3. Franchise Taxes

EGS's decreased Texas test-year franchise tax of $3,751,000 to $734,000. Ms. Spence explained that in Docket No. 12852, the Company was ordered to amortize a June 1994 Texas franchise tax refund of $115,084,000 over five years and offset it against the Company's franchise tax expense. The Company's adjustment is consistent with this order. GC Ex. 42 at 32. Ms. Spence determined that EGS's Texas Corporation Franchise Taxes are calculated on net taxable earned surplus. Thus, these taxes vary in relation to revenues. Therefore, the appropriate franchise tax is based on an effective rate to reflect this relationship applied to the revenue requirement approved in this docket.

Therefore, based on the ALJs' recommendations in this docket, EGS's Texas Franchise Tax should be ($259,000).

4. Ad Valorem Taxes

EGS requests $46,616,000 in ad valorem taxes, an increase of $13,200,000 from test-year expense relating primarily to the expiration of tax exemptions for River Bend in Louisiana.[698] Ms. Spence computed the 1997 taxes for River Bend to be $12,925,000. GC Ex. 42 at 25-28. Rebuttal witness Mr. Wright agreed with this amount. EGS Ex. 148 at 103.

Cities recommend that the Company provide the actual tax expense associated with the expiration of the ten-year exemption on River Bend for Louisiana property taxes so that the Commission could include the actual amount in its revenue requirement. Cities Ex. 102 at 32.

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[698]EGS Ex. 1 at WP/P AJ-30.

The ALJs conclude that the agreed $12,925,000 should be added to test-year expense.

General Counsel and Cities also recommend adjustments removing property taxes related to PHFU which they opposed including in rate base.[699] EGS stated that if the Commission disallows PHFU, the property taxes included in EGS's cost of service that are related to PHFU are $266,172, and not the $340,719 or $557,000 adjustments recommended by Cities and General Counsel. EGS Ex. 148 at 102-103.

The ALJs conclude that property tax should be based on applying an effective rate to the total rate base approved in this docket. Based on the ALJs recommendation, that amount is $29,904,000.

E. Federal Income Taxes

EGS included a federal income tax (FIT) expense of $108,962,000 in its cost of service.[700] The test-year FIT was $60,641,000.[701] The reasons for the difference are explained in very general terms by Mr. Wright at EGS Ex. 118 at 13-16.

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[699]GC Ex. 42 at 30; Cities Ex. 102 at 31.

[700]RFP Volume 17, Schedule A, column for existing rates--adjusted, lines 17, 20, and 23; and Volume 18, Schedule G-7.8, page 1.

[701]Schedule G-7.8, page 1.

1. Consolidated Tax Savings

a. Sharing Under PURA Section 36.060

Both Entergy and EGS have been filing consolidated income tax returns for years; EGS joined Entergy's affiliated group for tax purposes on December 31, 1993. GC Ex. 44 at 75. However, EGS believes it is not appropriate in this case to make a consolidated tax savings adjustment because EGS and its customers have not borne the expenses that have produced taxable losses. Therefore, EGS concludes that its fair share of any consolidated tax savings associated with the Entergy affiliates is $0.00.[702]

General Counsel recommends a consolidated tax savings (CTS) adjustment of ($877,030).[703] Cities recommend CTS of ($6,020,870) based on a cost of service method and $3,629,731 based on an interest credit method, calculated in Cities Ex. 106 at Ex. MLA-7 and MLA-6 updated, which incorporate the 1996 FIT. The ALJs recommend the Commission adopt General Counsel's adjustment.

PURA §36.060 (formerly §2.208(c)) requires the Commission allocate a fair share of consolidated tax savings under certain circumstances:

> If the public utility is a member of an affiliated group that is eligible to file a consolidated income tax return and if it is advantageous to the public utility to do so, income taxes shall be computed as though a consolidated return had been so filed and the utility had realized its fair share of the savings resulting from the consolidated return, unless it is shown to the satisfaction of the regulatory authority that it was reasonable to choose not to consolidate returns.

[702] EGS Ex. 118 at 7-8; EGS Ex. 146 at 47.

[703] GC Ex. 44, at Errata Attachment CR-TAX-9.

Cities' witness Mr. Arndt testified that the failure to recognize that EGS pays taxes as part of a consolidated entity would result in over recovery of EGS's revenue requirement. For example, he explained that in 1995 Entergy Corporation's gain companies reported more taxable income than Entergy reported on its consolidated income tax return because of losses in income realized by certain of Entergy's non-regulated affiliates. EGS has a tax allocation agreement with its subsidiaries that works like this: the gain companies pay taxes to Entergy on the basis of their gains, in 1995 for example, but Entergy paid much less than the amount it received from those gain companies in FIT. Entergy then allocated to the loss companies--in 1995, $82,343,000--the monies it received from the gain companies. Mr. Arndt believes this reallocation of tax monies should not be considered for ratemaking purposes because the impact is to enrich Entergy's non-regulated companies at the expense of monopoly ratepayers. If this is allowed, those non-regulated companies can gain an unfair economic advantage and under-price their competitors. Cities Ex. 106 at 77-80.

EGS disagrees. Mr. Warren testified that while it may be true that the tax benefit might not be available were it not for the presence within the consolidated group of one or more corporations with taxable income, it is equally true that there could be no tax benefit absent the expenditures of the loss affiliates. So, it is wrong to deprive the corporation of the cash tax consequences of its expenditures where such a benefit is realized by ratepayers. EGS Ex. 146 at 46.

b. <u>Calculation of CTS Adjustment</u>

The consolidated tax issue involves certain net operating losses (NOLs) attributable to the abeyed portion of the River Bend nuclear plant, NOLs which Gulf States Utilities, Inc. reported prior to its merger with Entergy in 1993. These tax losses resulted from regulatory disallowances and the deregulation of River Bend by the Louisiana Public Service Commission (LPSC). The Staff and Cities did not include any NOL carry forwards in their proposed CTS adjustment.[704]

Pursuant to the Commission's decision in the recent Central Power & Light case, Docket No. 14965, Mr. Arndt calculated a consolidated tax savings adjustment based on available tax information for the prior 15 years, 1981 to 1995.[705] Instead of using a 15-year historical period, Staff witness Candice Romines used a two-year period, 1994 and 1995, and for those two years calculated hypothetical taxable incomes for EGS on a stand-alone basis after NOL carry forwards.[706] She explained that the Commission's historical loan adjustment in Docket No. 14965 reflects the actual tax shield available after carry forward and utilization of NOLs. If the actual NOLs reported on the tax return are used in this case, EGS has no taxable income in 1994 and 1995 against which affiliate losses could be offset. She testified as follows:

> A hypothetical stand-alone calculation is only reasonable if *all* effects of disallowed plant are disregarded. Using the tax basis of the Abeyed River Bend and ACRS tax rates to restate EGS's history of NOL generation and utilization, I have determined

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[704]Mr. Arndt testified that he took into account the internal revenue service's (IRS's) separate return limitation year (SRLY) rule regarding the EGS pre-existing NOLs. According to Mr. Arndt, those rules provide that NOLs generated prior to the merger can only be used during the carry-forward period after the merger to the extent that EGS contributes taxable income in the post-merger years. Because her adjustments eliminate any NOL carry forward as of the merger date, Ms. Romines concluded that the SRLY rules are not applicable. GC Ex. 44 at 20.

[705]Cities Ex. 106 at 82; Ex. MLA-6.

[706]GC Ex. 44 at 18; Ex. Errata CR-TAX-9. Mr. Warren agrees it is appropriate to use Ms. Romines' two-year tax history. He believes Mr. Arndt erred in attempting to emulate the Commission's decision in Docket No. 14965 because Mr. Arndt *aggregated* 15 single-years savings rather than computing a single cumulative savings. Cities agree that due to the uniqueness of EGS's situation, a three-year approach proposed by Mr. Arndt at his Ex. MLA-7 is more representative of what EGS's fair share of savings will be in the future. Cities Brief at 93. *See* Cities Ex. 148, 149 confidential.

Also, Ms. Romines testified that she disregarded 13 of the 15 years because in some of those years the Commission ordered GSU to include CTS adjustments, which reflected the actual benefit, not just the time value of that benefit. In addition, even if those prior CTS adjustments are removed and all subsidiary losses are carried forward, the effect on EGS's revenue requirement is minimal. GC Ex. 44 at 18.

> that EGS's NOL carry forwards, had there been no Abeyed River Bend tax deductions, would have been fully utilized in 1995. I have assumed that rate orders in Louisiana, *e.g.*, phase-in plan, on EGS's taxable income extended the date the actual NOL carry forwards have been and will be utilized. Removing these effects for ratemaking speeds up the date recognized in the CTS adjustment that EGS's taxable income becomes available to shield losses of affiliates for ratemaking purposes.[707]

Mr. Warren testified on rebuttal that if Ms. Romines and Mr. Arndt had considered the carry forward, then there would be no consolidated tax savings adjustment assigned to EGS. He objected to a hypothetical tax calculation because all of the Texas consolidated tax adjustment proposals of which he is aware were computed based on the actual tax return.

ALJs' Recommendation:

The ALJs conclude that a CTS adjustment should be included in cost of service. First of all, Entergy's non-regulated affiliates benefit from their relationship with profitable utilities in the Entergy group. Those unregulated affiliates who lose money are paid *solely* because of the taxes paid to Entergy by the utility affiliates such as EGS. Furthermore, it is beneficial to EGS's ratepayers to share in the tax savings realized on a consolidated basis. This reasoning comports with the Commission's decision in Docket No. 14965.[708] Finally, we are persuaded that the NOLs, while not tied to a particular plant, are attributable to the abeyed River Bend decision and the Louisiana Commission deregulation decision. Accordingly, we recommend the Commission adopt Staff's proposed consolidated tax adjustment based on a two-year historical stand-alone calculation.

