct would be useful to govern interactions between regulated companies and their unregulated affiliates in a competitive market to ensure that unregulated companies do not receive preferential treatment.

469. Deleted.

470. EGS' market power and predatory pricing are issues that need to be considered as competition approaches.

471. T&D facilities are monopolies that are unlikely to be fully deregulated. It is reasonable to assume that EGS will be required to provide T&D services to all retail electricity generators and end-use customers at regulated rates even in a less-regulated environment.

472. Establishing an ISO, an RPX, and the reciprocity proposal are issues that will need to be addressed at the regional, state, and federal level during the transition period.

473. Once competition arrives, consumer protection standards will be necessary to address: switching customers to alternative energy providers without their informed consent; protecting against service disconnects during extreme weather, medical emergency, and

in cases of non-payment of unrelated services; keeping customer billing and payment records confidential; itemizing all services on one bill; maintaining uniform billing and collection practices; and resolving customer disputes through a neutral third party.

474. Affordable rates will be necessary for low-income customers once competition arrives. Affordable rates could be achieved through an income payment program, a universal service rate, an inverted block rate, and energy efficiency usage reduction programs.

475. Universal service should be preserved in a competitive electric market.

476. Default service is defined as providing electric service to consumers who fail to make an affirmative choice, are financially unqualified, or are not being served by a competitor they affirmatively select.

477. Default service may be competitively provided in EGS' service area post-transition.

478. Default providers or providers of last resort are a necessary part of the protection that should be afforded low-income customers.

479. Strandable benefits include: system reliability, research and development, universal service, resource diversity and renewable energy, energy efficiency, environmental protection, low-income programs, and consumer protections.

480. Supplier certification standards should be adopted to maintain the quality of service customers receive after the transition. These standards should require eligible suppliers to meet specific financial, operational, and technical qualifications.

480A. The Low-Income Agreement provides that EGSI shall track any lost-revenues that are created by the waiver of the customer service fee and that EGSI may request recovery in a future rate case.

480B. Under the Low-Income Agreement, EGSI will conduct load research on LILU rider customers for possible revision of the consumption-based eligibility requirements and conservation related billing adjustments. If the load research indicates that another method of pricing for low-income customers is reasonable and appropriate, EGSI shall file a revised low-income tariff in a future rate proceeding.

480C. Taken as a whole, the terms of the Low-Income Agreement are reasonable and consistent with the public interest.

Cajun 30% Share of River Bend

481. On December 22, 1997, EGS acquired what had been Cajun Electric Power Cooperative, Inc. (Cajun) 30% interest in River Bend.

482. It is reasonable for EGS to address its acquisition of the Cajun 30% interest in the River Bend plant in its next rate case if it has not filed the acquisition report in Docket No. 12104 by the date that it files its next rate case.

B. Conclusions of Law

1. EGS is an electric utility as defined by PURA § 31.002 and is therefore subject to the Commission's jurisdiction under PURA §§ 32.001, 33.051, 36.102, and 36.203.

2. SOAH has jurisdiction over all matters relating to the conduct of a hearing in this proceeding, including the preparation of a Proposal For Decision (PFD) with findings of fact and conclusions of law, pursuant to PURA § 14.053 and TEX. GOV'T CODE ANN. § 2003.049 (Vernon 1998).

3. Proper notice was given in this docket pursuant to the terms of TEX. GOV'T CODE ANN. §§ 2001.051 and 2001.052, PURA § 36.103; and P.U.C. PROC. R. 22.51.

4. The jurisdictional deadline applicable to this docket is July 31, 1998, as agreed to by the Company in a letter dated March 30, 1998. .

Fuel Reconciliation

5. EGS is entitled to the profits from the 1997 uranium sale under the principles outlined in *Public Util. Comm'n v. Gulf States Util. Co.*, 809 S.W.2d 201 (Tex. 1991).

6. Deleted.

7. EGS is entitled to a good cause exception to P.U.C. SUBST. R. 23.23(b)(2)(B) as to wheeling revenues and Account 565 expenses because these items are not eligible fuel expenses under the principles established in *SWEPCO*, Docket No. 17460.

8. EGS is entitled to a good cause exception to P.U.C. SUBST. R. 23.23(b)(3)(C) so as to use the surcharge to offset base-rate refunds for the Historical Refund Period instead of having the entire amount surcharged in one month.

9. EGS is not entitled to a good cause exception to P.U.C. SUBST. R. 23.23(b)(3)(C)(i)(V) so as to stop collecting interest before the end of the last surcharge month.

10. Tariffs for EGS' non-fixed fuel factor customers do not include fuel expenses recovered through a fuel factor subject to reconciliation under P.U.C. SUBST. R. 23.23(b)(3).

11. EGS has satisfied P.U.C. SUBST. R. 23.23(b)(3)(B)(i) by showing that (1) its eligible fuel expenses of about $668.5 million on a total company basis, as adjusted downward to incorporate the disallowances described in Finding of Fact Nos. 10-84 (stated on a total company basis), were reasonable and necessary; (2) the prices charged by its supplying affiliates were reasonable and necessary and not higher than the prices charged by the supplying affiliates to their other affiliates or divisions or to unaffiliated persons or corporations for the same item or class of items; and (3) it has properly accounted for the

amount of fuel-related revenues collected pursuant to the fuel factor during the reconciliation period.

Interim Fuel Factor

11A. Due to its incompleteness and relative incomprehensibility, EGS' fuel factor interim revision application and testimony fail to meaningfully provide information in the format specified by the Commission's filing package, as required by P.U.C. SUBST. R. 23.23(b)(2)(C). (SCoL 1).

11B. Due to its incompleteness and relative incomprehensibility, EGS' fuel factor interim revision application and testimony fail to prove that the estimated expenses, system sales, and off-system sales are reasonable, as required by P.U.C. SUBST. R. 23.23(b)(2)(D)(i)(1) and (2). (SCoL 2).

11C. Because of EGS' failure to satisfy the burden of proof, as shown in Finding of Fact Nos. 96A-96D and Conclusion of Law Nos. 11A and 11B, EGS' application to revise its fixed fuel factors on an interim basis must be denied. (SCoL 3).

Final Fuel Factor

11D. As to Finding of Fact No. 96N, under *Mississippi Power & Light Co. v. Mississippi*, 487 U.S. 354, 369-370, 108 S.Ct. 2428 (1988), a state utility commission must treat FERC-mandated system agreement payments as reasonably incurred operating expenses for the purpose of setting retail rates. This Supreme Court decision preempts the PUC from disallowing MSS-2 expenses in this case. (SCoL 4).

11E. EGS' request for a good cause exception 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) should not be denied since the expenses and revenue recorded in those accounts are not fuel expenses under the principles laid out in *SWEPCO*. (SCoL 5).

11F. Cities request for a good cause exception to deviate from the fuel rule so as to treat MSS-1 expenses as reconcilable should be denied.

11G. EGS has complied with P.U.C. SUBST. R. 23.23(b)(2)(C) by filing its application and supporting testimony in the format specified by the Commission's filing package.

11H. EGS has met its burden of proof under P.U.C. SUBST. R. 23.23(b)(2)(D)(i) by establishing that its: (1) estimated expenses are reasonable; (2) estimated system and off-system sales are reasonable; and (3) proposed fuel factor are reasonably differentiated to account for line losses, and its application to revise the fuel factor therefore must be granted.

Revenue Requirements

12. The revenues set forth in Commission Schedule I meet the PURA § 36.051 requirements that the Commission fix a utility's overall revenues at a level that will permit it a reasonable opportunity to earn a reasonable return on its invested capital used and useful in rendering service to the public over and above its reasonable and necessary operating expenses.

13. The expenses set forth in Commission Schedule I of this Order substantially comply with P.U.C. SUBST. R. 23.21(b).

14. P.U.C. SUBST. R. 23.21(d)(2)(B)(i) requires the inclusion of cash working capital in EGS' invested capital, on which it is entitled under PURA § 36.051 to earn a return. The calculation of cash working capital is established in Finding of Fact No. 114, and the reasonable and necessary amount of cash working capital is shown in Commission Schedule IV.

15. The methods and rates of depreciation implicit in Commission Schedules I and IV are proper and adequate and have been uniformly and consistently applied, in accordance with PURA § 36.056.

16. Under the *Bluefield* and *Hope* decisions, cited in Section VI of the PFD, a rate of return which is reasonably sufficient or adequate requires striking a balance between what the investor would want and what would benefit the ratepayer. The overall rate of return and components of rates of return addressed at Findings of Fact Nos. 125 through 135 substantially comply with the P.U.C. SUBST. R. 23.21(c)(1) and with those decisions.

17. The return set forth in Commission Schedule I will permit EGS a reasonable opportunity to earn a reasonable return over and above its reasonable and necessary operating expense, as required by PURA § 36.051.

18. Salary and wage expenses are properly adjusted for known and measurable changes to test year to the extent the adjustments capture all attendant impacts as prescribed by P.U.C. SUBST. R. 23.21(c).

19. Post-retirement benefits other than pension expense may be based on an estimate of future expense as permitted under P.U.C. SUBST. R. 23.21(c)(1)(H)(ii).

20. PURA § 36.062(1) and P.U.C. SUBST. R. 23.21(c)(2)(A) broadly prohibit the inclusion of legislative advocacy expenses in setting a utility's rates. Accordingly, EGS is not entitled to recover through rates those portions of dues paid to civic and industrial organizations that relate to legislative advocacy functions.

21. To permit recovery of pre-test-year cost savings expenditures related to the EGS and Entergy Corporation merger would violate ratemaking principles based on an historical test-year level of expenses. Also, under the Docket No. 11292 merger stipulation, EGS did not obtain the right to defer the CSE accruing before its first merger-mandated rate case. Therefore, pre-test year CSE should be excluded from cost of service.

22. EGS' CSE are non-recurring expenditures controlled by the conclusion that if the actual incurred expense in question or a similar expense cannot be anticipated to reoccur with any reasonable certainty within a given period, no allowance for that expense shall be made in cost of service. *See Application of Gulf States Utilities Company for a Rate Increase*, Docket No. 3871, 7 P.U.C. BULL. 410, 414 (Nov. 18, 1981), adopted in a policy statement by the Commission at 7 P.U.C. BULL. 450. Commission substantive rule 23.21(c)(1)(A) permits recovery of O&M expense incurred in furnishing *normal* utility service. Cost savings expenditures are not recurring, and hence not normal utility service. Therefore, CSE arising during the test year should be excluded from cost of service.

23. For a utility to recover through rates the costs of its transactions with its affiliates, PURA § 36.058 requires the Commission to find that the costs for each item or class of items of affiliate expense are reasonable and necessary and the price the utility pays is no higher than the prices charged by the supplying affiliate to other affiliates or divisions or to a nonaffiliated person for the same item or class of items. Under PURA § 36.058, findings based on a class of *total* ESI or EOI expenses are impermissible as a matter of law in this docket because the total amount billed to EGS is so large and involves so many different items of expense that a total-dollars review will not produce the necessary regulatory findings.

24. In prior dockets addressing affiliate expenses, the Commission has applied the standard established in PURA and in case law. In accordance with the standard established in *Railroad Commission of Texas v. Rio Grande Valley Gas Company*, 683 S.W.2d 783 (Tex. App.-Austin 1984, no writ), EGS must at least show the following:

    1. The prices it was charged by its affiliate were no higher than the prices charged by the supplying affiliate to its other affiliates.
    2. Disallowable expenses (*i.e.*, legislative advocacy, donations, entertainment, advertising products marketed by other subsidiaries, etc.) were not included in expenses allocated to the utility.

3. Each item of allocated expense was reasonable and necessary.
4. The allocated amounts reasonably approximate the actual cost of services to it.

25. PURA § 36.058 presumes a disallowance of all affiliate costs. Under P.U.C. PROC. R. 22.182 and Tex. R. Civ. Proc. 166a(c), the Commission is authorized to evaluate EGS' affiliate evidence presented in its direct case to determine whether it has met its burden of proof. If the Commission determines the utility did not meet that burden, the Commission may direct judgment against the utility. Because EGS failed to meet the standard of proof required under PURA and *Rio Grande* in its direct case at hearing, it is proper to direct judgment finding that no ESI or allocated EOI operations and maintenance affiliate expenses should be recovered from ratepayers for the test year related to this docket.

25A. Because EGS made a *prima facie* case pursuant to the standard of proof required under PURA and *Rio Grande* in its direct case at hearing, as it relates to direct-billed EOI operations and maintenance affiliate expenses, direct judgment on the issue of whether these expenses may be recovered from ratepayers for the test year related to this docket is not appropriate.

