KU
a e·on company

Mr. Jeff DeRouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

RECEIVED
MAY 27 2010
PUBLIC SERVICE
COMMISSION

Kentucky Utilities Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.eon-us.com

Lonnie E. Bellar
Vice President
T 502-627-4830
F 502-217-2109
lonnie.bellar@eon-us.com

May 27, 2010

RE: ***Application of Kentucky Utilities Company for an Adjustment of Its Base Rates* – Case No. 2009-00548**

Dear Mr. DeRouen:

Please find enclosed and accept for filing the original and ten (10) copies of the following testimonies in the above-referenced matter.

1. Rebuttal Testimony of S. Bradford Rives;
2. Rebuttal Testimony of Valerie L. Scott;
3. Rebuttal Testimony of Shannon L. Charnas;
4. Rebuttal Testimony of Ronald L. Miller;
5. Rebuttal Testimony of Daniel K. Arbough;
6. Rebuttal Testimony of William E. Avera;
7. Rebuttal Testimony of Lonnie E. Bellar;
8. Rebuttal Testimony of Robert M. Conroy;
9. Rebuttal Testimony of Butch Cockerill; and
10. Rebuttal Testimony of William Steven Seelye

Should you have any questions regarding the enclosed, please contact me at your convenience.

Sincerely,

Lonnie E. Bellar

cc: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

REBUTTAL TESTIMONY OF S. BRADFORD RIVES CHIEF FINANCIAL OFFICER KENTUCKY UTILITIES COMPANY

Filed: May 27, 2010

Q. Please state your name, position and business address.

A. My name is S. Bradford Rives. I am the Chief Financial Officer for Kentucky Utilities Company ("KU" or "Company') and an employee of E.ON U.S. Services Inc., which provides services to KU and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to address the consolidated tax adjustment proposal by Attorney General witness Michael Majoros, as well as his related interest synchronization adjustment; (2) to refute Kentucky Industrial Utility Customers, Inc. ("KIUC") witness Lane Kollen's assertion that revenue from KU's non-utility investment in Electric Energy, Inc. ("EEI"), should be included in KU's revenue requirement, and that the amount of EEI revenue included in the revenue requirement calculation should be normalized.

Consolidated Tax Adjustment

Q. Do you agree with Mr. Majoros's recommendation that consolidated income tax benefits should be reflected in income tax expense?

A. Absolutely not. This recommendation, if adopted, would represent a radical and abrupt departure from twenty years of the Commission's well-established, sound, and balanced policy prohibiting affiliate cross-subsidization.[1] The Commission should continue its long-standing practice of using the stand-alone method for income taxes.

---

[1] *See In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, Case No. 89-374, Order (May 25, 1990).

Q. Would you please explain the course of the Commission's requirement for the stand-alone method of calculating tax expenses?

A. Yes. In its May 25, 1990 Order in Case No. 89-374, *Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, the Commission approved LG&E's proposed reorganization and creation of a holding company structure. The consummation of this transaction resulted in LG&E Energy Corp. becoming the parent corporation of LG&E. As part of its application, LG&E proposed its Corporate Policies and Guidelines for Intercompany Transactions for the purpose of expressly establishing the affiliate transaction regulation of LG&E and its affiliates, including its parent corporation. The Commission's May 25, 1990 Order states in part:

> 11. LG&E and each related company shall comply with LG&E's Corporate Policies and Guidelines for Intercompany Transactions.[2]

These Corporate Polices and Guidelines for Intercompany Transactions require the following:

> Holding will file consolidated Federal and State income tax returns which will include LG&E's and any other subsidiaries' taxable income. The "stand alone" method will be used to allocate the income tax liabilities of each entity. Payment transfers for tax liabilities or tax benefits will be made on the dates established for the payment of Federal estimated income taxes.[3]

---

[2] *In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, Case No. 89-374, Order at 20 (May 25, 1990).

[3] Corporate Policies and Guidelines for Intercompany Transactions (LG&E Holding) at 4-5.

LG&E thus is obliged by the Commission's May 25, 1990 Order to comply with this requirement.

Q. Did the Commission adopt a similar requirement for KU?

A. Yes. The Commission approved an identical requirement (i.e., use of the stand-alone method to allocate the income tax liabilities of each entity) when KU proposed a similar corporate reorganization and holding company structure in Case No. 10296, *In the Matter of: Application of Kentucky Utilities Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith.*[4] The Commission required KU and KU Energy Corporation to adhere to similar Corporate Policies and Guidelines, which contained a stand-alone requirement for computing tax liabilities comparable to the stand-alone requirement approved for LG&E.

Thus, the Commission required both companies to adopt and implement similar Guidelines to protect their customers and the utilities themselves from the risks associated with non-utility activities. These Guidelines were intended to ensure that there would be no cross-subsidization between unregulated activities and the utilities or their customers in part by the requirement to follow the stand-alone method for computing tax liabilities.

Q. When the Commission approved LG&E's and KU's reorganizations into holding companies, did the Commission foresee the possibility that their unregulated activities could cause substantial losses?

A. Yes. The Commission clearly anticipated the risk that such unregulated activities might entail, including the possibility of significant losses. This is shown by the

[4] Corporate Policies and Guidelines for Intercompany Transactions (KU Holding) at 3.

requirement in the orders that each holding company, as a condition of approval, be willing to divest the utility in the event that losses on the unregulated side became so great that they posed a risk to the utility operations.[5]

Q. Did the Commission subsequently audit LG&E and KU to determine whether they were in compliance with their respective <u>Corporate Policies and Guidelines</u>?

A. Yes. The Commission conducted management audits of KU/KU Energy and LG&E/LG&E Energy. In the management audit report of July 1995 for LG&E/LG&E Energy, the auditors discussed their examination of LG&E's compliance with the requirements of the Commission's Order in Case No. 89-374 and had the following findings:

> <u>XIII-F1</u> "LG&E clearly documents inter-corporate transfers of assets, goods, services and the corresponding financial transactions."
>
> <u>XIII-F4</u> "LG&E has benefited from the exchange of services of Energy Corp."
>
> <u>XIII-F6</u> "Documentation of policies and procedures for intercompany cost allocation and billing is appropriate."
>
> <u>XIII-F7</u> "LG&E's ability to obtain financial resources has not been adversely affected by Energy Corp. or its unregulated affiliates."

In the management audit of KU/KU Energy issued in August 1994, the management auditors made specific reference to the reporting of KU/KU Energy in findings:

---

[5] *In the Matter of: Application of Louisville Gas and Electric Company for an Order Approving an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, Case No. 89-374, Order at 13-14, 21 (May 25, 1990); *In the Matter of: Application of Kentucky Utilities Company to Enter into an Agreement and Plan of Exchange and to Carry Out Certain Transactions in Connection Therewith*, Case No. 10296, Order at 12-13,18 (Oct. 6, 1988).

VIII-F1 "KU Energy Corporation and its subsidiaries, KU and KU Capital have comprehensive procedures for accounting for intercompany product and service transactions."

VIII-F3 "KU has sufficient supporting documentation, policies and guidelines regarding parent and affiliate transactions."

Q. Did the Commission approve new Guidelines that include the stand-alone requirement in connection with the approval of the LG&E and KU merger?

A. Yes. In its Order of September 12, 1997, in Case No. 97-300, *In the Matter of: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Merger*, the Commission ordered as follows:

> LG&E, KU and each related company shall, after the merger, comply with LG&E Energy's Corporate Policies and Guidelines for Intercompany Transactions.

Order, p. 39. LG&E Energy's Corporate Policies and Guidelines for Intercompany Transactions expressly state:

> LG&E Energy will file consolidated Federal and State income tax returns which will include LG&E's, KU's and any other subsidiaries' taxable income. The "stand alone" method will be used to allocate the income tax liabilities of each entity. Payment transfers for tax liabilities or tax benefits will be made on the dates established for the payment of Federal estimated income taxes.[6]

Rives Rebuttal Exhibit 1 contains an accurate copy of the LG&E, KU, and LG&E/KU Guidelines.

[6] Corporate Policies and Guidelines for Intercompany Transactions (LG&E Energy) at 5.

Q. Did the Commission require LG&E and KU to continue to follow the <u>Guidelines</u> as a condition of approving the PowerGen merger with LG&E Energy Corp.?

A. Yes. In its Order of May 15, 2000, in Case No. 2000-095, *In the Matter of: Joint Application of PowerGen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of a Merger*, in Appendix B the Commission ordered as follows:

> LG&E and KU should continue to comply with their <u>Corporate Policies and Guidelines for Intercompany Transactions</u> as well as employing other procedures and controls related to sales, transfers and cost allocation to ensure and facilitate the full review by the Commission and protection against cross-subsidization.

Thus, again, the Commission affirmed the <u>Guidelines</u> and the stand-alone method requirement therein.

Q. Did the Commission require LG&E and KU to continue to follow the <u>Guidelines</u> as a condition to the approval of the E.ON acquisition of PowerGen?

A. Yes. In its August 6, 2001 Order in Case No. 2001-104, *In the Matter of: Joint Application for Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company in Accordance with E.ON AG's Planned Acquisition of PowerGen plc*, the Commission required as a condition of its approval of the acquisition and transfer of ownership and control of LG&E and KU the acceptance of the following Commitment and assurance:

> E.ON, Powergen, LG&E Energy, LG&E and KU shall adhere to the conditions described in the Commission's Orders in Case Nos. 10296, 89-374, 97-300 and 2000-095 to the extent those conditions are not superseded by KRS 278.2201 through 278.2219 or the jurisdiction of the SEC or FERC. These conditions, restated in Appendix B to the Commission's May 15, 2000 Order in Case No. 2000-095, concern protection of

utility resources, monitoring the holding company and the subsidiaries and reporting requirements.

Order (May 6, 2001), Appendix A - No. 1.

Q. Has the Commission followed and applied the <u>Guidelines</u> in connection with ratemaking decisions?

A. Yes. In its June 20, 2005 Orders in Case Nos. 2004-00421 and 2004-00426, when approving LG&E and KU's 2004 Environmental Surcharge applications, the Commission determined that the <u>Guidelines</u> required LG&E and KU to transfer emission allowances at cost for purposes of implementing the proposed environmental surcharges: "The Guidelines clearly require that the transfer or sale of assets between LG&E and KU will be priced at cost."[7] The Commission further noted in those Orders, "The Commission ordered LG&E and KU to comply with the Guidelines after the merger."[8]

Also, in its June 11, 2002 Order in Case No. 2002-00029, the Commission determined that the <u>Guidelines</u> required LG&E and KU to transfer combustion turbines ("CTs") and associated property at cost: "The Commission agrees that the CTs should be priced at cost and finds that LG&E and KU should file their final determination of the cost of the transferred CTs within 30 days after the date of the

---

[7] *In the Matter of: The Application of Louisville Gas and Electric Company for Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2004-00421, Order at 12 (June 20, 2005); *In the Matter of: The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct Flue Gas Desulfurization Systems and Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2004-00426, Order at 16 (June 20, 2005).

[8] *In the Matter of: The Application of Louisville Gas and Electric Company for Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2004-00421, Order at 12 n.22 (June 20, 2005); *In the Matter of: The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct Flue Gas Desulfurization Systems and Approval of Its 2004 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2004-00426, Order at 15 n.30 (June 20, 2005).

transfer. The determination should be in accordance with the requirements of … LG&E Energy's Corporate Guidelines."[9]

Q. Please describe the stand-alone method.

A. The stand-alone method is based upon the following three closely related accounting and regulatory principles: (1) cost causation; (2) the benefits-burden relationship; and (3) prevention of cross-subsidies of, or by, affiliates. In other words, a utility's rates are set to recover the just and reasonable costs of providing utility service as adjusted in the rate case test year. The cost of income taxes allowed for recovery through rates, therefore, should be directly related to the revenues earned and costs incurred in providing utility service. In short, there should be a link or match between allowed income tax expense and regulatory utility service. The stand-alone method, emphatically approved by this Commission for the past twenty years, ensures this relationship by computing tax expense directly on test year revenues and costs and excluding the tax effects of revenue and expenses not associated with the provision of utility services.

Q. How does this compare with the AG's recommendation?

A. The AG's approach would abandon the Commission's time-tested stand-alone method of regulation. Under the AG's approach, the losses of an unregulated affiliate, which generate tax savings in a consolidated tax return and thus lower the consolidated tax liability, are used to effectively create a windfall benefit to the utilities' customers.

[9] *In the Matter of: Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Acquisition of Two Combustions Turbines*, Case No. 2002-00029, Order at 7 (June 11, 2002).

Q. How would the AG's proposal confer a windfall benefit on the utilities' customers?

A. The tax benefits of the unregulated affiliate are the direct result of tax losses incurred by the unregulated business. Consistent with the procedure to insulate the regulated entities from all of the effects of unregulated operations, utility customers were not charged any of the costs that produced these tax losses. Because utility customers did not incur or pay for these losses, they should have no claim on the tax benefits they produced. The AG's proposal, however, would do just that: give customers the tax benefits of losses for which they did not pay or bear any risk.

The benefits of any tax losses produced by an unregulated affiliate belong to the owners of the affiliate who invested in that enterprise seeking potential gain, and at the risk of potential loss.

Q. Please explain what the benefits-burden relationship principle is, how the Commission has followed it in the past, and how the AG's proposed consolidated tax-related income adjustment violates the principle.

A. The benefits-burden principle provides that reward should follow risk and benefits should follow burden. The Commission used this principle in connection with its analysis of the disposition of the proceeds from the sale of KU's railcars in a fuel adjustment case several years ago to conclude that, because ratepayers had paid the depreciation expense associated with the railcars, the ratepayers were entitled to the proceeds.[10] Though the filing of a consolidated return may result in tax offsets on a consolidated basis, the tax offsets only occur because certain members of the

---

[10] *In the Matter of: An Examination By the Public Service Commission of the Application of the Fuel Adjustment Clause of Kentucky Utilities Company From November 1, 1990 to October 31, 1992*, Case No. 1992-00493, Order at 20 (January 2, 1997).

consolidated group have incurred losses offsetting the gains of other members of the consolidated group. These entities that produce the net operating losses are entitled to retain the associated tax benefits because these entities, and not LG&E's or KU's customers, incurred the expenses that resulted in taxable losses. These expenses were not included in the utility cost of service and, consequently, were not recovered through rates. They were, in fact, paid by shareholders.

The financing costs associated with the PowerGen PLC acquisition of LG&E Energy Corp. and E.ON AG's acquisition of PowerGen PLC are another example of the benefit-burden principle. In each of the cases approving the transactions, the Commission expressly stated that these costs could not be recovered from the utilities' customers. These costs were borne by the shareholders who were thus entitled to the tax benefit (i.e., the tax deduction of the interest deduction). The AG's proposal would dramatically alter this historical balance.

Under the AG's consolidated approach, however, part of the shareholders' benefit for bearing the risk of its unregulated investments is confiscated for purpose of reducing customers' rates.

Q. **Please explain the principle preventing cross-subsidies between Commission-regulated and unregulated businesses, and how the AG's proposed consolidated tax approach would violate it.**

A. The Commission has permitted the parent companies of LG&E and KU to pursue unregulated businesses; however, there has always been a stipulation that there should be no cross-subsidization between regulated and unregulated businesses. If a utility's income tax expense is not calculated on a stand-alone method, but instead is adjusted using consolidated tax savings, the separation between a utility and its affiliates will be completely compromised. Imposing a consolidated tax adjustment ("CTA") creates a mathematical certainty that changes in the operations of unregulated affiliates will have the capacity to alter utility rates. If unregulated affiliate tax losses increase, utility rates will decrease. If unregulated affiliate tax losses decrease, utility rates will increase. Because the quantity of affiliate tax losses will depend directly on affiliate actions, the imposition of a CTA will drag the activities of unregulated affiliates into the regulatory arena, contrary to the long-standing principle of utility insulation. In order to prevent cross-subsidies, all regulated and unregulated members of a consolidated group should be treated fairly and equitably.

Q. Would acceptance of Mr. Majoros's recommendation jeopardize the ability of LG&E and KU to achieve their authorized rates of return?

A. Yes. Mr. Majoros's recommendation would preclude LG&E and KU from achieving their authorized rates of return because the recommendation would result in an imputed, as opposed to an actual, benefit. The only effect of the adjustment is to reduce revenues with no offsetting benefit. If all other revenue and expense items remain the same, diminished revenues will result in a rate of return that is necessarily less than authorized. LG&E and KU would not have a meaningful opportunity to earn a reasonable return on their capital invested in facilities to serve customers. The impact of such an adjustment could also affect LG&E and KU's ability to raise capital at reasonable and cost-effective rates because investors would view the adjustment as an effective discount to the allowed rate of return.

Q. Is there an authoritative accounting source that addresses the stand-alone method?

A. Yes. The text Accounting for Public Utilities by Robert L. Hahne and Gregory E. Aliff is a widely accepted and authoritative source in public utility accounting matters. The authors state:

> *Consolidated tax results* - It is not uncommon for a regulated utility to have subsidiary operations that produce tax losses which, on a consolidated tax return, offset taxable income from utility operations. Over the years, many have disagreed about how to allocate these taxes. One approach has been to use "effective tax rates," whereby the income tax benefits of affiliated company losses are used to reduce the tax costs of the utility. The only approach that is consistent with standard ratemaking principles that prohibit cross-subsidization between utility and non-utility activities is to put the regulated operation on a "stand alone" basis and to assign the full tax burden to the taxable gain source and a tax benefit to the tax loss source. The basic theory is that the regulated costs should not be affected by the results from nonregulated operations.[11]

They further state:

> Income tax normalization is consistent with a fundamental principle of the cost of service approach to ratemaking; the principle that consumers should bear the only costs for which they are responsible. Under this principle, there is a well-reasoned, and widely recognized, postulate that taxes follow the events they give rise to. Thus, if ratepayers are held responsible for costs, they are entitled to the tax benefits associated with the costs. If ratepayers do not bear the costs, they are not entitled to the tax benefits associated with the costs.
>
> Regulators have long used a ratemaking procedure that explicitly embraces this principle. The procedure is to identify utility activities (revenues and costs) and compute taxes directly related to the utility activities.
>
> Non-utility operations involve financial risks that are different from a utility's regulated operations. When these risks are not

[11] Hahne and Aliff, Accounting for Public Utilities § 7.08[3].

> borne by the ratepayers, it is unfair to make use of the business losses generated in those nonregulated entities to reduce the utility's cost in determining the rates to be charged for utility services. By the same token, when a company's nonjurisdictional activities are profitable, the ratepayers have no right to share in those profits, but neither are they required to pay any of the income taxes that arise as a result of those profits. Thus, a "stand alone" method (as opposed to a consolidated effective tax rate method) for computing the income tax expense component of cost of service is the proper and equitable method to be followed for ratemaking purposes.[12]

Q. Are you familiar with the consolidated income tax adjustment the Commission approved in its February 28, 2005 Order in Case No. 2004-00103, *In the Matter of: Adjustment of the Rates of Kentucky-American Water Company*? If so, please describe your understanding of that adjustment.

A. Yes. In Case No. 2004-00103, Kentucky American Water Company ("KAW") sought recovery of its income tax expense based on the federal statutory rate of 35% of its taxable income. The AG retained Andrea Crane as an expert witness and she proposed a consolidated income tax adjustment based on the fact that KAW files its federal taxes as part of a consolidated group. In her direct testimony, Ms. Crane proposed that because KAW files its federal tax returns as a member of a consolidated group, any tax benefits or savings realized by any member of the group should be enjoyed by KAW customers on an allocated basis.

Q. Did KAW oppose the consolidated tax adjustment?

A. Yes. KAW filed rebuttal testimony in which its expert witness explained that KAW, which has always had taxable income, always writes a check to its parent company for 35% of its taxable income that is then used for payment of federal taxes by the

[12] Hahne and Aliff, Accounting for Public Utilities § 17.06[3].

consolidated group. He explained that to the extent that any other member of the group has a tax loss, KAW never receives any benefit of that loss. The witness further explained that taking a benefit "earned" by one member of the group and giving some of that benefit to KAW is a "cross-subsidy" in that the Commission would be taking a benefit from an entity it does not regulate and giving it to an entity it does regulate.

Q. Did the Commission accept the proposed consolidated tax adjustment in that case?

A. Yes. The Commission held that the consolidated tax adjustment should be approved and reduced KAW's federal income tax expense by the amount proposed. However, the February 28, 2005 Order in Case No. 2004-00103 is clear that the Commission did not accept the adjustment on the basis that it generally favors or agrees with the consolidated tax adjustment concept. Instead, the lynchpin of the holding was that the Commission believed that KAW had committed in an earlier case that it would realize tax *savings* by virtue of being a member of a consolidated tax filing group.

> We find that Kentucky-American's present position on this issue conflicts with its stated position in Case No. 2002-00317. In that proceeding, Kentucky-American and others sought approval of the transaction that enabled RWE's acquisition of control of Kentucky-American. One feature of this transaction was the creation of TWUS, an intermediate holding company that would hold the stock of American Water and all of Thames Water Aqua Holdings GmbH's other U.S. affiliates. Kentucky-American asserted the creation of TWUS would permit the filing of consolidated U.S. tax returns. The ability to file such a tax return, Kentucky-American argued, benefited the public because it would reduce administrative expenses by eliminating the need to file multiple tax returns and permit some tax savings by allowing payment of taxes calculated on the net profits of all entities within the consolidated group.

> ...
>
> Having previously indicated the savings resulting from the filing of a consolidated tax filing would be viewed as a merger benefit, subject to allocation, we do not believe that acceptance of the AG's proposal represents a radical departure from past regulatory practice. Moreover, Kentucky-American and its corporate parents having previously touted TWUS's filing of consolidated tax returns as a benefit to obtain approval of the merger transaction, have no cause to object if we now act upon their representation. Accordingly, we find that the AG's proposed consolidated income tax is reasonable and have reflected it in our calculation of federal income taxes.[13]

Q. Has KU ever represented that a benefit of any of its mergers would be to calculate taxes on a consolidated basis for rate-making purposes?

A. No, neither KU nor any of the entities with which it has merged has ever represented that a merger benefit would be calculating income taxes on a consolidated basis for rate-making purposes, nor has the Commission or any other party ever asserted otherwise. In fact, in their merger KU and LG&E specifically adopted, with Commission approval, the stand-alone method in their policies and procedures. Therefore, there is no support for such a rate-making calculation in this proceeding.

Q. Are you aware that the Commission again addressed the issue of a consolidated tax adjustment in the rehearing phase of KU's 2003 rate case?

A. Yes. In its March 31, 2006 Order on Rehearing in Case No. 2003-00434 (*In the Matter of: An Adjustment of the Electric Rates, Terms and Conditions of Kentucky Utilities Company*), the Commission rejected the use of a consolidated group driven "effective" state tax rate in computing Kentucky income tax expense. In that case, KU argued that Kentucky's statutory rate should be used to calculate Kentucky

[13] *In the Matter of: Adjustment of the Rates of Kentucky-American Water Company*, Case No. 2004-00103, Order at 64-66 (Dec. 28, 2005).

income tax expense. The AG argued in favor of using an effective tax rate that resulted from KU's participation in a consolidated tax filing group. The AG cited the KAW decision above as "precedent" for use of an effective tax rate. The Commission rejected the AG's argument. The Commission decided that using an "effective" rate could well be viewed as forcing the utility to use unregulated activities to subsidize the regulated utility's operations:

> The Commission has previously expressed concerns about using an effective Kentucky income tax rate due to the annual fluctuations in the effective rate. These fluctuations occur because the effective Kentucky income tax rate is determined from the total of all the tax income and tax losses of all the entities that file on the same consolidated income tax return. For KU, the majority of the entities other than LG&E included in the consolidated income tax return of KU's parent corporation, E.ON US Investment Corp., reflect activities which are not regulated by the Commission. By having to recognize tax losses and other tax credits related to these non-regulated activities to derive an effective Kentucky income tax rate could well be viewed as forcing the utility to use these non-regulated activities to subsidize the regulated utility operations. There is also a concern that because of the way the apportionment of certain tax transactions is performed, the resulting effective Kentucky income tax rate could exceed the statutory Kentucky income tax rate. Thus, establishing the effective tax rate as the guideline or precedent, as the AG has requested on rehearing, could in the future result in higher utility rates to pay for taxes on non-regulated activities.
>
> ...
>
> The Commission further finds it reasonable to continue using the statutory Kentucky income tax rate for determining KU's revenue requirements in this case. The statutory Kentucky income tax rate is known and measurable and is not subject to fluctuations due to non-regulated tax losses or tax credits, or due to apportionment adjustments from non-regulated activities. The Commission has consistently utilized the statutory Kentucky income tax rate to determine utility revenue

> requirements absent an agreement or representation to the contrary by the utility.[14]

Q. How, then, would you characterize the Commission's order in Case No. 2004-00103?

A. To my knowledge, the order in Case No. 2004-00103 represents the only instance in which the Commission has varied from its consistent application of the benefits and burdens principle. The Commission articulated a rationale for that lone departure - and that rationale does not exist in this case. Consequently, the order does not represent relevant precedent in this proceeding.

Q. Should the Commission set aside the stand-alone tax methodology that has been in place for the past twenty years in order to reduce rates in this case?

A. No. Unwinding this policy and the associated cost allocation principles to reach a specific result in this case would undermine the Commission's heretofore consistent policy preventing cross-subsidization between regulated and unregulated businesses, and would also do violence to the basic market economic principle that benefit should follow risk. It is for this reason that the Commission adopted many years ago and continues to insist upon the stand-alone methodology.

Moreover, nothing has changed in the twenty years since the Commission adopted the stand-alone income tax concept to support a change in methodology. The Commission has reviewed this tax issue many times and in each instance the Commission has, for good reason, concluded that the stand-alone concept should remain.

---

[14] *In the Matter of: An Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 8-9 (March 31, 2006).

Q. Is Kentucky's historical rejection of CTAs consistent with the practice that prevails throughout the regulatory jurisdictions of this country?

A. Absolutely. The vast preponderance of regulatory jurisdictions in this country do not impose CTAs, and recent decisions from other states' commissions do not indicate a trend favoring such adjustments. In a December 30, 2009 order rejecting a proposed CTA in a Delmarva Power and Light Company rate case, the Maryland Public Service Commission stated, "In order to adopt the Staff's recommended CTA, we would have to depart substantially from prior Commission decisions on this issue and join a very small minority of commissions."[15]

Even more recently, the Public Service Commission of the District of Columbia rejected a proposed CTA in its March 2, 2010 order in Potomac Electric Power Company's base rate case, noting that the stand-alone methodology is the majority approach: "[T]he Commission has decided to adhere to our traditional stand-alone approach regarding federal and district tax expense, which is widely followed by the majority of Commissions throughout the country."[16]

Virginia, the other jurisdiction in which KU has significant operations, adopted as a matter of statutory law the "better and sounder policy" of using the stand-alone method. The Virginia legislature amended VA Code § 56-235.2 in 2007 to add the following language, which unambiguously endorses the stand-alone method:

[15] *In the Matter of the Application of Delmarva Power and Light Company for an Increase in Its Retail Rates for the Distribution of Electric Energy*, Public Service Commission of Maryland Case No. 9192, Order No. 83085 at 22 (Dec. 30, 2009).

[16] *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*, Public Service Commission of the District of Columbia Case No. 1076, Order No. 15710 at 92 (March 2, 2010).

> For ratemaking purposes, the Commission shall determine the federal and state income tax costs for investor-owned water, gas, or electric utility that is part of a publicly-traded, consolidated group as follows: (i) such utility's apportioned state income tax costs shall be calculated according to the applicable statutory rate, as if the utility had not filed a consolidated return with its affiliates, and (ii) such utility's federal income tax costs shall be calculated according to the applicable federal income tax rate and shall exclude any consolidated tax liability or benefit adjustments originating from any taxable income or loss of its affiliates.[17]

In sum, there is no doubt that the CTA Mr. Majoros proposes is contrary to all of this Commission's precedent and is contrary to the stand-alone methodology embraced by the vast majority of other states' public utility commissions.

Q. How would rejecting Mr. Majoros's consolidated tax proposal impact any of his proposed adjustments (including his proposed interest synchronization adjustment) that are computed using KU's effective tax rate?

A. Obviously, Mr. Majoros's "effective tax rate" calculated on Exhibit MJM-1, Schedule 1.4.1 embodies his CTA. If this Commission rejects his proposal to reflect in utility rates the benefits of unregulated affiliate tax losses, then any of his other proposed adjustments that incorporate his proposed "effective tax rate" must be similarly rejected.

<u>Rate Treatment of KU's Investment in Electric Energy, Inc.</u>

Q. Please give a brief history of KU's involvement with Electric Energy, Inc.

A. Several independent sponsoring companies, including KU, formed EEI in the early 1950s. EEI was formed for constructing, owning and operating the electric generating plant in Joppa, Illinois to provide power to a gaseous diffusion uranium plant owned and operated by the United States Atomic Energy Commission ("AEC")

[17] VA Code § 56-235.2(A).

near Paducah, Kentucky. Construction began on the 1,000 MW plant in 1951. Plant start-up occurred in 1954 and the plant reached full operation in summer 1955. At that time, the sponsoring companies purchased any excess power produced by the plant beyond the energy required by the AEC pursuant to a purchase power agreement with a definite term.

Today, Missouri-based utility holding company Ameren Energy holds an 80% stake in EEI; KU owns the remaining 20%. The gross capacity of the plant is currently 1,162 MW. Of that total, 1,086 MW is from the coal fired Joppa facility and 76 MW is combustion turbine capacity from Midwest Electric Power, Inc. By contract, EEI sold its energy to AEC and the sponsoring companies at cost-based rates until the expiration under its terms at the end of 2005. In late 2005, as a super-majority shareholder, Ameren Energy voted to sell this power into the market rather than to sponsoring companies beginning in 2006. (KU attempted to renew the cost-based purchase contract, but as a minority shareholder was unable to compel EEI to do so.) KU receives equity in earnings from 20% of the net income of EEI. KU also receives 20% of the cash dividends that are declared and paid by EEI.

Q. What has been the Commission's regulatory accounting treatment of KU's investment in EEI from the 1950s through today?

A. KU's investment in EEI has never been included in utility capitalization at KU.[18] Correspondingly, the earnings from EEI are now, and always have been, recorded

[18] *See In the Matter of: An Adjustment of the Electric Rates, Terms, and Conditions of Kentucky Utilities Company*, Case No. 2003-00434, Order at 16 and Appx. F (June 30, 2004); *In the Matter of: The Application of Kentucky Utilities Company for Approval of an Alternative Method of Regulation of Its Rates and Service*, Case No. 1998-00474, Order at 59-63 and Appx. C (Jan. 7, 2000); *In the Matter of: General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 8624, Order at 9-11 (March 18, 1983) (reducing KU's capitalization below KU's proposed capitalization, which included deductions for subsidiary investments. *See* Testimony of John N. Newton at Exh. 2.); *In the Matter of: General Adjustment of Electric Rates of Kentucky*

below the line, currently in "Other Income Less Deductions." KU records the earnings on its investments in EEI on the equity method of accounting. KU records its share of EEI's net income each period in proportion to KU's ownership percentage (20%).

Q. Given this history, please discuss why Mr. Kollen's proposed radical and abrupt change in rate treatment of KU's purely shareholder-financed investment in EEI is inappropriate and confiscatory.

A. Mr. Kollen's proposed radical and abrupt change in rate treatment of KU's purely shareholder-financed investment in EEI is wholly inconsistent with the rate treatment the Commission has approved for this investment for several decades. In short, Mr. Kollen proposes a series of accounting changes to confiscate KU's shareholder investment in EEI for the benefit of customers, notwithstanding that customers have not financed a single penny of KU's 20% equity stake in EEI.

Moreover, for several decades KU's customers benefitted from power KU was able to purchase from EEI at cost-based rates, which were significantly lower

---

Utilities Company, Case No. 8177, Order at 11-12 (Sept. 11, 1981) ("In determining the capital allocated to the Kentucky jurisdiction the Commission has reduced the total company common stock equity by $6,529,803 to exclude the equity in subsidiary earnings and by $7,450,161 related to other investments which include Old Dominion Power Company, Electric Energy, Inc., Ohio Valley Electric Corporation and miscellaneous investments."); *In the Matter of: General Adjustment of Rates of Kentucky Utilities Company*, Case No. 7804, Order at 5 (Oct. 1, 1980) ("In determining the Capital allocated to the Kentucky jurisdiction the Commission has reduced the total company Common Stock Equity by $6,536,780 to exclude the subsidiary earnings and by $6,466,533 related to other investments."); *In the Matter of: General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 7163, Order at 4 (Dec. 20, 1978) ("The Commission finds that subsidiary earnings of $7,362,824 and other investments totaling $4,910,000 should be subtracted from Common Equity ...."); *In the Matter of: General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 6906, Order at 4 (Mar. 20, 1978) ("The Commission finds that unappropriated undistributed subsidiary earnings of $7,158,863 and $4,537,627 of other investments should be subtracted from common equity ...."); *In the Matter of: General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 6236, Order at 3 (Sept. 19, 1975) ("The Commission finds that unappropriated undistributed subsidiary earnings of $5,559,982 should be subtracted from common equity ...."); *In the Matter of: General Adjustment of Electric Rates of Kentucky Utilities Company*, Case No. 5915, Order at 3 n.2 (July 10, 1974) (subtracting "Unappropriated Undistributed Subsidiary Earnings" from "Total Common Stock Equity").

than market rates, until the contract under which KU purchased the power expired on December 31, 2005. (Again, KU attempted to renew the cost-based purchase contract, but as a minority shareholder was unable to compel EEI to do so.) As discussed in my answer above, for the entire time that KU has had its purely shareholder-financed stake in EEI, the Commission has approved KU's exclusion of its investment from its capitalization and accounting for its EEI earnings below the line, which was and is appropriate for non-utility investments. And while KU earned very little on its EEI investment, neither KIUC nor any other party to KU's past rate cases have suggested a different rate treatment for that investment.

Now, though, KIUC, through Mr. Kollen, wants to change the rules. Mr. Kollen's proposed rate treatment would effectively confiscate KU's EEI investment, converting it to a utility asset and allowing KU a return on equity thereon while customers benefit from returns on an investment they did not make. When certain parties proposed a similar rate treatment of AmerenUE's investment in EEI in a rate proceeding before the Missouri Public Service Commission ("MPSC"), the MPSC rejected the proposal, concluding:

> While AmerenUE undoubtedly is obligated to deal fairly with its ratepayers, it has no obligation to donate what is clearly an asset of its shareholders to the benefit of its ratepayers. AmerenUE's stock in EEInc. belongs to its shareholders, not to ratepayers. For many years AmerenUE's ratepayers benefited from the ability of AmerenUE to purchase power from its affiliate. But power is the only thing ratepayers bought. They did not buy the right to own or otherwise control AmerenUE's shares of stock in EEInc. ... No reduction in revenue requirement is warranted.[19]

[19] *In the Matter of Union Electric Company d/b/a AmerenUE's Tariffs Increasing Rates for Electric Service Provided to Customers in the Company's Missouri Service Area*, Case No. ER-2007-0002, Tariff No. YE-2007-0007, Report and Order at 59 (issued May 22, 2007; effective June 1, 2007).

It is noteworthy that in the MPSC case discussed above, AmerenUE was (and is) the majority shareholder in EEI, and the MPSC determined that the company should retain the benefit of its non-utility investment. In KU's case, as the minority shareholder, the same logic should apply, particularly given KU's efforts to extend the cost-based power purchase contract from which its customers benefited for so many years. Therefore, like the MPSC, the Commission should reject Mr. Kollen's proposed confiscatory rate treatment of KU's purely shareholder-financed investment in EEI.

Q. Does KRS Chapter 278 contemplate that a utility might own non-utility assets outside the Commission's jurisdiction?

A. The plain language of several sections of KRS Chapter 278 clearly contemplate that a utility like KU could own non-utility, non-jurisdictional assets, like KU's ownership of EEI stock. For example, KRS 278.2201 states in relevant part:

> A utility shall not subsidize a nonregulated activity provided by an affiliate or by the utility itself. The commission shall require all utilities providing nonregulated activities, either directly or through an affiliate, to keep separate accounts and allocate costs in accordance with procedures established by the commission.

As I explained above, KU has *always* separately accounted for its investment in EEI stock, which has *always* been understood to be a non-utility asset.

In addition to plain statutory language, there is Commission precedent establishing that a utility may own a non-utility asset, including a non-utility asset that is an undivided portion of a physical utility asset. Specifically, the Commission prohibited KU's sister utility, LG&E, from including 25% of its investment in

Trimble County Unit 1 in its rate base. LG&E subsequently sold that interest, but the sale was not subject to Commission jurisdiction because it was not a utility asset.

In short, just as KU cannot put whatever it likes into its rate base and demand compensation from its customers, neither can its customers demand that KU place a non-utility, solely-shareholder-financed stock purchase in its rate base for the customers' benefit. Simply put, Mr. Kollen's proposal would be a pure taking of a private asset for public use without just compensation.

Q. How do you respond to Mr. Kollen's "belie[f] that the adjustment to [KU's] capitalization [to remove the EEI investment] was made historically to avoid double counting the return on investment"?

A. Mr. Kollen's "belief" is an assertion with no basis in statute, Commission precedent, or fact. He plainly admitted as much in his responses to the Commission Staff's data requests concerning EEI:

> Mr. Kollen is not aware of any Commission orders that adjudicated any controversy over the ratemaking treatment of KU's EEI earnings and investment; consequently, there was no need for the Commission to state its rationale. In fact, Mr. Kollen is unaware of any controversy over the Commission's ratemaking treatment until the circumstances changed in 2006.[20]
>
> . . .
>
> Mr. Kollen is unaware that the Commission has ever adjudicated this investment as a non-utility investment, and believes that the presumption is that it is a utility investment unless there is some valid demonstration otherwise.[21]

So Mr. Kollen flatly admits there is no basis in Commission precedent to support this demand for a donation from shareholder assets.

[20] KIUC Response to KPSC 1-5.
[21] KIUC Response to KPSC 1-6.

And the "double-recovery" is based upon a false premise, namely that the EEI earnings or EEI investment somehow were utility assets since the 1950s. The truth is that the Commission has always recognized that KU's EEI investment was and is for decades a purely shareholder-financed, non-utility asset of KU, which is clearly permissible under law; indeed, KRS Chapter 278 clearly anticipates that utilities will engage in non-utility businesses, as I discussed above.

Finally, in response to Mr. Kollen's assertion, "the presumption is that it [EEI] is a utility investment unless there is some valid demonstration otherwise," it's difficult to imagine what could be a more "valid demonstration otherwise" than decades of fully consistent Commission and KU practice, as well as clear statutory law anticipating that utilities will own non-utility assets.

Q. Should the fact that KU owns its EEI stock directly, rather than through a subsidiary, matter to the Commission?

A. Not at all. Mr. Kollen stated in response to a Commission Staff data request, "KU owns the 20% share in EEI, not some subsidiary or other affiliate, and this investment is included in KU's per books capitalization."[22] His assertion seeks to create a distinction without a difference. The simple fact is that EEI stock is not a utility asset, and whether KU owns it directly or by way of "EEI Stock Holdco LLC" is irrelevant.

[22] Id.