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[707] *Id.* at 19.

[708] *See* Docket No. 14965, Second Order on Rehearing at 12 and Findings of Fact Nos. 107 & 108 at 45.

2. Provision for Deferred Taxes

a. Amortization of Excess Deferred Taxes

General Counsel recommends that amortization of excess deferred federal income (EDIT) taxes be increased so that ratepayers receive tax benefits that EGS would have received had there been no tax deductions in prior years for the Abeyed River Bend (ARB) plant. Staff also recommends that the excess deferred taxes related to the NOLs carried back and utilized in years prior to 1987 be amortized.

i. Write-Off of EDIT

Gulf States Utilities, Inc. was in an NOL posture in 1991, when the statutory tax rate changed from 46 percent to 34 percent and excess deferred taxes were created. The deferred taxes in excess of 34 percent related to River Bend were removed from the books of the Company in the amount of $64 million. GC Ex. 44 at 14. In RFI responses to Staff requests, EGS stated it could not separately identify the amounts written-off by account number and that independent auditors had no information in their files related to this write-off. Other RFI responses indicated the $64 million were write-offs for both the River Bend excess and the non-nuclear excess. Because of confusion in RFI responses and in the Company's initial filing, Ms. Romines recommended amortizing the write-off over the remaining life of depreciable plant, which results in an annual amortization of ($2,381,293), total electric.

Mr. Wright testified that the 1991 $64 million write-off did not benefit shareholders. The EDIT entry did not impact the income statement or net income. He said that Ms. Romines' method would reduce net income in order to give the ratepayers the benefit of tax deductions never realized by the Company.

ii. Protected EDIT

Another controversy involves amortization of protected excess deferred taxes of $955,318. Ms. Romines determined that this amount appeared to be the amortization of "deficient" deferred taxes instead of excess deferred taxes--the amount is not on Schedule G-7.8 or G-7.9. *Id.* at 14-15. In rebuttal, EGS supplied a revised Schedule G-7.8 which includes, as a separate line item, the $955,318 as the protected excess deferred tax amount. Mr. Wright testified that at the time the Company filed its RFP no break-out of this amount was available, but that the Company provided this information later to Staff in an RFI response.[709]

ALJs' Recommendation:

The ALJs find that Ms. Romines' recommendation results from confusion during the discovery process and lack of clear information provided in the RFP.[710] However, Mr. Wright's response in rebuttal testimony does not clarify that all EDIT attributable to the abeyed and disallowed River Bend plant have been returned to ratepayers.

The write-off of the NOL DIT was offset by a write-off of EDIT related to accelerated tax depreciation.[711] General Counsel argues this differs from the ratable basis used by the Company to adjust accumulated deferred FIT for the ARB, because EGS's adjustment to accumulated deferred

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[709]*See* GC Ex. 45, Errata at Ex. CR-TAX-6, RFI No. PUCT 110-1213. EGS Ex. 148 at 37.

[710]GC Ex. 44 at 13-14; GC Brief at 69.

[711]*See* GC Ex. 44 at Att. CR-TAX-4.

FIT is allocation of the NOL to *all* timing differences, not just the accelerated depreciation. GC Reply Brief at 63. Moreover, EGS amortized its non-protected EDIT and did not refund to ratepayers all EDIT other than protected plant-related DIT as it claimed.[712]

The ALJs determined that it is appropriate to exclude all effects of the abeyed and disallowed River Bend plant from the tax calculation in this proceeding. However, the issue is muddied by EGS's rebuttal response that the Company amortized the $955,318 of protected EDIT during the test year, which is reflected in the FIT request. While it appears from GC. Ex. 44, CR-TAX-4 at page 8 that EDIT, which includes nuclear excess, has not been amortized, the amount remaining may not be the amount Ms. Romines suggests. EGS has the burden of proof and the responsibility to provide the correct calculation if it believes Staff's calculation is wrong. Because it did not provide the *without* ARB calculation, we conclude that to ensure that all effects of the ARB are captured, the Company should amortize the excess deferred FIT, including the $64 million write-off of EDIT, over the remaining life of the depreciable River Bend plant. This is an annual amortization of ($2,381,297) as recommended by Staff.

b. Permanent Differences, Depreciation Adjustment, and Temporary Differences

General Counsel recommends disallowing EGS's request for these differences which total $5,376,000, total electric. At a technical conference occurring during the discovery phase of this case, the Company was unable to explain these adjustments to Ms. Romines' satisfaction.

EGS claims it did provide the workpapers to support these items. EGS Ex. 148 at 39-41. Mr. Wright explained that workpapers WP/G-7.8, pages 297 through 302 contain these adjustments.

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[712] *See* EGS Ex. 148 at Ex. JDW-13, page 1, line 7.

The ALJs find there was a misunderstanding about what Ms. Romines sought from the Company at the technical conference. EGS Ex. 148 at 39. The Company uses these differences and adjustments in its Tax Method 2. Therefore, the Company's request should be adopted.

3. Investment Tax Credits

EGS seeks to amortize a negative $3.904 million of investment tax credits (ITCs). Staff proposes to amortize ($6,677,487) in ITCs. GC Ex. 45 Errata, Schedule V. The ALJs accept Staff's proposed methodology for amortizing ITCs and recommend using that proposal to amortize ITCs over the plant remaining life calculations and rates recommended in this PFD.

Investment Tax Credits attach to a qualifying asset and entitle the taxpayer to a percentage of the asset's cost as a credit. The benefit of the credit could only be realized by the offsetting of a tax liability otherwise due. If no tax liability occurred in a year, the credit could not be used in that year, but could be carried back three years and forward 15 years to offset tax liabilities in those years. The ITC was repealed as part of the Tax Reform Act of 1986, but existing carry forwards did survive. EGS Ex. 146 at 4. When the benefit of the credit is realized on a tax return, EGS defers the benefit and amortizes it as a reduction in the tax expense element of cost of service over the life of the asset producing the credit. *Id.* at 6. If there were no tax due, for example, the credit could not be used and the benefit would not accrue. If there is taxable income, and the ITC is used to offset the tax liability, then it is appropriate to amortize that ITC.

Because EGS took tax deductions related to the ARB, it did not utilize existing ITCs related to the abeyed portion of the plant. In Staff's recommendation for FIT, Ms. Romines excluded amortization of ITCs generated by the ARB expenditures, as required by the IRS (*See* GC Ex. 44 at 9, lines 11-12) but included an adjustment to amortize not only the utilized ITC but also the unutilized ITCs (ITC carry forwards and expired ITCs). Ms. Romines testified that this is not an actual tax adjustment, but rather is related to the consolidation of a utility's taxable income with the losses of its subsidiaries. In other words, because it is appropriate under the tax laws to disregard ITCs related to the abeyed portion of River Bend, so it is also correct to disregard the effects that the ARB tax deductions had on EGS's taxable income, and consequently on its utilization of ITCs. GC Ex. 44 at 8. The FIT included in the revenue requirement is the operating FIT, the FIT related to the allowed rate base. The ITC utilization for purposes of ITC amortization is based on the taxable income actually reported, adjusted for removal of ARB deductions. The adjustment increases hypothetically the amount of ITCs utilized, thereby increasing the amortization and decreasing FIT.

The ARB expenditures and tax benefits have not been included in rates; they have been taken below-the-line for ratemaking. Consequently, the related tax depreciation has created below-the-line, or non-operating NOLs. Therefore, according to Ms. Romines, all below-the-line effects of EGS's FIT, including limits on use of ITCs, should be removed. *Id.* at 10-11.

Finally, Ms. Romines assumed that all ITCs generated, except the ITCs generated by the ARB, would have been used but for the tax deductions associated with the ARB. If that assumption is not correct, then there would be a normalization violation. Therefore, she concluded it was imperative that EGS restate its requested FIT to remove *all* effects of the ARB and reflect a Texas jurisdictional allocator that removes the effect of rate orders issued by the Louisiana Commission. *Id.* at 11. Mr. Wright prepared restated FIT at EGS Ex. 148, Ex. JDW-11. Ms. Romines prepared an affidavit responding to Mr. Wright's attempt to recalculate ITC as Ms. Romines requested. GC Ex. 44B. In that affidavit, Ms. Romines concluded that EGS failed to appropriately account for all effects of the ARB in Mr. Wright's Exhibit JDW-11.

In his responsive affidavit, Mr. Wright admitted that he did not make an adjustment for the LPSC's actions regarding River Bend. Mr. Wright testified on rebuttal that the tax effects of the LPSC rate orders are excluded from the Texas jurisdictional income tax expense in the Company's filing. Also, EGS did not do a "with and without" calculation to determine if excluding the effect of ARB would result in no ITCs expiring. He assumed all would expire. EGS Ex. 148 at 32.

Mr. Warren testified for the Company that under Staff's proposal, the shareholders will, in effect, advance to customers a benefit that will be received by the shareholder at a later point in time or not at all. EGS Ex. 146 at 11. He fears that because the abeyed costs are reflected for tax purposes as depreciation claimed with respect to utility property, there exists a substantial risk that the regular ITC benefit-sharing rules continue to apply--no sharing can occur until the benefit is actually received. He felt this could be viewed as violating the ratable amortization limitation and the consistency rules incorporated into the Code. He relied on the private letter ruling (PLR) solicited under Docket No. 12852, which concludes that plant used in provision of utility service is public utility property. *See* EGS Ex. 146 at JIW-3. He recommended that if the Commission adopts Ms. Romines' proposal it do so contingent upon receipt of advice from the IRS that such treatment would not violate the normalization rules. *Id.* at 13-14.

General Counsel argues that on a hypothetical basis, a sharing of tax credits does occur as required by the Internal Revenue Code. This is because General Counsel does not recommend that the rate base be decreased by any of the unamortized ITC, utilized or not. GC Reply Brief at 55-56.

