> ***Collection Lag for Residential Customers***

As to the residential class, Mr. Joyce determined that the collection lag was 23.73 days. On behalf of the Cities, Mr. Pous disputed the accuracy of that estimate, complaining that it is substantially longer than the lag identified for commercial customers. Mr. Pous contended that Mr. Joyce determined the collection lag for residential customers by relying on a sample size that was too small. Mr. Pous examined the month-end accounts receivable data for ETI's entire residential class for the entire Test Year, and concluded that the collection lag for the class is actually 22.07 days (as compared to Mr. Joyce's figure of 23.73 days). Mr. Pous then calculated that this shorter lag period results in an additional negative cash working capital of $2.4 million.[75]

Mr. Joyce made several points in response. First, he noted that, although Mr. Pous is advocating reliance upon month-end accounts receivable data to calculate the collection lag in this case, he has testified in another proceeding that such data is unusable and unreliable. For example, in the Atmos Mid-Tex RRC proceeding, Mr. Pous argued *in favor* of measuring actual bill payment practices of actual customers (*i.e.*, the approach taken by Mr. Joyce in the present case) and *against* analyzing the monthly accounts receivable balances for each month of the Test Year (*i.e.*, the approach now being advocated for by Mr. Pous).[76] Next, Mr. Joyce disputed Mr. Pous' assertion that the sample size used by Mr. Joyce was too limited. According to Mr. Joyce, his sample of 100 residential customers is comparable to all of the residential collection lag calculations he has performed during his 15 years of performing lead-lag studies.[77] Mr. Joyce also accused Mr. Pous of inexplicably picking out a few data points, rather than relying upon the entirety of the sampling data, in order to derive his collection lag estimate.[78]

The ALJs are unpersuaded by Mr. Pous' criticisms and conclude that ETI has met its burden to show that the collection lag it utilized in the lead-lag study for residential customers is reasonable and appropriate.

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[75] Cities Ex. 5 (Pous Direct) at 77-79.

[76] ETI Ex. 54 (Joyce Rebuttal) at 13-15.

[77] *Id.* at 15-17.

[78] *Id.* at 17.

➢ ***Collection Lag for MSS-4 and ISB Affiliate Rate Classes***

As to MSS-4 and ISB rate classes, Mr. Joyce determined that the collection lags were 46.19 and 15.61 days, respectively.[79] Mr. Pous again disputed the accuracy of these estimates. Mr. Pous pointed out that the underlying data reveals that the majority of the MSS-4 revenue lag days range from 43 to 46 days, with only two values equaling or exceeding 50 days. Mr. Pous testified that the two values equaling or exceeding 50 days should be deemed unrepresentative and, therefore, excluded from the calculations for determining the average lag. Similarly, the majority of ISB revenue lag days range from 15 to 16 days, with only a few lags running as long as 22 days. Again, Mr. Pous contended that the longer revenue lag days should be deemed unrepresentative and excluded from the calculations for the average. Mr. Pous also complained that the payment deadlines for these affiliate transactions are stipulated in the Entergy System Agreement. Thus, it is Mr. Pous' opinion that ETI unreasonably contractually agreed to "excessively long" revenue lag days associated with the MSS-4 and ISB rate classes. Mr. Pous concluded that if what he considers to be the unrepresentative lag days are excluded from the calculations, then the collection lag would change for the MSS-4 class from 46.19 days to 45.14 days, and for the ISB class from 15.61 days to 14.77 days. Collectively, the lag for the two classes would be .77 days shorter, resulting in an additional negative cash working capital of $3.2 million.[80]

Mr. Joyce first responded by disputing Mr. Pous' contention that there are unusual outliers in the MSS-4 and ISB payment data. He noted that the lag days for MSS-4 payments ranged from 43 to 54 days. He described this as a "relatively tight payment range and certainly within the expected range of reasonableness."[81] Next, Mr. Joyce described Mr. Pous' assertion that outlier numbers should not be considered in the data as nonsensical. Mr. Joyce agreed that, in cases where sampling is used (such as was done for the residential customer class), it is appropriate to exclude data points that are unrepresentative of the population as a whole. In the case of the MSS-4 and ISB classes, however, Mr. Joyce determined the collection lag by reviewing the entire class populations.

[79] *Id.* at 18.

[80] Cities Ex. 5 (Pous Direct) at 79-81; ETI Ex. 54 (Joyce Rebuttal) at 18.

[81] ETI Ex. 54 (Joyce Rebuttal) at 19.

According to Mr. Joyce, it is inappropriate to eliminate data points when reviewing an entire population, unless it is necessary to make a known and measurable change.[82]

The ALJs are again unpersuaded by Mr. Pous' criticisms. The ALJs conclude that ETI has met its burden as to show that the collection lag it utilized in the lead-lag study is reasonable and appropriate.

(c) Receipt of Funds Lag

In the lead-lag study, Mr. Joyce identified the receipt of funds lag (*i.e.*, the delay between the date the funds are received from the customers and the date the funds clear the bank and are available to ETI). As required by P.U.C. SUBST. R. 25.231(c)(2)(B)(iii)(IV)(-d-), Mr. Joyce assumed that one business day is needed to clear any payments by methods other than electronic transfer, while electronic payments are available to ETI on the date received. Because 53.39 percent of customer payments were made by methods other than electronic transfer, Mr. Joyce calculated the receipt of funds lag to be .77 days.[83]

Mr. Pous again contended that this duration is too long. He acknowledges that P.U.C. SUBST. R. 25.231(c)(2)(B)(iii)(IV)(-d-) mandates the assumption that funds paid by check will be available "no later than" the following business day. However, he stated that this is merely the maximum possible duration, and ETI should take into account that fact that many checks are cleared (and therefore the funds are available) sooner than one day later. Therefore, the funds from all checks received on any day other than Saturday should be assumed to be available on the date of receipt, while the funds from checks received on Saturday should be assumed to be available two days later. Mr. Pous was also critical of the fact that Mr. Joyce treated the funds from all "walk-in" payments made by customers to be available the next day. Funds from walk-in payments ought to be deemed available on the date they are received. If these two changes are adopted, Mr. Pous

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[82] *Id.* at 19.

[83] ETI Ex. 17 (Joyce Direct) at 10. The receipt of funds lag is also sometimes referred to by the witnesses as the "cash receipts float."

contended that receipt of funds lag would be shortened from .77 days to .15 days, resulting in an additional negative cash working capital of $2.1 million.[84]

Mr. Joyce first responded by pointing out that Mr. Pous' contention that all funds are immediately available except for checks received on Saturdays is simply not accurate. Mr. Joyce cited from a 2007 Report to Congress made by the Board of Governors of the Federal Reserve System which supports the conclusion that most funds paid by check in this country are *not* available on the day they are received (and a significant portion are still not available the next business day).[85] Mr. Joyce also disagreed with Mr. Pous' contention that all walk-in payments should be considered immediately available. According to Mr. Joyce, walk-in payments are made at third-party vendor locations, such as grocery stores and check-cashing stores. Based upon his own investigation, Mr. Joyce determined that walk-in payments are actually available to ETI two days after receipt. Thus, his one-day assumption for walk-in payments is conservative.[86]

The ALJs conclude that ETI has met its burden as to show that the receipt of funds lag it utilized in the lead-lag study is reasonable and appropriate. The positions taken by Mr. Pous on this issue were unreasonable and counter to the requirements of P.U.C. SUBST. R. 25.231(c)(2)(B)(iii)(IV)(-d-).

2. The Expense Lead Component of the Lead-Lag Study

For the expense lead portion of his lead-lag study, Mr. Joyce calculated different expense lead days for numerous different categories of expenses. Each category will be discussed in turn.

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[84] Cities Ex. 5 (Pous Direct) at 81-82; Cities Ex. 5A (Errata No. 1).

[85] ETI Ex. 54 (Joyce Rebuttal) at 21-23.

[86] ETI Ex. 54 (Joyce Rebuttal) at 23-24.

(a) Expense Lead – Operations and Maintenance Expense

Mr. Joyce separated O&M expenses into two groups – energy costs and "other O&M" expenses. Each of those two groups was further divided into subgroups.[87]

➢ ***Energy Costs***

Fuel. Mr. Joyce explains that, during the Test Year, ETI purchased two kinds of fuel: (1) coal and oil; and (2) natural gas. He concluded that there were 44.27 expense lead days for coal and oil, based upon the time between the service periods and payment dates or payment due dates for all coal and oil invoices from the Test Year. As to natural gas, he determined that there were 40.63 expense lead days, based upon a comparison of the service period and payment due dates and the payment dates from a random sample of gas invoices.[88] No party challenged this approach, and the ALJs find no reason to do so either.

Purchased Power. Mr. Joyce explained that there were two components to ETI's purchased power energy costs in the Test Year: (1) MSS-4 Purchases; and (2) Other Purchased Power (consisting of Joint Account Purchases, MSS-3 Purchases, Reserve Equalization, Cogeneration Purchases, Renewable Energy Credits, and Toledo Bend Purchases). Relying upon either the entire population or a sample from the Test Year (depending upon the category), Mr. Joyce concluded that there were 58.76 expense lead days for MSS-4, and 35.79 expense lead days for Other Purchased Power.[89]

No party challenged the 35.79 day estimate for Other Purchased Power. However, on behalf of the Cities, Mr. Pous testified that the expense lead days for MSS-4 should be lengthened from 58.76 days to 60.65 days. According to Mr. Pous, Mr. Joyce made several errors in calculating the expense lead days for MSS-4 expenses. First, Mr. Joyce inadvertently placed the service period month after the billing month for two MSS-4 invoices. Mr. Pous based this conclusion on the fact that the expense leads for these two invoices are roughly 30 days shorter than the "vast majority" of

[87] ETI Ex. 17 (Joyce Direct) at 11.

[88] *Id.* at 11 and JJJ-3.

the other invoices.[90] In response, Mr. Joyce denied that he erroneously placed the service period month after the billing month, and pointed out that Mr. Pous lacks any evidence to support his assertion. Instead, Mr. Joyce considered the entire population of MSS-4 invoices for the Test Year. Those invoices show payment lead days ranging from 30 to 120 days, with most points being near 30, 60, or 70 payment lead days. According to Mr. Joyce, this is reasonable and well within the range he has experienced in other rate cases.[91]

Mr. Pous testified that Mr. Joyce erred in calculating the expense lead days for MSS-4 expenses by considering only the payment due dates specified in the Entergy System Agreement, rather than also considering the actual payment dates. According to Mr. Pous, in four instances during the Test Year, extensions were granted to ETI to allow it to make MSS-4 payments after the deadline specified in the Entergy System Agreement. Therefore, Mr. Pous stated that the expense lead days for MSS-4 payments should have been calculated using the later of the actual payment date or the allowable payment period.[92] Mr. Joyce largely agreed with Mr. Pous on this point. That is, he agreed that the payment lead days should be based on the later of the paid date or the due date. However, he disagreed with some of Mr. Pous' calculations on this issue because Mr. Pous wrongly designated several due dates of Saturday or Sunday, when he should have selected Fridays as the due date.[93]

Next, Mr. Pous testified that Mr. Joyce erred in calculating the expense lead days for MSS-4 expenses by erroneously concluding that one invoice had been paid on the first of the month when, in fact, it had been paid on the 18th of the month.[94] Mr. Joyce agreed with the change.[95] Mr. Joyce

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89 ETI Ex. 17 (Joyce Direct) at 12 and JJJ-3.

90 Cities Ex. 5 (Pous Direct) at 83-84.

91 ETI Ex. 54 (Joyce Rebuttal) at 26-28.

92 Cities Ex. 5 (Pous Direct) at 84.

93 ETI Ex. 54 (Joyce Rebuttal) at 28-29.

94 Cities Ex. 5 (Pous Direct) at 84.

95 ETI Ex. 54 (Joyce Rebuttal) at 29.

then recalculated the expense lead days for MSS-4 and revised the number of lead days from 58.76 to 59.81.[96]

The ALJs conclude that ETI has met its burden as to show that there were 59.81 expense lead days for MSS-4, and 35.79 expense lead days for Other Purchased Power.

➢ ***Other O&M Expenses***

This category of expenses was broken down in the lead-lag study into four groups – regular payroll costs, incentive payroll costs, affiliate service company costs, and all other O&M costs (such as materials, services, and so on).

Regular Payroll Costs. The lead days for regular payroll costs were computed by determining the average days of service being reimbursed and adding the days between the end of each service period and the payments to employees. This amount was then adjusted to incorporate the effects of vacation pay based upon actual ETI data. By this method, Mr. Joyce determined the expense lead for regular payroll costs to be 20.68 days.[97] No party challenged this approach, and the ALJs agree.

Incentive Pay Costs. ETI has an annual employee incentive program in place. Incentive payments for the year 2010 were made in the first quarter of 2011. The lead days for incentive pay costs were based on the weighted days between the midpoint of the service period (*i.e.*, July 1, 2010) and the date the incentives were paid (March 10, 2011). By this method, Mr. Joyce determined the expense lead for incentive pay costs to be 251.77 days.[98] No party challenged this approach, and the ALJs agree.

Affiliate Service Company Costs and Other O&M Costs. Charges from Entergy Services, Inc. (ESI) are paid in the month following the month in which the charges were incurred. The lead

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[96] ETI Ex. 54 (Joyce Rebuttal) at JJJ-R-2.

[97] ETI Ex. 17 (Joyce Direct) at 13 and JJJ-3.

[98] *Id.* at 14 and JJJ-3.

days for affiliate service company costs were based on the number of days from the mid-month to the later of the contractual due date or the actual settlement date in the following month. By this method, Mr. Joyce determined the expense lead for affiliate service company costs to be 39.64 days.[99]

The lead days for other O&M costs were based on a random sampling from the Test Year. Mr. Joyce originally determined the expense lead for other O&M costs to be 47.46 days.[100] However, to correct an error on his part, Mr. Joyce subsequently revised the expense lead time for other O&M costs down to 43.89 days.[101]

Mr. Pous testified that ETI's "FAS 106-related expenses" were wrongly included in either the affiliate service company costs or the other O&M costs. FASB is the body that establishes the rules that constitute GAAP. FASB's Statement Number 106 (FAS 106) establishes the standards for an employer's treatment of the non-cash retirement benefits it gives its employees. Based on the action taken by the Commission in Docket No. 16705,[102] Mr. Pous believes that ETI's FAS 106 costs should have been separately identified and accounted for in the lead-lag study. He contended that, when those costs are properly accounted for, it results in an additional negative cash working capital of $3.8 million.[103]

Mr. Joyce contended that the prior Commission decision upon which Mr. Pous relies, Docket No. 16705, dates from 1996, is inapplicable to the facts in the present case, is outdated, and has been superseded by subsequent Commission decisions. Mr. Pous advocated a 312.55-day expense lead for FAS 106 expenses. However, Mr. Joyce pointed out that, during the Test Year, ETI made its FAS 106 payments to a trust at the end of each month, resulting in a one-half month payment lead (15.25 days). Mr. Joyce testified that his treatment of FAS 106 expenses in his lead-lag study is

[99] ETI Ex. 17 (Joyce Direct) at 15, and JJJ-3.

[100] *Id.* at 15-17, and JJJ-3.

[101] ETI Ex. 54 (Joyce Rebuttal) at JJJ-R-2.

[102] *Application of Entergy Gulf States, Inc. for Approval of Its Transition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Underrecovered Fuel Costs*, Docket No. 16705, (Oct. 13, 1998).

[103] Cities Ex. 5 (Pous Direct) at 85-88.

consistent with the approach that was approved by the Commission in a recent Oncor ratemaking case, Docket No. 35717.[104]

The ALJs conclude that ETI met its burden to show that there were 39.64 expense lead days for Affiliate Service Company Costs and 43.89 expense lead days for Other O&M Costs.

(b) Expense Lead – Current Federal Income Tax Expense

As required by P.U.C. SUBST. R. 25.231(c)(2)(B)(iii)(IV)(-f-), Mr. Joyce calculated the lead days for federal income taxes by measuring the days between the midpoints of the annual calendar year service periods and the actual dates on which ETI made its estimated quarterly tax payments. By this method, Mr. Joyce determined the expense lead for current federal income tax costs to be 38 days. He then determined that this resulted in a $1.6 million cash working capital requirement associated with the Company's Federal Income Tax Expenses.[105]

Mr. Pous testified that the Company's cash working capital requirement for Federal Income Tax Expenses ought to be a negative number or, at most, zero. He bases this argument on his assertion that, during the past five years, the Company "has received in excess of a net $90 million of refunds" on its federal income taxes. In other words, because "refunds produce cash" for the Company, Mr. Pous contends that the Company is seeking a positive cash working capital requirement for cash transactions "that have not been made and are not being made."[106]

Mr. Joyce responds by disputing Mr. Pous' contention that "refunds produce cash." Mr. Joyce points out that any refund from the IRS merely represents a return of the Company's own cash for payments previously made. Moreover, Mr. Joyce stresses that his approach for calculating the expense lead for current federal income taxes is perfectly consistent with: (1) the requirements of P.U.C. SUBST. R. 25.231(c)(2)(B)(iii)(IV)(-f-); (2) current IRS guidelines found at IRS Publication 542; and (3) Commission precedent. Mr. Joyce further points out that, by contrast,

[104] ETI Ex. 54 (Joyce Rebuttal) at 29-32.

[105] ETI Ex. 17 (Joyce Direct) at 17, and JJJ-3.

[106] Cities Ex. 5 (Pous Direct) at 88-89.

Mr. Pous' approach has been consistently rejected by the RRC.[107] The ALJs find Mr. Joyce's arguments to be more persuasive on this point and conclude that ETI has met its burden as to show that the expense lead for current federal income tax costs it utilized in the lead-lag study is reasonable and appropriate.

The ALJs conclude that ETI met its burden to show that there were 39.64 expense lead days for Affiliate Service Company Costs and 43.89 expense lead days for Other O&M Costs.

(c) Expense Lead and Lag – Taxes Other than Income Taxes

This group of taxes consists of: (1) payroll-related taxes; (2) ad valorem taxes; (3) Texas state gross receipts taxes; (4) the PUC assessment tax; and (5) Texas state franchise taxes. Calculating from the midpoints of the work periods to the respective payment dates of the taxes, Mr. Joyce determined that the payroll taxes had an expense lead time of 16.45 days. As to the franchise taxes, Mr. Joyce concluded that the Company had a collection lag of 46.42 days because the Company was required to pay the taxes in May 2010. As to the other non-payroll-related taxes, Mr. Joyce calculated from the midpoint of the period for which the tax was assessed to the payment date, resulting in the following expense lead days: 213.51 days for ad valorem taxes; 74.28 days for Texas state gross receipts taxes; and 225.50 days for the PUC tax.[108] No party challenged this approach, and the ALJs agree.

F. Self-Insurance Storm Reserve [Germane to Preliminary Order Issue No. 5]

In Docket Nos. 16705 and 37744, the Commission authorized ETI to maintain a reasonable and necessary storm damage reserve account of $15,572,000.[109] As of June 30, 1996, ETI had a positive reserve balance of $12,074,581, constituting a reduction to rate base. Over the next 15 years, ETI charged $101,670,803 to the reserve related to more than 200 storms (excluding securitized events), but it accrued only $29,796,478 through base rates. Thus, ETI's end-of-test-year

[107] ETI Ex. 54 (Joyce Rebuttal) at 33-36, JJJ-R-1.

[108] ETI Ex. 17 (Joyce Direct) at 18-19, and JJJ-3.

[109] Staff Ex. 4 (Roelse Direct) at 8.

balance for its storm damage reserve in the present case was a negative \$59,799,744.[110] This negative balance is an addition to rate base.[111]

OPC and Cities argue that ETI's current storm damage reserve negative balance should be adjusted. OPC contends that ETI failed to prove that its storm damage expenses booked since 1996 were reasonable and prudently incurred, so it recommends disallowing all of those charges and refunding to customers the resulting positive balance that exceeds the authorized balance. Alternatively, OPC suggests that ETI's negative balance be reset to its currently authorized balance, with no refund to customers. Cities contend that ETI's current negative storm damage reserve balance should be reduced because it includes: unreasonable expenditures associated with a 1997 ice storm; expenses associated with former assets in Louisiana; and amounts that Cities claim should have been treated as insurance deductibles. Cities also recommend transferring ETI's Hurricane Rita Regulatory Asset to the storm damage reserve. The parties' recommendations are summarized as follows:

Party	Reserve Balance
ETI	(\$59,800,000)
Cities	(\$34,051,597)
OPC-1	\$41,871,059
OPC-2	\$15,572,000

1. The Effect of Prior Settled Cases

As with the Hurricane Rita Regulatory Asset (Section V.B.), the effect of the black-box settlements in Docket Nos. 34800 and 37744 is a significant issue concerning the storm damage reserve. However, the parties' positions are generally reversed from the positions taken on the Hurricane Rita Regulatory Asset. That is, ETI now argues that its storm reserve negative balance was resolved and approved in those settled dockets, while Cities and OPC argue that it was not.

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[110] \$12,074,581 + \$29,796,478 – \$101,670,803 = (\$59,799,744).

[111] P.U.C. SUBST. R. 25.231(c)(2)(E).

ETI notes that the final orders in Docket Nos. 34800 and 37744 contained "stipulated and agreed upon" conclusions of law stating that overall total invested capital through the end of the test year in those cases met the requirements of PURA § 36.053(a) that electric utility rates be based on the original cost, less depreciation, of property used by and useful to the utility in providing service.[112] Then ETI cites language in P.U.C. SUBST. R. 25.231(c)(2)(E), which provides that any deficit in a self-insurance plan will be considered an increase to rate base, or invested capital. As a result, ETI argues, the Commission could not make a determination that a rate base expense item was included in rate base as used and useful without also determining that the rate base expense was prudently and reasonably incurred.[113] Thus, ETI asserts, a Commission conclusion of law that approved invested capital as meeting the requirements of PURA § 36.053(a) necessarily also determined that an expense included in rate base was prudently and reasonably incurred. In other words, ETI states, the "prudent and reasonable" standard is incorporated into the "used and useful" standard in PURA § 36.053(a).[114] Therefore, ETI argues that by issuing a final orders in Docket Nos. 34800 and 37744 with conclusions of law that ETI's overall total invested capital met the requirements of PURA § 36.053(a), the Commission implicitly approved the negative balances of its insurance reserve in both prior dockets; consequently, those orders preclude litigation in the present case of whether those expenses were prudently and reasonably incurred.[115]

Cities reject ETI's contention that the storm damage reserve balance was approved in Docket Nos. 34800 and 37744. Cities point out that in order to comply with PURA, all final orders in rate cases must include a conclusion of law stating that the overall total invested capital through the end of the test year meets the requirements of PURA § 36.053(a). However, Cities contend, pursuant to

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[112] PURA § 36.053(a) provides: "Electric utility rates shall be based on the original cost, less depreciation, of property used by and useful to the utility in providing service."

[113] ETI cited: *City of Alvin v. Public Util. Comm'n of Texas*, 876 S.W.2d 346, 353-354 (Tex. App.—Austin, 1993, no pet.); *see also Application of Gulf States Utilities Company for Authority to Change Rates*, Docket Nos. 7195 and 6755, 14 P.U.C. BULL. 1943 at 1969 (May 16, 1998) ("dishonest or obviously wasteful or imprudent expenditures constitutionally can be excluded from a utility's rate base. Such costs clearly are not used and useful in providing serviced to the public.").

[114] ETI cited Docket No. 7195, 14 P.U.C. BULL. at 1969 ("the prudent investment test is embodied in traditional ratemaking principles as expressed through PURA Sections … 41."). PURA Section 41(a) is the predecessor to current Section 36.053.