Q. What is KU's position concerning Mr. Kollen's proposed adjustment to normalize EEI revenues?

A. Because any adjustment concerning EEI revenues would clearly contradict decades of Commission precedent and should be rejected, Mr. Kollen's proposed normalization adjustment should likewise be rejected.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **S. Bradford Rives**, being duly sworn, deposes and says that he is Chief Financial Officer for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

SBRives

S. Bradford Rives

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

Rives Rebuttal Exhibit 1

LG&E/LG&E Energy

Corporate Policies and Guidelines for Intercompany Transactions

Corporate Policies and Guidelines for Intercompany Transactions

These Policies and Guidelines have been established to set forth business practices to be observed in transactions between Louisville Gas and Electric Company (LG&E), its proposed Holding Company ("Holding") and any nonutility subsidiary created by Holding. As nonutility subsidiaries are created by Holding, these policies and guidelines will be revised and expanded to ensure that the non-regulated activities are not subsidized by LG&E's ratepayers. Updated policies and guidelines will be filed with the Public Service Commission on an annual basis.

Policies and Guidelines

1. Separation of costs between utility and non-utility activities will be maintained.

Distinct and separate accounting and financial records will be maintained and fully documented for each entity. All costs, which can be specifically identified and associated with an activity, will be directly assigned to that activity. Indirect costs, which provide a benefit to more than one activity, will be allocated to the activities that receive a benefit.

Although initially there will be a sharing of resources between LG&E and Holding, to the extent practicable, each subsidiary of Holding will acquire and maintain its own facilities, equipment, staff and financing.

2. Intercompany transactions shall be structured to ensure that non-regulated activities are not subsidized by the regulated utility.

Separate accounting and financial records will be maintained to ensure that intercompany transactions related to non-utility activities will not have an adverse impact on the utility or its customers.

Transfers or sales of assets will be priced at the greater of cost or fair market value for transfers or sales from LG&E to Holding or other subsidiaries and at the lower of cost or fair market value for transfers or sales made to LG&E from Holding or any of its subsidiaries. Settlement or transfer of liabilities will be accounted for in the same manner. Through this policy, the utility will receive the full benefit from intercompany transfers or sales.

LG&E shall furnish a report to the PSC annually of each transfer of utility assets between LG&E and Holding or any of its subsidiaries, which has a value of $250,000 or more. Transfers having a value of less than $250,000 will be grouped and reported by specific categories, such as transportation equipment, power operated equipment, etc.

Transfers or sales of nonutility assets, payment of dividends and normal recurring transactions are expressly excluded from this reporting requirement.

All good or services provided by the utility to Holding or any of its subsidiaries will be billed at cost, including the proper assignment of all indirect costs.

LG&E will utilize its automated responsibility accounting system to accumulate and allocate costs among the various companies. To the extent possible, specific activities or projects will be directly recorded in the accounting and financial records of the appropriate company. Transactions affecting more than one entity will be allocated among the affected companies by reference to some reasonable, objective standard related to the facts and circumstances of the transaction (i.e., number of employees, number of transactions, etc.)

Billings for intercompany transactions shall be issued on a timely basis with documentation sufficient to provide for subsequent audit or regulatory review. Payments for intercompany transactions shall be made within thirty (30) days of receipt of the invoice. If payment is not made by the due date, late charges will be assessed by the billing company.

3. <u>Strict internal controls will be maintained to provide reasonable assurance that intercompany transactions are accounted for in accordance with management's policies and guidelines</u>.

Accounting policies and procedures for intercompany transactions will be fully documented and provided to all entities.

Intercompany transactions will be fully documented in sufficient detail to enable verification of the relevant information. Periodic audits will be made of intercompany transactions and transfer prices to ensure that these policies and guidelines are being observed. Any detected deviations from these policies and guidelines shall be reported to management and such deviations shall be corrected in a timely manner.

4. Financial Reporting.

Holding and all subsidiaries shall prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial information shall be accumulated and prepared in accordance with Generally Accepted Accounting Principles. In addition, the accounting information prepared and maintained by LG&E shall conform to the requirements of the Public Service Commission of Kentucky and the Federal Energy Regulatory Commission's uniform system of accounts.

All intercompany transactions shall be reported and the nature and terms of the transactions should be fully described and explained.

Holding will file consolidated Federal and State income tax returns which will include LG&E's and any other subsidiaries' taxable income. The "stand alone" method will be used to allocate the income tax liabilities of each entity. Payment transfers for tax liabilities or tax benefits will be made on the dates established for the payment of Federal estimated income taxes.

0097103.01

KU/KU Energy

Corporate Policies and Guidelines for Intercompany Transactions

CORPORATE POLICIES AND GUIDELINES FOR INTERCOMPANY TRANSACTIONS

PURPOSE

The purpose of this statement is to establish Policies and Guidelines to govern transactions between Kentucky Utilities Company ("KU"), its proposed Holding Company ("Holding") and any other non-utility subsidiary of Holding that may be created. The guidelines have been established to ensure that the following policies are adhered to with respect to inter-party transactions:

I. A distinct separation of costs between utility and non-utility activities will be maintained.

II. Intercompany transactions will be structured, and reimbursement made, in such manner that such transactions do not have an adverse impact on utility customers.

III. Strict internal controls will be maintained with respect to inter-party transactions to ensure that these polices are observed and to provide for adequate and effective regulatory oversight of KU's electric utility operations.

IV. All books and records of KU and all affiliates will be maintained in accordance with Generally Accepted Accounting Principles and, in addition, the books and records of KU will continue to comply with the requirements of the Uniform System of Accounts.

GUIDELINES

I. <u>A distinct separation of costs between utility and non-utility activities will be maintained</u>.

In order to achieve the maximum level of efficiency it is anticipated that there will be sharing of corporate resources. In those instances the costs of such resources will be allocated to the party receiving the benefit.

II. <u>Intercompany transactions will be structured, and reimbursement made, in such manner that such transactions do not have an adverse impact on utility customers</u>.

Prompt and fair reimbursement will be made with respect to any sale or transfer of assets, liabilities, or services between the parties. Separate accountability of management and records will be maintained to assure that transactions involving non-utility activities will not have an adverse impact on the utility or its customers.

Sales or transfer of assets are to be settled by cost or fair market value, whichever is greater when transfers or sales are made by KU to Holding, or other parties, and such transfers or sales are to be settled by cost or fair market value, whichever is lower when transfers are made to KU from Holding or other parties. Settlement or transfer of liabilities are to be treated in the same manner. These guidelines will insure that the utility will not be negatively impacted by an inter-party transaction.

Sales or provisions of services fall into two broad categories; continuing services (such as payroll) and special or periodic services (such as sale of common stock). For continuing services KU already has in place a responsibility accounting system, which will be used as the basis for cost allocation. For each responsibility area, which provides continuing services, an objective measure of the services provided (i.e., number of employees) will be determined and used to allocate the costs of that responsibility to Holding or any other subsidiary based on that measure.

The special or periodic services will be assigned a project number for each project, all direct costs accumulated and, with assignment of proper overheads, billed to Holding or any other subsidiary as appropriate.

The foregoing cost allocation methods will be reviewed at least annually and modifications made to reflect current operating conditions to ensure that all costs incurred for each party are assigned to that party.

Inter-party billings shall be issued on a timely basis with sufficient detail attached to assure an adequate audit trail and to provide for adequate and effective regulatory review. Payment shall be due upon receipt and past due 30 days after receipt of invoice. Late charges will be assessed by the billing company on past due amounts.

III. Strict internal controls will be maintained with respect to inter-party transactions to ensure that these policies are observed and to provide for adequate and effective regulatory oversight of KU's electric utility operations.

These policies and guidelines will be adopted by KU, by Holding and by each other subsidiary of Holding. Intercompany transactions will be documented in a consistent manner and in sufficient detail to develop an adequate audit trail. Intercompany transactions will be periodically audited and reports given to management as to compliance with these policies and guidelines.

Internal controls will be designed to ensure proper accountability by (1) recognizing all intercompany transactions, (2) establishing appropriate value, and (3) recording each transaction properly.

IV. All books and records of KU and all affiliates will be maintained in accordance with Generally Accepted Accounting Principles and, in addition, the books and records of KU will continue to comply with the requirements of the Uniform System of Accounts.

Holding and all subsidiaries are expected to provide timely financial information necessary to compile the required financial statements and to comply with other reporting requirements. All books and records will be maintained in accordance with Generally Accepted Accounting Principles and, in addition, the books and records of KU must meet the requirements of the Uniform System of Accounts. Audited financial statements are to be accompanied by notes summarizing significant accounting policies and other required disclosures.

It is anticipated that KU and Holding will file consolidated Federal and State income tax returns. Holding will receive and disburse payments between parties, which result from the "stand alone" method of computing income tax liabilities. The payment transfers will include quarterly installment responsibilities.

MODIFICATION

These guidelines will be modified from time to time as experience may require to ensure that the costs of all inter-company transactions are properly allocated, recorded and reimbursed.

0097522.01

LG&E/KU

Corporate Policies and Guidelines for Intercompany Transactions

Corporate Policies and Guidelines
for Intercompany Transactions

These Policies and Guidelines have been established to set forth business practices to be observed in transactions between Louisville Gas and Electric Company ("LG&E"), Kentucky Utilities Company ("KU"), their Holding Company, LG&E Energy Corp. ("LG&E Energy") and any non-utility subsidiary created by LG&E Energy. As nonutility subsidiaries are created by LG&E Energy, these policies and guidelines will be revised and expanded to ensure that the non-regulated activities are not subsidized by LG&E's or KU's ratepayers. Updated policies and guidelines will be filed with the Public Service Commission on an annual basis.

Policies and Guidelines

1. Separation of costs between utility and non-utility activities will be maintained.

Distinct and separate accounting and financial records will be maintained and fully documented for each entity. All costs, which can be specifically identified and associated with an activity, will be directly assigned to that activity. Indirect costs, which provide a benefit to more than one activity, will be allocated to the activities that receive a benefit.

Although initially there will be a sharing of resources between LG&E, KU and LG&E Energy, to the extent practicable, each subsidiary of LG&E Energy will acquire and maintain its own facilities, equipment, staff and financing.

2. <u>Intercompany transactions shall be structured to ensure that non-regulated activities are not subsidized by the regulated utility</u>.

Separate accounting and financial records will be maintained to ensure that intercompany transactions related to non-utility activities will not have an adverse impact on the utilities or their customers.

Transfers or sales of assets will be priced at the greater of cost or fair market value for transfers or sales from LG&E or KU to LG&E Energy or other subsidiaries and at the lower of cost or fair market value for transfers or sales made to LG&E or KU from LG&E Energy or any of LG&E Energy's non-utility subsidiaries. Transfers or sales of assets between LG&E and KU will be priced at cost. Settlement or transfer of liabilities will be accounted for in the same manner. Through this policy, the utilities will receive the full benefit from intercompany transfers or sales.

LG&E or KU shall furnish a report to the PSC annually of each transfer of utility assets between themselves or between LG&E or KU and LG&E Energy or any of its non-utility subsidiaries, which has a value of $250,000 or more. Transfers having a value of less than $250,000 will be grouped and reported by specific categories, such as transportation equipment, power operated equipment, etc.

Transfers or sales of nonutility assets, payment of dividends and normal recurring transactions are expressly excluded from this reporting requirement.

All goods or services provided by LG&E or KU to LG&E Energy or any of its non-utility subsidiaries will be billed at cost, including the proper assignment of all indirect costs.

LG&E and KU will utilize their automated responsibility accounting system to accumulate and allocate costs among the various companies. To the extent possible, specific activities or projects will be directly recorded in the accounting and financial records of the appropriate company. Transactions affecting more than one entity will be allocated among the affected companies by reference to some reasonable, objective standard related to the facts and circumstances of the transaction (i.e., number of employees, number of transactions, etc.)

Billings for intercompany transactions shall be issued on a timely basis with documentation sufficient to provide for subsequent audit or regulatory review. Payments for intercompany transactions shall be made within thirty (30) days of receipt of the invoice. If payment is not made by the due date, late charges will be assessed by the billing company.

3. <u>Strict internal controls will be maintained to provide reasonable assurance that intercompany transactions are</u>

accounted for in accordance with management's policies and guidelines.

Accounting policies and procedures for intercompany transactions will be fully documented and provided to all entities. Intercompany transactions will be fully documented in sufficient detail to enable verification of the relevant information. Periodic audits will be made of intercompany transactions and transfer prices to ensure that these policies and guidelines are being observed. Any detected deviations from these policies and guidelines shall be reported to management and such deviations shall be corrected in a timely manner.

4. Financial Reporting.

LG&E Energy and all subsidiaries shall prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial information shall be accumulated and prepared in accordance with Generally Accepted Accounting Principles. In addition, the accounting information prepared and maintained by LG&E and KU shall conform to the requirements of the Public Service Commission of Kentucky and the Federal Energy Regulatory Commission's uniform system of accounts.

All intercompany transactions shall be reported and the nature and terms of the transactions should be fully described and explained.

LG&E Energy will file consolidated Federal and State income tax returns which will include LG&E's, KU's and any other subsidiaries' taxable income. The "stand alone" method will be used to allocate the income tax liabilities of each entity. Payment transfers for tax liabilities or tax benefits will be made on the dates established for the payment of Federal estimated income taxes.

1/185
0097968.01

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY	)	
UTILITIES COMPANY FOR AN	)	CASE NO. 2009-00548
ADJUSTMENT OF BASE RATES	)	

REBUTTAL TESTIMONY OF
VALERIE L. SCOTT
CONTROLLER
KENTUCKY UTILITIES COMPANY

Filed: May 27, 2010

Q. Please state your name, position and business address.

A. My name is Valerie L. Scott. I am the Controller for Kentucky Utilities Company ("KU" or "Company"), and an employee of E.ON U.S. Services Inc., which provides services to KU and Louisville Gas & Electric Company ("LG&E") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address and respond to certain points and assertions made by intervenors to this proceeding. Specifically, I will address intervenors' comments on the following topics: (1) adjustment to pension, post retirement and post employment benefits; and (2) CCS implementation costs.

Pension, Post Retirement and Post Employment Benefits

Q. Briefly explain Mr. Kollen's adjustment to the Company's pension, post retirement and post employment benefits.

A. Mr. Lane Kollen, who testified on behalf of the Kentucky Industrial Utility Customers, Inc. ("KIUC") has accepted the Company's updated pension, post retirement and post employment benefits information, as the Company revised its expenses based on the results of the 2010 Mercer Study.[1] The Company does not object to Mr. Kollen's acceptance of the Company's revised exhibit, in furtherance of the Commission's longstanding practice to require utilities to provide updated information throughout base rate proceedings. The Company presented revised revenue requirements, including updated pension, post retirement and post

[1] Direct Testimony of Lane Kollen of April 22, 2010 (Case No. 2009-00548) at 25.

employment benefits information, in response to the Fourth Data Request of Commission Staff.

CCS Implementation Expense

Q. Briefly explain the intervenors' objection to including the CCS implementation expenses in the revenue requirement.

A. Mr. Kollen is the only witness who objected to the inclusion of this expense in the revenue requirement and proposed an adjustment to remove this expense from net operating income. Mr. Kollen argued that because the expenses were one-time implementation costs that were non-recurring, the Company should not be permitted to include the expenses in the revenue requirement.[2] Mr. Kollen instead posits that the "expenses are more akin to capital costs" and as an alternative to removing the items from the test year, "the Commission could direct that they be added to the capital costs of CCS."[3]

Q. Should the CCS costs be removed from the calculation of the revenue requirement?

A. No. KU has appropriately included $1.349 million in expenses related to the implementation of CCS in its net operating income. While Mr. Kollen is correct that these expenses are non-recurring, these costs constitute reasonable and prudent expenditures that were necessary to implement the new customer service system. As these were reasonable and prudent expenditures wholly purposed upon implementing the new system, the Company should be permitted to recover its costs. Disallowing these costs from rates is arbitrary.

---

[2] Id at 23-24.
[3] Id.

Q. Can the Company merely add the expenses to capital costs as Mr. Kollen has suggested?

A. No. In determining how to allocate CCS costs between expensed and capitalized accounts, KU adhered strictly to Generally Accepted Accounting Principles ("GAAP"). GAAP provides clear and detailed guidelines as to the type of expenditures that can be capitalized. Thus, the implementation costs for which the Company is currently seeking recovery cannot be capitalized as Mr. Kollen suggests, as the expenditures comprising the implementation costs can only be expensed and not capitalized pursuant to GAAP guidelines. All costs that could be capitalized have been booked accordingly.

Q. As the implementation costs cannot be capitalized, will the Company be able to recover those costs through another adjustment?

A. No. Unless the Commission permits the Company to recover the $1.349 million in prudently incurred implementation costs, the Company will be unable to recover these costs, as the expenses cannot be capitalized. In including these costs in the revenue requirement, the Company chose not to seek recovery of ongoing maintenance and support costs that have increased from previous levels because of the new software associated with CCS. These ongoing costs are greater than the one-time implementation costs. If recovery of the implementation costs is not permitted, the Company will then have to seek recovery of the ongoing maintenance and support costs. Scott Rebuttal Exhibit 1 contains an illustration comparing the one-time implementation costs to the ongoing maintenance and support costs.

Q. Would the Company consider amortizing the one-time implementation costs for a period longer than the one year it proposed?

A. Yes. If the Commission will not allow KU to recover all of the implementation costs in one year as proposed, there are more reasonable alternatives to Mr. Kollen's punitive proposal. First, the Company proposes an amortization period of three years as an alternative to not permitting any recovery, as the costs cannot be capitalized. Although the expense is non-recurring, the implementation costs were prudent and necessary. An amortization period lessens the immediate impact to ratepayers while allowing the Company to recover its costs for expenditures that were prudently incurred.

Secondly, if the Commission does not allow KU to recover all of the implementation costs in one year as proposed, it should allow the Company to recover the ongoing maintenance and support costs.

Q. Does this conclude your testimony?

A. Yes, it does.

400001.134411/628494.2

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Valerie L. Scott**, being duly sworn, deposes and says that she is Controller for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge and belief.

Valerie L. Scott
Valerie L. Scott

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

Scott Rebuttal Exhibit 1

Kentucky Utilities Company
CCS Expenses

Category	Account	Estimated On-Going Expenses for CCS [1]	One-Time CCS Implementation Costs [2]	Difference	KY Juris Percent	KY JURIS One-Time CCS Implementation Costs
Incremental Labor						
	146	$ (12,365)	$ -	$ (12,365)		$ -
	903	(74,126)	-	(74,126)		-
	920	278,286	-	278,286		-
	935	560,425	-	560,425		-
Outside Services				-		
	910	-	1,256,656	(1,256,656)	99.939%	1,255,889
	920, 921, 923	18,879	-	18,879		-
				-		
Non-Labor				-		
	910	-	86,547	(86,547)	99.939%	86,494
	921, 926	-	5,339	(5,339)	89.197%	4,762
	935	1,260,870	-	1,260,870		-
TOTAL		**$ 2,031,969**	**$ 1,348,542**	**$ 683,427**		**$ 1,347,146**

[1] See response to question 44(c) of the KIUC's first data request dated March 1, 2010.

[2] See response to question 44 (a) of the KIUC's first data request dated March 1, 2010 (excluding amounts charged to account 426, not included in net operating income).

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

REBUTTAL TESTIMONY OF SHANNON L. CHARNAS DIRECTOR OF UTILITY ACCOUNTING & REPORTING KENTUCKY UTILITIES COMPANY

Filed: May 27, 2010

Q. Please state your name, position and business address.

A. My name is Shannon L. Charnas. I am the Director of Utility Accounting and Reporting for E.ON U.S. Services Inc., which provides services to Kentucky Utilities Company ("KU" or the "Company") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address and respond to certain points and assertions made by intervenors to this proceeding. Specifically, I will address intervenors' comments on the following topics: (1) recovery of expenditures from the 2008 Wind Storm and 2009 Winter Storm; (2) recovery of contributions to the Kentucky Consortium for Carbon Storage and the Carbon Management Resource Group; and (3) the change to International Financial Reporting Standards.

<u>Recovery of 2008 Wind Storm and 2009 Winter Storm Regulatory Assets</u>

Q. Briefly explain the intervenors' objections to the Company's proposed rate recovery of the regulatory assets established for the operating and maintenance expenses incurred due to the 2008 Wind Storm and 2009 Winter Storm.

A. Mr. Michael J. Majoros, Jr., a witness testifying on behalf of the Attorney General, objected to the Company's proposed five-year amortization schedule for the Commission-authorized regulatory assets established for the operation and maintenance costs incurred during the 2008 Wind Storm and 2009 Winter Storm.[1] Mr. Majoros has posited that the Company should not be permitted to recover any of

[1] Direct Testimony of Michael J. Majoros of April 26, 2010 (Case No. 2009-00548) at 4.

the costs from ratepayers, arguing instead that the Company should apply these costs to its accrued asset removal costs.[2]

Q. Is it necessary that the Company be permitted to recover these expenses in this proceeding?

A. Yes. KU is seeking to recover $2.2 million and $57.3 million for the regulatory assets established for the 2008 Wind Storm and 2009 Winter Storm, respectively[3]. As demonstrated in the proceedings, in which Mr. Majoros indicated he did not participate,[4] in which the Commission permitted the Company to establish the regulatory assets, these amounts represent prudently incurred sums that were wholly purposed upon restoring service and repairing the unprecedented damage to the Company's transmission and distribution infrastructure.

Q. Can the Company apply the accrued asset removal costs to the regulatory assets in the manner Mr. Majoros is seeking?

A. No. The cost of removal funds can only be used in regard to capital assets. Mr. Majoros's proposition would require the Company to utilize cost of removal funds that can only be applied to capital assets to offset operating and maintenance costs. This is wholly inappropriate because the regulatory assets are solely comprised of operating and maintenance expenditures. Further, as a result of the 2008 Wind Storm and 2009 Winter Storm, the Company incurred costs related to the replacement of capital assets, all of which were properly booked to the capital or cost of removal accounts. A chart illustrating the amounts booked to cost of removal accounts is

[2] Id. at 5.
[3] Reference Schedule 1.27 and 1.28 of Rives Exhibit 1.
[4] See Attorney General's Response to KPSC 1-1c.

attached as Charnas Rebuttal Exhibit 1. The information shown on this Exhibit is taken directly from the Company's general ledger. This Exhibit demonstrates that the Company has diligently recorded cost of removal charges as appropriate. Despite the clear division between capital and operating and maintenance accounts, Mr. Majoros has asked the Commission to require the Company to violate a basic accounting principle in order to reduce the Company's accrued asset removal costs.

Q. Why does Mr. Majoros seek to reduce the Company's accrued asset removal costs?

A. Pursuant to Commission orders, KU collects amounts from ratepayers throughout the useful life of a capital asset so that the Company will have the funds necessary to remove the asset at the end of its useful life. The Company has only collected amounts that are approved by the Commission after sufficient investigation.[5] Mr. Majoros, in prior proceedings in which these amounts were being approved, has consistently argued that the Company is "overrecovering" for the future cost of removal.[6] Although this argument has been rejected each time it has been advanced, Mr. Majoros's current adjustment is the latest attempt to reduce the Company's accrued asset removal costs.[7]

---

[5] The Companies' depreciation rates were last approved in Case Nos. 2007-00564 and 2007-00565. Also, in Case No. 2009-00329, the Commission approved the depreciation rates for Trimble County Unit No. 2.

[6] For example, in the 2007 proceeding in which the Companies filed new depreciation studies, Mr. Majoros alleged that the Companies' computation of cost of removal had led to inflated recovery. See Direct Testimony of Michael J. Majoros, Jr. of May 12, 2008 (Case Nos. 2007-00564 and 2007-00565) at 17-18.

[7] For example, in Case Nos. 2003-00433 and 2003-00434, the Commission expressly rejected Majoros' argument that cost of removal should not be recovered over the life of an investment by including cost of removal as a component of depreciation rates. The Commission denied rehearing on the issue in its August 12, 2004 Order.

Q. Is the Company over-recovering for asset removal costs?

A. Absolutely not. As mentioned above, the Company only collects amounts pursuant to Commission orders. Mr. Majoros incorrectly states in his testimony that because the asset removal account has an accrued balance, "KU did not use it for its intended purposes" and that because the Company "continues to collect excess removal costs through the commission-approved depreciation rates....the regulatory liability will continue to grow."[8] This argument demonstrates that Mr. Majoros ignores the distinction between an *accrued* balance and an *excessive* balance. The Company has an accrued balance because the account is being accumulated such that when capital assets are retired and consequently removed, sufficient funds are available. Mr. Majoros's argument relies upon the fact that the account has an accrued balance to allege that the Company is overrecovering, while simultaneously admitting that the Company is adhering to Commission-approved depreciated rates. Mr. Majoros has continued to advance this baseless position in response to data requests in which he characterized the accrued balance as the Company's "debt to ratepayers."[9] This contention is both inaccurate and misleading. Quite simply, Mr. Majoros, although acknowledging that KU's asset removal balance has accumulated in accordance with approved rates, is asking the Commission to take the extraordinary step of requiring the Company to book operating and maintenance expenses to a capital account. In responding to data requests, Mr. Majoros was unable to provide a single authority—whether it be an accounting principle, Commission order, or court opinion—that

---

[8] Direct Testimony of Michael J. Majoros of April 24, 2010 (Case No. 2009-00548) at 4.
[9] See Attorney General's Response to KPSC 1-1.

approved applying an accrued asset removal account to storm restoration expenses.[10] Mr. Majoros has failed to provide any meaningful reason for such a departure from accounting principles and as such, KU respectfully requests that the Commission deny his adjustments.

Q. Does the Company agree with Mr. Majoros' contention that there is "no question" that KU will record the cost of removal regulatory liability in its "income account"?[11]

A. Absolutely not. KU cannot understand the basis for Mr. Majoros' contention that the Company will knowingly transfer funds from the cost of removal regulatory liability to its "income account". The Company has been quite clear that the accumulated cost of removal will be utilized for its intended purpose. Mr. Majoros' argument wrongly accuses the Company of having the intent for future deceitful misconduct. The Company takes its obligation to observe proper accounting practices very seriously; unsupported accusations such as Mr. Majoros' are unfounded.

KCCS and CMRG Regulatory Assets

Q. Briefly explain Mr. Majoros's objection to the Company recovering its contributions to the Kentucky Consortium for Carbon Storage ("KCCS") and the Carbon Management Resource Group ("CMRG").

A. Mr. Majoros has posited that KU should apply its cost of removal regulatory liability to the Commission-approved regulatory assets established for the Company's contributions to KCCS and CMRG.[12] Both KCCS and CMRG are local research

[10] See Attorney General' Response to KU 1-3.
[11] See Attorney General's Response to KPSC 1-1.b.(4)
[12] Id. at 6.

endeavors purposed upon improving carbon storage in Kentucky produced as a result of coal-fired generation. Mr. Majoros provides no basis or support for his position, summarily asserting that "KU should also apply those commission-approved regulatory assets to its Cost of Removal Regulatory Liability."[13] In responding to data requests, Mr. Majoros confirmed that he could not cite any authority supporting applying accrued asset removal funds to research contributions.[14] Furthermore, when questioned by the Staff related to his basis for applying regulatory assets for research endeavors, which have no relationship to the removal of assets, to the cost of removal regulatory liability, Mr. Majoros provided no valid explanation.[15]

Q. Should LG&E apply its cost of removal account to the KCCS and CMRG regulatory assets?

A. No, as Mr. Majoros's adjustment would again require the Company to apply costs booked as expenses to a capital asset, as KU considers contributions to be non-capital expenditures, since the contribution does not result in KU's ownership in any asset. Mr. Majoros's position is even more dubious with regard to these regulatory assets as contributions to research projects are intangible—there is certainly no cost of removal associated with a research investment. For the reasons discussed above pertaining to the 2008 Wind Storm and 2009 Winter Storm regulatory assets, it is improper to utilize a capital account for expenses. Further, KU is surprised that the Attorney General's witness would seek to disallow costs for clean coal research. The General Assembly has statutorily enacted a policy "to foster and encourage use of Kentucky

---

[13] Id. at 6.
[14] See Attorney General's Response to KU 1-3.
[15] See Attorney General's Response to KPSC 1-2.

coal by electric utilities serving the Commonwealth."[16] While KU has contributed to investments that improve carbon management in furtherance of the General Assembly's stated policy, the Attorney General's witness seeks to disallow these important expenditures for Kentucky. For these reasons, Mr. Majoros's adjustment should be denied.

International Financial Reporting Standards

Q. **Briefly explain Mr. Majoros's objection regarding the International Financial Reporting Standards ("IFRS").**

A. Mr. Majoros, in support of his position that the Company should be required to utilize its asset removal account for the regulatory assets, asserts that KU will soon begin utilizing IFRS, which are new accounting standards.[17] Mr. Majoros then stated that when KU adopts IFRS, the regulatory liability will be reduced to present value and transferred into the Company's equity account.[18]

Q. **Does KU have a specified date on which it will adopt IFRS for regulatory accounting?**

A. No. The Company does not currently have an implementation date for IFRS related to regulatory accounting. Further, KU does not believe that it can unilaterally adopt IFRS for its regulatory accounting until the Commission so orders. The Commission is statutorily authorized, pursuant to KRS 278.220, to establish a system of accounts for utilities and to prescribe the manner in which such accounts shall be kept. To the Company's knowledge, the Commission has not approved the use of IFRS for

---

[16] KRS 278.020(1).
[17] Direct Testimony of Michael J. Majoros of April 24, 2010 (Case No. 2009-00548) at 5.
[18] Id.

regulatory accounting. Further, the statute requires that the system of accounts for electric utilities "shall conform as nearly as practicable" to the system approved by the FERC.[19] To date, the FERC has neither adopted IFRS nor established a date by which IFRS will be approved. Also, the Securities and Exchange Commission, which has advocated for the financial reporting accounting standards IFRS contains, has made clear that it envisions 2015 as the earliest possible date for the required use of IFRS instead of GAAP reporting[20]. As such, Mr. Majoros's contention that KU is soon going to adopt IFRS is inaccurate, as KU has no present intention to adopt IFRS for its regulatory accounting until so authorized or directed by the Commission. Mr. Majoros's argument does not provide a valid basis for utilizing the asset removal regulatory liability for the regulatory assets as KU has no present timetable for implementing IFRS.

Q. Does this conclude your testimony?

A. Yes, it does.

[19] KRS 278.220.
[20] Per SEC release Nos. 33-9109 and 34-61578, *Commission Statement in Support of Convergence and Global Accounting* Standards, issued February 24, 2010, available at http://www.sec.gov/rules/other/2010/33-9109.pdf.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says that she is Director – Utility Accounting and Reporting for E.ON U.S. Services, Inc., and that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge and belief.

Shannon L Charnas
Shannon L. Charnas

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

Charnas Rebuttal Exhibit 1

Retirement Costs from Janaury 2009 Wind and Ice Storms

Kentucky Utilities Company

Account	Project	Task		Amount
108901	124600	1631331R02	$	718.22
108901	124600	1734384R02		428.11
108901	124600	1766364R02		443.80
108901	124600	1766654R02		844.96
108901	124600	1784182R02		803.34
108901	124600	1784827R02		332.85
108901	124600	R		140,898.69
108901	K8-2009	BNVILLE-HARDIN		10,726.89
108901	K8-2009	BTOWN HDVILLE69K		18,446.83
108901	K8-2009	BVRDAM HFORD69		30,104.48
108901	K8-2009	CAPITAL-34.5KV-R		514,824.73
108901	K8-2009	CLINTON CITY161		8,634.70
108901	K8-2009	CLNTN CTY BDWELL		2,667.09
108901	K8-2009	CRITDEN-CO.TAP		7,833.49
108901	K8-2009	CRITDEN-PRNCTON		4,065.65
108901	K8-2009	CRTNDN-MRGNF161R		100,197.17
108901	K8-2009	DVILEN HBURG69		10,024.74
108901	K8-2009	DVILLEE-LANC.R		2,102.41
108901	K8-2009	EARLNGTON NEBO69		24,414.49
108901	K8-2009	ELIHU-WOFFOR69KV		5,300.59
108901	K8-2009	ERLNGT-LVNSG161R		518.06
108901	K8-2009	ERLNGTN-GRRVP69R		475,144.73
108901	K8-2009	ESVILLE.WFFORT69		75,711.70
108901	K8-2009	FEBWIND-T019.R		12,248.64
108901	K8-2009	FEBWIND-T024.R		4,475.25
108901	K8-2009	FEBWIND-T039.R		1,983.12
108901	K8-2009	FEBWIND-T061.R		6,595.58
108901	K8-2009	FEBWIND-T104.R		10,025.38
108901	K8-2009	FEBWIND-T125.R		11,430.92
108901	K8-2009	FREDONIA QUARRY		1,986.87
108901	K8-2009	GHENT-WFRANK.R		8,168.71
108901	K8-2009	GNRV.STEL-RUMSY		85,675.47
108901	K8-2009	GNRVPP ERLGTN161		13,473.50
108901	K8-2009	GNRVPP- IND HIL		62,973.17
108901	K8-2009	GNRVPP-HILSIDE		1,237,842.39
108901	K8-2009	GRNRV-GRRVST138R		139,415.15
108901	K8-2009	GRP-MORG 161.R		8,271.46
108901	K8-2009	GVILLE-DOE.R		2,087.59
108901	K8-2009	HANSON TAP69K		170,748.40

Account	Project	Task	Amount
108901	K8-2009	HARDIN BVILLE69K	57,155.06
108901	K8-2009	IND HIL-OHIO CO.	11,391.80
108901	K8-2009	JANICE-013-R	1,886.87
108901	K8-2009	JANICE-035-R	10,047.08
108901	K8-2009	JANICE-037-R	4,404.81
108901	K8-2009	KY DAM PADUCAH	535,074.60
108901	K8-2009	LBNON BVILLE69K	7,651.81
108901	K8-2009	LFIELD SBURG69K	15,307.55
108901	K8-2009	LIVNGS-CRTDN161R	91,016.45
108901	K8-2009	LOUDEN PARIS69K	6,525.87
108901	K8-2009	LREBA PLICK69K	39,061.18
108901	K8-2009	MADSNVILLE GE69K	153,376.99
108901	K8-2009	MDSVW GE69KV	196,527.40
108901	K8-2009	MGFIELD WBASH	258.69
108901	K8-2009	NEBO-MRGANFIELD	136,249.28
108901	K8-2009	NEBO-WHEATCRFT	32,942.72
108901	K8-2009	OHIO CO.-ROSNE	5,790.11
108901	K8-2009	PADUCH CLNTON69	350.67
108901	K8-2009	PDUCH LVNGSTN161	1,644.25
108901	K8-2009	PDUCH-GRHMVIL161	3,280.27
108901	K8-2009	PRCNTON-KY DAM	16,452.78
108901	K8-2009	PUDCAH CLTON161	1,076.88
108901	K8-2009	ROSNE-LTCHFIELD	8,677.83
108901	K8-2009	RUMSEY-ERLINGTN	216,477.81
108901	K8-2009	SIMPSVL SHELBYVL	10,512.13
108901	K8-2009	SOMERSETN-STAN.R	12,051.49
108901	K8-2009	WALKER OAKHL69	144,572.13
108901	K8-2009	WCLIFF-BOYLE.R	189.21
108901	K8-2009	WHTCRFT-MRGANFLD	1,923.79
108901	K8-2009	WKLIF-CLTN CTY69	28,499.92
108901	K8-2009	WLKER PRNCTON69	25,379.12
108901	STRMKU	012709R	2,776,815.32
108901	STRMKU	021109R	99,822.13
108901	K8-2008	SEPTWIND.R-T011	5,750.89
108901	K8-2008	SEPTWIND.R-T013	33,076.79
108901	K8-2008	SEPTWIND.R-T019	23,660.11
108901	K8-2008	SEPTWIND.R-T089	2,375.97
108901	K8-2008	SEPTWIND.R-T098	5,617.40
108901	K8-2008	SEPTWIND.R-T104	2,848.42
108901	K8-2008	SEPTWIND.R-T-141	8,935.35
108901	K8-2008	SEPTWIND.R-T150	3,829.69
		TOTAL KU:	$ 7,951,077.94

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	**CASE NO. 2009-00548**

REBUTTAL TESTIMONY OF
RONALD L. MILLER
DIRECTOR, CORPORATE TAX
KENTUCKY UTILITIES COMPANY

Filed: May 27, 2010

Q. Please state your name, position and business address.

A. My name is Ronald L. Miller. I am the Director of Corporate Tax for E.ON U.S. Services, Inc., which provides services to Kentucky Utilities Company ("KU" or "Company") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address and respond to certain points and assertions made by intervenors to this proceeding. Specifically, I will address intervenors' comments on the following topics: (1) removal of the Kentucky Coal Tax Credit; (2) the "Kentucky Clean Coal Incentive" tax credit; (3) the calculation of the Trimble County Unit No. 2's Advanced Coal Investment Tax Credit; and (4) errors in the intervenors' calculations.

Kentucky Coal Tax Credit

Q. Briefly explain the intervenors' objections to KU's removal of the Kentucky Coal Tax Credit.

A. Mr. Lane Kollen, testifying on behalf of the KIUC, objected to the Company's removal of the tax credit because the Company will be eligible for the credit through 2010.[1] Mr. Kollen argues that because KU will receive the credit in 2010, the credit is known and measurable.[2] He further attempts to characterize the adjustment as a post-test year adjustment.[3]

---

[1] Direct Testimony of Lane Kollen of April 22, 2010 (Case No. 2009-00548) at 26.
[2] Id. at 27-28.
[3] Id. at 28.

Q. Should the Company include the Kentucky Coal Tax Credit as a reduction to its property tax expense?

A. No. The purpose of pro forma adjustments is to produce a revenue requirement that accurately represents the going forward level of expenses and revenues. While Mr. Kollen admits the Kentucky Coal Tax Credit is expiring, the witness fails to provide any evidence suggesting that the credit will be legislatively extended. Further, the Company monitored the legislation discussed in the Kentucky General Assembly during the last legislative session and there was no activity regarding this statute. It is anticipated that the Kentucky Coal Tax Credit will sunset as scheduled, ending with coal purchases made in calendar-year 2009. Since this credit is expiring it cannot be properly considered an ongoing credit. While Mr. Kollen is correct that the Company received the credit during the test year, as the credit is expiring, it is not a recurring reduction. Because the revenue requirement demonstrates the Company's going forward revenues and expenses, the elimination of the Kentucky Coal Tax credit was proper.

Q. Briefly explain the intervenors' position regarding the "Kentucky Clean Coal Incentive" credit.

A. Mr. Kollen has asserted that if the Kentucky Coal Tax Credit is eliminated from the Company's calculation of its property tax expense, then the new "Kentucky Clean Coal Incentive" credit should be included.[4] This credit is pursuant to a 2005 statute enacted by the Kentucky General Assembly that provides a credit for Kentucky coal purchases for clean coal facilities beginning commercial operation after January 1,

[4] Direct Testimony of Lane Kollen of April 22, 2010 (Case No. 2009-00549) at 26.

2005. As explained in my direct testimony, the only KU facility that could potentially be eligible for the credit is Trimble County Unit No. 2, which has not yet begun commercial operation.