ALJs' Recommendation:

The ALJs conclude that it is appropriate, as an equitable treatment and as a matter of law, to disregard all effects of the abeyed portion of River Bend, which includes disregarding the tax deductions related to the ARB so that ratepayers receive the tax benefits related to the rate base upon which rates have been established. Also, because EGS has not provided all the information necessary to calculate the ITCs as Staff requested, i.e. the LPSC disallowance, Staff's recommendation should be adopted.

4. Interest Synchronization

All parties addressing the tax calculation used test-year interest expense synchronized with the cost of long-term debt to calculate the tax-deductible interest for ratemaking.[713] The amount of interest is based on the total rate base and cost of debt approved in this case.

F. Demand Side Management (DSM)

1. Test Year Programs

EGS seeks to recover $1,553,375 on a Texas retail basis for its demand-side management (DSM) program costs.[714] Excluded from its total costs, in accordance with P.U.C. SUBST. R. 23.21(c)(2)(F), are $1,666,151 in advertising and promotional expenses which promote the sale of electricity.[715] DSM programs are governed by the Commission's Energy Efficiency Plan (EEP) rule found at P.U.C. SUBST. R. 23.22. The EGS DSM programs include five residential programs, six commercial/industrial, and six economic development programs (EDPs). All other parties providing evidence on this issue recommended disallowance of these costs.

No issue stands out more clearly to the ALJs than this as an expenditure of funds totally in violation of Commission rules and past Commission practice. None of the monies expended on EGS's alleged DSM programs should be paid for by consumers; little or no benefits were realized by consumers; yet the net result of all of these programs was to increase revenues through increased energy usage and fuel shifting. The ALJs recommend the Commission disallow the entire amount.

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[713]EGS Ex. 99, Peters Direct at 30; GC Ex. 44 at 7; OPC Ex. 48 at 23.

[714]Revised Schedule N-2.1

[715]EGS Ex. 150 at 26; JTB-4.

In its initial filing, EGS asked for $1,857,415 in DSM costs, revised later to $1,553,375. In rebuttal, EGS witness Mr. Blakley testified that the new amount in Revised Schedule N-2.10 was derived by using a different methodology--cost of service methodology--not used in the original filing. Tr. 9401-9402. Mr. Blakley never explained why EGS changed its position about the use of the cost of service allocation factors and methodology; therefore, the General Counsel concludes that the original amount should be used to reflect the amount for the DSM programs. The ALJs disagree. The fact of the matter is that EGS plans to include only the $1,553,375 in cost of service, and we see no reason to disallow more than was requested.

a. The Programs

Almost every EGS DSM program is designed to and does, in fact, increase consumption of electricity.[716] In its prefiled case, EGS witness Kenneth M. Turner discussed the benefits of DSM as a resource plan to insure maximum flexibility for the Company. On the one hand, DSM can be viewed as an alternative to building new generating units. On the other hand, Mr. Turner testified that DSM has significant problems that make it unattractive at this time. EGS Ex. 106 at 27-28. For example, it raises major concerns from a stockholder perspective. "In particular, if competition occurs and the utility loses customers, then recovery of the DSM expenditures becomes doubtful." *Id.* at 29. The Company does not intend to implement any demand-reducing DSM programs in the short term. That is the Company's philosophy, which bears markedly on the types of DSM programs it instituted in the test year.

Mr. Jack T. Blakley explained all the programs in his testimony. EGS Ex. 90. Summarizing, EGS offers residential customers exterior lighting to enhance safety; encourages the replacement of existing water heaters with high-efficiency electric water heaters and heat pump water heaters;

[716]There may be an exception or two where a consumer is persuaded to move from a costly electric appliance to a more efficient electric appliance.

promotes installation of high-efficiency electric heating and cooling systems; promotes the design, construction, and sale of energy-efficient total electric single-family homes and apartments. The Company offers similar programs to commercial/industrial customers. For example, it offers energy efficient central electric space conditioning systems in large commercial buildings; promotes use of electric cooking equipment in food service facilities; promotes electrotechnologies for medical waste treatments, heat recovery options, and heat pumps for industry. Entergy's national accounts program and other EDPs are designed to influence national accounts and local entities to locate facilities within Entergy's service territories. EGS has research programs. A typical program determined the residential and commercial customers' saturation of electric appliances and equipment. Some of the research allows EGS to do load and energy use forecasting.

b. Parties' Analyses

Unlike EGS, it is the Environmental Defense Fund's (EDF's) position that DSM programs must contribute to energy efficiency, and each customer class should benefit from DSM programs. According to Mr. Daniel Kirshner, who testified for EDF, "Load building through new electric uses clearly does not increase energy efficiency and is sufficiently motivated by profit opportunities not to require general ratepayer support." EDF Ex. 2 at 3. He also emphasized that replacing standard air conditioning with high-efficiency heat pumps may be a legitimate DSM goal, but replacing gas heat with electric heat does not qualify as increasing energy efficiency. He testified that EGS's residential water heating program appears to be indiscriminate in its promotion of electric water heat.

OPC expert Mr. Kenan Ogelman testified that certain EGS's DSM programs that encourage all-electric facilities are consistent with an objective of increasing the EGS market share relative to gas technologies and have contributed to EGS's purported need to reactivate several previously retired power plants. He stated that shareholder interests are promoted when retired plants are brought on-line because they gain a return on the remaining capital cost. But EGS could design programs, if it had the will, that put more of the cost of DSM on the primary beneficiary, *i.e.* a loan for the purchase of DSM measures. Some of EGS's programs have a loan component, but all of the loans are for consumption-inducing programs. OPC recommends all DSM costs should be disallowed. OPC Ex. 53 at 4.

Staff witness Danielle Jaussaud agreed that to the extent programs that promote consumption of electricity are paid for by ratepayers they are anticompetitive. These same programs, she said, are not desirable if paid for by shareholders either because they promote inefficient appliances. GC Ex. 40 at 11.

It is EGS's policy that all DSM programs pass a rate impact measure (RIM) test. The RIM test assesses programs only in terms of their effect on rates. Unless the results are used in comparison with those calculated for the most likely supply-side alternative, the results of the test can be misleading--beneficial programs can be excluded by this test. This is because the revenue loss from a decrease in consumption has a negative effect under the RIM test that appears to diminish the positive impacts from avoided or deferred supply-side resources. OPC Ex. 53 at 5. *See also* GC Ex. 40 at DJ-7 which shows the Utility Cost Test (UCT) results for EGS's DSM programs. Each program shows a net-benefit loss under the UCT test, while at the same time showing a net-benefit gain under the RIM test.

Ms. Jaussaud testified that EGS failed to comply with its own EEP found at Schedule N-6 of the RFP. For example, the Company failed to provide the cost-benefit analysis for three out of the four of the required cost-benefit tests. Because EGS provided none of the information required by its EEP, it is impossible for the reviewer to assess whether the programs are designed and implemented prudently and can provide reasonable benefits to the customers compared to program *costs.* EGS has no evaluation plan for its programs nor protocol to verify the impact of them. *See* GC Ex. 40 at 6-7, Ex. DJ-4.

c. **Company Response**

In response, the Company agreed that it used the RIM test which screened out all conservation programs because the Company's avoided capacity cost was extremely low and because the Company felt such programs would increase rates. EGS Ex. 139, Turner Reb., at 55-56. Mr. Blakley disagreed that EGS's DSM programs promote increased consumption of electricity. He echoed Mr. Turner who testified that EGS's goal is to deliver reliable electric service and is open to all DSM options. The goal is also to encourage economic development, and if all DSM costs are disallowed, then the economic development costs will be lost as well. This is not appropriate, he testified, because other utilities have on-going economic development programs, and because they are good for Texas. EGS Ex. 150, Blakley Reb., at 7-9. He then described each economic development program.

Mr. Blakley denied that the Comfort Crafted Home and Apartment Programs are load building. The programs focus on keeping the operating cost at least neutral to that of a similar home constructed at code and equipped with base-level efficiency natural gas. He also protested the claim that these programs are load switching. He said, "When examining a program's impact estimates, it is important to remember that the kWh increase from one customer who was previously a natural gas customer, might overshadow the kWh savings from multiple customers replacing inefficient electric technologies." He also defended the Company's activities by saying they provide information on electric energy in a similar fashion to the way the Texas Railroad Commission provides information on gas suppliers. He said, "EGS's dilemma would be great if the Company was asked to provide efficiency information and then was penalized because customers use that information to select the system they feel best meets their needs for economy, comfort, safety, convenience and control."[717] *Id.* at 13-15.

[717]The ALJs are surprised that Entergy's Director of Retail Strategies would make such a statement and expect ratepayers to pay for programs that may not allow them to select a system that meets their needs.

In response to the claim that the DSM programs increase the system load factor, Mr. Blakley testified they actually improve the system load factor by filling valleys. The residential night watchman and commercial outdoor lighting programs use these low-load time frames. *Id.* at 16-17. Mr. Blakley could not defend any other DSM program in this manner. EGS argues that the Commission approved outdoor lighting programs in Docket No. 8425.[718] The total costs for these programs was $156,601. EGS Ex. 150 at 20, Ex. JTB-5; Schedule N-2.2.

ALJs' Recommendation:

OPC has taken a very strong stand to support energy conservation programs. That is a policing effort that could get lost in this changing regulatory framework. The ALJs are very much persuaded by OPC's evidence and argument on this issue. As OPC points out, P.U.C. SUBST. R. 23.3 defines "DSM resources" as activities that result in reductions in electric generation capacity needs or reductions in energy usage or both. OPC Brief at 31. None of EGS's programs meets this definition. The Commission has denied recovery of such program costs in the past, finding they promote marketing rather than conservation.[719]

EGS claims that several of its DSM programs encourage the efficient use of electricity by advertising methods of conserving energy or showing ways the consumer can effect a savings in total utility bills. The ALJs agree that is the effect when the consumer moves from standard electric appliances and heating and cooling systems to high-efficiency systems, but the evidence shows that all those programs move people away from more efficient gas fuel, as well.

