Exhibit No.:	
Issues:	*Property Tax*
	Gross Receipt Tax
	Injuries and Damages
	Maintenance
	Decommissioning Expense
	Hawthorn Settlements
Witness:	*Karen Lyons*
Sponsoring Party:	*MoPSC Staff*
Type of Exhibit:	*Surrebuttal Testimony*
File No.:	*ER-2010-0355*
Date Testimony Prepared:	*January 5, 2011*

MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

SURREBUTTAL TESTIMONY

OF

KAREN LYONS

KANSAS CITY POWER & LIGHT COMPANY

FILE NO. ER-2010-0355

Jefferson City, Missouri
January 2011

****<u>Denotes Highly Confidential Information</u>****

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Q. Please state your name and business address.

A. Karen Lyons, Fletcher Daniels State Office Building, Room G8, 615 East 13th Street, Kansas City, Missouri 64106.

Q. Are you the same Karen Lyons who previously filed direct and rebuttal testimony in this proceeding?

A. Yes. I filed information supporting Staff's Cost of Service Report in this case on November 10, 2010 and Rebuttal Testimony on December 8, 2010. I also provided input into Staff's Cost of Service Report in Case No. ER-2010-0356 filed on November 17, 2010 by KCPL Greater Missouri Operations (GMO) for its MPS and L&P operations. On December 15, 2010, I also filed Rebuttal Testimony in Case No. ER-2010-0356.

Q. What is the purpose of your Surrebuttal Testimony in this proceeding?

A. The purpose of my Surrebuttal Testimony is to respond to the Rebuttal Testimony of Melissa K. Hardesty of Kansas City Power & Light Company (KCPL or Company) with regard to Property Taxes and Gross Receipts Taxes (GRT). In addition, I will respond to the Rebuttal Testimony of Terry S. Hedrick of KCPL on production maintenance. I will also provide a response to the Rebuttal Testimony of KCPL witness John P. Weisensee on the topic of Injuries and Damages and Gross Receipts Taxes as related to Cash Working Capital and Rebuttal Testimony of KCPL witness Gregg N. Clizer on nuclear decommissioning expense. Finally, I will respond to the Rebuttal Testimony of KCPL witness Curtis D. Blanc on Hawthorn settlements received by KCPL.

EXECUTIVE SUMMARY

The Company and Staff disagree over the calculation of property taxes for plant added in 2010. KCPL includes an amount for property taxes based on all property owned in 2010. In contrast, the amount Staff includes is based on property owned on the assessment date January 1, 2010.

KCPL and Staff also disagree on how to handle Gross Receipts Tax. KCPL treats the taxes as a prepayment by the Company when calculating cash working capital. Staff's position is that KCPL pays the Gross Receipts Taxes after it collects them from its customers—referred to as payment in arrears-- and, therefore, they are a part of cash working capital with a positive expense lag.

The disagreement with injuries and damages is how Staff accounts for injuries and damages with regard to Cash Working Capital. KCPL believes that if actual cash payments are used for determining a normalized amount of expense for this rate case, injuries and damages can no longer be used when calculating Cash Working Capital. Staff's position is the use of the actual cash method to determine the normalized level of expenses included in rates does not mean it is proper to ignore the reality of the how these very cash payments are paid out over time. The sole purpose of the cash working capital analysis is to determine the flows of cash to the Company.

Staff also disagrees with the Company's method of indexing actual production maintenance costs to 2009 dollars by the use of the Handy Whitman (HW) index. Instead, Staff has determined an appropriate level of generation maintenance costs by relying on historical costs incurred.

Finally, Staff disagrees with how the Company accounted for the receipt of cash settlements for performance failure of a SCR and the failure of a transformer at the Hawthorn plant. As opposed to the Company, Staff's position is the ratepayers should benefit from the receipt of these settlements.

PROPERTY TAXES

Q. Will the Staff and Company difference with property taxes be addressed in this case's true-up?

A. Yes. Staff will adjust the property tax amount by using a ratio of the 2010 property tax payment to the January 1, 2010 plant and applying that level to January 1, 2011 (actually the December 31, 2010) plant in service balance. This data will become available for the true-up period.

Q. If the difference between Company and Staff can be resolved in the true-up, why are you addressing this issue in surrebuttal testimony?

A. Although the dollars associated with this issue may be resolved in the true-up, the Company and Staff continue to disagree with the methodology used to determine an appropriate level of expensed property taxes to include in the Company's cost of service.

Q. What are the differences between the Company and Staff relating to property taxes?

A. Staff included a level of estimated property taxes of $76,638,380 and the Company is proposing $72,032,532. The different amounts can be shown as follows:

	Staff	KCPL
Annualized Property Taxes	$76,281,290	$71,278,832
Spearville Pilot Payment	$357,090	$753,700
Total Property Taxes	$76,638,380	$72,032,532

Q. Explain the difference for the level of annualized property taxes between KCPL and Staff.

A. Staff calculated the annualized property tax level by developing a ratio using property taxes paid in 2009 and plant-in-service balances as of January 1, 2009. This ratio was then applied to the September 30, 2010 plant balance which include Iatan 2. The Company calculated an annualized property tax level based on actual 2010 assessments and actual property taxes on Iatan 2. The 2010 property taxes for Iatan 2 were assessed as construction work in process (CWIP).

Q. Is there any other differences between Staff and KCPL for the estimated property tax level for 2010?

A. Yes. KCPL included pilot payments for Spearville 2. Based on the documentation received by KCPL in Data Request No. 172, Spearville 2 pilot payments were not included. During the true up Staff will use the same method by developing a ratio of actual property taxes paid in 2010 to plant-in-service balances as of January 1, 2010 and applying the ratio to the Company’s January 1, 2011 plant balances.

Q. Please explain KCPL’s position regarding property taxes as identified in KCPL witness Hardesty's rebuttal testimony (page 5).

A. Ms. Hardesty's rebuttal testimony, page 5, lines 16-18 states, "the Company considers the inclusion of the 2010 Iatan Unit 2 previously capitalized property taxes as a component of property tax expense in this case to be appropriate."

Q. Does Staff agree with Ms. Hardesty's statement?

A. No. Since the Iatan 2 project was still under construction in 2010, the property taxes for the project would have been included with all other construction costs associated with the project and capitalized as part of the construction work order. Upon completion, the construction costs are transferred from CWIP to plant, at which time depreciation begins. Property taxes are based on plant that is in-service effective January 1 of any given year. Since Iatan 2 was not placed in service until August 26, 2010, property taxes through this period would be identified as capitalized property taxes and treated as part of the construction costs of Iatan 2. The capitalized property taxes are considered part of CWIP. While in construction, the Company receives a deferred return on its construction investment for as long as those costs are included in CWIP. This deferred return is known as allowance for funds used during construction (AFUDC). Since CWIP includes all costs to construct Iatan 2, including property taxes, a deferred return is calculated on these capitalized property taxes. During the operating life of the unit, KCPL will receive recovery of these costs through depreciation—referred to as "return of investment." While the unit is included in rate base the Company will also receive a "rate of return on the investment."

Iatan 2 will be assessed on January 1, 2011 as part as the Company's plant-in-service balance. The property taxes assessed on January 1, 2011 will not be paid until December 31, 2011. If the Commission had not ordered a true-up in this case of December 31, 2010, the Company's rates would be excessive because it would collect in rates for overstated plant assessments that will not be reflected in property tax values until the next assessment date of January 1 2011.

Q. What is the significance of the January 1 date?

A. Personal property taxes are assessed on a local and state basis on this date. The only property assessed is that which is owned on that date. The only property taxes that are expensed are those attributable to plant-in-service owned and assessed as of January 1 of any given year, in this case January 1, 2010 and for the true-up on January 1, 2011. However, Iatan 2 was still in the construction phase on January 1, 2010. While plant additions are under construction, the Company will capitalize all property taxes, along with all other construction costs. When the property is both owned and in-service on January 1, it will be assessed and associated property taxes will be expensed. Any property placed in-service from January 2nd through December 31st, will not be assessed until the following year. In this case, Iatan 2 will not be assessed for property tax expense purposes until January 1, 2011, with property tax not actually being due until the end of that year. Since the true-up in this case is based on the December 31, 2010 cut-off, property taxes on the Iatan 2 plant will be reflected in the true-up revenue requirement.

Q. Why is Staff opposed to including capitalized property taxes as expense as KCPL proposes?

A. The amount of capitalized property taxes for 2010 was included in CWIP and as of August 26, 2010 reflected in plant-in-service. What KCPL proposes is to include the 2010 property taxes in expenses while at the same time have the 2010 property taxes capitalized in plant. The same property tax dollars treated effectively twice—once in plant and as an expense in the cost of service. When rates go into effect in this case the Company would begin receiving a return of its investment including the capitalized property taxes (as depreciation expense item) and recovery of the same property taxes through property tax expense.

Q. Does Staff agree with Ms. Hardesty's rebuttal testimony on page 3 describing a computational error with Staff's property tax calculation?

A. Yes. Staff did have a computational error in its workpaper resulting in an incorrect property tax to plant ratio for 2010. Staff corrected the error and reflected the change in Staff's accounting schedules.

Q. When did you become aware of this computational error?

A. When I read Ms. Hardesty's rebuttal testimony.

Q. Is it customary to address errors in testimony?

A. No. It is my understanding there has been a long standing policy among the parties, and in particular, among the utility companies and Staff that errors are not addressed in testimony.

Q. How do errors get addressed in rate cases?

A. Typically, they are brought to the attention of Staff, either during prehearing conference or meetings and discussions with the company.

Q. Was there a prehearing in this case?

A. A prehearing occurred on November 22 through 23, 2010.

Q. Did the Company discuss mistakes in Staff's case during the prehearing?

A. On a very limited basis but the property tax matter was not discussed at all. Subsequent to the prehearing however, Staff and Company met in our audit room at KCPL's corporate offices for a series of meetings which dealt only with errors, omissions and inconsistencies in the three rate case filings made on November 10 and November 17. Nothing was discussed about the computational error found in my property tax work papers. In fact, Staff not only met in person with KCPL personnel, but also had many contacts with the Company through conference calls and e-mails. KCPL had every opportunity to bring this computational error to Staff's attention but chose not to do so. Perhaps it was simply an oversight on the Company's part. Under the press of the work load on everyone connected with these cases, I can certainly understand and appreciate how something can fall through the crack. And I do give the Company the benefit of the doubt that it was not intentional that they waited to bring this error up in rebuttal testimony.

Q. Why do errors occur in this process?

A. Regrettably, errors are part of the process. Thousands of calculations occur in the process of a revenue requirement calculation. In the case of the KCPL rate case, Staff is performing in essence three separate revenue requirement calculations—one for the Company and two for GMO under MPS and L&P. These certainly add to the level of increased mistakes. While it is certainly not ever a desire to have mistakes in the case, they do occur and are a part of the process. They range for computational errors such as the one occurred in the property tax area to getting incorrect or incomplete information from the Company which does occur on occasion.

Q. How did Staff correct the property taxes for the computational error?

A. Upon review of Ms. Hardesty's rebuttal testimony I immediately reviewed my property tax work papers and found the mistake. I made the necessary correction and provided an updated work paper to the Company. I made the necessary corrections to the revenue requirement model – the Exhibit Modeling System (EMS) run.

Q. What was the nature of computational error?

A. In the calculation we develop a ratio of the December 31 property taxes paid for expenses to the January 1 plant for the same year. I inadvertently applied the December 31, 2009 property taxes paid for expenses to the January 1, 2010 plant instead of the January 1, 2009 balance. This resulted in the property tax ratio being understated. I have now corrected this calculation and applied it to the right balance.

Also, the Spearville wind farm property taxes are paid differently from other property taxes. They are paid to the taxing agent as a lump sum amount known as Pilot payments. I inadvertently included those in the ratio when they should not have been so that was corrected as well.

Q. If this computational error for property taxes had been brought to the attention of Staff would it have been corrected?

A. Yes. If KCPL would have informed Staff of what it thought, and what turned out to be an error, Staff would have immediately fixed the mistake. If this approach had been used by the Company instead of waiting to the filing of rebuttal testimony there would not have been a need to address it here in my surrebuttal testimony.

Q. Does Staff intend to include Iatan 2 property taxes in the true-up for this case?

A. Yes. As explained in Staff's Cost of Service report filed on November 10, 2010, Staff calculated property taxes on all property that is currently providing service to customers based on property tax assessments made on January 1, 2010. Any property placed in-service after January 1, 2010 would not be assessed by the taxing authority until January 1, 2011. However, Staff made a decision to file a projected December 31, 2010 case at the time of direct filing. Staff's projected December 31, 2010 case includes anticipated costs for the

December 31, 2010 true-up which includes the Iatan 2 plant addition and the related property taxes. As mentioned earlier in this testimony, Staff applies a ratio of property taxes paid to plant-in-service to determine an appropriate level of expense for property taxes. To obtain an appropriate level of anticipated property taxes for 2011, Staff used the Company's September 30, 2010 plant balances which include the Iatan 2 plant addition. During the true up Staff will use the same method by developing a ratio of actual property taxes paid in 2010 to plant-in-service balances as of January 1, 2010 and applying the ratio to the Company's January 1, 2011 plant balances.

Q. What is Staff's recommendation on this issue?

A. KCPL should not be allowed to include costs it is recovering through deprecation and as a rate base component of cost of service (the capitalized property taxes), and also be permitted to add additional property tax expenses in rates for amounts it will only pay out once as capitalized property taxes at the end of 2010. However, the timing of the true-up should solve this issue as January 1, 2011 result in a new assessment with Iatan 2 now being considered plant-in-service by the taxing authorities. This in turn will result in the expensing of Iatan 2's property taxes in 2011.

GROSS RECEIPTS TAX

Q. Please explain KCPL's position regarding GRT it pays to cities and communities it serves as identified in KCPL witness Hardesty's Rebuttal Testimony (pages 6-8).

A. KCPL believes the GRT it pays to its municipalities are prepayments and treats them in cash working capital as though the Company paid these taxes before it collects the tax from its customers.

Q. What are the differences between the Company and Staff relating to gross receipts taxes?

A. Staff believes KCPL's approach is wrong and, therefore, should not be included in rates in this case. Staff has included a level of GRT in the cash working capital schedule as a payment in arrears while KCPL treats these payments as prepayments. The differences can be shown as follows:

	Staff	KCPL
KCMO - 6% GRT	72.28	(56.56)
KCMO - 4% GRT	39.34	34.00
All Other Cities (Monthly, Quarterly, Semi-Annual)	60.94	(38.93)

Q. What justification does KCPL provide to support GRT should be treated as a prepayment?

A. Ms. Hardesty states in her Rebuttal Testimony on page 7, lines 4-6, "Prior to January 1, 1943, the tax was prepaid annually based on the number of meters. Starting on January 1, 1943, the City converted from the prepaid meter tax to a prepaid gross receipts tax based on a franchise fee."

Q. Does Staff agree with Ms. Hardesty's statement indicating the tax was prepaid prior to January 1, 1943?

A. Yes. Prior to January 1, 1943 KCPL paid a yearly franchise tax that was based on the number of meters. The following excerpt was taken from a letter dated

January 25, 1943 to Arthur Anderson & Co. The entire letter is attached to this Surrebuttal Testimony as Schedule 1.

The yearly payment of franchise taxes based on the meters instead on the existing collection from customers was in fact a prepayment. Basing the franchise tax amount on the number of meters the Company paid to the city early in the year for the entire year—a prepayment. However, Kansas City no longer assesses a franchise tax in this manner.

Q. Does Staff agree with Ms. Hardesty's statement indicating the City converted from the prepaid meter tax to a prepaid gross receipts tax based on a franchise fee?

A. No. Although the City of Kansas City did convert to a GRT after January 1, 1943, the tax was not prepaid as stated by Ms. Hardesty. The following excerpt was taken from the amended ordinance, Section 9-1, identifying how the franchise tax would be collected after January 1, 1943. The entire amended ordinance is attached as Schedule 2.

> Every electric light or power company shall pay to the City a quarter-annual license fee to be due and payable to the City treasurer on or before the 30th days of January, April, July and October, respectively, of each year **<u>based upon the business done during the preceding period of three (3) calendar months ending, respectively, on the last days of December, March, June and September.</u>** The amount of such quarterly license fee shall be five per cent (5%) of gross receipts derived from the sale of electrical energy within the present or future boundaries of Kansas City. . .
> [emphasis added]

Q. Does Staff agree with KCPL's position on the ratemaking treatment for GRT?

A. No. Ms. Hardesty states in her rebuttal testimony on lines 9-25 of page 6, that KCPL has treated GRT as a prepayment based on the language contained in the Kansas City Missouri License and Miscellaneous Business Regulations Sec. 40-344 (Ordinance). The entire ordinance is attached as Rebuttal Schedule 1 to my rebuttal testimony filed on December 8, 2010. Like the initial ordinance establishing a gross receipts tax this ordinance clearly states the payments are based on the revenues received three months prior to when payment is due. The argument made by Ms. Hardesty on page 6, lines 26-30, is that the license fee is for the period for which the payment was made. Staff's position is that the period for the licensee fee is irrelevant, since the GRT funds are actually collected during the three months prior to the month in which the payment is actually made. Regardless what time period KCPL believes these collections are for, unmistakably these collections are made from KCPL's customers for prior months and remitted the month after.

As an example, the amount of GRT paid in January of any year is based on and collected during the three preceding months prior to this January payment. The following excerpt was taken from the Kansas City Missouri License and Miscellaneous Business Regulations Sec. 40-344.

> Every electric light or power company…shall pay to the City Treasurer on or before the 30th days of January, April, July and October, respectively, of each year, <u>based upon the business done during the preceding period of three (3) calendar months</u> ending respectively, on the last day of December, March, June and September.
> [emphasis added]

Q. Does Ms. Hardesty support Staff's argument in her rebuttal testimony?

A. Yes. On page 6, line 30 and page 7, line 1 of Ms. Hardesty's rebuttal testimony she states, "Thus a payment on the 30th of January would be for the license for the period of January 1 through March 31 and would be considered a prepayment even though the **measurement** period is the prior quarter."

Q. How does Ms. Hardesty's statement support Staff's position?

A. The statement made above by Ms. Hardesty that she refers as the measurement period being the prior quarter is in reality the "collection of the GRT from customers period" which occurs in the prior quarter. Monies collected up front and paid out in the month following the close of the collection quarter.