[115] ETI Initial Brief at 20-22; ETI Reply Brief at 17.

the parties' agreements in Docket Nos. 37744 and 34800, no determination was made as to what was included in ETI's total invested capital in those cases. Cities explain that in Docket Nos. 37744 and 34800 Cities claimed that certain expenses were not properly included in the storm reserve balance, while ETI argues that they were. However, neither Cities nor ETI's recommendation was specifically approved as part of the base rate settlement and neither of their recommended balances may be considered as the basis for setting rates in those dockets.[116] Thus, Cities argues, in such "black box" settlements no specific storm reserve balance is approved unless expressly stated. Cities also argues that the final orders in Docket Nos. 37744 and 34800 could just as logically be interpreted as denying ETI's request to include objectionable expenses in the storm damage reserve, because both orders specified that the revenue requirement approved in those cases did not include any prohibited expenses. Finally, Cities states that adoption of ETI's arguments would make black-box settlements impossible in the future.[117]

OPC makes arguments similar to Cities, and notes that no storm damage reserve amount was either agreed to by the parties or approved by the orders in either Docket No. 34800 or Docket No. 37744.[118]

The ALJs find that the Commission did not implicitly approved all of ETI's storm damage expenses and its storm damage reserve balances in the final orders in Docket Nos. 34800 and 37744. Although the orders in those settled cases contained conclusions of law the that overall total invested capital through the end of the test year met the requirements of PURA § 36.053(a), the orders made no findings of what the total invested capital included, and specifically there were no findings or conclusions approving the amount of the storm damage reserve. As pointed out by Cities, in those dockets the intervenors disputed various items in ETI's requested storm damage reserve, but the "black box" settlement did not specifically address those issues; consequently, it is as logical to conclude that objectionable expenses were excluded from the storm damage reserve and from the total invested capital as it is to conclude that the objectionable expenses were included. In

[116] Docket No. 37744, Final Order at Ordering Paragraph 14; *Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs*, Docket No. 34800 at Ordering Paragraph 12.

[117] Cities Reply Brief at 22-26.

[118] OPC Reply Brief at 7-8.

Section V.B., the ALJs conclude that ETI's Hurricane Rita regulatory asset should be considered as being included in the black-box settlement and final order in Docket No. 37744, even though the settlement and order did not expressly state how the Hurricane Rita regulatory asset issue was resolved. However, that issue involved unique circumstances and is distinguishable because PURA § 39.459(c) required the Commission to consider the insurance payments for the Hurricane Rita restoration expenses in ETI's next rate case, which was Docket No. 37744; ETI requested a true-up in that docket of the insurance proceeds it received concerning the regulatory asset; and no party objected to ETI's proposed regulatory asset or its proposed amortization. In contrast, intervenors in Docket Nos. 34800 and 37744 did object to ETI's proposed storm damage reserve and, under those circumstances, it is not possible to determine how the issues concerning the storm damage reserve were resolved by the black-box settlement. Therefore, the ALJs find that the black-box settlements and final orders in Docket Nos. 34800 and 37744 neither approved nor disapproved the reasonableness and necessity of ETI's storm damage expenses incurred since 1996 or ETI's current storm damage reserve negative balance.

2. OPC's Proposed Adjustment

OPC witness Nathan Benedict testified that ETI failed to prove that any of its $101,670,803 in storm damage expense booked since 1996 was prudently incurred, so he recommended disallowing all of those charges and refunding to customers the resulting positive balance that exceeds the authorized balance. Removing those charges would leave ETI with a current positive storm reserve balance of $41,871,059 (beginning balance of $12,074,581 + accruals of $29,796,478). This balance exceeds the currently approved storm reserve balance of $15,572,000 by $26,299,059, and Mr. Benedict proposed that this surplus be refunded to rate payers at a rate of $1,314,953 per year for 20 years. Mr. Benedict acknowledged that some storm damage expenses incurred by ETI since 1996 likely were reasonable and necessary. Therefore, as an alternative proposal, Mr. Benedict suggested that ETI's current storm balance reserve be set at the last approved amount of $15,572,000 (*i.e.*, without any surplus or deficit). This proposal would result in a $75,363,744 reduction to ETI's current storm damage reserve negative balance and rate base.[119]

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[119] OPC Ex. 6 (Benedict Direct) at 6-16; OPC Initial Brief at 19.

As discussed above, OPC disagrees with ETI's argument that the Commission implicitly approved these expenses in the final orders in Docket Nos. 34800 and 37744.[120] Therefore, OPC argues that ETI had to prove in the present case that the expenses were prudently incurred. Concerning ETI's burden of proof, OPC acknowledges that, although a utility has the ultimate burden to prove that its proposed rates are just and reasonable, once the utility establishes a *prima facie* case of prudence of a rate change, the burden shifts to the other parties to produce evidence to rebut that presumption. Then, if the other parties rebut the presumption, the burden shifts back to the utility to prove by a preponderance of the evidence that the challenged expenditures were prudent. However, OPC notes, if the utility fails to establish a *prima facie* case, the burden of going forward with evidence never shifts to the other parties.[121] In OPC's opinion, ETI never established a *prima facie* case because ETI's spreadsheet of storm damage expenses was excluded from evidence and ETI witness Greg Wilson acknowledged on cross examination that he made no analysis of whether ETI's storm damage costs were reasonable and necessary.[122]

ETI complains that Mr. Benedict simply sought a global rejection of more than $100 million of expenses without any evidence to support his position, and it stressed that even Mr. Benedict acknowledged that some of ETI's expenses were prudently incurred. ETI also states that, in any event, it met its burden of proof with regard to expenses booked to the storm damage reserve.

Concerning its proof, ETI states that its burden was to make a *prima facie* case supporting the prudence of its invested capital,[123] and once it made that showing, the burden shifted to the opposing parties to overcome the presumption of prudence by presenting evidence that reasonably challenged the expenditures.[124] This is the same position as OPC. ETI argues that it met its burden to prove a *prima facie* case.[125] ETI notes that it provided storm cost data accompanied by narrative testimony

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[120] OPC Reply Brief at 7-8.

[121] OPC Reply Brief at 2-3, *citing, Entergy Gulf States, Inc. v. Public Utility Comm'n*, 112 S.W.3d 208 (Tex. App. – 2003, pet. denied).

[122] OPC Reply Brief at 1-5.

[123] ETI Initial Brief at 22, *citing, Application of Texas Utilities Electric Company for Authority to Change Rates*, Docket No. 9300, 17 P.U.C. BULL. 2057, 2148, Order on Rehearing (Sept. 27, 1991).

[124] Docket No. 9300, 17 P.U.C. BULL. at 2148.

[125] Although ETI contended that the storm damage reserve has been approved in prior dockets, it argued that

that supported the reasonableness of ETI's self-insurance plan; storm preparedness and response; service quality; and cost of labor, materials, and services used to carry out distribution activities (including system restoration). For instance, ETI states, it presented its proposed storm reserve balance through the direct testimony of Mr. Greg Wilson[126] and in the Commission's rate filing package.[127] Mr. Wilson also explained the function of ETI's self-insurance program, described the $50,000 threshold to exclude minor weather events, and provided work papers detailing the nominal and trended losses for each storm booked to the reserve since 1986, as well as annual and total loss levels.[128]

Further, ETI witness Shawn Corkran presented testimony regarding subject matters that directly support the ability of the system to withstand storms, and ETI's ability to reasonably and efficiently respond to storm events, thereby supporting the conclusion that reasonable and necessary costs are booked to the storm reserve balance. This evidence included ETI's distribution operations, industry-recognized comprehensive storm plans, annual storm drills, storm response and restoration processes, distribution maintenance and asset improvement processes, service quality and continuous improvement programs, and vegetation management practices. ETI points out that Mr. Corkran also described how it prepares for emergency situations,[129] and Mr. Corkran explained how charges to the storm reserve are captured and recorded.[130] Mr. Corkran also noted that ETI has received either the Edison Electric Institute's Emergency Assistance Award or Emergency Response Award every year since 1998, which recognize ETI's exemplary storm restoration response.[131] Likewise, Mr. Corkran discussed ETI's reliability statistics since 2000, which demonstrated a high quality of service,[132] and he provided four exhibits demonstrating that, on both per-kilowatt-hour (kWh) and per-customer

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its evidence also supported storm damage charges going back to July 1, 1996. ETI Initial Brief at 23, n. 147.

[126] ETI Ex. 14 (Wilson Direct) at 11.

[127] ETI Ex. 3 (Schedules) at Schedule B-1, line 7; Schedule WP_B-1, page 7.

[128] ETI Ex. 14 (Wilson Direct) at 5-7; WP GSW-3_1.

[129] *Id.* at 28.

[130] *Id.* at 93.

[131] *Id.* at 29.

[132] *Id.* at 12-29.

bases, ETI's distribution O&M costs compared favorably to the costs of other utilities.[133] In ETI's opinion, because it carried out its distribution activities in the same efficient and cost-effective manner while performing routine activities as during storm restoration, those metrics and reliability statistics support the reasonableness of costs booked to the reserve.[134]

ETI also argues that it supported the reasonableness of the costs booked to its storm reserve through the direct testimony of its supply chain witness, Mr. Joseph Hunter. Mr. Hunter explained that ETI's procurement policies and procedures are designed to streamline the acquisition of materials and services through the use of strategic supply networks in order to achieve the lowest reasonable cost.[135] Mr. Hunter also described how the centralization of the supply chain function on a system-wide basis provides greater leverage and buying power in the procurement of materials and, thus, lower costs than could be achieved by ETI alone.[136] Furthermore, Mr. Hunter specifically noted that the standardization of supply chain activities "makes possible a smoother day-to-day operation as well as *rapid response to major storms or emergencies*."[137]

Finally, ETI stated that it provided an extensive amount of storm reserve data through the discovery process, which provided a basis for any interested party to investigate the reasonableness of any particular storm response or expenditure booked to the reserve. It stressed that OPC witness Benedict acknowledged that ETI provided 420 pages and over 22,220 lines of detail reflecting every charge to the storm reserve over the last 15 years,[138] which specified the month, year, state, project code, work order type, function, storm name, account number, resource code, resource code description, and amount.[139] Therefore, ETI argues that it made a *prima facie* case regarding its storm reserve through the presentation of narrative testimony, schedules, work papers, and expense detail

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[133] *Id.*, Exhibits SBC-2A, SBC-2B, SBC-2C, and SBC-2D.

[134] ETI Initial Brief at 22-24.

[135] ETI Ex. 16 (Hunter Direct) at 5, 9-10, and Exhibits JMH-1(Entergy Companies' Procurement Policy) and JMH-3 (Entergy Companies' Approval Authority Policy).

[136] ETI Ex. 16 (Hunter Direct) at 17.

[137] *Id.* at 18 (emphasis added).

[138] Tr. at 1703.

[139] Tr. at 1704.

and, accordingly, the burden shifted to parties seeking to disallow the expenses allocated to the storm damage reserve to present evidence that reasonably challenges their prudence.[140] Yet, ETI contends, OPC did not challenge any specific expenditure booked to the reserve other than the 1997 ice storm expenses discussed later. Therefore, ETI argues that it met its *prima facie* burden and OPC's proposed disallowance of either $101,670,803 or $75,363,744 should be denied.[141]

Although it is a close call, the ALJs find that ETI established a *prima facie* case that its storm damage expenses incurred since June 30, 1996, were prudently incurred. A *prima facie* case is a low burden. It is not the same as a preponderance of the evidence. Rather, as stated in *Town of Fairveiw v. City of McKinney, prima facie* evidence "is merely that which suffices for the proof of a particular fact until contradicted and overcome by other evidence."[142] Similarly, Black's Law Dictionary defines a *prima facie* case as sufficient evidence "to allow the fact-trier to infer the fact at issue and rule in the party's favor."[143]

Except for expenses incurred with the 1997 ice storm, ETI did not present any testimony that explicitly stated that the expenses included in its storm damage reserve were prudently incurred. However, ETI did present sufficient other evidence that at least allows the ALJs to infer that the expenses were prudently incurred. As noted above, a reasonable inference from the evidence presented is sufficient to establish a *prima facie* case. ETI witness Gregory Wilson presented testimony about the background of the storm damage reserve and about ETI's yearly major storm damage losses, although OPC is correct that he did not explicitly evaluate or determine whether ETI's expenses were reasonable and necessary.[144] In addition, OPC witness Benedict provided testimony that ETI has booked $101,670,908 to the storm damage reserve since 1996,[145] and that ETI's $50,000 threshold is a means of excluding from the reserve small storm-related expenses that ETI could anticipate as routine O&M expense and which should be excluded from the storm damage

[140] Docket No. 9300, 17 P.U.C. BULL. at 2147.

[141] ETI Initial Brief at 22-26; ETI Reply Brief at 16-19.

[142] 271 S.W.3d 461, 467 (Tex. App. – Dallas 2008 pet. denied).

[143] Black's Law Dictionary, 8th Ed. (2004).

[144] ETI Ex. 14 (Wilson Direct) at Ex. GSW-3.

[145] OPC Ex. 6 (Benedict Direct) at 7-8.

reserve.[146] ETI presented testimony that it had not recorded storm damage expense to both the storm damage reserve and to O&M expense,[147] and Mr. Benedict agreed that he had no information to contradict this[148] or that any securitized costs were charged to the storm damage reserve.[149] Although the document itself was excluded from evidence, Mr. Benedict testified that ETI provided him with a 420-page spreadsheet covering all of ETI's storm damage expenses back to 1996, including the month, year, state, project code, project name, work order type, function, storm name, account number, resource code, resource code description, and amount.[150] In addition, ETI provided other testimony described previously concerning its distribution operations, storm plans, storm response operations, purchasing procedures, and the like.

ETI did not present a witness who specifically testified that all of its storm damage expenses booked to the storm damage reserve were prudently incurred, except for expenses related to the 1997 ice storm. Such testimony would have been more helpful than the evidence ETI relied upon. Nevertheless, the burden of establishing a *prima facie* case does not require such direct testimony, if a fact can be reasonably inferred from other evidence presented. The ALJs reiterate that it is a close call, but they find that ETI did present sufficient evidence to infer that the expenses charged to the storm damage reserve were prudently incurred. At that point, the burden shifted to OPC to produce evidence to challenge specific expense items included in the storm damage reserve, but OPC did not present any such evidence except for the items discussed below. Therefore, the ALJs recommend that the Commission not adopt either of OPC's recommended denials of expenses contained in ETI's storm damage reserve.

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146 Tr. at 1694.

147 ETI Ex. 72 (Wilson Rebuttal) at 2-3.

148 Tr. at 1695-1696.

149 Tr. at 1698.

150 Tr. at 1704.

3. 1997 Ice Storm

ETI's proposed negative storm reserve balance includes $13,014,379 in expenditures associated with a 1997 ice storm. Cities and OPC contend that this expense should be excluded from the storm balance reserve.

Cities witness Pous explained that ETI first requested to include the 1997 ice storm expense in the storm damage reserve as a post test year adjustment in its 1995-1996 test-year rate case, Docket No. 16705. The Commission denied the requested post test year adjustment and stated that the expense should be considered in ETI's next rate case. Thereafter, ETI had a series of rate cases (Docket No. 20150 – 1998 rate case; Docket No. 30123 – 2004 rate case; Docket No. 34800 – 2007 rate case; Docket No. 37744 – 2009 rate case) in which intervenors challenged the 1997 ice storm expenses, but those cases all settled or were otherwise concluded without any express decision concerning the prudence of ETI's 1997 ice storm expenses.[151] Mr. Pous testified that these expenses are now appropriately at issue in the present case, and he recommended that the entire balance be excluded from the storm damage reserve. He pointed out that in Docket No. 18249, the Commission found that ETI's poor quality of service exacerbated the extent of damage caused by the storm, and it found that the response efforts were uneven and delayed and could have been more effective if ETI had a better communication and management program in place.[152] Mr. Pous also contended that in the present case ETI failed to prove that any portion of the 1997 Ice Storm expenses were reasonable.[153]

Thus, Cities argue that the Commission has already determined that ETI's negligence was a major factor in the extent and duration of the outages,[154] so no expenses associated with the 1997 ice storm should be eligible for recovery from customers through the storm damage reserve. In response to ETI's argument that it was already penalized for these issues in Docket No. 18249 through a

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[151] Cities Ex. 5 (Pous Direct) at 49-55.

[152] *Entergy Gulf States, Inc. Service Quality Issues Severed From Docket No. 16705*, Docket No. 18249, Final Order at FoF 97, 98, & 102 (Apr. 21, 1998).

[153] Cities Ex. 5 (Pous Direct) at 56-59; *see* Cities Initial Brief at 18-19.

[154] Cities Initial Brief at 18 ("The Company's failure to clear the limbs before the storm was a major factor in the number and duration of outages experienced by customers.").

reduction to the allowed ROE, Cities argue that the Commission did not absolve ETI from responsibility for damage caused by ETI's poor service quality, and ETI's customers should not be ordered to pay for expenses that were caused by ETI's negligence.[155]

OPC makes the same arguments as Cities concerning the 1997 ice storm expenses.[156]

ETI argues that, due to quality of service issues related to the 1997 ice storm, the Commission reduced Entergy Gulf States, Inc.'s (EGSI) ROE by 60 basis points in Docket No. 18249 and subjected EGSI to significant spending requirements and quantified performance guarantees. In ETI's opinion, it would be inequitable to now penalize ETI a second time for the same issues. Moreover, ETI argues that it established that its expenses were reasonable and necessary. ETI witness Shawn Corkran testified that the 1997 ice storm was the most destructive winter storm ever to hit the EGSI/ETI system, with about 3,400 miles of distribution lines and 560 miles of transmission lines de-energized during the storm's peak. A large part of the restoration effort involved clearing broken and fallen trees and tree limbs from lines. Mr. Corkran reviewed all of the costs incurred in response to the 1997 ice storm and stated that they were reasonable and necessary to reliably restore service to customers as quickly as possible after the storm. He provided an exhibit with a detailed breakdown of labor, materials, transportation, lodging, and other expenses incurred. In his opinion, all of these costs charged to the storm damage reserve, totaling \$13,014,379, were reasonable, necessary, and prudently incurred.[157]

The ALJs recommend that the Commission authorize ETI to include in the storm damage reserve its \$13,014,379 in expenditures associated with the 1997 ice storm. ETI established that those expenses were reasonable and necessary to repair the damage and restore power to its customers. ETI witness Mr. Corkran provided detailed testimony concerning the seriousness of the storm and the resulting expenses incurred for repair work and restoration of power to customers.[158]

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[155] Cities Reply Brief at 28-30.

[156] OPC Ex. 6 (Benedict Direct) at 12; OPC Initial Brief at 16; OPC Reply Brief at 7-10.

[157] ETI Ex. 48 (Corkran Rebuttal) at 2-12.

[158] ETI Ex. 48 (Corkran Rebuttal) at 2-12 and Ex. SBC-R-1.

In contrast, Cities and OPC did not challenge any specific item in these restoration expenses. Instead, they relied upon the Commission's findings in Docket No. 18249 that ETI's deficient maintenance exacerbated the amount of damage caused by the storm. However, in that docket the Commission also reduced ETI's ROE by 60 basis points due to poor service issues, including deficient preventative maintenance. The Commission made the reduction in ROE retroactive and required ETI to make refunds to customers. Likewise, in that docket the Commission found that the ice storm was severe and that significant damage would have occurred even with exemplary vegetation management and other preventative measures. It is not feasible to accurately determine now what portion of ice storm damage that occurred 15 years ago was caused by preventative maintenance issues.

The ALJs conclude, however, that the Commission's retroactive reduction of ETI's ROE in Docket No. 18249 in part compensated ratepayers for the poor service issues that exacerbated the storm damage. Nevertheless, once the ice storm occurred, ETI had to take appropriate action to repair the damage and restore service. ETI has established the expenses incurred in those efforts were reasonable and necessary, and the ALJs find that they should be included in the storm damage reserve. Therefore, the ALJs recommend that the Commission deny Cities and OPC's proposed adjustment.

4. Jurisdictional Separation Plan Allocation

Cities complained that ETI's storm damage reserve deficit includes $12,498,325 in costs that belong to Louisiana jurisdiction customers but were incorrectly transferred to Texas customers during implementation of the Jurisdiction Separation Plan. Cities explain that before the jurisdictional separation of EGSI into ETI and Entergy Gulf States Louisiana, LLC (EGSL), the transmission investment and expense associated with maintaining the transmission system, including storm restoration costs, was allocated between the Texas and Louisiana retail jurisdictions. In the jurisdictional separation of EGSI into ETI and EGSL, the transmission system investment was split between each company based upon a situs basis. The transmission facilities in Texas were transferred to ETI and the transmission facilities in Louisiana were transferred to EGSL. After the jurisdictional separation, ETI and EGSL were each responsible for future O&M expense, including storm restoration expense, associated with their respective transmission investments.

Cities claim that in the present case ETI has attempted to reverse the allocation of expenses incurred on behalf of Louisiana customers before the jurisdictional separation and to charge those expenses to Texas customers through the storm damage reserve. In Cities' opinion, any expense that was allocated to Louisiana customers prior to the jurisdictional separation was properly charged to Louisiana customers. Cities argue that ETI may not now reverse expenses allocated to Louisiana customers and charge them to Texas customers solely on the basis that ETI acquired the transmission investment located in Texas.[159]

In response, ETI witness Considine explained that an analysis of storm reserve charges was preformed prior to the jurisdictional separation to determine if storm charges were incurred for Texas or Louisiana property. The reclassification of certain charges was made as a result of that analysis, which is in evidence, to properly reflect the state in which the storm charges were incurred. The largest charge assigned to ETI through this analysis was a $10,652,130 charge related to project "E2PPSJ8291 Trans EGSI-TX Hurricane Rita 9-24-05," which expressly related to damages to the Texas portion of the former EGSI transmission system. Similarly, costs were assigned from ETI to EGSL for projects such as "E2PPSJ8296 Trans. Hurricane Katrina - EGSI-La" and "E2PPSJ8302 Trans EGSI-LA Hurricane Rita 9-24-05," that clearly related to assets located in Louisiana. In other words, prior to the separation, the Texas portion of the storm damage reserve could include charges for restoration work performed on assets located in Louisiana, and vice versa. The analysis conducted pursuant to the separation re-aligned the charges to the jurisdiction where the assets are located. In that way, ETI argues, neither jurisdiction has charges in its storm reserve balance for assets located in the other jurisdiction. In short, ETI argues that the assets and liabilities following the separation have been properly assigned and no improper cost shifting occurred.[160]

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[159] Cities Ex. 5 (Pous Direct) at 59-60; Cities Initial Brief at 19-20.

[160] ETI Ex. 46 (Considine Rebuttal) at 25 and Ex. MPC-R-3 at 25; ETI Initial Brief at 19-36; ETI Reply Brief at 20-21.

The ALJs recommend that the Commission deny Cities' proposed adjustment. ETI offered evidence to explain how its reclassification study reassigned various costs from the Texas jurisdiction to Louisiana, as well as from the Louisiana jurisdiction to Texas. This study resulted in more expenses from Louisiana being reassigned to the Texas jurisdiction than from Texas to Louisiana, but Cities offered no evidence to explain why the study was flawed or why the reassignments were in error. The ALJs found ETI's evidence to be credible and that it supported the jurisdictional allocation of these expenses as proposed by ETI.