Q. Should the "Kentucky Clean Coal Incentive" credit be included in KU's calculation of its tax expense?

A. No, the "Kentucky Clean Coal Incentive" credit should not be included because the credit is neither known nor measurable, which is the standard for pro forma adjustments to the Company's calculation of its revenue requirement. While the Company has contacted the State, we have been informed that there is no application process in place at this time. Thus, there is no way of determining whether the facility in fact will be eligible.

Q. Has the Company taken any steps to apply for the credit?

A. Yes, the Company initially made informal inquiries with representatives of the state regarding the certification process. Since these initial informal inquiries, the Company has subsequently written to the State of its intention on applying for the credit in anticipation of Trimble County Unit No. 2's impending commercial operation. However, because there is currently no existing regulation or certification process for applying, the Company does not know what credit, if any, it will be able to claim. Therefore, any adjustment to include this credit in the Company's revenue requirement is not appropriate because it is simply not known or measurable.

Q. Please discuss other uncertainties surrounding the "Kentucky Clean Coal Incentive" credit.

A. There are additional uncertainties associated with the "Kentucky Clean Coal Incentive" credit other than the current lack of a certification process. Another uncertainty is the amount of Kentucky coal that will be purchased for generation at Trimble County Unit No. 2. The KIUC, in its data request 2-11 to KU, asked the Company to provide the number of tons of coal that the Company will burn at Trimble County Unit No. 2 at an assumed 85% capacity factor. A copy of this data request and the Company's response is attached as Miller Rebuttal Exhibit 1. As noted in the Company's response, it is unclear at what capacity factor Trimble County Unit No. 2 will operate during its first few years of operation. Since the capacity factor is critical in determining the amount of coal purchased and burned, and of the credit, the amount of any credit to which the Company may be entitled cannot be reasonably estimated. This further demonstrates that the "Kentucky Clean Coal Incentive" credit is currently neither known nor measurable and thus should not be considered in calculating KU's tax expenses.

Trimble County Unit No. 2 Advanced Coal Investment Tax Credit

Q. Briefly explain Mr. Kollen's objection to KU's calculation of the Advanced Coal Investment Tax Credit ("ACITC").

A. Mr. Kollen acknowledged that the Company discovered an inadvertent error regarding the book depreciation lives used to amortize the ACITC, which the Company brought to the intervenors' and Commission's attention in response to

KPSC 2-47.[5] Mr. Kollen's adjustment merely accepts the Company's revised calculation. KU does not object to this adjustment but Mr. Kollen's revenue requirement reduction of $0.444 million on pages 4 and 31 of his testimony is incorrect. Mr. Kollen neglected to apply the Kentucky jurisdictional factor and gross up revenue factor in determining the revenue requirement impact of the revised adjustment. The correct revenue requirement reduction is $0.691 million ($0.444 million decreased ACITC basis adjustment times 0.97803 Kentucky jurisdictional factor divided by 0.6280857 gross-up factor).

Errors in Intervenors' Calculations

Q. **Were there any other errors in the calculations the intervenors submitted in their direct testimony?**

A. Yes, there were errors that impact the intervenors' adjustments and calculation of the Company's revenue requirement. Mr. Kollen's calculation of the revenue requirement impact of $4.032 million for the Kentucky Coal Tax Credit adjustment on pages 4 and 26 of his testimony is incorrect.[6] Specifically, Mr. Kollen did not reflect the loss of the federal income tax benefit as indicated in KU's response to KIUC 2-10. A copy of this data request and the Company's response is attached as Miller Rebuttal Exhibit 2. The correct revenue requirement impact of Mr. Kollen's adjustment for which the Company disagrees as discussed above is an increase of $3.117 million ($1.644 million increase in income tax expense less $0.575 million loss of federal income tax benefit @35% divided by 0.6280857 gross-up factor plus $1.415 million increase in property tax expense).

[5] Direct Testimony of Lane Kollen of April 22, 2010 (Case No. 2009-00548) at 31.
[6] Id. at 4, 26.

Also, Mr. Michael J. Majoros, Jr., testifying on behalf of the Attorney General, did not include the increased AG Federal and state income taxes amount in the Total adjustments (Line No. 50) or Adjusted Net Operating Income (Line No. 51) calculations of Exhibit MJM-1.[7] KU believes that the increase to AG Federal and state income taxes needs to be included in the spreadsheet formula to perform the AG's calculations correctly.

Q. Does this conclude your testimony?

A. Yes, it does.

[7] Direct Testimony of Michael J. Majoros, Jr. of April 26, 2010 (Case No. 2009-00548) at Exhibit MJM-1.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Ronald L. Miller**, being duly sworn, deposes and says that he is Director – Corporate Tax for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Ronald L. Miller

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

Miller Rebuttal Exhibit 1

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated March 26, 2010

Question No. 11

Responding Witness: Paul W. Thompson/Ronald L. Miller

Q-11. Refer to the Company's response to KIUC 1-46.

a. Is there any reason the Company believes that it will not qualify for the $2 per ton credit for eligible Kentucky coal purchases for new clean coal facilities?

b. Will the coal used at TC2 be subject to the tax imposed under KRS 143.020 as referenced in KRS 141.428(1)(d)? If not, please explain why it will not be.

c. Is the Company or its parent subject to tax under KRS 136.120 as referenced in KRS 141.428(2)(a) and (b)? If not, please explain why it will not be.

d. Please describe the taxes imposed by: i) KRS 136.070, ii) KRS 136.120, and iii) KRS 141.020 or 141.040, and 141.041 as referenced in KRS 141.428(3)(a).

e. To the extent the Company qualifies for the $2 per ton credit for eligible Kentucky coal purchases for new clean coal facilities and the credit is applied to reduce the Company's Kentucky state income tax, please confirm that the Company agrees that the revenue requirement effect is the amount of the credit grossed-up for income taxes. If the Company does not agree with this statement, then please explain why it disagrees and provide a copy of all research and/or source documents upon which it relies for such disagreement.

f. Please provide the number of tons of coal that the Company will burn at TC2 at an 85% assumed capacity factor. Please provide all assumptions necessary to replicate the Company's quantification.

g. Please provide the Btu content of the coal that the Company will burn at TC2.

h. Please provide the projected heat rate of TC2.

A-11. a. As stated in the response to KIUC 1-46 b and c, the Kentucky Department of Energy and Environment has not formulated the qualification criteria or procedures for certification. Without knowing the criteria and procedures, qualification is not known at this time.

b. KRS 143.020 imposes a tax on the severance and/or processing of coal in the state of Kentucky. KU expects that Kentucky sourced coal used at TC2 will be subject to the severance tax imposed under KRS 143.020. The remaining coal purchased will originate outside of Kentucky and will not be subject to the tax imposed under KRS 143.020.

c. Yes, KU is subject to tax under KRS 136.120 which imposes state property taxes on operating property of public service corporations, including gas and electric power companies.

d. i) KRS 136.070 imposed a corporation license tax on corporations either having a commercial domicile in this state or foreign corporations owning or leasing property within the State of Kentucky. This tax ended for tax periods ending on 12/31/05 and later. As a public service corporation KU was not subject to the tax under KRS 136.070 prior to its expiration under KRS 136.0701.

ii) KRS 136.120 imposes state property taxes on operating property for public service corporations, including gas and electric power companies. KU is a public service corporation that is centrally assessed property taxes under KRS 136.120.

iii) KRS 141.020 is the imposition of Kentucky state income taxes on individuals. KRS 141.040 is the imposition of Kentucky income taxes on corporations. KRS 141.041 is the imposition of Kentucky limited liability entity taxes. KU is subject to KRS 141.040.

e. If KU receives the new clean coal incentive tax credit and if the credit were applied to reduce Kentucky income taxes, the revenue requirement effect of the state credit (less the loss of applicable federal tax benefit) would be grossed up for income taxes. However, KU has not applied for nor received the new clean coal incentive tax credit.

f. The Company does <u>not</u> anticipate operating TC2 at an 85% capacity factor, particularly in the first year of operation. The tons burned for total Trimble County 2 at an 85% capacity factor is estimated at 2,500,000 per year. That is based on 6,942 MMBTU per hour, an 85% capacity factor, and a BTU content per pound of 10,340. Therefore the BTU calculation is 6,942 X 24 hours X 365 days X 85% Capacity Factor X 1,000,000 = 51,690,132,000,000 BTU's.

BTU's per ton = 10,340 BTU's per pound X 2000 pounds = 20,680,000.

Tons per year = 51,690,132,000,000 divided by 20,680,000 = approx. 2,500,000.

Tons Calculated Above	2,500,000
Adjustment for 25% IMEA/IMPA ownership	0.75
KU/LG&E ownership tons	1,875,000
KU ownership percentage	0.81
KU tons	1,518,750
Estimated Kentucky Purchases	0.53
KU Kentucky purchases	804,938

g. The expected BTU content of the coal is 10,340 BTU per Pound.

h. The projected average net heat rate for the unit is 8,774 (BTU/kWh) for the year 2010, and 8,753 (BTU/kWh) for the year 2011.

Miller Rebuttal Exhibit 2

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Second Set of Data Requests of Kentucky Industrial Utility Customers, Inc. Dated March 26, 2010

Question No. 10

Responding Witness: Ronald L. Miller

Q-10. Refer to the Company's response to KIUC 1-45(d). The question was addressed to the situation whereby the coal tax credit was applied to reduce the Kentucky state income tax. Please respond to the question that was asked.

A-10. The Company expects the 2009 coal tax credit that will be recognized in 2010 to be applied against the 2010 Property Tax. If the coal tax credit were applied to Kentucky state income tax, the state tax credit (less the loss of applicable federal tax benefit) would be grossed-up to quantify the revenue requirements.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

REBUTTAL TESTIMONY OF
DANIEL K. ARBOUGH
TREASURER
KENTUCKY UTILITIES COMPANY

Filed: May 27, 2010

Q. Please state your name, position and business address.

A. My name is Daniel K. Arbough. I am the Treasurer for Kentucky Utilities Company ("KU" or "Company") and an employee of E.ON U.S. Services Inc., which provides services to KU and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address and respond to certain points and assertions made by intervenors to this proceeding. Specifically, I will address intervenors' comments on the following topics: (1) proposed adjustments to the Company's equity ratio; (2) KU's short-term debt; (3) KU's long-term debt; (4) the cost of common equity to the Company; and (5) the adjustments related to the Company's involvement with Electric Energy, Inc.

Capital Structure and Debt/Equity Ratio

Q. Briefly explain the adjustment the Attorney General's Witness, Dr. J. Randall Woolridge, made to the Company's capital structure.

A. Dr. Woolridge recommended a capital structure for KU of 50% debt and 50% equity, which varies from the Company's capital structure at the end of the test year, which consisted of 45.60% long-term debt, 0.55% short-term debt and 53.85% equity.[1] Dr. Woolridge's basis for this adjustment to KU's capital structure was his review of the capital structure ratios for an Electric Proxy Group.[2] His conclusion was that because

---

[1] Direct Testimony of Dr. J. Randall Woolridge of April 22, 2010 (Case No. 2009-00548) at 12-13.
[2] Id.

the utilities in these groups tended to have a lower common equity ratio, KU was not currently exposed to enough financial risk.[3]

Q. Do you accept Dr. Woolridge's adjustment to the Company's capital structure?

A. No. Dr. Woolridge's analysis and recommendation ignores that the Company's capital structure is purposed upon achieving a rating in the "A" range, as defined by Standard & Poor's ("S&P") criteria. In May 2009, S&P revised its business and financial risk matrix structure, under which KU could obtain an "A-" rating by maintaining its current "Excellent" business risk profile and moving into the "Significant" category for its financial risk profile. A copy of the revised matrix and accompanying article is attached as Arbough Rebuttal Exhibit 1. Currently, KU is in the "Aggressive" category, which has resulted in a BBB+ rating. In order to fall within the "Significant" financial risk profile, S&P's guidelines suggest that KU must maintain a debt to capital ratio of 45-50%%, which results in a common equity of 50-55%. Note that these ratios are not calculated based on the financial statements as prepared using GAAP, but rather as adjusted by S&P. This is the reason the Company has maintained its equity ratio at its current level.

Q. How would Dr. Woolridge's recommendation for KU's capital structure impact its bond rating?

A. To achieve an "A-" rating, the Company needs to maintain its equity ratio, as adjusted by S&P, in the target range noted in my response above. KU's GAAP ratio and adjusted ratio were in this target range at the end of the test year at 53.93% and 51.44%, respectively. Dr. Woolridge's recommended capital structure would have

[3] Id.

the Company *decrease* its GAAP common equity to 50%, however. If the Commission accepts this adjustment to the capital structure, KU would, at best, remain at its current "BBB+" rating and in fact be at risk for a downgrade and thus higher interest expenses on its debt.

Q. Please explain the advantage of having an "A" rating, as opposed to "BBB" rating.

A. The recent financial crisis illustrated the advantages of having a rating in the "A" range, as well as the significant difference between an "A" and "BBB" rating. Attached as Arbough Rebuttal Exhibit 2 is an illustration which demonstrates the difference in bond spreads, which is the difference between the yield on a corporate bond and U.S. treasuries, between "A" and "BBB" utility corporate bonds during the recent economic downturn. During the height of the recession, the variance between "A" and "BBB" corporate bond yields grew significantly. Consequently, "BBB" rated utilities bonds were viewed as a significantly riskier investment. Although the divergence between "A" and "BBB" rated bond yields has narrowed as the economic situation improves, during volatile capital market conditions KU and its customers could face significantly higher interest expense if the Company fails to maintains its strong financial condition.

Q. Is KU's current equity ratio consistent with its prior capital structure?

A. Yes. Over the last ten years, KU's equity ratio has been very consistent. The equity ratio (including common and preferred stock, when applicable) during this period has ranged from 52.73% to 57.33%, as demonstrated by the Company's response to KPSC 1-3. This illustration demonstrates that the Company's common equity in the last decade has never been as low as the figure Dr. Woolridge recommended. KU's consistency in its equity ratio is important, because, as discussed, significant reductions in a company's equity ratio places the business at risk to suffer a credit rating downgrade. Further, KU's capital structure has been consistent over the last ten years - during which two rate case proceedings have occurred - and there has been no adjustment to the Company's capital structure or its objective of obtaining a rating in the "A" range. In addition, when presented with an argument for a "hypothetical capital structure" in a prior ECR proceeding[4], the Commission rejected the argument stating that it "has never utilized or established a hypothetical capital structure for the environmental surcharge" and it "utilizes the actual common equity ratio of the utility".[5] As the Company's capital structure is consistent and in keeping with its stated rating goals, KU respectfully requests that the Commission deny Dr. Woolridge's recommended capital structure, as the recommendation is not in the best financial interests of the Company or its ratepayers.

Short-Term Debt

Q. Briefly explain the adjustment that the KIUC's witness, Mr. Lane Kollen, made to KU's short-term debt.

A. Mr. Kollen added $18.061 million dollars to KU's short-term debt, altering the Company's capitalization at October 31, 2009.[6] Mr. Kollen's basis for this adjustment was that the Company's short-term debt was understated in its filing in

[4] See In the Matter of: The Application of Kentucky Utilities Company for a Certificate of Public Convenience and Necessity to Construct Flue Gas Desulfurization Systems and Approval of its 2004 Compliance Plan for Recovery by Environmental Surcharge (Case No. 2004-00426) Order, June 20, 2005.
[5] Id. at 20.
[6] Direct Testimony of Lane Kollen of April 22, 2010 (Case No. 2009-00548) at 35.

this proceeding as compared to the amounts of short-term debt during the test year.[7] Further, Mr. Kollen asserted that utilities could intentionally alter their amount of short-term debt on any given day in order to increase their cost of capital and claimed revenue requirement.[8] In order to prevent what Mr. Kollen perceived as manipulation by KU, Mr. Kollen consequently imputed $18.061 million of short-term debt. Mr. Kollen did so through advocating that the Commission should use a 13 month average to measure short-term debt, as opposed to the amount of short-term debt on the last day of the test year.[9]

Q. Is it fair to use the 13 month average as Mr. Kollen suggests?

A. No. Every figure contained in Rives Exhibit 2, which is the Company's capitalization at October 31, 2009, is based upon the amount *on that day.* The very title of the exhibit demonstrates that the capitalization worksheet captures the values on a single day. Mr. Kollen has suggested that the Company use a 13 month average for this one value, ignoring that the remainder of the exhibit would be calculated inconsistently. Mr. Kollen is urging this Commission to engage in selective averaging merely to reduce the Company's revenue requirement. Mr. Kollen has failed to provide the Commission with any basis for accepting this averaging concept, which is in contravention of well-established Commission precedent.

---

[7] Id. at 31.
[8] Id. at 34.
[9] Id. at 33.

Q. Please comment on the effect of Mr. Kollen's adjustment regarding the short-term debt.

A. In addition to imputing $18.061 million to KU's short-term debt, Mr. Kollen reduced the Company's long-term debt and common equity on a pro rata basis.[10] This reduction in long-term debt and equity altered the Company's capital structure, as the Company's equity was reduced to 53.57% from 53.85%.[11] As discussed above regarding Dr. Woolridge's adjustment to KU's equity ratio, reductions in the Company's equity ratio decrease the likelihood of KU obtaining a rating in the "A" range as defined by S&P. Even if the Commission accepts Mr. Kollen's position that some short-term debt should be imputed to KU, the adjustment should not be calculated in the manner in which Mr. Kollen has provided, as the calculation increases the leverage of the Company. Instead, the increase in short-term debt should be offset completely by a reduction in long-term debt.

Cost of Short-Term and Long-Term Debt

Q. Briefly summarize Mr. Kollen's comments regarding the Company updating its cost of debt.

A. Mr. Kollen correctly observed that it is the Commission's longstanding practice to require utilities to provide updated information throughout base rate proceedings, including updating the cost of debt.[12] In accordance with this practice and pursuant to Commission discovery, KU updated its cost of short-term debt and long-term debt in

---

[10] Id. at 35.
[11] Id. at Exhibit LK-19, page 1 of 2.
[12] Id. at 36.

updated responses to the KPSC 1-43. The Company does not object to Mr. Kollen's acceptance of this updated information.

Cost of Common Equity

Q. Please comment on Mr. Kollen's argument that the cost of common equity should be reduced.

A. This adjustment, principally asserted by another KIUC witness, Mr. Richard Baudino, is being addressed by Dr. William Avera's rebuttal testimony. I object to Mr. Baudino's and Mr. Kollen's adjustment for the reasons explained by Dr. Avera.

EEI Adjustments

Q. Briefly explain the adjustments Mr. Kollen has proposed regarding KU's investment in Electric Energy, Inc. ("EEI").

A. Mr. Kollen has proposed three adjustments regarding KU's investment in EEI. The first two are pro forma adjustments that seek to incorporate EEI earnings into KU's revenue requirement and normalize those earnings. These adjustments will be discussed by Mr. Rives in his rebuttal testimony. The final adjustment Mr. Kollen proposes regarding the Company's investment in EEI is to eliminate the adjustments the Company made to reduce capitalization for KU's original investment in EEI.[13] Mr. Kollen consequently increased capitalization by $1.295 million, while also eliminating KU's adjustment to reduce common equity for undistributed EEI earnings.[14] Before addressing the merits of the Company's decision to exclude this investment from capitalization, it should be noted that the adjustment to increase

---

[13] Id. at 38.

[14] Id.

capitalization and reduce common equity for undistributed EEI earnings are only proper if the Commission accepts Mr. Kollen's adjustment to include the EEI earnings in operating income. For the reasons explained in Mr. Rives's rebuttal testimony, the Company objects to these pro forma adjustments.

Q. If the Commission accepts Mr. Kollen's pro forma adjustments to operating income, should KU's capitalization be increased to reflect the Company's original investment in EEI?

A. Yes. If the Commission accepts Mr. Kollen's adjustments, KU's capitalization must be increased to reflect the investment in EEI. Otherwise, the Company would not be allowed to earn a rate of return on its investment in EEI.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Daniel K. Arbough
Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of May 2010.

Victoria B Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

Arbough Rebuttal Exhibit 1

STANDARD
&POOR'S

Global Credit Portal
RatingsDirect®

May 27, 2009

Criteria | Corporates | General:

Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

Primary Credit Analysts:
Solomon B Samson, New York (1) 212-438-7653; sol_samson@standardandpoors.com
Emmanuel Dubois-Pelerin, Paris (33) 1-4420-6673; emmanuel_dubois-pelerin@standardandpoors.com

Table Of Contents

Criteria | Corporates | General:

Criteria Methodology: Business Risk/Financial Risk Matrix Expanded

(Editor's Note: In the previous version of this article published on May 26, certain of the rating outcomes in the table 1 matrix were missated. A corrected version follows.)

Standard & Poor's Ratings Services is refining its methodology for corporate ratings related to its business risk/financial risk matrix, which we published as part of 2008 Corporate Ratings Criteria on April 15, 2008, on RatingsDirect at www.ratingsdirect.com and Standard & Poor's Web site at www.standardandpoors.com.

This article amends and supersedes the criteria as published in Corporate Ratings Criteria, page 21, and the articles listed in the "Related Articles" section at the end of this report.

This article is part of a broad series of measures announced last year to enhance our governance, analytics, dissemination of information, and investor education initiatives. These initiatives are aimed at augmenting our independence, strengthening the rating process, and increasing our transparency to better serve the global markets.

We introduced the business risk/financial risk matrix four years ago. The relationships depicted in the matrix represent an essential element of our corporate analytical methodology.

We are now expanding the matrix, by adding one category to both business and financial risks (see table 1). As a result, the matrix allows for greater differentiation regarding companies rated lower than investment grade (i.e., 'BB' and below).

Table 1

Business And Financial Risk Profile Matrix

Business Risk Profile	Financial Risk Profile					
	Minimal	**Modest**	**Intermediate**	**Significant**	**Aggressive**	**Highly Leveraged**
Excellent	AAA	AA	A	A-	BBB	--
Strong	AA	A	A-	BBB	BB	BB-
Satisfactory	A-	BBB+	BBB	BB+	BB-	B+
Fair	--	BBB-	BB+	BB	BB-	B
Weak	--	--	BB	BB-	B+	B-
Vulnerable	--	--	--	B+	B	CCC+

These rating outcomes are shown for guidance purposes only Actual rating should be within one notch of indicated rating outcomes.

The rating outcomes refer to issuer credit ratings. The ratings indicated in each cell of the matrix are the midpoints of a range of likely rating possibilities. This range would ordinarily span one notch above and below the indicated rating.

Business Risk/Financial Risk Framework

Our corporate analytical methodology organizes the analytical process according to a common framework, and it divides the task into several categories so that all salient issues are considered. The first categories involve fundamental business analysis; the financial analysis categories follow.

Our ratings analysis starts with the assessment of the business and competitive profile of the company. Two companies with identical financial metrics can be rated very differently, to the extent that their business challenges and prospects differ. The categories underlying our business and financial risk assessments are:

Business risk
- Country risk
- Industry risk
- Competitive position
- Profitability/Peer group comparisons

Financial risk
- Accounting
- Financial governance and policies/risk tolerance
- Cash flow adequacy
- Capital structure/asset protection
- Liquidity/short-term factors

We do not have any predetermined weights for these categories. The significance of specific factors varies from situation to situation.

Updated Matrix

We developed the matrix to make explicit the rating outcomes that are typical for various business risk/financial risk combinations. It illustrates the relationship of business and financial risk profiles to the issuer credit rating.

We tend to weight business risk slightly more than financial risk when differentiating among investment-grade ratings. Conversely, we place slightly more weight on financial risk for speculative-grade issuers (see table 1, again). There also is a subtle compounding effect when both business risk and financial risk are aligned at extremes (i.e., excellent/minimal and vulnerable/highly leveraged.)

The new, more granular version of the matrix represents a refinement--not any change in rating criteria or standards--and, consequently, holds no implications for any changes to existing ratings. However, the expanded matrix should enhance the transparency of the analytical process.

Financial Benchmarks

Table 2

Financial Risk Indicative Ratios (Corporates)

	FFO/Debt (%)	Debt/EBITDA (x)	Debt/Capital (%)
Minimal	greater than 60	less than 1.5	less than 25
Modest	45-60	1.5-2	25-35
Intermediate	30-45	2-3	35-45
Significant	20-30	3-4	45-50
Aggressive	12-20	4-5	50-60
Highly Leveraged	less than 12	greater than 5	greater than 60

How To Use The Matrix--And Its Limitations

The rating matrix indicative outcomes are what we typically observe--but are not meant to be precise indications or guarantees of future rating opinions. Positive and negative nuances in our analysis may lead to a notch higher or lower than the outcomes indicated in the various cells of the matrix.

In certain situations there may be specific, overarching risks that are outside the standard framework, e.g., a liquidity crisis, major litigation, or large acquisition. This often is the case regarding credits at the lowest end of the credit spectrum--i.e., the 'CCC' category and lower. These ratings, by definition, reflect some impending crisis or acute vulnerability, and the balanced approach that underlies the matrix framework just does not lend itself to such situations.

Similarly, some matrix cells are blank because the underlying combinations are highly unusual--and presumably would involve complicated factors and analysis.

The following hypothetical example illustrates how the tables can be used to better understand our rating process (see tables 1 and 2).

We believe that Company ABC has a satisfactory business risk profile, typical of a low investment-grade industrial issuer. If we believed its financial risk were intermediate, the expected rating outcome should be within one notch of 'BBB'. ABC's ratios of cash flow to debt (35%) and debt leverage (total debt to EBITDA of 2.5x) are indeed characteristic of intermediate financial risk.

It might be possible for Company ABC to be upgraded to the 'A' category by, for example, reducing its debt burden to the point that financial risk is viewed as minimal. Funds from operations (FFO) to debt of more than 60% and debt to EBITDA of only 1.5x would, in most cases, indicate minimal.

Conversely, ABC may choose to become more financially aggressive--perhaps it decides to reward shareholders by borrowing to repurchase its stock. It is possible that the company may fall into the 'BB' category if we view its financial risk as significant. FFO to debt of 20% and debt to EBITDA 4x would, in our view, typify the significant financial risk category.

Still, it is essential to realize that the financial benchmarks are guidelines, neither gospel nor guarantees. They can vary in nonstandard cases: For example, if a company's financial measures exhibit very little volatility, benchmarks may be somewhat more relaxed.

Moreover, our assessment of financial risk is not as simplistic as looking at a few ratios. It encompasses:

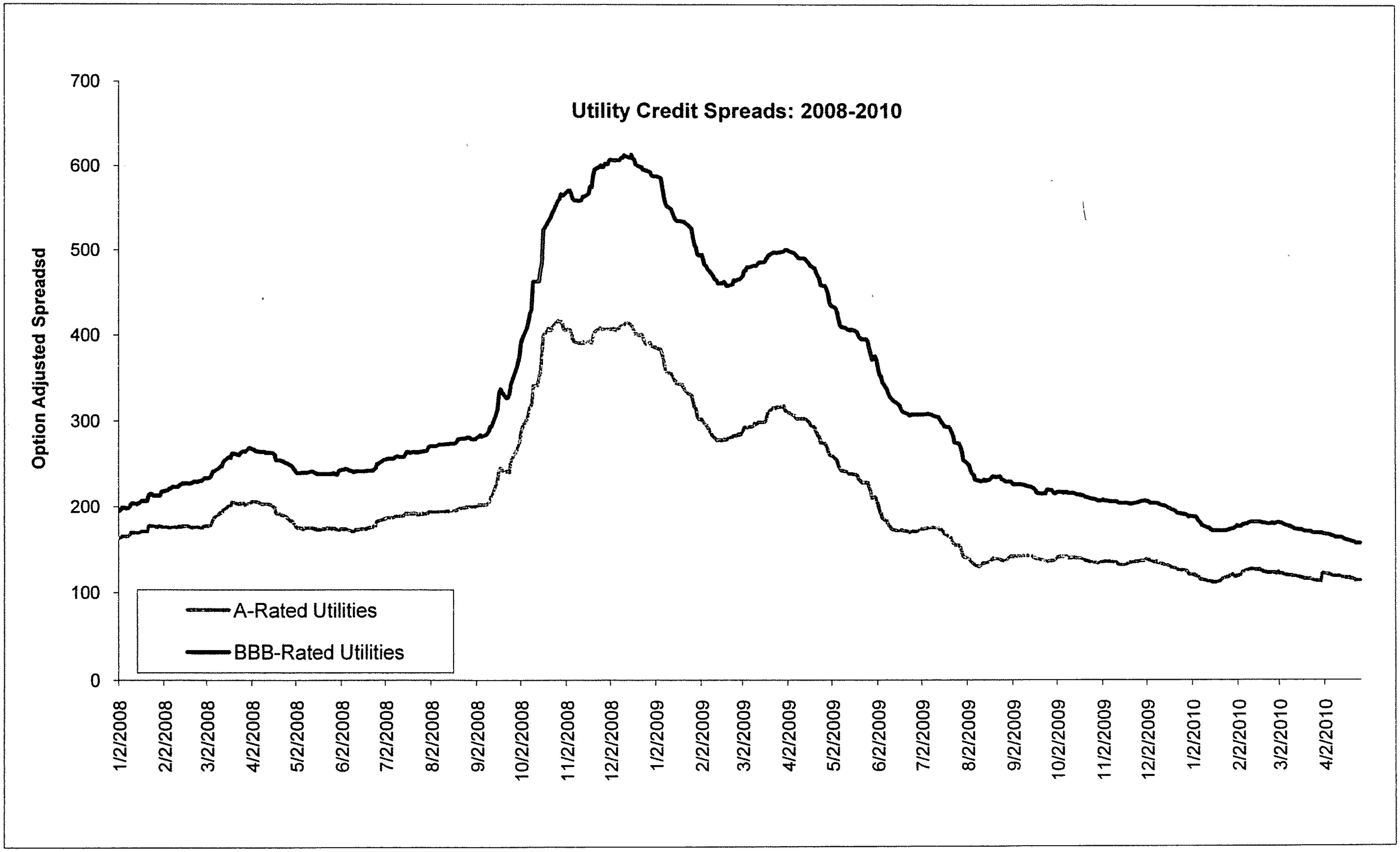
- a view of accounting and disclosure practices;
- a view of corporate governance, financial policies, and risk tolerance;
- the degree of capital intensity, flexibility regarding capital expenditures and other cash needs, including acquisitions and shareholder distributions; and
- various aspects of liquidity--including the risk of refinancing near-term maturities.

The matrix addresses a company's standalone credit profile, and does not take account of external influences, which would pertain in the case of government-related entities or subsidiaries that in our view may benefit or suffer from affiliation with a stronger or weaker group. The matrix refers only to local-currency ratings, rather than foreign-currency ratings, which incorporate additional transfer and convertibility risks. Finally, the matrix does not apply to project finance or corporate securitizations.

Related Articles

Industrials' Business Risk/Financial Risk Matrix--A Fundamental Perspective On Corporate Ratings, published April 7, 2005, on RatingsDirect.

Arbough Rebuttal Exhibit 2



Arbough Rebuttal Exhibit 2
Page 1 of 1

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))))	**CASE NO. 2009-00548**

REBUTTAL TESTIMONY

OF

WILLIAM E. AVERA

on behalf of

KENTUCKY UTILITIES COMPANY

Filed: May 27, 2010

REBUTTAL TESTIMONY OF WILLIAM E. AVERA

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. DID YOU PREVIOUSLY SUBMIT DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I did.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS CASE?

A. My purpose is to respond to the testimony of Dr. J. Randall Woolridge, submitted on behalf of the Kentucky Office of Attorney General ("OAG"), and Mr. Richard A. Baudino, on behalf of the Kentucky Industrial Utility Consumers ("KIUC"), concerning the fair rate of return on equity ("ROE") that Company ("KU" or "the Company") should be authorized to earn on its investment in providing electric utility service. In addition, I also respond to the capital structure recommendations of Dr. Woolridge.

Q. PLEASE SUMMARIZE THE PRINCIPAL CONCLUSIONS OF YOUR REBUTTAL TESTIMONY.

A. Dr. Woolridge's and Mr. Baudino's recommendations are flawed and should be rejected. Correcting and supplementing their analyses resulted in the following cost of equity estimates:

TABLE WEA-8
COST OF EQUITY – BAUDINO AND WOOLRIDGE PROXY GROUPS

Revised DCF Analysis	
Woolridge - Electric	11.0%
Baudino	10.6%
DCF Price Growth	
Woolridge - Electric	11.4%
Baudino	10.5%
Expected Earnings Approach	
Woolridge - Electric	10.9%
Baudino	11.2%
Allowed ROE	
Woolridge - Electric	10.7%
Baudino	10.6%
Average - All Analyses	**10.9%**

With respect to their analyses I conclude that:

- *Because of flaws in the screening criteria and data used Mr. Baudino and Dr. Woolridge,, their proxy groups of electric utilities should be rejected;*
- *Utilities have significantly altered their dividend policies in recent years and Mr. Baudino's and Dr. Woolridge's reliance on dividend growth rates to apply the discounted cash flow ("DCF") model imparts a downward bias to their results;*
- *Because Mr. Baudino Dr. Woolridge incorporated numerous illogical growth rate estimates, their DCF cost of equity estimates are biased downward;*
- *Because the calculations underlying Mr. Baudino's and Dr. Woolridge's internal growth rates are flawed and incomplete, this growth measure should be ignored;*
- *Growth in stock price is consistent with the assumptions underlying the DCF method and investors' expectations.*

My rebuttal testimony also demonstrates that:

- *Contrary to Dr. Woolridge's and Mr. Baudino's unsupported allegations, the expected earnings approach is entirely consistent with the regulatory and economic principles advanced in their testimony;*

- *Applying the expected earnings approach to the proxy groups of Mr. Baudino and Dr. Woolridge demonstrates that their recommendations are woefully inadequate to compensate investors in KU;*
- *While allowed ROEs demonstrate that Mr. Baudino's and Dr. Woolridge's recommendations are too low to be credible, Mr. Prisco failed to conduct any independent analyses or consider the relative risks of KU;*
- *Dr. Woolridge and Mr. Baudino ignored the results of their applications of the Capital Asset Pricing Model ("CAPM") and so should the Kentucky Public Service Commission ("KPSC");*
- *The failure of Mr. Baudino and Dr. Woolridge to consider the impact of flotation costs contradicts the findings of the financial literature and the economic requirements underlying a fair rate of return on equity.*

With respect to Dr. Woolridge's recommended capital structure, my rebuttal testimony demonstrates that there is no basis for the hypothetical equity ratio he selects. Finally, my rebuttal testimony demonstrates that Dr. Woolridge's and Mr. Baudino's criticisms of my alternative applications and conclusions are misguided and should be ignored.

II. DCF RESULTS ARE UNDERSTATED

Q. WHAT ARE THE FUNDAMENTAL DIFFERENCES BETWEEN YOUR DCF ANALYSIS AND THAT OF DR. WOOLRIDGE?

A. There are four key distinctions between my DCF analysis and that of Dr. Woolridge: 1) whereas Dr. Woolridge incorporates historical results as being indicative of what investors expect, my analysis focuses directly on forward-looking data; 2) Dr. Woolridge discounts reliance on analysts' growth forecasts for earnings per share ("EPS") as somehow biased, while my application of the DCF model recognizes that it is investors' *perceptions and expectations* that must be considered in applying the DCF model; 3) rather than looking to the capital markets for guidance as to investors' forward-looking expectations, Dr. Woolridge applies the DCF model based on his own personal views; and, 4) whereas my analysis explicitly excludes data that results in illogical cost of equity estimates, Dr. Woolridge essentially assumes that any resulting bias will be eliminated through averaging or by reference to the median.

Q. DO THE RESULTS OF DR. WOOLRIDGE'S DCF ANALYSIS MIRROR INVESTORS' LONG-TERM EXPECTATIONS IN THE CAPITAL MARKETS?

A. No. There is every indication that his DCF results are biased downward and fail to reflect investors' required rate of return. As I explained in my direct testimony (pp. 31-33), historical growth rates (such as those referenced by Dr. Woolridge to apply the DCF model) are colored by the structural changes and numerous challenges faced in the utility industry. Moreover, given recent financial trends in the utility industry and the importance of earnings in determining future cash flows and stock prices, growth rates in dividends per share ("DPS") and book value per share ("BVPS") are not likely to be indicative of investors' long-term expectations. As a result, DCF estimates based on these growth rates do not capture investors' required rate of return for the industry.

Consider Dr. Woolridge's reference to dividend growth rates, for example. If past trends in DPS are to be representative of investors' expectations for the future, then the historical conditions giving rise to these growth rates should be expected to continue. That is clearly not the case for utilities, where structural and industry changes have led to declining dividends as utilities significantly altered their dividend policies in response to more accentuated business risks in the industry. As a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties

As I explained in my direct testimony, specific trends in dividend policies for utilities and evidence from the investment community fully support my conclusion that earnings growth projections are likely to provide a superior guide to investors' expectations. While past conditions for utilities serve to depress DPS growth measures, they are not representative of long-term expectations for the utility industry.

Q. DID DR. WOOLRIDGE AND MR. BAUDINO RECOGNIZE THE PITFALLS ASSOCIATED WITH HISTORICAL GROWTH RATES?

A. Yes. Dr. Woolridge noted that:

> [T]o best estimate the cost of common equity capital using the conventional DCF model, one must look to long-term growth rate expectations.[1]

But as he acknowledged, historical growth rates can differ significantly from the forward-looking growth rate required by the DCF model:

> [O]ne must use historical growth numbers as measures of investors' expectations with caution. In some cases, past growth may not reflect future growth potential. Also, employing a single growth rate number (for example, for five or ten years), is unlikely to accurately measure investors' expectations due to the sensitivity of a single growth rate to fluctuations in individual firm performance as well as overall economic fluctuations (i.e., business cycles).[2]

Similarly, Mr. Baudino noted (p. 21) that the analysis of investors' cost of equity "is a forward-looking process," and that historical growth rates "may not accurately represent investors' expectations." Mr. Baudino concluded that analysts' forecasts

---

[1] Woolridge Direct at 28.

[2] *Id.*

"provide better proxies for the expected growth components in the DCF model than historical growth rates." Moreover, to the extent historical trends for utilities are meaningful, they are already captured in projected growth rates, including those published by Value Line, First Call, Zacks, and Thomson Reuters, since securities analysts also routinely examine and assess the impact and continued relevance (if any) of historical trends.

Q. IS THE DOWNWARD BIAS IN DR. WOOLRIDGE'S HISTORICAL GROWTH MEASURES SELF EVIDENT?

A. Yes, it is. As shown on page 3 of Exhibit JRW-10, approximately one-third of the individual historical growth rates reported by Dr. Woolridge for the companies in his electric proxy group were *zero* or *negative*, with over one-half being 1.5 percent or less. Combining a growth rate of 1.5 percent with Dr. Woolridge's dividend yield of 4.9 percent implies a DCF cost of equity of approximately 6.4 percent.[3] This implied cost of equity barely exceeds the yield currently available to investors from triple-B public utility bonds, which averaged 6.2 percent in April 2010.[4] Clearly, the risks associated with an investment in public utility common stocks exceed those of long-term bonds. As Mr. Baudino noted (p. 22), negative growth rates should be excluded because they "are inconsistent with the assumption of constant positive growth in the DCF formula." Dr. Woolridge's historical growth measures result in a built-in downward bias to his DCF conclusions, which provide no meaningful information regarding the expectations and requirements of investors.