26. Because affiliate expenses represent self-dealing, testimony of employees of the company or hired consultants alone about the reasonableness of those expenses is not a sufficient basis of proof to meet the PURA § 36.058 requirements. Consequently, the Commission's responsibility to protect public interests can not be achieved without inspecting underlying evidence and performing some independent analysis. The Company's direct evidence should include sufficient information to accomplish this review. Sufficient evidence could include a bench marking of costs found through surveys of other companies, a comparison of the utility's prior costs for the same services, and/or a demonstration that customers derive a benefit from the allocation of costs for services. Studies should demonstrate the necessity of the expenditures, that

they were appropriately provided by the affiliate and not duplicated within the utility, and that the costs are reasonable compared with alternative service providers.

27. In prior Commission dockets, utilities have provided independent evidence of the reasonableness and necessity of their affiliate expenses. *See Inquiry of the General Counsel Into the Reasonableness of the Rates and Services of Southwestern Bell Telephone Company*, Docket No. 8585, 17 P.U.C. BULL. 1045 (Nov. 29, 1990); *see also, Public Utility Commission v. GTE-Southwest, Inc.*, 901 S.W.2d 401 (Tex. 1995). It is appropriate under *Rio Grande,* other case law, and Commission precedent for a utility to provide extrinsic evidence supporting its affiliate expenses.

28. EGS failed to meet its burden under PURA § 36.058 to prove that its affiliate expenses from Entergy Services, Inc. and allocated affiliate expenses from Entergy Operations, Inc. are reasonable and necessary for each item or class of items of expenses and that the prices ESI and EOI charged, by allocation, to EGS for such expenses were no higher than prices charged to their other affiliates or divisions or to a nonaffiliated person for the same item or class of items. Consequently, neither charges from ESI nor allocated charges from EOI to EGS should be recovered from ratepayers through cost of service.

28A. EGS met its burden under PURA § 36.058 to prove that its direct-billed affiliate expenses from Entergy Operations, Inc. are reasonable and necessary for each item or class of items of expenses, *i.e.* production class, and that the prices direct-billed by EOI to EGS for such expenses were no higher than prices charged to their other affiliates or divisions or to a nonaffiliated person for the same item or class of items. Consequently, direct-billed charges from EOI to EGS should be recovered from ratepayers through cost of service.

29. The level of merger-related savings to be shared between ratepayers and shareholders set forth in Findings of Fact Nos. 171 through 176 is reasonable and conforms with the merger tracker requirements and calculations established in the merger agreement between EGS and Entergy Corporation approved in Docket No. 11292.

30. The proposed level of regulatory commission expense included in cost of service in this case is not unreasonable, preferential, prejudicial, or discriminatory within the meaning of PURA § 36.003.

31. It is within the Commission's discretion to allocate a fair share of consolidated federal income tax savings under PURA § 36.060 as set forth in Finding of Fact Nos. 196 through 198.

32. The IRS concluded that reflecting depreciation related to disallowed costs in the FIT expense for ratemaking would violate normalization rules. *See* EGS Ex. 146 at Ex. JIW-3, IRS private letter ruling per Docket No. 12852. In *PUC v. Texas Utilities Electric Company*, 935 S.W.2d 109, 110 (Tex. 1996) citing 901 S.W.2d at 411, the Supreme Court concluded that the Commission has neither the power nor the discretion to consider disallowed expenses or capital costs to determine the utility's income tax expense for ratemaking purposes.

33. In accordance with PURA §§ 36.051, 36.058, and 36.060 and *PUC v. GTE*, as discussed at Section VII.E. of the PFD, EGS is entitled to the amount shown in Commission Schedule I in its cost of service for federal income tax expense.

34. In *Application of Gulf States Utilities Company for Authority to Change Rates and Inquiry of the PUC into the Prudence and Efficiency of the Planning and Management of the River Bend Nuclear Generating Station*, Docket Nos. 7195 an 6755, 14 P.U.C. BULL. 1943, 2234 (May 16, 1988) regarding Gulf States Utilities' plant depreciation, the Commission rejected the end-of-year convention. Therefore, it is appropriate to apply the mid-year convention in establishing EGS' plant depreciation.

35. It is appropriate to reject inclusion of future interim additions to or retirements of plant in cost of service because they are not known or measurable, and including them in

depreciation rates would violate P.U.C. SUBST. R. 23.21(b). *See* Docket No. 14965, PFD at 208-209, Finding of Fact No. 94, Second Order on Rehearing at 42 (Oct. 15, 1997).

36. EGS' DSM programs promote the consumption of electricity in violation of P.U.C. SUBST. R. 23.21(c)(2)(F) and should be disallowed as established in Findings of Fact Nos. 202 through 206.

37. The revenue requirement set forth in Commission Schedules I through VI will permit EGS to earn a reasonable return on its invested capital used and useful in rendering service to the public over and above its reasonable and necessary operating expenses in accordance with PURA § 36.051.

38. The revenue requirement set forth in Commission Schedules I through VI will result in just and reasonable rates within the meaning of PURA § 36.003.

Rate Design

39. The service rules and regulations and tariffs are reasonable and consistent with PURA and the Commission's rules.

40. Interruptible service must meet a clearly defined resource need and be based on a market-based assessment of the value of the interruptible service in comparison to the extent of the difference between the interruptible rate and the firm rates.

41. The Stipulation in Docket No. 11292 does not bar the General Counsel from pursuing just and reasonable rates.

Competitive Issues

ECOM and Accelerated Recovery of River Bend

42. As set out in PURA § 11.002, the purpose of utility regulation is to serve as a substitute for competition not to guarantee utilities limited competition or higher than competitive returns.

43. The Fifth Amendment to the U.S. Constitution does not entitle a utility to rates based on the fair market value of its assets. Instead, the Fifth Amendment only entitles a utility to rates that will enable it to maintain its financial integrity, attract capital, and compensate investors for the risk they assume. Therefore, EGS is not be entitled under the Fifth Amendment to rates that would allow it to recover all of its ECOM. *Federal Power Commission v. Hope Natural Gas Co*., 64 S.Ct. 281, 286-89 (1944).

44. Under current law, EGS has no absolute right to recover its generation-related ECOM. Docket No. 14965, Second Order on Rehearing at CoL 88A.

45. The rate of return for ECOM may lawfully differ from the rate of return on other assets because such invested capital is economically less useful than EGS' other invested capital, and because the accelerated recovery of this invested capital reduces EGS' risk of under-recovery. Docket No. 14965, Second Order on Rehearing at FoF 364.

46. PURA § 36.051 entitles EGS to rates which will permit it a reasonable opportunity to earn a reasonable return on its invested capital used and useful in rendering service to the public over and above its reasonable and necessary operating expenses.

47. EGS is entitled to a reasonable return on invested capital found to be used and useful under PURA §§ 36.051 and 36.053; however, it is not necessarily entitled to recovery on an accelerated basis.

48. Deleted.

Depreciation Reclassification

49. Deleted.

Return Cap

50. PURA § 36.051 directs the Commission in setting the rates of the utility to fix the revenues of the utility at a level that will permit it to earn a reasonable return over and above its reasonable and necessary operating expenses. PURA does not limit ratesetting to a static assessment of the costs of providing service. A return cap may be a reasonable means of ensuring that the utility's return remains reasonable after it has been fixed by the Commission.

51. Under PURA § 36.052, the Commission has the authority to implement a banded ROE if the Commission determines the ROE plan is reasonable.

Performance Based Ratemaking

52. PURA § 36.203 requires the Commission to reconcile a utility's fuel costs; P.U.C. SUBST. R. 23.23(b)(2)(A) requires that eligible fuel expenses be recovered through the fuel factor; and nuclear fuel is considered an eligible fuel expense under P.U.C. SUBST. R. 23.23(b)(2)(B); therefore, it is reasonable for nuclear fuel to be reconciled as part of the fuel factor.

Discount Rates

53. PURA § 36.007 does not distinguish between basic and non-basic services in determining if a rate is discounted.

54. EGS' NUS rider will be considered a discount rate under PURA § 36.007, and if EGS prices a NUS service below fully-allocated embedded costs, the costs of serving the discount customer will be borne by EGS' shareholders.

55. PURA § 36.007(d) does not prohibit EGS from pricing below embedded costs; however, if it does price below embedded costs, the costs of serving the discount customers may not be borne by EGS' other ratepayers.

Market Structure

56. FERC has jurisdiction over establishing an ISO, approving transmission tariffs, and developing an RPX.

LILU

56A. The Commission may adopt the terms of a non-unanimous stipulation and agreement of it finds its terms are supported by the record, comply with PURA, are fair, equitable, reasonable, and consistent with the public interest in accordance with *City of El Paso v. Public Utility Comm'n of Texas*, 883 S.W.2d 179, 182-184 (Tex. 1994).

56B. The Low-income Agreement cannot, and does not, preclude a review by the Commission of whether any lost revenues attributable to the waiver of the customer service charge are recoverable by EGS.

56C. The Low-Income Agreement represents a reasonable resolution of a contested issue in Docket No. 16705, is fair, equitable, reasonable, and consistent with the public interest, and should be adopted as post of the Commission's order in this case.

VI. Ordering Paragraphs

1. The proposal for decision prepared by the State Office Of Administrative Hearings Administrative Law Judges is adopted to the extent consistent with this Order.

2. The application of Entergy Gulf States, Inc. (EGS) in this docket is granted to the extent provided in this Order.

3. Deleted.

4. EGS shall use the fuel surcharge amount to offset the base-rate refunds during the Historical Refund Period as described in Attachment A for its fixed fuel factor customers over the time periods specified in this Order.

4A. EGS' application to revise its fuel factor is granted as modified by this Order. EGS shall revise its appropriate tariff schedules in accordance with Commission Schedule KP-Fuel/1.

5. Deleted.

6. Deleted.

7. EGS shall file any future cash working capital lead-lag cost study in conformance with P.U.C. SUBST. R. 23.21(d)(2)(B)(iii)(V), as discussed at Section V.F. of the PFD.

8. Deleted.

9. Refunds and surcharges resulting from this Order for the Historical Refund Period of June 1, 1996 to the date that the prospective base rate reduction is implemented in this docket shall be implemented in accordance with the July 14, 1998 Interim Order Memorializing Initial Refund Procedures as clarified and modified by this Order. The base rate decrease ordered in this docket and extending beyond the end of the Historical Refund Period--that is, the Prospective Rate Decrease Period--shall be offset in each of the prospective period months by a proportionate amount of the remaining net AOD balance as adjusted to include interest on the remaining balance. As with the base rate-related refund in the historical period, the interest rate applicable to the remaining monthly net AOD balances shall be equivalent to the overall return approved in this docket. The net AOD amortizations shall be treated as surcharges. The interest on the fuel surcharges and the "actual taxes paid" surcharges shall be computed at a rate equal to the applicable over-/underbilling interest rate established pursuant to PUC SUBST. R. 23.45(h). The true-up mechanism established in the July 14, 1998 Interim Order shall

account for and allow EGS to recover any over-refunds that were attributable to treating the standby charge increase ordered in this docket as a retroactive, rather than prospective, increase.

10. EGS is ordered to synchronize fuel revenues and expenses in the compliance cost of service study by using the rate-year fuel expense and fuel revenues.

11. a. EGS is ordered to file tariffs consistent with this Order within 20 days from the date the Company is notified of the issuance of this Order in accordance with APA § 2001.042. No later than 10 days after the date of the tariff filing, the General Counsel shall file the Staff's comments recommending approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to the General Counsel's recommendations shall be filed no later than 15 days after the filing of the tariff. The Office of Policy Development shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter, based upon the materials submitted to the Commission under the procedure established herein.

    b. The tariff sheets shall be deemed approved and shall become effective upon the expiration of 20 days from the date of filing, in the absence of written notification of modification or rejection by the Office of Policy Development. In the event any sheets are modified or rejected, EGS shall file proposed revisions of those sheets in accordance with the Office of Policy Development's letter within 10 days of the date of that letter, and the review procedure set out above shall apply to the revised sheets.

    c. Copies of all filings and of any Office of Policy Development letters under this procedure shall be served on all parties of record and the General Counsel.

12. EGS shall file a detailed plan with its 1998 rate case application that demonstrates how EGS is enhancing the value of its plants and detailing its plans to achieve a market-based valuation of its ECOM. The plan shall be titled: *EGS' Plans for Reducing ECOM, Enhancing the Value of its Plants, and Achieving Market-Based Valuation of its ECOM.*

13. Deleted.

14. EGS shall be subject to the unbundling requirements established in the pending unbundling rulemakings, Project Nos. 16536 and 19205, when those requirements become effective.