5. $50,000 Reserve Threshold

Cities witness Pous also proposed a $10,950,000 reduction to ETI's negative storm damage reserve balance due to ETI including in the reserve the first $50,000 of expense for each separate storm event. Mr. Pous asserted that this amount is equivalent to a deductible for insurance purposes and should have not been charged to the reserve. Cities note that P.U.C. SUBST. R. 25.231(b)(1)(G) requires that a storm reserve only collect for "property and liability losses which occur, and which could not have been reasonably anticipated and included in operating and maintenance expenses." Because of ETI's low $50,000 threshold, Cities contend, ETI has recorded to the storm reserve expenses associated with 219 different weather events in the past 15 years. This equates to approximately 14.6 weather events per year, or 1.2 weather events per month, on average. In Cities' view, ETI's booking to the storm damage reserve of all expenses associated with a weather event exceeding $50,000 – including the first $50,000 – is inconsistent with P.U.C. SUBST. R. 25.231(b)(1)(G). Cities argue that ETI may not reasonably claim that such a recurring expense is "not reasonably anticipated" to qualify it for the storm reserve. Cities proposed adjustment is based on $50,000 for each of the 219 storm events, for a total of $10,950,000. In addition, based on the nature of ETI's recurring storm expense, Cities also recommend that the deductible amount be increased to $500,000, which Cities stated is consistent with the storm reserve treatment afforded to other utilities in Texas.[161]

ETI witness Gregory Wilson testified that Mr. Pous misconstrued the $50,000 trigger when he treated it as a deductible. Mr. Wilson explained that if a storm causes $50,000 or less in damage,

[161] Cities Ex. 5 (Pous Direct) at 61-63; Cities Initial Brief at 20-21.

the expenses are not charged to the storm damage reserve. However, if a storm causes more than $50,000 in damage, all of the expenses are charged to the reserve. He noted that if the $50,000 were treated as a deductible, then that amount would still be charged to O&M whenever storm damage exceeded the $50,000 threshold. But, under the current arrangement, when storm damage exceeds $50,000 all of the expenses are charged to the storm damage reserve, and the first $50,000 is not charged to O&M. Therefore, no double recovery occurs. Moreover, ETI argues that Cities' proposed retroactive removal of these amounts from the reserve would constitute a disallowance of costs without any finding of imprudence, as well as impermissible retroactive ratemaking. ETI also contends that even if the Commission were to implement Mr. Pous's recommendation prospectively, it would require a corresponding increase in ETI's O&M costs. Therefore, ETI disagreed with Cities' recommendation to reduce the current balance of the storm damage reserve by $10,950,000 or to change the current level of the threshold.[162]

The ALJs find that Cities' proposed adjustment to ETI's storm damage reserve is not warranted. ETI explained that the $50,000 threshold amount was included in the storm damage reserve whenever storm restoration expenses exceeded the threshold, but that amount was not included in O&M expense. Accordingly, no double recovery has occurred, and Cities presented no other valid reason to disallow the allocation of these expenses to the storm damage reserve. Therefore, the ALJs recommend that the Commission deny Cities' proposed $10,950,000 adjustment to ETI's current storm damage reserve balance. As a policy matter, the Commission may choose to increase ETI's threshold on a prospective basis to some higher amount, as recommended by Cities, but the evidence presented by the Cities on this issue was not sufficient for the ALJs to make such a recommendation.

6. Hurricane Rita Regulatory Asset

As discussed in Section V.B., Cities recommend an adjustment to the Hurricane Rita regulatory asset, and they recommended the adjusted balance be moved to the storm damage reserve. For the reasons stated in Section V.B., the ALJs recommend that the Commission not adopt Cities' proposal to move the Hurricane Rita regulatory asset to the storm damage reserve.

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[162] ETI Ex. 72 (Wilson Rebuttal) at 2-3; EIT's Initial Brief at 27-28; ETI Reply Brief at 21-22.

7. Conclusion

In conclusion, the ALJs find that ETI's storm damage expenses since 1996 and its storm damage reserve balance were not approved by the Commission as a result of the black-box settlements in Docket Nos. 34800 and 37744. The ALJs also find that ETI established a *prima facie* case concerning the prudence of its storm damage expenses incurred since 1996 and that intervenors' proposed adjustments should be denied. Therefore, the ALJs recommend that the Commission approve ETI's test-year-end storm reserve balance of negative $59,799,744.

G. Coal Inventory

ETI is the partial owner of two coal-fired power generating facilities. It owns a 29.75 percent interest in Nelson 6, a 550 megawatt (MW) unit located in Westlake, Louisiana (Nelson), and a 17.85 percent interest in Big Cajun II, Unit 3, a 588 MW unit located in New Roads, Louisiana (BCII/U3). EGSL is the majority owner and operator of Nelson and is responsible for the supply and delivery of coal to that facility. A third party, LaGen, is a co-owner of BCII/U3, and is the operator of the plant. Pursuant to a joint operating agreement between the co-owners, LaGen is responsible for the acquisition and delivery of coal to BCII/U3. The coal for both units comes, via train, from minefields in Wyoming.[163]

Entergy has adopted a "Coal Inventory Policy" at Nelson to ensure that a sufficient coal inventory is always maintained on-site to help mitigate transportation and unit operating risks. The policy calls for, among other things, a 12-month average inventory target of a 43-day supply of coal. Because Entergy is not the operator of BCII/U3, it does not have ultimate control over the coal inventories at that unit. Pursuant to the joint operating agreement for that unit, however, each year ETI nominates for the next calendar year the level of coal to be delivered for its account at BCII/U3. ETI's nomination process is targeted to ensure an end-of-year inventory target of a 43-day supply of coal.[164]

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[163] ETI Ex. 33 (Trushenski Direct) at 3-4.

[164] ETI Ex. 33 (Trushenski Direct) at 30-31.

In its application, ETI includes a coal inventory amount in its rate base that is based upon the average inventories at Nelson and BCII/U3 for the 13 months ending in June 2011.[165] The average coal inventory at Nelson was 384,860 tons, representing approximately 48 days of inventory, assuming an average daily burn rate of 8,000 tons. The total proposed dollar amount for the coal inventories at both facilities is $9,846,037. Of that total, the Nelson portion is $6,040,926, and the BCII/U3 portion is $3,805,111.[166] ETI witness Ryan Trushenski, the Manager of the Solid Fuel Supply Group for ESI, testified that the coal inventory levels that were maintained at Nelson and BCII/U3 during the test year were reasonable and the costs incurred to maintain those levels were reasonable.[167]

Cities do not challenge the reasonableness of the Company's 43-day inventory targets. Rather, Cities point out that the size of the actual inventory that was maintained on-site at Nelson during the Test Year exceeded the Company's inventory target level. Therefore, Cities contend that customers should not be forced to pay for inventory levels exceeding a 43-day supply (the amount that the Company determined, through its Coal Inventory Policy, to be a reasonable and necessary inventory to maintain on-site). According to Cities' witness, Karl Nalepa, a 43-day inventory of coal at Nelson would equate to 340,000 tons. He recommends that the value of a 43-day supply of coal be included in the rate base, but that $1,451,415 be excluded from the rate base to account for inventory at Nelson that was in excess of the 43-day supply.[168]

The evidence shows that the Company's inventory "target" was a 43-day supply, while actual inventories during the Test Year averaged around a 48-day supply. Mr. Trushenski pointed out, and the ALJs concur, that the 43-day "target" was never intended to represent a hard and fast figure from which no deviations could be allowed. Rather, the target merely represents an operational planning tool. Moreover, there are many real-world factors – such as train cycle times, coal burn rates, and so

[165] ETI Ex. 68 (Trushenski Rebuttal) at 2. Notably, the amount ETI is seeking in its Rate Base is calculated upon a 13-month average ending June 2011 (the last month of the Test Year), even though that amount is slightly *less* than the 12-month average for the Test Year.

[166] ETI Ex. 68 (Trushenski Rebuttal) at 2, and 3 at WP/P RB 4.2.

[167] ETI Ex. 33 (Trushenski Direct) at 30-31.

[168] Cities Ex. 6 (Nalepa Direct) at 28-29, 6C and 6E.

on – that can cause the actual coal inventory to fluctuate over time.[169] The ALJs conclude that the 48-day coal inventory was acceptably close to the 43-day target and was not unreasonable. The total proposed dollar amount for this coal inventory is $9,846,037. The ALJs conclude that the full value of the coal inventory was reasonable and should be included in rate base.

H. Spindletop Gas Storage Facility

ETI relies upon a variety of fuel types to generate electricity. A major fuel component is natural gas. However, energy generated from natural gas typically has the highest marginal cost and, therefore, it is most often the last resource deployed to generate electricity. The fluctuation of natural gas demand resulting from the changes in instantaneous demand is known as "swing." Although a portion of the system's base load requirement is met with natural gas, the primary role of natural gas is as a swing fuel on the system.[170]

Since 2004, ETI has owned and used the Spindletop Facility. ETI, through a third-party operator, uses the Spindletop Facility to maintain a natural gas inventory that can be used to supply ETI's Sabine Station and Lewis Creek power generating facilities. Spindletop consists of two salt-dome storage caverns (and associated equipment) located near Sabine Station.[171] The Spindletop Facility serves a function similar to that of a city water tower – it enables ETI to buy natural gas at one point in time, store it, and use it at some future point when supplies are not available elsewhere or when peak needs cannot otherwise be met. ETI maintains that the primary benefit of the Spindletop Facility is that it provides: (1) supply reliability; and (2) swing flexibility. "Supply reliability" means that the facility can provide a reliable supply of gas for Sabine Station and Lewis Creek during potential gas supply curtailments, such as can occur during hurricanes, freezes, or other unusual events. In a worst-case scenario, the Spindletop Facility is capable of providing 100 percent of the fuel requirements for all five units at Sabine Station and one Lewis Creek unit for four days at 70 percent of capacity. The Spindletop Facility also allows the Company

[169] ETI Ex. 68 (Trushenski Rebuttal) at 4.

[170] ETI Ex. 28 (McIlvoy Direct) at 7.

[171] *Id.* at 31.

to avoid almost all intra-day gas purchases for Sabine Station. This is important because intra-day purchases tend to be more expensive than longer-term purchases.[172]

Because major supply disruptions are more likely to occur during hurricane season and during the winter, ETI manages its gas inventories conservatively during the period from June through March in order to ensure that it can provide a reliable supply of fuel to meet peak generation loads for four consecutive days. During the remainder of the year, ETI will consider withdrawing gas from the Spindletop Facility when the current day spot market price is higher than the replacement cost for the gas, as determined by future market indicators. Conversely, ETI injects gas into the Spindletop Facility when the cost of gas in the current market is less than the price of gas in the futures market.[173] For these various reasons, ETI witness Karen McIlvoy, who is employed as the manager of ESI's Gas & Oil Supply Group, testified that that Spindletop Facility is used and useful for providing reliable, economical service to ETI's customers.[174] ETI witness Devon Jaycox, who is employed as the manager of ESI's Operations and Planning Group, testified that the Company is always evaluating how much reliability the Spindletop Facility can provide as compared to other options. He explained that, at Sabine Station, there is no other option that can provide ETI with the same level of reliability and flexible swing service that the Spindletop Facility provides.[175]

Cities are critical of the Spindletop Facility, contending that the costs of operating it outweigh the benefits gained from it. No other party challenged ETI's use of the Spindletop Facility. Cities' witness Karl Nalepa testified that it costs ETI $13,219,097 per year to operate the gas storage facility, whereas the Company could achieve the same supply reliability and swing flexibility benefits it gets from the Spindletop Facility through other gas supply options at a cost of only $1,724,659, thereby saving its customers $11,494,438. Thus, Mr. Nalepa stated that it is imprudent for ETI to continue operating the Spindletop Facility.[176]

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[172] ETI Ex. 28 (McIlvoy Direct) at 32-33; ETI Initial Brief at 39, n. 264.

[173] ETI Ex. 28 (McIlvoy Direct) at 33-34.

[174] *Id.* at 37.

[175] Tr. at 966.

[176] Cities Ex. 6 (Nalepa Direct) at 18-20; Cities Ex. 6B (Errata No. 2).

Mr. Nalepa testified that no other Entergy operating company owns or leases its own gas storage facility, yet those other companies are able to satisfy their needs for supply reliability and swing flexibility through other methods, such as existing gas supply and transportation contracts, at much lower costs. According to Mr. Nalepa, those other companies obtain supply reliability and swing flexibility through the use of monthly, daily, and intra-day natural gas supply contracts. In support of this claim, he pointed to one of the operating companies, EGSL, as an example. He pointed out that EGSL has no firm transportation contracts, no firm supply contracts, and no fuel oil back-up at its generating plants. Thus, Mr. Nalepa stated that the only cost incurred by EGSL for reliability and flexibility is the commodity cost of the natural gas it purchases. Mr. Nalepa testified that EGSL achieves the same level of service as ETI without incurring the large cost of the Spindletop Facility.[177]

Mr. Nalepa asserted that the long-term gas supply contract that ETI recently entered into with Enbridge Pipeline, L.P. (the Enbridge Contract) will help provide the Company with increased supply reliability because the gas supplied by Enbridge will come from production areas that are less susceptible to hurricane-related disruptions. Mr. Nalepa also noted that ETI could meet its swing flexibility requirements through use of spot gas purchases, its operational balancing agreement with the TETCO pipeline, and other pipeline companies, such as the Copano Pipeline that serves Lewis Creek.[178]

Mr. Nalepa also disputed ETI's contention that the Spindletop Facility serves as a valuable protection against extreme events such as hurricanes, by noting that the Spindletop Facility was out of service for almost two weeks in 2005 following Hurricane Rita.[179]

As noted above, Mr. Nalepa testified that it cost ETI $13,219,097 to operate the Spindletop Facility in the Test Year. Mr. Nalepa estimated that the sum of the Test Year withdrawals of gas from the Spindletop Facility equaled 8,560,604 MMBtu. He then divided his total estimated cost of the facility ($13,219,097) by his total estimated withdrawals of gas (8,560,604 MMBtu) to calculate

[177] Cities Ex. 6 (Nalepa Direct) at 22-23.

[178] Cities Ex. 6 (Nalepa Direct) at 25.

[179] *Id.* at 23-24.

an "all-in per unit rate" of $1.54 per MMBtu. He asserted that, by contrast, transportation costs on various gas pipelines connected to Sabine and Lewis Creek ranged from $0.025 to $0.22 per MMBtu. Mr. Nalepa estimated $0.18 per MMBtu as the average replacement cost that ETI would incur in transportation contracts if it were to stop using the Spindletop Facility and achieve the same level of supply reliability and swing flexibility through the use of gas supply contracts. By multiplying $0.18 times 8,560,604 MMBtu, he estimated that the benefits of the Spindletop Facility could have been achieved through other means at a cost of only $1,724,659. Thus, Mr. Nalepa recommended that $7,794,202 should be removed from ETI's base rate, and $5,424,895 should be excluded as an eligible fuel expense.[180]

ETI disagrees with essentially all of Mr. Nalepa's points and responds to his testimony on a number of fronts. Perhaps foremost, ETI points out that Mr. Nalepa's main premise – that ETI's customers pay all the costs of the Spindletop Facility while the other Entergy operating customers avoid those costs – is simply incorrect. According to ETI witnesses, 57.50 percent of the costs associated with the Spindletop Facility are billed to EGSL as part of the MSS-4 billing process between ETI and EGSL for its "legacy plants,"[181] and another 2.4 percent of the costs are passed on to other Entergy operating companies through the MSS-3 agreement. Only 40.1 percent of the Spindletop Facility costs are borne by ETI customers.[182] Thus, Mr. Nalepa's calculations greatly overstate the costs of the Spindletop Facility that are borne by ETI customers and greatly understate the costs that are borne by EGSL customers. ETI witness Considine also pointed out that the Commission has consistently and repeatedly concluded that the Spindletop Facility is used and useful and, therefore, has allowed ETI and its predecessors to recover the costs associated with the Spindletop Facility.[183]

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[180] *Id.* at 24-27; Cities Ex. 6B (Errata No. 2).

[181] The legacy plants are the four power generating plants that were owned by Entergy Gulf States, Inc. – Lewis Creek, Sabine Station, Nelson, and Willow Glen. When EGSI was broken into ETI and EGSL in 2007, ETI became the owner of Lewis Creek and Sabine Station, while EGSL became the owner of Nelson and Willow Glen. ETI Ex. 60 (McIlvoy Rebuttal) at 5-6; ETI Ex. 46 (Considine Rebuttal) at 3.

[182] ETI Ex. 46 (Considine Rebuttal) at 3-4; ETI Ex. 60 (McIlvoy Rebuttal) at 18-19.

[183] ETI Ex. 46 (Considine Rebuttal) at 3-4.

Ms. McIlvoy also testified that, contrary to Mr. Nalepa's testimony, the conditions under which the other Entergy operating companies operate are so different from the conditions under which ETI operates that it makes no sense to assume they have similar supply reliability and swing flexibility needs. For example, EGSL and ETI both own roughly the same generating capacity from gas-powered plants – 2,378 MW for EGSL versus 2,295 MW for ETI. However, the ETI plants are operated at a much higher capacity than the EGSL plants. During the Reconciliation Period, EGSL burned much less natural gas than did ETI – 63,420,554 MMBtu burned at the EGSL plants versus 144,538,535 MMBtu burned at the ETI plants. Moreover, EGSL has four gas-powered plants while ETI has only two. Of EGSL's four plants, two (Calcasieu and Ouachita) use combined cycle gas turbine technology. This gives them a quick-start and shut-down capability, allowing them to be operated primarily only at peak demand times. Thus, according to Ms. McIlvoy, Mr. Nalepa's premise – that because EGSL is able to reliably operate its gas-fired facilities without gas storage, ETI should be able to do so as well – makes no sense. Because ETI burns a vastly larger amount of natural gas than EGSL, its need for supply reliability and swing flexibility is much greater.[184]

Ms. McIlvoy also disputed Mr. Nalepa's assertion that ETI could use the Enbridge Contract and call options to provide the Company with sufficient supply reliability. She noted that the maximum amount of gas deliverable under the Enbridge Contract is insufficient to run the ETI plants even at minimum load. By contrast, the Spindletop Facility is capable of supplying all Sabine Station units and one unit at Lewis Creek for four days at 70 percent capacity. Moreover, the Enbridge Contract will expire, whereas the Spindletop Facility can be operated indefinitely. Ms. McIlvoy explains that the use of call options is not viable because a call option must be delivered "ratably," meaning the gas must be delivered at a constant, even rate throughout the delivery period. In order to have gas available to meet peak needs in the absence of the Spindletop Facility, ETI would have to exercise call options for a maximum delivery, but it would not need all of the gas delivered at off-peak times of the day.[185]

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[184] ETI Ex. 60 (McIlvoy Rebuttal) at 3-8.

[185] ETI Ex. 60 (McIlvoy Rebuttal) at 8-12.

ETI witness Jaycox disputed Mr. Nalepa's premise that ETI could use call options to ensure reliability. According to Mr. Jaycox, "call options are cheaper than storage, but there's no comparison" between the amount of reliability that they provide as compared to the Spindletop Facility.[186] Mr. Jaycox also explained that, due to their geographic location and the limited import capability to the ETI service area, Sabine Station and Lewis Creek are considered particularly critical, thereby increasing the need for reliability at those plants.[187]

When Mr. Nalepa calculated ETI's cost of achieving supply reliability and swing flexibility without the use of the Spindletop Facility, he estimated it would cost only $1,724,659. He did so, in part, by assuming that a five-day 35,000 MMBtu/day call option would cost ETI $26,250. Ms. McIlvoy asserted that it is not reasonable to assume that all options would cost as little as $26,250. Based upon her calculations, ETI would have to purchase 14 five-day 35,000 MMBtu/day call options per month to achieve supply reliability. She posited that, based upon the laws of supply and demand, the more call options ETI has to purchase, the higher the cost of those options would be. She also pointed out that Mr. Nalepa's proposed use of call options would require ETI to spend hundreds of thousands of dollars each month to purchase call options that it would never exercise. According to Ms. McIlvoy, it is unclear from Commission precedents whether ETI would be entitled to recover the costs of these un-exercised options.[188]

The evidence establishes that the Spindletop Facility is critical to providing reliability and swing flexibility to ETI's Texas plants. The ALJs conclude that the Spindletop Facility is a used and useful facility providing reliability and swing flexibility to ETI's customers at a reasonable price, and Cities' arguments to the contrary lack merit.

I. Short Term Assets

In its application ETI requested that, as short term assets, the following amounts be included in the rate base: prepayments in the amount of $7,218,037; materials and supplies in the amount of

[186] Tr. at 969.

[187] Tr. at 975, 986-87.

[188] ETI Ex. 60 (McIlvoy Rebuttal) at 12-15.

$29,252,574; and fuel inventory in the amount of $53,759,975. These amounts were derived using 13-month averages ending June 2011.[189] Staff witness Anna Givens agrees with the approach of using 13-month averages to determine the appropriate amounts for short term assets. However, she recommends using the 13-month period ending December 2011, because it is the most recent information available. Using this approach, Ms. Givens recommends that, as short term assets, the following amounts be included in the rate base: prepayments at $8,134,351 ($916,313 more than ETI's request); materials and supplies at $29,285,421 ($32,847 more than ETI's request); and fuel inventory at $52,693,485 ($1,066,490 less than ETI's request).[190] ETI does not oppose Staff's recommendation on this issue. No party has a criticism of Staff's estimates as to prepayment, materials and supplies, and fuel inventory, nor do the ALJs. Accordingly, the ALJs recommend adopting the numbers proposed by Staff.

J. Acquisition Adjustment

In its application, ETI included an adjustment of $1,127,778 for an "electric plant acquisition."[191] The proposed adjustment, which relates to costs incurred by ETI when it acquired the Spindletop Facility, consists of closing costs of $211,209 and legal and internal costs of $916,568.[192] ETI witness Considine explained that, prior to December 2009, the same amounts were included in the Electric Plant in Service (FERC Account 101). On January 11, 2010, FERC issued Opinion No. 505 in FERC Docket No. ER07-956-00 and ordered the Company to transfer the amounts above from Account 101 to FERC Account 114, Electric Plant Acquisition Adjustments. He also pointed out that the costs were included in ETI's filed rate base amounts in Docket Nos. 34800 and 37744.[193] Mr. Considine contended that these amounts should remain in rate base because they represent costs incurred by ETI for the purchase of a viable asset that benefits its retail customers. He pointed out that the amounts have previously been included in the Company's rate base, but the only thing that has changed is that the amounts were previously allocated to a different

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[189] ETI Ex. 3 at Sched. B-1.

[190] Staff Ex. 1 (Givens Direct) at 31-32.

[191] ETI Ex. 3 at Sched. C-1.

[192] ETI Ex. 46 (Considine Rebuttal) at 4.

[193] *Id.* at 4-5.

account. ETI argues that the fact that the costs were approved as part of rate base in two previous ETI dockets verifies that they were "reasonable, prudently incurred, and properly capitalized."[194] Thus, ETI contends it would be inappropriate to penalize it because of an accounting technicality imposed upon it by FERC.[195]

Staff advocates the removal of the entire electric plant acquisition adjustment from rate base, contending that, "[a]s a rule, the rate base component for plant in service includes only the original cost, net of accumulated depreciation."[196] Cities similarly contend, without citing to any legal authority, that acquisition adjustments are not legally permitted as an addition to rate base for ratemaking purposes or as a depreciable asset for regulatory ratemaking purposes.[197] Staff disputes ETI's contention that the fact that the costs were approved as part of rate base in two previous ETI dockets proves that they were reasonable, prudently incurred, and properly capitalized. Staff points out that those two prior dockets were settled rate cases and, therefore, "provide no illumination on this issue."[198] Finally, Staff argues that ETI failed to prove either element of the Commission's two-part *Hooks* test for the determination of whether the acquisition adjustment should be included in rate base. Pursuant to the *Hooks* test, in determining whether an acquisition adjustment should be included in rate base, "the Commission should consider whether or not the purchase price was excessive and whether or not specific and offsetting benefits have accrued to ratepayers."[199] According to Staff, ETI's acquisition adjustment should be disallowed because the Company failed to meet it burden of proof on these two issues.[200]

The ALJs are unpersuaded by the arguments of Staff and Cities. Their primary argument (*i.e.*, that acquisition adjustments are simply not allowed as an addition to rate base for ratemaking

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[194] ETI Initial Brief at 43.

[195] ETI Ex. 46 (Considine Rebuttal) at 5.

[196] Staff Ex. 1 (Givens Direct) at 35.

[197] Cities Initial Brief at 26.

[198] Staff Initial Brief at 11.

[199] *Application of Hooks Telephone Company for a Rate Increase within Bowie County*, Docket No. 2150, Examiner's Report at 2 (Mar. 28, 1980)(*Hooks*).

[200] Staff Reply Brief at 12.

purposes) is incorrect. Indeed, the *Hooks* decision, the precedent on which Staff relies for its fallback argument, suggests that, more often than not, acquisition adjustments should be included in rate base: "Amortization of an acquisition adjustment need not be allowed as an expense *in all cases*."[201]

Moreover, the evidence demonstrates that ETI met is burden under the *Hooks* test. As discussed more fully in Section V.H. of this PFD, above, there is ample evidence in the record to demonstrate that the Spindletop Facility is used and useful and provides specific and offsetting benefits to ratepayers in a cost-effective manner. The evidence further shows that the acquisition adjustment represents costs that were actually incurred by ETI in the furtherance of acquiring the Spindletop Facility, and not a mere mark-up in original cost. For these reasons, the ALJs conclude that the $1,127,778 incurred by ETI in internal acquisition costs associated with the purchase of the Spindletop Facility was reasonable, necessary, and properly incurred. Accordingly, the ALJs agree that it should be included in ETI's rate base.