---

[3] Adjusting Dr. Woolridge's average dividend yield of 4.9 percent (Exhibit JRW-10, p. 1) for one-half year's growth at 1.5 percent implies a dividend yield of approximately 4.5 percent.

[4] Moody's Investors Service, www.credittrends.com.

Q. DID DR. WOOLRIDGE MAKE ANY EFFORT TO TEST THE REASONABLENESS OF THE INDIVIDUAL GROWTH ESTIMATES HE RELIED ON TO APPLY THE CONSTANT GROWTH DCF MODEL?

A. No. Despite recognizing that caution is warranted in using historical growth rates, Dr. Woolridge simply calculated the average and median of the individual growth rates with no consideration for the reasonableness of the underlying data. In fact, as demonstrated above, many of the cost of equity estimates implied by Dr. Woolridge's DCF application make no economic sense.

For example, consider the 5-year historical BVPS growth rates included in Dr. Woolridge's evaluation. As shown on page 3 of Exhibit JRW-10, the individual values for the firms in his electric proxy group ranged from –2.0 percent to 14.5 percent. Combining these growth rates referenced by Dr. Woolridge with his average dividend yield suggests a DCF cost of equity range of 2.9 percent to 19.4 percent. Clearly, DCF estimates that imply a cost of equity below the yield on risk-free Treasury bonds or approaching 20 percent violate economic logic and hardly represent an informed evaluation of investors' expectations.

Q. DOES REFERENCE TO THE MEDIAN CORRECT FOR ANY UNDERLYING BIAS IN DR. WOOLRIDGE'S HISTORICAL GROWTH RATES?

A. No. The median is simply the observation with an equal number of data values above and below. For odd-numbered samples, the median relies on only a <u>single number</u>, *e.g.*, the fifth number in a nine-number set. Reliance on the median value for a series of illogical values does not correct for the inability of individual cost of equity estimates to pass fundamental tests of economic logic.

Q. HAS DR. WOOLRIDGE RECOGNIZED THE IMPORTANCE OF EVALUATING MODEL INPUTS IN OTHER FORUMS?

A. Yes. As Dr. Woolridge noted in his testimony (Appendix A, p. 1), he is a founder and managing director of *ValuePro*, which is an online valuation service largely based on application of the DCF model. *ValuePro* confirmed the importance of evaluating the reasonableness of inputs to the DCF model:

> Garbage in, Garbage out! Like any other computer program, if the inputs into our Online Valuation Service are garbage, the resulting valuation also will be garbage.[5]

Unlike his approach here, Dr. Woolridge advised investors to use common sense in interpreting the results of valuation models, such as the DCF:

> If a figure comes up for a certain input that is either highly implausible or looks wrong, indeed it may be. If a valuation is way out of line, figure out where the Service may have strayed on a valuation, and correct it.[6]

Given the fact that many of the growth rates relied on by Dr. Woolridge result in illogical cost of equity estimates, it is appropriate to take the same critical viewpoint when evaluating inputs to his DCF model.

Q. DO YOU AGREE WITH MR. BAUDINO (P. 39) THAT YOU "ERRED" BY IGNORING VALUE LINE'S DPS GROWTH PROJECTIONS IN YOUR APPLICATION OF THE DCF MODEL?

A. No. As I explained in my direct testimony, specific trends in dividend policies for utilities and evidence from the investment community fully support my conclusion that earnings growth projections are likely to provide a superior guide to investors' expectations. Indeed, while Mr. Baudino suggests (p. 40) that dividend growth

---

[5] http://www.valuepro.net/abtonline/abtonline.shtml.
[6] *Id.*

"must be considered," his own review of this information confirms my decision to exclude it. As shown on Mr. Baudino's Exhibit (RAB-7), the DPS growth rates for the firms in my Utility Proxy Group ranged from 1.0 percent to 13.0 percent. Even after excluding "aberrant or negative growth rates,"[7] Value Line's DPS growth rates for the firms in my Utility Proxy Group result in an average DCF cost of equity estimate of 8.92 percent, which falls far below even Mr. Baudino's downward biased 9.7 percent ROE recommendation.

Moreover, I disagree with Mr. Baudino's assertion (p. 39) that because Value Line's projected DPS growth rates "are widely available to investors," they can "reasonably be assumed to influence their expectation with respect to growth." Value Line publishes a wide variety of financial information, including growth rates in revenues and cash flows -- simply because a statistic is included in Value Line's report does not mean that investors would rely on it in determining their growth expectations. Indeed, Value Line makes a number of five and ten-year historical growth rates available to investors, including historical growth in DPS, which Mr. Baudino nevertheless rejected as inconsistent with investors' expectations.[8]

Q. IS THIS DOWNWARD BIAS ALSO APPARENT IN DR. WOOLRIDGE'S DPS GROWTH MEASURES?

A. Yes. Dr. Woolridge reported a median DPS growth rate for his electric proxy group based on Value Line's projections of 2.8 percent, which falls between 110 and 260 basis points lower than comparable values for his other forward-looking growth measures, and his median historical DPS growth rates were over 160 basis points below those indicated from his review of historical trends in EPS and BVPS.[9]

---

[7] Mr. Baudino failed to exclude growth rates of zero or 1.0 percent, despite the concerns noted on page 21 of his testimony.

[8] Baudino Direct at 21.

[9] Exhibit JRW-10, pp. 3-5.

Q. DO THE PROJECTED DPS GROWTH RATES FOR MR. BAUDINO'S PROXY GROUP EXHIBIT SIMILAR PROBLEMS?

A. Yes. As shown on page 1 of Mr. Baudino's Exhibit (RAB-4), DPS growth rates for four of the firms in his reference group were equal to 1.0 percent, and his average dividend growth rate of 3.97 percent was over 110 basis points below the growth rate indicated from his review of analysts' earnings growth projections. This mirrors the trend towards a more conservative payout ratio for electric utilities and the need to conserve financial resources to provide a hedge against heightened uncertainties. However, while utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry, this is not necessarily indicative of investors' long-term growth expectations. In fact, as discussed in my direct testimony, growth in earnings is far more likely to provide a meaningful guideline to investors' expected growth rate.

Q. DO YOU AGREE THAT THE SCREENING CRITERIA MR. BAUDINO APPLIED RESULTED IN A REASONABLE GROWTH ESTIMATE?

A. No. While I certainly agree that it is appropriate to evaluate the reasonableness of inputs to the DCF model, I take issue with the specific criteria applied by Mr. Baudino. After a review of the individual growth rates for the companies in his reference group, Mr. Baudino speculated (p. 23) that no growth rate of 10 percent or above is reasonable. Mr. Baudino's "Method 3" results omitted all double-digit growth rates, as well as those below 1 percent. But the growth expectations relevant to the DCF model are those of investors, not his personal assessment, and he presented no evidence to support his claim that the growth expectations that investors build into current stock prices could never equal 10 percent or above. Moreover, while I agree with Mr. Baudino that growth rates below 1 percent cannot be considered reasonable, his criterion retains numerous other low-end growth estimates that produce illogical cost of equity estimates.

Q. HAVE OTHER REGULATORS APPROVED DCF ESTIMATES BASED ON GROWTH RATES THAT EXCEED SINGLE DIGITS?

A. Yes. For example, in 2002 the FERC approved an ROE zone of reasonableness of 9.21 percent to 15.96 percent for the utility participants in the Midwest Independent Transmission System Operator, Inc., with the high-end of the DCF range being based on a growth rate of 11.00 percent.[10] Similarly, in 2009 FERC approved an ROE based on DCF cost of equity estimates for a proxy group of fifteen companies that incorporated twelve individual growth rates ranging from 8.0 percent to 11.5 percent.[11] These authorized DCF results contradict Mr. Baudino's conclusion that double-digit growth rates are *per se* illogical.

Q. HOW CAN LOW-END DCF ESTIMATES BE EVALUATED?

A. As discussed in my direct testimony,[12] it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock. Consistent with this principle, his DCF results must be adjusted to eliminate estimates that are determined to be outliers when compared against the yields available to investors from less risky utility bonds.

The Federal Energy Regulatory Commission ("FERC") evaluates DCF results against observable yields on long-term public utility debt and has recognized that it is appropriate to eliminate estimates that do not sufficiently exceed this threshold. FERC noted in *Kern River Gas Transmission Company* that:

---

[10] *Midwest Independent Transmission System Operator, Inc.*, 99 FERC ¶ 63,011 at Appendix A (2002).

[11] *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 (2009).

[12] Avera Direct at 37-40.

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[13]

The Commission upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[14] More recently, FERC affirmed that, "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[15]

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. As indicated in my direct testimony (pp. 38-40), it is generally expected that long-term interest rates will rise as the recession ends and the economy returns to a more normal pattern of growth. As shown in Table WEA-3 to my direct testimony, the increase in debt yields anticipated by IHS Global Insight and the Energy Information Administration imply an average triple-B bond yield of 7.26 percent for 2010, or 7.39 percent over the 5-year period 2010-2014.

Q. WHAT THEN IS A MORE REASONABLE APPLICATION OF MR. BAUDINO'S DCF ANALYSIS?

A. As explained in my direct testimony and demonstrated above, reference to trends in DPS result in distorted and illogical cost of equity estimates and should be ignored. Page 1 of Exhibit WEA-11 presents the individual cost of equity estimates produced by Mr. Baudino's DCF analysis based on projected EPS growth for each of the firms in his proxy group. As highlighted on this exhibit, a considerable number of the cost of equity estimates resulting from Mr. Baudino's DCF method are not

---

[13] *Kern River Gas Transmission Company*, Opinion No. 486, 117 FERC ¶ 61,077 at P 140 & n. 227 (2006).
[14] *Id.*
[15] *Southern California Edison Co.*, 131 FERC ¶ 61,020 at P 55 (2010).

sufficiently greater than the yields investors would expect to earn by investing in long-term public utility debt, with many falling below the average yield on triple-B public utility bonds. As shown on page 1 of Exhibit WEA-11, excluding these illogical values results in an average DCF cost of equity for Mr. Baudino's proxy group of approximately 10.6 percent.

Q. WHAT COST OF EQUITY IS IMPLIED BY A MORE REASONABLE APPLICATION OF DR. WOOLRIDGE'S DCF ANALYSIS?

A. As shown on page 2 of Schedule WEA-11, screening Dr. Woolridge's DCF cost of equity estimates based on EPS growth rates to eliminate illogical, low-end outliers resulted in an implied cost of equity range of 10.5 percent to 11.4 percent for the firms in his electric proxy group, with the average being 11.0 percent.

Q. WHY DID YOU IGNORE THE INTERNAL, "BR" GROWTH RATES CALCULATED BY DR. WOOLRIDGE AND MR. BAUDINO?

A. The internal growth rates calculated by Dr. Woolridge and Mr. Baudino are downward biased because of computational errors and omissions.[16] These witnesses based their calculations of the internal, "br" retention growth rate on data from Value Line, which reports end-of-period results. If the rate of return, or "r" component of the internal growth rate, is based on end-of-year book values, such as those reported by Value Line, it will understate actual returns because of growth in common equity over the year. This downward bias, which has been recognized by regulators,[17] is illustrated in Table WEA-8 below.

Consider a hypothetical firm that begins the year with a net book value of common equity of $100. During the year the firm earns $15 and pays out $5 in

---

[16] While Mr. Baudino calculated sustainable, "br" growth rates for the firms in his proxy group, his DCF analysis ignored these data.

[17] See, *e.g.*, *Southern California Edison Company,* Opinion No. 445 (Jul. 26, 2000), 92 FERC ¶ 61,070.

dividends, with the ending net book value being $110. Using the year-end book value of $110 to calculate the rate of return produces an "r" of 13.6 percent. As the FERC has recognized, however, this year-end return "must be adjusted by the growth in common equity for the period to derive an average yearly return."[18] In the example below, this can be accomplished by using the average net book value over the year ($105) to compute the rate of return, which results in a value for "r" of 14.3 percent. Use of the average rate of return over the year is consistent with the theory of this approach to estimating investors' growth expectations, and as illustrated below, it can have a significant impact on the calculated retention growth rate:

TABLE WEA-8
BR + SV GROWTH RATE – AVERAGE RATE OF RETURN

Beginning Net Book Value	$100
Earnings	15
Dividends	5
Retained Earnings	10
Ending Net Book Value	$110

"b x r" Growth	End-of Year	Average
Earnings	$ 15	$ 15
Book Value	$110	$105
"r"	13.6%	14.3%
"b"	66.7%	66.7%
"b x r" Growth	**9.1%**	**9.5%**

Because Dr. Woolridge and Mr. Baudino failed to account for this reality in their analyses, the "internal" growth rates that they calculated are downward-biased.

[18] *Id.*

Q. WHAT OTHER CONSIDERATION LEADS TO A DOWNWARD BIAS IN THE INTERNAL, "BR" GROWTH RATES OF DR. WOOLRIDGE AND MR. BAUDINO?

A. Both Dr. Woolridge and Mr. Baudino ignored the impact of additional issuances of common stock in their analyses of the sustainable growth rate. Under DCF theory, the "sv" factor is a component designed to capture the impact on growth of issuing new common stock at a price above, or below, book value. As noted by Myron J. Gordon in his 1974 study:

> When a new issue is sold at a price per share P = E, the equity of the new shareholders in the firm is equal to the funds they contribute, and the equity of the existing shareholders is not changed. However, if P > E, part of the funds raised accrues to the existing shareholders. Specifically...[v] is the fraction of the funds raised by the sale of stock that increases the book value of the existing shareholders' common equity. Also, "v" is the fraction of earnings and dividends generated by the new funds that accrues to the existing shareholders.[19]

In other words, the "sv" factor recognizes that when new stock is sold at a price above (below) book value, existing shareholders experience equity accretion (dilution). In the case of equity accretion, the increment of proceeds above book value (P > E in Professor Gordon's example) leads to higher growth because it increases the book value of the existing shareholders' equity. In short, the "sv" component is entirely consistent with DCF theory, and the fact that Dr. Woolridge and Mr. Baudino failed to consider the incremental impact on growth results in another downward bias to their "internal" growth rates, which should be given no weight.

---

[19] Gordon, Myron J., "The Cost of Capital to a Public Utility," MSU Public Utilities Studies (1974), at 31–32.

Q. DID DR. WOOLRIDGE PRESENT ANY EVIDENCE THAT UNDERMINES YOUR REFERENCE TO STOCK PRICE GROWTH IN APPLYING THE DCF MODEL?

A. No. As indicated in my direct testimony,[20] I also examined expected growth in each utility's stock price based on Value Line's projections. Apart from his misguided claim that analysts' EPS growth rates are overly optimistic, which I address subsequently, Dr. Woolridge presented no evidence to dispute my DCF analyses based on expected growth in stock prices.

In fact, the DCF model assumes that investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation over their holding period. Expected growth in stock price is a central question posed by most investors when evaluating common stocks, and projected stock prices from investment advisory services such as Value Line are widely reported and available to investors. In other words, projected growth in stock price is directly relevant to an analysis of the future cash flows that investors expect to receive when they purchase common stocks and is entirely consistent with the underlying basis of the DCF model.

Under the assumptions required to derive the constant growth form of the DCF model, stock price, earnings, dividends, and book value are all expected to grow at the same rate. Dr. Myron Gordon noted in his seminal article, *The Cost of Capital to a Public Utility* (1974), that growth in stock price could serve as another guide to investors' growth expectations in the constant growth DCF model, observing that, "[T]he rate of growth in the price of a stock … will respond to all of the factors mentioned above and, in addition, to the yield investors require on the

---

[20] Avera Direct at 37.

share."[21] Similarly, *The Cost of Capital – A Practitioner's Guide*, published by the Society of Utility and Regulatory Financial Analysts, observed that under the assumptions of the DCF model, "The stock price grows proportionally to the growth rate."[22] My reference to expected growth in common stock prices is entirely consistent with this paradigm.

Q. DID MR. BAUDINO PROVIDE A LOGICAL RATIONALE FOR IGNORING EXPECTATIONS FOR STOCK PRICE APPRECIATION?

A. No. Mr. Baudino wrongly argues that looking to the cash flows that an investor may expect to receive through appreciation in share price is "inconsistent with the principle embodied in the DCF model." Mr. Baudino incorrectly asserts that the only appropriate cash flows to consider in applying the DCF model "are based on earnings and dividends, not on a forecast of what a company's stock price might be in a few years."[23]

As discussed above in response to Dr. Woolridge, however, the expectation for capital gains associated with share price appreciation is entirely consistent with the underpinnings of the DCF model. Of course, one need only listen in on Bloomberg or any one of a host of business programs to recognize that expectations for share price appreciation are highly relevant to investors' expectations regarding the rewards of stock ownership. In fact, Mr. Baudino's argument on page 37 that stock prices are not relevant cash flows to consider in the DCF model is rebutted by his own testimony:

> The basic DCF approach is rooted in valuation theory. It is based on the premise that the value of a financial asset is determined by its

---

[21] Gordon, Myron J., "The Cost of Equity to a Public Utility," *MSU Public Utilities Studies* (1974).
[22] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997).
[23] Baudino Direct at 37.

> ability to generate future net cash flows. *In the case of a common stock, those future cash flows take the form of dividends and appreciation in stock price.*[24]

Q. WHAT ABOUT MR. BAUDINO'S OBSERVATION (P. 37) THAT STOCK PRICES ARE "INFLUENCED BY THE VICISSITDES OF THE MARKET?"

A. I agree that stock price projections do respond to changes in expectations regarding the outlook for the economy, capital market conditions, firm-specific factors, and a host of other considerations relevant to investors. In fact, the notion that stock prices capture all relevant information available to investors is the bedrock of modern capital market theory. But the fact that projections for share price appreciation change in response to economic and market cycles does not impugn the usefulness of price growth to serve as a gauge of investors' future expectations when they purchase common stock.

Q. WHAT DCF COST OF EQUITY IS INDICATED FOR THE PROXY GROUPS OF MR. BAUDINO AND DR. WOOLRIDGE BASED ON PROJECTED GROWTH IN STOCK PRICES?

A. As shown on page 1 of Exhibit WEA-12, growth rates implied by Value Line's stock price projections for Mr. Baudino's proxy firms result in an average DCF cost of equity of suggests a cost of equity of 10.5 percent. As shown on page 2 of Exhibit WEA-12, applying the DCF model based on the price growth expected for the firms in Dr. Woolridge's electric proxy group suggests a cost of equity of 11.4 percent.

Q. WHAT DO YOU CONCLUDE BASED ON YOUR REVIEW OF THE DCF ANALYSES PRESENTED BY DR. WOOLRIDGE AND MR. BAUDINO?

A. Historical growth rates and trends in DPS are distorted by fundamental changes in industry financial policies and Dr. Woolridge and Mr. Baudino failed to

---

[24] Baudino Direct at 15 (emphasis added).

evaluate the underlying reasonableness of individual growth rates. In addition, the calculations used to arrive at the internal growth rates reported by Dr. Woolridge and Mr. Baudino are flawed and incomplete. As a result, their DCF cost of equity estimates are biased downward and fail to reflect investors' required rate of return. Correcting their analyses to remove illogical values and incorporate alternative growth measures more indicative of investors' expectations demonstrates that the 9.5 percent and 9.7 percent recommendations of Dr. Woolridge and Mr. Baudino, respectively, are far too low to be considered credible.

III. CRITICISMS OF ANALYSTS' GROWTH RATES ARE MISGUIDED

Q. SHOULD THE KPSC GIVE ANY CREDENCE TO DR. WOOLRIDGE'S ALLEGATIONS THAT PROJECTED EPS GROWTH RATES ARE BIASED?

A. No. These arguments were addressed on pages 34-35 of my direct testimony. In applying the DCF model to estimate the cost of equity, the <u>only</u> relevant growth rate is the forward-looking expectations of investors that are captured in current stock prices. Dr. Woolridge's claim that analysts' estimates are not relied upon by investors is illogical given the reality of a competitive market for investment advice. If financial analysts' forecasts do not add value to investors' decision making, it would be irrational for investors to pay for these estimates. Similarly, those financial analysts who fail to provide reliable forecasts will lose out in competitive markets relative to those analysts whose forecasts investors find more credible. The reality that analyst estimates are routinely referenced in the financial media and in investment advisory publications implies that investors use them as a basis for their expectations.

The continued success of investment services such as IBES and Value Line, and the fact that projected growth rates from such sources are widely referenced, provides strong evidence that investors give considerable weight to analysts' earnings projections in forming their expectations for future growth. Earnings growth projections of security analysts provide the most frequently referenced guide to investors' views and are widely accepted in applying the DCF model. As explained in *Regulatory Finance: Utilities' Cost of Capital*:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts also exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of *g* [growth]. ... Published studies in the academic literature demonstrate that growth forecasts made by securities analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth.[25]

Q. DOES THE FACT THAT ANALYSTS' EPS PROJECTIONS MAY DEVIATE FROM ACTUAL RESULTS HAMPER THEIR USE IN APPLYING THE DCF MODEL, AS DR. WOOLRIDGE CONTENDS?

A. No. Investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. They can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock, and securities prices are constantly adjusting to reflect their assessment of available information. While the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices, and any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. While I did not rely solely on EPS

[25] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," Public Utilities Reports, Inc. (1994) at 154-155.

projections in applying the DCF model (as shown on Exhibits WEA-2 and WEA-4, I also examined the "br+sv", sustainable growth rates for the companies in my proxy groups), my evaluation clearly supports greater reliance on EPS growth rate projections than other alternatives. Moreover, there is every indication that expectations for earnings growth are instrumental in investors' evaluation and the fact that analysts' projections deviate from actual results provides no basis to ignore this relationship.

Q. DO THE SELECTED ARTICLES REFERENCED BY DR. WOOLRIDGE IN SUPPORT OF HIS CONTENTION THAT ANALYSTS ARE OVERLY OPTIMISTIC PAINT A COMPLETE PICTURE OF THE FINANCIAL RESEARCH IN THIS AREA?

A. No. In contrast to Dr. Woolridge's assertions, peer-reviewed empirical studies do not uniformly support his contention that analysts' growth projections are optimistically biased. For example, a study reported in "Analyst Forecasting Errors: Additional Evidence" found no optimistic bias in earnings projections for large firms (market capitalization of $500-$3,000 million), with data for the largest firms (market capitalization > $3,000 million) demonstrating a *pessimistic* bias.[26] Similarly, a 2005 article that examined analyst growth forecasts over the period 1990 through 2001 illustrated that Wall Street's forecasting is not inherently optimistic:

> The pessimism associated with profit firms is astonishing. Near the end of the sample period, almost three quarters of the quarterly forecasts for profit firms are pessimistic.[27]

---

[26] Brown, Lawrence D., "Analyst Forecasting Errors: Additional Evidence," *Financial Analysts Journal* (November/December 1997).

[27] Ciccone, Stephen, "Trends in analyst earnings forecast properties," *International Review of Financial Analysis*, 14:2-3 (2005).

Other research on this topic also concludes that there is no clear support for the contention that analyst forecasts contain upside bias:

> Our examples do demonstrate how some widely held beliefs about analysts' proclivity to commit systematic errors (e.g., the common belief that analysts generally produce optimistic forecasts) are not well supported by a broader analysis of the distribution of forecast errors. After four decades of research on the rationality of analysts' forecasts it is somewhat disconcerting that the most definitive statements observers and critics of earnings forecasters are willing to agree on are ones for which there is only tenuous empirical support.[28]

Similarly, while Dr. Woolridge cites a 2008 *Wall Street Journal* ("WSJ") article, an April 26, 2010 study reported in this publication contradicts his position. The WSJ concluded that analysts' earnings forecasts "are actually too pessimistic when it comes to predicting company earnings, particularly in the wake of recession."[29] The WSJ indicated that "analysts' expectations will continue to be trumped by better results as the current reporting season progresses,"[30] suggesting that current growth measures are more likely to be too low than too high.

More importantly, however, comparisons between forecasts of future growth expectations and the historical trend in actual earnings are largely irrelevant in evaluating the use of analysts' projections in the DCF model. For example, Dr. Woolridge references a paper he authored that reported that analysts' earnings growth rate estimates are overly optimistic, based on just such a historical comparison.[31] But as noted earlier, the investment community can only make decisions based on their best estimate of what the future holds in the way of long-

---

[28] Abarbanell, Jeffery and Reuven Lehavy, "Biased forecasts or biased earnings? The role of reported earnings in explaining apparent bias and over/under reaction in analysts earnings forecasts," *Journal of Accounting and Economics*, 36: 142 (2003).
[29] Denning, Liam, "Wall Street's Missed Expectations," *Wall Street Journal* at C8 (Apr. 26, 2010).
[30] *Id.*
[31] Woolridge, Randall J. and Custatis, Patrick, "The Accuracy of Analysts' Long-Term Earnings Per Share Growth Rate Forecasts" (January 24, 2008).

term growth for a particular stock, and the fact that projections deviate from actual results says nothing about whether investors rely on analysts' estimates. In using the DCF model to estimate investors' required returns, the purpose is not to prejudge the accuracy or rationality of investors' growth expectations. Instead, to accurately estimate the cost of equity we must base our analyses on the growth expectations investors actually used in determining the price they are willing to pay for common stocks – even if we do not agree with their assumptions. Indeed, despite the findings of his research, Dr. Woolridge reportedly "remains somewhat puzzled that so many continue to put great weight in what [analysts] have to say."[32] As Robert Harris and Felicia Marston noted in their article in *Journal of Applied Finance*:

> ...Analysts' optimism, if any, is not necessarily a problem for the analysis in this paper. If investors share analysts' views, our procedures will still yield unbiased estimates of required returns and risk premia.[33]

Similarly, there is no logical foundation for criticisms such as those raised by Dr. Woolridge that the purported upward bias of analysts' growth rates limits their usefulness in applying the DCF model. If investors' base their expectations on these growth rates, then they are useful in inferring investors' required returns – even if the analysts' forecasts prove to be wrong in hindsight.[34] As Dr. Woolridge granted with respect to Value Line's projections, for example:

---

[32] Boselovic, Len, "Study Finds Analysts' Forecasts Have Been Too Sunny," *Pittsburgh Post-Gazette* (Mar. 30, 2008).

[33] Harris, Robert S. and Marston, Felicia C., "The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts," *Journal of Applied Finance* 11 (2001) at 8.

[34] I began my military career in the Navy in the weather office at a Naval Air Station. Using the best available methods then available, we provided pilots with weather forecasts for their flight plans. In hindsight we were not very accurate, but I do not recall any pilot ignoring our forecast in planning a mission. In finance, as in weather, no one **knows** the future. But no one can afford to ignore the best available forecasts.

> If investors rely on these forecasts, then they are a factor in gauging future growth rate expectations.[35]

Q DID DR. WOOLRIDGE PROVIDE ANY MEANINGFUL SUPPORT FOR HIS ALLEGATION THAT VALUE LINE FORECASTS ARE "OVERLY OPTIMISTIC"?

A. No. Dr. Woolridge asserted his belief (p. 63-64) that Value Line projections have "a decidedly positive bias," based only on his personal belief that Value Line does not report a sufficient number of negative growth rates. But as Mr. Baudino noted (p. 22), negative growth rates are inconsistent with the assumptions of the DCF model and not likely to be representative of investors' expectations. Dr. Woolridge's personal opinions are irrelevant to a determination of what investors expect and, contrary to his conclusion, Value Line is a well-recognized source in the investment and regulatory communities. For example, *Cost of Capital – A Practitioners' Guide*, published by the Society of Utility and Financial Analysts, noted that:

> [A] number of studies have commented on the relative accuracy of various analysts' forecasts. Brown and Rozeff (1978) found that Value Line was superior to other forecasts. Chatfield, Hein and Moyer (1990, 438) found, further "Value Line to be more accurate than alternative forecasting methods" and that "investors place the greatest weight on the forecasts provided by Value Line".[36]

Given the fact that Value Line is perhaps the most widely available source of information on common stocks, the projections of Value Line analysts provide an important guide to investors' expectations.

Moreover, in contrast to Dr. Woolridge's unsupported assertion, the fact that Value Line is not engaged in investment banking or other relationships with the

---

[35] Response to KPSC Question 10.

[36] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at 8-28.

companies that it follows reinforces its impartiality in the minds of investors. Indeed, Value Line was among the providers of "independent research" that benefited from the Global Settlement cited by Dr. Woolridge (p. 60).[37]

IV. UTILITIES ARE NOT AN INVESTMENT ISLAND

Q. What is the fallacy underlying Dr. Woolridge's and Mr. Baudino's rejection of any reference to non-utility companies in evaluating a fair ROE for KU?

A. Dr. Woolridge and Mr. Baudino dismiss out of hand my analysis of the cost of equity for non-utility firms based on the claim that utilities are profoundly different and therefore less risky from other companies in the economy. The implication that an estimate of the required return for firms in the competitive sector of the economy is not useful in determining the appropriate return to be allowed for rate-setting purposes is wrong and inconsistent with reality, investor behavior, and the *Bluefield* and *Hope* decisions. In fact, returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. True enough, utilities are sheltered from competition, but they undertake other obligations and lose the ability to set their own prices and decide when to exit a market. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility.[38]

Consistent with this view, Mr. Baudino noted (pp. 12-13) that the notion of "opportunity cost" underlies the Supreme Court's economic standards, and that:

> One measures the opportunity cost of an investment equal to what one would have obtained in the next best alternative. … That alternative could have been another utility stock, a utility bond, <u>a mutual fund</u>, a money

---

[37] Tsao, Amy, "The New Era of Indie Research," *Business Week Online Edition* (June 12, 2003).

[38] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

> market fund, or any other number of investment vehicles. (emphasis added)

As Mr. Baudino correctly observed (p. 13), "The key determinant in deciding whether to invest, however, is based on comparative levels of risk," and he concluded, "[T]he task for the rate of return analyst is to estimate a return that is equal to the return being offered by other risk-comparable firms." In other words, Mr. Baudino recognized that investors gauge their required returns from utilities against those available from non-utility firms of comparable risk. My reference to a comparable-risk Non-Utility Proxy Group is entirely consistent with the guidance of the Supreme Court and the principles outlined in Mr. Baudino's own testimony.

Q. Do utilities have to compete with non-regulated firms for capital?

A. Most certainly. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives, which according to Dr. Woolridge include, "other enterprises having comparable risks."[39] Clearly the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment and there are a plethora of "other enterprises" available to investors beyond those in the utility industry.

Q. DID MR. BAUDINO OR DR. WOOLRIDGE PRESENT ANY OBJECTIVE EVIDENCE TO SUPPORT THEIR CONTENTION THAT YOUR NON-UTILITY PROXY GROUP IS RISKIER THAN KU OR YOUR UTILITY PROXY GROUPS?

A. No. Dr. Woolridge presented no meaningful evidence to rebut the results for my Non-Utility Proxy Group; rather, he simply observed that my Non-Utility Proxy Group "includes such companies as Abbott Labs, Coca-Cola, General Mills,

---

[39] Woolridge Direct at 23.

Hewlett Packard, IBM, Johnson & Johnson, McDonalds, Medtronic, Microsoft, and NIKE," and concluded these companies are "vastly different" from utilities and do not operate in a "highly regulated environment."[40] Similarly, apart from sweeping generalizations about the risk differences between regulated and non-regulated companies, Mr. Baudino provided no support whatsoever for his contention that my Non-Utility Proxy Group is riskier than KU or my Utility Proxy Group.

My Non-Utility Proxy Group is comprised of 69 of the best-known and most stable corporations in America and has risk measures that are comparable to, or less than the proxy groups of gas and combination utilities referenced in my analyses.[41] While these companies do not have the regulatory protections that utilities have, neither do they bear the burdens of losing control over their prices, undertaking the obligation to serve, and having to invest in infrastructure even in unfavorable market conditions. KU can't relocate its service territory to an area with greater customer density or higher prospects for economic growth, postpone capital spending necessary to maintain reliability and accommodate growth, or abandon customers when turmoil roils energy or capital markets.

Consider Mr. Baudino's statement that utilities "have protected markets … enjoy full recovery of prudently incurred costs, and may increase their rates to cover increases in costs."[42] Based on this, Mr. Baudino summarily concluded, "Obviously, the non-utility companies have higher overall risk structures." In fact, however, investors are quite aware that utilities are <u>not</u> guaranteed recovery of prudent costs and that there are many instances in which utilities are unable to increase rates to fully recoup reasonable and necessary costs, resulting in an

---

[40] Woolridge Direct at 52.
[41] Avera Direct at Table WEA-2.
[42] Baudino Direct at 36.

inability to earn the allowed rate of return on invested capital. The simple observation that a firm operates in non-utility businesses says nothing at all about the overall investment risks perceived by investors, which is the very basis for a fair rate of return.

For example, consider (1) an electric utility such as UniSource with frozen rates, a debt-to-capital ratio of 73 percent, and a junk bond credit rating, versus (2) Wal-Mart Stores, Inc. ("Wal-Mart"), which faces competition on numerous fronts. Despite its lack of a regulated monopoly, with a double-A bond rating, the highest Value Line Safety Rank, and a beta of 0.60, the investment community would undoubtedly regard Wal-Mart as a less risky alternative to the utility included in Dr. Woolridge's electric proxy group.

Q. DOES A COMPARISON OF OBJECTIVE RISK MEASURES SUPPORT DR. WOOLRIDGE'S AND MR. BAUDINO'S CONCLUSIONS REGARDING THE RELATIVE RISK OF YOUR NON-UTILITY PROXY GROUP?

A. No. In fact, the objective risk measures specifically cited by Mr. Baudino as being relevant indicia of overall investment risks contradict his assertions and those of Dr. Woolridge. As noted earlier, Mr. Baudino testified that bond ratings reflect a detailed and comprehensive analysis of the key factors contributing to a firm's overall investment risk, concluding (p. 14), "Bond ratings are tools that investors use to assess the risk comparability of firms." Contradicting Mr. Baudino's unsupported assertion (p. 37) that the companies in my Non-Utility Proxy Group "have higher overall risk structures," my direct testimony noted that the average corporate credit rating for the Non-Utility Proxy Group of "A" is <u>higher</u> than the "BBB+" average for the Utility Proxy Group and KU. In fact, the review of objective indicators of investment risk presented in my direct testimony (Table WEA-2), which consider the impact of competition and market share, demonstrated that, if anything, the Non-Utility Proxy Group could be considered somewhat less risky in the minds of investors than the common stocks of the proxy group of utilities.

Q. Does Dr. Woolridge apparently consider non-utility stock returns relevant to determining the cost of capital?

A. Indeed he does. Dr. Woolridge cites many studies of past and expected stock market returns in his testimony, including a list of over 30 studies included on page 5 of Exhibit JRW-11. *Not one* of these studies is limited to utilities, and all include a predominance of non-utility common stocks, e.g., Standard & Poor's 500 Index. Moreover, while Dr. Woolridge references a study of industry betas done at New York University (p. 19) that suggests utilities have lower risks than the average firm in the non-regulated sector, this establishes nothing more than the obvious – while some unregulated firms have higher risks than utilities, others have lower risks. As documented in my direct testimony, the firms in my Non-Utility Proxy Group are also in the lower ranges of risk as measured by objective, widely referenced benchmarks.

Q. Would it be consistent with the *Bluefield* and *Hope* cases to disregard required returns for non-utility companies?

A. No. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Indeed, if the requirement is business in the same part of the country and the utility has the exclusive franchise, then the Court could only be referring to non-utility businesses and any nearby utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Indeed, in teaching regulatory policy I usually observe that in the early applications of the comparable earnings approach, utilities were explicitly eliminated due to a concern about circularity. In other words, soon after the *Hope* decision regulatory commissions did not want to get involved in circular logic by looking to the returns of utilities that were established by the same or similar regulatory commissions in the same geographic region. To avoid circularity, regulators looked only to the returns of non-utility companies. Incidentally, the requirement in the *Bluefield* case of restricting the comparable group to the geographic region is often overlooked in the academic literature. It is interesting to note that virtually all of the firms in my Non-Utility Proxy Group have a significant presence in Kentucky.

Q. Does consideration of the results for the Non-Utility Proxy Group make the estimation of the cost of equity using the DCF model more reliable?

A. Yes. The estimates of growth from the DCF model depend on analysts' forecasts, or in the case of Dr. Woolridge, historical performance. It is possible for utility growth rates to be distorted by historical trends in the industry (e.g., changes in payout ratios) or the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. For example, Value Line recently observed that near-term growth rates understate the longer-term expectations for gas utilities:

> Natural Gas Utility stocks have fallen near the bottom of our Industry spectrum for Timeliness. Accordingly, short-term investors would probably do best to find a group with better prospects over the coming six to 12 months. Longer-term, we expect these businesses to rebound. An improved economic environment, coupled with

> stronger pricing, should boost results across this sector over the coming years.[43]

Because the Non-Utility Proxy Group includes low risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

V. NO BASIS TO IGNORE RETURNS ON BOOK VALUE

Q. IS THERE ANY BASIS FOR THE CONTENTION OF DR. WOOLRIDGE AND MR. BAUDINO THAT THE EXPECTED EARNINGS APPROACH IS NOT A VALID ROE BENCHMARK?

A. No. My expected earnings approach is predicated on the comparable earnings test, which developed as a direct result of the Supreme Court decisions in *Bluefield* and *Hope*. From my understanding as a regulatory economist, not as a legal interpretation, these cases required that a utility be allowed an opportunity to earn the same return as companies of comparable risk. That is, the cases recognized that a utility must compete with other companies (including non-utilities) for capital.

Q. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. As Mr. Baudino recognized (p. 12), economists refer to the returns that an investor must forgo by not being invested in the next best alternative as "opportunity costs".

---

[43] The Value Line Investment Survey at 445 (Mar. 12, 2010).

Q. **WHAT ARE THE IMPLICATIONS OF SETTING AN ALLOWED ROE BELOW THE RETURNS AVAILABLE FROM OTHER INVESTMENTS OF COMPARABLE RISK?**

A. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. In this situation the government is effectively taking the value of investors' capital without adequate compensation.

Q. **HOW IS THE COMPARISON OF OPPORTUNITY COSTS TYPICALLY IMPLEMENTED?**

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Q. **DR. WOOLRIDGE (P. 5) CLAIMS THE EARNINGS ON BOOK VALUE APPROACH "HAS NOT BEEN USED BY REGULATORY COMMISSIONS FOR YEARS." IS THAT YOUR EXPERIENCE?**

A. Not at all. While Dr. Woolridge is correct that this method predominated before the DCF model became fashionable with academic experts, I continue to encounter it around the country. Indeed, the Virginia State Corporation Commission ("VSCC") is required by statute (Virginia Code 56-585) to consider the earned returns on book value of electric utilities in its region. In an order issued on July 14, 2009 the VSCC confirmed the relevance of earned book returns in Docket PUE-2009-00019 for Virginia Electric and Power Company. Another example is Ms. Terri Carlock, the long-time financial analyst for the Idaho Public Utilities Commission. She has consistently presented evidence on book earnings for decades, and Idaho regulators continue to confirm the relevance of return on book equity evidence.[44]

Perhaps the most ardent proponent of earned returns as a benchmark for fair ROE is David C. Parcell, who frequently appears as a witness for regulatory agencies and other interveners. Mr. Parcell literally "wrote the book" for the Society of Utility and Regulatory Financial Analysts.[45] Mr. Parcell called the comparable earnings approach the "granddaddy" of cost of equity methods.[46] He also points out that the amount of subjective judgment required to implement this method is "minimal", particularly when compared to the DCF and CAPM methods.[47] Mr. Parcell also notes that this method is "easily understood" and firmly anchored in the regulatory tradition of the *Bluefield* and *Hope* cases.[48]

---

[44] The comparable earnings approach was identified as a favored method in determining the allowed ROE for 24 of the agencies surveyed in NARUC's compilation of regulatory policy. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996). In my experience, while a few Commissions have explicitly rejected comparable earnings, most regard it as a useful tool.