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[718]*See* Findings of Fact Nos. 171-174.

[719]Docket No. 7195, 14 P.U.C. BULL 1943, 2394.

The ALJs find EGS's programs do not comply with standards established in P.U.C. SUBST. R. 23.22, the EEP rule, because the Company failed to provide sufficient information about its programs. Further, by using only the RIM test to establish the cost/benefit relationship, EGS has skewed the actual effect of these programs.[720] While not required by rule or the EEP to conduct all four cost-benefit tests, the Company is required to produce the result of those cost-benefit tests. Tr. 8507-8508. We conclude that the RIM test used in isolation is not reliable, and in fact is misleading.

EGS's programs that promote the construction of all-electric homes and apartments are anti-competitive because they caused a 100 percent conversion from the use of natural gas to the use of electricity.[721] OPC Exhibit 38 shows that before implementation of these DSM programs[722] the kWh usage for the program area was zero and the gas usage showed numbers of MMBtus used. After implementation of each program, the MMBtus went to zero, and the kWhs rose into thousands of hours used. EGS clearly admits this effect, but touts the fact that while energy usage increased, there was little effect on demand. We conclude that all EGS's DSM programs promote the consumption of electricity in violation of P.U.C. SUBST. R. 23.21(c)(2)(F), which states that funds promoting increased consumption of electricity shall never be allowed as a component of cost of service.

The DSM programs are not in the public interest, are contrary to established Commission policy, and all cost recovery should be denied.

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[720]*See Application of Houston Lighting & Power to Amend Certificate of Convenience and Necessity for the Dupont Project Generating Unit*, Docket No. 11000, 19 P.U.C. BULL. 1679, 1740, Finding of Fact No. 47 (Nov. 5, 1993) [hereinafter Docket No. 11000] where the Commission found use of the RIM test by itself was improper.

[721]*See* OPC Ex. 38; Tr. 6394-6395.

[722]These include the water heater conversion programs, residential conversion, residential and commercial space heater, the new construction programs, unitary and large commercial HVAC, and commercial food service programs.

The OPC separately criticized EGS's economic development programs. Those costs, being part of the DSM program expenses, are herein disallowed. EGS has not shown how its economic development research programs benefit the ratepayer. Mr. Blakley admitted at hearing that there is no evidence in the record to show any benefit to the ratepayer from these programs. Tr. 9376-9378. Further, as OPC notes, these are not DSM programs at all. OPC Brief at 33. Mr. Blakley testified only that they provide information to prospective customers and local community leaders and chambers of commerce. Tr. 9373-9374. The ALJs conclude that because EGS failed to prove that its economic development programs benefit ratepayers or are even DSM programs, those program costs should be disallowed.

2. Proposed Low Income Programs

This matter was stipulated to by certain parties; the issues were severed from this docket into PUC Docket No. 18088; and a PFD was presented to the Commission addressing all parties' positions regarding the stipulation. The Commission issued a final order in that docket on December 18, 1997.

G. Return on Invested Capital

EGS's reasonable return on Invested Capital is $269,354,000, based on the recommendations in this PFD.

H. EGS's Request for Good Cause Exception to P.U.C. SUBST. R. 23.23(b)(2)(B)(vi)(II) (Wheeling Expenses and Revenues)

In the Phase I Fuel Reconciliation proceeding in this docket, the ALJ granted EGS's request for a good cause exception to the fuel rule, P.U.C. SUBST. R. 23.23(b)(2)(B), which requires FERC Account 565 expenses and wheeling revenues to be considered reconcilable fuel items. These include the MSS-2 transmission equalization expenses imposed on EGS under the Entergy System Agreement. The good cause exception allows these to be considered base rate items for purposes of reconciling the fuel expense in this docket. However, Judge Stewart also denied the request of EGS for a good cause exception to the fuel rule for purposes of the final fuel factor approved in this case. This means that EGS's wheeling revenues and expenses will not be included in the revenue requirement beginning with the effective date of rates in this proceeding, but will be allocated to the fuel factor ratepayers as determined by the Commission in designing rates.[723]

EGS paid $12,098,918 to other Entergy operating companies under Service Schedule MSS-2 during the test year. EGS Ex. 9, Turner (Fuel) Direct, at KMT-3. The expense is related to investment in transmission plant-in-service and loads on the Entergy System. EGS Ex. 99, Peters Direct, at 9-10. The wheeling revenues relate to wheeling transactions for access service in the amount of $2,572,652 million[724] and for Company Service wheeling of $33,493,408[725] totaling net revenue of $23,967,142. The ALJs suggest the matter be handled as recommended by Staff witness Ms. Spence, as follows:

1. Reclassify the $12.1 million of FERC Account 565 expenses from O&M Not Adjusted to fuel expense;

2. Decrease the Company's requested fuel expense by $36,066,000 ($2,573,000 + $33,493,000) for Access and Company Service revenues. GC Ex. 42 at 7.[726]

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[723]*See* discussion of this issue in the Rate Design portion of this PFD.

[724]Schedule P, Workpaper WP/P page RV2-1, Class Cost of Service Analysis.

[725]GC Ex. 6, Panjavan, at 9.

[726]In errata to her testimony, GC Ex. 43, Ms. Spence also includes an amount for fossil generation expenses, $11,218,000, in the calculation of the reclassified wheeling expenses. The ALJs disagree with this reclassification, as it appears the $11,218,000 is already included in reconcilable fuel and not in base rates. If this is not correct, the Company should advise the Commission in its exceptions to the PFD that the reclassification of fossil generation expenses proposed by Ms. Spence should be implemented.

VIII. Treatment of SO_2 Allowance Sales

EGS credited its base rate revenue requirement in this proceeding with revenues of $46,950 from the sale of SO^2 allowances.[727]

Cities contend EGS should record its SO_2 allowance revenues in a suspense account until the Commission has made a policy determination regarding whether these allowances should be in base rates or part of the fuel reconciliation. Commission Project No. 16847 is pending--it will determine the regulatory treatment. This is a new market--allowance trading--and there is no historical pattern to determine the market value of each allowance. Furthermore, the Commission can address this issue again in EGS's November 1998 rate filing. Cities recommend the $46,950 be removed from "Other Revenues" and recorded in Suspense Account FERC #254 pending the Commission's ruling. Cities Ex. 102 at 51-56.

The OPC recommends the revenues on sales of SO_2 emissions allowances be recognized as credits to reconcilable fuel costs in years when the allowances apply. OPC Ex. 51 at 13.

EGS witness Mr. Wright testified that P.U.C. SUBST. R. 23.23(b)(2)(B) does not include these allowances as part of eligible fuel expenses; therefore, the Company included them in base rate revenues. This issue was not contested in Docket No. 12852, and the Company has been including them in revenues since they became effective in March 1994. EGS Ex. 148 at 105.

The ALJs agree with Cities that the revenues should continue to be recorded in FERC Account 254 as they should have been since the Commission ordered that result in EGS's last fuel

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[727] EGS Ex. 148 at 104; EGS Ex. 25C at 3.

reconciliation proceeding.[728] The fuel reconciliation case occurred in 1996, final order in June 1997, and is the most recent treatment of this issue by the Commission. Therefore, the $46,950 in SO_2 emission revenues should be removed from FERC Account 411.8 - Gains from Disposition of Allowances and recorded in FERC Suspense Account 254. This treatment would continue that of the prior proceeding and can be changed in the Company's next rate case should the Commission determine in its pending project that a different treatment is required.

IX. Preliminary Order Issues

A. What is the appropriate revenue requirement (and components thereof) to use in setting Texas jurisdictional rates for EGS:

a. absent approval of a transition to competition plan?
b. if a transition plan is approved?

See ALJ Schedule I attached. *See also* introduction to Revenue Requirement portion of the PFD.

B. Is the Company's plan for Plant Held for Future Use (PHFU) reasonable? Should the Commission require the Company to engage in competitive bidding to determine if third parties can provide resources more reasonably than the Company can from PHFU? (E.g., Neches Station Units 4,5,6 and 8; Louisiana Station No. 2, units 7, 8, 9).

See §V.E.

C. In reference to Entergy Corporation's recent agreement to manage and operate the Maine Yankee Nuclear Plant:

1. Is the Maine Yankee agreement representative of a competitive market price for the management and operation of a nuclear plant?

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[728] *Application of Gulf States Utilities, Inc. to Reconcile Fuel Costs*, Docket No. 15102, ___P.U.C. BULL.____, Order on Rehearing at 66, Finding of Fact No. 231 (June 24, 1997) (not yet published).

2. If yes, in comparison to Maine Yankee, are the management and operation expenses associated with River Bend reasonable?

Mr. Yelverton testified in supplemental direct testimony that it is not meaningful to compare the two units. They are operated by different companies with different objectives, and they are different types of facilities representing different nuclear technologies and have different regulatory requirements. Maine Yankee is a combustion engineering pressurized water reactor licensed and constructed prior to 1979, the time of the Three Mile Island (TMI) accident. River Bend is a General Electric boiling water reactor licensed and constructed after TMI. River Bend requires, for example, more base staff to meet its technical specifications and NRC license commitments which far exceed those imposed on Maine Yankee.

Furthermore, River Bend has made significant improvements in its operating performance, recently setting the standard for Entergy's nuclear plants in many areas. By contrast, Maine Yankee is currently under a regulatory shutdown and is not operating. EGS Ex. 185A at 3-4.

The agreement with Maine Yankee is not representative of a competitive market price for management and operation of a nuclear plant because that is not the purpose of the agreement. ENI is not managing and operating Maine Yankee. ENI provides only supervisory services and advice, as well as occasional limited technical, engineering, and administrative services. *Id.* at 5-6.