K. Capitalized Incentive Compensation

In the application, some of the incentive payments ETI made to its employees were capitalized into plant in service accounts and ETI asks to include those amounts in rate base.[202] A portion of those capitalized accounts represents payments made by ETI for incentive compensation tied to financial goals (financially-based incentive compensation). Cities contend that, consistent with Commission precedent, ETI ought not be allowed to include in rate base the portion of its capitalized incentive compensation that is attributable to financially-based incentive compensation.[203] The issue of whether financially-based incentive compensation is recoverable as a portion of Operating Expenses is discussed at length in Section VII.D.2. of this PFD. ETI makes the same arguments in favor of recoverability in that section that it makes here as to the inclusion of financially-based incentive compensation in rate base. The discussion of that issue need not be repeated here, but the analysis is the same. In summary, the ALJs conclude that ETI should not be

[201] *Hooks* (emphasis added).

[202] Cities Ex. 2 (Garrett Direct) at 52.

[203] *Id.* at 52-53.

entitled to recover its financially-based incentive compensation costs. Thus, for the same reasons discussed in Section VII.D.2, the ALJs agree with Cities' contention that the portion of ETI's incentive payments that are capitalized and that are financially-based should be excluded from ETI's rate base.

On the other hand, the ALJs disagree with Cities as to the amount of that exclusion. Cities argue that $9,835,111 (Cities' estimate of ETI's financially-based incentive payments that are capitalized each year into plant in service) should be removed from rate base.[204] Broadly speaking, ETI has two categories of incentive compensation programs – annual incentive programs, and long-term incentive programs. To arrive at the figure of $9,835,111, Cities' witness Garrett assumed that: (1) 100 percent of the costs of the long-term incentive programs were financially-based and, therefore, should be excluded from rate base; and (2) his calculated percentage of the annual incentive programs were financially-based and, therefore, should be excluded from rate base. He then applied those percentages to the incentive costs that ETI capitalized in 2008, 2009, and the portion of 2010 prior to the Test Year.[205]

As explained in Section VII.D.2., the ALJs agree that Mr. Garrett was correct to recommend removing 100 percent of the cost of ETI's long-term incentive programs. However, as to the annual incentive programs, he defined what qualifies as "financially based" much too broadly, and therefore wrongly assumed that his calculated percentage of the costs of those programs should be excluded. Instead, the ALJs conclude that the actual percentages should be used to determine the amount that is financially based.[206]

Finally, ETI challenges Mr. Garrett's attempt to disallow capitalized incentive costs from 2008 through June 30, 2009.

> Much of the rate base that Mr. Garrett seeks to disallow (namely, costs from 2007 through June 30, 2009) is not presented for review in this rate case. Rather those

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[204] *Id.* at 52-53; Cities Initial Brief at 27.

[205] Cities Ex. 2 (Garrett Direct) at 53 and MG-2.10.

[206] *See* discussion in Section VII.D.2.

> costs were presented for review in the Company's last rate case, Docket No. 37744, in which the Company presented capital additions for the period of April 1, 2007, through June 30, 2009. . . . Even though Docket No. 37744 was a settled case, the final order concluded that '[b]ased on the evidence in this docket, the overall total invested capital through the end of the test year meets the requirements in PURA § 36.053(a) that electric utility rates be based on original cost, less depreciation of property used and useful to the utility in providing service.' This conclusion goes beyond merely settling issues without deciding anything and should be construed as to be conclusive as to the reasonableness of capital costs at issue in that prior case.[207]

The ALJs agree. The Test Year for ETI's prior ratemaking proceeding ended on June 30, 2009. The reasonableness of ETI's capital costs (including capitalized incentive compensation) was dealt with by the Commission in that proceeding and is not at issue here. Thus, the ALJs conclude that exclusion of capitalized incentive compensation that is financially-based can only be made for incentive costs that ETI capitalized during the period from July 1, 2009 (the end of the prior Test Year) through June 30, 2010 (the commencement of the current Test Year). The amount of the exclusion is not specifically known at this time.

VI. RATE OF RETURN [Germane to Preliminary Order Issue Nos. 4 and 11]

A. Capital Structure

ETI's capital structure is 50.08 percent debt and 49.92 percent equity. No party has taken issue with ETI's capital structure. Therefore, the ALJs recommend that the Commission enter an order finding that the appropriate capital structure for ETI is 50.08 percent debt and 49.92 percent equity.

B. Return on Equity

The United States Supreme Court has set forth a minimum constitutional standard governing equity returns for utility investors:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the

[207] ETI Initial Brief at 44, *quoting* Docket No. 37744, Order at CoL 10 (Dec. 13, 2010).

> return to the equity owner should be commensurate with returns on investments in other enterprises having comparable risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[208]

Thus, a utility must have a reasonable opportunity to earn a return that is: (1) commensurate with returns on equity investments in enterprises having comparable risks; (2) sufficient to ensure the financial soundness of the utility's operations; and (3) adequate to attract capital at reasonable rates, thereby enabling it to provide safe, reliable service. The allowed ROE should enable the utility to finance capital expenditures at reasonable rates and to maintain its financial flexibility during the period in which the rates are expected to remain in effect.

1. Proxy Group

Because ETI is not a publicly traded company, it is necessary to establish a group of companies that are publicly traded and that are comparable to ETI in certain fundamental business and financial respects to serve as its "proxy" in the ROE estimation process. Both financial theory and legal precedent support the use of comparable companies within a proxy group to determine a utility's ROE, and all of the ROE witnesses in this case have relied on proxy groups to estimate a required ROE for ETI.

ETI witness Hadaway started with all the vertically integrated electric utilities that are included in the Value Line Investment Survey (Value Line). To improve the group's comparability with ETI, which has a senior secured bond ratings of BBB+ (Outlook Negative) from Standard & Poor's (S&P) and Baa2 (stable) rating from Moody's Investors Service (Moody's), Dr. Hadaway imposed the following restrictions:

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[208] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603, 64 S. Ct. 281, 288 (1944); *see also Bluefield Waterworks & Improvement Co. v. Public Serv. Comm'n of W. Va.*, 262 U.S. 679, 692-93, 43 S. Ct. 675, 679 (1923) ("A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate,

- comparable companies had to have senior secured bond ratings of at least BBB by S&P or Baa by Moody's;
- comparable companies had to derive at least 70 percent of revenues from regulated utility sales;
- comparable companies had to have consistent financial records not affected by recent mergers or restructuring; and
- comparable companies had to have a consistent dividend record with no dividend cuts or resumptions during the past two years.

Those selection criteria resulted in a 23-utility proxy group.

State Agencies witness Miravete excluded Entergy from his proxy group, but otherwise his proxy group was identical to ETI's. Cities witness Parcell ran his calculations using both Dr. Hadaway's 23-utility proxy group and another 8-utility proxy group, but they produced similar ROE results. TIEC witness Gorman used the same 23 utility proxy group as ETI witness Hadaway used.

Staff witness Cutter was the only witness to use a different proxy group. He used a 13 utility proxy group for his discounted cash-flow (DCF) analysis. To arrive at this proxy group, Mr. Cutter started with all of the domestic electric-utility companies tracked by Value Line because Value Line is the most widely used, independent investment service in the world. Then he eliminated the utilities that did not meet the following criteria:

- Value Line Financial Strength ratings of A+, A or B++;
- A capital structure including less than 45 percent, or more than 55 percent, debt;
- Total capitalization in excess of five billion dollars;
- No recent dividend cuts or omissions;

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under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.").

- No recent or potential merger activities or other major capital expansion; and
- No Value Line appraisal of being outside the norm.

On his final analysis, Mr. Cutter eliminated three of his 13 utility proxy group, referring to those he eliminated as "outliers." ETI points out, however, that one of the remaining ten companies, Con Ed, is not comparable to ETI because it is a delivery company as opposed to a vertically integrated utility. ETI's essential criticism of Mr. Cutter's proxy group analysis is that he should have used a larger proxy group and that he admitted a better comparison to ETI could be obtained from using a larger proxy group.

2. DCF Analysis

To analyze ETI's cost of equity capital, all of the testifying experts first performed a DCF analysis. The DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its most general form, the DCF model is expressed as follows:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)} + \frac{D_\infty}{(1+k)}$$

Where P_0 represents the current stock price, $D_1 \ldots . D_\infty$ are all expected future dividends, and k is the expected discount rate, or required ROE. That equation can be simplified and rearranged to ascertain the required ROE:

$$k = \frac{D(1+g)}{P_0} + g$$

Where P_0 represents the current stock price, D is expected future dividends, g is the growth rate, and k is the expected discount rate, or required ROE.

This is commonly referred to as the "Constant Growth DCF" model in which the first term is the expected dividend yield and the second term is the expected long-term growth rate. The

Constant Growth DCF model requires assumptions of: (1) a constant growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant price-to-earnings multiple; and (4) a discount rate greater than the expected growth rate.

ETI witness Hadaway's DCF analysis was based on three versions of the DCF model. In the first version of the DCF model, he used the constant growth format with long-term expected growth based on analysts' estimates of five-year utility earnings growth. In the second version of the DCF model, for the estimated growth rate, Dr. Hadaway used only the long-term estimated gross domestic product (GDP) growth rate. In the third version of the DCF model, Dr. Hadaway used a two-stage growth approach, with stage one based on Value Line's three-to-five-year dividend projections and stage two based on long-term projected growth in GDP. The dividend yields in all three of the annual models are from Value Line's projections of dividends for the coming year and stock prices are from the three-month average for the months that correspond to the Value Line editions from which the underlying financial data are taken.[209]

The DCF results for Dr. Hadaway's comparable company group using the traditional constant growth model indicated an ROE of 9.90 percent to 10.00 percent. Dr. Hadaway then recalculated the constant growth results with the growth rate based on long-term forecasted growth in GDP. With the GDP growth rate, the constant growth model indicates an ROE range of 10.40 percent to 10.70 percent. Although the GDP growth rate is higher than the average of analysts' growth rates, Dr. Hadaway testified that his GDP estimate is within the analysts' range and slightly below the 6.00 percent 3-to-5 year average growth rate projection from Value Line. Finally, Dr. Hadaway's multistage DCF model indicated an ROE range of 10.20 percent to 10.30 percent. The results from the DCF model, therefore, indicate an ROE range of 9.90 percent to 10.70 percent.[210] In his rebuttal, Dr. Hadaway updated his ROE analysis using current market conditions but employing the same methodologies that he used in his previous analysis. After

[209] ETI Ex. 6 (Hadaway Direct) at 33-44.

[210] *Id.* at 44, Exhibit SCH-4.

making adjustments to the proxy group to stay consistent with his selection criteria, Dr. Hadaway's indicated DCF range was 10.00 percent to 10.20 percent.[211]

The principal argument against Dr. Hadaway's analyses is that he used unsupported and excessive growth rates. According to the intervenors, these excessive growth rates exaggerate future cash flows, which results in an inflated ROE.

Intervenors argue that Dr. Hadaway's Analysts' Constant Growth DCF model produces excessive return estimates.[212] In rebuttal, Dr. Hadaway's analysts' growth model produced a 10.1 percent group average ROE and a 10.0 percent group median ROE.[213] The intervenors contend that the group average long-term growth rate on which his DCF study was based was 5.62 percent, which is far too high to be sustainable in the long-term (as required as an input in the Constant Growth DCF model).[214] According to intervenors, the excessive level of his growth rate is apparent by comparison to current analysts' projected growth for U.S. GDP, which range from 4.5 percent to 5.0 percent.[215] Dr. Hadaway's growth rate is more than 60 basis points above the most generous expected growth of the U.S. economy. Intervenors contend that that nominal GDP should be the *ceiling* of a reliable proxy for a utility dividend growth rate. Because the evidence shows that nominal GDP as projected by consensus analysts, the Executive Branch, and the Congressional Budget Office is 5 percent, Dr. Hadaway's 5.62 percent growth rate is excessive and undermines the reasonableness of his models.

Intervenors criticize Dr. Hadaway's decision on rebuttal to exclude Edison International in his proxy group.[216] Dr. Hadaway did so because Edison International's ROE of 5.2 percent was below a 5.07 percent cost of debt based on an average of Triple B utility rates for the time period

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211 *Id.* at 44.

212 TIEC Ex. 2 (Gorman Direct) at 39.

213 ETI Ex. 52 (Hadaway Rebuttal) at Ex. SCH-R-6.

214 *Id.* at Ex. SCH-R-6; TIEC Ex. 2 (Gorman Direct) at 39; Cities Ex. 3 (Parcell Direct) at 36-37; OPC Ex. 1 (Szerszen Direct) at 23-24.

215 TIEC Ex. 2 (Gorman Direct) at 19; Cities Ex. 3 (Parcell Direct) at 37.

216 ETI Ex. 51 (Hadaway Rebuttal) at Ex. SCH-R-6.

January 12-March 12, plus 100 basis points.[217] Intervenors contend that this rationale is tenuous, and that had Dr. Hadaway included Edison International (or even excluded Hawaiian Electric, the utility in his proxy group that had the highest ROE) his own analysis (even with its excessive growth rates) would have resulted in a 9.85 percent average ROE.

Finally, Dr. Hadaway conceded that he used the same methodology for calculating GDP in this case as he did in the Oncor rate case.[218] Intervenors contend that Dr. Hadaway's GDP projections are not credible proxies for investor's expected dividend growth rates because they are not based on published analysts' or government GDP forecasts. Rather, Dr. Hadaway forecasts future GDP growth using his own personal calculation that forecasts GDP by examining historic GDP growth over the last 10, 20, 30, 40, 50, and 60-year periods and weighting those averages.[219] Intervenors note that this approach was rejected by the Commission in the Oncor rate case.[220]

Staff witness Cutter used the DCF model to project ETI's cost of equity. Under Mr. Cutter's view, the theory underlying the DCF model is that the price of a share is equal to the *present* value of all *future* earnings. Unless the stock is sold for a profit (or loss) from the price it was originally purchased, the only way to determine earnings on a share is to determine its future dividends. This requires, in Mr. Cutter's opinion, an understanding of investors' current expectations of growth of those dividends. The issue is the growth *expectation* that investors have embodied in the current price of the stock. According to Mr. Cutter, the best way to arrive at a reliable growth estimate of those dividends is to use the growth estimates of investment advisory firms rather than the estimates of a single, independent analyst.[221]

Mr. Cutter used both Value Line and Zacks Investment Service (Zacks) in ascertaining long-term earnings growth rates. He used Value Line because it is the most widely used independent

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217 *Id.*

218 Tr. at 227-228.

219 ETI Ex. 6 (Hadaway Direct) at Ex. SCH-3; Tr. at 218.

220 *Application of Oncor Electric Delivery Company, LLC, for Authority to Change Rates,* Docket No. 35717, PFD at 72-73.

221 Staff Ex. 6 (Cutter Direct) at 10-15.

investment service in the world and Zacks because it compiles consensus earnings forecasts from groups of professional security analysts.[222]

Mr. Cutter's DCF analysis resulted in range from 7.46 percent to 10.71 percent, with a point estimate for cost of equity being 9.3 percent.

TIEC witness Gorman's first DCF model was a constant growth model using consensus analysts' growth rates that resulted in an average constant growth DCF of 9.32 percent and a median constant growth DCF of 9.84 percent. The average analysts' growth rate was 4.94 percent.[223] According to TIEC, ETI does not claim that a constant growth model using analysts' growth rates is inappropriate and argues that Dr. Hadaway failed to offer any rebuttal testimony criticizing Mr. Gorman's Analysts' Growth DCF model.

Mr. Gorman also performed a constant growth DCF model using sustainable growth rates. His average sustainable growth rate for the proxy group was 4.54 percent and produced a proxy group average and median DCF result of 8.91 percent and 8.9 percent, respectively.[224] According to TIEC, a sustainable growth rate is based on the percentage of a utility's earnings that are retained and reinvested in utility plant and equipment.[225]

Mr. Gorman also performed a multi-stage DCF model to reflect changing growth expectations that would reflect the possibility of non-constant growth for a company over time. Mr. Gorman's multi-stage model reflected three growth periods: (1) a short-term growth period of five years; (2) a transition period for years six through ten; and (3) a long-term growth period, starting in year 11 through perpetuity. For the short-term period, Mr. Gorman relied on the consensus analysts' growth projections from his constant growth DCF model (*i.e.*, 4.94 percent). For the second stage (*i.e.*, the transition period), growth rates are reduced or increased by an equal factor, which reflect the difference between the analysts' growth rates and the GDP growth rate. For

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[222] Staff Ex. 6 (Cutter Direct) at 13.

[223] TIEC Ex. 2 (Gorman Direct) at Ex. MPG-4.

[224] TIEC Ex. 2 (Gorman Direct) at 18.

[225] TIEC Ex. 2 (Gorman Direct) at 17.

the long-term period, he assumed the maximum sustainable growth rate for a utility company as proxied by the consensus analysts' projected growth rate for the U.S. GDP (*i.e.*, 5.0 percent). The result of his multi-stage growth DCF model was an average ROE of 9.37 percent and a median of 9.48 percent.[226]

Cities witness Parcell calculated the DCF results for each company in his proxy group by using and considering five indicators of growth expectations consisting of: (i) 2007 – 2011 earnings retention; (ii) five-year historical average earnings per share, dividends per share, and book value per share; (iii) projected earnings retention; (iv) projected EPS, DPS, BVPS; and (v) projected EPS as reported by Yahoo Finance. Using this in his DCF model resulted in an ROE of 9.0 percent to 9.5 percent.[227]

OPC witness Szerszen's DCF analysis used the same group of 23 comparable companies included in Dr. Hadaway's DCF analysis. Dr. Szerszen's DCF analysis was framed with consideration of ETI's financial integrity as discussed by the major bond rating agencies, the current and projected interest rate environment, and investment analyst views of the regulated utility sector.[228] Interest rates are currently very low, as reflected in the yields to maturity and interest rates on various fixed income investments. OPC contends, in contrast to Dr. Hadaway, that utility stocks have been less volatile than the stock market in general.[229] This is confirmed by Value Line's December 23, 2011, observation that "electric utility stocks have long been viewed as a safe haven in volatile markets, due in large part to their generous dividend yields."[230] Dr. Szerszen also took exception to Moody's characterization of ETI as having above average business and regulatory risk. Moody's assessment is primarily based on the lack of pass-through regulatory lag-reducing cost recovery mechanisms in Texas compared to Entergy's Louisiana and Mississippi jurisdictions. Dr. Szerszen testified that ETI may not have a formula rate plan similar to the Louisiana and Mississippi Entergy operating companies, but it does have a Distribution Cost Recovery Factor (DCRF) and

[226] TIEC Ex. 2 (Gorman Direct) at 19, Ex. MPG-9.

[227] Cities Ex. 3 (Parcell Direct) at 24, 33.

[228] OPC Ex. 1 (Szerszen Direct) at 8-17.

[229] *Id.* at 15.

[230] *Id.*

Transmission Cost Recovery Factor (TCRF) available that "will allow ETI to charge ratepayers for additional distribution and transmission investments outside of a traditional rate request filing."[231] None of Entergy's other operating companies have TCRF and DCRF riders. OPC notes that Cities witness Parcell agrees that the availability of such recovery mechanisms affects ETI's level of risk; he testified that a combination of ETI's fuel factor rider, TTC rider, energy efficiency rider, hurricane cost recovery rider, rate case expense rider, proposed increased customer service charge, and DCRF and TCRF riders results in about 30 percent of ETI's total overall requested revenue requirement being subject to revenue risk and regulatory lag.[232]

Dr. Szerszen incorporated two different dividend yield calculations in her DCF model. The first calculation estimated a dividend yield using 2011 average stock prices and 2012 projected dividend rates for each company, and the second calculation incorporated more recent March 5, 2012, closing prices for the comparables. The average dividend yield using 2011 average stock prices was 4.66 percent and, using March 5, 2012, closing prices, was 4.32 percent.[233]

Dr. Szerszen provided some practical examples of how blind reliance on analyst earnings growth projections can lead to questionable DCF growth rates. At least five of the comparable utility companies had five-year earnings growth rate projections that ranged from 8.5 percent to 11 percent. Dr. Szerszen stated that she was unaware of any regulated utility company that has consistently achieved such high earnings growth rate over the past 28 years, and that it is reasonable to assume such performance is unlikely in the longer term future. Dr. Szerszen's review of the comparable company past and projected growth rates resulted in a reasonable dividend growth rate expectation of 3.9 percent to 5 percent. Depending on whether 2011 average stock prices are used or the updated 2012 stock prices are used, Dr. Szerszen's DCF analysis resulted in an ROE ranging from 8.32 percent to 9.32 percent.[234]

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[231] *Id* at 11-13.

[232] Cities Ex. 3 (Parcell Direct) at 16-18.

[233] OPC Ex. 1 (Szerszen Direct) at 17.

[234] *Id.* at 22.

State Agencies' witness Miravete's DCF analysis used calculations for three averaging periods, 30, 90 (the reference period), and 180 days ending on March 2, 2012, respectively. For the commonly used 90 day averaging period, the capitalization-weighted average ROE is 9.23 percent. Evaluating the averaging period at either 30 or 180 days produces ROE estimates of 9.24 percent and 9.34 percent, respectively. Dr. Miravete weighed the computations by the capitalization of each firm to correct the effect of each variable according to the relative market value of the corresponding utility. According to Dr. Miravete, this approach avoids the distortion caused by adding numerous, but possibly irrelevant, firms that may produce biased estimates. Dr. Miravete conceded that the effect of ignoring differences in scale of utilities in the determination of the ROE is substantial. He acknowledged that if he had ignored the differences in size of these electric utilities, his DCF ROE estimate would have been 9.68 percent.[235]

3. Risk Premium Analysis

Dr. Hadaway's risk premium studies are divided into two parts. First, he compared electric utility authorized ROEs for the period 1980-2010 to contemporaneous long-term utility interest rates. The differences between the average authorized ROEs and the average interest rate for the year is the indicated equity risk premium. He then added the indicated equity risk premium to the forecasted and current triple-B utility bond interest rate to estimate ROE.[236]

In calculating the equity risk premium, Dr. Hadaway adjusted for the inverse relationship between equity risk premiums and interest rates (when interest rates are high, risk premiums are low and vice versa). Dr. Hadaway provided regression analyses of the allowed annual equity risk premiums relative to interest rate levels. The negative regression coefficients confirm the inverse relationship between equity risk premiums and interest rates according to ETI. Dr. Hadaway used that negative interest rate change coefficient in conjunction with current and forecasted interest rates

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[235] State Agencies Ex. 1 (Miravete Direct) at 12-13.

[236] ETI Ex. 6 (Hadaway Direct) at 36-38, 45.

to establish the appropriate ROE.[237] Staff witness Cutter agreed that the risk premium analysis needs to reflect this adjustment.[238]

The results of Dr. Hadaway's initial equity risk premium studies indicate an ROE range of 10.00 percent to 10.01 percent. ETI states that these results reflect the sharp drop in interest rates that have occurred for high quality borrowers. The Federal Reserve System's continuing "easy money" policies have provided renewed liquidity in the credit markets that is reflected in these lower yields. These models, however, cannot capture the current equity volatility or the increased level of risk aversion for equity investors. These circumstances indicate that the cost of equity has not declined to the extent that interest rates on utility debt have dropped. Thus, Dr. Hadaway testified that the results of the risk premium analysis must be discounted and more emphasis placed on the DCF analysis.[239]

In his rebuttal, Dr. Hadaway updated his ROE analysis using current market conditions but employing the same methodologies that he used in his previous analysis.[240] His updated risk premium analysis was an ROE of 10.38 percent using projected triple-B utility interest rates and 9.96 percent using current triple-B utility interest rates.[241]

TIEC contends that Dr. Hadaway's utility risk premium analysis is flawed for two primary reasons. First, Dr. Hadaway developed a forward-looking risk premium model that relied on forecasted interest rates and volatile utility spreads that are uncertain and produce inaccurate results. As Mr. Gorman testified, it is more reasonable at this time to rely on current observable interest rates rather than forecasted projections. Over the last several years, forecasted yield projections have proven to be overstated because, even though interest rates have been projected to increase, those

[237] ETI Ex. 6 (Hadaway Direct) at 45-46, Ex. SCH-5; ETI Ex. 52 (Hadaway Rebuttal) at 32.