Cash working capital (CWC) is the amount of cash necessary for KCPL to pay the day-to-day expenses incurred to provide electric services to their respective customers. In other words, CWC can also be roughly defined as a **measurement** of the timing of the Company's revenues received from the customer and the payment to vendors, employees and taxing authorities—it is an analysis of the inflow and outflow of cash from the Company. Therefore, the statement by Ms. Hardesty actually supports Staff's argument taking into account the purpose of CWC which is the measurement of when revenues are collected from the customers and when payment is remitted to the taxing authority.

Q. Does any other witness for KCPL address the GRT issue?

A. Yes. KCPL witness John P. Weisensee addressed this issue in his Rebuttal Testimony on pages 19 and 20. Mr. Weisensee agrees with Ms. Hardesty's testimony on prepayments for the Kansas City, Missouri 6% GRT and states the Company treats "most other city GRT" as prepayments.

Q. Does Staff agree with the Company treating most of the cities GRT as a prepayment?

A. No. All cities for which the Company currently pays GRT are paid in the arrears. Staff reviewed the tax billings for each city and municipality assessing gross receipts taxes on KCPL and determined the appropriate expense lag for each. It weighted the various expense lag calculations and determined a composite expense lag for gross receipts taxes used in the cash working capital schedule. Please refer to Staff workpaper, Schedule 6.1 though 6.5 attached to my Rebuttal Testimony filed on December 8, 2010 in this case.

Q. Does it matter how KCPL treats gross receipts taxes on its books?

A. No. For the cash working capital analysis what matters is the collection of monies from customers in relation to the release of funds for the payment of goods and services to the utility. In the case of 6% Kansas City gross receipts taxes, KCPL collects the taxes in the three month period prior to payment in the month following the close of this three month period.

Regardless of what period KCPL believes the GRT is for, the cash flows of this tax are the essential element of this analysis. Cash working capital analysis is a cash flow analysis with a narrow focus of looking at the inflows and outflows of cash to and from the Company.

Q. Does the Company maintain its books on a cash basis?

A. Typically no. While most companies including KCPL keeps its accounting books on an accrual basis, the cash working capital analysis is strictly the measurement of cash. This analysis examines when the company gets cash and when it pays it out. Consequently, how KCPL treats gross receipts taxes on its books is irrelevant.

Q. What does the Staff analysis show?

A. The analysis shows the GRT has a much longer expense lag than the Company is suggesting the funds are collected by the ratepayers prior to the payment being submitted to the taxing authority.

Q. Does Staff have additional documentation to support Staff's position that KCPL collects GRT prior to payment being made to the taxing authority?

A. Yes. During Staff's review of KCPL's files containing city ordinances and various documents from the cities served by KCPL, Staff found a letter dated January 15, 1947 from the City of Sugar Creek, Missouri indicating the city had adopted an ordinance which reflected a change from a $25 "Merchants License Tax" to a 5% gross receipts tax. According to the letter, the City of Sugar Creek adopted an ordinance which levied a license fee equal to 5% of KCPL's gross receipts. Accompanied with the letter was a refund of $25 for the Merchants' License Tax referenced above. Please refer to Schedule 3 attached to my Surrebuttal Testimony for a copy of the entire letter and supporting documentation of the refund.

Q. Please explain how this document supports Staff's position that GRT is collected from the ratepayers in advance.

A. During the same review, Staff found a memorandum internally distributed to Company personal referencing the gross receipts tax and how payment would be made. The memorandum was dated January 29, 1947 and stated the following;

> Under date of December 16, 1946, an ordinance was passed by the City of Sugar Creek which requires us to pay a sum equal to 5% of our gross receipts derived from the sale of electricity used for domestic and commercial consumption. This is intended to mean that we will pay 5% of the revenue derived from the sale of current within the City Limits of Sugar Creek, Missouri less the same exceptions as are now contained in the federal 3 1/3% energy tax. <u>The first payment is due on or before July 31, 1947 and covers a period for the six months beginning January 1, 1947 to June 30, 1947 and a like tax will be paid in July and January each year for the proceeding six months.</u>
>
> Will you please see that the Customer's Accounting Department furnishes us with the gross revenue and the exceptions so that we may pay this tax covered by the ordinance.
> [emphasis added] (*See* Schedule 4)

Q. What is the significance of the memorandum described above?

A. The language in the memorandum is another example of how KCPL collects GRT from its customers prior to submitting a payment to the taxing authority.

Q. How does KCPL treat GRT for the city of Sugar Creek?

A. Despite the clear language of the 1947 ordinance that this city tax is a payment in arrears (monies collected in advance of payment), KCPL treats Sugar Creek as a prepayment—on its books and in its cash working capital schedule.

Q. Ms. Hardesty indicates at page 7 of her rebuttal testimony that if KCPL ceases to provide service to customers located in the city of Kansas City it would not owe the city any amount for the last quarter of operations. Does Staff agree with this statement?

A. First, Staff hopes KCPL plans to continue serving Kansas City since this is where most of its customers reside. It is assumed that KCPL, as an on-going concern and in receipt of the exclusive certificate of convenience and necessity to provide electric services to Kansas City area will perpetually be in business. So Staff doesn't expect Ms. Hardesty's example in her rebuttal to be valid.

But if KCPL did cease to be in business and all the lights went out in downtown Kansas City, unless the city gave specific instruction to no longer collect the gross receipts taxes for that last quarter of operation, KCPL would continue to collect the monies including gross receipts taxes from its customers to that very last kilowatt hour sold. And if the city said to the Company you don't need to remit those collected gross receipts taxes for that last quarter of business, then KCPL would receive quite a wind fall of funds.

Q. Does KCPL's affiliate, KCPL Greater Missouri Operations Company (GMO) account for gross receipts tax similar to how KCPL does?

A. No. As identified in my Rebuttal Testimony on pages 13 and 14, GMO accounts for the gross receipt taxes as a payment in arrears. The approach used by GMO to develop the GRT lag for cash working capital is the same one used by Staff. In other words, GMO has determined the GRT expense for all cities and municipalities it operates in is collected in advance from its customers before it pays out the funds to the taxing authorities. Both GMO and Staff have correctly calculated the GRT expense lag in the same way for many rate cases. This is especially important considering that both KCPL and GMO serve parts of the city of Kansas City and both pay gross receipt taxes under the exact same city ordinance.

Q. What is Staff's recommendation with this issue?

A. Based on Staff's research of all the cities and municipalities ordinances that KCPL operates in along with Staff's analysis of when the GRT is collected from the ratepayers and subsequently paid to each of these taxing authorities, all GRT paid by the Company is paid in the arrears. Staff recommends the Commission adopt the Staff's expense lag for Gross Receipts Taxes and order that going forward KCPL should account for gross receipts as a payment in arrears.

INJURIES AND DAMAGES

Q. What is the purpose of this portion of your surrebuttal testimony?

A. This section of the testimony is to respond to the rebuttal testimony of John P. Weisensee regarding KCPL's position on the cash working capital treatment of injuries and damages which appear on page 21.

Q. What is the difference between the Company and Staff's position?

A. According to Mr. Weisensee's rebuttal testimony on page 21, lines 3-11, the Company disagrees with how Staff accounts for injuries and damages with regard to Cash Working Capital. Specifically, the Company believes that if actual cash payments are used for determining a normalized amount for this rate case, injuries and damages can no longer be a separate component when calculating Cash Working Capital.

Q. What are the differences between the Company and Staff relating to injuries and damages?

A. The differences can be shown as follows:

	Staff	KCPL
Injuries and Damages	149.56	0.00

Q. Does Staff agree with Mr. Weisensee's argument?

A. No. While actual cash payments (or payouts) for injuries and damages were examined over several years to normalize the levels included in the revenue requirement calculation, the cash flow component (or timing of the cash payouts) of injuries and damages was used for CWC. In some instances, customers supply CWC when they pay for electric services received **before** the Company pays expenses incurred to provide that service. That is the case for injuries and damages. When this happens in the aggregate, customers are compensated for the CWC they provide by reducing rate base by the amount of CWC the ratepayers provide.

Q. What are injuries and damages?

A. Injuries and Damages relate to amounts paid to third parties who have made claims against the Company for injuries to person or damages to property. It represents the portion of legal claims against a utility that is not subject to reimbursement under the utility's insurance policies. Injuries and damages expense normally consists of the following components:

- General Liability
- Auto Liability
- Worker's Compensation

This includes worker's compensation claims as well as those who sustain injury from accidents while using the Company's electrical system. Staff and KCPL developed the proper level of normalized injuries and damages expenses using a three-year average of actual cash payments. However, the Company believes that there is a relationship between using the actual cash payments used to determine the normalized injuries and damages expense amount included in the cost of service analysis and ignoring the timing when those cash payments are made for cash working capital purposes. Staff disagrees with this approach.

Q. Please further explain Staff's position for injuries and damages.

A. Staff position on rate treatment of injuries and damages is to include a normalized level of annualized cash payouts in the cost of service. Staff uses this method because it can calculate <u>actual</u> cash payments that are known and measurable, as opposed to the use of an estimate when using the accrual approach. The known and measurable concept as it is used to develop expense amounts recommended to be included in the rate determination is that an expense that is both (1) "known", meaning that the amount is an actual incurred cost or actual liability, and (2) "measurable", meaning that a change (for example, a payroll rate increase) can be calculated with a high degree of accuracy.

The Staff has outlined three conditions which must be satisfied before they will consider recommending the use of a pro forma adjustment for ratemaking purposes:

1. The adjustment must be based on auditable information, i.e., the underlying event must have occurred and be adequately documented and capable of quantifications;

2. Potential pro forma adjustments must be considered for all components of the investment/revenue/expense relationship, so that an isolated "update" or change to one ratemaking

component is not made without considering possible offsetting impacts from updates to other ratemaking components; and,

3. The pro forma adjustments, viewed in totality within the investment/revenue/expense relationship, must significantly impact the revenue requirement for the utility as determined from test year data.

The use of the amounts of actual cash payments made for injuries and damages to determine the normalized level (the actual cash method) of expense was used in this case. As a result, the Company and Staff calculation for determining a normalized injuries and damages expense is the same. However, because it is appropriate to use the actual cash method to determine the normalized level of expenses included in rates does not mean it is proper to ignore the reality of when these very cash payments are paid out over time—the timing of the cash payments. That is the analysis for cash working capital.

Q. Is there a difference between including a normalized level of annualized cash payouts and including injuries and damages in cash working capital?

A. Yes. As previously mentioned, when calculating a normalized level of annualized cash payouts, Staff is determining the amount of expense the Company could incur for injuries and damages in the future. On the other hand, Staff calculates cash working capital by determining when revenues are collected by the ratepayers and when expenses are paid out. In other words, the amount that is reflected in cash working capital is based on timing of the actual payments made to those who have claims of injury in relation to when the injury took place. KCPL collects funds from its customers throughout the year on claims that could in many instances take years to actually pay out. Typically a claim will be paid out after an investigation of the claim, and in many instances, as a result of litigation for either actual court awarded damages or negotiated settlements. This could result in a substantial lag from the time of incurrence of an injury or property damages to an actual cash payment. While the cash basis is used to determine the ongoing level of costs to be recovered in rates, this in no way provides consideration to the timing of when those payments are actually made. This is the role of the cash working capital analysis where the timing of actual occurrence of the injury or accident is measured compared to when the actual cash payments for injuries and damages are paid out. These calculations determine who is paying for everyday on-going operations, the shareholders or ratepayers. The expense lag for injuries and damages used in the cash working capital schedule is the number of days between when events take place creating the need for the claim and when payments are actually made to those injured.

Q. Is there any similarity between determining a normalized expense level to include for injuries and damages and how injuries and damages are included in cash working capital schedule?

A. No. The analysis to determine the level of injuries and damages to include in expenses in the case simply looks at the amounts actually paid out over several years to determine a normalized expense level, just as a normalized maintenance or payroll expense level would be included in the case. Injuries and damages when associated with cash working capital, however, is a cash flow issue in which the Staff determines when a claim occurs, when the cash payment is paid, and who supplied the funds, ratepayers or stockholders. The first analysis—the levels paid out over several years—determines level of expense, and the second analysis—the timing of when the payout is made—identifies the interval of the occurrence of an event in relationship to when it was paid out.

Q. How does KCPL's affiliate GMO calculate its injuries and damages as it relates to CWC?

A. Although GMO used the same method as Staff in prior rate cases to develop the CWC timing impact of what it has identified as an average time it takes to make payments for claims in the past, and developed the normalized level based on cash payouts, GMO has adopted KCPL's method in this case. This average time period is measured by comparing when the injury takes place and how long it actually takes to make the payments for settlements and awards.

Q. What was the impact of GMO's cash working capital requirement for injuries and damages in the last rate case?

A. In Case No. ER-2009-0090, GMO-MPS calculated 707.13 days and GMO-L&P 1,122.84 days for injuries and damages in its CWC study which was consistent with what Staff included in its CWC for GMO in that case.

Q. What is the Company's recommendation for this issue?

A. Mr. Weisensee states in his rebuttal testimony on page 21, lines 13-16, "While a case could be made for such exclusion, the Company proposes that I&D expense be included in the "Net Other O&M Expense" line, a category where all O&M expenses are included that are not specifically included on other lines of the CWC schedule."

Q. Does Staff agree with the Company proposal?

A. No. The category Mr. Weisensee refers to is identified as "Cash Vouchers" on Staff's CWC account schedule, line 17. Mr. Weisensee is correct in stating this category is used to capture all O&M expenses that are not specifically included on other lines in the CWC schedule. However, the expense lag used for this category is 30 days. This means the

Company pays for all expenses captured in this category within 30 days. In other words, Mr. Weisensee is stating that on average all injury and damage claims are paid in 30 days for the actual occurance.

Q. Does Staff agree with Mr. Weisensee's recommendation of a 30 day expense lag for injuries and damages?

A. No. Staff is recommending an expense lag of 149.56 days for injuries and damages.

Q. How did Staff determine an expense lag of 149.56 days was appropriate in this case?

A. Staff analyzed information received from the Company identifying all claims paid during the 2009 test year through the update period June 30, 2010. Staff was able to calculate an expense lag using the date of each loss, date the claim was paid and the amount of the settlement. Please refer to Schedule 5 in this surrebuttal testimony.

Q. Has the Company identified an expense lag for injuries and damages in past cases?

A. Yes. The Company identified an expense lag for injuries and damages of 185 days in Case No. ER-2007-0291 and 185 days in Case No. ER-2009-0089. Based on the Company calculations in past cases and Staff's calculation in this case, a 30 day expense lag proposed by the Company does not accurately represent the timing of claims paid by the Company.

Q. What is Staff's recommendation for this issue?

A. Staff recommends the Commission adopt the Staff's expense lag for injuries and damages.

Q. Are there any other CWC issues Staff would like to address?

A. Yes. Based on Mr. Weisensee's rebuttal testimony, Mr. Meyer, an intervener in this case representing industrials, indicated the expense lag for Wolf Creek O&M was too low. Mr. Meyer and the Company agreed to change the lag from 13.81 days to 25.85 days. Staff agrees with Mr. Meyer and the Company and has reflected this change in Staff's CWC accounting schedule.

MAINTENANCE - NON-WAGE

Q. What is the purpose of your Surrebuttal Testimony in regards to Maintenance expense?

A. The purpose of my Surrebuttal Testimony is to respond to Company witness, Terry S. Hedrick Rebuttal Testimony, addressing the non-wage and non-fuel maintenance normalizations used by Staff.

Q. What is the difference between the Company and Staff's position?

A. Staff disagrees with the Company's use of the Handy Whitman (HW) index to determine a normalized level of production expenses on an ongoing basis. Staff has not used this method, relying instead on actual costs incurred for non-wage maintenance incurred by the Company.

Q. Identify the levels of operation and maintenance expenses that Staff and the Company have included in their cases.

A. The differences on a total KCPL basis (includes Kansas and wholesale) can be shown as follows:

	Staff	KCPL
Production	$27,186,949	$28,461,137
Nuclear	$11,203,194	$11,203,194
Other Production	$2,485,196	$2,485,196
Transmission	$2,241,370	$2,241,370
Distribution	$17,906,770	$17,906,770
Total Maintenance	**$61,023,479**	**$62,297,667**

The difference between KCPL and Staff regarding maintenance is only in the Production accounts and is $1,274,188.

Q. Why does the Company escalate the maintenance adjustment levels to 2009 dollars?

A. Based on Mr. Hedrick's Rebuttal Testimony, page 3, line 19, KCPL has chose to index production maintenance dollars as a result of market pricing fluctuations.

Q. Does Mr. Hedrick explain what is meant by market pricing fluctuations in his rebuttal testimony?

A. Yes. Based on Mr. Hedrick's testimony on page 4, lines 1-6, the Company "has faced cost fluctuations for its materials and contract labor costs related to generation maintenance."

Q. What is the HW index?

A. The HW index is a publication of index factors used to estimate costs for electric, gas and water construction projects.

Q. Is the indexing approach consistent with traditional ratemaking?

A. No. There are several reasons why the indexing approach is not consistent with traditional ratemaking. First, a Company's revenue requirement is determined using various adjusted, annualized and normalized expense and revenue items. Second, ratemaking in Missouri is based on using "known and measurable" historical costs. Inflationary factors are in conflict with the known and measurable concept as they are highly speculative in nature.

Q. Are there any other reasons inflation factors should not be used when determining an appropriate level of maintenance costs?

A. Yes. First, the HW index was developed to estimate future construction costs. This not only is apparent in the title of the bulletin "The Handy-Whitman Index of Public Utility Construction Costs, Trends of Construction Costs", but also throughout the entire bulletin (See Schedule 6 in this surrebuttal testimony). The HW index identifies cost trends by plant account as established by the Uniform System of Accounts (USOA) as established by the Federal Energy Regulatory Commission (FERC) (*See* Schedule 6 ("E-3") page 7 through 14). The chart found on page E-3 of the HW index includes FERC accounts 311-373 which are used for capitalized construction costs. KCPL uses the HW index to normalize non-labor production maintenance costs which are FERC accounts 510-514 and 551-554.

Second, the HW index numbers, used by the Company, are developed from prevailing wage rates (among other things). Since payroll is annualized separately in the ratemaking process any inflation index that also includes labor rates is not appropriate to use as it is inconsistent because the payroll driven index is being applied to non-payroll operation and maintenance costs. The maintenance costs that both KCPL and Staff are making adjustments for in this case relate strictly to non-labor maintenance costs. In other words, maintenance costs for material and supplies excluding salaries and wages. The HW index uses labor costs in computing the index numbers.