15. Deleted.

16. Deleted.

17. Deleted.

18. Deleted.

19. Deleted.

20. Deleted.

21. Deleted.

22. Deleted.

23. Deleted.

24. Deleted.

25. Deleted.

26. EGS shall withdraw its proposed EDR tariff and modify its EEDS tariff as recommended in the PFD.

27. EGS shall revise its NUS Rider so that it is clear that revenue erosion resulting from any service offered under this Rider will be borne by the Company, and not the ratepayers who will not take the service.

28. EGS shall revise its NUS Rider to clarify that incremental costs will be calculated in accordance with PURA § 36.007.

29. EGS shall file each NUS plan for Commission review and approval.

30. Deleted.

31. Deleted.

32. Deleted.

33. EGS shall address its acquisition of the Cajun 30% interest in River Bend in its next rate case if it has not filed the acquisition report in Docket No. 12104 by the date it files its next rate case.

34. On January 30 of each year, EGS shall file a report showing River Bend's three-year capacity factor, as well as the capacity factor, outages, and purchased power occurring each month during the prior calendar year.

35. In its next rate case, EGS shall file a comprehensive calculation, consistent with that proposed by General Counsel in this docket, to present its tax attributes disregarding the effects of the abeyed River Bend Plant and Louisiana Commission orders. In addition, EGS shall also file a comprehensive calculation in its next rate case to allow calculation of a consolidated tax savings in conformance with the methodology utilized in *CPL*, Docket No. 14965.

36. Entergy Gulf States, Inc.'s Correction to the Transcript for the October 7, 1997 Post-Hearing Conference, which requests that page 31, line 1, of the transcript which reads "was intended" be corrected to read "was not intended" is granted. No party filed objections to this request and no ruling was made by the ALJs.

37. The current tariff-based Interruptible Service shall be eliminated on the third anniversary of the effective date of this Order.

38. Because the Commission is freezing the IS customers' demand and energy charges at current levels, and not reducing those charges proportionately to the firm base rate reductions, the IS customers shall only be subject to the fuel surcharge, and that surcharge shall be spread out over twelve months commencing with the effective date of this Order. The IS customers shall not be subject to the AOD and the "actual taxes" surcharges otherwise applicable in this docket.

39. In its compliance filing in this docket, EGS shall revise the rate design for the LPS and HLFS classes to ensure that the cross-over point at which the rates of these two classes equal is approximately the 80% load factor point.

40. EGS is granted a good cause exception to P.U.C. SUBST. R. 23.23(b)(3) in that it is not required to file a fuel reconciliation in its November, 1998 rate case. The Company shall file a fuel reconciliation for the period July 1, 1996 through June 30, 1999 after the close of that period in accordance with P.U.C. SUBST. R. 23.23(b)(3).

41. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted herein, are hereby denied for want of merit.

SIGNED AT AUSTIN, TEXAS the ______ day of October 1998.

PUBLIC UTILITY COMMISSION OF TEXAS

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PAT WOOD, III, CHAIRMAN

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JUDY WALSH, COMMISSIONER

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PUC DOCKET NO. 39896
SOAH DOCKET NO. 473-12-2979

APPLICATION OF ENTERGY TEXAS, INC. FOR AUTHORITY TO CHANGE RATES, RECONCILE FUEL COSTS, AND OBTAIN DEFERRED ACCOUNTING TREATMENT	§ § § § §	**PUBLIC UTILITY COMMISSION** **OF TEXAS**

ORDER ON REHEARING

This Order addresses the application of Entergy Texas, Inc. for authority to change rates, reconcile fuel costs, and defer costs for the transition to the Midwest Independent System Operator (MISO). In its application, Entergy requested approval of an increase in annual base-rate revenues of approximately $111.8 million (later lowered to $104.8 million), proposed tariff schedules, including new riders to recover costs related to purchased-power capacity and renewable-energy credit requirements, requested final reconciliation of its fuel costs, and requested waivers to the rate-filing package requirements.

On July 6, 2012, the State Office of Administrative Hearings (SOAH) administrative law judges (ALJs) issued a proposal for decision in which they recommended an overall rate increase for Entergy of $28.3 million resulting in a total revenue requirement of approximately $781 million. The ALJs also recommended approving total fuel costs of approximately $1.3 billion. The ALJs did not recommend approving the renewable-energy credit rider and the Commission earlier removed the purchased-power capacity rider as an issue to be addressed in this docket.[1] On August 8, 2012, the ALJs filed corrections to the proposal for decision based on the exceptions and replies of the parties.[2] Except as discussed in this Order, the Commission adopts the proposal for decision, as corrected, including findings of fact and conclusions of law.

Parties filed motions for rehearing on September 25 and October 4, 2012 and filed replies to the motions for rehearing on October 15, 2012. The Commission considered the motions for

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[1] Supplemental Preliminary Order at 2, 3 (Jan. 19, 2012).

[2] Letter from SOAH judges to PUC (Aug. 8, 2012).

rehearing at the October 25, 2012 open meeting. The Commission granted Commission Staff's motion for rehearing that requested technical corrections to reflect the rates that resulted from the Commission Staff number-running memo that was filed on August 28, 2012. The Commission modifies findings of fact 205, 206, 208, and 210 as requested by Commission Staff and attaches Commission schedules I through V to reflects its decisions. The Commission granted the Department of Energy's motion for rehearing requesting that finding of fact 198 be modified to reflect the applicable off-season for the schedulable intermittent pumping service. Finding of fact 198 is modified to reflect that the off-season is October through May. In its motion for rehearing, Entergy noted that findings of fact 17B and 17D should be modified to more accurately reflect the procedural history. The Commission modifies findings of fact 17B and 17D to state that Entergy agreed to extend time to provide the Commission sufficient time to consider the issues in this proceeding on two occasions—at the July 27 and August 30, 2012 open meetings.

I. Discussion

A. Prepaid Pension Asset Balance

Entergy included in rate base an approximately $56 million item named Unfunded Pension.[3] This amount represents the accumulated difference between the annual pension costs calculated in accordance with the Statement of Financial Accounting Standards (SFAS) No. 87 and the actual contributions made by Entergy to the pension fund—Entergy contributed nearly $56 million more to its pension fund than the minimum required by SFAS No. 87.[4]

In Docket No. 33309, the Commission allowed a pension prepayment asset, excluding the portion of the asset that is capitalized to construction work in progress (CWIP), less accrued deferred federal income taxes (ADFIT) to be included in rate base.[5] For the excluded portion, the Commission allowed the accrual of an allowance for funds used during construction

[3] Proposal for Decision at 23 (July 6, 2012) (PFD).

[4] PFD at 23-24.

[5] *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 33309, Order on Rehearing (March 4, 2008).

(AFUDC).[6] The ALJs concluded that this approach was sound and should be followed in this case.[7] Thus, the ALJs recommended that the CWIP-related portion of Entergy's prepaid pension asset ($25,311,236) should be excluded from the asset and should accrue AFUDC.[8] However, the ALJs did not address ADFIT.

The Commission agrees that the CWIP-related portion of Entergy's pension asset should be excluded from the asset and that this excluded portion should accrue AFUDC. However, the Commission also finds that the impact of this exclusion on Entergy's ADFIT should be reflected. When items are excluded from rate base, the related ADFIT should also be excluded. The adjusted ADFIT for the prepaid pension asset remaining in Entergy's rate base should be reduced by $8,858,933, the deferred taxes related to the excluded $25 million. The Commission adds new finding of fact 28A to reflect this modification to Entergy's ADFIT.

B. FIN 48

The Financial Accounting Standards Board's Interpretation No. 48 (FIN 48) prescribes the way in which a company must analyze, quantify, and disclose the potential consequences of tax positions that the company has taken that are legally uncertain. Entergy reported that its uncertain tax positions totaled $5,916,461. FIN 48 requires that this amount be recorded on Entergy's balance sheet as a tax liability. Entergy also reported that it made a cash deposit with the IRS in the amount of $1,294,683 associated with its FIN 48 liability.[9]

The ALJs concluded that Entergy's FIN 48 liability should be included in its ADFIT balance, but the amount of the cash deposit made by Entergy to the IRS attributable to Entergy's FIN 48 liability should not be included in Entergy's ADFIT balance. Accordingly, the ALJs recommended that $4,621,778 (Entergy's FIN 48 liability of $5,916,461 less the $1,294,683 cash deposit Entergy has already made with the IRS) be added to Entergy's ADFIT balance and thus

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[6] *Remand of Docket No. 33309 (Application of AEP Texas Central Company for Authority to Change Rates)*, Docket No. 38772, Order on Remand (Jan. 20, 2011).

[7] PFD at 26.

[8] *Id.* at 24-26.

[9] PFD at 26-27 (citing Rebuttal Testimony of Roberts, Entergy Ex. 64 at 6), 29 (citing Rebuttal Testimony of Roberts, Entergy Ex. 64 at 8).

be used to offset Entergy's rate base.[10] The ALJs did not recommend the addition of a deferred-tax-account rider because no party expressly advocated the addition of such a rider.[11]

The Commission adopts the proposal for decision regarding the adjustment to Entergy's ADFIT for the amount attributable to Entergy's FIN 48 liability. However, the Commission also follows its precedent regarding the creation of a deferred-tax-account tracker and modifies the proposal for decision on this point. In CenterPoint's Electric Delivery Company's last rate case, Docket No. 38339,[12] the Commission found that tax schedule UTP—on which companies must describe, list, and rank each uncertain tax position—would provide the IRS auditors sufficient information to quickly determine which uncertain tax positions are of a magnitude worth investigating and that an IRS audit would be more likely to occur on some uncertain tax positions. If an IRS audit of a FIN 48 uncertain tax position results in an unfavorable outcome, the utility would not be able to earn a return on the amount paid to the IRS until the next rate case.

Accordingly, the Commission authorizes Entergy to establish a rider to track unfavorable FIN-48 rulings by the IRS. The rider will also allow Entergy to recover on a *prospective* basis an after-tax return of 8.27% on the amounts paid to the IRS that result from an unfavorable FIN-48 unfavorable-tax-position audit. The return will be applied prospectively to FIN-48 amounts disallowed by an IRS audit after such amounts are actually paid to the federal government. If Entergy subsequently prevails in an appeal of an unfavorable FIN-48 unfavorable-tax-position decision by the IRS, then any amounts collected under rider related to that overturned decision shall be credited back to ratepayers.

The Commission adds new finding of fact 40A and deletes finding of fact 41 consistent with its decision to authorize the deferred-tax-account tracker.

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[10] PFD at 29.

[11] *Id*. at 29.

[12] *Application of CenterPoint Electric Delivery Company, LLC for Authority to Change Rates*, Docket No. 38339, Order on Rehearing at 3-4 (June 23, 2011).

C. Capitalized Incentive Compensation

Entergy capitalized into plant-in-service accounts some of the incentive payments made to employees and sought to include those amounts in rate base. The ALJs determined that Entergy should not be able to recover its financially based incentive-compensation costs.[13] Therefore, the portion of Entergy's incentive-compensation costs capitalized during the period July 1, 2009 through June 30, 2010 that were financially based was excluded from Entergy's rate base. The ALJs also determined that the actual percentages should be used to determine the amount that is financially based.[14]

In discussing Entergy's incentive compensation as a component of operating expenses, the ALJs adopted the method advocated by Texas Industrial Energy Consumers (TIEC) for calculating the amount of the financially based incentive costs. This method uses the actual percentage reductions applicable to each of the annual incentive programs that included a component of financially-based costs.[15]

In its exceptions regarding capitalized incentive compensation, Entergy advocated for the use of TIEC's methodology to also calculate the amount of capitalized incentive compensation that is financially based. Entergy also noted that the amount of the disallowance reflected in the schedules, $1,333,352, was calculated using a disallowance factor that included incentive compensation tied to cost-control measures, which the ALJs found to be recoverable in the operating-cost incentive-compensation calculation.[16] When the TIEC methodology is applied to the capitalized incentive-compensation costs in rate base, the net result under TIEC's methodology is that only $335,752.96 should be disallowed from capital costs.[17]

The Commission agrees that capitalized incentive compensation that is financially based should be excluded from rate base and that the exclusion only applies to incentive costs that Entergy capitalized during the period from July 1, 2009 through June 30, 2010. However, the Commission finds that a consistent methodology should be used to calculate the amount to be

[13] PFD at 171.

[14] *Id.* at 72.

[15] *Id.* at 174; *see also* Entergy's Exceptions to the Proposal for Decision at 25-26 (July 23, 2012).

[16] Entergy's Exceptions to the Proposal for Decision at 25-26.

[17] *Id.* at 25-26.

excluded and therefore that TIEC's methodology should also be used for calculating the amount of capitalized financially based incentive-compensation costs that should be excluded from rate base. Accordingly, the total amount of capitalized incentive-compensation costs that should be disallowed from rate base is $335,752.96. Finding of fact 61 is modified to reflect this determination.