[238] Staff Ex. 6 (Cutter Direct) at 20.

[239] ETI Ex. 6 (Hadaway Direct) at 10-23, 45; Tr. at 233-235.

[240] ETI Ex. 52 (Hadaway Rebuttal) at 44.

[241] *Id.* at 45.

projections have consistently been proven wrong.[242] Accordingly, Dr. Hadaway's forecasted utility bond yield of 5.17 percent is overstated.

Second, TIEC argues that Dr. Hadaway's risk premium model is flawed because he improperly inflates his actual risk premium of 3.28 percent with an adjustment of 1.56 percent that he asserts reflects the inverse relationship between interest rates and utility risk premiums.[243] TIEC argues that Dr. Hadaway's use of this adjustment is improper and not supported by academic research. Mr. Gorman testified that "a relative investment risk differential cannot be measured simply by observing nominal interest rates."[244] He noted:

> While academic studies have shown that, in the past, there has been an inverse relationship with these variables, researchers have found that the relationship changes over time and is influenced by changes in perception of the risk of bond investments relative to equity investments, and not simply changes to interest rates.[245]

As described in Mr. Gorman's testimony, correcting Dr. Hadaway's models for the elimination of this inverse relationship adjustment puts Dr. Hadaway's risk premium in the range of 8.5 percent to 10 percent, with a midpoint of 9.3 percent.[246]

Staff witness Cutter's "conventional risk premium estimate" estimated the cost of ETI's equity by comparing the costs of equity authorized for utilities across the United States to the yields of large-company corporate bonds that are rated Baa by Moody's within the timeframe of 1980 through 2011. This risk premium approach relies on the historical relationship between two indices

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[242] TIEC Ex. 2 (Gorman Direct) at 42-43; OPC Ex. 1(Szerszen Direct) at 27-28.

[243] TIEC Ex. 2 (Gorman Direct) at 42-43; *see also* ETI Ex. 6 (Hadaway Direct) at Ex. SCH-5 at 1.

[244] TIEC Ex. 2 (Gorman Direct) at 44.

[245] TIEC Ex. 2 (Gorman Direct) at 44 (*citing* "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," Robert S. Harris and Felicia C. Marston, *Journal of Applied Finance*, Volume 11, No. 1, 2001 and "The Risk Premium Approach to Measuring a Utility's Cost of Equity," Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *Financial Management*, Spring 1985).

[246] TIEC Ex. 2 (Gorman Direct) at 45.

to forecast a value for one of the indices in a period for which it is unknown by using the known value of the other one during that same period.[247]

To account for the relationship between the authorized costs of equity and the bond yields required to quantify ETI's cost of equity, Mr. Cutter subtracted the bond yields from the authorized costs of equity to determine a risk premium for the riskier equity. He tested the data by performing a regression analysis, which showed with high confidence that there is a trend in the relationship. It is an inverse trend, in which the risk premiums increase as bond yields decrease. On average, from 1980 to 2011, risk premiums increased 0.4207 percent for every 1.00 percent that bond yields decreased.[248]

The calculation of the adjustment to the risk premium that the regression analysis indicated was incorporated in Staff's analysis. The results of this risk premium analysis produced a cost of equity of 9.81 percent.[249]

Mr. Gorman's risk premium analysis produced an ROE estimate in the range of 9.2 percent to 9.4 percent, with a midpoint estimate of approximately 9.3 percent. His risk premium model was based on two estimates of an equity risk premium. First, he estimated the difference between the required return on utility common equity investments and U.S. Treasury bonds for the period 1986 through 2011, which produced an equity risk premium of 5.23 percent. The second equity risk premium estimate was based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields for the period 1986 through 2011, which produced an equity risk premium of 3.8 percent. Mr. Gorman testified that "[t]he equity risk premium should reflect the relative market perception of risk in the utility industry today."[250]

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[247] Staff Ex. 6 (Cutter Direct) at 10, 19.

[248] Staff Ex. 6 (Cutter Direct) at 20.

[249] *Id.* at 20, Attachment SC-6.

[250] TIEC Ex. 2 Gorman Direct) at 26.

Accordingly, to gauge investor expectations he examined the yield spread between utility bonds and Treasury bonds over the last 32 years.[251]

According to TIEC, this analysis showed that the current utility bond yield spreads over Treasury bond yields are lower than the 32-year average spreads, which is evidence that "the market considers the utility industry to be a relatively low risk investment and demonstrates that utilities continue to have strong access to capital."[252] Mr. Gorman then added a projected long-term Treasury bond yield to his estimated equity risk premium over Treasury yields, which produced a common equity in the range of 8.2 percent to 9.95 percent. Due to unusually large yield spreads between Treasury bond and "Baa" utility bond yields, Mr. Gorman gave two-thirds weight to his high end risk premium of 9.95 percent and one-third weight to his low-end risk premium of 8.2 percent, which produced an equity risk premium of 9.4 percent. He also added his equity risk premium over utility bond yields to the current 13-week average yield on "Baa" rated utility bonds for the period ending March 2, 2012, of 5.05 percent. Adding his equity risk premium of 3.03 percent to 4.62 percent to the bond yield of 5.05 percent, produced an ROE in the range of 8.08 percent to 9.67 percent, which he then weighted more heavily on the high end estimate to produce a recommendation of 9.2 percent.[253]

The primary criticism that Dr. Hadaway lodged against Mr. Gorman's risk premium analysis was that Mr. Gorman did not adjust his analysis upward to reflect a purported inverse relationship between equity risk premiums and interest rates.[254] For example, Dr. Hadaway's risk premium analysis adjusted his risk premium results by 1.56 percent to account for this relationship.[255]

OPC witness Szerszen also performed a risk premium analysis, using Dr. Hadaway's study of historical authorized electric company allowed returns on equity and average bond yields. The

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[251] *Id.* at 25-28.

[252] *Id.* at 27.

[253] TIEC Ex. 2 (Gorman Direct) at 26-28.

[254] ETI Ex. 52 (Hadaway Rebuttal) at 32.

[255] ETI Ex. 6 (Hadaway Direct) at Ex. SCH-5.

average risk premium from Dr. Hadaway's 1980-2010 study was 328 basis points.[256] Adding this historical risk premium to current triple B bond yield (4.67 percent) results in a 7.95 percent risk-premium derived DCF rate, and using Dr. Hadaway's 5.17 percent projected bond yield results in a risk premium derived rate of 8.45 percent. Giving more weight to the 2001-2010 risk premiums shown in Dr. Hadaway's exhibit results in an average risk premium of 4.21 percent. This yields an 8.88 percent to 9.38 percent risk premium derived cost of equity based on the current 4.67 percent and projected 5.17 percent bond yields, according to Dr. Szerszen's analysis.[257]

4. Comparable Earnings

Cities witness Parcell also performed a Comparable Earnings analysis. According to Mr. Parcell, the Comparable Earnings method is derived from the "corresponding risk" standard of the *Bluefield* and *Hope* cases. This method is thus based upon the economic concept of opportunity cost. The cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.[258]

The Comparable Earnings method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, according to Mr. Parcell, this method provides a direct measure of the fair return, because the Comparable Earnings method translates into practice the competitive principle upon which regulation is based.[259]

The Comparable Earnings method normally examines the experienced and/or projected returns on book common equity. The logic for examining returns on book equity follows from the use of original-cost, rate-base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of

[256] ETI Ex. No. 6 (Hadaway Direct) at Ex. SCH-5.

[257] OPC Ex. 1 (Szerszen Direct) at 29-30.

[258] Cities Ex. 3 (Parcell Direct) at 28.

[259] *Id.* at 29.

capital costs to be recovered by the utility. Mr. Parcell stated that this technique is thus consistent with the rate base methodology used to set utility rates.[260]

Mr. Parcell conducted the Comparable Earnings methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. He testified that in this manner it is possible to assess the degree to which a given level of return equates to the cost of capital.

Mr. Parcell's Comparable Earnings analysis is based on market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, he testified that his analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, he stated that his analysis uses prospective returns and thus is not confined to historical data.[261]

Mr. Parcell's Comparable Earnings analysis considered the experienced equity returns of the proxy groups of utilities for the period 1992-2011 (*i.e.*, the last twenty years). His Comparable Earnings analysis required an examination of a relatively long period of time to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time to avoid any undue influence from unusual conditions that may occur in a single year or shorter period. Therefore, in forming his judgment of the current cost of equity he focused on two periods: 2002-2011 (the recent business cycle) and 1992-2001 (the prior business cycle).[262]

Based on the recent earnings and market-to-book ratios, Mr. Parcell's Comparable Earnings analysis indicated that the cost of equity for the proxy utilities is no more than 9.5 percent to 10.0 percent (9.75 percent mid-point). Recent returns of 10.0 percent to 12.1 percent have resulted in market-to-book ratios of 143 and greater. Prospective returns of 9.5 percent to 10.3 percent result in anticipated market-to-book ratios of over 125. As a result, it is apparent that returns below this

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[260] *Id.*

[261] Cities Ex. 3 (Parcell Direct) at 29.

[262] *Id.* at 30.

level would result in market-to-book ratios of well above 100. According to Mr. Parcell, an ROE of 9.5 percent to 10.0 percent should thus result in a market-to-book ratio of well over 100 .[263]

5. CAPM Analysis

The Capital Asset Pricing Model (CAPM) is a risk premium approach that estimates the ROE for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable, or systematic, risk of that security. The CAPM formula is as follows:

$$K_e = r_f + \beta(r_m - r_f)$$

Where K_e equals the required market ROE; β equals the Beta of an individual security; r_f equals the risk free rate of return; and r_m equals the required return on the market as a whole. In this equation, $(r_m - r_f)$ represents the market risk premium. According to the theory underlying the CAPM, because diversifiable risk can be diversified away, investors should be concerned only with non-diversifiable risk, which is measured by Beta. In effect, Beta represents the risk of the particular security relative to the market as a whole.

Only Staff witness Cutter, Cities witness Parcell, and State Agencies witness Miravete used the CAPM methodology to estimate ETI's ROE.

Mr. Cutter used CAPM in the qualitative analysis of ETI's cost of equity. He did not directly use the CAPM in the determination of ETI's cost of equity because it yielded a cost of equity that was over 200 basis points lower than the lower of the other two estimates, while those other two estimates were less than half a percent apart from each other.[264] The CAPM provides an additional indication that a significant drop to the estimated costs of equity that Staff made in prior dockets is appropriate because the CAPM estimate is lower than either of the two other approaches even when adjusted for the current low yield on Treasury Bonds.[265]

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[263] Cities Ex. 3 (Parcell Direct) at 31-32.

[264] Staff Ex. 6 (Cutter Direct) at 21.

[265] *Id.*

Mr. Cutter testified that the CAPM is one of the cornerstones of financial theory.[266] In its simplest sense, the model describes the relationship between the risk of an asset and its expected return, and assumes that investors will not hold a risky asset unless they are adequately compensated for the risk.[267]

In this case, without any adjustment to the way it has been used in recent rate cases at the Commission, the CAPM yielded a cost of equity for ETI of 6.93 percent. Mr. Cutter testified that aspects of the capital markets today were likely causing the CAPM's cost of equity estimate to be low. Specifically, the Federal Reserve System is following an aggressive policy designed to keep the yields of both short-term and long-term Treasury bonds low. This policy influences two of the three variables used in the CAPM formula to be lower, which, in turn, makes the CAPM's final estimate of ETI's cost of equity lower.[268]

To account for the impact of this aggressive Federal Reserve System policy, Mr. Cutter made two adjustments to his CAPM analysis. First, Mr. Cutter adjusted the risk-free rate variable in the CAPM because it is most influenced by current Federal Reserve System policy. By changing this variable to 3.7 percent (which is the average yield from 1926 through 2010 of the risk-free rate's proxy security, U.S. Treasury Bills), the CAPM's estimate of ETI's cost of equity increased from 6.93 percent to 7.92 percent, or by 99 basis points.[269]

The second adjustment to the CAPM result that Mr. Cutter made to account for the current aggressive Federal Reserve System policy was to the risk premium, which is also particularly sensitive to Federal Reserve System policy. By using the difference between the *averages* of the yield of long-term government bonds and the yield of large company stocks between 1926 and 2010, the effect of Federal Reserve System policy on the risk premium was significantly diluted. Mr. Cutter found that because the CAPM estimate of ETI's cost of equity was excessively low, even with adjustments for Federal Reserve System policy, it would be appropriate to further adjust it by

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[266] *Id.*

[267] *Id.*

[268] Staff Ex. 6 (Cutter Direct) at 21-24.

[269] *Id.* at 24.

multiplying the unadjusted estimate plus two times the effect of adjusting the risk-free rate, or: 6.93 percent + (2 * 0.99 percent) = 8.91 percent.[270] It is important to note, however, that Mr. Cutter used the CAPM analysis only as a qualitative check on its DCF and risk premium analyses, not as an independent source of analysis.

Although Cities witness Parcell did perform a CAPM analysis, he does not employ the CAPM results in arriving at his 9.0 percent to 10.0 percent range of results.[271]

State Agencies witness Miravete used the daily average of the yield of the ten-year Treasury bond between December 1, 2011, and March 2, 2012, as reported by the Board of Governors of the Federal Reserve System, as his risk-free return in his CAPM model. He used Value Line's most recent betas for the regulated utilities included in the proxy group. Dr. Miravete corrected the betas by substituting an average between their value and 1.0 to recognize that markets trend towards long-term equilibrium because these regulated utilities were able to attract investors during the most troubled times, which indicates that the perceived market risk of these utilities is lower than for other firms. Dr. Miravete's capitalization-weighted average CAPM ROE is 7.64 percent on a 90 days averaging period, with a range between 7.64 percent (30 days) and 8.28 percent (180 days). Dr. Miravete characterizes these estimates as low relative to those of the DCF model because of the low yields of Treasury bonds after the implementation of the quantitative easing monetary policy over the past two years.[272]

6. ALJs' Analysis

Given the detail, time, and effort that went into the various experts' testimony on this issue, one might easily conclude that the development of an estimated ROE is a precise science. But, as acknowledged by virtually all experts on the subject, estimating the cost of equity is not an exact science but rather a result of informed judgment.

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270 *Id.* at 21, 24-25.

271 Cities Ex. 3 (Parcell Direct) at 3, 25-28.

272 State Agencies Ex. 1 (Miravete Direct) at 19-21.

The first question that must be addressed is the appropriate proxy group. There were essentially only two competing views on this issue – one presented by Dr. Hadaway and the other by Mr. Cutter. The ALJs have reviewed the evidence and the arguments of both sides with respect to the composition of the proxy group. Although Staff's proxy group could, in some respects, be considered more comparable to ETI than Dr. Hadaway's larger group, the ALJs do not believe that this overcomes the flaws inherent in such a small group. In the end, a group of nine companies, while comparable, simply does not provide a robust enough sample to create a valid group for comparison. The ALJs therefore find that the 23 utility group selected by ETI witness Hadaway is the appropriate proxy group.

The next issue is the core issue to be decided: the appropriate ROE for ETI. The experts in this case testified to the following ROE ranges or estimates, depending on the calculation methodology employed:

Witness/Analysis	Range	Ultimate Recommendation
Hadaway - DCF	9.9 – 10.7	10.6
Hadaway – Risk Premium	9.96 – 10.38	
Cutter – DCF	7.46 – 10.71	9.6
Cutter – Risk Premium	9.81	
Cutter – CAPM	8.91	
Gorman –DCF	9.3 – 9.7	9.5
Gorman – Risk Premium	9.2 – 9.4	
Parcell – DCF	9.0 – 9.5	9.5
Parcell – Comparable Earnings	9.5 – 10.0	
Szerszen – DCF	8.32 – 9.32	9.3
Szerszen – Risk Premium	9.3	
Miravete – DCF	9.23 – 9.34	9.3
Miravete – CAPM	7.64 – 8.28	

Just focusing on the ultimate ROE recommendations, it is clear that there is a fairly tightly grouped range when considering Staff and the intervenors. This ranges from a low of 9.3 percent to a high of 9.6 percent. The range expands when it is considered that Staff witness Cutter did not contest ETI's assertion that Staff's DCF recommended ROE would be 10.0 percent if he had used the same proxy group as the other witnesses.[273] The ALJs believe that the criticisms leveled at Dr. Hadaway's ROE recommendation are generally correct, certainly to the point that the ultimate recommendation is so high as to be an outlier. The ALJs conclude that the proper range of acceptable ROEs would be from 9.3 percent to 10.0 percent. This is actually confirmed by ETI's own witness, Mr. Barrileaux, who testified that, from a cash flow metric standpoint, an ROE of 9.99 percent would provide "a reasonable outcome that balances debt and equity financing."[274]

The mid-point of the range discussed above is 9.65 percent. There has been a tremendous amount of testimony about the unsettled economic conditions facing utilities and the effect of those conditions on the appropriate ROE. The ALJs believe that this is an effect that must be taken into account, and that the effect would be to move the ultimate ROE towards the upper limits of the range determined to be reasonable. In this case, the ALJs find that the reasonable adjustment would be 15 basis points, moving the reasonable ROE to 9.80 percent. Accordingly, the ALJs recommend that the Commission find that 9.80 percent is the appropriate ROE for ETI.

C. Cost of Debt

ETI's weighted average cost of debt at the end of the test year was 6.74 percent.[275] No party has taken issue with that cost of debt. Therefore, the ALJs recommend that the Commission enter an order finding that the appropriate cost of debt for ETI is 6.74 percent.

D. Overall Rate of Return

The overall rate of return is a product of the capital structure, ROE, and cost of debt. Based on the discussions set forth above, the ALJs recommend that the Commission adopt the following overall rate of return for ETI:

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[273] Tr. at 1795.

[274] ETI Ex. 44 (Barrileaux Rebuttal) at 5, Ex. CEB-R-1.

[275] ETI Ex. 5 (Barrilleaux Direct) at 37.

Component	Cost	Weighting	Weighted Cost
Debt	6.74	50.08%	3.38
Equity	9.80	49.92%	4.89
Overall			8.27

VII. OPERATING EXPENSES [Germane to Preliminary Order Issue Nos. 2, 3, 4, and 16]

A. Purchased Power Capacity Expense [Germane to Supplemental Preliminary Order Issue No. 1]

One of the most hotly contested issues in this case concerned the appropriate size of ETI's purchased power capacity costs (PPCCs). In order to understand this issue, it is necessary to understand some background relative to how ETI obtains and uses power generation capacity.

1. The Sources of ETI's Purchased Power

The Entergy System Agreement is a FERC-approved tariff that mandates that the Operating Companies operate as a single, integrated system.[276] The System Agreement's essential function is to provide the contractual basis for the planning, construction, and operation of generation and transmission resources in an economic and reliable manner. By jointly planning and operating their electric systems, the Operating Companies believe they are able to aggregate their loads and jointly dispatch their resources to serve that load using the lowest cost resources available from all of the Operating Companies, resulting in lower total costs than the total cost of each Operating Company planning and operating separately. Another function of the Entergy System Agreement is to provide a basis for the equalization among the Operating Companies of any imbalances of costs arising from the construction, ownership, or operation of facilities that are used for the collective benefit of all Entergy Operating Companies.[277]

To provide reliable service, ETI must have sufficient generation capacity to meet the maximum demands imposed on its system. Some of this generation capacity (approximately

[276] ETI Ex. 30 (Jaycox Direct) at 5-6; ETI Ex. 39 (Cicio Direct) at 6-10.

[277] ETI Ex. 39 (Cicio Direct) at 6, 8-10, 11-30.

1,200 MW) is generating plants owned and operated by ETI.[278] The remainder of ETI's capacity comes from four types of purchased capacity: (1) capacity purchases from third parties; (2) capacity purchases from other Entergy affiliates through "legacy affiliate contracts" under MSS-4; (3) capacity purchases from other Entergy affiliates through "other affiliate contracts" under MSS-4; and (4) capacity purchases from the Entergy system through reserve equalization payments under MSS-1.[279] MSS-1 and MSS-4 are schedules included in the Entergy System Agreement which set out complex mathematical formulas whereby the various Operating Companies can equalize and share the costs of power capacity among themselves.[280] These four sources of purchased capacity are inversely related to one another: the more ETI purchases from one source, the less it needs to purchase from the others.[281]

➢ ***Capacity Purchases from Third Parties***

Third-party capacity contracts are contracts that the system has allocated in whole or part to ETI. ETI has contracted to purchase capacity from a number of third parties, including ConocoPhillips-SRW, Dow Pipeline, Frontier, Calpine-Carville, and Sam Rayburn Municipal Power Agency (SRMPA). Since 2009, ETI has been in the process of substantially increasing its reliance upon third party purchases of capacity. During the Rate Year, it plans to more than double the amount of capacity it purchases from third parties as compared to the amount it purchased during the Test Year.[282]

Since the Test Year, Entergy has been engaged in an effort to increase ETI's long-term power capacity through dealing with third parties. It has entered into a number of agreements in that regard:

- In 2009, it entered into a ten-year purchased power agreement with Calpine Energy Services (Calpine) to purchase 485 MW of capacity from Calpine's Carville Energy Center (Carville

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278 Tr. at 1539-40.

279 ETI Ex. 34 (Cooper Direct) at 20-21; Tr. at 1901; ETI Initial Brief at 71.

280 ETI Ex. 39 (Cicio Direct) at PJC-1, pp. 30 and 62.

281 Tr. at 1946-47.

282 ETI Ex. 34 (Cooper Direct) at 23; see also ETI Init. Br. at 75-76.

Contract). Purchases pursuant to the Carville Contract will commence during the Rate Year, on June 1, 2012, and 50 percent of this contract is allocated to ETI.[283]

- During the Period from July 2009 through June 2011, the Company executed an agreement with NRG for a 75 MW one-year call option, with a delivery period that began on March 1, 2011, and 100 percent of this contract is allocated to ETI.[284]

- During the Period from July 2009 through June 2011, the Company executed a three-year agreement with Dow Pipeline for 100 MW capacity, with a delivery period that began on April 1, 2011, and 100 percent of this contract is allocated to ETI.[285]

- During the Period from July 2009 through June 2011, the Company executed a 25-year agreement with SRMPA for 225 MW, with a delivery period beginning on December 1, 2011, and 100 percent of this contract is allocated to ETI. ETI contends that the SRMPA contract will be beneficial because it provides "much-needed long-term base load capacity at an economically attractive price."[286]

- An additional contract, the Frontier contract, was in place during the Test Year, and saw a 150 MW increase in contract capacity during the Test Year.[287]

ETI argues that its growing reliance on third-party purchases will diversify its energy portfolio and help the Company meet its reliability needs at a lower cost.[288] The new purchased power contracts will also reduce ETI's fuel costs and dependence upon aging, higher heat rate generation units within the Entergy system.[289]

> ***Capacity Purchases from Other Entergy Affiliates Through "Legacy" Affiliate Contracts Under MSS-4***

The term "legacy affiliate contracts" refers to those contracts resulting from the December 31, 2007, jurisdictional separation of EGSI into ETI and EGSL, pursuant to which ETI

[283] ETI Ex. 34 (Cooper Direct) at 16, 19.

[284] ETI Ex. 34 (Cooper Direct) at 16, 19.

[285] *Id.* at 17, 19.

[286] *Id.*

[287] Tr. 1937-38.

[288] ETI Ex. 34 (Cooper Direct) at 24.