[45] Parcell, David C., *The Cost of Capital – A Practitioner's Guide* (1997).

[46] *Id.* at 7-1.

[47] *Id.* at 7-3.

[48] *Id.*

Q. DO YOU AGREE WITH MR. BAUDINO (P. 42) THAT A METHODOLOOGY MUST BE "MARKET-BASED" TO BE USEFUL IN EVALUATING INVESTORS' OPPORTUNITY COSTS?

A. No. While I agree that market-based models are certainly important tools in estimating investors' required rate of return, this in no way invalidates the usefulness of the expected earnings approach. In fact, this is one of its advantages.

It is a very simple, conceptual principal that when evaluating two investments of comparable risk, investors will choose the alternative with the higher expected return. If KU is only allowed the opportunity to earn 9.5 percent or 9.7 percent return on the book value of its equity investment, as recommended by Dr. Woolridge and Mr. Baudino, while the comparable-risk utilities in my proxy group are expected to earn an average of 11.4 percent,[49] the implications are clear – KU's investors will be denied the ability to earn their opportunity cost.

Moreover, regulators do not set the returns that investors earn in the capital markets – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

---

[49] Avera Direct at Exhibit WEA-8.

Q. WHAT ROE IS IMPLIED IF THE EXPECTED EARNINGS APPROACH IS APPLIED TO THE COMPANIES IN THE PROXY GROUPS OF DR. WOOLRIDGE AND MR. BAUDINO?

A. As shown on page 1 of Exhibit WEA-13, the expected earnings approach implied an average cost of equity for the utilities in Mr. Baudino's proxy group of 11.2 percent. Meanwhile, page 2 of Exhibit WEA-13 shows that the expected book return on equity for Dr. Woolridge's electric proxy group is 10.9 percent. These book return estimates are an "apples to apples" comparison to the 9.7 percent and 9.5 percent recommended ROEs of Mr. Baudino and Dr. Woolridge, respectively.

Q. WHAT WOULD BE THE EFFECT OF AUTHORIZING A BOOK RETURN FOR KU THAT IS SO FAR BELOW THE AVERAGE EARNINGS OF THE UTILITIES THAT MR. BAUDINO AND DR. WOOLRIDGE CLAIM ARE COMPARABLE?

A Plain and simple, KU will find it difficult to compete for investors' capital and the Company would not be earning up to the Bluefield standard of comparable earnings:

> A public utility is entitled to such rates as will permit it to earn on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.[50]

---

[50] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923).

Q. WHAT IS THE RELEVANCE OF DR. WOOLRIDGE'S DISCUSSION OF MARKET-TO-BOOK RATIOS (PP. 15-17 & 69) TO THE DEVIATION BETWEEN HIS RECOMMENDED ROE AND THE EARNED RETURNS EXPECTED FOR COMPARABLE UTILITIES?

A. Based on his testimony here and in previous cases, I understand that Dr. Woolridge is trying to argue that utility earnings are generally too high because the market-to-book ratios generally exceed one. He wants the KPSC to sacrifice KU's financial strength to favor a theoretical ideal of market-to-book ratios equaling unity. The KPSC does not regulate utility stock market prices, and as discussed below, there are many leaps between his economic theory and reality. But if the theory is correct, then Dr. Woolridge is asking the KPSC to order a return that would almost certainly lead to a capital loss on the value of KU's investment. From an economic perspective, such an action would take the value of KU's property without compensation, the kind of behavior that upset the American colonists against the English Crown.

Q. DO YOU AGREE WITH DR. WOOLRIDGE THAT IT IS NECESSARY TO EXAMINE MARKET-TO-BOOK RATIOS IN APPLYING THE EXPECTED EARNINGS APPROACH?

A. No. Traditional applications of the expected earnings approach do not involve a market-to-book adjustment. I have never made a market-to-book adjustment, nor is such an adjustment recommended in recognized texts such as *Regulatory Finance: Utilities' Cost of Capital.*[51]

---

[51] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* (1994).

Q. IS THERE A CLEAR LINK BETWEEN MARKET-TO-BOOK RATIOS FOR ELECTRIC UTILITIES AND ALLOWED RATES OF RETURN?

A. No. Underlying Dr. Woolridge's criticism is the supposition that regulators should set a required rate of return to produce a market-to-book value of approximately 1.0. This is fallacious. For example, *Regulatory Finance: Utilities Cost of Capital* noted that:

> The stock price is set by the market, not by regulators. The M/B ratio is the end result of regulation, and not its starting point. The view that regulation should set an allowed rate of return so as to produce a M/B of 1.0, presumes that investors are masochistic. They commit capital to a utility with a M/B in excess of 1.0, knowing full well that they will be inflicted a capital loss by regulators. This is not a realistic or accurate view of regulation.[52]

With market-to-book ratios for most utilities above 1.0, Dr. Woolridge is suggesting that, unless book value grows rapidly, regulators should establish equity returns that will cause share prices to fall. Given the regulatory imperative of preserving a utility's ability to attract capital, this would be a truly nonsensical result.

Q. IS THERE ANYTHING UNUSUAL ABOUT A STOCK PRICE EXCEEDING BOOK VALUE?

A. No. In fact the majority of stocks currently sell substantially above book value. For example, Value Line reports that over 1,300 of the approximately 1,700 stocks it follows (including utilities and other industries) sell for prices in excess of book value.[53]

Moreover, regulators previously recognized the fallacy of relying on market-to-book ratios in evaluating cost of equity estimates. For example, the Presiding Judge in *Orange & Rockland* concluded, and the FERC affirmed that:

---

[52] *Id.* at 256.

[53] www.valueline.com (retrieved Apr. 29, 2010).

> The presumption that a market-to-book ratio greater than 1.0 will destroy the efficacy of the DCF formula disregards the realities of the market place principally because the market-to-book ratio is rarely equal to 1.0.[54]

The Initial Decision found that there was no support in Commission precedent for the use of market-to-book ratios to adjust market derived cost of equity estimates based on the DCF model and concluded that such arguments were to be treated as "academic rhetoric" unworthy of consideration.

Q. WHAT OTHER EVIDENCE INDICATES THAT THE RECOMMENDATIONS OF MR. BAUDINO AND DR. WOOLRIDGE ARE INSUFFICIENT TO MEET REGULATORY STANDARDS?

A. Reference to allowed rates of return for other utilities provides one useful guideline that can be used to assess the extent to which the 9.7 percent and 9.5 percent ROE recommendations of Mr. Baudino and Dr. Woolridge are comparable and sufficient. As shown on page 1 of Exhibit WEA-14, data from the April 2010 *AUS Monthly Utility Report* (a source relied on by Dr. Woolridge and Mr. Baudino) indicates that the average authorized ROE for the firms in Mr. Baudino's proxy group is 10.64 percent, or 94 basis points higher than his recommendation for KU.

With respect to the group of electric utilities that Dr. Woolridge concluded were most comparable to KU's jurisdictional utility operations, as shown on page 2 of Exhibit WEA-14, these firms are presently authorized an average rate of return on equity of 10.7 percent, or 120basis points more than Dr. Woolridge's ROE recommendation. It is unreasonable to suppose that investors would be attracted by Dr. Woolridge's or Mr. Baudino's recommendations for KU, which fall

---

[54] *Orange & Rockland Utilities, Inc.*, Initial Decision, 40 FERC ¶ 63,053, 1987 WL 118,352 (F.E.R.C.).

significantly below the allowed returns for other utilities they consider to be comparable.

VI. CAPM RESULTS SHOULD BE DISREGARDED

Q. DID EITHER DR. WOOLRIDGE OR MR. BAUDINO RELY ON THEIR CAPM RESULTS IN ARRIVING AT THEIR RECOMMENDATIONS IN THIS CASE?

A. No. Dr. Woolridge ignored his 7.8 percent CAPM cost of equity estimate in arriving at his 9.5 percent recommendation, which is at the top of his 7.8 percent to 9.5 percent cost of equity range. Dr. Woolridge noted that he gave "primary weight" to the DCF model,[55] and he concluded that the CAPM provides "a less reliable indication of equity cost rates for public utilities."[56] Similarly, as Mr. Baudino noted,[57] his ROE recommendation was based solely on cost of equity estimates implied by his application of the DCF model and ignored his CAPM results entirely.

Q. IS THERE GOOD REASON TO ENTIRELY DISREGARD THE RESULTS OF THE CAPM ANALYSES PRESENTED BY DR. WOOLRIDGE AND MR. BAUDINO?

A. Yes. As discussed in my direct testimony,[58] applying the CAPM is complicated by the impact of the recent capital market turmoil and recession on investors' risk perceptions and required returns. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors sought a safe haven in U.S. government bonds and this "flight to safety" pushed Treasury yields

[55] Woolridge Direct at 2.
[56] Woolridge Direct at 21.
[57] Baudino Direct at 3.
[58] Avera Direct at 44-46.

significantly lower while yield spreads for corporate debt widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased. This is simply not the time for the KPSC to give any weight to the CAPM, irrespective of methodology.

Meanwhile, the backward-looking, historical approaches employed by Dr. Woolridge and Mr. Baudino incorrectly assume that investors' assessment of the relative risk differences, and their required risk premium, between Treasury bonds and common stocks is constant and equal to some past average. At no time in recent history has the fallacy of this assumption been demonstrated more concretely. This incongruity between investors' current expectations and requirements and historical risk premiums is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently.

As a result, there is every indication that the historical CAPM approach fails to fully reflect the risk perceptions of real-world investors in today's capital markets, which would violate the standards underlying a fair rate of return by failing to provide an opportunity to earn a return commensurate with other investments of comparable risk. As the Staff of the Florida Public Service Commission recently concluded:

> [R]ecognizing the impact the Federal Government's unprecedented intervention in the capital markets has had on the yields on long-term Treasury bonds, staff believes models that relate the investor-required return on equity to the yield on government securities, such

> as the CAPM approach, produce less reliable estimates of the ROE at this time.[59]

While I agree with the decision of Dr. Woolridge and Mr. Baudino to give no weight to their CAPM results, for completeness my rebuttal testimony nevertheless addresses the major flaws associated with their applications of this approach.

Q. WHAT IS THE FUNDAMENTAL PROBLEM ASSOCIATED WITH THE HISTORICAL APPROACHES USED BY DR. WOOLRIDGE AND MR. BAUDINO TO APPLYING THE CAPM?

A. Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflect the expectations of actual investors in the market. Dr. Woolridge recognized that "ex post returns are not the same as ex ante expectations" and noted that "market risk premiums can change over time; increasing when investors become more risk-averse."[60] Nevertheless, his application of the CAPM method was based entirely on *historical* – not projected – rates of return, as was the CAPM method presented on Mr. Baudino's Exhibit (RAB-6). Morningstar recognized the primacy of current expectations:

> The cost of capital is always an expectational or forward-looking concept. While the past performance of an investment and other historical information can be good guides and are often used to estimate the required rate of return on capital, the expectations of future events are the only factors that actually determine cost of capital.[61]

---

[59] *Staff Recommendation for Docket No. 080677-EI - Petition for increase in rates by Florida Power & Light Company*, at p. 280 (Dec. 23, 2009).
[60] Woolridge Direct at 39-40.
[61] Morningstar, *Ibbotson SBBI, 2008 Valuation Yearbook* at 23.

Because the backward-looking analyses of Dr. Woolridge and Mr. Baudino ignore the returns investors are currently requiring in the capital markets, the resulting CAPM estimates significantly understate investors' required rate of return.

Q. IS THERE EVIDENCE THAT THE STUDIES REFERENCED BY DR. WOOLRIDGE DO NOT REFLECT INVESTORS' EXPECTATIONS?

A. Many of the results of the equity risk premium studies reported by Dr. Woolridge do not make economic sense and contradict his own testimony. As shown on page 5 of Dr. Woolridge's Exhibit JRW-11, 25 of the historical studies included in Dr. Woolridge's assessment found market equity risk premiums of approximately 4.75 percent or below. But combining a market equity risk premium of 4.75 percent with Dr. Woolridge's 4.75 percent risk-free rate results in an indicated cost of equity for the market as a whole of 9.5 percent, which is *equal* to Dr. Woolridge's ROE recommendation in this case. Many of his other benchmarks for the market rate of return fall *below* the anemic cost of equity he recommends for KU. For example, Dr. Woolridge conjures a market rate of return of 7.00 percent based on his "building blocks" approach,[62] which falls 185 basis points below his recommended ROE in this case,

Meanwhile, after noting that beta is the only relevant measure of investment risk under modern capital market theory, Dr. Woolridge concluded that his comparison of beta values (Exhibit JRW-8) indicates that investors' required return on the market as a whole should exceed the cost of equity for utilities.[63] Based on Dr. Woolridge's own logic, it follows that a market rate of return that does not exceed his own downward biased ROE recommendation has no relation to the

---

[62] Woolridge Direct at 45. Similarly, Dr. Woolridge reported market rates of return of 7.27 percent and 7.62 percent from the selected surveys cited at page 46 of his testimony.

[63] Woolridge Direct at 19.

current expectations of real-world investors. The fact that much of his CAPM "evidence" violates the risk-return tradeoff that is fundamental to finance and illustrates the frailty of Dr. Woolridge's analyses.

Q. DR. AVERA, ARE YOU IN ANY WAY ALLEGING THAT ALL THESE STUDIES AND SURVEYS ARE INHERENTLY FLAWED?

A. No, not at all. The point that I am making is that there is more than one way to define and calculate an equity risk premium. The problem with Dr. Woolridge's approach is that, instead of looking directly at an equity risk premium based on current expectations – which is what is required in order to properly apply the CAPM – he undertakes an unrelated exercise of compiling a list of selected computations culled from the historical record. Average realized risk premiums computed over some selected time period may be an accurate representation of what was actually earned in the past, but they don't answer the question as to what risk premium investors were actually expecting to earn on a forward-looking basis during these same time periods. Similarly, calculations of the equity risk premium developed at a point in history – whether based on actual returns in prior periods or contemporaneous projections – are not the same as the forward-looking expectations of today's investors, which are premised on an entirely different set of capital market and economic expectations.

Likewise, surveys of selected corporate executives or economists, or building blocks based on academic research, are not equivalent to investors' required returns in the coming period. Since the benchmark for a fair ROE requires that the utility be able to compete for capital in the current capital market, the relevant inquiry is to determine the return that real world investors in today's markets require from KU in order to compete for capital with other comparable risk alternatives. In short, while there are many potential definitions of the equity risk premium, the only relevant issue for application of the CAPM in a regulatory context is the return investors currently expect to earn on money invested today in the risky market portfolio versus the risk-free U.S. Treasury alternative.

Q. WERE DR. WOOLRIDGE OR MR. BAUDINO JUSTIFIED IN RELYING ON GEOMETRIC MEANS AS A MEASURE OF AVERAGE RATE OF RETURN WHEN APPLYING THE HISTORICAL CAPM?

A. No. While both the arithmetic and geometric means are legitimate measures of average return, they provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The arithmetic mean measures what the expected return would have to be each period to achieve the realized change in value over time.

In estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. When referencing realized rates of return in the past, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods. *Regulatory Finance: Utilities' Cost of Capital* had this to say:

> One major issue relating to the use of realized returns is whether to use the ordinary average (arithmetic mean) or the geometric mean return. *Only arithmetic means are correct for forecasting purposes and for estimating the cost of capital.* When using historical risk premiums as a surrogate for the expected market risk premium, the

> relevant measure of the historical risk premium is the arithmetic average of annual risk premiums over a long period of time.[64]

Similarly, Morningstar concluded that:

> For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. ... The geometric average is more appropriate for reporting past performance, since it represents the compound average return.[65]

I certainly agree that both geometric and arithmetic means are useful, since my Ph.D. dissertation was on the usefulness of the geometric mean.[66] But the issue is not whether both measures can be useful; it is which one best fits the use for a forward-looking CAPM in this case. One does not have to get deeply into finance theory to see why the arithmetic mean is more consistent with the facts of this case. The KPSC is not setting a constant return that KU is guaranteed to earn over a long period. Rather, the exercise is to set an expected return based on test year data. In the real world, KU's yearly return will be volatile, depending on a variety of economic and industry factors, and investors do not expect to earn the same return each year. The usefulness of the arithmetic mean for making forward-looking estimates was confirmed in *Quantitative Investment Analysis* (2007), one of the textbooks included in the study curriculum for the Chartered Financial Analyst designation, which concluded that the arithmetic mean is the appropriate measure when calculating an expected equity risk premium in a forward-looking context.[67]

---

[64] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports* AT 275 (1994) (emphasis added).

[65] Morningstar, *Ibbotson SBBI 2008 Valuation Yearbook* at 77.

[66] William E. Avera, *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice* (1972).

[67] DeFusco, Richard A., Dennis W. McLeavey, Jerald E. Pinto, and David E. Runkle, *Quantitative Investment Analysis*, John Wiley & Sons, Inc. (2007) at 128.

Just as importantly, by relying directly on expectations and estimates of investors' required rate of return, as incorporated in the CAPM analysis presented in my direct testimony, there is no need to debate the merits of geometric versus arithmetic means, because neither is required to apply this forward-looking approach.

Q. WHAT DOES THIS IMPLY WITH RESPECT TO DR. WOOLRIDGE'S AND MR. BAUDINO'S CAPM RESULTS?

A. For a variable series, such as stock returns, the geometric average will <u>always</u> be less than the arithmetic average. Accordingly, reference to geometric average rates of return provides yet another element of built-in downward bias to the CAPM applications of Dr. Woolridge and Mr. Baudino.

Q. WHAT ABOUT DR. WOOLRIDGE'S VIEW THAT THE MARKET RETURN USED IN YOUR FORWARD-LOOKING CAPM ANALYSIS (EXHIBITS WEA-6 AND WEA-7) IS "EXCESSIVE"?

A. As explained earlier and in my direct testimony, I estimated the current equity risk premium by first applying the DCF model to estimate investors' current required rate of return for the firms in the S&P 500 and then subtracting the yield on government bonds. Dr. Woolridge contends that this CAPM analysis is flawed because of an alleged upward bias in the analysts' growth estimates used to estimate investors' expected return on the S&P 500.

The fallacy of these arguments was addressed earlier in my discussion of the growth rates used in the DCF model. Moreover, Dr. Woolridge also relied on analysts' estimates in applying the DCF model and, as indicated earlier, the use of forward-looking expectations in estimating the market risk premium is well accepted in the financial literature. For example, the table on page 4 of Dr. Woolridge's Exhibit JRW-11 noted that:

> Current financial market prices (simple valuation ratios or DCF-based measures) can give most objective estimates of feasible ex ante equity-bond risk premium.

I grant that my forward-looking CAPM approach produces an equity risk premium for the S&P 500 that is significantly higher than his unrealistic benchmarks. But rather than look backwards to a select subset of academic studies, or a "building blocks" risk premium based largely on historical data, as Dr. Woolridge advocates, my analysis appropriately focused on the expectations of actual investors in today's capital markets.

Q. APART FROM YOUR EARLIER DISCUSSION, WHAT OTHER EVIDENCE INDICATES THAT THE MARKET RETURN USED IN YOUR CAPM ANALYSIS IS NOT INFLATED?

A. While Dr. Woolridge argues that the 9.2 percent expected growth rate and resulting 11.9 percent market return that I used to apply the CAPM are "overstated," his own exhibits and sources contradict his personal view. Consider Exhibit JRW-15, for example, which presents historical earnings for the S&P 500. In 21 of the years included in Dr. Woolridge's table, growth in earnings exceeded the 9.2 percent forward-looking estimate used to compute my market rate of return. Similarly, Morningstar reported that since 1926 the actual realized return on large-company stocks exceeded the 11.9 percent forward-looking estimate used in my CAPM analysis in over one-half of those years, in many cases by a considerable margin.[68]

[68] Morningstar, *Ibbotson SBBI 2010 Valuation Yearbook* at Table B-1.

Q. IS THERE ANY REASON THAT THE GROWTH RATES USED IN A DCF ANALYSIS MUST BE CONSTRAINED BY THE OVERALL GROWTH OF THE ECONOMY, AS DR. WOOLRIDGE ASSERTS (P. 67)?

A. No. Dr. Woolridge suggested that it would be illogical for investors to expect long-term growth for the market as a whole to exceed the rate of growth of the economy. The real issue here is not Dr. Woolridge's sense of logic, but rather the expectations of investors. Few investors are likely to adopt Dr. Woolridge's theoretical approach and growth in excess of the economy as a whole is consistent with investors' expectations.[69] Indeed, Multex Investor, a publisher of financial research and investment information that is now an arm of Thomson Reuters, advised that "all equity investors ... should look for growth rates that are at least as strong as growth of Real GDP and Inflation."[70] As a practical matter, investors do not look to that distant horizon where all companies must grow at the rate of the economy. Not only is it impossible to predict the distant future, it simply doesn't matter. In terms of the DCF model, the present value of cash flows in far distant years – beyond the foreseeable future – is so small as to have little effect on investment decisions today.

Q. DO THE SHORT-TERM TREASURY BILL RATES REFERENCED BY MR. BAUDINO (P. 30) PROVIDE AN APPROPRIATE BASIS TO ESTIMATE THE COST OF EQUITY USING THE CAPM?

A. No. Unlike debt instruments, common equity is a perpetuity and as a result, any application of the CAPM to estimate the return that investors require must be predicated on their expectations for the firm's long-term risks and prospects. This does not mean that every investor will buy and hold a particular common stock into

---

[69] As discussed earlier, the fact that Dr. Woolridge's DCF analysis considered historical growth rates below single-digits provides further confirmation that his results fail to reflect the views of real-world investors.

[70] www.multexinvestor.com

perpetuity. Rather, it recognizes that even an investor with a relatively short holding period will consider the long-term, because of its influence on the price that he or she ultimately receives from the stock when it is sold. This is also the basic assumption underpinning the DCF model, which in theory considers the present value of all future dividends expected to be received by a share of stock.

Shannon P. Pratt, a leading authority in business valuation and cost of capital, recognized that the cost of equity is a long-term cost of capital and that the appropriate instrument to use in applying the CAPM is a long-term bond:

> The consensus of financial analysts today is to use the 20-year U.S. Treasury yield to maturity as of the effective data of valuation for the following reasons:
>
> - It most closely matches the often-assumed perpetual lifetime horizon of an equity investment.
> - The longest-term yields to maturity fluctuate considerably less than short-term rates and thus are less likely to introduce unwarranted short-term distortions into the actual cost of capital.
> - People generally are willing to recognize and accept the fact that the maturity risk is impounded into this base, or otherwise risk-free rate.
> - It matches the longest-term bond over which the equity risk premium in measured in the Ibbotson Associates data series.[71]

Similarly, in applying the CAPM Ibbotson Associates recognized that the cost of equity is a long-term cost of capital and the appropriate interest rate to use is a long-term bond yield:

> The horizon of the chosen Treasury security should match the horizon of whatever is being valued. … Note that the horizon is a function of the investment, not the investor. If an investor plans to hold a stock in a company for only five years, the yield on a five-year

---

[71] Pratt, Shannon P., *Cost of Capital, Estimation and Applications* at 60 (1998).

> Treasury note would not be appropriate since the company will continue to exist beyond those five years.[72]

Accordingly, proper application of the CAPM should focus on long-term government bonds and analyses based on 5-year Treasury notes should be ignored.

Q. MR. BAUDINO (PP. 41-42) POINTS OUT THAT YOU HAVE PREVIOUSLY APPLIED THE CAPM USING HISTORICAL DATA. IS THERE ANY INCONSISTENCY IN YOUR POSITION?

A. None whatsoever. While reference to historical data represents one way to apply the CAPM, these realized rates of return reflect, at best, an indirect estimate of investors' current requirements. I have consistently observed that, in order to accurately estimate required returns, the CAPM must be applied using data that reflect the expectations of actual investors.

In other words, my position has been, and continues to be, that the only appropriate application of the CAPM is one based on the forward-looking expectations of investors. As I recognized, while historical data are sometimes referenced as a proxy for investors' expectations, they are a poor substitute for the forward-looking approach presented in my direct testimony. Similarly, Mr. Baudino concluded (p. 29), "There is no real support for the proposition that an unchanging, mechanically applied historical risk premium is representative of current investor expectations and return requirements."

---

[72] Ibbotson Associates, *2003 Yearbook* (Valuation Edition) at 53.

Q. IS THERE ANY MERIT TO MR. BAUDINO'S ARGUMENT (P. 40-41) THAT YOUR ANALYSIS OF THE MARKET RATE OF RETURN SHOULD NOT HAVE BEEN LIMITED SOLELY TO THE DIVIDEND PAYING FIRMS IN THE S&P 500?

A. No. As Mr. Baudino recognized (p. 15-16), under the constant growth form of the DCF model, investors' required rate of return is computed as the sum of the dividend yield over the coming year plus investors' long-term growth expectations. Because the dividend yield is a key component in applying the DCF model, its usefulness is hampered for firms that do not pay common dividends. Accordingly, my DCF analysis of the market rate of return properly focused on the dividend paying firms included in the S&P 500.

Meanwhile, Mr. Baudino (p. 28) predicated his DCF analysis of the market rate of return on the companies followed by Value Line. Of these approximately 1,700 companies, over 750 do not pay common dividends. In other words, close to one-half of the companies that underpin Mr. Baudino's DCF analysis do not have the data necessary to implement this approach. Further, many of these firms are relatively small and lack a meaningful operating history. As a result, there is also greater uncertainty associated with estimating the future growth expectations that are central to the application of the DCF method. Taken together, these factors impugn the reliability of Mr. Baudino's market risk premium and confirm my decision to restrict my analysis to the established, dividend paying firms in the S&P 500.

Q. WHAT OTHER PROBLEMS ARE ASSOCIATED WITH MR. BAUDINO'S MARKET RATE OF RETURN BASED ON VALUE LINE DATA?

A. As detailed in my direct testimony and explained earlier here, expected growth in earnings is far more likely to be representative of investors' forward-looking expectations. As Mr. Baudino noted, "[I]t is not surprising that earnings and cash flow are considered more important than book value and dividends, particularly for non-utility companies that may not pay out much in the way of dividends."[73] But despite this admission and the fact that over one-half of the companies underlying his CAPM analysis do not even pay common dividends, Mr. Baudino nevertheless included dividend and book value growth rates in the DCF analysis he employed to estimate the expected market rate of return. This had the effect of understating the resulting CAPM cost of equity estimates.

VII. FLOTATION COSTS SHOULD BE CONSIDERED

Q. PLEASE RESPOND TO THE ARGUMENT THAT THERE IS NO BASIS TO CONSIDER THE IMPACT OF FLOTATION COSTS IN ESTABLISHING THE COMPANIES' ROE.

A. The need for a flotation cost adjustment to compensate for past equity issues has been recognized in the financial literature. In a *Public Utilities Fortnightly* article, for example, Brigham, Aberwald, and Gapenski demonstrated that even if no further stock issues are contemplated, a flotation cost adjustment in all future years is required to keep shareholders whole, and that the flotation cost adjustment must consider total equity, including retained earnings.[74] Similarly, *Regulatory Finance: Utilities' Cost of Capital* contains the following discussion:

> Another controversy is whether the underpricing allowance should still be applied when the utility is not contemplating an imminent common stock issue. Some argue that flotation costs are real and should be recognized in calculating the fair rate of return on equity, but only at the time when the expenses are incurred. In other words,

---

[73] Baudino Direct at 39.

[74] Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly,* May, 2, 1985.

> the flotation cost allowance should not continue indefinitely, but should be made in the year in which the sale of securities occurs, with no need for continuing compensation in future years. This argument implies that the company has already been compensated for these costs and/or the initial contributed capital was obtained freely, devoid of any flotation costs, which is an unlikely assumption, and certainly not applicable to most utilities. ... The flotation cost adjustment cannot be strictly forward-looking unless all past flotation costs associated with past issues have been recovered.[75]

Q. CAN YOU PROVIDE A SIMPLE NUMERICAL EXAMPLE ILLUSTRATING WHY A FLOTATION COST ADJUSTMENT IS NECESSARY TO ACCOUNT FOR PAST FLOTATION COSTS?

A. Yes. The following example demonstrates that investors will not have the opportunity to earn their required rate of return (*i.e.*, dividend yield plus expected growth) unless an allowance for past flotation costs is included in the allowed rate of return on equity. Assume a utility sells $10 worth of common stock at the beginning of year 1. If the utility incurs flotation costs of $0.48 (5 percent of the net proceeds), then only $9.52 is available to invest in rate base. Assume that common shareholders' required rate of return is 11.5 percent, the expected dividend in year 1 is $0.50 (*i.e.*, a dividend yield of 5 percent), and that growth is expected to be 6.5 percent annually. As developed below, if the allowed rate of return on common equity is only equal to the utility's 11.5 percent "bare bones" cost of equity, common stockholders will not earn their required rate of return on their $10 investment, since growth will really only be 6.25 percent, instead of 6.5 percent:

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$ 10.00	1.050	11.50%	$ 1.09	$ 0.50	45.7%
2	$ 9.52	$ 0.59	$ 10.11	$ 10.62	1.050	11.50%	$ 1.16	$ 0.53	45.7%
3	$ 9.52	$ 0.63	$ 10.75	$ 11.29	1.050	11.50%	$ 1.24	$ 0.56	45.7%
Growth			**6.25%**	**6.25%**			**6.25%**	**6.25%**	

---

[75] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports* at 175 (1994).

The reason that investors never really earn 11.5 percent on their investment in the above example is that the $0.48 in flotation costs initially incurred to raise the common stock is not treated like debt issuance costs (*i.e.*, amortized into interest expense and therefore increasing the embedded cost of debt), nor is it included as an asset in rate base.

Q. CAN YOU ILLUSTRATE HOW THE FLOTATION COST ADJUSTMENT ALLOWS INVESTORS TO BE FULLY COMPENSATED FOR THE IMPACT OF PAST ISSUANCE COSTS?

A. Yes. As discussed in my direct testimony, one method for calculating the flotation cost adjustment is to multiply the dividend yield by a flotation cost percentage. Thus, with a 5 percent dividend yield and a 5 percent flotation cost percentage, the flotation cost adjustment in the above example would be approximately 25 basis points. As shown below, by allowing a rate of return on common equity of 11.75 percent (an 11.5 percent cost of equity plus a 25 basis point flotation cost adjustment), investors earn their 11.5 percent required rate of return, since actual growth is now equal to 6.5 percent:

Year	Common Stock	Retained Earnings	Total Equity	Market Price	M/B Ratio	Allowed ROE	Earnings Per Share	Dividends Per Share	Payout Ratio
1	$ 9.52	$ -	$ 9.52	$ 10.00	1.050	11.75%	$ 1.12	$ 0.50	44.7%
2	$ 9.52	$ 0.62	$ 10.14	$ 10.65	1.050	11.75%	$ 1.19	$ 0.53	44.7%
3	$ 9.52	$ 0.66	$ 10.80	$ 11.34	1.050	11.75%	$ 1.27	$ 0.57	44.7%
Growth			**6.50%**	**6.50%**			**6.50%**	**6.50%**	

The only way for investors to be fully compensated for issuance costs is to include an ongoing adjustment to account for past flotation costs when setting the return on common equity. This is the case regardless of whether or not the utility is expected to issue additional shares of common stock in the future.

Q. PLEASE RESPOND TO DR. WOOLRIDGE'S SPECIFIC CRITICISMS OF YOUR FLOTATION COST ADJUSTMENT.

A. First, while Dr. Woolridge suggests that flotation costs should be ignored because my adjustment was not predicated on a precise accounting for KU, this belies the point of the adjustment. As discussed in my direct testimony, in contrast to debt issuance costs, which are specifically accounted for on the books of the utility, there is no comparable method for equity flotation costs. The approach outlined in my direct testimony is supported by recognized regulatory textbooks and based on research reported in the academic literature, and the lack of a precise accounting of KU's past issuance expenses provides no basis to ignore a flotation cost adjustment.

Meanwhile, Dr. Woolridge mistakenly claims that a flotation cost adjustment "is necessary to prevent dilution of the existing shareholders."[76] In fact, a flotation cost adjustment is required in order to allow the utility the opportunity to recover the issuance costs associated with selling common stock. Dr. Woolridge's observation about the level of market-to-book ratios may be factually correct, but it has nothing to do with flotation costs. The fact that market prices may be above book value does not alter the fact that a portion of the capital contributed by equity investors is not available to earn a return because it is paid out as flotation costs. Even if the utility is not expected to issue additional common stock, a flotation cost adjustment is necessary to compensate for flotation costs incurred in connection with past issues of common stock.

Dr. Woolridge's argument (p. 71) that flotation costs are "not out-of-pocket expenses" is simply wrong. Dr. Woolridge apparently believes that if investors in past common stock issues had paid the full issuance price directly to the utility and

---

[76] Woolridge Direct at 70.

the utility had then paid underwriters' fees by issuing a check to its investment bankers, that flotation cost would be a legitimate expense. Dr. Woolridge's observation merely highlights the absence of an accounting convention to properly accumulate and recover these legitimate and necessary costs.

With respect to Dr. Woolridge's (p. 71) and Mr. Baudino's (p. 43) contention that flotation costs are somehow accounted for in current stock prices,[77] *Regulatory Finance: Utilities' Cost of Capital* has this to say:

> A third controversy centers around the argument that the omission of flotation cost is justified on the grounds that, in an efficient market, the stock price already reflects any accretion or dilution resulting from new issuances of securities and that a flotation cost adjustment results in a double counting effect. The simple fact of the matter is that whatever stock price is set by the market, the company issuing stock will always net an amount less than the stock price due to the presence of intermediation and flotation costs. As a result, the company must earn slightly more on its reduced rate base in order to produce a return equal to that required by shareholders.[78]

Similarly, the need to consider past flotation costs has been recognized in the financial literature, including sources that Dr. Woolridge relied on in his testimony. Specifically, Ibbotson Associates concluded that:

> Although the cost of capital estimation techniques set forth later in this book are applicable to rate setting, certain adjustments may be necessary. One such adjustment is for flotation costs (amounts that must be paid to underwriters by the issuer to attract and retain capital).[79]

---

[77] Woolridge Direct at 71:17-20.

[78] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utilities Reports, Inc.* at 174 (1994).

[79] Ibbotson Associates, *Stocks, Bonds, Bills, and Inflation, Valuation Edition, 2006 Yearbook*, at 35. In addition, the July 19, 2007 decision of the Maryland Public Service Commission in Case No. 9093 cited by Dr. Woolridge (p. 55) approved an adjustment for flotation costs.

VIII. PROXY GROUP REVENUE TEST IS UNSUPPORTED

Q. DO YOU AGREE WITH DR. WOOLRIDGE AND MR. BAUDINO THAT THE SOURCE OF A UTILITY'S REVENUES IS A VALID CRITERION IN SELECTING A PROXY GROUP FOR KU?

A. No. Mr. Baudino selected proxy companies with at least 50 percent of their revenues from electric operations,[80] while Dr. Woolridge argued for the elimination of companies from his electric proxy group if less that 80 percent of total revenues were attributable to electric utility service.[81] However, both witnesses failed to demonstrate how their arbitrary criteria translate into differences in the investment risks perceived by investors. Any comparison of objective indicators demonstrates that the investment risks for the firms in my proxy groups are relatively homogeneous and comparable to KU. Moreover, there are significant errors and inconsistencies associated with the approach adopted by Mr. Baudino and Dr. Woolridge that justify rejecting their proposed proxy group criteria.

Q. DID DR. WOOLRIDGE OR MR. BAUDINO DEMONSTRATE A NEXUS BETWEEN THEIR REVENUE CRITERIA AND OBJECTIVE MEASURES OF INVESTMENT RISK?

A. No. Under the regulatory standards established by *Bluefield*[82] and *Hope*,[83] the salient criterion in establishing a meaningful proxy group to estimate investors' required return is *relative risk*, not the source of the revenue stream. Dr. Woolridge and Mr. Baudino presented no evidence to demonstrate a relationship between the

---

[80] Baudino Direct at 17.

[81] Woolridge Direct at 11.

[82] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679 (1923).

[83] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

arbitrary criteria that they employed and the views of real-world investors in the capital markets.

Moreover, the comfort that Dr. Woolridge and Mr. Baudino take in limiting his proxy groups is misplaced. Due to differences in business segment definition and reporting among utilities, it is often difficult for investors to accurately apportion financial measures, such as total revenues, between utility segments (*e.g.*, electric and natural gas) or regulated and non-regulated sources. In fact, other regulators have rebuffed these notions, with the Federal Energy Regulatory Commission ("FERC") rejecting attempts to restrict a proxy group to companies based on sources of revenues. As FERC recently concluded:

> This is inconsistent with Commission precedent in which we have rejected proposals to restrict proxy groups based on narrow company attributes.[84]

Similarly, FERC has specifically rejected arguments a utility "should be excluded from the proxy group given the risk factors associated with its unregulated, non-utility business operations."[85]

Q. DO OBJECTIVE CRITERIA CONFIRM THE CONCLUSION THAT DR. WOOLRIDGE'S AND MR. BAUDINO'S ARBITRARY REVENUE TESTS DO NOT REFLECT COMPARABLE RISK IN THE MINDS OF INVESTORS?

A. Yes. Credit ratings are perhaps the most objective guide to utilities' overall investment risks and they are widely cited in the investment community and referenced by investors. While the credit rating agencies are primarily focused on the risk of default associated with the firm's debt securities, credit ratings and the

---

[84] *Pepco Holdings, Inc.*, 124 FERC ¶ 61,176 at P 118 (2008).

[85] *Bangor Hydro-Elec. Co.*, 117 FERC ¶ 61,129 at PP 19, 26 (2006).

risks of common stock are closely related. As noted in *Regulatory Finance: Utilities' Cost of Capital*:

> Concrete evidence supporting the relationship between bond ratings and the quality of a security is abundant. ... The strong association between bond ratings and equity risk premiums is well documented in a study by Brigham and Shome (1982).[86]

Indeed, Dr. Woolridge and Mr. Baudino apparently agree. Both reviewed the bond ratings of the companies in their alternative proxy groups and Mr. Baudino testified (p. 14) that bond ratings are based on "detailed analyses of factors that contribute to the risks of a particular investment" and "quantify the total risk of a company."

All of the utilities followed by Value Line identified as having electric revenues less than Mr. Baudino's 50 percent cutoff have bond ratings equal to or stronger than the criterion used to establish his proxy group.