D. Is EGS used directly or indirectly to enhance the competitive position of its unregulated affiliates? If yes, is EGS's cost of service (or revenue requirement) adjusted accordingly to account for the benefits provided by EGS to its affiliates?

E. How is EGS reimbursed for services that it provides to other entities? Does EGS provide services to others under a cost-based, market-based, or some other pricing methodology?

1. **Does EGS credit its cost of service with the full amount of the revenues that it receives (or is allocated) from the entities to which it provides services?**

2. **If not, should EGS be required to credit its cost of service with the full amount of revenues received (or is allocated)?**

3. **Where an affiliated entity of EGS provides services or products to a third party, which services or products are based at least in part on EGS's resources (including EGS's personnel, computer hardware or software, business processes, expertise, know-how, etc.), has EGS's cost of service properly been credited with the value added by the EGS resources to the market value of the affiliate's service or product?**

Mr. Buck addressed these issues in his supplemental testimony. EGS Ex. 92. He stated that EGS did not provide any goods or services to Entergy Corporation or to any Entergy unregulated company and did not indirectly enhance the competitive position of these companies. *Id.* at 24. EGS did provide services to ESI, EOI, and to the Entergy operating companies. EGS bills for these services at cost. EGS does not credit its cost of service for the revenues from providing these services. Entergy's accounting system deducts the costs of providing the services directly from expenses each month. EGS's income statement is not affected, and the costs of providing the goods and services do not appear in EGS's cost of service as expense. *Id.* at 27-28. Mr. Buck did not discuss the last part of the question, regarding value added to the market value of the affiliate's service or product.

F. If EGS is receiving a service from another entity:

1. **Could EGS provide that service to itself at lower prices through its own employees?**

In supplemental testimony, Mr. Buck stated that EGS could not provide the service at a lower price because it would not enjoy the economies of scale available to Entergy service companies.

Mr. Buck included a chart that shows non-fuel O&M expenses have declined since EGS became part of the Entergy system due mostly to the economies of scale. EGS Ex. 92 at 10-11; Ex. LEB-13.

2. As an alternative, could EGS receive it through other, more efficient means?

The Company did not directly address this issue. There is no evidence of EGS's stand-alone bids or solicitations to determine costs for services and compare them to the services received from ESI or EOI. Mr. Uffelman testified in supplemental direct about incentives to lower costs through centralization of services and allocation of costs. EGS Ex. 94. He stated that benefits will accrue in cost savings, and regulators should consider such benefits of restructuring and exhibit flexibility in dealing with the issue of affiliate transactions and cost allocations. *Id.* at 6-7. Mr. Uffelman provided no EGS-specific data except he attached bill survey comparisons to his supplemental testimony. The ALJs reason that those non-fuel O&M rates for EGS were in place before the merger; therefore, one can not draw a conclusion about the economies of affiliate transactions causing EGS electric bills to compare favorably with other utilities.

3. Has EGS taken advantage of all reasonable opportunities to lower costs by "outsourcing" services, or otherwise acquiring services at market-based prices?

The evidence would not support a conclusion that EGS has taken advantage of all such opportunities to lower costs.

G. Has the Company appropriately allocated expenses to or from its Texas jurisdictional cost of service to account for the use, if any, of Entergy Texas employees at non-jurisdictional facilities? If EGS or an affiliate makes a profit by selling nuclear expertise to unrelated entities, how should Entergy Texas be compensated for providing that expertise?

H. Since the effective date of its last rate case, has Entergy (or EGS) transferred, or does Entergy (or EGS) have plans to transfer in the near future, employees from EGS to an affiliate(s) of EGS? If yes:

a. What were the titles and responsibilities of those who were transferred, and where did they appear on the EGS organizational chart?

b. What was the level of expertise of those who were transferred out of EGS, and what was the level of expertise of their replacements?

c. Has EGS been able to maintain an adequate level of reliability and safety despite the transfers?

Mr. Buck discussed transfer of EGS employees to Entergy affiliates. A very large number of EGS employees have transferred to ESI, EOI and a few other operating companies. Mr. Buck stated that only one employee had transferred to an unregulated company, and two have transferred to Entergy Nuclear, Inc. (ENI). An agreement between the operating companies requires transfers to be done at market value subject to SEC approval, unless such pricing method is detrimental to ratepayers. EGS Ex. 92 at 19; Ex. LEB-14a, para. 8. It appears to the ALJs from Mr. Buck's testimony, that EGS is not being harmed by movement of employees to non-regulated enterprises. For example, he argued that since no employee is compelled to take a position with ENI, presumably any transferred employee would be just as inclined to accept a similar offer from a non-Entergy entity. *Id.* at 22. Mr. Buck did not discuss the element of profit from selling expertise to unrelated entities.

Mr. Yelverton also addressed this issue in supplemental direct testimony. EGS Ex. 185A. He stated that expenses for use of EGS employees at non-jurisdictional facilities are charged to the entity receiving the services. The charges reflect all costs of providing the service. No EGS employees are being used by ENI. The SEC rules prohibit EGS and EOI from providing personnel or services to an unregulated entity like ENI. Thus, EGS will not profit from such activities. *Id.* at 7-8.

Costs are associated with the two ventures, one with the state of New York where negotiations were terminated prior to reaching an agreement and the other with Maine Yankee. All New York project costs were charged either to Entergy shareholders or to New York for reimbursement. Maine Yankee costs were accounted for separately and charged to ENI following its organization and capitalization. ENI does not charge any of its time or expenses to the regulated nuclear business. "The only nuclear support provided for Maine Yankee from an Entergy regulated subsidiary comes from the nuclear personnel who are on the Entergy Services, Inc. payroll. Their costs are captured and ultimately paid for by ENI, pursuant to an existing SEC approved service agreement between ESI and EEI, which is the parent company for ENI." *Id.* at 9.

Because the other parties declined to offer any evidence on affiliate issues after the decisions in Order Nos. 124 and 143, they did not address these affiliate questions, including questions C, D, E, and F above, in their evidence or in post-hearing briefs. *See* Section VII.A.6. above.

X. EGS's Rate Design Application

The primary purpose of the cost allocation/rate design phase of a rate case is to determine how the revenue requirement for the utility is to be recovered from the customers in the coming rate year. Once decisions are made about the costs that are to be borne by each rate class, rates are designed to recover those amounts. The following parties participated in the cost allocation and rate design phase:

General Counsel, the State of Texas, OPC, Texas Industrial Energy Consumers (TIEC), the Cities, High Load Factor Commercial Customer Group (HLFCCG), North Star Steel Texas, Inc. (NSST), and Low Income Intervenors (LII).

The Company's cost allocation and rate design proposals reflect changes stemming from the merger of Entergy Corporation and Gulf States Utilities Company. EGS used a cost allocation methodology different from GSU's prior cases to be consistent with Entergy System's other utility operating companies. The Company also proposed structural changes to its tariffs and has unbundled its rates in preparation for competition. The Company proposes no overall base rate increase, but redistributions of revenue recovery to apportion cost responsibility among customer classes differently.

XI. Adjusted Test-Year Sales and Revenues

P.U.C. SUBST. R. 23.21 requires electric utilities to base their rates upon the cost of rendering service during the historical twelve-month test year. Adjustments are made because base rates are set for prospective application. The rule specifically requires that adjustments to the historical test year reflect only known and measurable changes. EGS's adjustments reflect abnormal weather conditions, number of customers and miscellaneous reclassifications. In this case two adjustments are contested: a weather adjustment and a proposed adjustment to demand based on weather. The Company's other adjustments are not opposed.

A. <u>Weather Adjustment</u>

1. EGS' Proposal

A utility's test-year revenues need to be adjusted to reflect representative sales under normal weather conditions. When unusually hot or cold weather produces increased sales, the company's test-year revenues must be reduced to reflect representative revenues based on more normal weather conditions. In this case, EGS's sales revenues were larger than would normally be expected. EGS proposes a weather adjustment to test-year sales of -156,221 MWh for the residential customer class, -1,884 MWh for the SGS commercial class, -26,267 MWh for the GS commercial class, and -5,758 for the LGS commercial class. GC Ex. 74 at 3, Zhu Dir. EGS proposes a $9,069,594 base rate revenue reduction due to the abnormal weather. OPC proposes a smaller revenue reduction of $6,269,804. OPC Initial Brief at 5. General Counsel recommends that commercial sales not be adjusted and that residential sales be adjusted by -153,242 MWh. GC Initial Brief at 5.

2. OPC

OPC proposes a $6,269,804 weather-adjusted revenue reduction. OPC asserts that EGS's weather adjustment is fundamentally flawed, because the Company did not use weighted billing cycle sales matched with the weather occurring on each day. OPC contends that its witness Patrick Moast matched weather and sales by using weighted billing cycle sales data for each day of the month, which exactly matches weather to sales. OPC Ex 96 at 23. OPC asserts that the use of weighted billing cycle sales is the method recommended by the Electric Power Research Institute

(EPRI) and the American Gas Association (AGA). OPC Ex. 96 at 7-8; PM-Ex. 6 at 1. PM-Ex. 7 at 1 and 3; and PM-Ex. 8 at 1. OPC claims that the Company's approach of using two calendar months worth of weather to one month of sales is problematical. Mr. Moast testified that using "twice the number of degree days during the year to estimate sales is like double counting weather." OPC also contends that the Company's use of calendar month degree day weather data is explicitly discouraged by EPRI.