[289] Tr. at 1112-13, 1940-41.

purchases its allocated share of power from plants such as the River Bend nuclear plant, located in Louisiana and owned by EGSL as a result of the separation. The legacy affiliate purchases are made under MSS-4.[290]

> ***Capacity Purchases from Other Entergy Affiliates Through "Other" Affiliate Contracts Under MSS-4***

"Other affiliate contracts" refers to all affiliate contracts other than legacy contracts whereby ETI purchases capacity and associated energy from other Operating Companies.[291] The other affiliate purchases are also made under MSS-4.[292] Among others, in 2009 ETI entered into a new affiliate contract with Entergy Arkansas, Inc. (EAI) for wholesale base load resources (the EA WBL Contract), whereby ETI was allocated 31.7 percent of 336 MW capacity.[293]

> ***Capacity Purchases from the Entergy System Through Reserve Equalization Payments Under MSS-1***

Reserve Equalization payments are made under MSS-1. In any given month, some of the Operating Companies might be "long" on the amount of generating capacity they own (meaning that they own more capacity than they need) while others might be "short" on capacity (meaning they own less capacity than they need). In such a month, the long Operating Companies would receive MSS-1 payments from the short Operating Companies for use of their capacity.[294]

2. ETI's Request Regarding PPCCs

During the Test Year, ETI had total PPCCs of $245,432,884.[295] In the application, however, ETI is not seeking to recover its Test Year expenses. Rather, it is asking to recover roughly

[290] ETI Ex. 39 (Cicio Direct) at 24-26.

[291] ETI Ex. 34 (Cooper Direct) at 21.

[292] ETI Ex. 39 (Cicio Direct) at 24-26.

[293] Cities Ex. 6 (Nalepa Direct) at 13-14.

[294] ETI Ex. 39 (Cicio Direct) at 11-13; Cities Ex. 4 (Goins Direct) at 13.

[295] TIEC Ex. 1 (Pollack Direct) at Ex. JP-1; Tr. at 652-53.

$276 million, which represents the Company's anticipated PPCCs in the Rate Year.[296] In other words, ETI is seeking roughly $31 million more than its actual Test Year expenses. ETI derived this estimate based largely upon what it believes will the purchased power agreements in place during the Rate Year.[297]

As the following tables illustrate, ETI projects that, during the Rate Year, the total quantity, and the relative quantities purchased from each source, will differ substantially from its Test Year purchases.

Test Year vs. Rate Year Power Capacity Quantities (MW-Months)[298]		
Purchase	**Test Year**	**Rate Year**
Third Party Purchases	5,884	12,834
Affiliate Purchases (both Legacy and Other) Under MSS-4	21,670	21,711
Reserve Equalization Under MSS-1	8,309	5,262
Total	35,863	39,807

Test Year vs. Rate Year Power Capacity Costs[299]		
Purchase	**Test Year**	**Rate Year**
Third Party Purchases	$32,094,893	$69,061,200
Affiliate Purchases (both Legacy and Other) Under MSS-4	$189,032,442	$188,430,917
Reserve Equalization Under MSS-1	$25,461,353	$18,317,367
Total	$246,588,688[300]	$275,809,484

[296] TIEC Ex. 1 (Pollack Direct) at JP-1; ETI Ex. 34 (Cooper Direct) at 20; ETI Ex. 34A (Errata to Cooper Direct).

[297] TIEC Ex. 1 (Pollack Direct) at 22.

[298] TIEC Ex. 1 (Pollack Direct) at 22, Table 1 (Errata).

[299] Cities Ex. 12.

[300] Cities now agree that the correct amount for the Test Year is $245,432,884. *See* TIEC Reply Brief at 18.

This indicates ETI will purchase roughly 11 percent more power in the Rate Year than it did in the Test Year. Moreover, while the purchases pursuant to MSS-4 will remain fairly stable, the third-party purchases will substantially increase, with a somewhat corresponding decrease for purchases pursuant to MSS-1. In other word, ETI's plan is to become "less short" (on capacity) relative to the other Operating Companies in the Rate Year than it was in the Test Year.

ETI contends that the shift toward more third party purchases is part of its effort to develop a more diverse, modern, and efficient portfolio of generation supply resources, both to serve current customer needs and to serve anticipated load growth. This, in turn, will lower energy costs and result in savings for customers.[301]

ETI's initial request in this case was for a Purchased Power Rider (PPR) that would allow the Company to recover $276 million, but would be subject to future reconciliation based on actual expenses and revenues, much like a fuel factor.[302] The intervenors point out that the PPR proposal, while unprecedented, would have at least matched any post-Test Year increases in total purchased capacity costs with corresponding increases in sales, and would also have allowed for a prudence review of any post-Test Year purchased power capacity expenses in a future reconciliation proceeding.[303] The Commission, however, rejected the PPR proposal in its Supplemental Preliminary Order.[304] In lieu of the PPR proposal, ETI now proposes to simply recover the $276 million as part of its base rates.

3. Staff and Intervenors' Opposition to ETI's PPCCs Proposal

Staff and all of the actively-engaged intervenors oppose ETI's proposed adjustment to its Test Year PPCCs. They make a number of arguments against ETI's proposal.

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301 ETI Ex. 47 (Cooper Rebuttal) at 7-8.

302 Tr. at 1954; Cities Ex. 4 (Goins Direct) at 14.

303 TIEC Init. Br. at 25-26; Tr. at 1954; Cities Init. Br. at 37; Cities Ex. 6 (Nalepa Direct) at 8.

304 Supplemental Preliminary Order at 2 (Jan. 9, 2012).

(a) The PPCCs Requested by ETI Are Not Known and Measurable

First, they contend that ETI's Rate Year forecast cannot be considered known or measurable. Staff points out that the four[305] components from which ETI purchases power are interrelated, such that, "when ETI adds capacity under one element, such as through third party contracts, the other components, such as ETI's MSS-1 payments, will decrease."[306] Staff describes each of the components comprising ETI's PPCC Rate Year forecast as being "infected" with numerous assumptions.[307] For example, ETI necessarily made projections, rather than relying upon actual payments, when it estimated what it will pay for third-party contracts in the Rate Year.[308] Many of the third party contracts that will be in effect in the Rate Year do not contain fixed price terms. Rather, the amounts ETI will pay will fluctuate based upon factors such as required availability and performance. Nevertheless, ETI simply assumed it would pay the maximum amount possible under each of its third party contracts, and disregarded any of the contractual factors that might reduce its Rate Year payments.[309] Thus, the intervenors contend that ETI's cost estimates for third party purchased power are merely projections, as opposed to known and measurable changes.[310]

Similarly, ETI's contractual agreements with its affiliate Operating Companies require ETI to make assumptions about their future costs. The contracts do not definitively fix prices or quantities. Rather, prices and quantities under the contracts will fluctuate based on the specific operational conditions actually experienced by the various Operating Companies during the Rate Year.[311] The ultimate determination of payments made in the Rate Year will be calculated based upon the complex mathematical formula set out in schedule MSS-4. That formula contains a great number of variables. ETI had to make assumptions about each one of those variables in order to estimate its

[305] Staff (and some of the intervenors) describe them as three components, by combining affiliate purchases under legacy contracts and affiliate purchases under other contracts into one component.

[306] Staff Initial Brief at 25 (*citing* Tr. at 1946).

[307] Staff Initial Brief at 26.

[308] Tr. at 704.

[309] Tr. at 704-05.

[310] TIEC Initial Brief at 29-30; Staff Initial Brief at 26.

[311] Tr. at 606.

Rate Year costs.[312] The intervenors point to ETI's new contract with EAI (the EA WBL Contract) as evidence of the "inherently speculative nature" of ETI's PPCCs request. According to the intervenors:

- the EA WBL Contract was signed on April 11, 2012 (only days before the hearing in this matter commenced); purchases will not commence under the contract until January 1, 2013;
- pricing under the contract will be determined in 2013 pursuant to the complex formula contained in MSS-4;
- the quantity of capacity ETI ultimately purchases under the contract will be based on a yet-to-be-determined allocation percentage between ETI and the other Operating Companies;
- the contract itself may never go into effect because it is contingent upon ETI receiving all necessary "regulatory approvals" before August 1, 2012; and
- if it does go into effect, it will still be subject to at least two further revisions before any power is received by ETI under the contract.[313]

The EA WBL Contract accounts for more than one-third of ETI's upward adjustment to its Test Year PPCCs. The intervenors contend that, in order for ETI to arrive at its forecasted PPCCs for the Rate Year, it had to make myriad assumptions as to the future values of the many variables in the EA WBL Contract (and the other affiliate contracts).[314] Therefore, the intervenors argue that ETI's cost estimates for its contractual agreements with its affiliate Operating Companies are merely projections, as opposed to known and measurable changes.[315]

ETI's estimated costs for its MSS-1 payments also require assumptions about the future. In order to calculate its future reserve equalization responsibilities using the complex formula set out in MSS-1, ETI had to forecast its own future loads, along with the future loads of all the other Operating Companies. If those assumptions prove to be wrong, then ETI's actual MSS-1 costs will

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[312] *See* Staff Initial Brief at 27; Tr. 606.

[313] ETI Ex. 47 (Cooper Rebuttal) at RRC-R-1, and Tr. at 628-9.

[314] Staff Initial Brief at 27-28. Staff makes the further point that, because the EA WBL Contract was executed only days before the hearing, Staff has been unable to determine whether the contract is even a prudent one.

[315] TIEC Initial Brief at 30-32; Staff Initial Brief at 27-28.

be different than as projected in the application.[316] It is noteworthy, according to the intervenors, that ETI projected the future load growths of all the Operating Companies when it calculated its projected Rate Year MSS-1 costs because, elsewhere in ETI's evidence, the Company has taken the position that future projected loads should not be considered known and measurable.[317] Staff argues:

> ETI cannot have it both ways. It cannot claim load growth to be speculative in one context, and then claim that it can forecast with absolute certainty the respective load growths for each EOC on the Entergy System.[318]

TIEC points out that ETI's estimated MSS-1 payments "were still changing on the eve of the hearing."[319] In the following exchange, even ETI witness Phillip May, one of the Company's primary witnesses regarding its PPCCs, seems to have conceded that the Company's MSS-1 projections are not known and measurable:

> Q: Do you think that the projection . . . of rate year sales that is implicit in the calculation of MSS-1 costs . . . is a known and measurable change?
>
> A: I think that there is some uncertainty with regard to that projection, yes, sir.[320]

In sum, the intervenors contend that ETI's cost estimates for all components of purchased power in the Rate Year are merely projections, as opposed to known and measurable changes.[321]

(b) The PPCCs Requested by ETI Violate the Matching Principle

Second, the intervenors acknowledge the principle that Test Year expenses may be adjusted for known and measurable changes. However, they contend that such adjustments can only be made where the attendant impacts on all aspects of a utility's operations (including revenue, expenses, and

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316 Tr. at 651-52.

317 Tr. at 1907; *see also* Staff Initial Brief at 28; TIEC Initial Brief at 27-28.

318 Staff Initial Brief at 29; *see also* TIEC Initial Brief at 37.

319 TIEC Initial Brief at 28.

320 Tr. at 1918-19.

321 TIEC Initial Brief at 27-28; Staff Initial Brief at 29.

invested capital) can with reasonable certainty be identified, quantified, and matched.[322] They assert that ETI's proposed adjustment does not satisfy this matching principle. The intervenors complain that ETI is improperly attempting to "compare apples to oranges" by mixing a forecast of future Rate Year PPCCs with actual Test Year billing determinants. As explained by Cities witness Nalepa, "[u]nder the company's approach of mixing estimated rate year costs with test year billing units, there is a failure to recognize customer growth and increased sales revenue – thus overstating the revenue requirement."[323] The argument, essentially, is that the various new or expanded contracts that ETI has entered into were executed so that, in whole or in part, ETI would be able to meet future demand, but that ETI is seeking to recover the costs of those new contracts from its existing customers.[324]

The intervenors offer various examples, of which the following is typical, to illustrate why it was inappropriate for ETI to fail to take load growth into account when it calculated its Rate Year PPCCs. Assume that, during the Test Year, Utility X had 100 billing units and $500 of PPCCs. Also assume that, during the Rate Year, Utility X had 200 billing units and $1,000 of PPCCs. If Utility X were limited to setting its rates based solely on its Test Year numbers, then it would recover precisely the right amount to cover its PPCCs in both the Test Year (100 billing units x $5 per unit = $500 of PPCCs) and in the Rate Year (200 billing units x $5 per unit = $1,000 of PPCCs). If, on the other hand, Utility X were allowed to set its rates based upon it billing units from the Test Year (100) and its PPCCs from the Rate Year ($1,000), then Utility X would unfairly recover twice the amount needed to cover its actual PPCCs in the Rate Year (200 billing units x $10 per unit = $2,000).[325] Thus, intervenors contend that ETI's load growth must be taken into account if PPCCs are to be based on Rate Year projections.[326] They point out that ETI itself expects steady load

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[322] Cities Ex. 6 (Nalepa Direct) at 12, *citing* P.U.C. SUBST. R. 25.231(c)(2)(F).

[323] Cities Ex. 6 (Nalepa Direct) at 8; Cities Ex. 4 (Goins Direct) at 14-15.

[324] Cities Ex. 6 (Nalepa Direct) at 11; *see also* Cities Initial Brief at 38, Staff's Initial Brief at 30, TIEC Initial Brief at 35-39.

[325] Cities Ex. 4 (Goins Direct) at 16-17.

[326] Cities Ex. 4 (Goins Direct) at 17; *see also* TIEC Ex. 23.

growth in the next few years,[327] and experienced "good" growth over the two years preceding the Test Year.[328]

For its part, ETI denies that its increased capacity has been obtained in order to meet load growth. Rather, it contends that it has added capacity in order to be "less short" in comparison to the other Operating Companies.[329] Moreover, ETI contends that the load growth adjustments proposed by intervenors are "uncertain and unnecessary."[330]

(c) ETI's Proposal Would Preclude Prudence Review

Third, TIEC contends that ETI's future Rate Year proposal would set rates based on projections without any effective Commission review of: (1) what the actual expenditures under purchased capacity contracts turn out to be; (2) whether those expenditures turn out to be reasonable; and (3) whether the future contracts were prudent.[331]

4. The Intervenors' Recommendations Regarding PPCCs

The intervenors agree that the amount requested by ETI is unreasonable, excessive, and should be rejected. They do not universally agree, however, about what the proper number for PPCCs should be. Staff, TIEC, and State Agencies argue that ETI's PPCCs should be set at the amount of the Company's Test Year PPCCs: $245.4 million. This position is best summarized by Staff:

> Staff recommends that the Commission adhere to traditional ratemaking principles and set the amount of ETI's purchased power expenses based on what the Company actually experienced during its test year. During its test year, ETI had total purchased power capacity expenses of $245.4 million. This amount is not in dispute.

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327 Cities Ex. 4 (Goins Direct) at 17; Tr. at 706.

328 Tr. at 130.

329 ETI Initial Brief at 68-69.

330 *Id.* at 69.

331 TIEC Initial Brief at 33-35.

> This amount *is* known. This amount *is* measurable. The Commission should utilize this amount to set just and reasonable rates for ETI and its ratepayers.[332]

Rather than recommending Test Year PPCCs, Cities offer two alternatives – one recommended by its witness Dr. Dennis Goins, and another recommended by its witness Mr. Nalepa.[333] Dr. Goins recommends that ETI be allowed to recover PPCCs of roughly \$242.9 million.[334] This amount is roughly \$33 million less than ETI's requested amount and \$3 million less than ETI's actual Test Year costs. To arrive at this amount, Dr. Goins made several calculations. First, he adjusted the average per kW cost of ETI's legacy and other affiliate purchases using cost data from November 2010 through October 2011, which is slightly more current data than that relied upon by ETI.[335] Second, as to MSS-4 costs, because the EA WBL contract is set to expire sooner than the three years he assumed ETI's new rates will be in effect, Dr. Goins "normalized" the costs of the EA WBL contract over the three year period.[336] Finally, he adjusted the Rate Year total PPCCs estimate to reflect the effects of load growth, based upon ETI forecasts.[337]

Mr. Nalepa took a slightly different approach. He recommended that ETI be allowed to recover PPCCs of \$236,838,634, or roughly \$39 million less than ETI's requested amount and \$8 million less than ETI's Test Year costs.[338] To arrive at this amount, Mr. Nalepa first calculated the per kW cost of ETI's third party Rate Year capacity and applied it to ETI's Test Year-end capacity. In this way, "the increased cost of the new resources is recognized, but current demand is better matched to current resources."[339] Second, he made the same adjustment as Dr. Goins as to MSS-4 costs due to the EA WBL contract.[340]

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332 Staff Initial Brief at 29.

333 Cities Initial Brief at 40.

334 Cities Ex. 6 (Nalepa Direct) at 17, and Errata No. 3.

335 Cities Ex. 4 (Goins Direct) at 17-18.

336 Cities Ex. 4 (Goins Direct) at 18; Cities Ex. 6 (Nalepa Direct) at 15-16.

337 Cities Ex. 4 (Goins Direct) at 18-19.

338 Cities Ex. 6 (Nalepa Direct) at 17.

339 Cities Ex. 6 (Nalepa Direct) at 12-13.

340 *Id.* at 15-16.

TIEC explains it is reluctant to "descend into the rabbit hole and engage in ratemaking based on prognostications, estimates, projections, and assumptions about what may happen in the future."[341] If the Commission were to do so, however, TIEC argues that the final result would be lower than the Test Year PPCCs, not higher. TIEC's witness Jeffry Pollock calculated the impact of projected unit prices based upon ETI's projections, and he eliminated the expiring EA WBL Contract. His result, which TIEC is not advocating, would allow ETI to recover PPCCs of $238.8 million, roughly $7 million less than its Test Year costs.[342]

ETI describes the proposals made by TIEC and Cities as "extreme" and contrary to common sense.[343] For example, Mr. Pollock's calculations indicate that ETI's MSS-1 costs would increase by roughly $5 million, while its third-party and affiliate contracts would slightly decrease. ETI argues that this is the opposite of reality. By adding capacity through third party contracts, its reliance upon the other purchased power components, especially MSS-1, will necessarily decline, not increase.[344] ETI also argues that load growth is inherently uncertain and should not be taken into account.[345]

5. The ALJs' Analysis Regarding PPCCs

The ALJs conclude that ETI failed to meet its burden to prove that the adjustment it seeks to its Test Year PPCCs is known and measurable. The known and measurable standard is an *exception* to the actual data contained in the Test Year. The point of a historical Test Year is to review actual costs, which include the ups and downs of what actually occurred. As to a forecast of the Rate Year, by contrast, the evidence demonstrates that the costs attributable to a particular contract to purchase capacity cannot currently be known because there are so many variables that will play into the amount ETI ultimately pays. As stated above, ETI's third party contracts lack fixed prices and the amounts ETI will pay could fluctuate based upon factors such as required availability and performance. ETI simply assumed it would pay the maximum amounts under those contracts, and

[341] TIEC Initial Brief at 41.

[342] TIEC Ex. 1 (Pollack Direct) at 25-27; TIEC Initial Brief at 41-42.

[343] ETI Initial Brief at 83.

[344] *Id.* 83.

[345] *Id.* 84.

disregarded the contractual factors that could lower the payment amounts. Yet this assumption runs counter to ETI's historical experience with its contracts.[346] Similarly, ETI's affiliate contracts do not fix prices or quantities, and the amount ETI ultimately pays will fluctuate based upon operational conditions experienced by all of the Operating Companies during the Rate Year. Those operational conditions obviously cannot be known at this time. Both the affiliate contracts under MSS-4 and the equalization payments under MSS-1 are based upon highly complex mathematical formulae that utilize numerous variables. Any of the variables could change during the Rate Year, thereby altering the amounts paid by ETI under affiliate contracts or MSS-1. As a result, the evidence demonstrates that there could be a substantial difference between ETI's projected Rate Year costs and what actually ends up occurring. ETI asks the Commission to trust it that these differences would be "small,"[347] but provides no evidence as to what small means.

The efforts made by ETI, Cities, and TIEC to forecast Rate Year PPCCs further illustrate the difficulty of deviating from actual Test Year data in an area that involves so many future contingencies and unknowns. Those forecasts swung wildly – ETI estimated Rate Year PPCCs that were $31 million *more* than the Test Year, while the Cities' and TIEC's estimates came in at $3 million, $8 million, and $7 million *less* than the Test Year, respectively. Indeed, even Cities' own witnesses disagreed substantially among themselves as to what the proper amount should be. Moreover, arguably ETI could not even agree with itself regarding the proper amount because, in its Initial Brief, it suggested that a reduction of roughly $4.5 million might be warranted to account for its latest projection of its MSS-1 costs in the Rate Year.[348]

The ALJs are similarly convinced that ETI's request violated the matching principle by mixing its forecast of future Rate Year PPCCs with Test Year billing determinants. It is logically inconsistent for ETI to have, on the one hand, based its estimate of Rate Year MSS-1 costs on its projections of the load growths of ETI and all the other Operating Companies and, on the other hand, argue that load growth cannot be considered known and measurable when calculating its overall

[346] Tr. at 705.

[347] ETI Initial Brief at 81.

[348] ETI Initial Brief at 77 (citing Tr. at 684, 1945).

PPCCs. This argument does not withstand scrutiny, especially in light of the fact that ETI clearly believes its load will be larger in the Rate Year than it was in the Test Year and it has, in fact, contracted for six percent more load in the Rate Year.[349]

Simply put, the intervenors presented substantial evidence that all of the components of ETI's purchased power capacity contain significant variability and uncertainty in costs, thereby leading to the conclusion that estimates of Rate Year PPCCs cannot be considered known and measurable. For this reason, the ALJs recommend that ETI's PPCCs request be rejected. In its place, the ALJs recommend that ETI be allowed to recover its Test Year PPCCs of $245,432,884.

B. Transmission Equalization (MSS-2) Expense

The Entergy system transmission grid is a large, integrated transmission network that is operated for the mutual benefit of all of the Entergy Operating Companies.[350] Service Schedule MSS-2 is a FERC jurisdictional tariff that equalizes the ownership costs of certain high voltage transmission facilities among ETI and the other Operating Companies, so that each Operating Company pays its just and reasonable share of those costs. Accordingly, those costs are referred to as "transmission equalization" payments.[351] MSS-2 generally applies to equalization of transmission costs for transmission assets of 230 kV and larger.[352]

In any given month, some of the Operating Companies might be "long" on the amount of transmission capacity they own (meaning that they own more capacity than they need) while others might be "short" on capacity (meaning they own less capacity than they need). In such a month, the long Operating Companies would receive MSS-2 payments from the short Operating Companies for

[349] ETI Ex. 47 (Cooper Rebuttal) at 4; Tr. at 667-68.

[350] Tr. at 450, 793.

[351] Tr. at 724; ETI Ex. 39 (Cicio Direct) at 15-17 and PJC-1 at 38.

[352] Tr. at 450-51, 731.

use of their transmission facilities.[353] Over the course of the Test Year, ETI was short, meaning that it paid a total of $1,753,797 in MSS-2 payments to various other Operating Companies.[354]

In the application, rather than seeking to recover only the $1.7 million in Test Year MSS-2 costs, ETI is seeking to recover roughly $10.7 million, which represents its anticipated MSS-2 expenses in the Rate Year.[355] The additional $9 million that ETI seeks is based on the Company's estimates of transmission construction projects that are expected to have been completed by or during the Rate Year which will result in changes to the relative transmission line ownership ratios between the Operating Companies. In other words, ETI expects that, by or during the Rate Year, its ownership share under the MSS-2 will decrease relative to the other Operating Companies (as the transmission capacity owned by the other Operating Companies increases), thereby driving the amount of ETI's MSS-2 payments upward.[356]

The increase is driven by ETI's prediction that $184.9 million in additional transmission capacity will be built by other Operating Companies by the end of the Rate Year. ETI identified six construction projects that are either underway or approved for construction and which, collectively, will account for roughly $141 million of the predicted $184.9 million in additional transmission capacity. Of those six projects, one was completed and went into service on December 16, 2011, after the end of the Test Year. The other five are either under construction or still in the planning phase and are currently scheduled to go into service on dates ranging from June 29, 2012, to December 31, 2012.[357] According to ETI, the remaining $43.9 million of the $184.9 million in additional transmission capacity is derived from "an estimate of the capital investment necessary to maintain equalizable [*i.e.* MSS-2 qualifying] transmission investments across the Entergy

[353] Tr. at 731, 735.

[354] Tr. at 723-24, 737; Cities Ex. 28.

[355] Tr. at 452-53, 738, 760.

[356] Tr. at 775-77.

[357] ETI Ex. 59 (McCulla Rebuttal) at 2 and MFM-R-1; Tr. at 456-58.