Q. WHAT DO YOU CONCLUDE FROM THIS REVIEW OF INDEPENDENT, OBJECTIVE RISK FACTORS USED BY THE INVESTMENT COMMUNITY?

A. Considering that credit ratings provide one of the most widely accepted benchmarks for investment risks, a comparison of this objective indicator demonstrates that the range of risks for the companies eliminated under the arbitrary revenue criterion proposed by Mr. Baudino are either less risky than or comparable to those of the other firms in my Utility Proxy Group. Contrary to the assertions of Mr. Baudino,[87] comparisons of this objective, published indicator that incorporates consideration of a broad spectrum of risks confirms that there is no link between the 50 percent electric revenue test he applied to define his proxy group and the risk perceptions of investors. In other words, there is no basis to distinguish between the risks that

---

[86] Morin, Roger A., "Regulatory Finance: Utilities' Cost of Capital," *Public Utility Reports* at 81 (1994).
[87] *See, e.g*, Case No. 2009-00459, Response to KPCo 1-9.

investors associate with the companies that Mr. Baudino would eliminate under his revenue criterion and those included in his proxy group.

Q. ARE THERE INCONSISTENCIES AND ERRORS ASSOCIATED WITH THE REVENUE TEST PROPOSED BY MR. BAUDINO?

A. Yes. While Mr. Baudino screened all electric and combination electric and gas utilities followed by Value Line, his revenue test was based solely on <u>electric</u> revenues and ignored the revenue impact of gas utility operations. For example, despite the fact that SCANA Corporation reported in its 2009 Form 10-K report that electric and gas utility operations contributed 73 percent of consolidated revenues, Mr. Baudino would exclude this firm under his revenue test. Similarly, while Mr. Baudino's source reports that CenterPoint Energy, Inc.'s electric utility operations contributed only 19 percent of total revenues, the electric and gas utility segments posted 2009 revenues equal to 65.1 percent of the total consolidated revenues. Meanwhile, Wisconsin Energy Corporation reported in its 2009 Form 10-K Report (p. 109) that its regulated utility segment accounted for approximately 99.7 percent of total revenues. Considering the similarities in the regulatory and business environments for regulated electric and gas utility operations, the failure of Mr. Baudino to incorporate gas utility revenues in implementing his test is inappropriate.

The arbitrary nature of the 50 percent revenue criterion proposed by Mr. Baudino is further illustrated by the lack of any independent, objective findings to support his imposed threshold. Apart from the absence of any evidence to link revenues with investors' risk perceptions, Mr. Baudino granted that there is no underlying basis for his arbitrary test.[88]

The subjective nature of the revenue criteria proposed by Mr. Baudino and Dr. Woolridge is further illustrated by the wide disparity between the thresholds imposed by these respective witnesses. Apart from the absence of any objective evidence to link revenues with investors' risk perceptions, the fact that one witness would impose a 80 percent electric revenue criterion (Dr. Woolridge) while the other would set the bar at 50 percent (Mr. Baudino) reveals the lack of any underlying basis for their tests.

In fact, Dr. Woolridge cannot seem to decide for himself what the correct cutoff should be. For example, in his November 2008 testimony in Case No. 080317-EI before the FPSC involving Tampa Electric Company, Dr. Woolridge argued to exclude companies with less than 75 percent of revenues attributable to electric operations. Similarly, Dr. Wooridge's artificial revenue threshold for his electric utility group here is inconsistent with his findings for gas utilities included in his analyses presented in Case No. 2009-00549 before the KPSC, where he applied a 50 percent threshold to identify his gas proxy group.[89] If Dr. Woolridge finds it acceptable for certain gas utilities to have less than 80 percent of revenues from gas utility operations, why then did he exclude comparably situated electric utilities? Alternatively, why did he not hold gas utilities to the same 80 percent revenue threshold imposed on his electric proxy group if this is a meaningful indicator of comparable risk? The answer, of course, is that Dr. Woolridge's

[88] Response to KPSC 1-11. In addition, as indicated in response to data request KPCo 1-9 (b) in Case No. 2009-00459, "Mr. Baudino did not prepare any studies or documentation for the 50% regulated electric revenue criterion." Mr. Baudino granted in response to KPCo 1-9 (c) that he had no analyses, studies, or publications to support his position that the percent of revenues from electric utility operations is related to investors' risk perceptions.

[89] Direct Testimony of J. Randall Woolridge at p. 13, Case No. 2009-00549.

revenue statistic has no demonstrable link to risk and his internal inconsistency merely highlights the entirely subjective and baseless nature of his "test".

Q. ARE THERE OTHER PROBLEMS ASSOCIATED WITH THE DATA USED BY DR. WOOLRIDGE AND MR. BAUDINO TO SCREEN HIS PROXY GROUP?

A. Yes. These witnesses applied their credit rating screen based on bond ratings reported by AUS Utility Reports. However, these reflect senior debt ratings, not the corporate, or issuer, credit rating for the utility as a whole. Because equity investors are focused on the overall investment risks of the firm, and not those attributable to a specific debt issue, the appropriate measure is the corporate credit rating.

For example, while Dr. Woolridge included UniSource Energy Corporation ("UniSource") in his electric proxy group based on a reported S&P bond rating of "BBB+", the corporate credit rating corresponding to UniSource is "BB+".[90] This rating falls below the ladder of investment grade ratings and places UniSource in the same category as speculative, or "junk" investments. As S&P informed investors, UniSource's finances and risks reflect "the continuing effect of a series of losses and near bankruptcy two decades ago."[91] Similarly, prior to requesting that S&P withdraw its ratings in December 2009,[92] Central Vermont Public Service Corporation, which was included in Dr. Woolridge's electric proxy group, was also assigned a corporate credit rating of "BB+". These junk bond ratings do not reflect comparable risks to KU and the financial and operating challenges that typically

[90] Standard & Poor's Corporation, "Tucson Electric Power Co.," *RatingsDirect* (Dec. 22, 2009). S&P's ratings, including those relied on by Mr. Baudino, reflect its assessment of UniSource's primary subsidiary.
[91] *Id.*
[92] Standard & Poor's Corporation, "Research Update: Central Vermont Public Service Corp. Ratings Withdrawn At The Company's Request," *RatingsDirect* (Dec. 10, 2009).

accompany a speculative grade rating skew the data used to estimate the cost of equity and seriously compromise the resulting DCF estimates.

Q. ARE THERE OTHER MANIFESTATIONS OF THIS PROBLEM REFLECTED IN THE TESTIMONY OF MR. BAUDINO AND DR. WOOLRIDGE?

A. Yes. As noted above, due to differences in business segment definition and reporting between utilities, it is often impossible to accurately apportion financial measures, such as total revenues, between utility and non-utility sources based on the financial information available to investors. Consider the example of Dominion Resources, Inc. (Dominion), which Mr. Baudino and Dr. Woolridge excluded from their sample groups based on the contention that only 43 percent of Dominion's revenues were from electric utility sources. This 43 percent figure used to apply Mr. Baudino's electric revenue criterion is unrelated to the actual percentage of regulated revenues for Dominion, which classifies its operations into three primary segments – Dominion Virginia Power, Dominion Energy, and Dominion Generation.

Dominion Virginia Power includes regulated electric distribution and transmission, as well as non-regulated retail energy marketing operations. Similarly, Dominion Energy includes the regulated natural gas distribution business, as well as tariff-based natural gas pipeline and natural gas storage businesses subject to varying degrees of rate regulation, LNG import and storage activities, and petroleum exploration and production. Meanwhile, Dominion Generation includes the generation operations for both the electric utility and merchant power generation operations. As a result, even ignoring the fact that there is no clear link between the source of a utility's revenues and investors' risk perceptions, it is not possible to accurately apply Mr. Baudino's criterion.

IX. THE COMPANY'S CAPITAL STRUCTURE SHOULD BE APPROVED

Q. WHAT WAS DR. WOOLRIDGE'S RATIONALE FOR REJECTING THE CAPITALIZATION REQUESTED BY KU?

A. Dr. Woolridge's assertion that KU's capital structure should be rejected was based solely on his conclusion that the equity ratio implied by the Company's capitalization is higher than the average for his electric proxy group.[93]

Q. DOES THIS PROVIDE A LOGICAL BASIS TO REJECT KU'S ACTUAL CAPITALIZATION?

A. No. As noted in my direct testimony, while industry averages provide one benchmark for comparison, each firm must select its capitalization based on the risks and prospects it faces, as well as its specific needs to access the capital markets. While the degree of debt leverage is one consideration impacting investors' risk perceptions, it is not the whole picture. Overall investment risk, such as that reflected in bond ratings and other risk measures referenced by investors, also consider the specific business risks underlying a utility's operations. KU's credit ratings, which Dr. Woolridge relied on to establish his proxy group, already reflect the combined impact of these business and financial risk exposures. Moreover, KU's equity ratio falls within the range of capitalizations maintained by the firms in the proxy groups that Dr. Woolridge and I relied on to estimate the cost or equity.

As discussed in my direct testimony, investors and bond rating agencies are increasingly focused on the importance of regulatory support. Making unwarranted adjustments to the capital structure or adopting an unreasonably low ROE would undoubtedly have a negative impact on investors' risk perceptions, and doing both

---

[93] Woolridge Direct at 14.

would be outright alarming. Dr. Woolridge's proposed hypothetical capital structure amounts to nothing more than an ill disguised attempt to engineer a lower overall rate of return by substituting debt for equity.

Q. DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

STATE OF TEXAS	)	
	)	**SS:**
COUNTY OF TRAVIS	)	

The undersigned, **William E. Avera**, being duly sworn, deposes and says he is President of FINCAP, Inc., that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

____
William E. Avera

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of May 2010.

LENA PHAN
Notary Public
STATE OF TEXAS
My Comm. Exp. Sept. 18, 2010

______________________________(SEAL)
Notary Public

My Commission Expires:

September 18, 2010

VISED DCF ANALYSIS

UDINO PROXY GROUP

	(a)	Growth Rates (b)			Cost of Equity Estimates (c)		
	Dividend	Value		First Call/	Value		First Call/
Company	Yield	Line	Zacks	Thomson	Line	Zacks	Thomson
ALLETE, Inc.	5.4%	-0.5%	3.7%	5.3%	$\boxed{4.9\%}$	9.1%	10.8%
Alliant Energy Corp.	5.2%	7.0%	4.0%	5.6%	12.3%	9.3%	10.9%
Con. Edison, Inc.	5.5%	2.5%	3.0%	3.3%	8.1%	8.6%	8.9%
DTE Energy Company	5.1%	7.0%	5.0%	5.0%	12.3%	10.3%	10.3%
Edison International	3.7%	3.5%	5.0%	2.0%	$\boxed{7.3\%}$	8.8%	$\boxed{5.8\%}$
Entergy Corporation	3.8%	5.0%	4.0%	6.7%	8.9%	7.9%	10.6%
Exelon Corporation	4.5%	1.5%	0.5%	0.0%	$\boxed{6.0\%}$	$\boxed{5.0\%}$	$\boxed{4.4\%}$
IDACORP, Inc.	3.9%	4.5%	5.0%	5.0%	8.4%	9.0%	9.0%
Northeast Utilities	3.9%	7.0%	7.9%	7.8%	11.0%	12.0%	11.9%
Pepco Holdings, Inc.	6.7%	0.5%	5.3%	5.3%	$\boxed{7.2\%}$	12.2%	12.2%
PG&E Corporation	4.0%	6.5%	7.7%	7.0%	10.6%	11.8%	11.1%
Progress Energy Inc.	6.4%	4.5%	4.0%	3.7%	11.0%	10.5%	10.2%
PS Enterprise Group	4.3%	7.5%	1.0%	2.2%	12.0%	$\boxed{5.3\%}$	$\boxed{6.5\%}$
Southern Company	5.4%	4.5%	7.4%	5.1%	10.0%	13.0%	10.6%
Wisconsin Energy Corp.	3.0%	8.0%	8.7%	9.5%	11.1%	11.8%	12.7%
Xcel Energy Inc.	4.8%	6.5%	5.7%	6.2%	11.5%	10.6%	11.1%
Average (d)					**10.6%**	**10.5%**	**10.8%**
						10.6%	

Exhibit (RAB-3).

Exhibit (RAB-4).

Sum of dividend yield and respective growth rate.

Excludes highlighted values.

REVISED DCF ANALYSIS

WOOLRIDGE ELECTRIC PROXY GROUP

		(a)	Growth Rates (b)				Cost of Equity Estimates (c)			
	Company	Dividend Yield	Value Line	First Call	Zacks	Reuters	Value Line	First Call	Zacks	Reuters
1	ALLETE, Inc.	5.4%	-0.5%	5.3%	3.7%	6.5%	4.8%	10.8%	9.2%	12.0%
2	American Electric Power Co.	5.0%	3.0%	4.0%	3.6%	4.7%	8.1%	9.1%	8.7%	9.8%
3	Central Vermont PS Corp.	4.6%	3.0%	8.9%	N/A	N/A	7.7%	13.7%	N/A	N/A
4	Cleco Corporation	3.6%	8.0%	4.0%	9.0%	4.0%	11.7%	7.7%	12.8%	7.7%
5	DPL Inc.	4.4%	6.5%	4.5%	5.0%	11.7%	11.1%	9.0%	9.5%	16.4%
6	Edison International	3.7%	3.5%	2.0%	5.0%	3.0%	7.2%	5.7%	8.7%	6.7%
7	Empire District Electric Co.	7.1%	7.0%	6.0%	N/A	N/A	14.3%	13.3%	N/A	N/A
8	FirstEnergy Corporation	5.1%	2.0%	3.3%	3.5%	4.0%	7.1%	8.5%	8.7%	9.2%
9	Hawaiian Electric	6.1%	7.0%	8.8%	8.6%	5.8%	13.4%	15.2%	15.0%	12.1%
10	IDACORP, Inc.	3.9%	4.5%	5.0%	5.0%	5.0%	8.5%	9.0%	9.0%	9.0%
11	Northeast Utilities	3.9%	7.0%	7.8%	7.9%	7.6%	11.0%	11.8%	11.9%	11.6%
12	NSTAR	4.5%	5.5%	5.7%	6.0%	5.4%	10.1%	10.4%	10.6%	10.0%
13	Pinnacle West Capital Corp.	6.0%	3.0%	7.0%	7.0%	6.5%	9.1%	13.2%	13.2%	12.7%
14	PPL Corporation	4.5%	5.0%	11.0%	11.4%	8.6%	9.7%	15.7%	16.2%	13.4%
15	Portland General Electric	5.2%	3.5%	6.0%	5.8%	7.0%	8.8%	11.4%	11.2%	12.4%
16	Progress Energy Inc.	6.4%	4.5%	3.7%	4.0%	3.9%	11.1%	10.3%	10.6%	10.4%
17	Southern Company	5.3%	4.5%	4.8%	7.1%	4.9%	9.9%	10.2%	12.6%	10.3%
18	UIL Holdings Corp.	6.3%	3.0%	4.4%	4.0%	4.1%	9.3%	10.8%	10.4%	10.5%
19	UniSource Energy	3.9%	17.0%	5.0%	5.0%	N/A	21.2%	9.0%	9.0%	N/A
20	Xcel Energy Inc.	4.9%	6.5%	6.1%	5.7%	6.1%	11.5%	11.1%	10.7%	11.2%
	Average (d)						**10.5%**	**11.2%**	**11.0%**	**11.4%**

11.0%

(a) Exhibit JRW-10, p. 2.
(b) Exhibit JRW-10, p. 3.
(c) Sum of dividend yield and respective growth rate.
(d) Excludes highlighted values.

DCF PRICE GROWTH

BAUDINO PROXY GROUP

	Company	(a) Dividend Yield	(b) Price Growth	(c) Cost of Equity
1	ALLETE, Inc.	5.4%	0.9%	$\boxed{6.3\%}$
2	Alliant Energy Corp.	5.2%	7.6%	13.0%
3	Con. Edison, Inc.	5.5%	3.3%	8.8%
4	DTE Energy Company	5.1%	4.0%	9.3%
5	Edison International	3.7%	8.9%	12.8%
6	Entergy Corporation	3.8%	6.9%	10.8%
7	Exelon Corporation	4.5%	5.7%	10.3%
8	IDACORP, Inc.	3.9%	2.5%	$\boxed{6.4\%}$
9	Northeast Utilities	3.9%	8.2%	12.3%
10	Pepco Holdings, Inc.	6.7%	3.6%	10.4%
11	PG&E Corporation	4.0%	4.2%	8.3%
12	Progress Energy Inc.	6.4%	2.5%	8.9%
13	PS Enterprise Group	4.3%	7.0%	11.5%
14	Southern Company	5.4%	6.2%	11.8%
15	Wisconsin Energy Corp.	3.0%	7.0%	10.1%
16	Xcel Energy Inc.	4.8%	3.3%	8.1%
	Average (d)			**10.5%**

(a) Exhibit (RAB-3).
(b) The Value Line Investment Survey (Feb. 26, Mar. 26, & May 7, 2010).
(c) Sum of dividend yield (adjusted for one-half year's growth) and growth rate.
(d) Excludes highlighted values.

WOOLRIDGE ELECTRIC PROXY GROUP

	Company	(a) Dividend Yield	(b) Price Growth	(c) Cost of Equity
1	ALLETE, Inc.	5.4%	0.9%	6.2%
2	American Electric Power Co.	5.0%	4.3%	9.4%
3	Central Vermont PS Corp.	4.6%	9.0%	13.9%
4	Cleco Corporation	3.6%	2.3%	6.0%
5	DPL Inc.	4.4%	6.6%	11.2%
6	Edison International	3.7%	8.9%	12.8%
7	Empire District Electric Co.	7.1%	6.8%	14.1%
8	FirstEnergy Corporation	5.1%	11.2%	16.6%
9	Hawaiian Electric Industries, Inc.	6.1%	1.0%	7.2%
10	IDACORP, Inc.	3.9%	2.5%	6.4%
11	Northeast Utilities	3.9%	8.2%	12.2%
12	NSTAR	4.5%	6.4%	11.0%
13	Pinnacle West Capital Corp.	6.0%	2.9%	9.0%
14	PPL Corporation	4.5%	7.8%	12.5%
15	Portland General Electric	5.2%	5.2%	10.5%
16	Progress Energy Inc.	6.4%	2.5%	9.0%
17	Southern Company	5.3%	6.2%	11.7%
18	UIL Holdings Corporation	6.3%	2.1%	8.4%
19	UniSource Energy Corporation	3.9%	14.3%	18.5%
20	Xcel Energy Inc.	4.9%	3.3%	8.2%
	Average (d)			**11.4%**

(a) Exhibit JRW-10, p. 2.
(b) The Value Line Investment Survey (Feb. 26, Mar. 26, & May 7, 2010).
(c) Sum of dividend yield (adjusted for one-half year's growth) and growth rate.
(d) Excludes highlighted values.

BAUDINO PROXY GROUP

		(a)	(b)	(c)
			Value Line	
	Company	**Expected ROE**	**Adjustment Factor**	**Adjusted ROE**
1	ALLETE, Inc.	8.0%	1.0251	8.2%
2	Alliant Energy Corp.	11.5%	1.0261	11.8%
3	Con. Edison, Inc.	9.5%	1.0165	9.7%
4	DTE Energy Company	9.0%	1.0265	9.2%
5	Edison International	9.0%	1.0262	9.2%
6	Entergy Corporation	12.5%	1.0318	12.9%
7	Exelon Corporation	16.0%	1.0322	16.5%
8	IDACORP, Inc.	8.5%	1.0307	8.8%
9	Northeast Utilities	9.0%	1.0274	9.2%
10	Pepco Holdings, Inc.	7.5%	1.0254	7.7%
11	PG&E Corporation	12.0%	1.0386	12.5%
12	Progress Energy Inc.	9.0%	1.0162	9.1%
13	PS Enterprise Group	14.5%	1.0421	15.1%
14	Southern Company	13.0%	1.0321	13.4%
15	Wisconsin Energy Corp.	12.0%	1.0278	12.3%
16	Xcel Energy Inc.	10.0%	1.0290	10.3%
	Average (d)			**11.2%**

(a) The Value Line Investment Survey (Feb. 26, Mar. 26, & May 7, 2010).
(b) Adjustment to convert year-end "r" to an average rate of return based on data from The Value Line Investment Survey (Feb. 26, Mar. 26, & May 7, 2010).
(c) (a) x (b).
(d) Excludes highlighted values.

EXPECTED EARNINGS APPROACH

WOOLRIDGE ELECTRIC PROXY GROUP

		(a)	(b)	(c)
			Value Line	
		Expected	Adjustment	Adjusted
	Company	ROE	Factor	ROE
1	ALLETE, Inc.	8.0%	1.0251	8.2%
2	American Electric Power Co.	10.0%	1.0293	10.3%
3	Central Vermont PS Corp.	6.5%	1.0342	6.7%
4	Cleco Corporation	11.0%	1.0318	11.3%
5	DPL Inc.	28.0%	1.0204	28.6%
6	Edison International	11.0%	1.0262	11.3%
7	Empire District Electric Co.	10.0%	1.0208	10.2%
8	FirstEnergy Corporation	13.0%	1.0284	13.4%
9	Hawaiian Electric Industries, Inc.	10.5%	1.0253	10.8%
10	IDACORP, Inc.	7.5%	1.0306	7.7%
11	Northeast Utilities	9.0%	1.0274	9.2%
12	NSTAR	14.0%	1.0238	14.3%
13	Pinnacle West Capital Corp.	9.0%	1.0348	9.3%
14	PPL Corporation	16.5%	1.0271	16.9%
15	Portland General Electric	8.5%	1.0305	8.8%
16	Progress Energy Inc.	9.0%	1.0162	9.1%
17	Southern Company	13.0%	1.0321	13.4%
18	UIL Holdings Corporation	10.5%	1.0186	10.7%
19	UniSource Energy Corporation	11.0%	1.0286	11.3%
20	Xcel Energy Inc.	10.5%	1.0290	10.8%
	Average (d)			**10.9%**

(a) Exhibit JRW-10, p. 4.
(b) Adjustment to convert year-end "r" to an average rate of return based on data from The Value Line Investment Survey (Feb. 26, Mar. 26, & May 7, 2010).
(c) (a) x (b).
(d) Excludes highlighted values.

ALLOWED ROE

BAUDINO PROXY GROUP

	Company	Allowed Return on Common Equity
1	ALLETE, Inc.	10.74%
2	Alliant Energy Corp.	10.41%
3	Con. Edison, Inc.	10.03%
4	DTE Energy Company	11.00%
5	Edison International	10.66%
6	Entergy Corporation	10.76%
7	Exelon Corporation	10.30%
8	IDACORP, Inc.	10.18%
9	Northeast Utilities	9.72%
10	Pepco Holdings, Inc.	10.15%
11	PG&E Corporation	11.35%
12	Progress Energy Inc.	12.00%
13	PS Enterprise Group	9.88%
14	Southern Company	11.93%
15	Wisconsin Energy Corp.	10.43%
16	Xcel Energy Inc.	10.72%
	Average	**10.64%**

Source: *AUS Monthly Report* (Apr. 2010).

ALLOWED ROE

WOOLRIDGE ELECTRIC PROXY GROUP

	Company	Allowed Return on Common Equity
1	ALLETE, Inc.	10.74%
2	American Electric Power Co.	10.66%
3	Central Vermont PS Corp.	10.71%
4	Cleco Corporation	10.70%
5	DPL Inc.	11.00%
6	Edison International	10.66%
7	Empire District Electric Co.	10.80%
8	FirstEnergy Corporation	10.67%
9	Hawaiian Electric Industries, Inc.	10.82%
10	IDACORP, Inc.	10.18%
11	Northeast Utilities	9.72%
12	NSTAR	12.50%
13	Pinnacle West Capital Corp.	11.00%
14	PPL Corporation	9.57%
15	Portland General Electric	10.80%
16	Progress Energy Inc.	12.00%
17	Southern Company	11.93%
18	UIL Holdings Corporation	8.75%
19	UniSource Energy Corporation	10.13%
20	Xcel Energy Inc.	10.72%
	Average	**10.70%**

Source: *AUS Monthly Report* (Apr. 2010).

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

REBUTTAL TESTIMONY OF
LONNIE E. BELLAR
VICE PRESIDENT OF STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY

Filed: May 27, 2010

Q. Please state your name, position and business address.

A. My name is Lonnie E. Bellar. I am the Vice President of State Regulation and Rates for Kentucky Utilities Company ("KU" or "Company") and an employee of E.ON U.S. Services Inc., which provides services to KU and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to affirm the importance of industrial customers to the Companies and the Commonwealth; (2) to rebut a proposed off-system-sales ("OSS") margin normalization adjustment proposed by Kentucky Industrial Utility Customers, Inc. ("KIUC") witness Lane Kollen; and (3) to address the concerns of low-income customers regarding ability to pay and late-payment charges.

<u>The Importance of Industrial Customers</u>

Q. The KIUC has submitted testimony by Dr. Paul Coomes in this proceeding to explain the importance of industrial customers to Kentucky's economy. What is KU's position on the importance of such customers?

A. There is no question about the importance of such customers. They are important to the Commonwealth's economy in terms of providing jobs and tax revenues, and they are important to KU and LG&E because they are the Companies' largest customers. Neither KU nor LG&E contests the importance of these customers to the Companies or the Commonwealth.

That notwithstanding, KU believes it has proposed fair, just, and reasonable rates in this proceeding, including those for industrial customers.

Off-System Sales Revenues Should Not Be Normalized (KIUC/Kollen)

Q. What standard applies to all pro forma adjustments?

A. The standard that applies to all pro forma adjustments made to historical-test-year results is 807 KAR 5:001 § 10(7): "[A] utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period."

Q. Does the off-system sales normalization Mr. Kollen proposes meet that standard?

A. No, it certainly does not. The data Mr. Kollen cites to support his adjustment show that the Companies' OSS margins have generally declined over the last five years. According to the testimony of the KIUC, the level of OSS margin credited to customers in the test year is $22.7 million ($18.2 million for LG&E, $4.5 million for KU); however, as the Company indicated in response to a KIUC data request, the actual OSS margin in the test year was $13.2 million ($9.1 million for LG&E, $4.1 million for KU).[1]

Q. Do you agree with Mr. Kollen's calculation of the OSS margin in the test year?

A. No. He apparently has taken the OSS revenues reported in the monthly environmental surcharge filings and the fuel expense from the monthly fuel adjustment clause filings to calculate the OSS margins in his testimony. This calculation mixes data from two different rate mechanisms and ignores the interaction between inter-company sales reflected in the fuel clause calculation. The calculation of the actual OSS margin in the test year ($13.2 million -$9.1 million for LG&E, $4.1

[1] First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. dated March 1, 2010 Question No. 66 (KU) and Question No. 63 (LG&E).

million for KU) presented in First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. dated March 1, 2010 Question No. 66 (KU) and Question No. 63 (LG&E) was done according to the methodology presented by LG&E and KU in regulatory filings to this Commission for at least the last ten years and properly reflects the appropriate revenues and expenses associated with OSS.

Q. Will you please explain why the off-system sales normalization Mr. Kollen proposes does meet the "known and measureable" standard?

A. Yes. Notwithstanding the error in his calculation of the OSS margins in the test year, in contrast the adjustment presented by Mr. Kollen, the data Mr. Kollen cites show that the Companies' OSS margins have generally declined over the last five years. The actual OSS margin in the test year was $13.2 million ($9.1 million for LG&E, $4.1 million for KU).[2] The Companies' projected OSS margin for calendar year 2011— Trimble County Unit 2 ("TC2") will be commercially operational the whole year—is just $11.8 million ($11 million LG&E, $800,000 for KU), which is in line with their test-year results. No party to these proceedings has challenged the Companies' projections. Therefore, there is no "known and measurable change[]" that would support any pro forma adjustment to the historical test-year OSS margin amounts embedded in the Companies' proposed base electric rates; rather, the historical data Mr. Kollen cites, as well as the Companies' uncontested OSS margin projection for 2011, clearly demonstrate that the amount of OSS margins embedded in the Companies' proposed rates are reasonably indicative of the OSS margins that can be expected in the near term. Mr. Kollen's testimony fails to demonstrate that the

[2] First Set of Data Requests of Kentucky Industrial Utility Customers, Inc. dated March 1, 2010 Question No. 66 (KU) and Question No. 63 (LG&E).

KIUC's simple five-year average of OSS (calendar years 2005 to 2008 and the test year) is indicative of future OSS margins with any reasonable certainty.

Q. Why is the Companies' projected OSS margin for 2011 lower than the test year margin if TC2 will be in full commercial operation that year?

A. First, the Companies have experienced a reduction in generation sources in recent years. On December 31, 2005, KU's purchase contract with Electric Energy, Inc., expired on its own terms, resulting in a loss of 200 MW of firm, low-cost generation capacity. This month, KU's contract with Owensboro Municipal Utilities ("OMU") also expired, resulting in a loss of over 160 MW of summer-rated capacity. Therefore, though the addition of TC2 will result in a net generation capacity increase to the Companies, it is not as large as Mr. Kollen suggests. Moreover, Mr. Kollen's assertion that the Companies can expect higher OSS margins in the future because "[t]he Companies have added significant peaking capacity in recent years" cannot be supported by the facts.[3] The last peaking units (combustion turbines) the Companies put in service were Trimble County Units 9 and 10, which went in service on July 1, 2004, well before the test year in this proceeding, and even before the five years over which Mr. Kollen seeks to average OSS margins.

Second, as Mr. Kollen's own forward electric energy price curve shows, wholesale electric energy rates through 2015 (about $50.00/MWh in 2011, climbing to $57.00/MWh in 2014-2015) are not expected to come close to the levels achieved in 2005 ($76/MWh) and 2008 ($73/MWh), when the Companies' OSS margins were more substantial than in the test year. Including such aberrantly high-priced years in

[3] KIUC Response to KPSC 1-3.

a normalization, when there is no expectation that such highs will be achieved again in the foreseeable future, would be blatantly results-oriented and selective in nature.

Third, any economic recovery in the Companies' service areas will likely lead to increased electric energy usage to fuel new economic activity, making less capacity and energy available for OSS. This fact undermines Mr. Kollen's assertion that a rebounding national economy will necessarily mean increased OSS margins for the Companies.[4]

All of these factors demonstrate that the amount of OSS margins embedded in the Companies' proposed base rates is reasonably representative of a going-forward level.

Q. Why wouldn't an OSS normalization adjustment be comparable to the other kinds of normalization adjustments the Companies have proposed?

A. There are precisely three kinds of normalization adjustments the Companies have proposed in these base rate proceedings: weather, storm damage, and injuries and damages. Contrary to Mr. Kollen's exaggerated assertion, these are not "among others"; this is the entire list.

There is a reason the list is so short: they constitute exceptions to the rule I quoted above from 807 KAR 5:001 § 10(7): "[A] utility may request pro forma adjustments for known and measurable changes to ensure fair, just and reasonable rates based on the historical test period." Mr. Kollen asserts that "Normalization adjustments are standard ratemaking practice."[5] They are no such thing, and certainly not before this Commission.

---

[4] KIUC Response to KPSC 1-4(a).
[5] KIUC Response to KPSC 1-2(a).

The few normalization exceptions to the general "known and measurable" rule exist primarily because the revenues or expenses being normalized are essentially random occurrences without any upward or downward trend that is incorporated into the adjustment. The weather will be what it will be, and what storms will come the Companies can neither predict nor affect. Furthermore, with temperature, storms and injuries and damages there is a central tendency for events to fall within a range that will typically equal a mean value when measured over time. While the number of heating degree days, cooling degree days, storms, or injuries vary from year to year, the average values of these random variables are very stable and predictable over time. Though the Companies strive to minimize injuries and damages and the effect of storms, they will occur, and in no discernible pattern. For these reasons, there is no reason to think that any given test year's storm or injuries and damages costs are indicative of future costs; what is normal can only be understood in reference to the past over a long span of time.

Off-system sales, on the other hand, are not predictable or stable over long periods of time. They are subject to upward and downward cycles that are entirely unpredictable. They are heavily dependent on the economy, the price of fuel, demand for capacity, the relationship between supply and demand characteristics in the region, wheeling costs across transmission systems, and the Company's ability to market power to third parties, none of which can be described as a random variable with a identifiable central tendency.

The purpose of a establishing a test year in a rate case is to identify levels of revenues and expenses that are representative on a going forward basis. In offering his adjustment, Mr. Kollen is essentially supplanting what actually occurred during the test year and with his own prediction of what power markets will look like in the future. History has shown that such predictions are unreliable at best. But more significantly, Mr. Kollen's adjustment does not rise to the standard of being known and measurable.

Q. Has the Commission ever approved an OSS margin normalization adjustment of the kind Mr. Kollen proposes?

A. No, and Mr. Kollen frankly admitted as much in a response to a Commission Staff data request: "Mr. Kollen is not aware that ... the Commission has adopted a normalization adjustment to OSS margins based on average historic margins."[6] Nothing he has presented suggests the Commission should change its unbroken practice in this proceeding by adopting his purely results-oriented OSS margin normalization adjustment.

Q. What is the Companies' position on an OSS tracker mechanism of the kind Mr. Kollen suggests?

A. The imposition of surcharges in recent years under these circumstances has proven to be problematic. This is best illustrated by contrasting the position of KIUC in this case (i.e., proposing an OSS tracker) while vehemently opposing the Companies' renewable surcharge mechanism in the recent wind power proceeding, Case No. 2009-00353. Mr. Kollen is correct that the Companies' consent to such a tracker is typically required by the Commission before imposing such a significant change in regulation. For example, the Commission allowed the Companies to choose whether

[6] KIUC Response to KPSC 1-2(a).

they would operate under the Earnings Sharing Mechanism several years ago. The Attorney General's consent to such a surcharge under the present circumstances is only a remote possibility.

The Commission's historic policy of including OSS margins in base rates has fairly balanced the interests of customers and shareholders, provided an appropriate and symmetrical incentive to maximize OSS margins when possible and shielded retail customers from the risks of the wholesale power market. Mr. Kollen has failed to present sufficient reasons or evidence why the Commission should deviate from its historic policy.

Low-Income Concerns

Q. What is KU's response to concerns that low-income and fixed-income customers may have difficulty paying KU's requested rates?

A. We sympathize with the difficulties these groups face, and will continue efforts to assist these customers. For example, KU sought and received approval from the Commission in 2007 to continue the Home Energy Assistance ("HEA") Program, which provides hardship assistance to low-income customers through the collection of 15 cents per residential meter per month. KU has also implemented a FLEX program to allow customers on fixed incomes 16 additional days to pay their bills (i.e., their bills are due 28 days from the bill date), effectively allowing participating customers to pay their bills after they receive their monthly incomes.[7] Finally, KU

[7] CAC witness Jack Burch appears to misunderstand what the FLEX program does. In CAC's response to KPSC 1-3, he states: "The billing cycle needs to be extended because the FLEX option ... does not give people more time from the date of bill issuance to the due date." Contrary to Mr. Burch's assertion, that is precisely what the FLEX option does; it extends the bill due date to 28 days after the bill date.

personnel continue to work with low-income groups' representatives, meeting regularly in working groups to address new and ongoing needs, issues, and concerns.

Q. Can KU waive late-payment charges for low-income customers?

A. Community Action Council witness Jack Burch suggests in his testimony that KU should waive late-payment charges for low-income customers; however, KU does not have the authority to waive late-payment charges for low-income customers. First, KU must follow its tariff:

> No utility shall charge, demand, collect, or receive from any person a greater or less compensation for any service rendered or to be rendered than that prescribed in its filed schedules, and no person shall receive any service from any utility for a compensation greater or less than that prescribed in such schedules.[8]

Second, KU must treat equally all customers in a rate class:

> No utility shall, as to rates or service, give any unreasonable preference or advantage to any person or subject any person to any unreasonable prejudice or disadvantage, or establish or maintain any unreasonable difference between localities or between classes of service for doing a like and contemporaneous service under the same or substantially the same conditions.[9]

The Commission has rejected income level as a reasonable ground for maintaining any distinction between customers.[10] For these reasons, KU simply cannot waive late-payment charges for low-income customers.

Q. Does this conclude your testimony?

A. Yes.

---

[8] KRS 278.160(2).
[9] KRS 278.170(1).
[10] *In the Matter of Application for Adjustment of Electric Rates of Kentucky Power Company*, Case No. 1991-00066, Order (Oct. 31, 1991); *In the Matter of the Consideration of Life-Line Rates as Required by Section 114 of the Public Utility Regulatory Policies Act*, Administrative Case No. 248, Order (Feb. 28, 1982).

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for Kentucky Utilities Company and an employee of E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of May 2010.

Victoria B. Harper (SEAL)

Notary Public

My Commission Expires:

Sept 20, 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2009-00548

REBUTTAL TESTIMONY OF ROBERT M. CONROY DIRECTOR, RATES KENTUCKY UTILITIES COMPANY

Filed: May 27, 2010

Q. Please state your name, position and business address.

A. My name is Robert M. Conroy. I am the Director of Rates for E.ON U.S. Services Inc., which provides services to Kentucky Utilities Company ("KU" or "Company") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky.

Q. What are the purposes of your testimony?

A. The purpose of my testimony is to address and respond to certain points and assertions made by intervenors to this proceeding. Specifically, I will address intervenors' comments on the following topics: (1) the percentage used to calculate off-system sales revenues for Environmental Cost Recovery ("ECR"); (2) the adjustment to ECR if the Commission normalizes off-system sales margins; and (3) the availability of the All Electric School ("AES") rate for new customers.

Off-System Sales ("OSS") Revenues Calculation for ECR

Q. Please describe the intervenors' objection to the Company's adjustment to reduce OSS revenues for the portion of the ECR revenue requirement allocated to off-system sales.

A. Mr. Lane Kollen, testifying on behalf of the Kentucky Industrial Utility Customers, Inc., is the only intervenor who objected to the Company's adjustment.[1] While Mr. Kollen accepts the purpose of the adjustment, his disagreement is in how the adjustment was calculated. Mr. Kollen objects to KU's use of an annualized simple average of surcharge factors (percentages), arguing that a weighted average

[1] Direct Testimony of Lane Kollen of April 22, 2010 (Case No. 2009-00548) at 8-9.

percentage should be utilized because OSS revenues and the ECR factors vary considerably each month.[2] Mr. Kollen argues that use of the simple average results in an overstatement of the average ECR factor, which results in a greater reduction in OSS revenue.

Q. Why does the Company currently use a simple average in the calculation?

A. As explained in response to KPSC 2-29, the simple average is utilized because it is consistent with the method the Commission adopted in Case No. 98-474. Further, this method has been used consistently by KU in all base rate proceedings since that proceeding. Although Mr. Kollen's testimony states that the Company "provided corrected computations" in response to KPSC 2-29, which asked KU to provide a revised version of the calculation using the weighted average approach, this contention is inaccurate.[3] The Company's use of the simple average was not incorrect, as KU was complying with established Commission precedent.

Q. Does KU object to Mr. Kollen's position as to the use of a weighted average?

A. No. KU believes that use of the simple average, as well as the weighted average, are reasonable approaches. The Company does agree that the weighted average is mathematically more accurate.[4] While the Company does not object to use of the weighted average, it is not appropriate to continuously vacillate between the simple average and weighted average methods. If the Commission recommends use of the weighted average in this proceeding, Mr. Kollen and the other intervenors should not argue for use of the simple average in KU's subsequent base rate proceedings merely

---

[2] Id. at 9.
[3] Id. at 9.
[4] See KU's response to KPSC 3-14.

because use of the simple average may result in a greater reduction in the revenue requirement than the weighted average. While the Company is amenable to either approach, it is important that the Commission establish a consistent methodology for this computation.