Third, the HW index used by KCPL is for a large region not specific to the Company's Missouri operations, therefore, it does not apply to any real inflation that KCPL may or may not be experiencing for operation and maintenance costs for its production, transmission and distribution facilities.

Fourth, the KCPL approach to maintenance normalization has resulted in an over collection of maintenance dollars. Two out of three rate cases, maintenance costs included in rates were higher than actually incurred.

Q. Please explain the dollar difference between Staff and Company proposals for non-labor production maintenance.

A. Staff has proposed $27,186,949 for production maintenance accounts 510-514 based on a two year average of actual historical costs for the years 2008 and 2009. The Company’s proposal for the same accounts of $28,461,137 is based on an indexed seven (7) year average. The difference between Staff and Company production maintenance normalization is $1,274,188 on a total Company basis. On a total Missouri jurisdictional basis the difference is $681,691 ($1,274,188 times Missouri jurisdiction demand allocation factor 53.50%).

Q. Does KCPL believe Staff’s proposal for production maintenance represents future production maintenance costs?

A. No. Based on Mr. Hedrick’s testimony, page 3, lines 3-7, he states Staff’s proposal will not accurately reflect future production maintenance costs because Staff used a two (2) year average as opposed to the Company proposal of a seven (7) year indexed average.

Q. Why does the Company believe a seven (7) year indexed average is appropriate?

A. Mr. Hedrick states on page 3, lines 4 and 5, "Staff's use of a two-year average of actual costs ignores the reality that turbine maintenance is scheduled roughly every seven years."

Q. Does Staff agree with Mr. Hedrick's statement indicating Staff ignored turbine maintenance when using a two (2) year average?

A. No. In the two year average used by Staff for 2008 and 2009 KCPL had major maintenance performed on Iatan 1 and Montrose Unit 1. Those outages were included in the two year average.

As outlined in Staff's Cost of Service Report and Rebuttal Testimony, several steps were taken to analyze production maintenance. One such step was analyzing production maintenance, including major maintenance, using a two (2) year average through a seven (7) year average. Based on Staff's analysis, Staff used a two (2) year average for 2008 and 2009. The two (2) year average used by Staff represents more then what KCPL has spent for production maintenance in five of the last seven years for production maintenance including major maintenance. Please refer to my Rebuttal Schedule 7.

Q. If Staff used a seven (7) year average as proposed by the Company what would be the result?

A. A seven (7) year average using actual historical costs would result in a normalized level of $25,783,875 for production maintenance or in other words,

$1,403,074 less than Staff's proposal in this case. As a result, Staff does not believe that a seven (7) year average reflects an appropriate amount for future production maintenance costs.

Q. Is the difference between KCPL's proposal the result of using a seven (7) year average of KCPL's use of the HW index?

A. Mr. Hedrick would have the Commission believe Staff ignored major maintenance in its analysis. As mentioned above, Staff analyzed production maintenance expense including major maintenance, using a two (2) year average to a seven (7) year average. The difference between Staff's and KCPL's proposal is not a result of using a seven (7) year average or ignoring major maintenance overhauls but in fact the use of the HW index used by KCPL.

Q. Has KCPL collected more in rates than actually experienced for maintenance?

A. Yes. KCPL has collected more maintenance dollars from their customers based on rates set in two out of the last three rate cases. The table below illustrates that KCPL collected more in maintenance dollars in 2007 and 2008 than it actually incurred. Is also should be noted that KCPL may have under collected during the twelve (12) month period ending August 31, 2010. However, KCPL did not under collect in the area of production.

continued on next page

	Maintenance	Maintenance	Commission	Maintenance	Commission	Maintenance
	Agreement	**Balances**	**Order**	**Balances**	**Order**	**Balances**
	Case No. ER-2009-0089	**12-Month Period Ending August 31, 2010**	**Case No. ER-2007-0291**	**2008**	**Case No. ER-2006-0314**	**2007**
Rates in Effect	**September 1, 2009**		**January 1, 2008**		**January 1, 2007**	
		Actual		Actual		Actual
Production	$29,753,040	$29,192,691	$27,489,357	$29,700,543	$26,335,410	$26,827,119
Wolf Creek	$10,386,698	$12,405,235	$11,996,183	$11,627,624	$12,021,367	$10,648,013
Production Other	$1,397,237	$2,310,465	$1,046,792	$1,397,237	$765,351	$1,284,242
Transmission	$1,920,763	$3,969,502	$3,376,788	$1,920,763	$1,517,048	$1,766,579
Distribution	$15,444,941	$17,827,970	$21,668,896	$15,444,941	$21,629,071	$14,857,099
Vegetation Management	$3,100,000					
Total	**$62,002,679**	**$65,705,863**	**$65,578,016**	**$60,091,108**	**$62,268,247**	**$55,383,052**
Over or under collection	**-$3,703,184**		**$5,486,908**		**$6,885,195**	

Q. Was the HW Index used in any of the above rate cases?

A. Yes. In Case Nos. ER-2006-0314 and ER-2007-0291, KCPL was allowed to use this index to determine maintenance expense for those rate cases. In the 2006 rate case, rates become effective in January 1, 2007 so the actual 2007 maintenance costs were compared to the level included in rates for that case. For the 2007 rate case, rates became effective January 1, 2008 so actual 2008 maintenance costs were compared to the level included in rates for that case. The combined total of over collection of maintenance costs from customers was $12.4 million ($5.5 million in 2008 and $6.9 million in 2007). When the last rate case—the 2009 case-- the under collection of $3.7 million is taken into consideration, KCPL over collected $8.7 million over the last three rate cases.

Q. Was an agreement reached in the Case No. ER-2009-0089 regarding maintenance?

A. Yes. An agreement between KCPL and Staff for maintenance was made in the 2009 case. A copy of this agreement is attached to this surrebuttal testimony as Schedule 7.

Since rates became effective on September 1, 2009 for the 2009 case, Staff compared the actual maintenance costs for the 12 months ended August 31, 2010 to the levels agreed to by the Company and Staff in that case.

Q. Did KCPL perform extensive major maintenance in 2010?

A. In KCPL's response to Data Request No. 43, major maintenance was performed on LaCygne 1, Hawthorn 5 and Hawthorn 9. During the true-up in this case, Staff will review 2010 production maintenance dollars, including major maintenance, and make a determination whether or not Staff will need to update its proposal for production maintenance.

Q. Please summarize the Staff's disagreement with the Company's use of the HW index for normalizing its maintenance expense.

A. KCPL is using inflationary factors, not generally accepted in traditional ratemaking, that are based on labor related capitalized construction costs to normalize its non-labor related expensed maintenance costs. In addition, using inflationary factors to increase maintenance costs would not be considered a known and measurable cost. The last area of concern with the Staff and the use of HW index is the lack of incentive that inflationary factors provide to the Company to improve efficiency. Inflationary factors put all the risk on the ratepayers.

DECOMMISSIONING EXPENSE

Q. What is the purpose of this portion of your Surrebuttal Testimony?

A. This section of the Surrebuttal Testimony is to respond to the Rebuttal Testimony of Gregg N. Clizer the Nuclear Decommissioning Trust Fund contributions (Trust Fund).

Q. What is the issue with the Trust Fund contributions?

A. Based on Staff's Cost of Service Report Staff witness David Murray recommends no change to the Company's current level of Trust Fund contributions. In addition, I accepted the Company proposal to reduce the annual funding level by $122,847 from its current level of $1,281,264 to $1,158,417. As a result, Staff was inconsistent with its recommendation for the Trust Fund contributions.

Q. Does the Company agree to Mr. Murray's recommendation of making no change to the Trust Fund contribution?

A. Yes. Based on Mr. Clizer's rebuttal testimony on page 2, lines 9-15, the Company will accept leaving the Trust Fund contributions at the higher level if Staff removes adjustment E-38.1. However, it is expected that KCPL actually make the contribution to the decommission Trust Fund at the higher level not at its initial proposed reduced level.

Q. Has Staff removed adjustment E-39.1?

A. Yes. Staff has removed its Trust Fund adjustment which has changed to adjustment E-41.1 in Staff's Accounting Schedules.

HAWTHORN 5 SELECTIVE CATALYTIC REDUCTION SETTLEMENT

Q. What is the purpose of this portion of your Surrebuttal Testimony?

A. This section of the Surrebuttal Testimony is to respond to the Rebuttal Testimony of KCPL witness Curtis D. Blanc on settlement proceeds received by the

Company in 2007 related to the performance standards of a selective catalytic reduction system (SCR).

Q. Please describe what led to the settlement proceeds received by the Company for the failure of the SCR?

A. In February 1999 an explosion entirely destroyed the Unit 5 boiler located at the Hawthorn generating plant. After the explosion Babcock & Wilcox (B&W or Babcock) and KCPL entered into an engineering, procurement, and construction (EPC) agreement for the construction of Hawthorn Unit 5 boiler island (B&W Agreement or Agreement). The Agreement required B&W to install an SCR at Hawthorn Unit 5. The SCR was installed to reduce pollution associated with operating a coal-fired generating unit. Under the Agreement, B&W guaranteed specific performance standards, including an ammonia slip test. After the SCR was placed in service in June 2001, the boiler failed the ammonia slip test. The guaranteed performance standards were part of the contractual agreement between B&W and KCPL. The contract price KCPL paid for the SCR equipment included the guaranteed performance standard.

As a result of the failed performance standards, KCPL and B&W tried to resolve the issues by B&W doing additional work in 2002. Although attempts were made by B&W to adhere to the guaranteed performance standards, problems with the equipment still existed in 2004. Since B&W was unable to meet the performance standards set forth in the Agreement, B&W and KCPL entered into a Memorandum of Understanding (MOU), and revised the requirements of the ammonia slip test standards. This revision lowered SCR performance standards originally agreed to by B&W that was identified in the original contract Agreement regarding the ammonia slip test. Subsequently, B&W failed to meet these revised lowered standards. Because the SCR never met either the original contract performance standards or the revised lowered standards, B&W's failure to meet the ammonia slip test standards caused KCPL to experience increased replacements of catalysts, increased usage of ammonia, plus additional cleaning and maintenance expense, all resulting in significantly higher than expected costs to run and maintain the SCR equipment. After the revised standards identified in the MOU could not be met, KCPL requested liquidated damages from B&W based on the difference between the costs KCPL would incur if the standards were met and what costs KCPL incurred because the standards were not met.

In 2007, KCPL received a settlement from B&W as recognition of the higher costs to operate this generating unit. Because the performance standards identified in the initial Agreement and the MOU were never met the settlement in essence recognized a lower performing piece of equipment which would require higher operating and maintenance costs over the life of the unit—all of the costs KCPL has and will pass on to its customers.

Q. How much did KCPL receive in settlement proceeds from B&W?

A. KCPL received a settlement of ** ________ ** on a total KCPL basis on December 12, 2007.

Q. How did KCPL treat the settlement proceeds for ratemaking purposes in Case ER-2009-0089?

A. KCPL made an adjustment to remove the settlement proceeds from its cost of service in the last case.

Q. What is the significance of how KCPL treated the settlement proceeds?

A. KCPL adjustments passed the settlement proceeds to Great Plains Energy shareholders. KCPL effectively gave all the benefits from the settlement proceeds to

Great Plains while the customers have to pay the higher plant costs for the equipment under the original B&W contract, the higher maintenance costs due to SCR failure and higher fuel costs for the ammonia. All of these costs have been reflected in rates starting with the 2006 rate case. The higher costs were also reflected in the 2007 and 2009 rate cases.

Q. What is Staff's position regarding the settlement proceeds for the SCR?

A. The performance standards of the SCR were never met and, as such have resulted in higher capital and O&M maintenance costs that have been paid in the past and are currently being paid by KCPL customers. KCPL has, and continues to experience increased capital and operating and maintenance costs at Hawthorn 5 as the direct result of the performance failure of the SCR. As a result of the terms and agreement of the settlement, KCPL accepted lower performance standards for the SCR then what was initially guaranteed by B&W. By KCPL's own admission the lowered performance standards have resulted in increased costs for ammonia included in the fuel costs, more frequent replacements of catalysts resulting in higher capital and maintenance costs, and increased cleaning of the catalysts resulting higher maintenance costs. These increased costs started occurring in 2001 at the time the unit was placed back in service from the rebuild and continue to exist today resulting in higher operating and maintenance costs which KCPL customers are required to pay. Consequently, KCPL customers should receive the benefit of the settlement proceeds since they have and will continue to pay for all the capital and operating and maintenance costs over the life of the plant. Staff is proposing to reduce KCPL's rate base by the amount of the settlement proceeds. A detailed discussion on this proposed treatment is identified in the Staff Cost of Service Report filed on November 10, 2010, at page 108 under Section E-Other Non-Labor Adjustments—Hawthorn 5 SCR Impairment adjustment.

Q. Does KCPL agree that customers should benefit for the settlement proceeds?

A. No. It is KCPL's position that KCPL customers are not entitled to the settlement proceeds because they claim the settlement proceeds represented reimbursement for replacement of purchased power and increased ammonia costs. KCPL claims the customers never paid for these costs. Mr. Blanc provides four reasons in his Surrebuttal Testimony, page 49, lines 7-18, why KCPL customers are not entitled to the settlement proceeds. They are as follows:

> **(1)** The proceeds of this litigation have nothing to do with the test year in this case.
>
> **(2)** The cost of replacement power and additional ammonia expenses that resulted from the H5 catalyst outage (representing 90% of the settlement proceeds) was never paid by the customers.
>
> **(3)** To the extent KCP&L personnel were included in the process there would not have been any incremental costs to the Company or in turn its customers.
>
> **(4)** This issue represents retroactive ratemaking, which is not appropriate, where for the Company's benefit or detriment.

Q. Does Staff agree with Mr. Blanc's first statement "The proceeds of this litigation have nothing to do with the test year in this case" ?

A. It is correct the settlement proceeds were not received in the test year for this case. Staff considers this issue to be a continuation of Case No. ER-2009-0089. Staff addressed this issue in its Cost of Service Report and again in Surrebuttal Testimony in Case No. ER-2009-0089. The Commission did not hear the arguments related to this issue because a settlement was reached between the parties in this case.

In addition, the settlement proceeds are a direct result of increased capital and O&M maintenance costs all of which directly relate to this rate case. These increased costs began when the SCR was placed in service in 2001, continued in the 2009 test year of this case and continue today. KCPL should have reflected the proceeds as a reduction to rates at the time of receipt of the proceeds but chose not to. In response to Data Request No. 133 in Case No. ER-2009-0089, KCPL stated:

> **____
> ____
> ____
> ____
> ____
> _______
>
> ____
> ____
> ____
> ____
> ____
> ______________________ **

Although KCPL received the settlement proceeds in 2007, two years prior to the test year in this case, KCPL customers paid for increased capital and O&M maintenance costs during the test year and will continue to pay increased maintenance costs throughout the life of the plant. Yet, despite this increase in operating and maintenance costs and the increase in capital costs which increases return and depreciation costs, KCPL passed all the settlement benefits to its owner- Great Plains.

Q. Does KCPL recognize that its customers are currently incurring and will continue to incur additional capital costs, additional fuel expense and additional maintenance expenses as a result of this under-performing SCR plant being included in KCPL's rate base?

A. Yes. As noted in the quote above KCPL recognizes that the additional costs caused by this under-performing plant equipment will be paid for by its customers through the life of the plant.

NP

Q. Explain why KCPL has and will continue to incur additional costs for replacement catalysts.

A. Since B&W was never able to meet the performance standards they guaranteed, KCPL will need to change out the catalysts more frequently then what would be expected if the performance standards had been met. According to a memorandum dated June 6, 2007 provided by KCPL in Data Request No. 530 in Case No. ER-2009-0089,

> ** **
>
> [emphasis added] (The entire memorandum is attached to the surrebuttal testimony as Schedule 8)

Q. What are the costs KCPL would expect for changeout of the catalyst if the performance standards were met?

NP

A. KCPL states in the memorandum mentioned above, the changeout costs would range from **______________ . **

Q. What is the significance of the costs KCPL is anticipating over the life of the plant as a direct result of the failed performance standards?

A. KCPL received a settlement for **______ ** for damages related to the failure of B&W to meet specific performance standards. KCPL is expecting its customers to absorb costs over the life of the plant ranging from **______________ . ** These costs represent the costs associated with changing out the catalysts more frequently in the future due solely from the failure of this equipment to meet the original performance standards. When additional ammonia costs and other O&M costs are included, KCPL customers will pay significantly higher costs over the life of the plant and not receive any benefit of the settlement proceeds. This is the classic case of the customers pay for all the costs and shareholders reap the benefits of the settlement.

Q. Does the settlement with B&W cover all the costs to operate the SCR?

A. No. Unfortunately, the settlement only will cover a fraction of the substantial costs caused by this contract failure. While customers unquestionably should get the benefit of the settlement, they have had to pay and will have to continue to pay capital costs increases and O&M cost increases until the SCR is replaced or retrofitted.

Q. Does it appear that KCPL made a good settlement?

A. Considering all the higher costs KCPL has and will experience for this under-performing equipment which it has and fully intends on passing on to its customers, the settlement does not cover much of those costs. Considering the range of increase costs KCPL estimated of **______________ ** compared to **________ ** level, this settlement leaves a lot of additional costs that will not be covered by the settlement. Yet, regardless of the level, the settlement should be fully given as benefit to the customers for the cost increases they will have to endure because of this failed equipment.

Q. Does Staff agree with Mr. Blanc's second statement "The cost of replacement power and additional ammonia expenses that resulted from the H5 catalyst outage (representing 90% of the settlement proceeds) was never paid by the customers."

A. No. Based on the Company response to Data Request No. 133 in Case No. ER-2009-0089, the Company accounted for the settlement proceeds as a reduction to FERC expense accounts 501, 512 and 555. The highly confidential dollar settlement distribution is identified in the following chart.

**

**

Although the Company distributed ** __ ** of the settlement proceeds to a purchased power expense account, the damage incurred, by KCPL's own admission, manifested in several areas: ** ______________________________ ______________________________ ** The major expenses incurred in the past, currently and in the future will be the higher operating fuel costs, higher maintenance costs and higher capital costs.

NP

Q. Have KCPL's customers paid plant-related, purchased power and maintenances costs, as a result of this under-performing SCR plant being included in rate base and the excess maintenance costs included in KCPL's cost of service.