As noted by Commission Staff, this disallowance to plant-in-service alters the expense for ad valorem taxes. Accounting for this disallowance, the appropriate expense amount for ad valorem taxes is $24,921,022,[18] an adjustment of $1,222,106 to Entergy's test year amount. Finding of fact 151 is modified to reflect this adjustment to property taxes.

D. Rate of Return and Cost of Capital

The ALJs found the proper range of an acceptable return on equity for Entergy would be from 9.3 percent to 10.0 percent.[19] The mid-point of the range is 9.65 percent. The ALJs found that the effect of unsettled economic conditions facing utilities on the appropriate return on equity should be taken into account and that the effect would be to move the ultimate return on equity towards the upper limits of the range that was determined to be reasonable.[20] The ALJs found that the reasonable adjustment would be 15 basis points, moving the reasonable return on equity to 9.80 percent.[21]

The Commission must establish a reasonable return for a utility and must consider applicable factors.[22] The Commission disagrees with the ALJs that a utility's return on equity should be determined using an adder to reflect unsettled economic conditions facing utilities. The Commission agrees with the ALJs, however, that a return on equity of 9.80 percent will allow Entergy a reasonable opportunity to earn a reasonable return on its invested capital, but finds this rate appropriate independent of the 15-point adder recommended by the ALJs. A return on equity of 9.80 percent is within the range of an acceptable return on equity found by

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[18] Commission Number-Run Memorandum at 2 (Aug. 28, 2012).

[19] PFD at 94.

[20] *Id.*

[21] *Id.* at 94.

[22] PURA §§ 36.051, .052.

the ALJs. Accordingly, the Commission adds new finding of fact 65A to reflect the Commission's decision on this point.

E. Purchased-Power Capacity Expense

The ALJs rejected Entergy's request to recover $31 million more in purchased-power capacity costs than its actual test-year expenses because Entergy had failed to prove that the adjustment was known and measurable,[23] and because the request violated the matching principle.[24] Consequently, the ALJs recommended that Entergy's test-year expenses of $245,432,884 be used to set rates in this docket.[25]

Entergy pointed to an additional $533,002 of purchased-power capacity expenses that were properly included in Entergy's rate-filing package, but not provided for in the proposal for decision.[26] The Commission finds that an additional $533,002 ($6,132 for test-year expenses for Southwest Power Pool fees, $654,082 for Toledo Bend hydro fixed-charges, and -$127,212 for an Entergy intra-system billing adjustment that were all recorded in FERC account 555) of purchased-power capacity costs were incurred during the test-year and should be added to the purchased-power capacity costs in Entergy's revenue requirement. The Commission modifies findings of fact 72 and 86 to reflect the inclusion of the additional $533,002 of test-year purchased-power capacity costs, increasing the total amount to $245,965,886.

F. Labor Costs – Incentive Compensation

The ALJs found that $6,196,037, representing Entergy's financially-based incentives paid in the test-year, should be removed from Entergy's O&M expenses.[27] The ALJs agreed with Commission Staff and Cities that an additional reduction should be made to account for the FICA taxes that Entergy would have paid for those costs,[28] but did not include this reduction in a finding of fact.

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[23] PFD at 108-09.

[24] *Id.* at 109.

[25] *Id.*

[26] Entergy's Exceptions to the Proposal for Decision at 51.

[27] PFD at 175.

[28] *Id.* at 175-76.

The Commission agrees with the ALJs, but modifies finding of fact 133 to specifically include the decision that an additional reduction should be made to account for the FICA taxes Entergy would have paid on the disallowed financially-based incentive compensation. The Commission notes that this reduction for FICA taxes is reflected in the schedules attached to this Order.[29]

G. Affiliate Transactions

OPUC argued that Entergy's sales and marketing expenses exclusively benefit the larger commercial and industrial customers, but the majority of the sales, marketing, and customer service expenses are allocated to the operating companies based on customer counts. Therefore, the majority of these expenses are allocated to residential and small business customers. OPUC argued that it is inappropriate for residential and small business customers to pay for these expenses.[30] The ALJs did not adopt OPUC's position on this issue.

The Commission agrees with OPUC and reverses the proposal for decision regarding allocation of Entergy's sales and marketing expense and finds that $2.086 million of sales and marketing expense should be reallocated using direct assignment. The Commission has previously expressed its preference for direct assignment of affiliate expenses.[31] The Commission finds that the following amounts should be allocated based on a total-number-of-customers basis: (1) $46,490 for Project E10PCR56224 – Sales and Marketing – EGSI Texas; (2) $17,013 for Project F3PCD10049 – Regulated Retail Systems O&M; and (3) $30,167 for Project F3PPMMALI2 – Middle Market Mkt. Development. The remainder, $1,992,475, should be assigned to (1) General Service, (2) Large General Service and (3) Large Industrial Power Service.[32] The reallocation has the effect of increasing the revenue requirement allocated to the large business class customers and reduces the revenue requirement for small business and residential customers. New finding of fact 164A is added to reflect the proper allocation of these affiliate transactions.

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[29] *See* Commission Number Run-Memorandum at 3 (Aug. 28, 2012).

[30] Direct Testimony of Carol Szerszen, OPUC Ex. 1 at 44-45.

[31] *Application of Central Power and Light Company for Authority to Change Rates*, Docket No. 14965, Second Order on Rehearing at 87, COL 29 (Oct. 16, 1997).

[32] Direct Testimony of Carol Szerszen, OPUC Ex. 1 at Schedule CAS-7.

H. Fuel Reconciliation

Entergy proposed to allocate costs for the fuel reconciliation to customers using a line-loss study performed in 1997. Entergy conducted a line-loss study for the year ending December 31, 2010, which falls in the middle of the two year fuel reconciliation period—July 2009 through June 2011—and therefore reflects the actual line losses experienced by the customer classes during the reconciliation period. Cities argued that the allocation of fuel costs incurred over the reconciliation period should reflect the current line-loss study performed by Entergy for this case and recommended approval on a going-forward basis. Fuel factors under P.U.C. SUBST. R. 25.237(a)(3) are temporary rates subject to revision in a reconciliation proceeding described in P.U.C. SUBST. R. 25.236. P.U.C. SUBST. R. 25.236(d)(2) defines the scope of a fuel reconciliation proceeding to include any issue related to the reasonableness of a utility's fuel expenses and whether the utility has over- or under-recovered its reasonable fuel expenses.[33] Cities calculated a $3,981,271 reduction to the Texas retail fuel expenses incurred over the reconciliation period using the current line-losses. The ALJs rejected Cities' proposed adjustment finding that the P.U.C. SUBST. R. 25.237(c)(2)(B) requires the use of Commission-approved line losses that were in effect at the time fuel costs were billed to customers in a fuel reconciliation.[34]

The Commission agrees with Cities and reverses the proposal for decision regarding which line-loss factors should be used in Entergy's fuel reconciliation. Entergy used the 2010 study line-loss calculations to calculate the demand- and energy-related allocations in its cost of service analysis supporting its requested base rates. These same currently available line-loss factors should have been utilized in Entergy's fuel reconciliation. The Commission finds that Entergy's 2010 line-loss factors should be used to calculate Entergy's fuel reconciliation over-recovery. As a result, Entergy's fuel reconciliation over-recovery should be reduced by $3,981,271. Finding of fact 246A and conclusions of law 19A and 19B are added to reflect the Commission's finding that the 2010 line-loss factors be used to reconcile Entergy's fuel costs.

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[33] Cities' Exceptions to the Proposal for Decision at 20-21 (July 23, 2012).

[34] PFD at 327-328.

I. MISO Transition Expenses

During the Commission's consideration of the proposal for decision, the parties that contested the amount of Entergy's MISO transition expenses and how the transition expenses should be accounted for reached announced on the record that they had reached an agreement on these issues.[35] Those parties agreed that the MISO transition expenses would not be deferred and that Entergy's base rates should include $1.6 million for MISO transition expense.[36] The Commission adopts the agreement of the parties and accordingly modifies finding of fact 251 and deletes finding of fact 252.

J. Purchased-Power Capacity Cost Baseline

The Commission modified the amount of purchased-power capacity expense in the test-year to be $245,965,886 (see section E above). Finding of fact 255 is modified to reflect the change to the proper test-year purchased-power capacity expense.

K. Other Issues

New findings of fact 17A, 17B, 17C, 17D, and 17 E are added to reflect procedural aspects of the case after issuance of the proposal for decision.

In addition, to reflect corrections recommended by the ALJs, findings of fact 116, 123, 192, 194, and 202 are modified; and new finding of fact 182A is added.

The Commission adopts the following findings of fact and conclusions of law:

II. Findings of Fact

Procedural History

1. Entergy Texas, Inc. (ETI or the company) is an investor-owned electric utility with a retail service area located in southeastern Texas.

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[35] Open Meeting Tr. at 138 (Aug. 17, 2012).

[36] *Id.*

2. ETI serves retail and wholesale electric customers in Texas. As of June 30, 2011, ETI served approximately 412,000 Texas retail customers. The Federal Energy Regulatory Commission (FERC) regulates ETI's wholesale electric operations.

3. On November 28, 2011, ETI filed an application requesting approval of: (1) a proposed increase in annual base rate revenues of approximately $111.8 million over adjusted test-year revenues; (2) a set of proposed tariff schedules presented in the Electric Utility Rate Filing Package for Generating Utilities (RFP) accompanying ETI's application and including new riders for recovery of costs related to purchased-power capacity and renewable energy credit requirements; (3) a request for final reconciliation of ETI's fuel and purchased-power costs for the reconciliation period from July 1, 2009 to June 30, 2011; and (4) certain waivers to the instructions in RFP Schedule V accompanying ETI's application.

4. The 12-month test-year employed in ETI's filing ended on June 30, 2011 (test-year).

5. ETI provided notice by publication for four consecutive weeks before the effective date of the proposed rate change in newspapers having general circulation in each county of ETI's Texas service territory. ETI also mailed notice of its proposed rate change to all of its customers. Additionally, ETI timely served notice of its statement of intent to change rates on all municipalities retaining original jurisdiction over its rates and services.

6. The following parties were granted intervenor status in this docket: Office of Public Utility Counsel; the cities of Anahuac, Beaumont, Bridge City, Cleveland, Conroe, Dayton, Groves, Houston, Huntsville, Montgomery, Navasota, Nederland, Oak Ridge North, Orange, Pine Forest, Rose City, Pinehurst, Port Arthur, Port Neches, Shenandoah, Silsbee, Sour Lake, Splendora, Vidor, and West Orange (Cities), the Kroger Co. (Kroger); State Agencies; Texas Industrial Energy Consumers; East Texas Electric Cooperative, Inc.; the United States Department of Energy (DOE); and Wal-Mart Stores Texas, LLC, and Sam's East, Inc. (Wal-Mart). The Staff (Staff) of the Public Utility Commission of Texas (Commission or PUC) was also a participant in this docket.

7. On November 29, 2011, the Commission referred this case to the State Office of Administrative Hearings (SOAH).

8. On December 7, 2011, the Commission issued its order requesting briefing on threshold legal/policy issues.

9. On December 19, 2011, the Commission issued its Preliminary Order, identifying 31 issues to be addressed in this proceeding.

10. On December 20, 2011, the Administrative Law Judges (ALJs) issued SOAH Order No. 2, which approved an agreement among the parties to establish a June 30, 2012 effective date for the company's new rates resulting from this case pursuant to certain agreed language and consolidate *Application of Entergy Texas, Inc. for Authority to Defer Expenses Related to its Proposed Transition to Membership in the Midwest Independent System Operator*, Docket No. 39741 (pending) into this proceeding. Although it did not agree, Staff did not oppose the consolidation.

11. On January 13, 2012, the ALJs issued SOAH Order No. 4 granting the motions for admission pro hac vice filed by Kurt J. Boehm and Jody M. Kyler to appear and participate as counsel for Kroger and the motion for admission *pro hac vice* filed by Rick D. Chamberlain to appear and participate as counsel for Wal-Mart.

12. On January 19, 2012, the Commission issued a supplemental preliminary order identifying two additional issues to be addressed in this case and concluding that the company's proposed purchased-power capacity rider should not be addressed in this case and that such costs should be recovered through base rates.

13. ETI timely filed with the Commission petitions for review of the rate ordinances of the municipalities exercising original jurisdiction within its service territory. All such appeals were consolidated for determination in this proceeding.

14. On April 4, 2012, the ALJs issued SOAH Order No. 13 severing rate case expense issues into *Application of Entergy Texas, Inc. for Rate Case Expenses Severed from PUC Docket No. 39896*, Docket No. 40295 (pending).

15. On April 13, 2012, ETI adjusted its request for a proposed increase in annual base rate revenues to approximately $104.8 million over adjusted test-year revenues.