Transmission System."[358] The estimate is based upon the Operating Company's projected budgets and historical spending patterns for maintenance of transmission facilities.[359]

Staff, State Agencies, TIEC, and Cities all oppose ETI's effort to recover $10.7 million in MSS-2 expenses. The parties make a number of arguments. First, they point out that MSS-2 utilizes a complex mathematical formula to calculate each Operating Company's liability (or credit) under the equalization process. There are a great number of variables that are used in the formula, such as the amount of investments made by each Operating Company in transmission facilities, the costs of capital for each Operating Company, the size of the load demanded by each Operating Company, and the amount of state and federal taxes paid by each Operating Company. Changes to any of these variables can change the amount ETI owes (or is due) pursuant to MSS-2.[360] Moreover, these variables relate not only to ETI, but to all of the Operating Companies. Indeed, Cities calculate that, to perform the MSS-2 calculation, at least 360 "mini-forecasts" must be made, only 60 of which relate to ETI.[361] As explained by TIEC witness Pollock, any effort to estimate future amounts of these many variables "is susceptible to a host of uncertainties."[362] The intervenors argue that for ETI to arrive at its estimate of $10.7 in MSS-2 costs during the Rate Year, the Company had to speculate as to what the many MSS-2 variables would be in the Rate Year. In other words, they contend that ETI's estimate of its future MSS-2 costs cannot possibly be considered "known and measurable" and, therefore, is not recoverable.[363] State Agencies and Staff liken ETI's attempt to obtain an MSS-2 adjustment for not-yet-complete construction projects to an impermissible request to recover the costs of CWIP without having to meet PURA's burden of proving that recovery is necessary to protect the utilities financial integrity.[364]

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[358] ETI Ex. 59 (McCulla Rebuttal) at 3.

[359] *Id.*

[360] ETI Ex. 39 (Cicio Direct) at PJC-1 at 38-43; Tr. at 454-55.

[361] Cities Reply Br. at 68-69.

[362] TIEC Ex. 1 (Pollock Direct) at 29.

[363] Staff Initial Brief at 31; State Agencies Initial Brief at 11-13; TIEC Initial Brief at 44-45; Cities Initial Brief at 44.

[364] State Agencies Initial Brief at 12 (*citing* PURA § 36.054; P.U.C. SUBST. R. 25.231(c)(2)(D)); Staff Reply Brief at 20.

Second, the parties oppose ETI's effort to recover its predicted MSS-2 expense in the Rate Year point out that the primary driver of the increased costs over the Test Year comes from a number of transmission projects that have not yet come into service, and are still in the planning or construction phase. ETI concedes that if the projects do not actually come into service at the currently estimated times, then the Company's estimates of its MSS-2 costs during the Rate Year will be inaccurate.[365] Thus, Staff contends that ETI's projections about future MSS-2 costs cannot be considered known and measurable.[366] Moreover, TIEC and Staff contend that ETI is effectively seeking higher rates based upon expenses associated with projects that are not yet completed and, therefore, the projects cannot be considered "used and useful."[367] As explained by TIEC:

> It would be bad public policy for the Commission to rely on speculative construction end dates to form the basis of a known and measurable change to test year costs. ETI's own witness Mr. Cicio admitted that in-service dates can be uncertain. . . . Similarly, costs can change upward or downward. For this reason, the Commission has typically followed the policy that proper ratemaking requires that a utility actually build the transmission infrastructure suggested by its projections, and then seek to account for that investment on a historical basis in a future rate case. In Docket No. 28906, for example, the Commission held that LCRA's projections of future transmission investment did not support a finding that its projected capital needs satisfied the known and measurable test. It is similarly unreasonable for ETI to make a post-test year adjustment associated with transmission projects that are not serving any of its customers and that may or may not impact ETI's transmission equalization expense, depending on when the projects are finally completed.[368]

Third, in addition to the six transmission projects that are under development, another driver of the increased costs over the Test Year comes from ETI's estimate that $43.9 million will be spent to maintain transmission investments across the Entergy Transmission System. The intervenors contend that ETI has provided little to no evidentiary support for this estimate. State Agencies and Cities also point out the unfairness of allowing ETI to begin recovering $10.7 million per year in its rates immediately based upon new transmission facilities, even though many of those new facilities

[365] Tr. at 800-801

[366] Staff Initial Brief at 32.

[367] TIEC Initial Brief at 47; Staff Initial Brief at 19-20.

[368] TIEC Initial Brief at 47 (*citing* Docket No. 28906, Order at 6).

will not come into service (and ETI will therefore not incur higher MSS-2 payments for those facilities) for many months.[369]

Fourth, Cities points out that Entergy and the various Operating Companies have announced a plan to sell all of their transmission assets to a third party. That process is currently underway. The evidence suggests that, if and when that transaction is complete, ETI's MSS-2 expenses will disappear.[370]

Finally, TIEC argues that there is no need to grant ETI's request for a *pro forma* adjustment to its test year MSS-2 expenses because the Company can avail itself of a TCRF if its Rate Year costs deviate substantially from its Test Year costs. Thus, if it turns out that ETI experiences an increase in its MSS-2 expenses during the Rate Year, the utility has cost recovery mechanisms at its disposal that could make it whole in a timely manner.

Staff and State Agencies argue that only $1.7 million (representing ETI's actual Test Year expenses) should be approved in this proceeding. TIEC witness Pollock recommends approving a slight upward adjustment to account for the fact that ETI's MSS-2 expenses were substantially higher in the second six months of the Test Year than they were in the first six months. Mr. Pollock and TIEC recommend a *pro forma* adjustment equal to twice the amount of MSS-2 payments incurred by ETI in the second six months of the Test Year, or $2.7 million.[371]

Cities' witness Goins presented yet another alternative. Dr. Goins proposes to adjust the projected Rate Year costs for known expenses incurred after the Test Year. He proposed reducing the adjusted Rate Year MSS-2 expense to a Test Year level by applying a load growth adjustment using ETI's own projected load growth as a benchmark indicator of the reasonable anticipated level of growth. (Cities invoke essentially the same "matching principle" argument regarding load growth

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[369] State Agencies Initial Brief at 12; Cities Initial Brief at 45.

[370] Cities Reply Brief at 67-68; Tr. at 113-14; Cities Ex. 4 (Goins Direct) at 20-21. Admittedly, if these expenses disappear, ETI will still have to bear transmission expenses. However, it is impossible to know, at this time, what those expenses would be.

[371] TIEC Ex. 1 (Pollack Direct) at 32-33.

that they raised with respect to PPCCs). The result of Dr. Goins' adjustment would be to would allow ETI to recover $4,103,850 in MSS-2 expenses.[372]

ETI responds to these arguments on a number of fronts. It contends that the main driver of changes in MSS-2 expenses is the relative amount of equalizable transmission investment in the transmission system by ETI and the other Operating Companies, compared to their proportionate responsibility for that investment, based on each company's responsibility ratio.[373] ETI argues that the other elements of the formula are relatively stable, and do not vary significantly from year to year.[374] ETI contends its requested level of MSS-2 expense is based on a known and measurable change because it is based on the $184.9 million in additional transmission investment for all of the Operating Companies that ETI knows will occur and can reasonably measure. ETI points out that "the vast majority" of the planned transmission projects have received full funding approval and have been constructed or are on schedule to be completed before the end of the Rate Year, while the remaining amount is reasonably quantified and measured based on the budget and historical spending for maintenance of equalizable transmission facilities.[375]

ETI also argues that its actual MSS-2 expenses have steadily trended upward since the Test Year. ETI explains as follows:

> [I]n the last month of the test year (June 2011), ETI's payments began to increase significantly, as the balance of relative equalizable investment levels shifted among the Operating Companies. ETI's actual monthly payments have climbed steadily ever since, reaching $698,289 in the most recent actual month's bill (February 2012). Annualization of this most recent actual data yields an annual MSS-2 amount of $8.4 million, almost five times the test year level. In light of this trend in actual

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[372] Cities Ex. 4 (Goins Direct) at 20-21.

[373] ETI Ex. 45 (Cicio Rebuttal) at 3-4. Responsibility Ratio is an allocator that reflects the relative contribution of each Operating Company to the System's coincident peak load – in other words, an Operating Company's coincident peak load divided by the System peak load, calculated on a rolling twelve-month average. ETI Ex. 39 (Cicio Direct) at 12.

[374] Tr. at 763 and 780.

[375] ETI Ex. 59 (McCulla Rebuttal) at 2-3; ETI Initial Brief at 88-89.

> historical data, the notion of basing the MSS-2 expense in rates on the test year level is unreasonable on its face.[376]

Thus, ETI contends its requested expense level is "consistent" with actual recent historical levels of MSS-2 expense.[377]

ETI describes Cities' concern regarding load growth as a "red herring." ETI contends that load growth is not the cause of changes in MSS-2 costs. Instead, its MSS-2 increases are driven by the other Operating Companies' transmission investments, "separate and apart from, and unaffected by," any increase in ETI's load.[378] Moreover, ETI contends that load growth adjustments are not known and measurable and are not the proper subject of a post-test year adjustment for ordinary expenses such as MSS-2 costs.[379]

Finally, if the Commission rejects its request for $10.7 million in MSS-2 costs, ETI suggests annualizing the most recent period of its actual MSS-2 costs, by multiplying its February 2012 MSS-2 bill times 12, resulting in an amount of $8,379,480. ETI contends this would be more representative of expected Rate Year MSS-2 costs than the amounts proposed by the intervenors.[380]

For largely the same reasons as were discussed relative to PPCCs, the ALJs conclude that ETI failed to meet its burden to prove that its proposed Rate Year MSS-2 costs are known and measurable. The MSS-2 formula requires assumptions about a great number of variables. Changes to any of the variables could occur during the Rate Year, thereby altering the amount paid by (or received by) ETI during the Rate Year. The projects that underlie ETI's Rate Year request are largely not yet built, and might never be built. Additionally, much like with the PPCCs estimates, there is a wide gulf between the competing estimates by ETI, Cities, and TIEC of forecast Rate Year MSS-2 costs, illustrating the problem of deviating from actual Test Year data in an area that involves so many future contingencies and unknowns.

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[376] ETI Initial Brief at 90-91; Tr. at 784.

[377] ETI Initial Brief at 91.

[378] ETI Ex. 45 (Cicio Rebuttal) at 4-5; ETI Initial Brief at 93.

[379] ETI Ex. 57 (May Rebuttal) at 12; ETI Initial Brief at 93.

The ALJs are equally unconvinced by ETI's alternative proposal to multiply its February 2012 MSS-2 bill times 12, resulting in an amount of $8,379,480. ETI offered no evidence to establish that a single month's costs can serve as a reasonable representation of what ETI's future Rate Year MSS-2 costs will be. Moreover, February 2012 is outside of the Test Year.

The intervenors presented substantial evidence to demonstrate that ETI's estimate of its Rate Year MSS-2 costs cannot be considered known and measurable. For this reason, the ALJs recommend that ETI's MSS-2 request be rejected. In its place, the ALJs recommend that ETI be allowed to recover its Test Year MSS-2 costs of $1,753,797.

C. Depreciation Expense [Germane to Preliminary Order Issue No. 12]

ETI currently has an annual depreciation expense of approximately $72.1 million. This expense is based on the previously approved depreciation rates.[381] ETI now requests depreciation rates that would result in an annual depreciation expense of approximately $86 million. This requested amount represents an increase in the annual depreciation expense of approximately $13.9 million - almost 20 percent - from the current annual depreciation expense.[382] The depreciation expense ultimately included in retail rates, however, will be derived by applying the Commission approved rates to the test year end plant balances as of June 30, 2011.

The other parties have accepted the vast majority of ETI's recommendations, but take issue with the Company on a few issues related to generation, transmission, distribution, and general plant accounts. Staff recommends an annual depreciation expense of approximately $78.2 million, an increase of approximately $6.1 million from the current annual depreciation expense.[383] Cities recommend an annual depreciation expense of approximately $67.6 million.[384]

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[380] ETI Ex. 46 (Considine Rebuttal) at 37; ETI Initial Brief at 32.

[381] ETI Ex. 13 (Watson Direct) Attachment DAW-1. Appendix B at 3.

[382] ETI Ex. 13 (Watson Direct) at 7.

[383] Staff Ex. 2 (Mathis Direct) at 8.

[384] Cities Ex. 5C (Pous Depreciation Study) at 2.

The identical positions of ETI, Staff, and Cities on depreciation issues are set forth in the following table:[385]

Plant Group	Approved	ETI Proposal	Staff Proposal	Cities Proposal
Hydro Production	$7,137	$245	$245	n/a
Regional Trans. & Market Operations	$685,351	$685,351	$685,351	n/a
General Amortized Plant	$4,175,311	$5,946,949	$5,946,949	n/a

The differing positions of ETI, Staff, and Cities on depreciation issues are set forth in the following table:[386]

Plant Group	Approved	ETI Proposal	Staff Proposal	Cities Proposal
Steam Production	$17,497,781	$18,660,946	$14,709,942	n/a
Transmission Plant	$13,679,827	$16,493,761	$16,417,727	$13,451,479
Distribution Plant	$32,110,774	$40,493,392	$38,806,863	$33,186,546
General Plant	$3,943,450	$1,604,644	$1,604,644	$973,519
General Plant Reserve Deficiency	$0	$2,134,924	$0	n/a
TOTAL	$72,099,631	$86,020,212	$78,171,721	n/a[387]

The competing positions of ETI, Staff, and Cities reflected in the table above are primarily the result of different: (1) net salvage rates for certain accounts; (2) remaining life parameters for certain accounts; and (3) treatment of a potential general plant reserve deficiency. Cities witness

[385] ETI Ex. 13 (Watson Direct) at 7; Staff Ex. 2 (Mathis Direct) at 7-8; Cities Ex. 5C (Pous Depreciation Study) at 7, 8, and 34.

[386] ETI Ex. 13 (Watson Direct) at 7; Staff Ex. 2 (Mathis Direct) at 7-8; Cities Ex. 5C (Pous Depreciation Study) at 7, 8, and 34.

[387] A total value of Cities' adjustments in this format would be out of context and is therefore not provided in this table.

Pous also questions the reliability of the data employed by ETI witness Watson in the performance of his study.

An analysis of the competing net salvage rates and life parameters for each account is presented in detail below, organized by plant and account group.

1. Terminology and Methodology

Depreciation is a method of allocating the loss of the service value, not restored by current maintenance, over the useful life of an asset. This loss may be caused by wear and tear, decay, obsolescence, or changes in demand.[388]

Within the context of a rate case, the purpose of depreciation is to allow a company to recover the cost of an asset over the asset's useful life. Ideally, the cost of the asset is spread out evenly across the years the asset is in service, thus recovering the cost of the asset from the customers who receive the benefit of the asset.[389]

Both ETI and Staff use the remaining-life technique, average life group procedure, and straight-line method to calculate the depreciation rate.[390] The basic formula for the remaining life technique is presented below.

$$depreciation\,rate\,(\%) = \left\{\frac{1 - book\,reserve\,ratio - net\,salvage\,ratio}{composite\,remaining\,life}\right\} * 100$$

For example, if an asset has a book reserve ratio of 0.5 (*i.e.*, 50 percent of the asset's value has already been recovered through prior depreciation expense), a net salvage ratio of zero (*i.e.*, the asset will cost nothing to retire, or all retiring costs will be recovered through its subsequent sale), and the composite remaining life is ten years (*i.e.*, the asset is expected to remain in service for another ten years), then the depreciation rate will be 5 percent (*i.e.*, {[(1 - 0.5 - 0) / 10] *100}).

[388] Staff Ex. 2 (Mathis Direct) at 8.

[389] Staff Ex. 1 (Mathis Direct) at 8-9.

By operation of the remaining-life formula, a greater net salvage value will reduce the numerator and result in a lower depreciation rate and a lower depreciation expense. Likewise, a lower net salvage value will increase the numerator and result in a higher depreciation rate and a higher depreciation expense. Similarly, a longer remaining-life will result in a lower depreciation rate and lower depreciation expense, and a shorter remaining-life will result in a higher depreciation rate and a higher depreciation expense.

Because net salvage and remaining-life values are the two contested variables in the remaining-life formula, a clear explanation of net salvage and remaining-life will be helpful.

Net Salvage Value. Net salvage is calculated by taking the amount received for an asset as a result of its sale, reuse, or reimbursement, and subtracting that amount from the cost associated with retiring the asset. This figure is then divided by the original cost of the asset to determine the net salvage ratio. For example, if an asset with an original cost of $200 is resold for $20, but it costs the owner $10 to ship the asset to the purchaser, then the net salvage value of that asset would be $10 ($20 - $10), and the net salvage ratio of that asset would be 5 percent ($10/$200).

ETI witness Watson and Staff witness Mathis used different methods of calculating a net salvage rate.[391] Mr. Watson took the average (mean) of recorded net salvage values for groups of successive years (rolling bands), and then selected the net salvage rate from among these averages.[392] Ms. Mathis also used rolling band averages (means), but then took the median from a representative group of rolling bands when the historical salvage data would have otherwise produced what Mr. Watson considers skewed results.[393]

Ms. Mathis' method of calculating net salvage rates follows recent Commission precedent.[394] As Mr. Watson explained at the hearing, it is appropriate to infer acceptance of a methodology by

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390 ETI Ex. 13 (Watson Direct) at 15; Staff Ex. 2 (Mathis Direct) at 10-11.

391 Tr. at 415-416.

392 ETI Ex. 13 (Watson Direct) at 20-21.

393 *Id.* at 22-23, 32-33.

394 Tr. at 1766; Staff Ex. 9 (Docket No. 38339 Final Order) at FoF 126, 128, 130, and 131.

looking at whether the Commission adopted the conclusions that the methodology produced.[395] In other words, if the Commission adopts the conclusions, then by inference the Commission has adopted the methodology used to derive those conclusions. Thus, it is necessary to examine recent litigated rate cases to ascertain Commission precedent.

In the most recent fully-litigated rate case, Docket No. 38339,[396] Staff disagreed with CenterPoint's depreciation witness, Mr. Watson, concerning the net salvage rates for five accounts.[397] In its order, the Commission adopted Staff's recommended net salvage rates for four out of those five accounts for which Staff disagreed with Mr. Watson.[398] Staff's method for calculating net salvage rates is the same in the present case as it was in the CenterPoint rate case.[399]

ETI argues that the use of a median, as employed by Ms. Mathis, is not a sufficiently rigorous or expansive approach to depreciation analysis. According to ETI, depreciation training and texts, as well as authoritative statistical texts, favor the average, or mean, not the median, as the best indicator of the central tendency of a data set. ETI argues that this is particularly the case because depreciation analysis requires careful consideration of trends over time.[400] ETI then offers the following comments:

> [Ms. Mathis] agreed in response to a hypothetical that the median value of an initial period of ten years of +5% net salvage, followed by one year of 0% salvage, followed by the most recent period of ten years of -5% salvage, would be 0%. This hypothetical plainly illustrates how reliance on the median can overlook data trends. In the hypothetical, if the depreciation analyst would otherwise wish to give more weight to the most recent historical period as indicative of conditions going forward, the use of the median would obscure that important trend information.[401]

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[395] Tr. at 397.

[396] *Application of CenterPoint Energy Houston Electric, LLC, for Authority to Change Rates,* Docket No. 38339 (June 23, 2011).

[397] Tr. at 401-402.

[398] *See* Staff Ex. 9 (Docket No. 38339 Final Order); Tr. at 402.

[399] Tr. at 415-416.

[400] ETI Initial Brief at 105.

[401] *Id.*

A close examination of the hypothetical shows that in the case posited by ETI, however, the median and the mean are identical: both are zero. While the use of the median would produce a result that ignores the trend that ETI says should be taken into account, the mean produces the same result. Changing the hypothetical produces no more clarity. If the examination was of a period that had ten years of positive five percent salvage value, followed by one year of zero percent net salvage value, followed by the most recent 10-year period, which had negative 10 percent net salvage value, the median would still be zero but the mean would be negative 2.38 percent. This appears to support the trending argument advanced by ETI. If the analysis then focuses on a different hypothetical, one with ten years of positive 10 percent net salvage value followed by one year of zero percent net salvage value, with the most recent ten-year period having negative five percent net salvage value, the results are more perplexing. The median is still zero, but the mean, which ETI contends will recognize the trending, is 2.38. Although this does in some respects recognize the trend to a negative salvage value, it does not recognize it as well as the median.

Principles and Procedures of Statistics, by Steel and Torrie, states: "Certain types of data show a tendency to have a pronounced tail to the right or the left. Such distributions are said to be skewed, and the arithmetic mean may not be the most informative central value." Where the average of the incomes of a group of individuals is required, and most of those incomes are low, the mean income could be considerably larger than the median. In Docket No. 38339, Staff posed the following example, which the ALJs found both informative and persuasive: Suppose a sample of 50 incomes from professional baseball players was taken that happened to include the salary of two of the most highly compensated players in the league today. As a result, the mean of the salaries would likely be far greater than the median salary, because the use of the median would be skewed by the very high salaries. The median would likely provide a more accurate measure of the central tendency of the salaries. Such circumstances are found where using the median to find the central tendency prevents outliers in data that "skews" or shows extreme variations rather than showing more symmetrical variations. The ALJs believe this is as accurate today as it was during the Docket No. 38339 timeframe. They therefore find that the use of the median is the more appropriate methodology for determining net salvage value.

Remaining Life. Composite remaining life is the weighted average remaining life of the property account for a group of all vintages. The average remaining life represents the future years of service expected for the surviving property.

There are numerous ways to calculate the remaining life (life parameter) of a group of assets in a depreciation study. Examples include the interim retirement rate method and the retirement (actuarial) rate method. The interim retirement rate method uses interim retirement curves to model (predict) the retirement of individual assets within plant accounts. Alternatively, the retirement (actuarial) rate method uses historical mortality data for a group of assets and compares that data to various known patterns of industrial asset mortality rates (Iowa Curves). If the historical data creates a pattern of mortality that closely follows one of the Iowa Curves, then that Iowa Curve may be used to approximate the remaining lives of that given group of assets in the future. Whether the historical mortality data creates a pattern that closely follows a given Iowa Curve is determined through plotting both sets of data (the historical mortality data and the Iowa Curve) on a graph and quantifying the closeness of fit through statistical analysis and visual examination.

Mr. Watson used multiple methods to calculate the remaining lives of assets, depending on the asset. Generally, he used the retirement rate (actuarial) method.[402] However, to calculate the remaining life of production plant accounts, he used the interim retirement rate method.[403] Ms. Mathis disagreed with the use of the interim retirement rate method because the Commission has rejected the application of interim retirement rates of production plant, as they are based on future projection of retirements, for ETI and Central Power and Light Company in Docket Nos. 16705[404] and 14965,[405] respectively.

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[402] ETI Ex. 13 (Watson Direct) at 16.

[403] Staff Ex. 2 (Mathis Direct) at 14.

[404] *Application of Entergy Gulf States, Inc., for Approval of its Transition to Competition to Competition Plan and the Tariffs Implementing the Plan, and for the Authority to Reconcile Fuel Costs, to Set Revised Fuel Factors, and to Recover a Surcharge for Under-recovered Fuel Costs,* Docket No. 16705 (Oct. 14, 1998).

[405] *Application of Central Power & Light Company for Authority to Change Rates,* Docket No. 14965 (Oct. 16, 1997).