A. Yes. In the last three KCPL rate cases, Case No. ER-2006-0314, Case No. ER-2007-0291 and Case No. ER-2009-0089 the plant-related costs for the under-performing SCR plant were included in rate base and the excess maintenance costs were included in KCPL's cost of service. The higher fuel costs for ammonia additive were fully reflected in each of the three rate cases. The higher purchased power costs was also included in the rate case and reflected in rates. Staff witness Cary G. Featherstone will address these higher costs in his Surrebuttal Testimony. In each of these cases, Staff includes operating costs and plant levels consistent with the test year, update period and true-up period ordered by the Commission. Likewise, Staff includes an expense level that is consistent with the test year and update period for each case.

Q. What were the test years and true-up periods used in past KCPL rate cases?

A. The following table identifies the test year and update period for each of the three cases.

Case Number	Test Year	Update Period	True-Up Period	Effective Date of Rates
ER-2006-0314	Calendar Year 2005	June 30, 2006	September 30, 2006	January 1, 2007
ER-2007-0291	Calendar Year 2006	March 31, 2007	September 30, 2007	January 1, 2008
ER-2009-0089	Calendar Year 2007	September 30, 2008	March 31, 2009	September 1, 2009

Q. KCPL claims customers have never had to pay for any of the costs relating to the settlement. Is this true?

A. No. According to Mr. Blanc's statement the settlement proceeds represented reimbursement for cost of replacement power (90% of the proceeds) and additional ammonia expenses that resulted from the Hawthorn 5 catalyst outage. The catalyst outage began February 24, 2007 and ended March 9, 2007. This information was provided by KCPL in Data Request No. 533 in Case No. ER-2009-0089. The Company also provided a study in Data Request No. 533 which was used as the basis for its position related to reimbursement of purchase power costs. (See Schedule 9 in this surrebuttal testimony).

As mentioned earlier in this testimony, Mr. Blanc claims KCPL customers have never paid for the costs of replacement power or additional ammonia expenses that resulted from the Hawthorn 5 catalyst outage. In addition, he states on page 50, lines 2-4, in his Rebuttal Testimony, "KCP&L did not request a rate increase at any time during the outage or subsequent to the outage that resulted in recovery of the replacement power costs and the additional ammonia expenses. Thus, customers have never paid these costs." These statements are simply not true. Both KCPL and Staff developed their respective revenue requirements case in Case No. ER-2009-0089 using a test year for that case based on the twelve (12) month period ending December 31, 2007. The replacement purchased power and the additional ammonia costs for the catalyst outage would have been included in the test year. Consequently, Mr. Blanc inferring KCPL customers have never paid for expenses for the under-performing SCR equipment is incorrect. The higher fuel and purchased power costs were included which will be discussed by Staff witness Featherstone. The higher maintenance costs were clearly reflected in the three rate cases and ultimately in rates. The higher plant costs were included in each of the last three rate cases—not just the 2009 rate case. Thus, customer's rates reflect higher depreciation and return costs.

Q. Did KCPL provide the Staff all settlement documents related to the SCR?

A. Yes. Staff requested all documents related to the SCR settlement in Data Requests No. 133 and 530 in Case No. ER-2009-0089. As a result, Staff received correspondence to and from B&W addressing the Company position with the SCR performance, Memorandum of Understanding revising the SCR performance to lower standards and the Settlement Agreement.

Q. Did any of these documents indicate KCPL was seeking damages for replacement power costs?

A. No. Staff did not find any documentation indicating KCPL was seeking damages for recovered replacement power costs. According to the documents provided to Staff, KCPL was seeking damages for ** ____ ____ **

Q. Does Staff agree with Mr. Blanc's third statement appearing at page 49 of his rebuttal "To the extent KCP&L personnel were included in the process there would not have been any incremental costs to the Company or in turn its customers"?

A. No. Mr. Blanc's statement referring to incremental costs related to KCP&L employee costs is irrelevant. As noted earlier in this testimony, rates were set in the last three KCP&L rates based on the costs KCPL incurred during the test year, update period, and true-up period established in each case. Negotiations related to the SCR performance standards were occurring during the time period of each of these cases and as such any costs related to this issue would have been included in KCPL's cost of service by virtue of how Staff develops its case. As shown below in response to Data Request No. 271 in Case No. ER-2009-0089, KCPL provided a long list of senior KCPL executives and employees who were involved with the Hawthorn SCR performance issues, litigation, settlement discussions and settlement agreement over several years. KCPL's customers are paying the salaries and benefits to each of these executives and employees who worked to get the under-performing SCR plant settlement, not KCPL's shareholders.

> **Question No. 0271:**
> Please provide a list of all KCPL/GPE employees who were directly or indirectly involved with the Hawthorn SCR performance issues, litigation, settlement discussions and settlement agreement. For each, please describe this involvement.
>
> **Response:**
> Steve Easley's (Senior Vice President, Supply) involvement was lead negotiator regarding the settlement and was involved with George Burnett (Consulting Engineer, Production Engineering Services), Gerald Reynolds (Assistant General Counsel, Law Department) and Peter Vanderwarker (Senior Attorney, Law Department) in developing the "damages" KCP&L was expected to incur due to the SCR/catalyst's inability to meet its ammonia slip performance guarantee. The following individuals had indirect involvement in this process: Lora Cheatum (Vice President of Procurement, Procurement), David Price (Vice President of Construction, Construction Management) and William Riggins (Vice President of Legal and Environmental Affairs and General Counsel, Law Department).

Q. Were other KCPL personnel involved in the effects of the poor performance surrounding the Hawthorn 5 SCR?

A. Yes. Hawthorn 5 plant personnel have to handle all the additional operation and maintenance issues relating this problem. KCPL engineers located at the corporate office are also involved in the operational and maintenance issues concerning the SCR failures. The fuels departments have to procure more ammonia at greater prices for the Hawthorn 5 SCR. These individual departments would very likely been involved in supplying information on the performance of the SCR and the evaluation of options for correcting the problem. The settlement process would have included a body of support from the performance issues to the resolution options. Staff does not believe only employees working on this settlement were those specifically identified in the data request response.

Q. Were the costs regarding the settlement incremental costs?

A. There likely were incremental costs as well as direct out of pocket costs associated with the settlement. The point that is important to recognize is that KCPL has an infrastructure in place for employees to work on this project as well as others. Customers pay for all these costs—not the shareholders. To suggest KCPL alone without customer support was responsible for this settlement is just pain inaccurate.

Q. Does Staff agree with Mr. Blanc's fourth statement appearing at page 49 of his rebuttal "This issue represents retroactive ratemaking, which is not appropriate, where for the Company's benefit or detriment."

A. No. This statement is similar to Mr. Blanc's first statement, "The proceeds of this litigation have nothing to do with the test year in this case." Staff agrees with Mr. Blanc that the settlement proceeds were received two years prior to the 2009 test year established in this case. However, does not agree this issue represents retroactive ratemaking.

KCPL received settlement proceeds as a direct result of B&W's failure to meet performance standards for the SCR. The failed performance standards have led to increased capital and maintenance costs. Although the settlement was received in 2007, KCPL's customers have paid and will continue to pay for these increased capital and maintenance costs throughout the life of the plant. Since KCPL customers have and will continue to pay for increased costs associated with a under-performing SCR plant, retroactive ratemaking does not apply. To suggest as Mr. Blanc has that customers have not had to pay increased costs for the SCR is simply inaccurate and misleading.

Q. If KCPL would have treated the settlement as Staff is recommending could KCPL now make any claim of retroactive ratemaking?

A. No. If KCPL would have correctly treated the settlement as a reduction to the plant investment when they received it in 2007 the Company could not now attempt to hide behind a claim of retroactive ratemaking. In addition, Staff considers this issue to be a continuation of Case No. ER-2009-0089. Staff addressed this issue in its Cost of Service Report and again in Surrebuttal Testimony in Case No. ER-2009-0089. The Commission did not hear the arguments related to this issue because a settlement was reached between the parties in this case.

Q. Is there anything else you need to address relating to KCPL's position on this issue?

A. Yes. Mr. Blanc makes the statement in his Rebuttal Testimony on page 49, lines 16-18, "I don't think Ms. Lyons would support the Company if it were to propose to reach back to 2007 and charge customers now for the cost of replacement power and additional ammonia expense during this period." KCPL customers have already paid for the cost of replacement power and additional ammonia expense during the catalyst outage period by virtue of how Staff develops its case. The higher costs for all impacts of the poorly performing SCR have been paid for by the customers. And, unfortunately customers will continue to have to pay these higher costs in the future.

Q. Mr. Blanc addresses the issue of retroactive ratemaking in his Rebuttal Testimony. Has KCPL had a history of seeking rate recovery of costs that were incurred several years prior to initiating a rate case?

A. Yes. In KCPL's 2006 rate case, No. ER-2006-0314, the Commission ordered that KCPL be allowed to recover an annual level of $4.5 million for ice storm costs that were incurred by KCPL in 2002 and deferred under an Accounting Authority Order (AAO). The closest test year to the year KCPL incurred the ice storm cost in 2002 was three years later in the 2005 test year ordered by the Commission in KCPL's 2006 rate case. On page 60 of its report and Order in Case No. ER-2006-0314, the Commission characterized KCPL's position on ice storm expense recovery as follows "because the amortization allowed by the AAO case was in effect during the test year and true-up period, KCPL asserts that it should be able to recover those costs."

Q. How does the 2002 ice storm issue relate to the SCR settlement issue in this case?

A. The Commission allowed recovery of the 2002 ice storm expenses because the amortization allowed by the AAO was in effect during the test year and true-up period for that case. Similarly, customers paid for increased maintenance costs as a result of the under-performing SCR plant during the test year and true-up in this case and will continue to pay for increased maintenance costs throughout the life of the plant.

Customers are paying for the higher fuel costs for ammonia. Customers are paying higher depreciation costs because of the higher plant investment—the initial investment which is higher than it should be because of a lesser performance standard and higher subsequent investment resulting from the increases capital costs for more frequent replacement of the catalysts.

Q. Does Mr. Blanc provide any additional points in his Rebuttal Testimony?

A. Yes. Mr. Blanc suggests the Commission has dealt with a similar issue in another KCPL rate case. Mr. Blanc states on page 50, lines 17-20 in his Rebuttal Testimony, "In the ER-2007-0291 case, the company removed from its case the impact of receiving $16.9M in subrogation proceeds that were recorded by KCP&L in 2006 related to the H5 boiler explosion that occurred in 1999. The Commission found the issue in favor of KCP&L for precisely the same reasons I raise here."

Q. Does Staff agree with Mr. Blanc's statement?

A. No. The subrogation proceeds received by KCPL in 2006 and the settlement proceeds for the SCR received in 2007 are two distinctly different issues. The Hawthorn 5 subrogation issue that was litigated in Case No. ER-2007-0291 involved costs that were directly related to the 1999 Hawthorn plant explosion. Specifically, costs that occurred during the period beginning when the explosion occurred in 1999 and ended when the plant was placed back in service in 2001. The only similarity between the subrogation issue and the SCR settlement is KCPL claimed a majority of the proceeds represented costs incurred for replacement power. The time period representing the costs incurred for replacement power for the subrogation proceeds was 1999-2001. Unlike the SCR incident, KCPL did not file a rate case any time during the Hawthorn explosion or subsequent to this time period during the rebuilding of this generating unit. As demonstrated earlier in this testimony, KCPL recovered the costs for the SCR settlement as a result of rates set in the last three rate cases. This was not the case in the subrogation issue. In addition, the Commission stated in its Report and Order in Case No. ER-2007-0291, "The proceeds are an unusual non-recurring event. . ." Unlike the costs related to the Hawthorn 5 subrogation proceeds, the costs associated with the under-performing Hawthorn 5 SCR plant that KCPL passes on to its customers, by KCPL's own admission, is being incurred currently and will be incurred over the life of the plant. The operating and maintenance costs and capital cost increases are recurring in nature and, and for this reason, are reflected in rates. The costs for replacement power that KCPL claims their customers never paid for in this issue were paid for by KCPL customers based on the rates set in Case No. ER-2009-0089. Higher capital and operating and maintenance costs that occurred during the last three rates cases have also been reflected in KCPL's rates. Customer rates today reflect all these higher costs.

Q. Please summarize Staff's position with the Hawthorn 5 SCR settlement.

A. KCPL would have the Commission believe the settlement proceeds received from B&W represented costs KCPL customers have never paid for and thus should not be entitled to the proceeds. Staff has presented evidence that contradicts KCPL's position. KCPL customers paid for the costs the Company claims the customers never paid and KCPL customers are responsible for all the future capital and operating and maintenance costs that KCPL will incur as a result of the Company accepting lower performance standards for the SCR. Staff recommends KCPL customers receive the benefit of the settlement proceeds by making an adjustment to increase depreciation reserve and making a corresponding adjustment to depreciation in effect reducing KCPL's rate base as discussed in Staff's Cost of Service Report at pages 108 to 111.

HAWTHORN 5 TRANSFORMER SETTLEMENT

Q. What is the purpose of this portion of your Surrebuttal Testimony?

A. This section of the Surrebuttal Testimony is to respond to the Rebuttal Testimony of KCPL witness Curtis D. Blanc on settlement proceeds received by the

Company in 2008 related to the failure of a generating step-up transformer (GSU or transformer), located at the Hawthorn generating plant.

Q. Please describe what led to the settlement proceeds received by the Company for the transformer?

A. In August 2005, the generator step-up transformer on KCPL's Hawthorn 5 failed. In September 2005, a backup step-up transformer was installed. During June 2006, a new step-up transformer was installed. KCPL sued the contractors and subcontractors claiming they were responsible for the transformer failure. The case settled at the end of 2007, and was finalized in 2008 with payment made to KCPL. KCPL received a dollar settlement for the transformer failure from Siemens Power Transmission & Distribution, Inc. (Siemens). KCPL has made no adjustment in its books and records to provide any benefit of this settlement to its customers. It is Staff's position that KCPL's customers should receive the benefit of the settlement since they are the ones who paid higher costs for the substandard plant performance due the transformer failure.

All the increased costs to KCPL of the operation of Hawthorn 5 resulting from the transformer failure were paid by KCPL customers in its utility rates. These costs include the salaries and benefits, office space, and all employee-related costs of KCPL's attorneys and employees who worked on KCPL's dispute with the contractors and subcontractors, increased maintenance, increased fuel and purchased power expense, and increased expenses that were capitalized to the new plant.

Q. Did KCPL provide Staff with documentation to support KCPL incurred increased maintenance costs prior to the transformer failing in 2005?

A. Yes. According to the First Amended Petition (Petition), included in KCPL's response to Data Request No. 527 in Case No. ER-2009-0089, Siemens performed maintenance on the transformer prior to it failing in 2005. The following excerpt was taken from the Petition:

> ** ____
> ____
> ____
> ________________ **

Selected pages of the First Amended Petition are attached to this surrebuttal testimony as Schedule 10. Staff felt the entire document was too voluminous to attach as a schedule. However, the highly confidential document is available for review by the Commission or other parties.

Q. How much did KCPL receive in settlement proceeds from Siemens?

A. KCPL received a total settlement of ** __________ ** of which, ** ________ ** was received by KCPL, net of legal costs incurred for this settlement. The settlement is on a total KCPL basis and was received on February 7, 2008.

Q. How did KCPL book the settlement proceeds?

A. Based on the Company response to Data Request No. 510 in Case No. ER-2010-0355, the Company accounted for the settlement proceeds in the following FERC accounts 108, 555 and 923. The highly confidential dollar settlement distribution is identified in the following chart.

continued on next page

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Q. Does Staff believe KCPL customers should receive the benefit of the full amount of the net proceeds of ** ________ ** ?

A. No. In Staff's Cost of Service Report, Staff recommended an increase to depreciation reserve and a corresponding adjustment to depreciation for the entire amount of the net proceeds. After Staff's direct filing, November 10, 2010, Staff received a response to Data Request No. 510 learning the net proceeds were distributed to the FERC accounts detailed above. Based on KCPL's response to this data request, Staff believes KCPL customers are entitled to the proceeds booked to FERC account 555-Purchased Power-Energy Capacity Purchases which is the ** ________ ** amount. Staff has reflected the change in its EMS-Accounting Schedules. Staff treated the amount the same as an increase to depreciation reserve with a corresponding adjustment to depreciation.

Q. How did KCPL treat the settlement proceeds for ratemaking purposes in Case No. ER-2009-0089?

A. KCPL made an adjustment to remove the settlement proceeds from its cost of service in the last case.

Q. What is the significance of how KCPL treated the settlement proceeds?

A. KCPL adjustments passed the full amount of the settlement proceeds to Great Plains' shareholders. KCPL effectively gave all the benefits from the settlement proceeds to Great Plains while KCPL customers paid all employee-related costs of KCPL's attorneys and employees who worked on KCPL's dispute with the contractors and subcontractors, increased maintenance, fuel and purchased power expense, and increased expenses that were capitalized to the new plant. All of these costs have been reflected in rates starting with the 2006 rate case. The higher costs were also reflected in the 2007 and 2009 rate cases.

Q. What is Staff's position regarding the settlement proceeds for the transformer?

A. The Staff's position is the settlement dollars received by KCPL during the updated test year in Case No. ER-2009-0089 represents a reimbursement to KCPL for the costs of the defective transformer. As previously mentioned in this surrebuttal testimony, KCPL customers paid for all the costs relating to the replacement of the transformer in rates set in the last three rate cases. A detailed discussion on this proposed treatment is identified in the Staff Cost of Service Report filed on November 10, 2010, at page 111 under Section E-Other Non-Labor Adjustments— Hawthorn 5 Transformer Settlement.

Q. Does KCPL agree that customers should benefit for the settlement proceeds?

A. No. It is KCPL's position that KCPL customers are not entitled to the settlement proceeds for the same reasons identified in the SCR settlement presented in this surrebuttal testimony. Mr. Blanc states in his Rebuttal Testimony on page 51, lines 8-14:

> These proceeds were received as a result of activities that happened in a prior period. The corresponding costs are not in this test year. KCPL's customers never paid the costs being reimbursed by this settlement. KCP&L did not have a fuel adjustment clause that would have recovered replacement power costs. It is no more appropriate to reach back beyond the test year as Staff proposes, than it is for the Company to reach back for rate increased foregone between rates cases.

Q. Does Staff agree with Mr. Blanc's statement "These proceeds were received as a result of activities that happened in a prior period. The corresponding costs are not in this test year."?