16. The hearing on the merits commenced on April 24 and concluded on May 4, 2012.

17. Initial post-hearing briefs were filed on May 18 and reply briefs were filed on May 30, 2012.

17A. On August 7, 2012, the SOAH ALJs filed a letter with the Commission recommending changes to the PFD.

17B At the July 27, 2012 open meeting, ETI agreed to extend time to August 31, 2012 to provide the Commission sufficient time to consider the issues in this proceeding.

17C. The Commission considered the proposal for decision at the August 17, 2012 and August 30, 2012 open meetings.

17D. At the August 30, 2012 open meeting, ETI agreed to extend time to September 14, 2012 to provide the Commission sufficient time to consider the issues in this proceeding.

17E. At the August 17, 2012 open meeting, parties announced on the record a settlement of the amount of costs for the transition to MISO.

Rate Base

18. Capital additions that were closed to ETI's plant-in-service between July 1, 2009 and June 30, 2011, are used and useful in providing service to the public and were prudently incurred.

19. ETI's proposed Hurricane Rita regulatory asset was an issue resolved by the black-box settlement in *Application of Entergy Texas, Inc. for Authority to Change Rates and Reconcile Fuel Costs*, Docket No. 37744 (Dec. 13, 2010).

20. Accrual of carrying charges on the Hurricane Rita regulatory asset should have ceased when Docket No. 37744 concluded because the asset would have then begun earning a rate of return as part of rate base.

21. The appropriate calculation of the Hurricane Rita regulatory asset should begin with the amount claimed by ETI in Docket No. 37744, less amortization accruals to the end of the test-year in the present case, and less the amount of additional insurance proceeds received by ETI after the conclusion of Docket No. 37744.

22. A Test-Year-end balance of $15,175,563 for the Hurricane Rita regulatory asset should remain in rate base, applying a five-year amortization rate beginning August 15, 2010.

23. The Hurricane Rita regulatory asset should not be moved to the storm damage insurance reserve.

24. The company requested in rate base its prepaid pension assets balance of $55,973,545, which represents the accumulated difference between the Statement of Financial Accounting Standards (SFAS) No. 87 calculated pension costs each year and the actual contributions made by the company to the pension fund.

25. The prepaid pension assets balance includes $25,311,236 capitalized to construction work in progress (CWIP).

26. It is not necessary to the financial integrity of ETI to include CWIP in rate base, and there was insufficient evidence showing that major projects under construction were efficiently and prudently managed.

27. The portion of the prepaid pension assets balance that is capitalized to CWIP should not be included in ETI's rate base.

28. The remainder of the prepaid pension assets balance should be included in ETI's rate base.

28A. When items are excluded from rate base, the related ADFIT should also be excluded. The amount of ADFIT associated with the $25 million capitalized to CWIP and excluded from rate base is $8,858,933. The adjusted ADFIT for the prepaid pension asset remaining in Entergy's rate base should be reduced by $8,858,933.

29. ETI should be permitted to accrue an allowance for funds used during construction on the portion of ETI's Prepaid Pension Assets Balance capitalized to CWIP.

30. The Financial Accounting Standard Board (FASB) Financial Interpretation No. 48 (FIN 48), "Accounting for Uncertainty in Income Taxes," requires ETI to identify each of its uncertain tax positions by evaluating the tax position on its technical merits to determine whether the position, and the corresponding deduction, is more-likely-than-not to be sustained by the Internal Revenue Service (IRS) if audited.

31. FIN 48 requires ETI to remove the amount of its uncertain tax positions from its Accumulated Deferred Federal Income Tax (ADFIT) balance for financial reporting

purposes and record it as a potential liability with interest to better reflect the company's financial condition.

32. At test-year-end, ETI had $5,916,461 in FIN 48 liabilities, meaning ETI has, thus far, avoided paying to the IRS $5,916,461 in tax dollars (the FIN 48 liability) in reliance upon tax positions that the company believes will not prevail in the event the positions are challenged, via an audit, by the IRS.

33. ETI has deposited $1,294,683 with the IRS in connection with the FIN 48 liability.

34. The IRS may never audit ETI as to its uncertain tax positions creating the FIN 48 liability.

35. Even if ETI is audited, ETI might prevail on its uncertain tax positions.

36. ETI may never have to pay the IRS the FIN 48 liability.

37. Other than the amount of its deposit with the IRS, ETI has current use of the FIN 48 liability funds.

38. Until actually paid to the IRS, the FIN 48 liability represents cost-free capital and should be deducted from rate base.

39. The amount of $4,621,778 (representing ETI's full FIN 48 liability of $5,916,461 less the $1,294,683 cash deposit ETI has made with the IRS for the FIN 48 liability) should be added to ETI's ADFIT and thus be used to reduce ETI's rate base.

40. ETI's application and proposed tariffs do not include a request for a tracking mechanism or rider to collect a return on the FIN 48 liability.

40A. It is appropriate for ETI to create a deferred-tax-account tracker in the form of a rider to recover on a prospective basis an after–tax return of 8.27% on the amounts paid to the IRS that result from an unfavorable FIN 48 audit. The rider will track unfavorable FIN 48 rulings and the return will be applied prospectively to FIN 48 amounts disallowed by an IRS audit after such amounts are actually paid to the federal government. If ETI prevails in an appeal of a FIN 48 decision, then any amounts collected under the rider related to that decision should be credited back to ratepayers.

41. Deleted.

42. Investor-owned electric utilities may include a reasonable allowance for cash working capital in rate base as determined by a lead-lag study conducted in accordance with the Commission's rules.

43. Cash working capital represents the amount of working capital, not specifically addressed in other rate base items, that is necessary to fund the gap between the time expenditures are made and the time corresponding revenues are received.

44. The lead-lag study conducted by ETI considered the actual operations of ETI, adjusted for known and measurable changes, and is consistent with P.U.C. SUBST. R. 25.231(c)(2)(B)(iii).

45. It is reasonable to establish ETI's cash working capital requirement based on ETI's lead-lag study as updated in Jay Joyce's rebuttal testimony and on the cost of service approved for ETI in this case.

46. As a result of the black-box settlements in *Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs*, Docket No. 34800 (Nov. 7, 2008) and Docket No. 37744, the Commission did not approve ETI's storm damage expenses since 1996 and its storm damage reserve balance.

47. ETI established a prima facie case concerning the prudence of its storm damage expenses incurred since 1996.

48. Adjustments to the storm damage reserve balance proposed by intervenors should be denied.

49. The Hurricane Rita regulatory asset should not be moved to the storm damage insurance reserve.

50. ETI's appropriate Test-Year-end storm reserve balance was negative $59,799,744.

51. The amount of $9,846,037, representing the value of the average coal inventory maintained at ETI's coal-burning facilities, is reasonable, necessary, and should be included in rate base.

52. The Spindletop gas storage facility (Spindletop facility) is used and useful in providing reliable and flexible natural gas supplies to ETI's Sabine Station and Lewis Creek generating plants.

53. The Spindletop facility is critical to the economic, reliable operation of the Sabine Station and Lewis Creek generating plants due to their geographic location in the far western region of the Entergy system.

54. It is reasonable and appropriate to include ETI's share of the costs to operate the Spindletop facility in rate base.

55. Staff recommended updating ETI's balance amounts for short-term assets to the 13-month period ending December 2011, which was the most recent information available. Staff's proposed adjustments should be incorporated into the calculation of ETI's rate base.

56. The following short-term asset amounts should be included in rate base: prepayments at \$8,134,351; materials and supplies at \$29,285,421; and fuel inventory at \$52,693,485.

57. The amount of \$1,127,778, representing costs incurred by ETI when it acquired the Spindletop facility, represent actual costs incurred to process and close the acquisition, not mere mark-up costs.

58. ETI's \$1,127,778 in capitalized acquisition costs should be included in rate base because ETI incurred these costs in conjunction with the purchase of a viable asset that benefits its retail customers.

59. In its application, ETI capitalized into plant in service accounts some of the incentive payments ETI made to its employees. ETI seeks to include those amounts in rate base.

60. A portion of those capitalized incentive accounts represent payments made by ETI for incentive compensation tied to financial goals.

61. The portion of ETI's incentive payments that are capitalized and that are financially-based should be excluded from ETI's rate base because the benefits of such payments inure most immediately and predominantly to ETI's shareholders, rather than its electric

customers. ETI's capitalized incentive compensation that is financially based is $335,752.96 and should be removed for rate base.

62. The test-year for ETI's prior ratemaking proceeding ended on June 30, 2009, and the reasonableness of ETI's capital costs (including capitalized incentive compensation) for that prior period was dealt with by the Commission in that proceeding and is not at issue in this proceeding.

63. In this proceeding, ETI's capitalized incentive compensation that is financially-based should be excluded from rate base, but only for incentive costs that ETI capitalized during the period from July 1, 2009 (the end of the prior test-year) through June 30, 2010 (the commencement of the current test-year).

Rate of Return and Cost of Capital

64. A return on common equity (ROE) of 9.80 percent will allow ETI a reasonable opportunity to earn a reasonable return on its invested capital.

65. The results of the discounted cash flow model and risk premium approach support a ROE of 9.80 percent.

65A. It is not appropriate to add 15 points to the ROE due to unsettled economic conditions facing utilities.

66. A 9.80 percent ROE is consistent with ETI's business and regulatory risk.

67. ETI's proposed 6.74 percent embedded cost of debt is reasonable.

68. The appropriate capital structure for ETI is 50.08 percent long-term debt and 49.92 percent common equity.

69. A capital structure composed of 50.08 percent debt and 49.92 percent equity is reasonable in light of ETI's business and regulatory risks.

70. A capital structure composed of 50.08 percent debt and 49.92 percent equity will help ETI attract capital from investors.

71. ETI's overall rate of return should be set as follows:

COMPONENT	CAPITAL STRUCTURE	COST OF CAPITAL	WEIGHTED AVG COST OF CAPITAL
LONG-TERM DEBT	50.08%	6.74%	3.38%
COMMON EQUITY	49.92%	9.80%	4.89%
TOTAL	100.00%		8.27%

Operating Expenses

72. ETI's test-year purchased capacity expenses were $245,965,886.

73. ETI requested an upward adjustment of $30,809,355 as a post-test-year adjustment to its purchased capacity costs. This request was based on ETI's projections of its purchased capacity expenses during a period beginning June 1, 2012 and ending May 31, 2013 (the rate-year).

74. ETI's purchased capacity expense projections were based on estimates of rate-year expenses for: (a) reserve equalization payments under Schedule MSS-1; (b) payments under third-party capacity contracts; and (c) payments under affiliate contracts.

75. ETI's projection of its rate-year reserve equalization payments under Schedule MSS-1 is based on numerous assumptions, including load growths for ETI and its affiliates, future capacity contracts for ETI and its affiliates, and future values of the generation assets of ETI and its affiliates.

76. There is substantial uncertainty with regard to ETI's projection of its rate-year reserve equalization payments under Schedule MSS-1.

77. ETI's projection of its rate-year third-party capacity contract payments includes numerous assumptions, one of which is that every single third-party supplier will perform at the maximum level under the contract, even though that assumption is inconsistent with ETI's historical experience.

78. There is substantial uncertainty with regard to ETI's projection of its rate-year third-party capacity-contract payments.

79. ETI's estimates of its rate-year purchases under affiliate contracts are based on a mathematical formula set out in Schedule MSS-4.

80. The MSS-4 formula for rate-year affiliate capacity payments reflects that these payments will be based on ratios and costs that cannot be determined until the month that the payments are to be made.

81. Over $11 million of ETI's affiliate transactions were based on a 2013 contract (the EAI WBL Contract) that was not signed until April 11, 2012.

82. There is uncertainty about whether the EAI WBL Contract will ever go into effect.

83. ETI projects purchasing over 300 megawatts (MW) more in purchased capacity in the rate-year than it purchased in the test-year.

84. ETI experienced substantial load growth in the two years before the test-year, and it continues to project similar load growth in the future.

85. ETI did not meet its burden of proof to demonstrate that a known and measurable adjustment of $30,809,355 should be made to its test-year purchased capacity expenses.

86. ETI's purchased capacity expense in this case should be based on the test-year level of $245,965,886.

87. ETI incurred $1,753,797 of transmission equalization expense during the test-year.

88. ETI proposed an upward adjustment of $8,942,785 for its transmission equalization expense. This request was based on ETI's projections of its transmission equalization expenses during the rate-year.

89. The transmission equalization expense that ETI will pay in the rate-year will depend on future costs and loads for each of the Entergy operating companies.

90. ETI's projection of its rate-year transmission equalization expenses is uncertain and speculative because it depends on a number of variables, including future transmission investments, deferred taxes, depreciation reserves, costs of capital, tax rates, operating expenses, and loads of each of the Entergy operating companies.