Adjustment to ECR Calculation for Normalized OSS Margins

Q. Briefly explain the intervenors' adjustment to OSS margins.

A. Mr. Kollen has proposed an adjustment to normalize OSS margins.[5] Additionally, Mr. Kollen has asserted that if the Commission allows his adjustment to normalize OSS revenues, his adjustment to the ECR calculation discussed above will have to be increased from the exhibit Mr. Kollen included in his direct testimony to reflect any base rate increases authorized in this proceeding. KU objects to Mr. Kollen's adjustments regarding OSS normalization for the reasons explained in Mr. Lonnie Bellar's rebuttal testimony in this proceeding.

Availability of the AES Rate for New Customers

Q. Briefly explain the intervenors' objection to KU's proposal to restrict the AES rate to customers taking service under the rate as of February 6, 2009.

A. Only one witness, Mr. Charles Buechel, testifying on behalf of the Kentucky School Boards Association, objected to KU's clarification of the AES tariff to restrict its use to customers taking service under the rate as of February 6, 2009.[6] The restriction was not proposed in the present proceeding but was an outcome of Case No. 2008-

[5] Id. at 10-11.
[6] Direct Testimony of Charles D. Buechel of April 22, 2010 (Case No. 2009-00548) at 4.

00251. Mr. Buechel argued that some schools were not aware that they qualified for the AES tariff and thus took service under different tariffs.[7] Mr. Buechel further argued that other schools may want to take service under this rate in the future and should be afforded the opportunity to do so.[8]

Q. **Mr. Buechel asserts that some schools who qualified for service under Rate AES were mistakenly provided service under different tariffs. Can you comment on this assertion?**

A. Yes. When customers initiate service for their facility, the Company does its best to put them on the rate schedule that is applicable for their service. However, the responsibility when two or more rate schedules are available to a customer is specifically stated in the Terms and Conditions, Original Sheet No. 97, of the Company's Tariff:

> OPTIONAL RATES
>
> If two or more rate schedules are available for the same class of service, it is Customer's responsibility to determine the options available and to designate the schedule under which customer desires to receive service.
>
> Company will, at any time, upon request, advise any customer as to the most advantageous rate for existing or anticipated service requirements as defined by the customer, but Company does not assume responsibility for the selection of such rate or for the continuance of the lowest annual cost under the rate selected.
>
> In those cases in which the most favorable rate is difficult to predetermine, Customer will be given the opportunity to change to another schedule, unless otherwise prevented by the rate schedule under which Customer is currently served, after trial of the schedule originally designated; however, after the first such change, Company shall not be required to make a change in schedule more often than once in twelve (12) months.

---

[7] Id.
[8] Id. at 4-5.

> From time to time, Customer should investigate Customer's operating conditions to determine a desirable change from one available rate to another. Company, lacking knowledge of changes that may occur at any time in Customer's operating conditions, does not assume responsibility that Customer will at all times be served under the most beneficial rate.
>
> In no event will Company make refunds covering the difference between the charges under the rate in effect and those under any other rate applicable to the same class of service.

While the Company will work with customers on requesting service, the customer is in a better position to understand their load characteristics and determine the rate schedule that will minimize the cost of energy for their facilities. For the reasons discussed below, Rate AES was restricted in the prior rate case for new customers.

Q. Should the tariff language, which restricts the rate to customers taking service as of February 6, 2009, be accepted as KU proposed in its filing?

A. Yes. The decision to restrict the AES tariff to customers taking service as of February 6, 2009, was proposed in the prior rate case proceeding, Case No. 2008-00251, and was agreed to by all parties during the settlement of that base rate proceeding. This issue was examined in the prior proceeding and the Commission approved limiting the future availability of this tariff when it approved the settlement. Thus, KU's adjustment, which clarifies the language approved in the 2008 proceeding, does not represent a substantial change in the AES tariff as the limitation on the future availability of the rate has been in effect since the last base rate case.

Q. What were the reasons behind KU's decision to seek to limit the future availability of the AES tariff?

A. The tariff was initially created to encourage schools to use all electric energy just as many other rates, such as All-Electric Residential rates, Off-Peak Water Heating rates, and Space Heating rates were proposed to encourage the use of electricity. These promotional rates supported the expansion of the electric system at a time when it was needed and lowered prices by providing economies of scale through increased system efficiencies. Conditions have changed, however, and it is no longer reasonable to promote the use of electricity through specialty rates that do not reflect cost. The impetus behind the creation of the tariff is no longer relevant as school customers are not distinguishable from any other KU commercial customer, as discussed by Mr. Seelye. Since the rate is not supportable from an economic standpoint, KU proposed limiting its future availability, which helps simplify the Company's rate design. As there were valid reasons supporting the Company's limitation of this rate, the Commission approved the Company's proposed change in the last base rate proceeding when it approved the settlement.

Q. Does this conclude your testimony?

A. Yes, it does.

400001.134411/628469.2

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is Director - Rates for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Robert M. Conroy

Robert M. Conroy

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC BASE RATES	))))	CASE NO. 2009-00548

REBUTTAL TESTIMONY OF SIDNEY L. "BUTCH" COCKERILL DIRECTOR, REVENUE COLLECTIONS KENTUCKY UTILITIES COMPANY

Filed: May 27, 2010

Q. Please state your name, position and business address.

A. My name is Sidney L. "Butch" Cockerill. I am the Director, Revenue Collections for E.ON U.S. Services Inc., which provides services to Kentucky Utilities Company ("KU" or "Company") and Louisville Gas and Electric Company ("LG&E") (collectively, "Companies"). My business address is 220 West Main Street, Louisville, Kentucky 40202. A statement of my qualifications is included in the Appendix attached hereto.

Q. Have you testified previously before the Commission?

A. Yes, I have previously testified before the Commission, and did so in the Company's last general rate case, Case No. 2008-00251. In addition, I testified in Case Nos. 2007-00117 and 2007-00161, concerning responsive pricing and real-time pricing pilot programs, respectively.

Q. Are you adopting the testimony of John Wolfram as your own in this proceeding?

A. Yes. Mr. Wolfram is no longer with the Company, so I am adopting his pre-filed direct testimony as my own.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are: (1) to confirm that KU has determined to rescind its proposal to allow only those customers who have not been disconnected for non-payment to pay any necessary deposits in installments; and (2) to address the concern that the FLEX program does not address difficulties fixed-income customers face in paying their bills on time.

Q. What is KU's proposal concerning payment of deposits in installments, and why?

A. KU proposes not to alter the deposit installment options currently available to customers required to make a deposit as a condition of reconnection. These options currently include, and will continue to include, allowing customers who have been disconnected for non-payment to pay required deposits in up to four installments upon request. KU's initial proposal to disallow that option was based on incomplete deposit installment payment default data. On further review, KU determined the proposal is not necessary and is rescinding it.

Q. Please explain why KU's FLEX option addresses the concern Community Action Council witness Jack Burch raised in his testimony concerning bill due dates.

A. Mr. Burch expressed concern in his testimony that the current KU bill due date, which is twelve calendar days after the mailing date of the bill, has made it more difficult for residential customers on fixed incomes to make their payments on time. He further mistakenly asserts that KU's FLEX option does not resolve this issue. In fact, the FLEX option gives customers on fixed incomes who have demonstrated an ability to pay by a particular date each month an additional sixteen days to pay their bills (i.e., the ability to pay up to 28 days after the bill date). This directly resolves the concern Mr. Burch presents; if a customer's difficulty is not an overall inability to pay, but rather is only an inability to pay by a certain date, the FLEX program effectively allows qualifying customers to pay their bills after their monthly income arrives.

I would also like to note that though a non-FLEX-option customer's bill is due twelve calendar days after the bill's mailing date, KU does not assess a late-payment charge to the bill or take any adverse credit action until the sixteenth day following the bill's mailing date.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Sidney L. "Butch" Cockerill**, being duly sworn, deposes and says that he is Director – Revenue Collections for E.ON U.S. Services, Inc., and that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Sidney L. "Butch" Cockerill

Sidney L. "Butch" Cockerill

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 25th day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

APPENDIX A

S. L. "Butch" Cockerill
Director, Revenue Collections
E.ON U.S. Services Inc.
220 West Main Street
P. O. Box 32010
Louisville, Kentucky 40202
(502) 627-4772

Education

Spaulding University, B.A. in Business Administration – 1998

Previous Positions

Louisville Gas and Electric Company, Louisville, Kentucky
2002-2003 - Director of Distribution Operations
2000-2002 - Director of Gas Control and Storage
1997-2000 - Manager of Gas Storage Operations
1995-1997 - Manager of Gas Distribution
1990-1995 - Manager of Transportation Department

Professional Trade Memberships

American Gas Association
Kentucky Gas Association
Electric Utilities Fleet Management

Civic Activities

Kentucky Derby Festival, Director

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In re the Matter of:

APPLICATION OF KENTUCKY UTILITIES	)	
COMPANY FOR AN ADJUSTMENT OF	)	CASE NO. 2009-00548
BASE RATES	)	

REBUTTAL TESTIMONY OF
WILLIAM STEVEN SEELYE
PRINCIPAL & SENIOR CONSULTANT
THE PRIME GROUP, LLC

Filed: May 27, 2010

Table of Contents

Exhibits

Seelye Rebuttal Exhibit 1 - Watkins' On/Off Peak Costs

Seelye Rebuttal Exhibit 2 - Academic Sources for Weighted Regression Analysis

Seelye Rebuttal Exhibit 3 - Weighted Regression in the Software Package R

Seelye Rebuttal Exhibit 4 - Example of Unweighted Regression Underlying Data Points

Seelye Rebuttal Exhibit 5 - Example of Unweighted Regression using Summary Data

Seelye Rebuttal Exhibit 6 - Example of Weighted Regression using Summary Data

Seelye Rebuttal Exhibit 7 - Calculation of Customer Costs using Watkins' Cost of Service

Seelye Rebuttal Exhibit 8 - Automatic Benefit of Conjunctive Billing using Random Loads

Seelye Rebuttal Exhibit 9 - Automatic Benefit of Conjunctive Billing for two Actual Multi Site Customers

Seelye Rebuttal Exhibit 10 - Copy of Response to KCTA-1, Q. 2

Seelye Rebuttal Exhibit 11 - Copy of Response to KPSC-3, Q. 3a

Seelye Rebuttal Exhibit 12 - Effect of Switching from Levelized to Non-Levelized Carrying Charges

Seelye Rebuttal Exhibit 13 - Recalculation of Proposed CATV Charge

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is William Steven Seelye and my business address is The Prime Group, LLC, 6001 Claymont Village Dr., Suite 8, Crestwood, Kentucky, 40014.

Q. Did you submit direct testimony in this proceeding?

A. Yes.

Q. On whose behalf are your testifying?

A. I am testifying on behalf of Kentucky Utilities Company ("KU" or "Company").

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to rebut Attorney General ("AG") witness Glenn A. Watkins concerning his proposed cost of service study, revenue allocation, and rate design; Kentucky Industrial Utility Customers, Inc. ("KIUC") witness Stephen J. Baron concerning cost of service and rate design; KIUC witness Dennis W. Goins concerning his recommendations regarding curtailable service; KIUC witness Lane Kollen regarding unbilled revenues; The Kroger Co. ("Kroger") witness Neal Townsend concerning his recommendations to implement conjunctive demand billing; The Kentucky Cable Telecommunications Association ("KCTA") witness Patricia D. Kravtin regarding cable television pole attachment charges; and Kentucky School Board Association ("KSBA") witness Charles D. Buechel concerning rate design.

II. CLASS COST OF SERVICE AND THE ALLOCATION OF THE REVENUE INCREASE

A. ALLOCATION OF FIXED PRODUCTION COSTS

Q. Is there agreement among the intervenor witnesses on the methodology that should be used to allocate costs in the class cost of service study?

A. No. In this proceeding, KU submitted a class cost of service study using a methodology that was first adopted by Louisville Gas and Electric Company ("LG&E") in the early 1980s and used by KU since the late 1990s. On a number of occasions, the Commission has determined that the Company's methodology is reasonable and should be used as a guide for setting rates. A critical facet of the cost of service study is the methodology used to allocate fixed production costs (i.e., production capacity costs). As in prior rate case filings, the Company proposed to allocate fixed production costs using the modified Base-Intermediate-Peak ("BIP") methodology. Under the modified BIP methodology, a portion of fixed production costs are classified as "summer peak" costs and allocated on the basis of each customer class's loss-adjusted contribution to the system peak demand during the Summer ("summer coincident peak allocator"); another portion of fixed production costs are classified as "winter peak" costs and allocated on the basis of each customer class's loss-adjusted contribution to the system peak demand during the Winter ("winter coincident peak allocator"); and the remaining portion of fixed production costs are classified as "base" costs and allocated on the basis of each customer class's average demand ("average demand allocator").

A critical difference among the intervenor witnesses is the amount of fixed production costs allocated on the basis of an average demand allocator. In KU's cost of service study, 34.89% of fixed production costs were allocated on the basis of an average demand allocator. Mr. Baron, testifying on behalf of KIUC, and Mr. Selecky, testifying on behalf of Walmart, both maintain that the modified BIP methodology allocates *too much* of the Company's fixed production costs on the basis of an average demand allocator; whereas, Mr. Watkins, who is testifying on behalf of the AG, maintains that the modified BIP methodology allocates *too little* of the Company's fixed production costs on the basis of an average demand allocator.

Because fixed production costs represent approximately 37% of the total cost of service, modifying the allocation factor used to assign these costs would have a significant impact on the results of the cost of service study. Allocating a larger percentage of fixed production costs on the basis of a demand allocator tends to shift costs to customer classes that use capacity *less efficiently*. Conversely, allocating a larger percentage of fixed production costs on the basis of an average demand allocator tends to shift costs to customer classes that use capacity *more efficiently*. In this context, "efficiency" relates to the extent to which the capacity is fully utilized and is generally measured by the load factor of a customer class. Greater utilization of the fixed assets corresponds to greater efficiency and a higher load factor. Lower utilization of the fixed assets corresponds to lesser efficiency and a lower load factor. The efficient utilization of capacity is not something that is considered only in the utility industry. Rather, it is a concept that is extremely important in any capital intensive industry – such as the airline industry or the shipping industry. For example, it is more efficient, and extremely important, for an airline to fill all of the seats on its planes, for a railway company to fill all of the cars on its trains, and for an overseas shipping company to fill all of the holds in its ships. A standard objective of companies operating in capital intensive industries is to maximize the utilization of their capacity. Companies operating in capital intensive industries are continuously looking for creative ways to increase the load factor and utilization of their capital investments.

Q. How do the witnesses propose to allocate fixed production costs?

A. Mr. Selecky proposes to allocate all fixed production costs on the basis of a coincident peak allocator. He argues that because a portion of fixed costs are allocated on the basis of an average demand allocator the modified BIP methodology "double counts" a portion of the average demand which is also included in the peak demand. Mr. Selecky argues as follows:

> By allocating some capital costs relative to average demand, and some relative to coincident peak demand, energy is counted twice – once by itself and the second time as a subset of the coincident peak. If the year-round energy is analogous to base load units, which supply capacity on a continuing basis throughout the year, then it follows that the only time when intermediate and peaking units would be needed to meet the system demands are when they are in excess of the average year demand. The BIP method improperly allocates the cost of this additional capacity relative to the total coincident demand, rather than the excess demand. (Case No. 2009-00548, Direct Testimony of James T. Selecky, pp. 8-9.)

Although he does not advance an alternative cost of service methodology, Mr. Baron maintains also that the modified BIP methodology allocates too much costs on the basis of an average demand allocator. Mr. Baron makes the following statement regarding the Company's cost of service methodology:

> While I do not believe that the BIP methodology is the most reasonable approach to class cost of service analysis, I have relied on this methodology in this case. In particular, the BIP method tends to allocate a greater percentage of the Companies' production and transmission costs to high load factor industrial rate classes because a significant portion of these costs are allocated as energy related (the base portion of the BIP method). (Case Nos. 2009-00549 and 2009-00548, Direct Testimony of Stephen J. Baron.)

Mr. Watkins, on the other hand, maintains that the Company's cost of service study does not allocate enough costs on the basis of average demand. Specifically, Mr. Watkins proposes to allocate 82.12% of the Company's fixed production costs on the basis of an average demand allocator. He argues that because a large percentage of the Company's production capacity is made up of coal-fired steam units, the original BIP methodology would have allocated most of KU's production fixed costs on the basis of an average demand allocator.

The following table illustrates the positions of the parties regarding the percentage of fixed production costs that should be allocated on the basis of demand and energy:

Percentages of Fixed Production Cost Allocated on the Basis of Peak and Average Demand		
Party	**Percentage Allocated on Peak Demand**	**Percentage Allocated on Average Demand**
AG (Mr. Watkins)	17.88%	82.12%
KU	65.11%	34.89%
KIUC (Mr. Baron)	Something greater than 65.11%	Something less than 34.89%
Walmart (Mr. Selecky)	100.00%	0.00%

As can be seen from this table, the percentage of production fixed costs allocated on the basis of demand or energy in the Company's cost of service study falls between the positions advocated by other parties in this proceeding. Because the Company is trying to balance the interests of all customer classes, KU's recommendation should be given greater weight in this proceeding.

Q. Do you agree with Mr. Selecky's or Mr. Baron's argument that the modified BIP methodology allocates too much cost on the basis of an average demand allocator?

A. I agree that care must be taken in any cost of service study to avoid allocating too large of a percentage of fixed production costs on the basis of average demand. From a purely academic perspective, changes in a customer class's average demand do not have any impact on the Company's capacity costs. For example, the Company's fixed production costs will not increase if any given customer class were to increase its average demand without altering its contribution to the system peak demand. The converse, however, is not true. Except in situations where prolonged periods of excess capacity exist, if a customer class increases its demand at the time of the peak without altering its average demand, then the utility's fixed production costs will certainly increase over time. Particularly, the utility will need additional generation capacity to meet the increase in peak demand. The same result is applicable in any capital intensive industries. Recalling the earlier example from the airline industry, increasing the *average* number of passengers on a flight (or flights) will not have any impact on an airline's *fixed* costs. Increasing the maximum number of passengers on flights can have a dramatic impact on fixed costs, including creating the necessity to buy additional planes, which, like power plants, are not inexpensive.

Mr. Selecky makes the somewhat arcane but not incorrect argument – akin to the mean value theorem in mathematical statistics – that any average number is numerically included within a maximum number. But the crux of his and Mr. Baron's argument seems to be that average demand has little or nothing to do with capacity costs. A further point of theirs is that allocating fixed production costs on the basis of average demand penalizes efficient utilization of capacity and rewards inefficient utilization of capacity – sort of like the absurd proposition of an airline awarding *infrequent flier miles* rather than *frequent flier miles*. In fact, many airlines have developed revenue management systems designed to maximize the revenue collected from each flight by increasing load factor and implementing tiered pricing structures. These sophisticated revenue management models often involve complex dynamic programming algorithms to target discretionary fliers and to deal with overbooking situations. See Kalyan T. Talluri and Garrett J. Van Ryzin, *The Theory and Practice of Revenue Management* (Springer, 2005), especially chapters 1, 2, and 4.

From an economics and production planning perspective, Mr. Selecky and Mr. Baron make cogent points. But relying entirely on a coincident peak allocator has its own problems. Using a coincident peak allocator will often result in free riders. For example, if a particular rate class – such as outdoor lighting or a set of industrial loads with unusual operating characteristics – is completely off line at the time of the system peak, then the rate class will not be allocated any fixed production costs. Consequently, the customer would not make any contribution toward the utility's fixed production costs. From a purely economic and production planning perspective, allocating no fixed production costs to outdoor lighting may make perfect sense, but from a marketing or regulatory policy perspective such a result is unreasonable. A utility's generation capacity is used to provide service to customer classes that may not contribute much to peak, and customers in these classes derive some benefit from the utility's generation. This is the regulatory policy basis for assigning some fixed production costs to all classes on the basis of average demand. The issue is how much fixed production cost to assign in an effort to balance the system planning and regulatory policy perspectives.

Q. Do you agree with Mr. Watkins that almost all fixed production costs should be allocated on the basis of average demand?

A. No. In Mr. Watkins' cost of service study, approximately 82% of KU's fixed production and transmission costs are allocated on the basis of an energy allocator. Other than the studies performed by Mr. Watkins, I cannot recall ever seeing a cost of service study that allocates such a large percentage of production and transmission capacity costs on the basis of energy. The Company has traditionally allocated approximately 30 percent of these capacity costs on the basis of an energy allocator. Allocating 82% of the Company's production and transmission capacity costs on the basis of energy is a direct consequence of his misapplication of the BIP methodology. Mr. Watkins designated nearly all of KU's and LG&E's coal-fired steam units as "base" units without considering how the units are used to provide service to native load customers and, more significantly, without considering why the units were originally installed by the Companies. For more than thirty years, increases in peak demand have been driving the need for new generation capacity on the LG&E and KU systems. The Companies must have sufficient capacity to meet the maximum demand placed on the two systems; therefore, allocating 82% of production capacity costs on the basis of energy cannot be supported by cost of service principles.

Q. How does Mr. Watkins misapply the BIP methodology?

A. Mr. Watkins attempts to use the original BIP methodology developed on an experimental basis to assign fixed production costs to costing periods in accordance with studies that were being conducted in the late 1970s related to requirements set forth in the Public Utilities Regulatory Policy Act. To my knowledge, the original

BIP methodology was never adopted by any regulatory commission. The original BIP methodology was abandoned because it produced somewhat ridiculous results when applied to a generation mix that relied heavily on coal-fired generation. When the original BIP methodology was developed by EBASCO (an engineering consulting firm) in the late 1970s, the methodology was originally applied to a couple of utilities that had generation resource mixes that consisted of generating units that could be readily identified as "Base", "Intermediate", and "Peak" units. LG&E's resource mix consisted of a much larger percentage of base-load generation than the utilities originally used to test the BIP methodology. When LG&E hired EBASCO in 1980 to assist in developing a time-differentiated cost of service study it quickly became apparent that the "traditional" BIP Methodology would not produce reasonable results. Specifically, when the traditional BIP Methodology was applied to LG&E's generation resources it produced peak period costs that were lower than off-peak costs, which was obviously a counter-intuitive result. LG&E worked closely with EBASCO, the original developers of the BIP Methodology, to design a Modified BIP Methodology that would produce more reasonable results.

Q. Does an unmodified application of the BIP Methodology still produce counterintuitive results?

A. Yes. In his cost of service study, Mr. Watkins applied the traditional BIP Methodology to KU's fixed production costs. It still produces fixed production costs that are higher during the off-peak period than the winter on-peak period. As shown in Seelye Rebuttal Exhibit 1, Mr. Watkins' cost of service study produces off-peak fixed production costs of $0.01922 per kWh and winter on-peak fixed production costs of $0.002652. This demonstrates that there is a serious flaw in Mr. Watkins' cost of service study. Under no reasonable circumstance should fixed production costs be higher during the off-peak period than during an on-peak period. Because KU's generation *capacity* costs are unaffected by customers consuming more power during the off-peak period, an argument can be made that production capacity costs are zero during the off-peak period.

Q. Do you believe that the Company's cost of service study strikes a reasonable balance in the amount of fixed production costs allocated on the basis of average demand?

A. I believe that it does. In Mr. Watkins' study, far too much fixed production cost is allocated on the basis of average demand Furthermore, unlike Mr. Selecky's alternative, the Company's study avoids the possibility of allocating zero fixed production costs to rate classes that happen to be off the peak, such as outdoor lighting classes. An argument can certainly be made that some small portion of the Company's fixed production costs should be allocated on the basis of average demand to account for the fact that there is some value associated with the "utilization" of capacity, even though, from a purely economic and production planning perspective, average demand does not have any impact on the cost of providing service. In prior rate case orders, the Commission has determined that it is reasonable to allocate at least some portion of fixed production costs on the basis of "utilization". If the Commission continues to adhere to this policy, then a percentage determined by dividing the system minimum demand by the system maximum demand – which is the approach used in the modified BIP methodology – continues to be reasonable. The rationale for continuing to use the relationship of the minimum system demand to the maximum system demand for purposes of determining the percentage of fixed production costs to be allocated on the basis of "utilization" is that the Companies' production facilities will always supply an amount of production capacity at least equal to the minimum demand. Consequently, this minimum percentage of production capacity will be "utilized" each and every hour of the year. Thus, each rate class, regardless of when it needs the capacity, will be making at least some contribution to this minimum percentage of capacity.

C. ZERO INTERCEPT METHODOLOGY

Q. Does Mr. Watkins modify the way that the zero intercept methodology is applied?

A. Yes. In KU's cost of service study, certain distribution costs are classified as customer-related or demand-related using a methodology that is referred to as a "zero intercept" methodology. The central idea behind the zero intercept methodology is to determine, using a regression analysis, the portion of costs that are invariant with respect to the load-carrying capability of certain distribution facilities. The zero intercept methodology is typically applied to overhead conductor, underground conductor, and transformers. In applying the zero intercept methodology, KU has traditionally used a weighted regression analysis. Although Mr. Watkins accepts the zero intercept methodology, he recommends that an unweighted least-squares regression analysis be used.

Q. Is it appropriate to use an unweighted regression analysis in performing the zero intercept methodology?

A. No. Contrary to the assertions made by Mr. Watkins, weighted regression is not some type of bizarre mathematical trickery – or in his words "a clever arithmetic exercise" that "violates theoretical statistical principles of linear regression and skews his results." On the contrary, weighted least squares is a standard regression methodology included in most commercially available statistical software packages, including SAS, SPSS, Minitab, S-Plus, R, and Matlab. Weighted least squares regression is also an accepted methodology covered in most standard reference books on multiple regression analysis.[1] If weighted least squares regression were merely a "clever arithmetic exercise," it would not be included as a standard option in all of these statistical software packages and would not be described in so many textbooks on multiple regression analysis.

Mr. Watkins seems to be concerned about the presence of square roots in the weighted regression equation. The square root terms in the equation are simply a

[1] For example, see Douglas C. Montgomery, Elizabeth A. Peck, and G. Geoffrey Vining, *Introduction to Linear Regression Analysis*, Fourth Edition (Wiley Series in Probability and Statistics: 2006), pp. 179-183; Samprit Chatterjee and Bertram Price, *Regression Analysis by Example*, First Edition (Wiley: 1978), pp. 101-115. The mathematical steps used by the Company to perform least squares regression in an Excel spreadsheet are described in the Chatterjee and Price textbook. Numerical techniques used to perform weighted least squares are discussed in Åke Björck, *Numerical Methods for Least Squares Problems* (Society for Industrial and Applied Mathematics, 1996). Weighted least squares is also covered in numerous textbooks on econometrics. For example, see J. Johnson, *Econometric Methods*, Third Edition ((McGraw-Hill Book Company, 1983), pp. 293-296; and Potluri Rao and Roger LeRoy Miller, *Applied Econometrics* (Wadsworth Publishing Company, 1971), pp. 116-121. As explained in these texts, weighted least squares is necessary to account for the heteroscedasticity introduced from using average, summary, or aggregated data in a regression analysis. A copy of the sections dealing with weighted least squares is included in Seelye Rebuttal Exhibit 2.

product of the analytical derivation of the weighted regression equations.[2] However, even without understanding the mathematics involved, the Company's results can be verified easily by using the weighted regression option in any standard statistical software package. Seelye Rebuttal Exhibit 3 shows the output from performing a weighted regression analysis for overhead conductor using the statistical software package R. R is an open source statistical package heavily used in academia that has similar functionality to the commercially available statistical software package S-Plus. As can be seen from page 2 of this exhibit, a weighted regression analysis performed using R yields the same results as the spreadsheet model used in the Company's analysis. Using either R or the Company's Excel spreadsheet model, the zero intercept is 0.756973. Over the years, I have verified the results of the Company's model using other commercially available statistical software packages, such as SAS and S-Plus.

---

[2] In weighted least squares regression, the objective is to determine the parameters that minimize the least squares equation with the squared difference of each observation weighted by the number of items N_i (e.g., number of poles or feet of conductor), as follows:

$$\begin{aligned}\text{Sum of Weighted Square Differences} &= \sum_{i=1}^{n} N_i(\hat{y} - y_i)^2 \\ &= \sum_{i=1}^{n} N_i([a + bx_i] - y_i)^2 \\ &= \sum_{i=1}^{n} \left(\left[a\sqrt{N_i} + bx_i\sqrt{N_i}\,\right] - y_i\sqrt{N_i}\right)^2\end{aligned}$$

This last equation is the same as a multivariable least squares problem with no intercept, using $\sqrt{N_i}$ as the first independent variable, $x_i\sqrt{N_i}$ as the second independent variable, and $y_i\sqrt{N_i}$ as the dependent variable. Although Microsoft Excel does not have a weighted regression option, a weighted regression model can be developed in Excel using the no-intercept option of the LINEST function in Excel to perform a regression model with $\sqrt{N_i}$ and $x_i\sqrt{N_i}$ as the two independent variables and $y_i\sqrt{N_i}$ as the independent variable. This approach will produce the same result as using a weighted regression analysis performed in SAS, S-Plus, R, etc.

Q. Why is it necessary to use weighted regression in performing a zero intercept analysis?

A. Weighted least squares is necessary in a zero intercept analysis because the summary data used in the analysis includes average cost information reflecting vastly different quantities of the various types of plant identified in the analysis. For example, in the cost data used to perform the zero intercept analysis for KU's transformers, there were 64,074 transformers with a size rating of 25 KVA but only 12 transformers with a size rating of 3000 KVA. On a very basic level, the 3000 KVA transformers – totaling only 12 transformers – should not be given the same weight in the analysis as the 64,074 25 KVA transformers when there are many times more of them included in the analysis. Using weighted least squares regression more accurately replicates the results that would be obtained if a regression were performed using cost data for each transformer rather than summary data (average) for each type of transformer. For instance, if cost data were available for each transformer (rather than each type of transformer), then there would be 64,074 data points for the 25 KVA transformers and only 12 data points for the 3000 KVA transformers. In fact, there would be 64,062 more 25 KVA transformers in the regression analysis than 3000 KVA transformers, and the 25 KVA transformers would have a correspondingly larger impact on the results of the regression analysis. Obviously, if cost data were available for each and every transformer on the system, then the 3000 KVA transformers would have very little impact on the results of a regression analysis performed using cost data for each transformer. In fact, it is likely that the 12 3000

KVA transformers could be removed from the analysis without indicating any noticeable effect on the regression coefficients.

The purpose of a zero-intercept analysis is to properly represent the actual composition of a utility's distribution facilities. If the analysis is weighted then it accomplishes this task. But if the analysis is not weighted, then the zero intercept analysis will not accurately represent the distribution of the various types of overhead conductor, underground conductor, and line transformers actually installed by the utility, and will thus produce inaccurate results.

Q. Mr. Watkins claims that unweighted least squares regression is the standard approach used to perform the zero intercept analysis. Is he correct?

A. No. *The Electric Utility Cost Allocation Manual* published by the National Association of Regulatory Utility Commissioners ("NARUC"), January, 1992, clearly indicates that the zero intercept analysis should be weighted. NARUC's *Electric Utility Cost Allocation Manual* provides the following instructions for overhead conductor, underground conductor and transformers:

> **Account 365 – Overhead Conductors and Devices**
>
> - Determine minimum intercept of conductor cost per foot using cost per foot by size and type of conductor *weighted* by feet or investment in each category, and developing a cost for the utility's minimum size conductor.
>
> **Account 366 and 367 – Overhead Conductors and Devices**
>
> - Determine minimum intercept of cable cost per foot using cost per foot by size and type of cable *weighted* by feet of investment in each category.

Account 368 – Line Transformers

- Determine zero intercept of transformer cost using cost per transformer by type, <u>*weighted*</u> by number for each category.

(NARUC's *Electric Utility Cost Allocation Manual*, January, 1992, pp. 93-94. Emphasis supplied.)

Mr. Watkins' claim that unweighted least squares regression represents the industry standard approach cannot be reconciled with these instructions from NARUC's *Electric Utility Cost Allocation Manual*, which clearly indicates that the analysis should be *weighted.*

A recent text book on electric ratemaking written by Lawrence J. Vogt, P.E. titled *Electric Pricing: Engineering Principles and Methodologies* (CRC Press, Taylor & Francis Group, 2009) also explains that a weighted regression analysis must be used in the application of the zero intercept methodology. Mr. Vogt states as follows:

> The *minimum intercept* or *zero-intercept methodology* provides a rational basis for separating the cost of a device between its customer and demand components. <u>*The zero-intercept methodology is a weighted linear regression*</u> of the unit costs of standard ratings or sizes of a specific device, such as a single-phase overhead line transformer, plotted as a function of its capacity characteristic, which would be kVA for a line transformer. The objective of the regression analysis is to determine the y-intercept. The y-intercept represents that portion of a device's total cost that is associated with zero capacity and thus the customer-related component. <u>*The unit costs must be weighted by the numbers of devices because of the uneven distribution of the various ratings or sizes of the devices in service*</u>.
>
> (Lawrence J. Vogt, P.E., *Electricity Pricing: Engineering Principles and Methodologies*, p. 500. Emphasis supplied.)

Furthermore, I can say with certainty that weighted regression has been utilized in applying the zero-intercept methodology by more than 150 utilities throughout the U.S. and Canada. Contrary to being simply a "clever arithmetic exercise," as claimed by Mr. Watkins, weighted least squares regression is the standard approach used in the industry to perform zero intercept analysis.

Q. Were cost of service studies utilizing weighted regression to perform the zero intercept analysis found to be reasonable by this Commission in earlier Commission Orders?

A. Yes, on many occasions. For example, weighted least squares regression was accepted by the Commission in its Order dated November 10, 2004, in Case No. 2004-00067 approving rates for Delta Natural Gas Company. The AG's own witness in that proceeding also utilized weighted least squares regression to perform a zero intercept analysis.

Q. In making his recommendation, has Mr. Watkins demonstrated that weighted least-squares regression produces incorrect results?

A. No. Calling weighted least-squares regression a "clever arithmetic exercise" does not demonstrate that it produces incorrect results. He claims that it "violates theoretical statistical principles of linear regression and skews his results" but he fails to indicate what "theoretical principles of linear regression" are violated and to demonstrate how the results are "skewed" by application of the methodology. Offering rhetoric without support is not sufficient grounds for arguing against weighted least-squares regression. It is incumbent on Mr. Watkins to *demonstrate* that weighted regression is mathematically flawed, statistically inaccurate, or otherwise produces incorrect results. He has not demonstrated that the methodology is flawed in any respect. Significantly, he has failed to recognize that a different type of regression methodology is required when analyzing *summary data* than when analyzing *individual unit cost data*.

Q. What is the difference between "summary data" and "individual unit cost data"?

A. In the context of a zero intercept analysis, "individual unit cost data" refers to the cost of each *piece* (unit) of property recorded on the utility's books. In the case of line transformers, "individual unit cost data" would refer to the cost of each individual transformer purchased by the utility. Utilities generally do not retain information on the cost of each individual transformer that it has purchased, or at least not in any readily accessible database. Consequently, the data used to perform a zero intercept analysis is almost always provided in *summary* form. With "summary data," the information retained for each type of transformer (or other types of property) includes the total cost of each transformer type and the total number of transformers (or units) by type. From this type of summary data, the *average unit cost* by transformer type can be calculated by dividing (i) the total cost for each type of transformer by (ii) the total number of transformers for that particular transformer type. This is the kind of *summary data* that is normally used to perform a zero intercept analysis.[3]

Q. Is it appropriate to use unweighted least squares when analyzing *summary data*?

A. No. Although it would be appropriate to use unweighted regression if *individual unit cost data* were analyzed, using unweighted least squares regression to analyze

[3] See NARUC's *Electric Utility Cost Allocation Manual*, January, 1992, pp. 93-94.

summary data will almost certainly produce incorrect results. As unambiguously stated in NARUC's *Electric Utility Cost Allocation Manual,* the summary cost data for each type of property must be weighted by the number of units shown for each property type.

Q. Could you provide an example demonstrating that the failure to use weighted least squares will produce incorrect parameter estimates?

A. Yes. Perhaps the clearest way to demonstrate that unweighted regression yields incorrect results is to perform a least squares regression analysis using *individual unit cost data* and compare the results of that analysis to the results of an unweighted regression analysis performed using *summary data* for the same dataset. Comparing the regression coefficients from the two procedures will demonstrate that performing unweighted regression using summary data will produce incorrect parameter estimates -- i.e., results that differ significantly from the "true" results determined from the underlying individual unit cost data. But we will be able to see that the parameter estimates determined by applying weighted least squares to the summary data will produce the exact same coefficients determined from the application of unweighted least squares to the underlying data. These comparisons will thus invalidate the zero intercept methodology recommended by Mr. Watkins but will confirm the methodology used by the Company.

Q. Please describe the underlying unit cost data used in your example.

A. In order to demonstrate the fundamental problem with using unweighted regression to analyze summary data, I will perform unweighted regression on a sample dataset containing individual unit cost data for six different transformer types. Specifically, the dataset includes twenty 25 KVA transformers, three 50 KVA transformers, twenty 100 KVA transformers, three 200 KVA transformers, and twenty 500 KVA transformers. The purpose of this sample is to illustrate the effect on a regression analysis of including transformer types for which there are relatively few units. In this case, there are only three 50 KVA transformers and three 200 KVA transformers. These two transformer types will not have a major impact on a regression analysis performed using the underlying data, but will have a major impact when Mr. Watkins' recommended methodology is applied to the summary data. I have limited the number of transformer types and the quantity of transformers to a minimum to make it easier to analyze the individual unit cost data. The unit cost data is shown in the following table:[4]

[4] It should be noted that while the data shown in the table represent purely hypothetical unit cost information virtually any realistic cost distribution could be utilized to demonstrate that Mr. Watkins' methodology will produce incorrect parameter estimates.

Transformer Type	25 KVA	50 KVA	100 KVA	200 KVA	500 KVA
Individual Unit Cost of Transformer	$ 400	$ 400	$ 1,800	$ 11,000	$ 7,800
	500	500	1,800	12,000	7,800
	600	600	1,900	13,000	7,900
	700		1,900		7,900
	800		2,000		8,000
	850		2,000		8,000
	900		2,000		8,000
	950		2,100		8,100
	950		2,100		8,100
	1,000		2,100		8,100
	1,000		2,100		8,100
	1,050		2,100		8,100
	1,050		2,100		8,100
	1,100		2,200		8,200
	1,150		2,200		8,200
	1,200		2,200		8,200
	1,300		2,300		8,300
	1,400		2,300		8,300
	1,500		2,400		8,400
	1,600		2,400		8,400
Average Unit Cost	$ 1,000	$ 500	$ 2,100	$ 12,000	$ 8,100

Q. Please describe the results of performing a least squares regression analysis using this dataset.

A. Because the dataset contains individual unit cost data, it is appropriate in this instance to use unweighted least-squares regression to calculate the intercept and slope coefficients. The least squares analysis is performed using the cost of each transformer as the dependent variable (y) and the transformer size (KVA) as the independent variable (x). Performing an unweighted regression analysis using this underlying data produces the following regression estimates:

$$y = a + bx$$
$$y = 929.97 + 15.10x$$

Stated another way, the intercept (a coefficient) of the model is $929.97 and the slope (b coefficient) is $15.10. The results of this regression analysis are shown in Seelye Rebuttal Exhibit 4.