A. It is correct the settlement proceeds were not received in the test year for this case. However, KCPL should have reflected the proceeds as a reduction to rates at the time of receipt of the proceeds but chose not to. In addition, Staff considers this issue to be a continuation of Case No. ER-2009-0089. Staff addressed this issue in its Cost of Service Report and again in Surrebuttal Testimony in Case No. ER-2009-0089. The Commission did not hear the arguments related to this issue because a settlement was reached between the parties in the 2009 rate case.

Q. Does Staff agree with Mr. Blanc's statement "KCPL's customers never paid the costs being reimbursed by this settlement. KCP&L did not have a fuel adjustment clause that would have recovered replacement power costs."

A. No. Similar to the SCR settlement, KCPL customers paid for the costs related to the replacement of the transformer in rates set in the last three rate cases. In the last three KCPL rate cases, Case No. ER-2006-0314, Case No. ER-2007-0291 and Case No. ER-2009-0089 the plant-related costs for the defective transformer were included in rate base and the excess maintenance costs were included in KCPL's cost of service. Staff witness Cary G. Featherstone will address the higher costs for fuel and purchased power in his Surrebuttal Testimony. In each of these cases, Staff includes operating costs and plant levels consistent with the test year, update period and true-up period ordered by the Commission. Likewise, Staff includes an expense level that is consistent with the test year and update period for each case.

As mentioned earlier in this surrebuttal testimony, the transformer failed August 2005. A back-up transformer was installed September 2005 and the new transformer was installed June 2006. The capital costs and operating expenses leading up to the replacement of the transformer in 2006 would have been included in the rates set in Case No. ER-2006-0314 and the capital costs and operating expenses following the replacement were included in rates set in Case No. ER-2007-0291 and Case No. ER-2009-0089. According to KCPL's response to Data Request No. 529 in Case No. ER-2009-0089:

> **____
> ____
> ____
> ____
> ____
> ______ **

KCPL experienced two outages as a result of the transformer failure. The first occurred from August 29, 2005-date the Siemens transformer failed to September 29, 2005-when an old back-up transformer was placed in service. The back-up transformer was used until KCPL received a new transformer to replace the Siemens transformer. The second outage occurred from June 6, 2006 to June 19, 2006 when KCPL replaced the old back-up transformer with a new GE Transformer. This information was provided by KCPL in Data Request No. 526.1. Based on this information, the outages occurred during the 2005 test year for Case No. ER-2006-0314 and the 2006 test year for Case No. ER-2007-0291. As such, any increases to purchase power expense were included in rates set in that case. Therefore, KCPL customers paid for the replacement power related to the outages.

Q. Have KCPL's customer paid higher rates in the past and will they continue to pay higher rates because of issue?

A. Yes. According to KCPL's response to Data Request No. 366.1 in Case No. ER-2006-0314, KCPL included ** ________ ** in new plant in its rate base for the purchase of the new GE transformer and retired ** ________ ** from plant-in-service for the original transformer. At a minimum, KCPL customers were charged for additional plant of ** ________ . **

Q. When was the original transformer installed at the Hawthorn power plant?

A. According to the Petition discussed earlier in this testimony ** ________ ________ ** This documentation supports that KCPL admitted the original transformer was defective.

Q. Was KCPL reimbursed for the costs related to the services identified above?

A. Yes. In Case No. ER-2006-0314, KCPL normalized production maintenance expense using a six (6) year average of 2000-2005. The costs related to the services identified above occurred during this period.

Q. Was the normalization of production maintenance expense using a six (6) year average of 2000-2005 used to set rates in Case No. ER-2006-0314.

A. Yes. The Commission ruled in favor of KCPL's position on production maintenance expense. KCPL customers began paying the rates set in the 2006 rate case effective January 1, 2007.

Q. Similar to the Hawthorn SCR settlement, does KCPL suggest the transformer settlement is related to the Hawthorn subrogation proceeds litigated in Case No. ER-2007-0291?

A. Yes. Mr. Blanc states in his Rebuttal Testimony, page 51, lines 6-8, Staff's position here, like the H5 SCR settlement and the subrogation proceeds, is a violation of the "matching" principle and represents retroactive ratemaking.

Q. Does Staff agree with Mr. Blanc's statement?

A. No. Similar to the SCR previously discussed in this surrebuttal testimony. The subrogation proceeds received by KCPL in 2006 is a distinctly different issue then the settlement proceeds for the Siemens transformer. KCPL recovered the costs related to the transformer failure through rates set in the last three rates cases. The costs for replacement power that KCPL claims their customers never paid for in this issue were paid for by KCPL customers based on the rates set in Case No. ER-2006-0314. Higher capital and operating and maintenance costs that occurred as a result of the transformer failure were paid by KCPL customers through rates set in Case No. ER-2006-0314.

Q. Please summarize Staff's position with the Hawthorn 5 transformer settlement.

A. KCPL would have the Commission believe the settlement proceeds received from Siemens represented costs KCPL customers have never paid for and thus should not be entitled to the proceeds. Staff has presented evidence that contradicts KCPL's position. KCPL customers paid for the costs the Company claims the customers never paid. Staff recommends KCPL customers receive the benefit of the settlement proceeds by making an adjustment to increase depreciation reserve and making a corresponding adjustment to depreciation in effect reducing KCPL's rate base as discussed in Staff's Cost of Service Report at pages 111 to 112.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of the Application of Kansas City Power & Light Company for Approval to Make Certain Changes in its Charges for Electric Service to Continue the Implementation of Its Regulatory Plan	))))	File No. ER-2010-0355

AFFIDAVIT OF KAREN LYONS

STATE OF MISSOURI)
) ss.
COUNTY OF COLE)

Karen Lyons, of lawful age, on her oath states: that she has participated in the preparation of the foregoing Surrebuttal Testimony in question and answer form, consisting of 59 pages to be presented in the above case; that the answers in the foregoing Surrebuttal Testimony were given by her; that she has knowledge of the matters set forth in such answers; and that such matters are true and correct to the best of her knowledge and belief.

Karen Lyons
Karen Lyons

Subscribed and sworn to before me this 5th day of January, 2011.

D. SUZIE MANKIN
Notary Public - Notary Seal
State of Missouri
Commissioned for Cole County
My Commission Expires: December 08, 2012
Commission Number: 08412071

D Suzie Mankin
Notary Public

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SUITE 1902 POWER & LIGHT BUILDING
KANSAS CITY MISSOURI

January 25, 1943

Arthur Anderson & Co
1604 Commerce Building
Kansas City, Missouri

Re: Kansas City Power & Light Co.

Gentlemen:

On November 9, 1943 the Council of Kansas City, Missouri enacted an ordinance known as "Committee substitute for Ordinance No. 7373 as Amended" by the terms of which Chapter 9 of Ordinance No. 7100 was amended by repealing Sections 9-1.1 to 9-1.19, inclusive, and enacting in lieu thereof 980 new sections relating to the same subjects and fixing license fees for every corporation etc. engaged in electric light or power businesses etc,,. said new sections to be numbered [-] to 9-1.980 inclusive

By virtue of this section, the Kansas City Power & Light Company is no longer obligated to pay the license Fee of $1,000.00 imposed upon electric light companies by Section 9-1 (case 788 of the revised Ordinances of Kansas City, 1941).

We are of the opinion that, by virtue of said power, that Kansas City Power and Light Company is no longer required to pay the license fee of fifty cents per year for the use of electrical meters provided for in said Section 9-1.

We are also of the opinion that the Kansas City Power & Light is no longer obligated to pay the rental of $274.08 per year heretofore imposed upon the Kansas City Electrical Wire Subway Company for the rental of conduit space.

By virtue of Section 9-1-99 of the new ordinance, the Company will pay, in lieu of all other license or franchise Taxes, a license fee of 5% of the gross receipts derived from

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KANSAS CITY MISSOURI

the sale of electrical energy with in the present or future boundaries Kansas City for domestic or commercial consumption as in said section defined and delimited. Said section further provides that the first quarter-annual license fee shall be due hereunder on or before January 30, 1943, for the three months period commencing January 1, 1943, and ending March 31, 1943. And it further provides that license fees paid prior to the enactment of the ordinance shall be prorated as of January 1, 1943 and any amounts due licensee on account of any prepayment of license fees shall be credited upon said first quarter-annual license fee payment due and payable January 30, 1943.

Inasmuch as the meter tax of fifty cents per meter was paid in advance on the first day of November, 1943, for the fiscal year ending October 31, 1943 the company may deduct ten-twelfths of the amount so paid from the first quarter-annual license fee payment under the new ordinance.

Yours very truly,

JOHNSON, LUCAS, GRAVES & PAIN

FROM ORDINANCE NO. 7473, as AMENDED.

Sec. 9-1.99. ELECTRIC LIGHT OR POWER BUSINESS. Every electric light or power company, and every corporation, company association, joint stock company or association, partnership and person, their lessees, trustees or receivers appointed by any court whatsoever, owning, operating, controlling, leasing or managing any electric plant or system generating, maunfacturing, selling, distributing or transmitting electricity for light, heat or power, shall pay to the City a quarter-annual license fee to be due and payable to the City Treasurer on or before the 30th days of January, April, July and October, respectively, of each year, based upon the business done during the preceding period of three (3) calendar months ending, respectively, on the last days of December, March, June and September. The amount of such quarterly license fee shall be five per cent (5%) of the gross receipts derived from the sale of electrical energy within the present or future boundaries of Kansas City during the said preceding period of three (3) months ending as aforesaid for domestic or commercial consumption, as hereinafter defined, and not for resale. No electrical energy sold to the United States or to the State of Missouri, or to any agency or political subdivision thereof, shall be included in the computation of said gross receipts. The sale of electrical energy to an owner or lessee of a building, who purchases such electrical energy for resale to the tenants therein, shall, for the purposes of this section, be considered as a sale for consumption and not for resale, but the resale to the tenant shall not be considered as a sale for consumption. The licensee shall and it is hereby required to make true and faithful reports under oath to the Director of Finance and to the License Collector of Kansas City, in such form as may be prescribed by the Director of Finance, and containing such information as may be necessary to determine the amounts to which the license tax shall apply, on or before the 30th days of January, April, July, and October of each year, for all gross receipts for the three (3) calendar months ending, respectively, on the last days of December, March, June and September. Each fee so paid shall constitute payment for the three (3) months beginning on the first days of the months of January, April, July and October, respectively, during which months such payments shall be due and payable as herein prescribed; provided, however, that the acceptance of such fee shall not prejudice the right of the city to collect any additional fees thereafter found to be due. The city, the Director of Finance thereof and his assistants, and any public accountants selected by the City Council or by the City Manager shall have the right, at all reasonable times during business hours, to make such examinations and inspections of the books of said licensee as may be necessary to determine the correctness of such reports, and the originals of all records, books, documents, accounts, contracts and vouchers, showing accurately the true condition of the gross income and business of the licensee, shall be kept in its office in Kansas City, Missouri, and licensee shall not remove the same from the city except when necessary for temporary use or when temporarily required to do so by legal process, and in any such case of temporary use or process, the same shall be promptly returned at the conclusion thereof to the office of the licensee in Kansas City, Missouri. The city shall have the right, at its own expense, to employ the same accountants who make the annual audit of the books, records and accounts of the business of the licensee, to audit, at the same time, its accounts and records and certify as to the correctness of any payments due and payable by the licensee to Kansas City.

For each and every month or part thereof, any such license fee remains unpaid, after the same becomes due and payable, there shall be added to such license fee, as a penalty for such delayed payment, ten per cent (10%) of the amount of such license fee for the first month or part thereof the same is unpaid, and for each and every month thereafter two per cent (2%) of the amount of such license fee until the same is fully paid.

The term "gross receipts" as applied to sales of electrical energy for domestic or commercial purposes, as used in this section, shall not include (1) electrical energy sold for industrial consumption such as for use in manufacturing, processign, mining, refining, ship-building, and building construction, and (2) that sold for other uses, which likewise cannot be classed as domestic or commercial, such as the electrical energy used by public utilities, telephone, telegraph and radio communication companies, railroads, or other common carriers, educational institutions not operating for profit, churches and charitable institutions; as such sales and usages have been construed by the United States Department of Internal Revenue under the Revenue Act of 1932 and amendments thereof.

Permission is hereby granted to licensee to trim trees upon and overhanging streets, alleys, sidewalks, and public places of said city so as to prevent the branches of such trees from coming in contact with the wires and cables of licensee, all the said trimming to be done under the supervision and direction of any city official to whom said duties have been or may be delegated.

Nothing herein contained shall be construed as giving to a licensee any exclusive privileges, nor shall it affect any prior or existing rights of a licensee to maintain an electric plant within said city.

Where an additional amount is added for failure to make payment of any electric bill within a prescribed period the license fee shall be based on the total amount actually paid, as part of the "gross receipts" of the licensee.

The first quarter-annual license fee shall be due and payable hereunder on or before January 30, 1943, for the three (3) months period commencing January 1, 1943, and ending March 31, 1943, and licensee fees heretofore paid for the businesses herein described shall be prorated as of January 1, 1943, and any amounts due licensee on account of any prepayment of license fees shall be credited upon said first quarter-annual licensee fee payment due and payable January 30, 1943.

Three per cent (3%) of all fees hereafter collected and paid into the City Treasury for licenses under and pursuant to the provisions of this Section shall belong exclusively to the Firemen's Pension Fund, and it shall be the duty of the City Council to appropriate and of the Director of Finance to apportion and credit such fees to said Firemen's Pension Fund from time to time as the same are collected and paid.

Form 911-028—50M—7-45

Kansas City Power & Light Co.
INTER-OFFICE CORRESPONDENCE

File No.

Date January 15, 1947

Subject City of Sugar Creek, Missouri

Mr. Frank P. Clark
Controller

Dear Sir:

I am returning to you herewith check #92 of this Company in the amount of $25 payable to the City Collector of the City of Sugar Creek, Mo., for the Merchants' License Tax for the year 1947.

The Board of Aldermen of the City of Sugar Creek on December 16 adopted an ordinance No. R-1097 which levies a license fee equal to 5% of the gross receipts of this Company derived from the sale of electricity for domestic and commercial consumption within the present or future boundaries of such city. The ordinance applies to all receipts from and after January 1, 1947. We are proceeding to accept this ordinance and as soon as I have received certified copies thereof I shall furnish you a copy and ask that you please see that the reports are prepared and filed and that payments are made thereunder when due.

Yours very truly,

H. B. Munsell.

hbm:ns
Enc. (check)

Cancel Voucher and await new ordinance
arrange for Cust. Acctg Dept to furnish earnings for Sugar Creek & tax computations

FORM 90

ACCOUNTS PAYABLE CARD

INVOICE DATE	INVOICE NO.	GROSS AMT.	DISCOUNT	NET AMT.
1 / 1 / 42		25.00		25.00

DISTRIBUTION CARD

LOC.	PURCH. ORDER LOT NO.	OFF	FUNCTION	ACCOUNT WORK ORDER	QUANTITY	AMOUNT	CR.
10	132-001	1					
						25.00	

City of Sugar Creek
Office of City Clerk
Sugar Creek, Jackson County, Missouri

10	0985	P. & S. LOADING	
10	0986	CASH DISC. OTHER	CR.
10	6081	CASH DISC. MDSE.	CR.

ACCTS.

V.

DIST.

V.

ORIGINAL VOUCHER JAN 6 1947

KANSAS CIT POWER & LIGI F COMPANY

KANSAS CITY, MO.

PAID BY CHECK NO.

2500

VOUCHER TO CITY COLLECTOR
OFFICE OF CITY CLERK
SUGAR CREEK MO

IN FULL SETTLEMENT OF ACCOUNT SHOWN ON ATTACHED STATEMENT

NOT NEGOTIABLE

VENDOR NO.	MO	VOUCHER NO.	INVOICE DATE MO.	DAY	YR.	INVOICE NO.	GROSS AMOUNT	DISCOUNT	NET AMOUNT
2851	1	71	1	01	47		2500		2500
							2500		2500
						Merchants license tax for the year 1947			

CHECKED BY: AUDITED: ASST. SECRETARY APPROVED: ASST. SECR. OR VICE PRESIDENT APPROVED: PRESIDENT - SECR. OR TREAS.

January 29, 1947

Mr. H. C. Davis

Dear Sir:

Under date of December 16, 1946, an ordinance was passed by the City of Sugar Creek which requires us to pay a sum equal to 5% of our gross receipts derived from the sale of electricity used for domestic and commercial consumption. This is intended to mean that we will pay 5% of the revenue derived from the sale of current within the City Limits of Sugar Creek, Missouri less the same exemptions as are now contained in the federal 3 1/3% energy tax. The first payment is due on or before July 31, 1947 and covers a period for the six months beginning January 1, 1947 to June 30, 1947 and a like tax will be paid in July and January each year for the proceeding six months.

Will you please see that the Customer's Accounting Department furnishes us with the gross revenue and the exemptions so that we may pay this tax covered by the ordinance.