91. ETI seeks increased transmission equalization expenses for transmission projects that are not currently used and useful in providing electric service. ETI's post-test-year adjustment is based on the assumption that certain planned transmission projects will go

into service after the test-year. At the close of the hearing, none of the planned transmission projects had been fully completed and some were still in the planning phase.

92. It is not reasonable for ETI to charge its retail ratepayers for transmission equalization expenses related to projects that are not yet in-service.

93. ETI's request for a post-test-year adjustment of $8,942,785 for rate-year transmission equalization expenses should be denied because those expenses are not known and measurable. ETI's post-test-year adjustment does not with reasonable certainty reflect what ETI's transmission equalization expense will be when rates are in effect.

94. ETI's transmission equalization expense in this case should be based on the test-year level of $1,753,797.

95. P.U.C. SUBST. R. 25.231(c)(2)(ii) states that the reserve for depreciation is the accumulation of recognized allocations of original cost, representing the recovery of initial investment over the estimated useful life of the asset.

96. Except in the case of the amortization of the general plant deficiency, the use of the remaining life depreciation method to recover differences between theoretical and actual depreciation reserves is the most appropriate method and should be continued.

97. It is reasonable for ETI to calculate depreciation reserve allocations on a straight-line basis over the remaining, expected useful life of the item or facility.

98. Except as described below, the service lives and net salvage rates proposed by the company are reasonable, and these service lives and net salvage rates should be used in calculating depreciation rates for the company's production, transmission, distribution, and general plant assets.

99. A 60-year life for Sabine Units 4 and 5 is reasonable for purposes of establishing production plant depreciation rates.

100. The retirement (actuarial) rate method, rather than the interim retirement method, should be used in the development of production plant depreciation rates.

101. Production plant net salvage is reasonably based on the negative five percent net salvage in existing rates.

102. The net salvage rate of negative 10 percent for ETI's transmission structures and improvements (FERC Account 352) is the most reasonable of those proposed and should be adopted.

103. The net salvage rate of negative 20 percent for ETI's transmission station equipment (FERC Account 353) is the most reasonable of those proposed and should be adopted.

104. The net salvage rate of negative five percent for ETI's transmission towers and fixtures (FERC Account 354) is the most reasonable of those proposed and should be adopted.

105. The net salvage rate of negative 30 percent for ETI's transmission poles and fixtures (FERC Account 355) is the most reasonable of those proposed and should be adopted.

106. The net salvage rate of negative 30 percent for ETI's transmission overhead conductors and devices (FERC Account 356) is the most reasonable of those proposed and should be adopted.

107. A service life of 65 years and a dispersion curve of R3 for ETI's distribution structures and improvements (FERC Account 361) are the most reasonable of those proposed and should be approved.

108. A service life of 40 years and a dispersion curve of R1 for ETI's distribution poles, towers, and fixtures (FERC Account 364) are the most reasonable of those proposed and should be approved.

109. A service life of 39 years and a dispersion curve of R0.5 for ETI's distribution overhead conductors and devices (FERC Account 365) are the most reasonable of those proposed and should be approved.

110. A service life of 35 years and a dispersion curve of R1.5 for ETI's distribution underground conductors and devices (FERC Account 367) are the most reasonable of those proposed and should be approved.

111. A service life of 33 years and a dispersion curve of L0.5 for ETI's distribution line transformers (FERC Account 368) are the most reasonable of those proposed and should be approved.

112. A service life of 26 years and a dispersion curve of L4 for ETI's distribution overhead service (FERC Account 369.1) are the most reasonable of those proposed and should be approved.

113. The net salvage rate of negative five percent for ETI's distribution structures and improvements (FERC Account 361) is the most reasonable of those proposed and should be adopted.

114. The net salvage rate of negative 10 percent for ETI's distribution station equipment (FERC Account 362) is the most reasonable of those proposed and should be adopted.

115. The net salvage rate of negative seven percent for ETI's distribution overhead conductors and devices (FERC Account 365) is the most reasonable of those proposed and should be adopted.

116. The net salvage rate of positive five percent for ETI's distribution line transformers (FERC Account 368) is the most reasonable of those proposed and should be adopted.

117. The net salvage rate of negative 10 percent for ETI's distribution overhead services (FERC Account 369.1) is the most reasonable of those proposed and should be adopted.

118. The net salvage rate of negative 10 percent for ETI's distribution underground services (FERC Account 369.2) is the most reasonable of those proposed and should be adopted.

119. A service life of 45 years and a dispersion curve of R2 for ETI's general structures and improvements (FERC Account 390) are the most reasonable of those proposed and should be approved.

120. The net salvage rate of negative 10 percent for ETI's general structures and improvements (FERC Account 390) is the most reasonable of those proposed and should be adopted.

121. It is reasonable to convert the $21.3 million deficit that has developed over time in the reserve for general plant accounts to General Plant Amortization.

122. A ten-year amortization of the deficit in the reserve for general plant accounts is reasonable and should be adopted.

123. FERC pronouncement AR-15 requires amortization over the same life as recommended based on standard life analysis. A standard life analysis determined that a five-year life was appropriate for general plant computer equipment (FERC Account 391.2). Therefore, a five year amortization for this account is reasonable and should be adopted.

124. ETI proposed adjustments to its test-year payroll costs to reflect: (a) changes to employee headcount levels at ETI and Entergy Services, Inc. (ESI); and (b) approved wage increases set to go into effect after the end of the test-year.

125. The proposed payroll adjustments are reasonable but should be updated to reflect the most recent available information on headcount levels as proposed by Commission Staff. In addition to adjusting payroll expense levels, the more recent headcount numbers should be used to adjust the level of payroll tax expense, benefits expense, and savings plan expense.

126. Staff has appropriately updated headcount levels to the most recent available data but errors made by Staff should be corrected. The corrections related to: (a) a double counting of three ETI and one ESI employee; (b) inadvertent use of the ETI benefits cost percentage in the calculation of ESI benefits costs; (c) an inappropriate reduction of savings plan costs when such costs were already included in the benefits percentage adjustments; and (d) corrections for full-time equivalents calculations. Staff's ETI headcount adjustment (AG-7) overstated operation and maintenance (O&M) payroll reduction by $224,217, and ESI headcount adjustment (AG-7) understated O&M payroll increase by $37,531.

127. ETI included $14,187,744 for incentive compensation expenses in its cost of service.

128. The compensation packages that ETI offers its employees include a base payroll amount, annual incentive programs, and long-term incentive programs. The majority of the compensation is for operational measures, but some is for financial measures.

129. Incentive compensation that is based on financial measures is of more immediate and predominant benefit to shareholders, whereas incentive compensation based on operational measures is of more immediate and predominant benefit to ratepayers.

130. Incentives to achieve operational measures are necessary and reasonable to provide utility services but those to achieve financial measures are not.

131. The $5,376,975 that was paid for long term incentive programs was tied to financial measures and, therefore, should not be included in ETI's cost of service.

132. Of the amounts that were paid pursuant to the Executive Annual Incentive Plan, $819,062 was tied to financial measures and, therefore, should be disallowed.

133. In total, the amount of incentive compensation that should be disallowed is $6,196,037 because it was related to financial measures that are not reasonable and necessary for the provision of electric service. An additional reduction should be made to account for the FICA taxes ETI would have paid on the disallowed financially based incentive compensation.

134. The amount of incentive compensation that should be included in the cost of service is $7,991,707.

135. To attract and retain highly qualified employees, the Entergy companies provide a total package of compensation and benefits that is equivalent in scope and cost with what other comparable companies within the utility business and other industries provide for their employees.

136. When using a benchmark analysis to compare companies' levels of compensation, it is reasonable to view the market level of compensation as a range rather than a precise, single point.

137. ETI's base pay levels are at market.

138. ETI's benefits plan levels are within a reasonable range of market levels.

139. ETI's level of compensation and benefits expense is reasonable and necessary.

140. ETI provides non-qualified supplemental executive retirement plans for highly compensated individuals such as key managerial employees and executives that, because of limitations imposed under the Internal Revenue Code, would otherwise not receive retirement benefits on their annual compensation over $245,000 per year.

141. ETI's non-qualified supplemental executive retirement plans are discretionary costs designed to attract, retain, and reward highly compensated employees whose interests are more closely aligned with those of the shareholders than the customers.

142. ETI's non-qualified executive retirement benefits in the amount of $2,114,931 are not reasonable or necessary to provide utility service to the public, not in the public interest, and should not be included in ETI's cost of service.

143. For the employee market in which ETI operates, most peer companies offer moving assistance. Such assistance is expected by employees, and ETI would be placed at a competitive disadvantage if it did not offer relocation expenses.

144. ETI's relocation expenses were reasonable and necessary.

145. The company's requested operating expenses should be reduced by $40,620 to reflect the removal of certain executive prerequisites proposed by Staff.

146. Staff properly adjusted the company's requested interest expense of $68,985 by removing $25,938 from FERC account 431 (using the interest rate of 0.12 percent for calendar year 2012), leaving a recommended interest expense of $43,047.

147. During the test-year, ETI's property tax expense equaled $23,708,829.

148. ETI requested an upward *pro forma* adjustment of $2,592,420, to account for the property tax expenses ETI estimates it will pay in the rate-year.

149. ETI's requested *pro forma* adjustment is not reasonable because it is based, in part, upon the prediction that ETI's property tax rate will be increased in 2012, a change that is speculative is not known and measurable.

150. Staff's recommendation to increase ETI's test-year property tax expenses by $1,214,688 is based on the historical effective tax rate applied to the known test-year-end plant in service value, consistent with Commission precedent, and based upon known and measurable changes.

151. ETI's test-year property tax burden should be adjusted upward by $1,222,106 for a total expense of $24,921,022.

152. Staff recommended reducing ETI's advertising, dues, and contributions expenses by $12,800. The recommendation, which no party contested, should be adopted.

153. The final cost of service should reflect changes to cost of service that affect other components of the revenue requirement such as the calculation of the Texas state gross receipts tax, the local gross receipts tax, the PUC Assessment Tax and the Uncollectible Expenses.

154. The company's requested Federal income tax expense is reasonable and necessary.

155. ETI's request for $2,019,000 to be included in its cost of service to account for the company's annual decommissioning expenses associated with River Bend is not reasonable because it is not based upon "the most current information reasonably available regarding the cost of decommissioning" as required by P.U.C. SUBST. R. 25.231(b)(1)(F)(i).

156. Based on the most current information reasonably available, the appropriate level of decommissioning costs to be included in ETI's cost of service is $1,126,000.

157. ETI's appropriate total annual self-insurance storm damage reserve expense is $8,270,000, comprised of an annual accrual of $4,400,000 to provide for average annual expected storm losses, plus an annual accrual of $3,870,000 for 20 years to restore the reserve from its current deficit.

158. ETI's appropriate target self-insurance storm damage reserve is $17,595,000.

159. ETI should continue recording its annual storm damage reserve accrual until modified by a Commission order.

160. The operating costs of the Spindletop facility are reasonable and necessary.

161. The operating costs of the Spindletop facility paid to PB Energy Storage Services are eligible fuel expenses.

Affiliate Transactions

162. ETI affiliates charged ETI $78,998,777 for services during the test-year. The majority of these O&M expenses—$69,098,041—were charged to ETI by ESI. The remaining affiliate services were charged (or credited) to ETI by: Entergy Gulf States Louisiana,

L.L.C.; Entergy Arkansas, Inc.; Entergy Louisiana, LLC; Entergy Mississippi, Inc.; Entergy Operations, Inc.; and non-regulated affiliates.

163. ESI follows a number of processes to ensure that affiliate charges are reasonable and necessary and that ETI and its affiliates are charged the same rate for similar services. These processes include: (a) the use of service agreements to define the level of service required and the cost of those services; (b) direct billing of affiliate expenses where possible; (c) reasonable allocation methodologies for costs that cannot be directly billed; (d) budgeting processes and controls to provide budgeted costs that are reasonable and necessary to ensure appropriate levels of service to its customers; and (e) oversight controls by ETI's Affiliate Accounting and Allocations Department.

164. Affiliates charged expenses to ETI through 1292 project codes during the test-year.

164A. The $2,086,145 in affiliate transactions related to sales and marketing expenses should be reallocated using direct assignment. The following amounts should be allocated to all retail classes in proportion to number of customers: (1) $46,490 for Project E10PCR56224 – Sales and Marketing – EGSI Texas; (2) $17,013 for Project F3PCD10049 – Regulated Retail Systems O&M; and (3) $30,167 for Project F3PPMMALI2 – Middle Market Mkt. Development. The remainder, $1,992,475, should be assigned to (1) General Service, (2) Large General Service and (3) Large Industrial Power Service.