3. The EGS Response

EGS counters that nothing in Mr. Moast's methodology, except for his use of cycle weighted billing data, is grounded in any precedent or published methodology. The Company does not dispute that it has previously used cycle-weighted data, but claims that the unavailability of data on a current basis from the National Oceanographic and Atmospheric Administration (NOAA) during the test year made a cycle-weighted analysis impossible. Instead, the Company used a comparison of monthly sales to both the current and the prior month's data. Tr. at 12255. The Company contends that its use of two months of weather to compare with one month of sales is not inconsistent with the recommendations of EPRI and AGA, because the Company's method accounts for the fact that cycle billed sales occur over two consecutive months. EGS Ex. 169 at 7-8. Thus, the occurrence of weather is matched to the periods covered in the sales billing. *Id.* Although General Counsel witness Dr. Tom Zhu testified that the use of billing cycle weighted degree days "would be the best approach", he also testified that the Company's use of two months of data instead of cycle weighted data was acceptable. Tr. at 11519, 11531-32.

4. General Counsel's Position

According to General Counsel, EGS's weather adjustment for the three commercial classes is flawed, because EGS used aggregated data from the SGS, GS, and LGS rate classes to estimate a commercial class weather adjustment equation, but applied the weather adjustment to each commercial class separately. General Counsel asserts that EGS violated the statistical requirement that there be consistency between the level of data aggregation used to obtain a weather adjustment equation and the way the weather adjustment is applied. GC Ex. 74 at 7. General Counsel contends that a separate weather adjustment equation should be developed for each of the major rate classes, because weather sensitivity is different among rate classes. Dr. Zhu attempted to develop separate weather adjustment equations for each of the commercial rate classes, but he was unable to do so, because the quality of the data disaggregated by rate class was questionable. Id at 10.

General Counsel is concerned that EGS's proposed weather adjustments for the commercial rate classes will overly reduce test -year sales, allowing EGS to increase the rates that EGS would be authorized to charge. General Counsel asserts that EGS should not be permitted to benefit from its failure to manage the data needed for proper weather adjustments. General Counsel urges that the ALJs reject EGS's flawed weather adjustments for the commercial rate classes, and that EGS be ordered to correct the problems with the commercial class data so that proper weather adjustments can be performed in future rate cases.

5. The EGS Reply

Citing a Commission staff publication that states "some uniform method of weather adjustment is superior to no weather adjustment at all," EGS contends that its commercial weather adjustment should be used. EGS Ex. 169 at 19-29; EGS Ex. 162. EGS argues that the effect of Dr. Zhu's recommendation would be to make no weather adjustment at all for 22 percent of all kilowatt hours sold during the test year, which would guarantee a significant under-or overstatement of rate year sales. Tr. At 11553-54. EGS claims that General Counsel's recommendation would be punitive. EGS asserts that the use of aggregated commercial class data to perform a weather adjustment is consistent with the previously accepted Company filings in Docket Nos. 7195 and

Ex. 74 at Attachment TZ-6, p. 2. Other adjustments involved matters other than weather, customers, or reclassifications, such as correction of sales from a month outside the test year. *Id.* at Attachment TZ-6. Dr. Zhu reviewed these adjustments, found them to be appropriate, and recommended that they be adopted. *Id.* at 12-13. No party challenged these adjustments.

2. Cities' Objections

Cities assert that EGS used incorrect coincident peak (CP) demand data when it allocated production and transmission costs to steam operations. Cities recommend that the 12 CP value used by EGS (41,662 kW per EGS Schedule P 7-2, page 1) be replaced with the actual 12 CP average (54,092 kW) derived from information provided by EGS in response to discovery. Cities Ex. 150 at 19. EGS did not controvert this adjustment.

3. The ALJs' Findings and Recommendations

The ALJs recommend approval of EGS's adjustments to the RS, SGS, and GS classes based on the number of customers at the end of the test year, the several reclassification adjustments caused by customer transfers between classes, and the miscellaneous adjustments, because General Counsel considered them to be appropriate. The ALJs also approve the adjustment recommended by Cities that the 12CP values used by EGS be replaced with the actual 12 CP average (54,092 kW), as this recommendation is not controverted by the Company.

C. Demand Adjustment

1. The Issue

The issue is whether the Company's test-year demand (measured in MWs) should be adjusted for cost allocation purposes by the same percentage that test-year sales (measured in MWhs) are adjusted for number of customers and weather. General Counsel witness Dr. Zhu recommended that test-year demand be adjusted on an equal percentage basis as the energy/sales adjustment produced by the Company's customer adjustment and General Counsel's weather adjustment. GC Ex. 74 at 13-14; Tr. at 11558-59. EGS and TIEC oppose such an adjustment. OPC, General Counsel, and Cities support the adjustment. EGS did not provide any testimony to dispute the recommendation concerning the customer adjustments. However, EGS opposes demand adjustments to reflect weather normalization.

2. General Counsel's Position

General Counsel witness Dr. Zhu testified that many utilities make demand adjustments based on the assumption that the weather effect on energy is the same as the weather effect on demand. Tr. at 11560-61. General Counsel also claims that the Commission has previously ordered demand adjustments to reflect weather normalization. *Application of Texas Utilities Electric Company for Authority to Change Rates and Investigation of the General Counsel into the Accounting Practices of Texas Utilities Electric Company*, Docket No. 11735, 20 P.U.C. BULL. 1029, 1235-1236, 1374, 1430, 1456 (May 27, 1994). General Counsel also notes that the industry recognizes that both energy sales and peak demand are affected by the weather EGS Ex. 169 at 23-24.

8702. EGS Ex. 169 at 20. EGS sees no reasonable grounds for rejecting such an adjustment in this case. Citing its own witness, EGS finally asserts that the inconsistency in rate class information that Dr. Zhu found troubling is due to movement of customers among classes, not inaccurate data. *Id.* at 22. EGS concludes that its commercial class weather adjustment is reasonable, based on an acceptable methodology, and superior to making no adjustment at all for this large group of customers.

6. General Counsel's Response to the EGS Reply

General Counsel counters that EGS did not use a uniform method of weather adjustment. And EGS appears to admit that the equation did not indicate a good fit statistically when applied to the separate rate classes. Tr. at 11550, GC Ex. 74 at TZ-5.

The only issue that General Counsel has with EGS's proposed residential class weather adjustment is due to Dr. Zhu's use of more recent data, resulting in a residential weather adjustment of -153,242, which is 2 percent less than EGS's proposed adjustment. Tr. at 11564. EGS continues to support its own residential weather adjustment, by noting that Dr. Zhu used six months of test-year data, which is inconsistent with the Staff's internal guidelines directing that the data sample not include the test year. EGS Ex. 169 at 20,22-23.

7. The ALJs' Findings and Recommendations

The EPRI document upon which OPC relies in support of Mr. Moast's recommendation does not clearly support OPC's position. OPC Ex. 96, PM-Ex. 7. According to the publication, there must be a matching of weather data with sales data. The matching must reflect that customers are billed in different cycles for different days. Nowhere does the publication state that the weighted billing cycle sales is the method recommended by EPRI and AGA. Although the Commission may require companies to file billing cycle information in its rate filing package, it does not require the use of weighted billing cycle sales. Weighted billing cycle sales may be the best method, but there is no indication that the method the Company used is unacceptable. The Company's use of two months of weather to compare with one month of sales is not inconsistent and is not unreasonable. The ALJs, therefore, approve the overall weather adjustment methodology employed by the Company.

The ALJs do not, however, approve of EGS's weather adjustment for the commercial classes. The ALJs agree with General Counsel that the Company did not use a uniform method of weather adjustment. Moreover, EGS admitted that the equation did not indicate a good fit statistically when applied to the separate rate classes.

The ALJs recommend denial of General Counsel's residential adjustment because General Counsel did not controvert EGS's allegation that test data were incorrectly used.

B. Customer Reclassification and Miscellaneous Adjustments

1. The EGS Proposal

EGS performed an adjustment to the Residential (RS), Small General Services (SGS), and General Services (GS) classes based on the number of customers at the end of the test year to ensure that the rate design reflects the number of customers expected to be receiving service during the rate year. General Counsel witness Dr. Zhu testified that the Company's methodology was identical to that used by the General Counsel in previous cases.

The Company also made several reclassification and miscellaneous adjustments. Reclassification adjustments were made to reflect customer transfers between rate classes. GC

General Counsel admits that the weather in January and February 1997 was aberrant in two ways. Because the average temperature was warmer than normal and energy consumption was less, Dr. Zhu's weather normalization of energy increased the energy for those months. Under the method used by Dr. Zhu to adjust demand for weather, Dr. Zhu increased demand for those months by the same percentage as he increased energy. But his adjustment failed to consider that demand was higher than normal for the two months because of extremely cold temperatures a few days. General Counsel, therefore, recommends that the demands in January and February not be adjusted, but asserts that there is no evidence that the weather in the remaining months of the test-year was aberrant. General Counsel recommends that adjustments still be made to EGS's test year demand using the same percentage as the energy adjustments, except for the months of January and February.

3. The OPC Argument

OPC argues that a weather adjustment that reduces higher than expected revenues should also reduce the demand and energy costs that produced the revenues. OPC Ex. 97 at 11-15. Referring to the last rate cases of Texas Utilities Electric Company and Houston Lighting and Power Company, OPC asserts that the Commission routinely approves the application of the weather adjustment to the demand and energy data used for allocation in the class cost of service study, because atypical weather produces costs that may not reoccur. OPC Ex. 97 at 13. OPC reasons that costs will be arbitrarily set at a rate above that which normally occurs if revenues are reduced to reflect a typical weather and the demand that produced those revenues is not. OPC argues that EGS cannot have it both ways.