Yours very truly,

FPC:vlt

cc: R. O. Linville
C. E. Steele
L. A. Brindley

SCHEDULE 4

SCHEDULE 5

HAS BEEN DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

NP

Bulletin No. 172

1912 to July 1, 2010

The Handy-Whitman Index® of Public Utility Construction Costs™

Trends of Construction Costs

COMPILED & PUBLISHED BY

Whitman, Requardt & Associates, LLP

Engineers, Architects and Planners

801 South Caroline Street

Baltimore, Maryland 21231

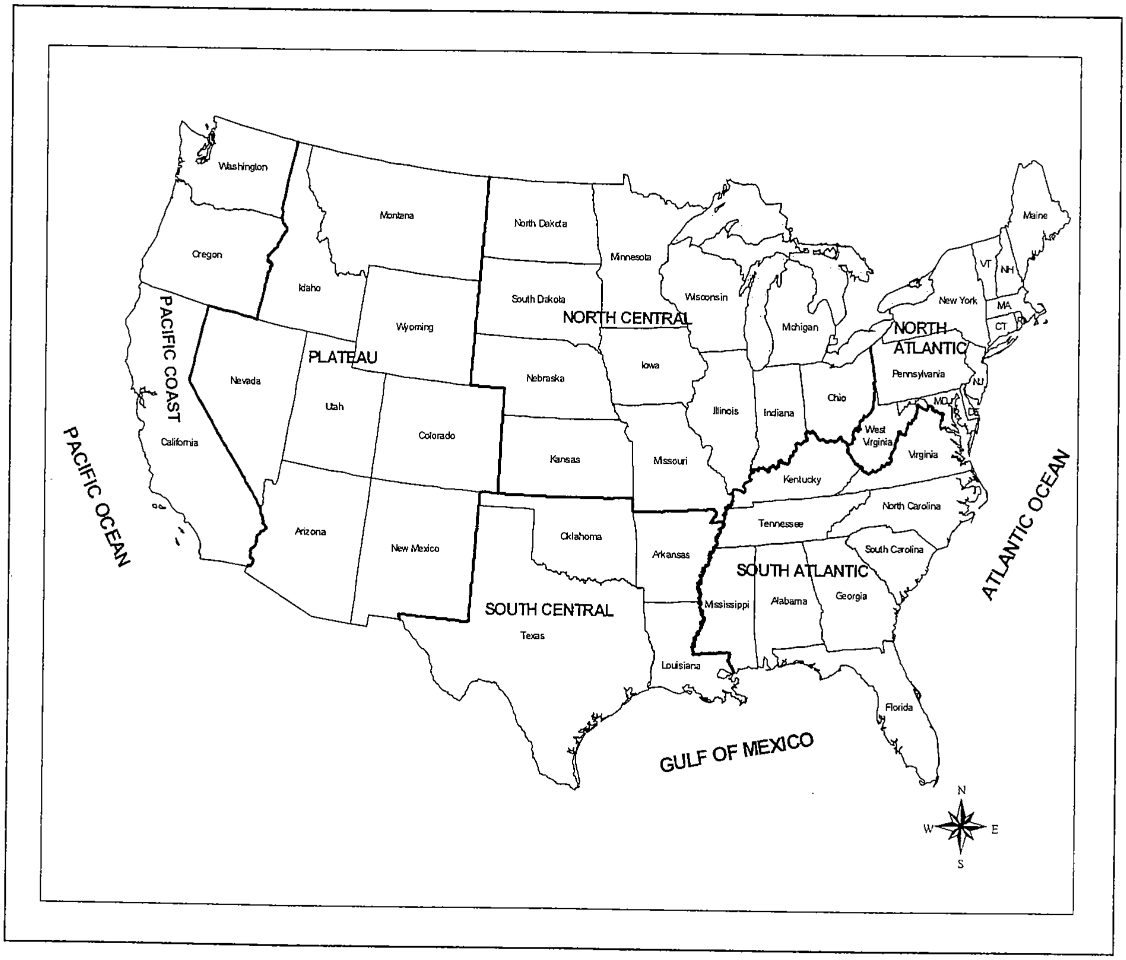
410-235-3450

ISSN 1092-955X

TRENDS OF PUBLIC UTILITY CONSTRUCTION COSTS

TRENDS OF PUBLIC UTILITY CONSTRUCTION COSTS

GEOGRAPHIC REGIONS



SCHEDULE 6 - 4

Tradition of Quality

The Handy-Whitman Index of Public Utility Construction Costs has been published continuously since 1924. Formerly the Handy Index, Bulletin Nos. 1 through 15 were developed by William W. Handy of Baltimore who had wide valuation experience in public utilities. *He believed that valuation studies should not be confined to rate cases but should be kept alive to the benefit of the utility industry.* He began publishing index numbers for electric and gas construction cost trends. Carrying on with the *tradition of quality*, after Mr. Handy=s death, we continued publication for his estate beginning with Bulletin 16. Then, January 1, 1950, Whitman, Requardt and Associates, LLP purchased rights to the publication and have since been the sole publishers.

The name AHandy-Whitman Index@ was adopted for Bulletin No. 53 and succeeding issues to combine the names of Mr. Handy and Ezra B. Whitman, a well-known valuation engineer. In 1957 an index of water utility construction costs was added. Mr. Whitman was a consultant on the publication of the Index until his death in 1963.

Whitman, Requardt and Associates, LLP

Ezra B. Whitman, a well-known valuation engineer was one of the founders of our firm. Major Whitman, as he was known from his World War I service, had already made a name for himself. Prior to the founding of the firm in 1915, Major Whitman had been President and Chief Engineer of the Water Board of the City of Baltimore. He designed the first rapid sand filtration plant serving a major city while he was the Baltimore Water Engineer. He was also president of the American Society of Civil Engineers and of the American Institute of Consulting Engineers and a chairman of the Public Service Commission of Maryland.

The Handy-Whitman Index is prepared especially for electric, gas and water utilities and is the only known publication of its kind available to the public. The list of subscribers is international and includes operating utilities, regulatory bodies, valuation engineers, equipment industries, insurance companies and reference libraries.

Tradition of Quality Continued

Since 1915, Whitman, Requardt and Associates, LLP, has been an independent consulting engineering firm organized to serve government, industry and private enterprise.

The firm has steadily expanded its engineering capabilities, providing complete services for civil, sanitary, structural, mechanical and electrical engineering and architectural projects from job inception through construction management. Construction cost data from utility projects of all types are available from design and valuation assignments. The staff is composed of specialists in these and related disciplines who bring a diverse professional and academic expertise to each assignment. A full-time staff is maintained specifically for preparing the Handy-Whitman Index.

Methods of Preparation of Indexes

An index number is a percentage ratio between the cost of an item at any stated time and its cost at a base period, or:

$$\text{Index Number} = \frac{\text{cost at stated time}}{\text{cost at base period}} \times 100$$

Index numbers have been prepared for many items, including wage rates, cost-of-living, material and equipment costs, and financial transactions. In the Handy-Whitman Index, index numbers have been developed for ABuilding Construction@, AElectric Utility Construction@, AGas Utility Construction@ and AWater Utility Construction@. Prices of basic materials such as cement, sand, gravel, cast iron pipe, wire, etc., are obtained from publications such as Engineering News-Record and checked against prices actually being paid for such materials. Labor cost trends are computed from labor rates obtained from sources such as the Construction Labor Research Council. Prices and cost trends of equipment are obtained from nationally recognized manufacturers, and operating utilities.

Handy-Whitman Index numbers are developed from wage rates and prices prevailing on January 1 and July 1 each year. The index numbers are generally based on 1973 = 100, although those items of recent origin are based on a later year.

The proportions of basic materials, labor, equipment and other cost components used in the Handy-Whitman Index are based on analyses developed during valuation and design assignments and on data furnished by utilities and industrial sources willing to assist with the Index. These data are reviewed continuously, and weightings and components are revised as required. This review assures that the indexes published reflect current construction practice.

Geographic Regions

To reflect differing cost trends throughout the 48 contiguous states, the index has been divided into six geographical regions of similar characteristics. They are shown on the accompanying map.

Use of Index Numbers

Handy-Whitman Index numbers have been widely used to trend earlier valuations and original cost records to estimate reproduction cost at prices prevailing at a certain date. The use of indexes for an appropriate property item or group will provide a reliable guide to changes in cost. Cost trends are given for all the important items of property. The electric and gas groups are arranged by the Federal Energy Regulatory Commission Uniform System of Accounts. The water property accounts are arranged to follow the classification of the National Association of Regulatory Utility Commissioners and the American Water Works Association.

The Handy-Whitman Index will furnish a yardstick for the fluctuations in value of property which will be satisfactory for many purposes. In rate cases, when a more exact determination of value is desired, however, the Index must be used carefully. Average prices and cost trends are used to develop the Index, and any direct application of cost trends without checking with actual local experience may not be accepted without controversy. When local experience is compared with the index and the correlation between the two trends is determined, the result is satisfactory. Costs trended by such a method are used to assist in establishing a rate base.

Indexes in these bulletins are used to trend earlier valuations or original cost records for insurance purposes.

The Handy-Whitman Index has a general application in valuations of all types of property. The building construction cost trends may be used wherever similar items of property are to be compared. Many of the other trends may be used for related items in other industries because of their similarity.

State-of-the-art changes often affect costs independently of inflation. New regulatory and environmental requirements, changes in work rules and improved design standards, for instance, increase construction costs even though the price of wages, materials and equipment may be static. Trended construction costs will not reflect such changes. However, trended costs are a reasonably accurate measure of the cost of reproducing actual plant.

Although every effort is made to maintain accuracy, Whitman, Requardt and Associates, LLP disclaim any responsibility for the use of these indexes, because local conditions may vary.

No guarantee or warranty of any kind is made in the sale of the Handy-Whitman Index. Published numbers are occasionally subject to change based upon receipt of new or different information. These numbers will be bolded.

Further inquiries on electric, gas and water indexes should be addressed to Whitman, Requardt and Associates, LLP.

Total Electric Plant and Function

Three indexes are provided for total plant. The first is for all steam generation and the other two for weighted combinations of steam and nuclear, and steam and hydro generation. Indexes are also provided for each function.

Indexes are not maintained for plant accounts 323,324,325,341,345 and 346. We believe that indexes for comparable accounts in other functions are sufficiently accurate for these accounts.

The indexes for total nuclear production and total other production incorporate comparable indexes from the steam production function for the accounts not listed.

Value of Index Numbers

We believe that present-day reproduction cost of any property can be calculated more accurately using index numbers than by repricing a complete inventory.

Trending the controlling items of property in any utility by the index method saves time and effort in arriving at a valuation. Analyzing and determining cost trends for all of the great numbers of articles of plant that represent only a very small proportion of the value of the utility is not necessary. They may be assumed to follow in general the trend of the controlling items, and the fluctuations in value above or below the trends of the controlling items will tend to offset each other and have a very slight effect on the total value.

Comments on Bulletin No. 172

During the twelve month period ending July 1, 2010 , the average index of all geographical regions for Total Gas Plant increased 4.6% and the comparable index for Electric Plant-All Steam Generation increased 5.2%.

November 2010
Whitman, Requardt and Associates, LLP

E-3

COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

NORTH CENTRAL REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS													
			1912	1913	1914	1915	1916	1917	1918	1919	1920	1921	1922	1923	1924	1925
1	Total Plant-All Steam Generation		11	10	10	11	13	16	18	19	21	20	18	19	19	19
2	Total Plant-All Steam & Nuclear Gen.		-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total Plant-All Steam & Hydro Gen.		-	-	-	11	13	16	19	20	22	20	19	19	20	20
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		9	9	9	9	12	16	18	18	20	19	17	18	19	18
7	Structures & Improvements-Indoor	311	0	0	0	9	12	16	17	18	21	19	18	18	18	18
8	Structures & Improvements-Semi-Outdoor	311	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Boiler Plant Equipment-Coal Fired	312	8	8	8	9	10	16	19	17	18	16	14	16	17	16
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		10	10	10	9	11	18	20	20	19	18	17	18	18	19
12	Turbogenerator Units	314	9	9	9	9	13	14	18	19	22	23	20	19	19	19
13	Accessory Electrical Equipment	315	15	15	15	15	16	18	21	25	27	28	26	26	27	28
14	Misc. Power Plant Equipment	316	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Structures & Improvements	321	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		-	-	-	9	10	13	15	16	18	17	16	16	16	16
23	Structures & Improvements	331	8	8	9	9	12	16	17	18	21	19	18	18	18	18
24	Reservoirs, Dams & Waterways	332	-	-	-	9	10	14	16	17	18	18	17	17	18	18
25	Water Wheels, Turbines & Generators	333	-	-	-	7	9	11	12	13	13	13	12	12	12	12
26																
27	**Other Production Plant**															
28	Total Other Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Fuel Holders, Producers & Accessories	342	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Gas Turbogenerators	344	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																
32	**Transmission Plant**															
33	Total Transmission Plant		11	11	11	11	14	16	19	21	22	21	19	20	21	21
34	Station Equipment	353	16	16	15	16	17	21	25	27	31	31	28	29	30	30
35	Towers & Fixtures	354	8	9	9	9	12	15	16	16	17	16	15	15	16	16
36	Poles & Fixtures	355	6	6	6	7	7	9	9	11	14	14	13	13	14	14
37	Overhead Conductors & Devices	356	17	16	15	16	24	27	30	31	32	23	21	23	24	25
38	Underground Conduit	357	7	7	7	8	8	11	13	14	17	18	17	16	17	16
39	Underground Conductors & Devices	358	13	12	11	12	17	18	21	22	23	19	18	22	21	21
40																
41	**Distribution Plant**															
42	Total Distribution Plant		13	12	12	13	14	17	20	22	24	22	21	21	22	22
43	Station Equipment	362	18	18	18	18	18	22	26	27	31	31	29	30	32	32
44	Poles, Towers & Fixtures	364	6	6	6	7	7	9	11	12	14	14	14	13	14	14
45	Overhead Conductors & Devices	365	13	13	12	13	19	21	24	24	26	19	17	18	19	20
46	Underground Conduit	366	8	8	8	9	9	12	15	16	19	21	19	19	19	19
47	Underground Conductors & Devices	367	13	12	11	12	17	19	22	23	24	20	19	23	22	22
48	Line Transformers	368	43	43	43	43	43	46	62	65	69	70	62	61	62	61
49	Pad Mounted Transformers	368	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Services-Overhead	369	12	11	10	11	16	17	19	20	21	16	14	16	16	17
51	Services-Underground	369	12	12	12	14	16	17	20	22	23	19	16	17	18	19
52	Meters Installed	370	31	31	31	31	31	36	40	44	46	49	46	44	44	43
53	Street Lighting-Overhead	373	-	-	-	-	-	-	-	-	-	-	-	-	22	23
54	Mast Arms & Luminaires Installed	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Street Lighting-Underground	373	-	-	-	-	-	-	-	-	-	-	-	-	23	23
56																

E-3

COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

NORTH CENTRAL REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS													
			1926	1927	1928	1929	1930	1931	1932	1933	1934	1935	1936	1937	1938	1939
1	Total Plant-All Steam Generation		19	19	19	20	19	19	18	18	20	20	20	22	22	22
2	Total Plant-All Steam & Nuclear Gen.		-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total Plant-All Steam & Hydro Gen.		20	19	20	20	20	19	17	18	19	20	20	22	22	23
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		18	18	18	19	19	18	17	17	19	19	20	22	22	22
7	Structures & Improvements-Indoor	311	18	18	17	17	16	16	14	14	16	15	16	17	17	17
8	Structures & Improvements-Semi-Outdoor	311	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Boiler Plant Equipment-Coal Fired	312	16	16	16	16	16	16	14	14	16	16	17	19	19	20
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		19	19	20	20	20	20	18	16	16	16	17	19	19	19
12	Turbogenerator Units	314	19	19	19	21	22	22	21	22	25	26	26	29	30	30
13	Accessory Electrical Equipment	315	28	27	28	30	29	29	28	28	30	30	31	33	33	33
14	Misc. Power Plant Equipment	316	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Structures & Improvements	321	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		16	16	17	17	17	16	14	15	16	16	17	18	18	18
23	Structures & Improvements	331	18	18	17	17	16	16	14	14	16	15	16	17	17	17
24	Reservoirs, Dams & Waterways	332	18	18	18	18	18	17	15	15	16	16	17	18	18	18
25	Water Wheels, Turbines & Generators	333	12	12	13	14	14	14	13	13	14	16	16	17	18	19
26																
27	**Other Production Plant**															
28	Total Other Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Fuel Holders, Producers & Accessories	342	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Gas Turbogenerators	344	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																
32	**Transmission Plant**															
33	Total Transmission Plant		20	20	21	21	20	19	18	19	20	20	21	23	23	23
34	Station Equipment	353	30	30	30	31	30	30	28	30	32	33	33	36	36	36
35	Towers & Fixtures	354	16	15	15	15	15	15	13	13	14	14	16	17	17	17
36	Poles & Fixtures	355	14	13	13	13	14	14	13	12	13	13	14	15	15	15
37	Overhead Conductors & Devices	356	24	23	25	27	23	22	20	21	23	23	23	25	24	24
38	Underground Conduit	357	16	17	17	17	17	17	15	15	16	16	16	17	18	18
39	Underground Conductors & Devices	358	21	20	21	24	19	19	18	19	21	21	22	25	22	22
40																
41	**Distribution Plant**															
42	Total Distribution Plant		21	20	21	22	21	20	19	19	20	20	22	23	23	24
43	Station Equipment	362	30	30	30	31	31	32	30	30	32	33	33	35	36	36
44	Poles, Towers & Fixtures	364	14	13	13	14	14	13	12	12	13	13	14	15	16	16
45	Overhead Conductors & Devices	365	19	19	20	22	19	17	16	16	18	18	19	20	19	19
46	Underground Conduit	366	19	19	19	19	19	19	17	17	18	18	19	19	20	20
47	Underground Conductors & Devices	367	22	21	22	25	20	20	19	20	22	22	23	26	23	23
48	Line Transformers	368	58	53	52	56	55	54	52	53	55	56	56	60	61	61
49	Pad Mounted Transformers	368	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	Services-Overhead	369	16	16	17	19	16	15	14	14	16	16	16	18	17	17
51	Services-Underground	369	19	19	18	19	18	17	16	16	17	17	18	21	19	18
52	Meters Installed	370	43	43	43	43	43	43	43	44	48	48	48	48	48	48
53	Street Lighting-Overhead	373	22	21	22	22	22	22	22	21	23	23	24	25	24	24
54	Mast Arms & Luminaires Installed	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Street Lighting-Underground	373	23	22	23	24	25	25	25	25	25	25	25	26	26	26
56																