165. ETI agreed to remove the following affiliate transactions from its application: (1) Project F3PPCASHCT (Contractual Alternative/Cashpo) in the amount of $2,553; (2) Project F3PCSPETEI (Entergy-Tulane Energy Institute) in the amount of $14,288; and (3) Project F5PPKATRPT (Storm Cost Processing & Review) in the amount of $929.

166. The $356,151 (which figure includes the $112,531 agreed to by ETI) of costs associated with Projects F5PCZUBENQ (Non-Qualified Post Retirement) and F5PPZNQBDU (Non Qual Pension/Benf Dom Utl) are costs that are not reasonable and necessary for the provision of electric utility service and are not in the public interest.

167. The $10,279 of costs associated with Project F3PPFXERSP (Evaluated Receipts Settlement) are not normally-recurring costs and should not be recoverable.

168. The $19,714 of costs associated with Project F3PPEASTIN (Willard Eastin et al) are related to ESI's operations, it is more immediately related to Entergy Louisiana, Inc. and Entergy New Orleans, Inc. As such, they are not recoverable from Texas ratepayers.

169. The $171,032 of costs associated with Project F3PPE9981S (Integrated Energy Management for ESI) are research and development costs related to energy efficiency programs. As such, they should be recovered through the energy efficiency cost recovery factor rather than base rates.

170. Except as noted in the above findings of fact Nos. 162-169, all remaining affiliate transactions were reasonable and necessary, were allowable, were charged to ETI at a price no higher than was charged by the supplying affiliate to other affiliates, and the rate charged is a reasonable approximation of the cost of providing service.

Jurisdictional Cost Allocation

171. ETI has one full or partial requirements wholesale customer – East Texas Electric Cooperative, Inc.

172. ETI proposes that 150 MW be set as the wholesale load for developing retail rates in this docket. Using 150 MW to set the wholesale load is reasonable. The 150 MW used to set the wholesale load results in a retail production demand allocation factor of 95.3838 percent.

173. The 12 Coincident Peak (12 CP) allocation method is consistent with the approach used by the FERC to allocate between jurisdictions.

174. Using 12CP methodology to allocate production costs between the wholesale and retail jurisdictions is the best method to reflect cost responsibility and is appropriate based on ETI's reliance on capacity purchases.

Class Cost Allocation and Rate Design

175. There is no express statutory authorization for ETI's proposed Renewable Energy Credits rider (REC rider).

176. REC rider constitutes improper piecemeal ratemaking and should be rejected.

177. ETI's test-year expense for renewable energy credits, $623,303, is reasonable and necessary and should be included in base rates.

178. Municipal Franchise Fees (MFF) is a rental expense paid by utilities for the right to use public rights-of-way to locate its facilities within municipal limits.

179. ETI is an integrated utility system. ETI's facilities located within municipal limits benefit all customers, whether the customers are located inside or outside of the municipal limits.

180. Because all customers benefit from ETI's rental of municipal right-of-way, municipal franchise fees should be charged to all customers in ETI's service area, regardless of geographic location.

181. It is reasonable and consistent with the Public Utility Regulatory Act (PURA) § 33.008(b) that MFF be allocated to each customer class on the basis of in-city kilowatt hour (kWh) sales, without an adjustment for the MFF rate in the municipality in which a given kWh sale occurred.

182. The same reasons for allocating and collecting MFF as set out in Finding of Fact Nos. 178-181 also apply to the allocation and collection of Miscellaneous Gross Receipts Taxes. The company's proposed allocation of these costs to all retail customer classes based on customer class revenues relative to total revenues is appropriate.

182A. ETI's proposed gross plant-based allocator is an appropriate method for allocating the Texas franchise tax.

183. The Average and Excess (A&E) 4CP method for allocating capacity-related production costs, including reserve equalization payments, to the retail classes is a standard methodology and the most reasonable methodology.

184. The A&E 4CP method for allocating transmission costs to the retail classes is standard and the most reasonable methodology.

185. ETI appropriately followed the rate class revenue requirements from its cost of service study to allocate costs among customer classes. ETI's revenue allocation properly sets rates at each class's cost of service.

186. It is reasonable for ETI to eliminate the service condition for Rate Groups A and C in Schedule SHL [Street and Highway Lighting Service] that charges a $50 fee for any replacement of a functioning light with a lower-wattage bulb.

187. It is appropriate to require ETI to prepare and file, as part of its next base rate case, a study regarding the feasibility of instituting LED-based rates and, if the study shows that such rates are feasible, ETI should file proposals for LED-based lighting and traffic signal rates in its next rate case.

188. An agreement was reached by the parties and approved by the Commission in Docket No. 37744 that directed ETI to exclude, in its next rate case, the life-of-contract demand ratchet for existing customers in the Large Industrial Power Service (LIPS), Large Industrial Power Service-Time of Day, General Service, General Service-Time of Day, Large General Service, and Large General Service-Time of Day rate schedules.

189. ETI's proposed tariffs in this case did not remove the life-of-contract demand ratchet from these rate schedules consistent with the parties' agreement in Docket No. 37744.

190. A perpetual billing obligation based on a life-of-contract demand ratchet, as ETI proposed, is not reasonable.

191. ETI's proposed LIPS and LIPS Time of Day tariffs should be modified to reflect the agreement that was adopted by the Commission as just and reasonable in Docket No. 37744. Accordingly, these tariffs should be modified as set out in Findings of Fact No. 192-194.

192. ETI's Schedule LIPS and LIPS Time of Day § VI should be changed to read:

> DETERMINATION OF BILLING LOAD
>
> The kW of Billing Load will be the greatest of the following:
>
> (A) The Customer's maximum measured 30-minute demand during any 30-minute interval of the current billing month, subject to §§ III, IV and V above; or
>
> (B) 75% of Contract Power as defined in § VII; or
>
> (C) 2,500 kW.

193. ETI's Schedule LIPS and LIPS Time of Day § VII should be changed to read:

> DETERMINATION OF CONTRACT POWER
>
> Unless Company gives customer written notice to the contrary, Contract Power will be defined as below:
>
> Contract Power - the highest load established under § VI(A) above during the 12 months ending with the current month. For the initial 12 months of Customer's service under the currently effective contract, the Contract Power shall be the kW specified in the currently effective contract unless exceeded in any month during the initial 12-month period.

194. The Large General Service, Large General Service-Time of Day, General Service, and General Service-Time of Day schedules should be similarly revised to eliminate ETI's life-of-contract demand ratchet.

195. In its proposed rate design for the LIPS class, the company took a conservative approach and increased the current rates by an equal percentage. This minimized customer bill impacts while maintaining cost causation principles on a rate class basis.

196. It is a reasonable move towards cost of service to add a customer charge of $630 to the LIPS rate schedule with subsequent increases to be considered in subsequent base rate cases.

197. It is a reasonable move towards cost of service to slightly decrease the LIPS energy charges and increase the demand charges as proposed by Staff witness William B. Abbott.

198. DOE proposed a new Schedule LIPS rider—Schedule "Schedulable Intermittent Pumping Service" (SIPS) for load schedulable at least four weeks in advance, that occurs in the off-season (October through May), that can be cancelled at any time, and for load not lasting more than 80 hours in a year. For customers whose loads match these SIPS characteristics (for example, DOE's Strategic Petroleum Reserve), the 12-month demand ratchet provision of Schedule LIPS does not apply to demands set under the provisions of the SIPS rider. The monthly demand set under the SIPS provisions would be applicable for billing purposes only in the month in which it occurred. In short, if a customer set a

12-month ratchet demand in that month, it would be forgiven and not applicable in the succeeding 12 months.

199. DOE's proposed Schedule SIPS is not restricted solely to the DOE and should be adopted. It more closely addresses specific customer characteristics and provides for cost-based rates, as does another ETI rider applicable to Pipeline Pumping Service.

200. Standby Maintenance Service (SMS) is available to customers who have their own generation equipment and who contract for this service from ETI.

201. P.U.C. SUBST. R. 25.242(k)(1) provides that rates for sales of standby and maintenance power to qualifying facilities should recognize system wide costing principles and should not be discriminatory.

202. It is reasonable to move Schedule SMS toward cost of service by: (a) adding a customer charge equivalent to that of the LIPS rate schedule only for SMS customers not purchasing supplementary power under another applicable rate; and (b) revising the tariff as follows:

Charge	Distribution (less than 69KV)	Transmission (69KV and greater)
Billing Load Charge ($/kW):		
Standby	$2.46	$0.79
Maintenance	$2.27	$0.60
Non-Fuel Energy Charge (¢/kWh)		
On-Peak	4.245¢	4.074¢
Off-Peak	0.575¢	0.552¢

203. ETI's Additional Facilities Charge rider (Schedule AFC) prescribes the monthly rental charge paid by a customer when ETI installs facilities for that customer that would not normally be supplied, such as line extensions, transformers, or dual feeds.

204. ETI existing Schedule AFC provides two pricing options. Option A is a monthly charge. Option B, which applies when a customer elects to amortize the directly-assigned facilities over a shorter term ranging from one to ten years, has a variable monthly charge. There is also a term charge that applies after the facility has been fully depreciated.

205. It is reasonable and cost-based to reduce the Schedule AFC Option A rate to 1.11 percent per month of the installed cost of all facilities included in the agreement for additional facilities.

206. It is reasonable and cost-based to reduce the Schedule AFC Option B monthly rate and the Post Term Recovery Charge as follows:

Selected Recovery Term	Recovery Term Charge	Post Recovery Term Charge
1	9.52%	0.28%
2	5.14%	0.28%
3	3.68%	0.28%
4	2.95%	0.28%
5	2.52%	0.28%
6	2.23%	0.28%
7	2.03%	0.28%
8	1.88%	0.28%
9	1.76%	0.28%
10	1.67%	0.28%

207. The revisions in the above findings of fact to Schedule AFC rates reasonably reflect the costs of running, operating, and maintaining the directly-assigned facilities.

208. It is reasonable to modify the Large General Service rate schedule by increasing the demand charge from $8.56 to $11.43; decreasing the energy charge from $.00854 to $.00458; and reducing the customer charge to $260.00.

209. Staff's proposed change to the General Service (GS) rate schedule to gradually move GS customers towards their cost of service by recommending a decrease in the customer charge from the current rate of $41.09 to $39.91, and a decrease in the energy charges is reasonable and should be adopted.

210. ETI's Residential Service (RS) rate schedule is composed of two elements: a customer charge and a consumption-based energy charge. In the months November through April (winter), the rates are structured as a declining block, in which the price of each unit is reduced after a defined level of usage. ETI's proposed increase in the RS customer charge to $6 per month is reasonable and should be adopted. For the RS summer rate and

the first winter block rate, the 6.296¢ per kWh energy charge resulting from the increased revenue requirement for residential customers is reasonable and should be adopted.

211. ETI's Schedule RS declining block rate structure is contrary to energy-efficiency efforts and the Legislature's goal of reducing both energy demand and energy consumption in Texas, as stated in PURA § 39.905.

212. Schedule RS winter block rates should be modified consistent with the goal set out in PURA § 39.905, with the initial phase-in of a 20 percent reduction in the block differential proposed by ETI and subsequent reductions should be reviewed for consideration at the occurrence of each rate case filing.

213. Other elements of Schedule RS are just and reasonable.

Fuel Reconciliation

214. ETI incurred $616,248,686 in natural-gas expenses during the reconciliation period, which is from July 2009 through June 2011.

215. ETI purchased natural gas in the monthly and daily markets and pursuant to a long-term contract with Enbridge Inc. pipeline. ETI also transported gas on its own account and negotiated operational balancing agreements with various pipeline companies.

216. ETI employed a diversified portfolio of gas supply and transportation agreements to meet its natural-gas requirements, and ETI prudently managed its gas-supply contracts.

217. ETI's natural gas expenses were reasonable and necessary expenses incurred to provide reliable electric service to retail customers.

218. ETI incurred $90,821,317 in coal expenses during the reconciliation period.

219. ETI prudently managed its coal and coal-related contracts during the reconciliation period.

220. ETI monitored and audited coal invoices from Louisiana Generating, LLC for coal burned at the Big Cajun II, Unit 3 facility.

221. ETI's coal expenses were reasonable and necessary expenses incurred to provide reliable electric service to retail customers.

222. ETI incurred $990,041,434 in purchased-energy expenses during the reconciliation period.

223. The Entergy System's planning and procurement processes for purchased-power produced a reasonable mix of purchased resources at a reasonable price.

224. During the reconciliation period, ETI took advantage of opportunities in the fuel and purchased-power markets to reduce costs and to mitigate against price volatility.

225. ETI's purchased-energy expenses were reasonable and necessary expenses incurred to provide reliable electric service to retail customers.