4. The Cities' Argument

Cities note that EGS has reduced test-year revenues based on the claim that weather during the test year was aberrant and increased test-year revenues to account for customer additions during the test year. Cities comment that EGS failed to make corresponding adjustments to the demand and energy data used to allocate costs among classes, which creates a mismatch between revenues and allocated costs. Cities assert that this mismatch creates a significant bias in the Company's allocation of costs among Texas retail rate classes, the largest impact of which occurs in the residential class, because 60 percent of EGS's growth adjustment and 85 percent of EGS's weather adjustment are the result of changes in residential billing determinants. Cities claim that EGS's combination of *pro forma* revenues, with unadjusted test year allocation factors, results in a net $3.6 million over-statement of the residential class's responsibility for Texas retail revenue requirement. Cities Ex. 150 at 17.

5. The EGS Response

EGS does not dispute that weather affects demand, but asserts that there is insufficient support for adjusting demand on an equal percentage basis as the weather adjustment to energy. EGS Initial Brief at 7. EGS witness Dillon testified that the electric industry is just beginning to focus on the need for tools and systems that provide accurate hourly energy and demand. He implied that EGS does not have the tools and systems necessary to determine an hourly load based weather adjustment. EGS Ex. 169 at 23-24. EGS asserts that the demand adjustment is too speculative and could result in an inaccurate allocation of the Company's revenue requirement. EGS takes issue with General Counsel's assertion that other utilities make this adjustment, noting that Dr. Zhu did not name the utilities to which he referred. EGS also challenges General Counsel's assertion that Commission precedent mandates the demand adjustment. EGS claims that the Commission provided no reasoning in support of adjusting billing demands for abnormal weather. Docket No. 11735, 20 P.U.C. Bull. 1029, 1235-38, 1374 (FOF 138), 1456.

6. TIEC's Argument

TIEC questions parties' efforts to adjust demands by applying the same percentage allocation change in demand data as in the sales data, asserting that demands do not follow energy adjustments, and because EGS did not have the data. TIEC points out that demand is calculated by looking at only one period in the month, whereas energy sales cover the whole month. Because demand in January and February was effected by a few unusually cold days, whereas energy sales were actually less than normal in those months because overall the months January and February during the test year were warmer than usual, there would be no correlation between the two. Tr. at 10733.

7. The ALJs' Findings and Recommendations

The ALJs are persuaded that a weather adjustment should be made to demand. Although EGS witness Dillon testified that the electric industry is just beginning to focus on the need for tools and systems that provide accurate hourly energy and demand, he did not state that it unreasonable at this point to make such an adjustment. Although energy sales and peak demands are not necessarily affected by weather in the same degree, there is also no indication that the difference is substantial. TIEC witness Ms. Theodora Carlson testified that it would have been more consistent if EGS had weather normalized allocation factors as well as revenues, admitting that there could be an impact on class allocations. Tr. at 10660-63. The ALJs determine that is not reasonable to ignore the issue. It would be inconsistent to allow EGS to adjust revenues but not demand. General Counsel recommends that the demands in January and February not be adjusted. But because there is no evidence that the weather in the remaining months of the test year was aberrant, the ALJs approve the adjusted demands recommended by Dr. Zhu for the remaining months.

The ALJs also approve the customer adjustments recommended by Dr. Zhu because there was no objection to them by EGS.

XII. Jurisdictional Cost Allocation

A. Preliminary Order Issue C-1

What are the appropriate jurisdictional and interclass cost allocation methodologies (and components thereof) to use in setting Texas jurisdictional rates for EGS (a) absent approval of a transition to competition plan?

B. Methodology

A cost of service study is used to allocate a utility's total cost of service to the jurisdictions and classes to which it provides service. EGS and General Counsel recommend a 12 coincident peak (CP) method to allocate production and capacity-related costs. The CP method is a commonly used production capacity-related cost allocation method. The CP method allocates costs on the basis of system peak. This method assumes that the system-peak drives all production capacity-related costs and assigns cost to customer classes based on each class's relative contribution to the system coincident peak demand. Multiple CPs rather than a single CP are often used. The 12CP method is based on the twelve monthly peaks of EGS's various jurisdictions, thus reflecting, to a degree, the kWh load patterns of EGS's jurisdictions. GC Ex. 76 at 12. EGS and General Counsel agree that the use of the 12CP method is appropriate because EGS uses the 12CP method to allocate the System Agreement costs to the Entergy operating companies, and EGS uses the 12CP method in two other jurisdictions--Louisiana and FERC. *Id.* at 12-13.

General Counsel also recommends use of the 12CP methodology for allocation of transmission capacity-related costs at the jurisdictional level. General Counsel asserts without challenge that it is appropriate to allocate jurisdictional transmission capacity-related costs in the same manner as jurisdictional production capacity-related costs, because the transmission system is considered to be an extension of the production system. *Id.* at 14.

The ALJs find that use of the 12 CP method reasonably allocates production capacity-related and transmission capacity-related costs.

C. Proposed Revisions to EGS Allocations

1. Weather Adjustment

OPC argues that EGS should make a weather adjustment for sales in other jurisdictions to reflect weather differences between Louisiana and Texas. OPC further asserts that even if one were to believe that the weather in Texas and Louisiana is identical, an adjustment is still required for jurisdictional cost allocation factors to develop a more accurate reflection of Texas retail costs, because customer class composition varies between the two states. OPC Ex. 97 at 14. Although the Company failed to address this issue, the ALJs are reluctant to approve OPC's weather adjustment without a more specific recommendation from OPC about how the adjustment should be made.

2. Special Rate Revenues

a. The Cities' Contentions

Cities assert that one of the consequences of increased competitive pressure is an increase in rate proposals designed to serve special needs and customers, which frequently foster or conceal cross-subsidies among jurisdictions. Cities recommend that EGS's adjustments to the following special purpose rates be reversed: Large qualifying facilities (LQF), Standby and Maintenance Service (SMQ), Short Term Maintenance service (MSS), and Economic-as-Available Power (EAPS). Cities note that EGS treats the sales and revenues for these special purpose rates as system sales. EGS removes the revenues from those rates from the Texas retail total. The revenues are then combined with corresponding Louisiana revenues. EGS then allocates the combined revenues among the Texas retail, Louisiana retail and FERC jurisdictions. Cities assert that the Company's treatment of "special rate" sales and revenues creates an opportunity for subsidies among jurisdictions. Citing actual test-year revenues, Cities note that EGS allocates $5.1 million of the total base rate revenues of $12,557,000 for the four special rates to Texas for a net loss of $396,000 in revenues to Texas. Cities Ex. 150 at 22; Cities Initial Rate Design Brief at 5.

Cities also complain about the accounting of fuel revenues from the special rates. They note that fuel charges for EAPS and SMQ services are based on incremental rather than average fuel expense. During the test year, incremental fuel expense was higher than system average fuel expense. For the Texas retail jurisdiction, the EAPS and SMQ tariffs produced $.679 million of fuel revenues in excess of revenues that would have been produced at prices based on system average fuel expense. Cities complain that EGS failed to pass this revenue surplus through to EGS's captive customers as a contribution toward the recovery of fixed production and transmission costs. Cities Ex. 150 at 25-26.

b. <u>OPC's Position</u>

In OPC's opinion, EAPS is a discounted rate for cogenerators. Unlike other discounted rates, OPC complains, EGS omits EAPS loads from the allocation factors when it divides costs between jurisdictions. Instead, EAPS revenues for the system are allocated back to the jurisdictions. OPC witness Clarence Johnson recommends that both the load and revenue be directly assigned to the jurisdiction in which the EAPS customer is served. OPC complains that assignment of the system revenues in the manner used by EGS allows each jurisdiction to export the discounts to the other jurisdictions. OPC asserts that the result of treating EAPS like other discounted rates would be a decline of $859,539 to Texas retail requirements and a decrease of revenues of $556,231 resulting in a net effect of an increase of $339,308 to Texas retail revenues.

c. <u>The EGS Response</u>

The Company urges the ALJs to reject Cities' and OPC's recommendations. EGS witness James Thornton testified that the EAPS, MSS, SMQ, and LQF tariffs are excluded from the allocation of costs in the cost of service study, while the revenues from each jurisdiction are totaled and allocated back to the jurisdictions and respective rate classes as compensation for use of the system. Mr. Thornton testified that the Company's method has been historically implemented by the Company and previously approved by the Commission. EGS Ex.172 at 17. He further testified that the loads have been historically excluded because of the unpredictable nature of the loads associated with the real time pricing and the "economy purchase nature of the EAPS rate and the standby nature of the MSS and SMQ rates." *Id.* He also stated that there are no loads associated with the LQF rate, because it is a tariff that establishes the procedures by which the Company purchases power from customer-owned generators. The revenues come from system hookup costs EGS charges. *Id.* Mr. Thornton sees no reasonable basis for the Commission to order a change in the current allocation method. He notes, however, that should Commission order direct assignment to each applicable jurisdiction, the associated revenue should be placed in Other Operating Revenues and be allocated as recommended by EGS witness Donald Peters so that the adjustment does not affect revenue requirement. *Id.* at 18-19. Peters recommends that the revenues and loads associated with the EAPS, MSS, SMQ, and LQF tariffs be collected in a separate class within the jurisdictions so that the loads can be used to appropriately allocate costs. EGS Ex. 165 at 47. To directly assign these revenues to the jurisdiction of origin without including the corresponding loads in the allocation factors would violate the principle of matching revenues with the associated costs. *Id.* at 47-48.

The Company also requests that the ALJs reject OPC's recommendation to treat the EAPS rate as a discount rate and to impute revenue to the Company as if the customers had taken under firm service. The Company notes that OPC would establish a separate class for EAPS loads and revenues. Revenues would be determined by capturing the actual revenue from EAPS sales and then imputing additional revenue resulting in a reduction of the revenue otherwise actually recovered by the Company. The Company argues that EAPS cannot be justified as firm service and therefore, no revenue should be imputed to the actual revenue received from EAPS customers.

d. ALJs' Findings and Recommendations

OPC and Cities have not provided sufficient justification for ordering changes in the current procedure. Although EGS may be willing to consider Cities proposal it did so with sufficient qualifications, the issues of which were not sufficiently explored. Moreover, OPC's recommendation is based on the premise that EAPS be considered a discount rate, which has been rejected by the ALJs in § XV.B.2. There is not a sufficient basis for implementing the recommendations of OPC.