E-3

COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

NORTH CENTRAL REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS													
			1940	1941	1942	1943	1944	1945	1946	1947	1948	1949	1950	1951	1952	1953
1	Total Plant-All Steam Generation		22	23	24	24	24	25	28	33	36	38	40	45	46	49
2	Total Plant-All Steam & Nuclear Gen.		-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Total Plant-All Steam & Hydro Gen.		23	24	24	25	25	25	29	34	37	39	40	44	46	49
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		23	24	24	24	24	25	29	32	36	39	40	44	45	47
7	Structures & Improvements-Indoor	311	18	19	20	20	21	22	24	28	32	33	34	37	38	40
8	Structures & Improvements-Semi-Outdoor	311	-	-	-	-	-	-	-	-	-	-	-	38	38	41
9	Boiler Plant Equipment-Coal Fired	312	20	21	22	22	22	22	24	27	32	38	38	41	42	44
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		19	20	21	21	21	21	23	26	29	30	33	36	37	38
12	Turbogenerator Units	314	30	30	30	30	30	31	38	43	45	47	48	52	52	56
13	Accessory Electrical Equipment	315	33	34	34	34	32	32	37	42	44	46	49	57	58	61
14	Misc. Power Plant Equipment	316	-	-	-	-	-	-	-	-	-	37	38	41	43	45
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Structures & Improvements	321	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		19	20	21	21	21	22	25	29	33	34	35	38	40	43
23	Structures & Improvements	331	18	19	20	20	21	22	24	28	32	33	34	37	38	40
24	Reservoirs, Dams & Waterways	332	19	20	21	21	21	22	25	29	32	34	35	38	39	42
25	Water Wheels, Turbines & Generators	333	20	21	22	23	23	23	26	31	34	35	37	41	43	46
26																
27	**Other Production Plant**															
28	Total Other Production Plant		-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Fuel Holders, Producers & Accessories	342	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Gas Turbogenerators	344	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31																
32	**Transmission Plant**															
33	Total Transmission Plant		24	24	25	25	26	26	29	34	38	39	41	46	47	50
34	Station Equipment	353	36	37	38	37	35	35	40	48	50	53	57	64	66	69
35	Towers & Fixtures	354	17	18	19	19	20	21	23	27	29	31	33	36	37	40
36	Poles & Fixtures	355	16	17	18	19	21	22	24	29	32	32	34	37	38	41
37	Overhead Conductors & Devices	356	24	25	26	26	26	27	32	37	40	40	42	46	49	52
38	Underground Conduit	357	18	18	19	20	20	22	24	27	31	32	34	36	38	41
39	Underground Conductors & Devices	358	23	26	27	27	26	26	31	36	43	47	51	62	64	64
40																
41	**Distribution Plant**															
42	Total Distribution Plant		24	25	26	26	26	27	30	36	39	40	41	45	47	50
43	Station Equipment	362	36	37	37	37	35	36	40	45	47	49	52	57	59	62
44	Poles, Towers & Fixtures	364	16	18	18	19	21	23	24	29	32	32	34	36	38	40
45	Overhead Conductors & Devices	365	19	19	21	21	21	22	25	29	31	31	33	37	39	41
46	Underground Conduit	366	20	21	22	22	22	23	26	29	33	34	36	38	40	41
47	Underground Conductors & Devices	367	24	27	28	28	27	27	32	38	45	50	53	66	68	67
48	Line Transformers	368	61	63	63	59	59	59	66	82	85	87	92	103	104	110
49	Pad Mounted Transformers	368	-	-	-	-	-	-	-	-	-	103	103	103	103	103
50	Services-Overhead	369	17	17	18	19	19	19	22	26	28	28	30	35	37	39
51	Services-Underground	369	20	23	23	24	24	24	27	31	35	36	38	44	43	43
52	Meters Installed	370	48	49	49	49	49	49	55	62	65	71	71	71	70	73
53	Street Lighting-Overhead	373	24	26	26	26	26	26	29	36	39	42	44	49	50	51
54	Mast Arms & Luminaires Installed	373	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Street Lighting-Underground	373	26	27	28	28	29	29	31	38	42	42	42	46	47	47
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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

NORTH CENTRAL REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS													
			1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967
1	Total Plant-All Steam Generation		50	52	56	60	61	62	62	61	61	61	63	65	66	69
2	Total Plant-All Steam & Nuclear Gen.		-	-	-	-	-	-	-	-	-	-	-	64	66	69
3	Total Plant-All Steam & Hydro Gen.		50	51	56	59	61	62	61	61	61	61	62	64	66	69
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		49	51	57	62	65	66	65	63	63	63	65	66	68	70
7	Structures & Improvements-Indoor	311	42	44	47	50	51	53	54	54	54	55	56	58	60	62
8	Structures & Improvements-Semi-Outdoor	311	42	44	50	55	56	57	57	56	56	57	58	59	61	62
9	Boiler Plant Equipment-Coal Fired	312	46	48	54	60	62	64	65	64	65	65	66	68	69	71
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		41	43	48	53	54	57	60	60	60	61	62	63	65	68
12	Turbogenerator Units	314	57	59	68	76	81	80	75	70	68	68	69	70	71	73
13	Accessory Electrical Equipment	315	62	64	67	71	73	74	68	60	61	59	62	66	67	72
14	Misc. Power Plant Equipment	316	46	48	51	54	55	58	58	59	60	61	62	64	65	68
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		-	-	-	-	-	-	-	-	-	-	-	66	67	70
18	Structures & Improvements	321	-	-	-	-	-	-	-	-	-	-	-	62	64	66
19	Reactor Plant Equipment	322	-	-	-	-	-	-	-	-	-	-	-	66	68	71
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		44	46	50	53	55	57	58	58	59	60	61	62	64	67
23	Structures & Improvements	331	42	44	47	50	51	53	54	54	54	55	56	58	60	62
24	Reservoirs, Dams & Waterways	332	43	45	48	51	52	54	56	56	57	58	60	62	64	67
25	Water Wheels, Turbines & Generators	333	47	49	56	62	65	66	66	65	64	65	66	67	69	71
26																
27	**Other Production Plant**															
28	Total Other Production Plant		-	-	-	-	-	-	-	-	-	-	72	73	75	83
29	Fuel Holders, Producers & Accessories	342	-	-	-	-	-	-	-	-	-	-	61	62	64	66
30	Gas Turbogenerators	344	-	-	-	-	-	-	-	-	-	-	74	74	77	85
31																
32	**Transmission Plant**															
33	Total Transmission Plant		51	53	57	58	60	60	60	58	58	58	60	63	66	69
34	Station Equipment	353	71	72	78	82	86	84	78	70	69	65	69	72	75	79
35	Towers & Fixtures	354	41	42	45	47	49	51	52	53	54	55	57	60	63	66
36	Poles & Fixtures	355	42	43	46	49	50	50	52	53	54	55	56	58	60	63
37	Overhead Conductors & Devices	356	53	57	62	65	64	62	63	63	65	60	64	66	69	71
38	Underground Conduit	357	42	43	46	48	50	51	53	54	55	57	58	60	62	64
39	Underground Conductors & Devices	358	65	69	67	59	58	61	62	61	61	62	66	71	72	74
40																
41	**Distribution Plant**															
42	Total Distribution Plant		51	52	55	57	57	59	59	59	59	59	61	63	65	68
43	Station Equipment	362	64	66	72	76	78	79	77	71	72	70	72	73	75	78
44	Poles, Towers & Fixtures	364	41	42	45	48	49	49	51	52	53	54	55	57	59	61
45	Overhead Conductors & Devices	365	42	46	50	49	49	50	51	52	54	54	56	59	61	65
46	Underground Conduit	366	43	45	47	49	51	52	54	56	57	59	60	61	62	64
47	Underground Conductors & Devices	367	69	72	71	62	61	64	65	64	64	65	70	75	76	78
48	Line Transformers	368	112	112	115	122	119	114	113	109	100	93	93	95	96	100
49	Pad Mounted Transformers	368	103	103	103	103	103	103	101	96	95	96	92	91	94	97
50	Services-Overhead	369	40	43	46	44	44	46	48	49	50	50	52	55	57	61
51	Services-Underground	369	44	44	46	45	43	44	42	43	45	46	48	52	56	59
52	Meters Installed	370	75	72	75	79	81	83	84	83	83	83	83	83	83	84
53	Street Lighting-Overhead	373	54	55	58	62	66	65	65	65	65	66	67	67	69	73
54	Mast Arms & Luminaires Installed	373	-	59	65	71	72	67	68	67	66	67	68	69	73	72
55	Street Lighting-Underground	373	52	54	55	59	62	62	63	62	61	62	62	62	67	75
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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

NORTH CENTRAL REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS													
			1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
1	Total Plant-All Steam Generation		72	77	83	90	94	100	119	138	146	156	166	181	198	216
2	Total Plant-All Steam & Nuclear Gen.		71	77	83	90	95	100	119	138	145	155	165	181	197	215
3	Total Plant-All Steam & Hydro Gen.		72	77	84	90	95	100	119	138	146	156	165	181	198	215
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		72	76	81	89	95	100	118	136	145	155	168	186	203	221
7	Structures & Improvements-Indoor	311	66	71	77	86	92	100	117	129	133	141	155	169	184	197
8	Structures & Improvements-Semi-Outdoor	311	65	71	76	86	92	100	123	138	138	142	156	173	193	201
9	Boiler Plant Equipment-Coal Fired	312	74	77	82	89	95	100	120	141	151	161	176	193	211	230
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		70	73	80	89	96	100	113	125	135	145	162	180	195	212
12	Turbogenerator Units	314	73	75	81	90	98	100	110	128	140	154	165	183	199	220
13	Accessory Electrical Equipment	315	76	82	88	93	97	100	116	135	143	158	166	179	194	216
14	Misc. Power Plant Equipment	316	72	77	83	89	94	100	114	127	135	148	160	176	192	215
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		72	77	83	90	95	100	114	128	137	147	159	174	190	208
18	Structures & Improvements	321	69	74	81	89	94	100	114	125	130	138	150	165	180	193
19	Reactor Plant Equipment	322	73	78	84	91	95	100	114	129	139	147	159	173	190	208
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		70	75	80	87	94	100	116	130	135	143	156	173	191	206
23	Structures & Improvements	331	66	71	77	86	92	100	117	129	133	141	155	169	184	197
24	Reservoirs, Dams & Waterways	332	70	75	80	87	93	100	117	129	131	137	150	167	185	196
25	Water Wheels, Turbines & Generators	333	73	78	83	89	95	100	114	129	142	157	171	189	208	233
26																
27	**Other Production Plant**															
28	Total Other Production Plant		87	90	94	98	99	100	107	132	146	161	166	180	193	212
29	Fuel Holders, Producers & Accessories	342	69	75	82	89	95	100	114	129	139	150	166	182	198	215
30	Gas Turbogenerators	344	89	92	95	98	100	100	107	132	147	162	168	181	194	213
31																
32	**Transmission Plant**															
33	Total Transmission Plant		72	78	85	91	94	100	122	143	150	160	166	180	198	216
34	Station Equipment	353	82	86	90	92	94	100	125	148	152	164	175	189	205	222
35	Towers & Fixtures	354	69	76	81	87	93	100	122	140	140	145	159	176	196	204
36	Poles & Fixtures	355	65	71	78	83	87	100	126	143	143	149	158	174	190	210
37	Overhead Conductors & Devices	356	72	81	91	100	99	100	118	146	167	180	172	184	207	232
38	Underground Conduit	357	68	73	80	91	97	100	111	122	131	141	153	166	178	194
39	Underground Conductors & Devices	358	72	79	84	83	92	100	135	136	138	151	151	180	216	237
40																
41	**Distribution Plant**															
42	Total Distribution Plant		71	78	85	91	95	100	119	138	144	154	162	178	191	211
43	Station Equipment	362	81	87	91	92	94	100	122	141	145	160	171	181	195	213
44	Poles, Towers & Fixtures	364	64	70	78	84	89	100	124	142	142	150	161	181	197	216
45	Overhead Conductors & Devices	365	69	79	89	98	99	100	116	143	161	174	170	182	201	220
46	Underground Conduit	366	67	74	81	88	93	100	111	121	126	136	148	161	172	185
47	Underground Conductors & Devices	367	76	83	88	88	99	100	125	129	133	142	151	185	209	214
48	Line Transformers	368	103	101	102	102	100	100	109	130	134	145	155	164	164	192
49	Pad Mounted Transformers	368	99	97	97	99	100	100	104	105	107	118	131	138	159	187
50	Services-Overhead	369	65	75	87	94	97	100	108	119	127	139	150	163	181	195
51	Services-Underground	369	64	72	78	81	88	100	115	108	111	118	126	137	162	181
52	Meters Installed	370	87	91	95	100	101	100	108	124	133	140	144	148	146	163
53	Street Lighting-Overhead	373	75	82	90	94	98	100	122	148	156	169	185	205	224	245
54	Mast Arms & Luminaires Installed	373	73	78	92	96	98	100	117	138	151	168	183	200	222	250
55	Street Lighting-Underground	373	71	77	90	96	99	100	120	148	158	171	188	209	226	245
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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

NORTH CENTRAL REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS													
			1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
1	Total Plant-All Steam Generation		229	235	241	246	249	254	272	284	293	297	302	311	324	336
2	Total Plant-All Steam & Nuclear Gen.		228	235	241	246	249	254	272	284	293	296	301	310	323	335
3	Total Plant-All Steam & Hydro Gen.		227	234	241	246	249	254	272	284	292	296	301	310	323	335
4																
5	**Steam Production Plant**															
6	Total Steam Production Plant		231	239	248	255	259	266	283	294	303	306	312	323	337	348
7	Structures & Improvements-Indoor	311	204	212	221	228	234	240	251	261	264	264	270	281	295	304
8	Structures & Improvements-Semi-Outdoor	311	200	205	218	227	233	241	252	260	262	254	256	270	287	297
9	Boiler Plant Equipment-Coal Fired	312	242	248	258	266	270	280	297	309	323	330	337	347	359	369
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		229	226	230	234	237	249	272	280	281	285	288	293	301	311
12	Turbogenerator Units	314	234	247	255	258	257	263	280	289	295	300	305	315	331	343
13	Accessory Electrical Equipment	315	243	251	247	249	254	256	288	302	312	318	330	341	351	368
14	Misc. Power Plant Equipment	316	235	246	255	267	272	280	293	305	314	319	326	338	356	366
15																
16	**Nuclear Production Plant**															
17	Total Nuclear Production Plant		223	231	237	242	245	254	268	279	285	289	295	304	317	327
18	Structures & Improvements	321	203	210	217	222	225	232	240	246	251	253	260	271	285	292
19	Reactor Plant Equipment	322	223	231	237	242	246	258	272	285	292	296	301	309	318	329
20																
21	**Hydro Production Plant**															
22	Total Hydraulic Production Plant		214	222	230	237	242	249	260	266	270	272	276	287	298	307
23	Structures & Improvements	331	204	212	221	228	234	240	251	261	264	264	270	281	295	304
24	Reservoirs, Dams & Waterways	332	202	209	217	223	230	237	245	249	251	251	256	267	279	286
25	Water Wheels, Turbines & Generators	333	247	257	266	272	273	278	297	310	317	329	329	337	346	356
26																
27	**Other Production Plant**															
28	Total Other Production Plant		229	235	238	241	245	264	309	333	341	346	354	359	351	355
29	Fuel Holders, Producers & Accessories	342	230	230	235	242	248	257	272	285	293	298	302	309	316	324
30	Gas Turbogenerators	344	230	236	239	242	246	267	315	341	348	354	362	366	355	359
31																
32	**Transmission Plant**															
33	Total Transmission Plant		231	237	239	243	246	249	275	289	300	306	309	319	335	351
34	Station Equipment	353	236	237	241	245	247	255	267	282	299	301	310	321	337	350
35	Towers & Fixtures	354	208	214	227	236	243	251	261	268	271	265	269	281	298	309
36	Poles & Fixtures	355	223	228	234	237	243	247	267	286	298	318	335	342	363	376
37	Overhead Conductors & Devices	356	259	279	268	267	270	259	344	354	356	366	344	355	370	404
38	Underground Conduit	357	210	217	223	227	231	238	252	263	265	265	269	276	286	293
39	Underground Conductors & Devices	358	250	253	249	242	267	271	284	307	360	403	412	416	420	431
40																
41	**Distribution Plant**															
42	Total Distribution Plant		224	229	232	235	238	240	255	268	276	280	283	289	298	309
43	Station Equipment	362	234	236	235	239	242	250	275	299	320	322	322	325	336	355
44	Poles, Towers & Fixtures	364	228	232	236	240	245	248	257	265	275	286	301	310	330	344
45	Overhead Conductors & Devices	365	231	244	246	247	249	248	293	304	306	313	305	316	330	355
46	Underground Conduit	366	197	210	218	221	225	232	249	269	268	262	264	271	284	292
47	Underground Conductors & Devices	367	211	213	212	218	229	234	239	255	266	272	275	278	281	293
48	Line Transformers	368	207	210	212	214	215	214	216	225	228	228	232	233	238	234
49	Pad Mounted Transformers	368	186	188	205	207	215	238	262	276	282	291	291	298	300	302
50	Services-Overhead	369	205	210	224	223	225	231	250	264	265	267	266	273	284	299
51	Services-Underground	369	181	199	203	187	181	194	208	224	227	218	216	216	225	233
52	Meters Installed	370	190	203	204	206	211	211	198	188	189	203	202	205	195	192
53	Street Lighting-Overhead	373	261	262	273	283	283	271	274	284	292	302	313	326	342	358
54	Mast Arms & Luminaires Installed	373	263	268	286	298	290	280	281	296	306	318	331	340	360	373
55	Street Lighting-Underground	373	265	265	275	285	287	273	276	284	293	302	312	326	340	356
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COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