226. ETI provided sufficient contemporaneous documentation to support the reasonableness of its purchased-power planning and procurement processes and its actual power purchases during the reconciliation period.

227. The Entergy system sold power off system when the revenues were expected to be more than the incremental cost of supplying generation for the sale, subject to maintaining adequate reserves.

228. The System Agreement is the tariff approved by the FERC that provides the basis for the operation and planning of the Entergy system, including the six operating companies. The System Agreement governs the wholesale-power transactions among the operating companies by providing for joint operation and establishing the bases for equalization among the operating companies, including the costs associated with the construction, ownership, and operation of the Entergy system facilities.

229. Under the terms of the Entergy System Agreement, ETI was allocated its share of revenues and expenses from off-system sales.

230. During the reconciliation period, ETI recorded off-system sales revenue in the amount of $376,671,969 in FERC Account 447 and credited 100 percent of off-system sales revenues and margins from off-system sales to eligible fuel expenses.

231. ETI properly recorded revenues from off-system sales and credited those revenues to eligible fuel costs.

232. The Entergy system consists of six operating companies, including ETI, which are planned and operated as a single, integrated electric system under the terms of the System Agreement.

233. Service schedule MSS-1 of the System Agreement determines how the capability and ownership costs of reserves for the Entergy system are equalized among the operating companies. These inter-system "reserve equalization" payments are the result of a formula rate related to the Entergy system's reserve capability that is applied on a monthly basis.

234. Reserve capability under service schedule MSS-1 is capability in excess of the Entergy system's actual or planned load built or acquired to ensure the reliable, efficient operation of the electric system.

235. By approving service schedule MSS-1, the FERC has approved the method by which the operating companies share the cost of maintaining sufficient reserves to provide reliability for the Entergy system as a whole.

236. Service schedule MSS-3 of the System Agreement determines the pricing and exchange of energy among the operating companies. By approving service schedule MSS-3, the FERC has approved the method by which the operating companies are reimbursed for energy sold to the exchange energy pool and how that energy is purchased.

237. Service schedule MSS-4 of the System Agreement sets forth the method for determining the payment for unit power purchases between operating companies. By approving service schedule MSS-4, the FERC has approved the methodology for pricing inter-operating company unit power purchases.

238. The Entergy system is planned using multi-year, annual, seasonal, monthly, and next-day horizons. Once the planning process has identified the most economical resources that can be used to reliably meet the aggregate Entergy system demand, the next step is to procure the fuel necessary to operate the generating units as planned and acquire wholesale power from the market.

239. Once resources are procured to meet forecasted load, the Entergy system is operated during the current day using all the resources available to meet the total Entergy system demand.

240. After current-day operation, the System Agreement prescribes an accounting protocol to bill the costs of operating the system to the individual operating companies. This protocol is implemented via the intra-system bill to each operating company on a monthly basis.

241. ETI purchased power from affiliated operating companies per the terms of service schedule MSS-3 of the System Agreement. The payments made under Schedule MSS-3 to affiliated operating companies are reasonable and necessary, and the FERC has approved the pricing formula and the obligation to purchase the energy. ETI pays the same price per megawatt hour for energy under service schedule MSS-3 as does any other operating company purchasing energy under service schedule MSS-3 during the same hour.

242. The Spindletop facility is used primarily to ensure gas-supply reliability and guard against gas-supply curtailments that can occur as a result of extreme weather or other unusual events.

243. The Spindletop facility provides a secondary benefit of flexibility in gas supply. ETI can back down gas-fired generation to take advantage of more economical wholesale power, or use gas from storage to supplement gas-fired generation when load increases during the day and thereby avoid more expensive intra-day gas purchases.

244. ETI's customers received benefits from the Spindletop facility during the reconciliation period through reliable gas supplies and ETI's monthly and daily storage activity.

245. ETI prudently managed the Spindletop facility to provide reliability and flexibility of gas supply for the benefit of customers.

246. ETI proposed new loss factors, based on a December 2010 line-loss study, to be applied for the purpose of allocating its costs to its wholesale customers and retail customer classes.

246A. ETI's 2010 line-loss factors should be used to reconcile ETI's fuel costs. Therefore, ETI's fuel reconciliation over-recovery should be reduced by $3,981,271.

247. ETI's proposed loss factors are reasonable and shall be implemented on a prospective basis as a result of this final order.

248. ETI seeks a special-circumstances exception to recover $99,715 resulting from the FERC's reallocation of rough production equalization costs in FERC Order No. 720-A, and to treat such costs as eligible fuel expense.

249. Special circumstances exist and it is appropriate for ETI to recover the rough production cost equalization costs reallocated to ETI as a result of the FERC's decision in Order No. 720-A.

Other Issues

250. A deferred accounting of ETI's Midwest Independent Transmission System Operator (MISO) transition expenses is not necessary to carry out any requirement of PURA.

251. ETI should include $1.6 million in base rates for MISO transition expense.

252. Deleted.

253. Transmission Cost Recovery Factor baseline values should be set during the compliance phase of this docket, after the Commission makes final rulings on the various contested issues that may affect this calculation.

254. Distribution Cost Recovery Factor baseline values should be set during the compliance phase of this docket, after the Commission makes final rulings on the various contested issues that may affect this calculation.

255. The appropriate amount for ETI's purchased-power capacity expense to be included in base rates is $245,965,886.

256. The amount of ETI's purchased-power capacity expense includes third-party contracts, legacy affiliate contracts, other affiliate contracts, and reserve equalization. Whether the amounts for all contracts should be included in the baseline for a purchased-capacity rider that may be approved in Project No. 39246 is an issue that should be decided in that project.

III. Conclusions of Law

1. ETI is a "public utility" as that term is defined in PURA § 11.004(1) and an "electric utility" as that term is defined in PURA § 31.002(6).

2. The Commission exercises regulatory authority over ETI and jurisdiction over the subject matter of this application pursuant to PURA §§ 14.001, 32.001, 32.101, 33.002, 33.051, 36.101–.111, and 36.203.

3. SOAH has jurisdiction over matters related to the conduct of the hearing and the preparation of a proposal for decision in this docket, pursuant to PURA § 14.053 and TEX. GOV'T CODE ANN. § 2003.049.

4. This docket was processed in accordance with the requirements of PURA and the Texas Administrative Procedure Act, Tex. Gov't Code Ann. Chapter 2001.

5. ETI provided notice of its application in compliance with PURA § 36.103, P.U.C. PROC. R. 22.51(a), and P.U.C. SUBST. R. 25.235(b)(1)-(3).

6. Pursuant to PURA § 33.001, each municipality in ETI's service area that has not ceded jurisdiction to the Commission has jurisdiction over the company's application, which seeks to change rates for distribution services within each municipality.

7. Pursuant to PURA § 33.051, the Commission has jurisdiction over an appeal from a municipality's rate proceeding.

8. ETI has the burden of proving that the rate change it is requesting is just and reasonable pursuant to PURA § 36.006.

9. In compliance with PURA § 36.051, ETI's overall revenues approved in this proceeding permit ETI a reasonable opportunity to earn a reasonable return on its invested capital used and useful in providing service to the public in excess of its reasonable and necessary operating expenses.

10. Consistent with PURA § 36.053, the rates approved in this proceeding are based on original cost, less depreciation, of property used and useful to ETI in providing service.

11. The ADFIT adjustments approved in this proceeding are consistent with PURA § 36.059 and P.U.C. SUBST. R. 25.231(c)(2)(C)(i).

12. Including the cash working capital approved in this proceeding in ETI's rate base is consistent with P.U.C. SUBST. R. 25.231(c)(2)(B)(iii)(IV), which allows a reasonable allowance for cash working capital to be included in rate base.

13. The ROE and overall rate of return authorized in this proceeding are consistent with the requirements of PURA §§ 36.051 and 36.052.

14. The affiliate expenses approved in this proceeding and included in ETI's rates meet the affiliate payment standards articulated in PURA §§ 36.051, 36.058, and *Railroad Commission of Texas v. Rio Grande Valley Gas Co.*, 683 S.W.2d 783 (Tex. App.—Austin 1984, no writ).

15. The ADFIT adjustments approved in this proceeding are consistent with PURA § 36.059 and P.U.C. SUBST. R. 25.231(c)(2)(C)(i).

16. Pursuant to P.U.C. SUBST. R. 25.231(b)(1)(F), the decommissioning expense approved in this case is based on the most current information reasonably available regarding the cost of decommissioning, the balance of funds in the decommissioning trust, anticipated escalation rates, the anticipated return on the funds in the decommissioning trust, and other relevant factors.

17. ETI has demonstrated that its eligible fuel expenses during the reconciliation period were reasonable and necessary expenses incurred to provide reliable electric service to retail customers as required by P.U.C. SUBST. R. 25.236(d)(1)(A). ETI has properly accounted for the amount of fuel-related revenues collected pursuant to the fuel factor during the reconciliation period as required by P.U.C. SUBST. R. 25.236(d)(1)(C).

18. ETI prudently managed the dispatch, operations, and maintenance of its fossil plants during the reconciliation period.

19. The reconciliation period level operating and maintenance expenses for the Spindletop facility are eligible fuel expenses pursuant to P.U.C. SUBST. R. 25.236(a).

19A. Fuel factors under P.U.C. SUBST. R. 25.237(a)(3) are temporary rates subject to revision in a reconciliation proceeding.

19B. P.U.C. SUBST. R. 25.236(d)(2) defines the scope of a fuel reconciliation proceeding to include any issue related to the reasonableness of a utility's fuel expenses and whether the utility has over- or under-recovered its reasonable fuel expenses. It is proper to use the new line-loss study to calculate Entergy's fuel reconciliation and over-recovery.

20. Special circumstances are warranted pursuant to P.U.C. SUBST. R. 25.236(a)(6) to recover rough production equalization payments reallocated to ETI by the FERC.

21. ETI's rates, as approved in this proceeding, are just and reasonable in accordance with PURA § 36.003.

IV. Ordering Paragraphs

In accordance with these findings of fact and conclusions of law, the Commission issues the following orders:

1. The proposal for decision prepared by the SOAH ALJs is adopted to the extent consistent with this Order.

2. ETI's application is granted to the extent consistent with this Order.

3. ETI shall file in Tariff Control No. 40742 *Compliance Tariff Pursuant to Final Order in Docket No. 39896 (Application of Entergy Texas, Inc. for Authority to Change Rates, Reconcile Fuel Costs, and Obtain Deferred Accounting Treatment)* tariffs consistent with this Order within 20 days of the date of this Order. No later than ten days after the date of the tariff filings, Staff shall file its comments recommending approval, modification, or rejection of the individual sheets of the tariff proposal. Responses to the Staff's recommendation shall be filed no later than 15 days after the filing of the tariff. The Commission shall by letter approve, modify, or reject each tariff sheet, effective the date of the letter.

4. The tariff sheets shall be deemed approved and shall become effective on the expiration of 20 days from the date of filing, in the absence of written notification of modification or rejection by the Commission. If any sheets are modified or rejected, ETI shall file proposed revisions of those sheets in accordance with the Commission's letter within ten

days of the date of that letter, and the review procedure set out above shall apply to the revised sheets.

5. Copies of all tariff-related filings shall be served on all parties of record.

6. ETI shall prepare and file as part of its next base rate case a study regarding the feasibility of instituting LED-based rates and, if the study shows that such rates are feasible, ETI should file proposals for LED-based lighting and traffic signal rates in that case. If ETI has LED lighting customers taking service, the study shall include detailed information regarding differences in the cost of serving LED and non-LED lighting customers. ETI shall provide the results of this study to Cities and interested parties as soon as practicable, but no later than the filing of its next rate case.

7. All other motions, requests for entry of specific findings of fact and conclusions of law, and any other requests for general or specific relief, if not expressly granted, are denied.

SIGNED AT AUSTIN, TEXAS the ______ day of October 2012.

PUBLIC UTILITY COMMISSION OF TEXAS

____
DONNA L. NELSON, CHAIRMAN

____
ROLANDO PABLOS, COMMISSIONER

I respectfully dissent regarding the utility- and executive-management-class affiliate transactions. To be consistent with Commission precedent in Docket No. 14965,[37] the indirect costs of the management of Entergy's ultimate parent should not be borne by Texas ratepayers. Therefore, I would disallow the following: $173,867 for Project No. F3PCCPM001 (Corporate Performance Management); $372,919 for Project No. F3PCC31255 (Operations-Office of the CEO); and $74,485 for Project No. F3PPCOO001 (Chief Operating Officer). I join the Commission in all other respects for this Order.

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KENNETH W. ANDERSON, JR., COMMISSIONER

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[37] *Application of Central Power and Light Company for Authority to Change Rates*, Docket No. 14965, Second Order on Rehearing (Oct. 16, 1997).