ETI argues that the life span procedure, without the use of interim retirement curves, is unrealistic in its assumption that all production plant assets are "depreciated (straight-line) for the same number of periods and retire at the same time (the terminal retirement date)." Use of interim retirements is an important refinement that adds accuracy to the determination of the depreciation rates according to ETI. Mr. Watson offered the following explanation:

> Adding interim retirement curves to the procedure reflects the fact that some of the assets at a power plant will not survive to the end of the life of the facility and should be depreciated (straight-line) more quickly and retired earlier than the terminal life of the facility.[406]

ETI contends that this issue presents a unique situation where all the experts agree with the theoretical soundness of Mr. Watson's approach, but Mr. Pous and Ms. Mathis recommend its rejection due to the existence of contrary Commission precedent. The impact of their position is a $1,558,081 reduction to depreciation expense, based on December 31, 2010, plant balances. Mr. Pous generally supports the use of interim retirements because "I think it's right,"[407] and he uses the method in other jurisdictions, where it is a prevalent practice. Ms. Mathis "also appears to recognize the theoretical soundness of utilizing interim retirements."[408] Even in Docket No. 16705, the precedent cited by Mr. Pous and Ms. Mathis, the Staff depreciation witness agreed that the use of interim retirements was appropriate, though not blessed by the Commission. ETI argues that use of interim retirements reflects the undisputable fact that "generating units will have retirements of depreciable property before the end of their lives."[409]

ETI is correct that neither Ms. Mathis nor Mr. Pous provide any reasoning behind the prior Commission precedent. Moreover, it is also true that the Commission precedent is relatively old at this point (dating back to the mid-1990s) and apparently has not been revisited in any recent cases. ETI argues that the Commission has in at least one other case used interim retirements (Docket

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[406] ETI Ex. 13 (Watson Direct) at Ex. DAW-1, at 7-8.

[407] ETI Ex. 71 (Watson Rebuttal) at 71, *citing* Pous Deposition at 49, 51.

[408] Staff Ex. 2 (Mathis Direct) at 12-13.

[409] ETI Ex. 13 (Watson Direct) at Ex. DAW-1, p. 8.

No. 15195[410]), but provides little more than that comment to support the concept. It is true that in concept, interim retirements are determined in much the same fashion as other elements of depreciation analysis. Primarily based on historical accounting data, the analyst identifies characteristics in the history of the data upon which to base a reasoned assessment of retirements going forward, which is similar to what occurs in determining asset lives or net salvage. Interim retirement determinations are supported by their own Iowa Curves, just as is the analysis of plant lives.

Although the ALJs are persuaded by ETI's arguments that the use of interim retirements may be the more theoretically correct methodology to employ, Commission precedent clearly disfavors the use of interim retirements and the ALJs are reluctant to rule contrary to Commission precedent. Accordingly, the ALJs find that the retirement (actuarial) rate method, rather than the interim retirement method, should be used.

2. Production Plant

(a) Lives

Mr. Watson primarily used the life span method to calculate remaining lives of the production plant accounts.[411] The life span method estimates a production plant's life based on consultation with utility management, financial, and engineering staff.[412] However, he used interim retirement methodology to reduce the remaining lives determined by the life span method. Staff does not dispute the remaining lives determined by the life span methodology, but does dispute the use of interim retirements. For the reasons discussed in Section VII.C.1, ETI should not be allowed to use the interim retirement methodology to adjust downward the remaining lives of its production plant accounts.

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410 *Application of Texas Utilities Electric Company for the Reconciliation of Fuel Costs,* Docket No. 15195 (Aug. 26, 1997).

411 ETI Ex. 13 (Watson Direct) at 16.

412 Staff Ex. 2 (Mathis Direct) at 14.

Cities witness Pous disputed only the remaining life determination for ETI's Sabine Power Plant Units 4 and 5, ETI's largest and newest gas fired generating units. Mr. Pous recommended a life span for Sabine Units 4 and 5 of 64 years based on assessment of the units, comparison to the estimated life span of similar units owned by ETI as well as other gas fired generating units across the country. ETI proposes a 60-year life for the two units. Mr. Pous noted that a "64-year life span recommended for Sabine Units 4 and 5 is consistent with the life span proposed by the Company for its Lewis Creek 1 generating unit. Lewis Creek Unit 1 is an older, smaller, and generally less efficient generating unit than Sabine Units 4 and 5. Cities contend that there is no basis or logic for assigning a shorter life span for a more capital-intensive asset that is newer, larger, and generally more efficient."[413]

ETI witness Watson explained that he primarily relied on the determination of Company personnel to arrive at the 60-year life for the Sabine Units. Although Cities attempted to cast doubt on Mr. Watson's determinations regarding the life of these units, it is clear that his determinations are based on conversations with ETI various generation personnel and that those conversations confirmed that based on evaluation of a variety of considerations, including age, operational role, level of funding, unit condition, and operational risk, 60 years constitutes a reasonable threshold for the expected life of Sabine Units 4 and 5. It is also clear that comparisons to Lewis Creek Unit 1 are not appropriate. Lewis Creek Unit 1 has significant differences, which explain its longer life-span. Unlike the Sabine Units, ETI is planning to spend in excess of $100 million to refurbish the Lewis Creek critical equipment over the next three years to sustain operating reliability. ETI is not performing similar refurbishment activities at Sabine.[414]

The Sabine Units are projected to be "must-run" units. This means that these units are, for the most part, deployed to operate whenever they are available for service. Mr. Pous compared these units to EAI's Lake Catherine Units 1 & 2,[415] but ETI contends this is not a reasonable comparison. EAI's Lake Catherine Units 1 & 2 are not "must-run" units. They experience very infrequent

[413] Cities Ex. 5C (Pous Depreciation Study) at 9.

[414] ETI Ex. 51 (Garrison Rebuttal) at 3.

[415] Cities Ex. 5 (Pous Direct) at 7-8.

operation and are not projected to run much in the future. Other things being equal, according to ETI, this would justify the longer 67-year life span assigned to these Arkansas units, because they would not be experiencing the wear and tear of daily operation.[416]

The explanations offered by ETI for the 60-year life of the Sabine Units 4 and 5 generating facilities are convincing. It appears that Mr. Watson engaged knowledgeable people within ETI to gather pertinent information and applied that information appropriately. The comparison to Lake Creek units is not appropriate given the planned refurbishment of those units. Similarly, the comparison to the Lake Catherine units also fails. A unit that does not carry the "must-run" designation can easily be expected to perform longer than a unit, such as the Sabine Units, that carries the "must-run" designation. Accordingly, the ALJs find that ETI's choice of a 60-year life for the Sabine Units 4 and 5 is reasonable.

(b) Net Salvage Value

In determining the net salvage attributable to production plant, ETI witness Watson started with the negative 5 percent net salvage factor approved most recently for ETI in PUC Docket No. 16705. This is a net salvage value that the Commission has adopted in a number of cases for production plant.[417] Mr. Watson testified that the net salvage calculation must reflect known changes in the cost of retiring production plant since the net salvage factor was last set. Accordingly, Mr. Watson's study used the Handy-Whitman labor index to calculate the change in labor costs applicable to removal activity for the years 1997 to 2010. Consideration of the increases in labor costs over this 13-year period resulted in an increase in the cost of removal, and a corresponding increase in the level of negative net salvage, from negative five percent to negative 8.5 percent.[418]

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[416] ETI Ex. 51 (Garrison Rebuttal) at 3.

[417] Staff Ex. 2 (Mathis Direct) at 17.

[418] ETI Ex. 13 (Watson Direct) at Ex. DAW-1, at 64.

Both Staff witness Mathis and Cities witness Pous disagreed with ETI's proposal for production plant net salvage. Ms. Mathis proposed that the existing negative 5 percent net salvage factor be retained. Ms. Mathis stated that Mr. Watson's analysis is flawed for three reasons:

- First, Mr. Watson did not calculate a gross salvage value for each plant. This is a necessary element of the fundamental net salvage rate calculation.[419]

- Second, Mr. Watson unreasonably assumed that all steam production plants would be demolished at the end of their estimated remaining lives without any consideration of reuse of the unit after refurbishment, or mothballing the unit or selling the unit in the event of deregulation of the generating function of the utility.[420]

- Third, Mr. Watson did not provide detailed plans for the actual demolition of each of its power plants. The Commission has consistently approved negative five percent net salvage rates for production plants if detailed plant-specific and reasonable demolition cost studies were not filed by the utility.[421]

ETI responds that Staff's recommendation fails to account for the fact that the negative 5 percent benchmark is stale, having been established in a Commission proceeding 35 years ago. Since that time, "labor costs have escalated by 267 percent with the rational expectation that they will continue to increase at least with inflation."[422]

Cities witness Pous recommended moving from the current negative five percent net salvage to a positive 5 percent net salvage; *i.e.*, that it should be determined that the gross salvage from the power plants will exceed the removal cost. Mr. Pous stated that he bases this claim on the ETI's actual experience over the past 45 years as well as current trends within the industry in the last 14 years. According to Mr. Pous, ETI has retired many units since 1965 and demolished or sold the units and achieved a range of net salvage values from zero percent net salvage to positive 180 percent.[423] Other utilities in Texas and elsewhere have also experienced positive net

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[419] Staff Ex. 2 (Mathis Direct) at 16-17.

[420] *Id.* at 17.

[421] *Id.*

[422] ETI Ex. 71 (Watson Rebuttal) at 17, 19.

[423] Cities Ex. 5 (Pous Direct) at 15.

salvage levels.[424] Mr. Pous testified that since 1998 over 1,000 generating units have been sold, and in all instances resulted in positive net salvage.[425] He also claims that his positive five percent production net salvage is consistent with the Commission's decision in the most recent SPS case, Docket No. 32766, where Mr. Watson was hired by SPS as a depreciation witness and the Commission ultimately approved a positive five percent net salvage.[426] As ETI notes, however, the SPS rate case was the result of settlement[427] and is of little precedential value.

ETI argues that Cities witness Pous appears to primarily base this claim on the fact that the sale of utility plants in circumstances bearing no relationship to depreciation analysis has yielded gains that Mr. Pous characterizes as "positive net salvage." He uses as examples sales that form a part of the restructuring of the Texas utility business to introduce retail competition. Ms. Mathis also concluded, without elaboration, that ETI's production plant net salvage analysis is flawed because it does not consider the possibility that the unit could be sold as a consequence of deregulation. Neither Ms. Mathis nor Mr. Pous, however, pointed to any instance in which the Commission has adopted such an approach to determining net salvage.

ETI contends that this argument should be rejected for a number of reasons. It argues that although there is no precedent supporting Ms. Mathis' and Mr. Pous' approach, there is clear recent precedent rejecting the inclusion of sales in depreciation analysis.[428] The sales referenced by these witnesses are unique and unpredictable events, as should be evident from the use of the restructuring of the utility industry as an example of this type of activity. Indeed, at this time the Texas Legislature has halted for the foreseeable future any ETI move to competition. For purposes of depreciation analysis, net salvage is aimed at determining the salvage received at the end of the plants' useful lives. Mr. Pous' analysis necessarily assumed that, due to the sale, the life of the

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[424] Cities Ex. 5C (Pous Depreciation Study) at 11; Cities Ex. 5 (Pous Direct) at 15-16.

[425] Cities Ex. 5C (Pous Depreciation Study) at 11.

[426] Cities Ex. 5 (Pous Direct) at 17.

[427] *See* ETI Ex. 71 (Watson Rebuttal) at 6.

[428] *See Application of AEP Texas Central Co. for Authority to Change* Rates, Docket No. 33309, FoF 107, 108, 112 (Mar. 4, 2008) (proceeds from sale of building properly removed from depreciation analysis as non-recurring item).

plants will be truncated. Yet he made no adjustment to production plant lives to account for the effect of theoretical sales.[429]

ETI also contends that Mr. Pous' other examples of positive net salvage are equally unavailing. Mr. Pous points to ETI's retirement of Neches Station as an example of positive salvage,[430] but fails to mention that: (1) this outcome was uniquely the result of insurance proceeds received by ETI after a boiler explosion; and (2) the proceeds flowed back to customers via means other than depreciation rates.[431] ETI contends that Mr. Pous' claim that a contractor paid $1 million for the right to demolish a power plant, apparently based on unrecorded hearsay conversations, and without any information from Mr. Pous regarding the facts and circumstances surrounding the transaction, proves nothing.

Finally, Mr. Pous stated that Mr. Watson's adjustment to the net salvage rates is flawed because it does not adequately reflect the increase in scrap metal prices in recent years. ETI responds that although scrap metal prices have gone up recently, it is unknown what the prices will be in the future, and these commodity prices have proven to be quite volatile and unpredictable.[432] According to ETI, it is not reasonable to assume, as does Mr. Pous, that prices will stay indefinitely at what is their historically highest level. ETI argues that Mr. Pous' method is based on speculation and broad, conclusory opinions regarding economic trends, as to which he makes no attempt to actually arrive at a quantifiable analysis that yields his unprecedented positive net salvage recommendation.[433]

Mr. Pous' testimony that net salvage value should be revised to reflect a value of positive 5 percent is seriously flawed. First, pointing to a settled case as precedent carries no weight. Second, attempting to draw conclusions from sales that were forced to comply with the regulatory framework and apply those conclusions to an entity that is not subject to the same regulatory

[429] ETI Ex. 71 (Watson Rebuttal) at 5-7.

[430] Cities Ex. 5 (Pous Direct) at 14.

[431] ETI Ex. 46 (Considine Rebuttal) at 49-50.

[432] ETI Ex. 71 (Watson Rebuttal) at 17-18.

[433] ETI Initial Brief at 103.

framework is equally flawed. Finally, Mr. Pous attempted to use ETI's own experience to support his position ignores the fact that ETI's experiences were driven by factors that were unique to ETI at the time and circumstances involved; they do not support the more universal application urged by Mr. Pous.

Ms. Mathis' analysis, in some respects, suffers from the same flaws as Mr. Pous'. Nevertheless, some of her points carry more weight. The ALJs believe that Mr. Watson is correct that labor costs have increased since the negative five percent net salvage value was first established by the Commission. However, that is not the end of the story. Are there other factors that also have changed in the corresponding time period? There is no evidence on this point, and that is the crux of the matter. As Ms. Mathis argues, there is only one way that all the changing values can be evaluated; through the introduction of plant-specific demolition cost studies. Had studies of that nature been provided, the parties would have been able to evaluate them and provide a supportable, fully-vetted recommendation. The ALJs recommend that the Commission find that a negative 5 percent net salvage value for production plant is appropriate.

(c) Depreciation Reserve

TIEC argues that $1.1 million of ETI's requested $13 million increase in depreciation expenses is related to ETI's production plant assets.[434] ETI has a $92,537,000 surplus in production plant assets. A surplus depreciation reserve occurs when the theoretical reserve (the reserve that would exist if the current proposed rates had been in place in the past) exceeds the per book depreciation reserve. According to TIEC, this indicates that ETI customers have overpaid the value of production plant assets.[435] Since ETI has already over-recovered the value of the production plant assets, there is no valid reason to seek any additional recovery. TIEC contends that ETI has not shown why it needs to increase production depreciation rates at this time given that the production depreciation reserve has a considerable surplus. Therefore, it argues, $1.1 million of the proposed increase should be rejected.

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[434] ETI Ex. 13A (Watson Workpapers) at Appendix B. This figure is derived by subtracting the expenses from the existing production plant account from the proposed production plant account.

[435] TIEC Ex. 1 (Pollock Direct) at 36-37, Ex. JP-5.

ETI rejects TIEC's recommendation because it is clearly contrary to Commission policy and precedent. According to ETI, the Commission has consistently adopted the remaining life, straight-line method for determining depreciation rates.[436] This method requires that the remaining life of the asset be determined, and depreciation rates established to recover the asset's remaining cost in equal installments over that life. In this way, by the end of the life, the costs will be recovered. Mr. Pollock's approach ignores these principles, and seeks to look back in time to compare how the depreciation rates now proposed would have affected the recovery in the past. Those past depreciation rates, however, were authorized for use by the Commission. ETI argues that depreciation rates are at all times estimates, subject to adjustment using updated studies, and there is no reason for adoption of Mr. Pollock's alternative. Finally, the Commission expressly rejected adjustment to the outcome of remaining life depreciation determinations based on differences between theoretical and book depreciation reserves in CenterPoint Docket No. 38339.[437]

The ALJs agree with TIEC that the Commission's decision in Docket No. 38339 is not four-square on point with this case. That is not sufficient, however, to overcome the arguments advanced by ETI in favor of its position in the current case. The Commission has consistently used the remaining life, straight-line methodology for determining depreciation rates, and that methodology requires that the remaining life of the asset be determined, and depreciation rates established to recover the asset's remaining cost in equal installments over that life. Mr. Pollock's proposal ignores that consistently applied methodology. The ALJs recommend that the Commission approve ETI's recommended treatment of the production plant depreciation reserve.

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[436] *See Application of AEP Texas Central Co. for Authority to Change* Rates, Docket No. 33309, PFD at 127-128 (Mar. 4, 2008); *Application of CenterPoint Electric Delivery Company for Authority to Change Rates;* Docket No. 39339, PFD at 86 (Dec. 3, 2010); *Application of Oncor Electric Delivery Company, LLC, for Authority to Change Rates,* Docket No. 35717, PFD at 153-154 (June 2, 2009).

[437] ETI Ex. 71 (Watson Rebuttal) at 75-77 (*citing CenterPoint* Docket No. 38839 PFD).

3. Transmission Plant

(a) Lives

Mr. Watson's study presents ETI's life proposal for transmission Accounts 350.2 to 359, a total of eight accounts.[438] Neither Staff witness Mathis nor Cities witness Pous took issue with any of the recommended lives for transmission plant accounts.[439] Accordingly, the ALJs recommend that the Commission adopt ETI's proposed lives for these accounts.

(b) Net Salvage Value

Staff disagrees with Mr. Watson's recommendations for two of the eight transmission accounts, and Mr. Pous disagrees regarding three of the accounts. The parties' positions on transmission net salvage values in dispute are set out below:

Transmission Account Net Salvage				
Account	**Current Net Salvage Value**	**ETI Proposal**	**Staff Proposal**	**Cities Proposal**
352-Structures & Improvements	-5%	-10%	-5%	-10%
353-Station Equipment	+5%	-20%	-20%	0%
354-Towers & Fixtures	-5%	-20%	-5%	-20%
355-Poles and Fixtures	-25%	-30%	-30%	-15%
356-Overhead Conductors & Devices	-20%	-30%	-30%	-10%

(i) Account 352-Structures & Improvements

Mr. Watson's analysis of this account, and for all the accounts in his study, included the examination of trends and bands for numerous years. For Account 352, he found the five-year and ten-year moving averages for the years 2008-2010 particularly telling.[440] A moving average is a rolling average that updates each year to include the additional year as part of the average for the longer period under study. Mr. Watson testified that his recommendation of negative 10 percent net

[438] ETI Ex. 13 (Watson Direct) at Ex. DAW-1 at 30-36.

[439] Staff Ex. 2A (Mathis Direct) at 21; Cities Ex. 5 (Pous Direct) at 28.

[440] ETI Ex. 71 (Watson Rebuttal) at 56.

salvage is consistent (albeit less negative) with the five-year and ten-year moving averages for 2008, which range from negative 16.31 percent to negative 16.80 percent. Although the moving averages for 2009 and 2010 appear more positive, this was the result of a large, atypical gross salvage in 2009.[441] Cities propose no change to Mr. Watson's recommendation.

Staff witness Mathis recommended a net salvage rate of negative five percent for Account 352. This recommendation is based on analysis of historical salvage data for the period of 1984 through 2010. Specifically, the three-year moving average for the same period produces a net salvage rate of negative 5.53 percent, which is very close to the currently approved net salvage rate for this account. Moreover, an examination of the mean and median rolling band averages for Account 352 shows a range of net salvage rates between positive 0.08 percent and negative 6.83 percent.[442] Thus, according to Ms. Mathis, the net salvage rate of negative 5 percent is a reasonable estimate based on the available historical data.

In response to Mr. Watson's contention that the 2008 moving average is the most important, Ms. Mathis pointed out that the 2009 five-year and ten-year moving averages feature *positive* 16.66 percent and *positive* 4.45 percent net salvage rates, respectively. Moreover, the 2010 five-year and ten-year moving averages feature *positive* 25.13 percent and *positive* 6.75 percent net salvage rates, respectively.[443] Ms. Mathis stated that if it is a sound depreciation methodology to select a net salvage rate based on recent five-year and ten-year moving averages, then the rate for this account should be significantly greater than either Ms. Mathis' or Mr. Watson's recommendation.[444]

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[441] ETI Ex. 13 (Watson Direct) at Ex. DAW-1 at 65. The atypical gross salvage resulted from the sale of a spare transformer, an asset whose cost is booked to an entirely different account. ETI Ex. 71 (Watson Rebuttal) at 57. The atypical amount is shown at Appendix E-2 at 1 of Mr. Watson's depreciation study.

[442] Staff Ex. 2 (Mathis Direct) at 22, Appendix C at 1.

[443] *Id.*

[444] According to Ms. Mathis, if 2009's moving averages are adopted, the net salvage ratio should be around positive 4.45 percent or positive 16.66 percent. If 2010's moving averages are adopted, the net salvage ratio should be around positive 6.75 percent or positive 25.13 percent.

Although the moving averages cited by Ms. Mathis for 2009 and 2010 appear to belie the arguments raised by Ms. Watson, the ALJs are persuaded that those are significantly influenced by the atypical gross salvage resulting from the 2009 sale of a spare transformer, an asset whose cost is booked to an entirely different account. If, as claimed by Mr. Watson, the sale was sufficiently atypical, it would influence both 2009 and 2010 moving averages, making them unreliable. Accordingly, the ALJs recommend that the Commission adopt ETI's negative 10 percent net salvage value for Account 352.

(ii) Account 353-Station Equipment

Similar to Account 352, a large atypical positive salvage amount in this account makes the most recent moving average appear more positive than the history would otherwise suggest.[445] Mr. Watson recommended setting net salvage at negative 20 percent, which he contended is a reasonable middle ground between the values suggested by the five-year and ten-year moving averages for transaction year 2010 (which show net salvage of negative 14.42 percent and negative 20 percent, respectively).[446] Ms. Mathis agreed with the Company's proposal on this account.

Although Mr. Pous acknowledged that retention of the current Commission-approved positive five percent net salvage is supported by ETI's experience, he ultimately opted for a recommendation that the net salvage value be reduced to zero percent. Mr. Pous noted that the actual per book data for a five-year band and a ten-year band are a positive 117.04 percent and a positive 31.95 percent, respectively.[447] Mr. Pous stated that his analysis does not ignore the positive net salvage recorded by ETI because of the sale of transmission investment, rather he testified that:

> the Company has reported five separate sales during the past 22 years, or about once every four years. Such activity cannot be considered an 'unusual circumstance' or an outlier, and should be taken into consideration as an event that may continue to occur

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[445] The atypical amount is shown at Appendix E-2, p. 1 of 10 of Mr. Watson's depreciation study.

[446] ETI Ex. 13 (Watson Direct) at Ex. DAW-1 at 65.

[447] Cities Ex. 5C (Pous Depreciation Study) at 21, 23.

> in the future. In a proper evaluation phase of a depreciation study, recognition of some level of future sales is appropriate.[448]

Mr. Pous' analysis also reflected that transformers, which contain large quantities of copper and produce gross salvage when retired, comprise a significant level of investment in this account, but were underreported in the five-year and ten-year band analyses.[449] Mr. Pous stated that, given the significant increase in the value of copper, the future proportionate retirement of transformers will result in future net salvage values being less negative or more positive than the historical data.

ETI responds that Cities' criticism that the *per book data* in Mr. Watson's workpapers show a large positive net salvage value for the five-year and ten-year bands is unfounded. According to ETI, Mr. Watson's workpapers clearly indicate that adjustments were required and made to the per book data for unique transactions involving sales and storm activity. As to sales, the workpapers[450] show that in the 26 years of data for Account 353, there were three occasions with very large sales proceeds for the sale of substations. As to storm activities, the same workpapers show only one occasion in 26 years where gross salvage amounts were recorded. ETI contends that these unique events are properly excluded from net salvage analysis and Mr. Pous' reliance on the per book data to establish positive net salvage is erroneous. With respect to Mr. Pous' concern's relating to the price of copper, ETI responds that Mr. Pous' reliance on copper's scrap value is pure speculation, unsupported by any ETI-specific data regarding the amount of copper at issue, or any consideration of the offsetting significant and increasing labor costs involved in the removal of large station transformers.

As explained by Mr. Watson, it appears to the ALJs that the adjustments made were, indeed, required because of the unique nature of the events they reflected. The ALJs also find that Mr. Pous' concerns relating to the price of copper are speculative. Coupled with the fact that Staff supports ETI's proposed net salvage value, the ALJs recommend that the Commission approve ETI's recommended negative 20 percent net salvage value.

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[448] *Id.*

[449] *Id.* at 22.