NORTH CENTRAL REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS												
								2001		2002		2003		2004	
			1996	1997	1998	1999	2000	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1
1	Total Plant-All Steam Generation		342	349	355	360	372	381	390	395	402	411	410	418	434
2	Total Plant-All Steam & Nuclear Gen.		341	348	354	359	371	380	389	393	401	409	409	417	433
3	Total Plant-All Steam & Hydro Gen.		341	348	354	359	371	380	389	393	401	409	409	417	433
4															
5	**Steam Production Plant**														
6	Total Steam Production Plant		357	365	371	379	394	404	414	417	428	438	436	446	456
7	Structures & Improvements-Indoor	311	311	318	323	333	347	357	371	371	383	389	386	398	413
8	Structures & Improvements-Semi-Outdoor	311	308	315	319	328	343	348	358	360	364	369	369	396	404
9	Boiler Plant Equipment-Coal Fired	312	377	385	392	400	415	426	440	442	453	458	454	459	475
10	Boiler Plant Equipment-Gas Fired	312	-		-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		318	325	329	336	342	350	359	360	367	373	370	381	394
12	Turbogenerator Units	314	349	361	367	371	388	396	394	400	410	433	434	438	441
13	Accessory Electrical Equipment	315	379	388	395	405	427	446	463	472	493	505	504	513	522
14	Misc. Power Plant Equipment	316	372	383	390	402	418	427	439	441	452	457	453	465	479
15															
16	**Nuclear Production Plant**														
17	Total Nuclear Production Plant		333	342	347	353	366	374	382	386	395	404	405	410	422
18	Structures & Improvements	321	300	309	312	319	332	338	353	354	364	370	367	378	388
19	Reactor Plant Equipment	322	334	340	345	351	361	368	376	379	387	391	393	396	413
20															
21	**Hydro Production Plant**														
22	Total Hydraulic Production Plant		315	324	329	336	346	350	356	357	363	367	368	382	384
23	Structures & Improvements	331	311	318	323	333	347	357	371	371	383	389	386	398	413
24	Reservoirs, Dams & Waterways	332	295	303	307	316	325	328	338	337	346	348	348	364	370
25	Water Wheels, Turbines & Generators	333	363	375	382	383	394	398	385	395	390	396	402	410	393
26															
27	**Other Production Plant**														
28	Total Other Production Plant		368	373	385	398	421	441	412	417	429	436	439	430	437
29	Fuel Holders, Producers & Accessories	342	334	343	351	359	366	373	382	383	392	397	397	402	427
30	Gas Turbogenerators	344	372	377	389	403	404	402	413	418	430	437	439	428	434
31															
32	**Transmission Plant**														
33	Total Transmission Plant		357	364	372	371	383	396	406	410	413	418	417	427	454
34	Station Equipment	353	352	357	367	372	388	401	414	417	423	428	424	427	466
35	Towers & Fixtures	354	320	328	335	345	359	366	372	381	382	389	390	417	424
36	Poles & Fixtures	355	392	406	410	402	405	412	427	432	436	442	444	453	457
37	Overhead Conductors & Devices	356	410	415	428	404	411	438	448	451	442	447	448	455	487
38	Underground Conduit	357	299	306	316	327	332	338	350	354	367	377	376	388	404
39	Underground Conductors & Devices	358	437	442	444	450	453	464	447	451	460	467	469	473	523
40															
41	**Distribution Plant**														
42	Total Distribution Plant		313	318	324	326	332	339	346	352	359	367	369	373	391
43	Station Equipment	362	353	359	373	376	380	383	387	388	383	387	386	391	441
44	Poles, Towers & Fixtures	364	354	364	367	371	378	384	395	399	411	419	423	425	434
45	Overhead Conductors & Devices	365	363	370	379	373	386	404	416	422	427	439	442	449	468
46	Underground Conduit	366	298	306	313	323	336	342	352	356	374	383	380	393	395
47	Underground Conductors & Devices	367	300	303	307	313	320	330	319	324	329	333	335	337	354
48	Line Transformers	368	230	221	225	228	227	230	237	241	247	248	253	244	264
49	Pad Mounted Transformers	368	315	320	322	324	327	328	350	351	362	359	359	387	457
50	Services-Overhead	369	302	306	312	314	323	330	338	344	349	362	362	371	378
51	Services-Underground	369	233	236	233	231	241	247	246	249	260	264	264	268	269
52	Meters Installed	370	196	211	217	213	207	216	235	256	270	282	282	319	319
53	Street Lighting-Overhead	373	377	387	389	393	401	407	416	423	442	467	471	474	480
54	Mast Arms & Luminaires Installed	373	398	408	406	405	410	417	421	427	433	438	444	447	453
55	Street Lighting-Underground	373	374	384	388	394	402	409	419	426	450	481	484	488	492
56															

COST TRENDS OF ELECTRIC UTILITY CONSTRUCTION

NORTH CENTRAL REGION (1973=100)

entered 2011
dated 12-16-10

Line	CONSTRUCTION AND EQUIPMENT	FERC	2005 Jan. 1	2005 Jul. 1	2006 Jan. 1	2006 Jul. 1	2007 Jan. 1	2007 Jul. 1	2008 Jan. 1	2008 Jul. 1	2009 Jan. 1	2009 Jul. 1	2010 Jan. 1	2010 Jul. 1
1	Total Plant-All Steam Generation		453	460	481	495	518	529	561	580	585	564	579	587
2	Total Plant-All Steam & Nuclear Gen.		452	459	480	494	517	527	559	578	583	561	577	585
3	Total Plant-All Steam & Hydro Gen.		452	459	479	493	516	527	559	578	583	561	577	585
4														
5	**Steam Production Plant**													
6	Total Steam Production Plant		477	481	495	503	520	531	547	576	570	554	566	577
7	Structures & Improvements-Indoor	311	435	438	451	458	474	482	501	530	532	518	528	535
8	Structures & Improvements-Semi-Outdoor	311	418	425	438	445	457	483	501	513	514	490	495	498
9	Boiler Plant Equipment-Coal Fired	312	495	499	514	521	534	543	557	585	591	577	589	597
10	Boiler Plant Equipment-Gas Fired	312	-	-	-	-	-	-	-	-	-	-	-	-
11	Boiler Plant Piping Installed		439	443	460	465	477	475	491	530	545	529	538	550
12	Turbogenerator Units	314	464	461	471	483	499	501	513	559	514	489	502	525
13	Accessory Electrical Equipment	315	562	572	596	616	661	682	719	744	774	793	812	828
14	Misc. Power Plant Equipment	316	511	513	531	538	540	544	555	593	595	587	597	603
15														
16	**Nuclear Production Plant**													
17	Total Nuclear Production Plant		447	449	462	471	486	489	502	530	521	510	521	532
18	Structures & Improvements	321	406	410	420	427	438	433	447	462	462	455	461	466
19	Reactor Plant Equipment	322	439	441	455	463	476	480	489	518	512	502	513	521
20														
21	**Hydro Production Plant**													
22	Total Hydraulic Production Plant		397	400	410	417	432	442	454	471	469	461	467	475
23	Structures & Improvements	331	435	438	451	458	474	482	501	530	532	518	528	535
24	Reservoirs, Dams & Waterways	332	384	388	399	404	417	428	439	446	447	441	445	449
25	Water Wheels, Turbines & Generators	333	399	397	406	416	436	444	455	493	481	469	478	496
26														
27	**Other Production Plant**													
28	Total Other Production Plant		428	435	445	456	516	529	582	603	620	655	675	688
29	Fuel Holders, Producers & Accessories	342	454	460	469	478	494	497	512	548	554	537	541	540
30	Gas Turbogenerators	344	420	427	435	447	511	524	581	602	619	659	680	693
31														
32	**Transmission Plant**													
33	Total Transmission Plant		471	485	512	528	553	568	603	631	640	591	617	619
34	Station Equipment	353	483	495	517	533	567	583	604	627	640	641	658	665
35	Towers & Fixtures	354	436	439	454	457	468	494	513	515	523	500	506	506
36	Poles & Fixtures	355	476	493	502	515	526	529	561	570	583	587	596	574
37	Overhead Conductors & Devices	356	511	542	605	643	678	695	753	828	831	580	669	677
38	Underground Conduit	357	436	436	454	458	477	472	494	527	536	519	520	526
39	Underground Conductors & Devices	358	529	547	590	594	605	610	790	828	829	840	836	828
40														
41	**Distribution Plant**													
42	Total Distribution Plant		408	417	446	466	499	507	563	562	581	567	583	591
43	Station Equipment	362	457	464	492	503	537	555	573	595	606	608	629	637
44	Poles, Towers & Fixtures	364	453	457	470	480	496	497	511	525	537	538	547	545
45	Overhead Conductors & Devices	365	489	512	555	579	609	624	670	715	725	612	666	679
46	Underground Conduit	366	420	422	449	451	471	468	487	495	509	507	501	504
47	Underground Conductors & Devices	367	382	393	423	428	507	514	554	586	647	639	593	600
48	Line Transformers	368	275	283	320	361	408	416	602	506	532	555	581	606
49	Pad Mounted Transformers	368	492	541	562	653	689	820	642	759	728	665	668	646
50	Services-Overhead	369	395	402	428	428	451	452	475	485	491	457	477	484
51	Services-Underground	369	279	292	335	372	356	352	349	350	325	327	328	350
52	Meters Installed	370	306	306	310	316	319	326	330	332	334	334	346	347
53	Street Lighting-Overhead	373	499	508	526	594	617	627	641	672	738	751	771	719
54	Mast Arms & Luminaires Installed	373	482	496	524	555	574	585	576	587	709	705	714	728
55	Street Lighting-Underground	373	510	517	535	615	640	651	671	708	766	784	809	735
56														

Settlement of all Non-wage Maintenance Issues for Kansas City Power & Light Case No. ER-2009-0089 and KCPL Greater Missouri Operations Case No. ER-2009-0090

(non-KCPL labor, dollars are total company except where noted)

KCP&L

Production (excluding Wolf Creek)

Production maintenance expense, excluding Wolf Creek, will be based on 2008 actual expense of $31,150,277 per Data Request 178R, with no addition at true-up for Iatan 1 AQC. This amount is made up of FERC accounts 510, 511, 512, 513 and 514 of $29,753,040 and FERC accounts 551, 552, 553 and 554 of $1,397,237.

Production - Wolf Creek (excluding amortization of refueling outage costs determined to be above "normal outage levels")

Wolf Creek production maintenance expense will be based on unadjusted 2007 actual expense of $10,386,698 including $7,378,432 for test year amortization of Outage #15 costs but before consideration of Outage #16 costs identified as being above "normal outage levels" addressed as a separate issue below.

Transmission & Distribution

Transmission and Distribution maintenance expense will be based on 2008 actual expense of $17,365,704 (transmission- $1,920,763 and distribution- $15,444,941) per Data Request 178R plus an additional $3,100,000 (Missouri jurisdictional) for incremental costs related to the new Vegetation Management regulations. Infrastructure and Reliability Reporting effects will be deferred for consideration in the next rate case.

KCPL agrees to maintain reasonable and adequate records to separately identify the costs to implement the vegetation management costs between Missouri and Kansas using FERC accounts 593000 (distribution) and 571005-006 (transmission), department 252. Similar segregation of costs will occur for the infrastructure (inspection) costs, involving many different FERC accounts.

KCPL agrees not to request a Vegetation Management tracker mechanism in this case.

IT Maintenance

IT maintenance will be based on 2008 actual expense of $3,132,762.

Wolf Creek Refueling O&M Costs

The Missouri jurisdictional portion of Wolf Creek Outage #16 refueling O&M costs considered to be above "normal outage levels" ($1,570,581) will be set up in a regulatory asset and amortized over five years beginning with the effective date of new rates in this case, with one-fifth of this cost included in cost of service in this case.

GMO

Maintenance expense in this case will be based on the 12 months ending December 2008 for production, distribution and transmission maintenance expense. The amounts using this method for MPS are: production- $14,695,784; transmission- $1,782,445; and distribution- $10,238,425, for a total of $26,716,654. For SJLP the amounts are: production- $6,232,522; transmission- $617,729 and distribution- $2,194,658 for total of $9,044,909. GMO is not requesting any additional funds for the new Vegetation Management, Infrastructure or Reliability Reporting regulations in this case.

GMO agrees to maintain reasonable and adequate records to separately identify the costs to implement the vegetation management costs between Missouri and Kansas using FERC accounts 593000 (distribution) and 571005-006 (transmission), departments 752 (MPS) and 952 (SJLP). Similar segregation of costs will occur for the infrastructure (inspection) costs, involving many different FERC accounts.

GMO agrees not to request a Vegetation Management tracker mechanism in this case.

SCHEDULE 8

HAS BEEN DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

NP

Kansas City Power & Light Company
File No. ER-2010-0355

Total Purchased Power Expense for Haw 5 Catalyst outage (2/24/07-3/9/07) **$ 2,305,700.00**

Replacement power studies serve as the source for this information. These studies import a "base case" output file from PACE. "Base case" references actual conditions on our system (load, generation, purchases and sales). The output file is modified to consider a scenario where a particular unit is available (in this case Haw5).

SCHEDULE 9 - 1

Kansas City Power & Light Company
File No. ER-2010-0355

HAWTHORN 5 REPLACEMENT COST SUMMARY - 2007
Daily Summary for Month of Feb

Feb07H5	Unit Off				Unit On						Net Difference				Total Replace
	Total Gen		Total Purchase		CT's Rep	H5 Add	Total Gen		Total Purchase		Increased Generation		Reduced Purchases		Costs
Date	MWh	$	MWH	$	MWh	MWh	MWh	$	MWH	$	MWh	$	MWh	$	$
Feb0107.															
Feb0207.															
Feb0307.															
Feb0407.															
Feb0507.															
Feb0607.															
Feb0707.															
Feb0807.															
Feb0907.															
Feb1007.															
Feb1107.															
Feb1207.															
Feb1307.															
Feb1407.															
Feb1507.															
Feb1607.															
Feb1707.															
Feb1807.															
Feb1907.															
Feb2007.															
Feb2107.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Feb2207.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Feb2307.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Feb2407.	44,423	$ 593,950	3,130	$ 201,840		2,886	47,309	$ 554,840	244	$ (4,690)	2,886	$ (39,110)	(2,886)	$ (206,530.00)	$ 245,640
Feb2507.	44,392	$ 544,810	3,316	$ 144,520		3,182	47,574	$ 555,260	134	$ (6,720)	3,182	$ 10,450	(3,182)	$ (151,240.00)	$ 140,790
Feb2607.	48,506	$ 601,600	2,114	$ 136,360		2,109	50,615	$ 524,650	5	$ (110)	2,109	$ (76,950)	(2,109)	$ (136,470.00)	$ 213,420
Feb2707.	49,155	$ 602,420	1,558	$ 62,710		1,110	50,265	$ 520,470	448	$ (28,770)	1,110	$ (81,950)	(1,110)	$ (91,480.00)	$ 173,430
Feb2807.	49,213	$ 555,850	753	$ 17,820		736	49,949	$ 517,130	17	$ (10)	736	$ (38,720)	(736)	$ (17,830.00)	$ 56,550
	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Total	**235,689**	**$ 2,898,630**	**10,871**	**$ 563,250**	**0**	**10,023**	**245,712**	**$ 2,672,350**	**848**	**$ (40,300)**	**10,023**	**$ (226,280)**	**(10,023)**	**$ (603,550)**	**$ 829,830**

Total Replacement Cost $ 829,830

Notes:

1) Production calculations based on daily WindowCouger unit commitment runs.
   For the Units Off case, the model runs a fixed dispatch for the day as it occurred; Generation, Load, Sales and purchases are all as they actually occurred for the day.
   For the Units On case, the model is made to run H5 at max of 560 MW, L-1 at 350 MW, L-2 at 340 MW, M-1 at 160 MW, M-2 at 170 MW, M-3 at 179 MW, I-1 at 469 MW x 24 hrs per day,
   commit and dispatch generating units, dispatch purchases (use as needed), and keep load and sales as they occurred in the base case (unless higher capacity is demonstrated).
2) The production cost runs do not evaluate any potential lost interchange sales.
3) Runs can be reproduced; Files are in e:\pub\couger\2005\mmmddyy.inp
4) LaCygne 1 Add MWH represents the additional generation that could have been produced had the unit been available.

SCHEDULE 9 - 2

SCHEDULE 9 - 2

Kansas City Power & Light Company
File No. ER-2010-0355

HAWTHORN 5 REPLACEMENT COST SUMMARY - 2007
Daily Summary for Month of Mar

Mar07H5	Unit Off				Unit On						Net Difference				Total Replace Costs
	Total Gen		Total Purchase		CT's Rep	H5 Add	Total Gen		Total Purchase		Increased Generation		Reduced Purchases		
Date	MWh	$	MWH	$	MWh	MWh	MWh	$	MWH	$	MWh	$	MWh	$	$
Mar0107.	48,495	$ 545,630	3,617	$ 183,740		3,428	51,923	$ 532,480	189	$ (3,190)	3,428	$ (13,150)	(3,428)	$ (186,930.00)	$ 200,080
Mar0207.	49,880	$ 537,480	2,445	$ 127,690		2,168	52,048	$ 532,940	277	$ (3,010)	2,168	$ (4,540)	(2,168)	$ (130,700.00)	$ 135,240
Mar0307.	51,579	$ 532,580	1,045	$ 60,930		1,045	52,624	$ 523,630	-	$ -	1,045	$ (8,950)	(1,045)	$ (60,930.00)	$ 69,880
Mar0407.	50,263	$ 525,840	397	$ 25,010		397	50,660	$ 518,080	-	$ -	397	$ (7,760)	(397)	$ (25,010.00)	$ 32,770
Mar0507.	43,160	$ 554,740	4,311	$ 264,450		4,311	47,471	$ 476,010	-	$ -	4,311	$ (78,730)	(4,311)	$ (264,450.00)	$ 343,180
Mar0607.	41,353	$ 580,950	4,681	$ 322,010		4,681	46,034	$ 448,640	-	$ -	4,681	$ (132,310)	(4,681)	$ (322,010.00)	$ 454,320
Mar0707.	40,143	$ 449,720	5,433	$ 373,190		1,210	41,353	$ 580,950	4,681	$ 322,010	1,210	$ 131,230	(752)	$ (51,180.00)	$ (80,050)
Mar0807.	41,644	$ 499,190	5,444	$ 365,060		5,444	47,088	$ 551,100	-	$ -	5,444	$ 51,910	(5,444)	$ (365,060.00)	$ 313,150
Mar0907.	43,447	$ 518,390	5,708	$ 300,240		5,617	49,064	$ 504,060	91	$ 4,360	5,617	$ (14,330)	(5,617)	$ (295,880.00)	$ 310,210
Mar1007.															
Mar1107.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar1207.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar1307.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar1407.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar1507.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar1607.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar1707.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar1807.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar1907.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar2007.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar2107.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar2207.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar2307.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar2407.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar2507.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar2607.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar2707.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar2807.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar2907.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar3007.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Mar3107.	-	$ -	-	$ -		-	-	$ -	-	$ -	-	$ -	-	$ -	$ -
Total	**409,964**	**$ 4,744,520**	**33,081**	**$ 2,022,320**	**0**	**28,301**	**438,265**	**$ 4,667,890**	**5,238**	**$ 320,170**	**28,301**	**$ (76,630)**	**(27,843)**	**$ (1,702,150)**	**$ 1,778,780**

Total Replacement Cost $ 1,778,780

Notes:

1) Production calculations based on daily WindowCouger unit commitment runs.
   For the Units Off case, the model runs a fixed dispatch for the day as it occurred; Generation, Load, Sales and purchases are all as they actually occurred for the day.
   For the Units On case, the model is made to run H5 at max of 560 MW, L-1 at 350 MW, L-2 at 340 MW, M-1 at 160 MW, M-2 at 170 MW, M-3 at 179 MW, I-1 at 469 MW x 24 hrs per day, commit and dispatch generating units, dispatch purchases (use as needed), and keep load and sales as they occurred in the base case (unless higher capacity is demonstrated).
2) The production cost runs do not evaluate any potential lost interchange sales.
3) Runs can be reproduced; Files are in e:\pub\couger\2005\mmmddyy.inp
4) LaCygne 1 Add MWH represents the additional generation that could have been produced had the unit been available.

SCHEDULE 9 - 3

SCHEDULE 10

HAS BEEN DEEMED

HIGHLY CONFIDENTIAL

IN ITS ENTIRETY

NP