D. Treatment of Wheeling Revenues

1. The EGS Request

In Phase I, the Company requested a good cause exception to the treatment of wheeling revenues prescribed in the fuel rule to include wheeling revenues and expenses in base rates. EGS's proposal also asks the Commission to allocate those revenues and expenses using demand allocators. General Counsel and Cities recommend that EGS's request be denied. The ALJs have recommended that the Commission deny EGS's request for a good cause exception. Therefore, the issue to be decided in Rate Design is how the cost of service study is affected by the denial of the request.

Recognizing that the Commission might deny the Company's request for a good cause exception, the Company recommends that Account 565 Expenses be allocated with the appropriate transmission demand-related factor. EGS Ex. 165 at 21. EGS also recommends that Access Service revenues be eliminated from "other revenues" in the Company's cost of service study and that they be included as a credit to reconcilable costs and allocated with the appropriate transmission demand-related factor. *Id.* In addition, EGS recommends that Company Services revenues, which would require a reclassification of Company services revenues from non-reconcilable to reconcilable, be allocated with the appropriate transmission demand-related factor and that all the wheeling rate classes be eliminated from all the cost of service study allocation factors. *Id.* at 23-26.

2. General Counsel's Response

In the Fuel Phase, General Counsel recommended allocating the total company eligible fuel expense and wheeling revenues and expenses to the Texas retail jurisdiction based on energy. In the Rate Design Phase, General Counsel witness Kit Szeto also recommends allocating eligible fuel expenses, including wheeling revenues and expenses, on the basis of the energy allocator. She eliminated the wheeling rate classes from the studies by excluding their billing determinants from all related allocation factors. This had the effect of allocating transmission costs to the wheeling classes. In response to EGS's assertions that General Counsel's treatment resulted in a double-dip allocation problem, Ms. Szeto revised the General Counsel's cost of service study so that the wheeling classes were not allocated any transmission costs. GC Ex. 77 at p. 1, # 5 and p. 52 of 154.

General Counsel also recommends allocating Account 565 expenses and Access Services revenues on the basis of energy, as it did in the Fuel Phase, asserting that Account 565 and Access Service revenues are part of eligible fuel expenses.

EGS contends that although General Counsel credited reconcilable costs with the amount of access service revenues, access service revenues were not eliminated from "other revenues" in

EGS's cost of service studies, resulting in access revenues being included twice. In response, General Counsel witness Szeto eliminated access service revenues of $2,573,000 from "other revenue" in the cost of service study. GC Ex. 77 at p.21, # 10 and p. 70 of 154.

3. The Cities' Recommendation

Cities recommend allocating net wheeling revenues on the basis of energy to conform with the energy based allocation of costs and revenue credits prescribed by the fuel rule. Cities Reply Brief at 2. Cities assert that it would be inequitable to allocate wheeling revenues on a kWh basis while allocating associated costs on the basis of 12 CP transmission demands. Cities recommend the following adjustments.

1. Decrease base rate revenue requirement allocated to each jurisdiction and each Texas retail class by an amount equal to net wheeling revenues. This decrease in revenue requirement should be allocated among jurisdictions and classes using the allocation factors applicable to high voltage transmission costs.

2. Match the first adjustment with an offsetting increase in base rate revenue requirement that is allocated among jurisdictions and classes in proportion to loss adjusted kWh sales.

Cities argue that the combination of the two adjustments would have no impact on total base rate revenue requirement, but would result in a net reallocation of transmission costs among jurisdictions and classes that neutralizes the redistribution of net wheeling revenues. Cities Ex. 150 at 46.

4. TIEC's Position

TIEC notes that it would support Cities' recommendation if certain adjustments beyond those recommended by Dr. Andersen are made to EGS's cost of service study. TIEC states that Dr. Andersen's recommendation is that net wheeling revenues be allocated on the basis of energy and that an adjustment be made in the base rate revenue requirement of each class that would compensate for the fact that wheeling revenues are being allocated on an energy basis even though they are demand related. TIEC asserts that these adjustments will ensure that the total cost paid by a class will not change if net wheeling revenues are credited to ratepayers through the fuel factor. The adjustments that TIEC recommends are:

1. The fuel factor should be lowered to reflect the offset for net wheeling revenues;
2. Fuel revenues should be recalculated based on the revised fuel factor;
3. Reconcilable fuel expense for each class should be set equal to fuel revenues, which should be lower because of the reflection of the offset for net wheeling revenues;
4. Transmission expenses should be increased by the amount of the net wheeling revenue because the revenue credit has to be transferred to reconcilable fuel expense; and
5. The adjustment to transmission expense should be allocated to the classes based on energy.

TIEC Ex. 27 at 9. TIEC requests that Cities' recommendation be adopted only if these adjustments are made in order to hold each class harmless from the allocation of net wheeling revenues on an energy basis.

5. Cities' Response to TIEC and EGS

Cities do not object to TIEC's adjustments as long as the adjustment to transmission expense that TIEC proposes "be allocated to the classes based on energy" is a direct adjustment to base rate revenue requirement rather than an adjustment to class cost of service calculations. Cities claim that windfall gains to high load factor classes will be avoided only if base rates are actually increased to compensate for the reduction in fuel expense that will result from the reconcilable treatment of wheeling revenues.

EGS points out that Dr. Andersen has identified the inequities of allocating Net Wheeling Revenues on an energy basis while allocating the associated costs on the basis of transmission demand, but EGS asserts that Dr. Andersen's recommendation only alleviates the problem for the test year. EGS asserts that its recommendation solves problems in the test year as well as for any changes to the level of Net Wheeling Revenues. EGS Ex. 165 at 28-29.

In response to EGS's criticism of Dr. Andersen's method, Cities note that any method can produce inequities as a result of changes in load, revenues, and costs from one rate case to the next. However, Cities counter that its procedure conforms with the allocation prescribed by the fuel rule.

6. ALJs' Findings and Recommendations

It appears to the ALJs that all the parties have attempted in one way or another to deal with inconsistencies caused by the dictates of the fuel rule. Cities recommendation is an attempt to cure the inequity of allocating wheeling revenues on a kWh basis while allocating associated costs on the basis of transmission demands. Unfortunately, in trying to promote consistency, more complexities arise. TIEC will accept Cities' method if further adjustments are made, to which Cities counters with an additional proviso. Whatever inequities have been caused by wheeling revenues being allocated on the basis of energy, they are not sufficient to negate use of the more appropriate transmission demand-related factor that is traditionally used to allocate transmission costs. The ALJs adopt the recommendation of General Counsel that wheeling revenues and expenses be allocated on the basis of energy. The wheeling classes should be eliminated from the cost of service studies by excluding their billing determinants from all related allocation factors. Wheeling classes should not be allocated any transmission costs, and access service revenues should not be included in Other Revenue.

XIII. Class Cost Allocation

A. Preliminary Order Issue C-1

What are the appropriate jurisdictional and interclass cost allocation methodologies (and components thereof) to use in setting Texas jurisdictional rates for EGS (a) absent approval of a transition to competition plan?

B. Methodology for Allocating Production and Transmission Plant

1. Introduction

Selecting a cost of service study is a process of identifying costs associated with generating and delivering electricity and then allocating those costs to classes in an appropriate way. The largest portion of a utility's revenue requirement is associated with its production and transmission plant. The choice of methodology for allocating those costs is generally one of the most contested issues in a rate case.

2. EGS' Recommendations

The Company originally recommended use of the average 12 CP method for allocating production and transmission at the class level. EGS Ex. 172 at 4-5. However, in rebuttal and at the hearing, EGS witness James Thornton testified that the average and excess (A&E) 4CP method was more appropriate, because extreme cold spells in January and February during the test year caused a greater than normal proportion of monthly coincident peak contribution by the residential class. EGS Ex. 172 at 6; Tr. 9878-9880.

3. General Counsel and TIEC Recommendations

General Counsel and TIEC recommend that EGS's Texas retail class production capacity-related and transmission capacity-related costs be allocated using the A&E 4CP method. TIEC asserts that the 12CP methodology is inappropriate for a utility like EGS, which has a pronounced summer peak. A 12CP methodology does not appropriately take the summer peak into account because it allocates demand-related costs based equally on usage in the off-peak months. TIEC argues that the 12CP methodology is inconsistent with actual electricity usage in Texas and with EGS's cost causation. Using an A&E 4CP methodology avoids the concern that the allocation factors could be distorted by questionable data, such as the demand data resulting from the extreme January and February 1996 weather. General Counsel asserts that the A&E 4CP method best recognizes the contribution of both peak demand and the pattern of capacity use throughout the year to production demand-related costs. GC Ex. 76 at 13. TIEC and General Counsel note that the A&E 4CP is the methodology approved for use by most of the investor-owned utilities in Texas, including West Texas Utilities Company, Houston Lighting & Power Company, Texas-New Mexico Power Company, El Paso Electric Power Company, and GSU in the past. GC Ex. 76 at 11; TIEC Ex. 21. General Counsel notes that use of different allocation methods for jurisdictional and class cost of service studies is not uncommon for multi-jurisdictional utilities. For purposes of consistency, General Counsel recommends using the A&E 4CP for allocation of transmission plant at the class level as well.

4. The OPC Proposal

OPC proposes using the A&E 12CP method for allocating production and transmission plant. OPC asserts that most parties, including EGS, General Counsel, and TIEC, agree that the A&E method should be used, but disagree about whether 12CP or 4CP is the appropriate measure of peak demand. OPC advocates the use of A&E 12CP because it most fairly recognizes the impact of class