Q. Do these parameter estimates represent accurate estimates of the linear model that best fit the data?

A. Yes. Because individual unit cost data is analyzed, unweighted least squares provides the parameter estimates for a linear model (i.e., a straight line) that most accurately fits the data.[5] Therefore, these parameter estimates can be used to evaluate the accuracy of model estimates determined from applying unweighted and weighted least squares to summary data developed from the underlying dataset.

Q. How would unweighted least squares regression (Mr. Watkins' approach) be performed using summary data?

A. The summary data for this dataset consists of the average cost of each type of transformer, as follows:

	Average Cost
25 KVA	$ 1,000
50 KVA	$ 500
100 KVA	$ 2,100
200 KVA	$12,000
500 KVA	$ 8,100

[5] This statement assumes that the standard "Euclidean" measure of distance between two points -- i.e., the square root of $((x-x_i)^2 + (y-y_i)^2)$ -- is the appropriate *norm* for purposes of performing regression analysis.

Using Mr. Watkins' approach, unweighted regression would be applied to these five data points without giving any consideration to the number of transformers installed for each transformer type. Applying unweighted least squares regression to these five data points produces the following regression estimates:

$$y = a + bx$$
$$y = 1{,}750.42 + 17.08x$$

The intercept (a coefficient) of the model using Mr. Watkins' approach is $1,750.42 and the slope (b coefficient) is $17.08. These regression estimates are clearly not the same as those determined by performing least squares regression using the individual unit cost data. The results of this regression analysis are shown in Seelye Rebuttal Exhibit 5.

Q. What conclusion can be drawn from this analysis?

A. It demonstrates that Mr. Watkins' methodology is fundamentally flawed. If his methodology were correct, then it would produce results that were somewhere close to the coefficients obtained from the underlying individual unit cost data. In this example, his methodology produces coefficients that are nowhere close to the original estimates.

Q. How would weighted least squares regression (the standard approach used by the Company) be performed using summary data?

A. Using the methodology prescribed by NARUC's *Electric Utility Cost Allocation Manual* and utilized by the Company, the average cost of each type of transformer would be weighted by the number of units for each transformer type. Mathematically, this is done by weighting the squared differences by the number of units (n_i), and calculating the regression coefficients that minimize the sum of squared differences. Applying weighted least squares regression to the five data points produces the following regression estimates:

$$y = a + bx$$
$$y = 929.97 + 15.10x$$

The intercept (a coefficient) of the model using the Company's approach is $929.97 and the slope (b coefficient) is $15.10.These regression estimates are exactly the same as those determined by performing least-squares regression using the individual unit cost data. The results of this regression analysis are shown in Seelye Rebuttal Exhibit 6.

Q. What conclusion can be drawn from this regression analysis?

A. It demonstrates that the methodology used by the Company is fundamentally sound and produces zero intercept estimates that accurately represent the underlying data.

Q. Do you have any comments concerning Mr. Watkins' proposal to use the ampacity of overhead and underground cable rather than the cross-sectional size of the cable?

A. Yes. The use of ampacity is not a standard approach in the industry. For example, the instructions in NARUC's *Electric Utility Cost Allocation Manual* state that the minimum intercept of conductor is determined "using cost per foot by size and type of conductor weighted by feet or investment in each category." The *Electric Utility Cost Allocation Manual* does not specify the use of ampacity. A major problem with using ampacity is that it is not a fixed quantity for any particular conductor. As stated in T. A. Short, *Electric Power Distribution Handbook* (CRC Press: 2004), "A given conductor has several ampacities depending on its application and the assumptions used." (See pp.61-63). The ampacity of a conductor is affected by cable design, ambient temperature change, sunlight, and wind speeds. Thus, ampacity introduces greater variability into the analysis, relative to using conductor size. This is suggested by the low R-Squares from the regression analysis used by Mr. Watkins to develop his zero intercept estimates for overhead conductor. Specifically, his non-weighted regression analysis using ampacities yields an R-square of only 0.59052 for overhead conductor compared to 0.9053 in the Company's weighted regression analysis. Most power system engineers with whom I have discussed the matter maintain that because of variations in ampacity for different types of conductor, it is more appropriate to use the cross sectional area of the conductor rather than the ampacity in a zero intercept analysis. The use of ampacity should not be adopted until it is recognized as a standard within the industry or until an engineering study is submitted in support of the use of ampacity in connection with a minimum intercept analysis.

Q. On page 27 of his testimony, Mr. Watkins says that he "used Mr. Seelye's 21 categories of KU's various sizes and types of overhead conductor." Did he use the same 21 categories of sizes and types of overhead conductor or did he delete a large number of sizes and types of conductor?

A. He deleted numerous data points. In the regression analysis shown on page 1 of Schedule GAW-3, he deleted #12 conductor, #8 conductor, 350 MCM conductor, 556 MCM overhead conductor, 750 MCM conductor, 954 MCM conductor, and 1000 MCM conductor. Therefore, he deleted seven of the 21 categories of overhead conductor used in my analysis, or 33% of the data points. In his regression analysis for underground conductor shown on page 2 of Schedule GAW-3, Mr. Watkins deleted #4 copper conductor, 3/0 copper conductor, 200 MCM copper conductor, and 500 MCM copper conductor. Thus, he deleted four of the 13 categories of underground conductor, or approximately 31% of the data points. On page 27 of his testimony Mr. Watkins states, "While I have used Mr. Seelye's 21 categories of KU various sizes and types of overhead conductors." Yet, at the top of Schedule GAW-3 a note states, "Exclude small Quantities". He fails to provide statistical support for the criteria used to drop these data points from his analysis. Presumably, he is attempting to account for the large differences in the quantities of various conductor sizes by arbitrarily deleting approximately one third of the data points. Removing a large number of data points without any explanation lacks rigor. The standard statistical methodology for accounting for differences in quantity is not to toss out a large number of data points but to use a weighted regression analysis.

D. TREATMENT OF CURTAILABLE CREDITS IN THE COST OF SERVICE STUDY

Q. Mr. Baron makes an adjustment to the pro-forma rates of return in the cost of service study to reflect *actual* as opposed to *proposed* interruptible credits under the Curtailable Service Rider. Do you disagree with Mr. Baron's approach?

A. No, particularly if the results of the cost of service study are used in a formulaic manner to reduce class subsidies in the allocation of the revenue increase, as recommended by Mr. Baron. In developing his recommended allocation of KU's revenue increase, Mr. Baron proposes to reduce subsidies by 25%. If this recommendation is approved by the Commission, then Mr. Baron's approach, which produces a significantly lower rate of return for Fluctuating Load Service, represents a reasonable basis for calculating class subsidies. Particularly, if subsidies are reduced by 25%, as recommended by Mr. Baron, or even a smaller percentage, then his approach provides a reasonable starting point for allocating the increase to Fluctuating Load Service, which has a large amount of curtailable load.

E. ALLOCATION OF THE REVENUE INCREASE

Q. Earlier, you mentioned that there was no agreement among the intervenor witnesses regarding the cost of service methodology. Is there agreement among them on how the increase should be allocated to the rate classes?

A. No. Mr. Baron and Mr. Selecky proposes a much larger percentage increase for Residential and All Electric Schools than is being proposed by KU. Mr. Baron proposes to reduce the subsidies paid or received for all KU rate classes by 25% using the Company's cost of service methodology. As a result, Mr. Baron would increase Residential rates by 19.56% and All Electric Schools by 20.47%, based on the full increase proposed by the Company. Mr. Baron proposes two, less extreme alternatives if the Commission decides not to reduce subsidies by a full 25% in this proceeding, resulting in a 13.54% increase for the Residential rate class under Alternative 1 and a 12.74% increase for Residential rate class under Alternative 2.

Mr. Selecky proposes to allocate a much larger percentage of the overall increase to the Residential and All Electric Schools rate classes. Mr. Selecky states that Residential and All Electric Schools "would need rate increases of 15.5% and 18.8% to bring their rates to cost of service under the BIP methodology." (Direct Testimony of James T. Selecky, page 7.) Ultimately, Mr. Selecky recommends that if the Commission awards KU a smaller increase than the Company proposed, the reduction should be assigned to all of the other rate classes other than Residential and All Electric Schools.

Mr. Watkins accepts the Company's recommended allocation of the increase. Mr. Watkins states that, "Mr. Seelye does recognize the ROR disparity that exists between classes and makes some movement toward ROR parity. In these regards, Mr. Seelye's relative class revenue increases are reasonable." (Prepared Direct Testimony of Glenn A. Watkins, p. 30.)

Mr. Buechel, on the other end of the spectrum, expresses concern about the amount of increase allocated to All Electric Schools and seems to suggest that the rate should continue be available to new customers. In the rates approved in Case No. 2008-00251, a provision was included in the All Electric Schools rate that restricted the availability of the rate schedule to customers taking service as of February 6, 2009, which is the effective date when the schedule was approved by the Commission in Case No. 2008-00251. The reason that this restriction was implemented is that there is no discernable difference between the cost of providing service to customers served under the All Electric Schools rate and the cost of providing service under one of the Company's standard rate schedules, such as Power Service -- Rate PS, Time-of-Day Secondary Service – TODS, or Time-of-Day Primary Service – TODP. Over the last several years, both KU and LG&E have taken steps either to eliminate or restrict *promotional rates* that cannot be supported by cost of service, such as rates for water heating, mining, residential heating, and all electric schools. Mr. Buechel does not present an alternative cost of service study in support of his position. Furthermore, he fails to offer any substantive criticisms of the Company's cost of service study. Mr. Watkins and Mr. Selecky both offer alternative cost of service studies that indicate that the rate of return for All Electric Schools is inadequate.

Q. Do you have any comments concerning Mr. Baron and Mr. Selecky's recommendation to assign a large portion of the increase to Residential and All Electric Schools?

A. Yes. Certainly, a larger increase for the Residential and All Electric Schools rate schedules could have been supported by the cost of service study. I would not feel comfortable recommending a larger percentage increase for these two classes than were proposed by the Company, as suggested by Mr. Baron. However, if the Commission authorizes a smaller overall increase than what is being proposed by KU, then it would not be unreasonable to assign a larger relative portion of any such reduction to the rate classes that are currently paying subsidies and to assign a smaller relative portion of any such reduction to the rate classes that are currently receiving subsidies, such as the Residential and All Electric Schools rate classes.

III. RATE DESIGN

A. BASIC SERVICE CHARGE

Q. Is the Company proposing to move the basic service charges closer to the actual cost of service?

A. Yes. It has been a longstanding goal of the Company to move basic service charges (formerly called "customer charges") more in line with the actual cost of service. Because of the infrequency of rate case filings by the Company and because a number of base rate changes over the last 20 years have resulted in decreases, it has been difficult for the Company to make much progress in this area. In the settlement submitted in Case No. 2003-00434, the parties agreed to basically double the basic service charge. In the settlement in the previous rate case (Case No. 2008-00251), the parties agreed to maintain the basic service charge at the same level even though the case resulted in a revenue decrease. Therefore, in both of these proceedings some progress was made to move the basic service charge more in line with cost of service. However, not nearly enough movement has been made in this direction. The basic customer cost of serving a residential customer is $19.78 per month, whereas the Company's basic service charge is currently $5.00 per month. Thus, $14.78 per customer per month in customer-related fixed distribution costs are being recovered through a volumetric kWh charge rather than through the basic service charge where these costs should be collected. This violates the basic ratemaking principle of collecting fixed costs through fixed charges and variable costs through variable charges. When this principle is violated, it results in intra-class subsidies, as is the case here where customers with above average usage are paying more than their fair share of customer-related fixed distribution costs and customers with below average usage are paying less than their fair share of customer-related fixed distribution costs and are being subsidized. When the cost of service is not followed, customers are provided inaccurate price signals which encourage them to make incorrect decisions about energy efficiency. The residential basic service charge is currently almost 25 percemt of the actual cost of providing service. I am unaware of any other charge billed by KU that is this far out of line with the actual cost of providing service.

Q. What does Mr. Watkins' own cost of service study indicate that the basic service charge should be?

A. Mr. Watkins' own cost of service study indicates that the residential basic service charge should be $15.09 per month. Even though Mr. Watkins claims that KU's monthly residential customer cost is only $4.59 per month, he gets there by ignoring the results of his own cost of service study. In his cost of service study, he classifies a portion of poles, overhead conductor, underground conductor, and transformers as customer related, but he ignores these same costs when he calculates his proposed customer charge. Specifically, he only includes costs associated with services, meters, meter reading, and records and collections in the calculation of his proposed customer charge, ignoring costs associated with poles, overhead conductor, underground conductor, transformers and certain administrative and general expenses[6] that were classified as customer-related in his own cost of service study. Furthermore, Mr. Watkins provides no sound rationale or basis for this omission. The following table compares the costs identified as customer-related in Mr. Watkins' cost of service study with the costs that he considered customer-related for purposes of developing the basic service charge:

[6] In Mr. Watkins' cost of service study he classifies administrative and general ("A&G") expenses using internally generated allocation factors that reference distribution expenses that were classified as customer related. Therefore, a portion of A&G expenses are classified as customer-related in Mr. Watkins' cost of service study.

COST ITEM	IDENTIFIED AS CUSTOMER-RELATED IN WATKINS' COST OF SERVICE STUDY	IDENTIFIED AS CUSTOMER-RELATED IN CALCULATING HIS BASIC SERVICE CHARGE
Poles	Yes	*No*
Overhead Conductor	Yes	*No*
Underground Conductor	Yes	*No*
Transformers	Yes	*No*
Services	Yes	Yes
Meters	Yes	Yes
Meter Reading	Yes	Yes
Records and Collection	Yes	Yes
Customer Accounts Supervision Expenses (Account 901)	Yes	*No*
Uncollectible Accounts (Account 904)	Yes	*No*
Miscellaneous Customer Accounts Expenses (Account 905)	Yes	*No*
Customer Service Supervision (Account 907)	Yes	*No*
Customer Assistance Expense (Account 908)	Yes	*No*
Customer Information and Instruction (Account 909)	Yes	*No*
Miscellaneous Customer Service	Yes	*No*
A&G Expenses	Yes	*No*

In calculating his proposed basic service charge, Mr. Watkins specifically excludes a large number of costs identified as customer-related in his own cost of service study, including costs classified as customer costs through the application of his zero intercept analysis.

By leaving costs out of his calculation of customer-related costs in his Exhibit GAW-7, Mr. Watkins calculates a residential customer charge of only $4.59 per month. Seelye Rebuttal Exhibit 7 is a recalculation of Mr. Watkins' residential customer cost adding back in costs that were classified as customer-related in his own cost of service study. As can be seen from this exhibit, Mr. Watkins' own cost of service study indicates that the monthly customer cost for the residential class is $15.09 per customer per month.

Q. Has the Commission rejected this type of selective interpretation of the cost of service study in prior rate orders?

A. Yes. In its Order dated September 27, 2000, in Case No. 2000-080, an LG&E rate case, the Commission specifically rejected this same type of selective and attenuated approach for determining basic service charges. Just as Mr. Watkins has done in the current proceeding, the AG's cost of service witness proposed a basic service charge in Case No. 2000-080 that ignored costs identified as customer-related in the zero intercept analysis. The Commission rejected the AG's calculation in that proceeding and should do the same in this proceeding.

Q. Do you have any other comments regarding the customer charge recommended by Mr. Watkins?

A: Yes. Even though he claims that his study can only support a $4.59 basic service charge, he recommends a basic service charge of $5.00, the current level. KU's cost of service study would support a basic service charge of $19.78. KU's proposed basic service charge more accurately reflects the cost of providing service than Mr. Watkins' proposal.

Mr. Watkins' proposal would recover more of the Company's fixed customer-related costs through a "volumetric" charge (i.e., energy charge) and send incorrect price signals to customers. The basic service charge basically covers the minimum amount of equipment necessary to provide a customer with grid access, and an artificially low customer charge sends the incorrect price signal that this minimum amount of equipment is relatively inexpensive. His proposal would increase the volatility in customer bills by collecting too much customer-related fixed distribution cost during peak months and during periods of extreme weather while collecting too little during periods of mild weather. This has the undesirable effect of unnecessarily increasing the volatility of customer energy bills, with the high bills higher than necessary and the low bills lower than necessary. Likewise, Mr. Watkins' proposal would increase the Company's revenue volatility.

Mr. Watkins' proposal would force customers such as low-income customers, whose energy use is greater than the average, to pay more than the cost of service, while allowing other customers to pay less than the cost of service. His proposal would further penalize these customers by charging them an average rate that moves further away from the cost of providing service.

Furthermore, Mr. Watkins' proposal would provide a disincentive for KU to promote energy efficiency thus creating a poor regulatory environment for encouraging the Company to take additional measures for customers to reduce their energy usage. If customer-related fixed costs are inappropriately recovered through the energy charge assessed on a kWh basis rather than a fixed monthly basic service charge, then the utility *ceteris paribus* will see a reduction in margins whenever customers reduce their consumption of electric energy as a result of improved energy efficiency. Many regulators have recognized the need to make rate design changes that align the interests of utilities and customers so as not to penalize the utility when customers reduce their energy consumption as a result of improved efficiency. Mr. Watkins' regressive recommendation would take us back to the failed approaches of the 1970s, when the accepted view was to try to induce utility customers to reduce energy usage by increasing volumetric charges. The Company's approach is forward looking and more consistent with progressive rate design philosophies that create a win/win for both the customer and the utility when customers use energy more efficiently.

Q. But can't a properly designed demand-side management (DSM) recovery mechanism protect utilities against the adverse financial consequences of improved energy efficiency?

A. Not necessarily. Unless the mechanism includes some type of broad-based decoupling mechanism, which completely severs the relationship between energy sales and revenues, then a DSM mechanism will not shield the utility against customer-initiated improvements in energy efficiency. While the Company's DSM cost recovery mechanism includes a lost revenue component designed to provide limited recovery of lost net revenues from *company-initiated* programs, the mechanism does not include a decoupling mechanism and therefore will not recover lost revenues from *customer-initiated* energy efficiency efforts, such as replacing incandescent bulbs with more efficient compact fluorescent lamps (CFLs) or light emitting diodes (LEDs) and implementing smart energy technologies with low-power sensor networks using IEEE 802.15.4 MAC protocols or Zigbee architectures.

Q. Mr. Buechel opposes the proposed increases in the basic service charges because of "rate continuity" and "gradualism". Does he have any valid arguments?

A. No. Mr. Buechel expresses concern about the proposed increases in the basic service charges for General Service - Rate GS, Power Service - PS, Time-of-Day Secondary Service - Rate TODS, and Time-of-Day Primary Service - Rate TODP. Mr. Buechel does not feel that the increases are gradual enough. Yet, he fails to provide a single piece of empirical evidence – either in the form of cost support or actual customer impacts – to support his vague notion that the basic service charges are not gradual enough. Mr. Buechel fails to explain why – and under what circumstances – the principles of "gradualism" or "rate continuity" should take priority over the principle of "cost of service". As the late professor James C. Bonbright stated, "Without doubt the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service." (James C. Bonbright, *Principles of Public Utility Rates*, Columbia University Press: 1961; p. 294.) In fact, rate continuity is not listed as one of the three "primary" objectives identified by professor Bonbright – (i) revenue requirement objective, (ii) cost apportionment objective, and (iii) economic efficiency objective. (*Id.*, at p. 292.)

Ultimately, Mr. Buechel's vague and opaque notions of "gradualism" and "rate continuity" are too imprecise to be of any use as a regulatory guideline for setting rates. For example, Mr. Buechel does not recommend a specific basic service charge, and he fails to specify the point where a specific increase in the basic service charge is no longer "gradual". Mr, Buchel obscures the fact that, with respect to the principles of "gradualism" and "rate continuity", the impact on the total bill has far more significance than the impact of particular components of a rate. Yet he has not produced any empirical evidence demonstrating that the Company's proposed increase in the basic service charge will result in any greater hardship for actual customers than continuing to recover customer-related costs through the energy charge.

B. CURTAILABLE SERVICE RIDER

Q. Please briefly summarize the proposed changes to the Company's curtailable service riders.

A. The Company currently has three CSR riders – CSR1, CSR2 and CSR3 – which evolved from negotiated settlements in LG&E and KU's last two rate cases. Two LG&E customers and one KU customer currently take service under CSR1, and one KU customer takes service under CSR3. The Company is proposing to consolidate these three curtailable service riders into a single rider, which will be called Curtailable Service Rider CSR. The Rider will provide up to 500 hours of total curtailment and will provide credits consistent with CSR1. Under the proposed CSR, the Company will have the right to request up to 100 hours of physical curtailment without buy-through and up to 400 hours of curtailment with a buy-through option, where the customer can choose to either curtail its load or purchase buy-through power. This structure was presented to the Company by its customers. The buy-through power will be priced at an automatic, formula-based price determined by multiplying an indexed cost of natural gas ($/MMBtu) by a specified heat rate (.01200 MMBtu/kWh) representative of the heat rate of a typical single-cycle combustion turbine. The Company will provide at least a 10 minute notice prior to curtailment.

Importantly, under the proposed CSR, the credit will only be applied during periods of the day when the Company is likely to need curtailable service. Specifically, the credit will be applied to the difference between (a) the Customer's measured maximum kilowatt demand during any 15-minute interval during the following time periods: (i) for the summer peak months of May through September, from 10 A.M. to 10 P.M., and (ii) for the months October continuously through April,[7] from 6 A.M. to 10 P.M., and (b) the firm contract demand. This is arguably the most significant change that the Company is proposing. Under the proposed CSR the Company may request or cancel curtailment at any time during any hour of the year despite the periods used to calculate the demand credit.

Q. Why is the Company proposing to consolidate the three riders into a single tariff?

A. The current structure of having three curtailable service riders is difficult for the Company to manage from an operational perspective, particularly since the terms and conditions of the three tariffs are not consistent with one another. Under CSR3, the customer must curtail its load whenever the Company issues a request for

[7] It should be noted that there is a typographical error in the proposed tariff sheets for CSR included in Tab 7 and Tab 8 of the Statutory Notice, Application, Financial Exhibit, Table of Contents, Filing Requirements filed on January 29, 2010. On Original Sheet No. 50.1, in the section "Curtailable Billing Demand", under small Roman numeral (iii), the non-summer months should be listed as "October continuously through April" instead of "October continuously through May".

curtailment. However, the Company can only request 100 hours of curtailment during any 12 month period. CSR1, however, currently does not include a provision that requires the customer to physically curtail its load. Under the current CSR2, the customer can choose either to curtail its load or request that the Company go into the market to buy power to serve the load. The Company needs to have the ability to call on its curtailable customers to physically interrupt their loads in order for this resource to have value for the Company in the planning process and for avoiding future capacity additions. During certain conditions, including emergencies, it is important for the Company to be able to call on these customers – to which it is paying a hefty capacity credit of $5.10 to $5.20 per kW per month – to physically curtail their load. Currently, there are far less costly options for obtaining capacity than providing curtailable customers a $5.10 to $5.20 per kW monthly credit. The Company can currently purchase capacity at a far lower cost than is currently being "paid" to its curtailable customers for the right to buy-through on their behalf without the ability to require them to actually reduce their loads. The Company proposes to include a provision in its curtailable service rider that provides up to 100 hours of physical curtailment during any 12 month period.

Q. **KIUC witness Dennis W. Goins makes a number of specific recommendations concerning the Company's proposed tariffs. He proposes that KU offer a CSR10 with ten minutes notice and CSR30 with 30 minutes notice. Do you have any general comments regarding CSR10 and CSR30?**

A. Yes. Mr. Goins and I are not too far apart on a number of issues. We both agree that curtailable service provides economic benefits to the Company and its customers.

Mr. Goins recommends that both CSR10 and CSR30 be subject to a total of 100 hours of physical interruption. Also, at least provisionally, he does not object to the adoption of KU's proposed formula-based methodology for pricing buy-through power. Furthermore, we are not too far apart on the maximum level of the curtailable credit that should be offered. Although, Mr. Goins acknowledges, but offers no criticism concerning, the Company's proposed change in the period during which curtailable demand is determined, I assume that we are also in agreement on this point.

Q. **Mr. Goins recommends that if the Company's formula-based buy-through pricing approach is approved by the Commission, then it should be reviewed and evaluated in a future case to determine if it produces reasonable and fair results. Do you agree with this recommendation?**

A. Yes. I agree that it would be reasonable to re-examine the buy-through pricing approach in a future case to determine if it produces fair and reasonable results. In proposing this approach, the Company is attempting to simplify the buy-through process, on behalf of both the Company and its customers. Purchasing buy-through power is time consuming and difficult to accomplish, especially in terms of purchasing the correct amount of buy-through power. Eliminating the need to contract for each buy-through transaction through the application of the proposed formula-based pricing should greatly simplify the process. However, it will be prudent to review the approach as a part of a future rate case proceeding. Curtailable service has been carefully scrutinized by all of the affected parties in the last several rate cases. Because of its importance to the Company and its customers, I do not anticipate this situation to change in the future and fully expect that the buy-through pricing formula and other aspects of the tariff will be reviewed in the Company's next rate case.

Q. **Do you have any objections to Mr. Goins' methodology for determining the amount of buy-through energy determined under CSR?**

A. No. Mr. Goins proposes to determine the amount of energy priced under the automatic buy-through formula rate to be determined by subtracting (i) the customer's firm demand multiplied by the number of hours (or fractional number of hours) of curtailment from (ii) the customer's actual energy use during the curtailment period. This approach is reasonable.

Q. **Do you have any objection to Mr. Goins' recommendation to place a limit on the availability of curtailable service to the current MW of CSR1 and CSR3 curtailable load plus an additional 100 MW?**

A. No. I believe that there should be some sort of limitation on the addition of new load under the curtailable service riders. Mr. Goins recommendation to allow only 100 MW of additional curtailable load above the current curtailable load of customers served under CSR1, CSR2, and CSR3 is reasonable.

Q. **Do you agree with Mr. Goins' proposal to provide a credit of $5.40 and $5.50 per kW-month for primary and transmission curtailable service under CSR10 and with his proposal to limit the maximum hours of curtailment to 350 hours?**

A. No. I continue to maintain that a credit of $5.10 and $5.20 per kW-month for transmission and primary curtailable service with 500 annual hours of curtailment is reasonable in the power market environment today. The Company can currently purchase capacity in the market at a delivered price that is far less than $5.10 per kW-month. Although the market price of capacity may turn around, the issue can be re-examined in KU's next rate case. Ultimately, Mr. Goins and I are not too far apart on the level of the credit that should be provided. The more critical issue is the total number of hours of curtailment during a 12 month period. Again, I continue to maintain that it is reasonable to require curtailable service customers to curtail their load for up to 500 hours during a 12 month period in exchange for a fairly robust curtailable credit – or at least robust in today's power market.

Q. **Do you have any comments concerning Mr. Goins' proposal to allow customers to avoid noncompliance penalties if the customer agrees to install, pay for, and cede to KU control of the equipment necessary to curtail the customers' load in excess of the firm demand?**

A. Yes. The Company is willing to work with its curtailable customers to install the necessary telecommunication and control equipment to allow the Company to control customers' curtailable load as long as the Company's and the customer's individual responsibilities are clearly defined and the customer pays for the necessary equipment. Furthermore, the Company is willing to waive the non-compliance charge if the <u>*Company's*</u> telecommunication and control equipment, which will need to be fully isolated from the customer's telecommunication and control equipment, fails to send the necessary control signals to curtail the customer's load. However, the Company is not willing to waive the non-compliance charge if a failure of the <u>*Customer's*</u> telecommunication and control or other equipment results in the load not being curtailed. It is not reasonable to require KU to take responsibility of telecommunication and control equipment within the customer's manufacturing facilities or of equipment that is owned, operated, maintained, and controlled by the customer.

Additionally, if an arrangement is made to install telecommunication and control equipment to control the customer's curtailable load, then backup arrangements must be established in the event that either the Company's or the customer's telecommunication and control equipment fails. Such backup arrangements would require guaranteed telephone access to an operator at the customer's facilities so that the customer can be notified of a request to curtail the load. In other words, if the Company sends an electronic signal to curtail the customer's curtailable load and if the load is not curtailed due to either a failure of the Company's telecommunication and control equipment or a failure of the customer's telecommunication and control or other equipment, the Company may, but is not required to, contact the customer by telephone and make an oral request for curtailment. If a failure of the customer's telecommunication and control equipment resulted in the load not being curtailed originally, then the customer would be responsible for paying any non-compliance charges as of the time of the initial electronic request. However, if a failure of the Company's telecommunication and control equipment resulted in the load not being curtailed, then a non-compliance charge would not be charged. If the Company exercises its option to call and if the customer fails to answer the dedicated phone line, or if the dedicated phone line rolls over to voice mail, and the customer does not curtail its load upon being provided a 10 minute notice, then a non-compliance charge would be applied based on the time

10 minutes after the initiation of the telephone call. The customer's dedicated phone line must have voice mail capability.

Q. Do you have any objection to Mr. Goins' proposal for KU to provide a good faith estimate of a curtailment's estimated duration when KU issues a curtailment notice?

A. No. However, if the Commission accepts this modification then there should be a reciprocal obligation for the customer to provide a good faith estimate of its production schedules. Both estimates should be non-binding. It must be noted that at all times the Company must have detailed knowledge about the availability of all of its generation resources, including its combustion turbines. If KU is to rely on curtailable load as a resource, it is equally important that the Company also have detailed knowledge about the availability of curtailable load on its system.

Q. Do you have any objection to Mr. Goins' proposal for KU to offer a CSR30 that requires the Company to provide customers served under the rider a 30 minute notice?

A. No. However, I believe that the credit should be significantly lower than the credit provided for CSR10, which would only require 10 minutes notice. The ability to call on a customer to curtail load within 10 minutes is of great value to the Company, especially during emergencies. If the customer is to receive a curtailable credit approximately equal to the avoided capacity cost of a quick-start combustion turbine, then the Company should be able to curtail the load within 10 minutes, which is the maximum amount of time that it takes to synchronize a quick-start combustion turbine to the grid. In my opinion, the credit for CSR30 should not exceed 60% of the credit for CSR10. Therefore, if the credit for CSR10 is \$5.10 and \$5.20 per kW-Month for transmission and primary service, the credit for CSR30 should not exceed \$3.06 and \$3.12 per kW-Month.

C. FLUCTUATING LOAD SERVICE

Q. Please describe the changes that the Company is proposing to the Fluctuating Load Service.

A. The Company is proposing to simplify Fluctuating Load Service (currently called "Industrial Service IS") by implementing the time-of-day rate structure similar to the structure being proposed for the Company's standard time-of-day rates applicable to large industrial and commercial customers, but with demands determined on a 5-minute integrated demand basis. As in all of the Company's other proposed larger power rate schedules -- Time-of-Day Secondary Service – TODS, , Time-of-Day Primary Service – TODP, and Retail Transmission Service – RTS – the Company is proposing a 75% demand ratchet applicable to the Base demand charge and a 60% demand ratchet applicable to the Peak and Intermediate demand charges. With a demand ratchet, the billing demand for the current month reflects the higher of (i) the maximum demand during the month, or (ii) the highest demand during the previous 11 months multiplied by the ratchet percentage. Demand ratchets of between 50 to 75% are common throughout the United States for large power rate schedules.

Q. What is the purpose of having a demand ratchet?

A. Demand ratchets help ensure the recovery of the fixed costs of facilities installed to meet the customer's maximum demand. They also allow the utility to recover some of the stranded fixed costs incurred by the Company when an industrial or commercial customer shuts down its operations. Much like a basic service charge, demand ratchets help stabilize a utility's revenue from one month to another. Perhaps most importantly, demand ratchets encourage customers to maintain high annual load factors. Ratchets reward customers that maintain high annual load factors, penalize customers that have low annual load factors, and help eliminate intra-class subsidies. Although they help stabilize monthly billings, demand ratchets do not alter the revenue requirement collected from any particular rate class. With or without demand ratchets, the test-year revenues collected are the same. While they do not affect the overall test-year revenue collected from a particular class, demand ratchets do have varying impacts on individual customers within a particular rate schedule. Specifically, when demand ratchets are in place, customers with high annual load factors (i.e. customers whose loads are relatively flat throughout the year) will pay a lower average charge than Customers whose demands vary significantly from one month to another. Consequently, demand ratchets provide a powerful incentive for customers to improve their annual load factors and thus utilize installed generation, transmission and distribution capacity more efficiently.

Q. Do you agree with Mr. Baron's recommendation to reduce the demand ratchet for Fluctuating Load Service?

A. No. In fact, I am more than a little puzzled by his recommendation. On the one hand, Mr. Baron criticizes the Company's cost of service study because it allocates too much fixed production and transmission costs to high load factor customers (see Direct Testimony of Stephen J. Baron, page 5, lines 4-7), but he objects to the implementation of a demand ratchet, which is a powerful ratemaking mechanism designed to reward customers that maintain high load factors. His two positions cannot be reconciled. It is also important to note that Mr. Baron does not object to the implementation of a demand ratchet for Time-of-Day Secondary Service – TODS, Time-of-Day Primary Service – TODP, and Retail Transmission Service – RTS, under which a number of *high load factor* KIUC members take service. As I mentioned earlier, customers with high annual load factors, such as large chemical plants and manufacturing facilities that operate around the clock, tend to benefit from the implementation of a demand ratchet.

D. CONJUNCTIVE DEMAND

Q. Does KU object to implementing conjunctive demand billing?

A. No. As stated in my direct testimony, KU does not object to conjunctive demand billing as long as it is implemented in a cost-based and equitable manner and as long as customers under a properly design conjunctive demand rate reimburse the Company for any additional metering, billing and other administrative costs involved in providing the service. Additionally, as with all rates, any conjunctive billing rate must be applied and billed the same way that it is calculated. A properly structured conjunctive demand rate would consist of a distribution and transmission demand charge that would be applied to the customer's maximum demand at each delivery point and production demand charge that would be applied to the customer's demand determined either on an aggregated or individual customer basis at the time of the Company's system peak. In other words, the distribution and transmission demand charge would be calculated and billed on the basis of the customer's non-coincident peak demands (maximum individual demand) and the production demand charge would be calculated and billed on a coincident peak basis. A conjunctive demand rate designed and applied in this manner would be cost-based and would not be inherently preferential to a customer that has multiple stores, warehouses, schools, or factories operating in the Company's service territory.

Q. Why is the conjunctive demand rate that you describe "cost based"?

A. In the Company's cost of service study, peak and intermediate period generation demand costs are allocated to the customer classes on the basis of each customer class's demand at the time of the Company's system peak. In other words, the Company's fixed production costs are driven by coincident peak demands. In the cost of service study, most distribution costs are assigned on the basis of a non-coincident peak allocator. Therefore, a conjunctive demand rate that recovers production costs through a coincident peak charge and recovers distribution costs through a non-coincident peak charge closely mirrors the way that costs are allocated in the cost of service study.

Q. Why is the conjunctive demand rate that you describe not inherently preferential?

A. A conjunctive demand rate designed and applied in the manner as described above would result in the same billings regardless of whether the charges are applied on an aggregated or individual, unaggregated basis. In other words, a coincident peak demand charge calculated and applied to the aggregated (or totalized) loads for multiple service locations will produce the same total demand billings as a coincident peak demand charge applied individually to the loads for multiple service locations, added together. Consequently, there is no inherent advantage for applying a coincident peak to the aggregated demands of multiple store, warehouse, school, or factory locations.

Q. Is the conjunctive demand rate proposed by Kroger witness Neal Townsend inherently preferential?

A. Yes. Mr. Townsend proposes that a conjunctive demand rate be developed that would apply a production demand charge to the maximum aggregated demands of mult-site businesses or entities. Under such a rate structure, businesses such as Kroger that have multiple stores operating in the Company's service territory would automatically realize a billing reduction compared to non-multi-site businesses. Simply by aggregating their demands, Kroger and any other entity with multi-site accounts operating in the Company's service territory would automatically realize a bill reduction in relation to other customers without any change to their operation or change in their consumption of electric energy or demand. In virtually all real world situations, the maximum monthly demand of the aggregated loads of multiple accounts will be less than the sum of the maximum demands of the individual loads of multiple accounts. This is equivalent to the following mathematical expression:

$$\max_{j} \sum_{i=n}^{n} Load_{ij} \leq \sum_{i=1}^{n} \max_{j}\{Load_{ij}\}$$

where $Load_{ij}$ refers to load of customer i during the 15-minute interval j, and n refers to the total number of customers being aggregated. The expression on the right hand side of the greater than or equal sign (≤) corresponds to the current way that generation billing demand would be determined for multi-site customers. The expression on the left hand side of the greater than or equal sign corresponds to the way that Mr. Townsend proposes that the generation billing demand for multi-site customers would be determined. Therefore, Mr. Townsend's proposal will almost certainly result in an automatic windfall to Kroger and other multi-site businesses without encouraging them to do anything to operate more efficiently.

The above mathematical principle can be illustrated numerically by adding the individual maximum values of two randomly generated series of numbers -- Series A and Series B -- between 0 and 100, and then comparing the sum of these two maximum values to the maximum value of the series determined by adding (aggregating) each element of Series A and Series B. No matter how many times different sets of random numbers are generated, the maximum value of the series determined by adding each element of Series A and Series B will be less than the sum of the maximum value of Series A plus the maximum value of Series B. This is illustrated in Seelye Rebuttal Exhibit 8. This exhibit shows that the maximum value of the randomly generated Series A is 99 and the maximum value of the randomly generated Series B is 95. The sum of these two maximum values is therefore 194. But the maximum value of the aggregated series determined by adding each element of Series A to the corresponding element of Series B is only 167. Therefore, on a purely random basis, aggregation results in a lower maximum value.

Q. Do you have a real world example where the demands of two multi-site customers are aggregated?

A. Yes. Seelye Rebuttal Exhibit 9 shows the effect of aggregating the actual 15-minute demands of two multi-site stores during January 2010. The maximum 15-minute demand of Customer A during the month is 1,381.8 kW. The maximum 15-minute demand of Customer B during the month is 997.8 kW. The total of the two maximum demands for the two stores is 2,379.6 kW. When the 15-minute demands for the two stores are aggregated, the maximum aggregated demands of the two stores is 2,343.0 kW. Therefore, aggregation results in a demand savings of 36.6 kW per month. Of course, increasing the number of accounts that are aggregated would increase the savings. It is important to point out that these demand savings are realized without the customers taking any action to manage their loads in a more efficient manner.

Q. Mr. Townsend indicates that conjunctive demand billing has been adopted in Michigan on a pilot basis by Detroit Edison and Consumers Energy. Do you have any comments about the Michigan pilot programs?

A. Yes. The economic and regulatory environment in Michigan is quite different than in Kentucky. Detroit, in particular, is one of the most economically-distressed urban areas in the United States. More importantly, Michigan is a "retail access" or "customer choice" state, which means that customers can choose to purchase generation service from a competitive supplier. Therefore, the economic and regulatory environment in Michigan is in no way comparable to the economic and regulatory environment in Kentucky. For Detroit Edison, the "Experimental Load Aggregation Provision" was authorized as a part of a Stipulation Agreement in Case

No. U-14838 which was approved by the Michigan Public Service Commission on August 31, 2006. For Consumers Energy, the "Aggregate Peak Demand Provision," which was modeled after the provision set forth in the Detroit Edison Stipulation, was approved by the Michigan Public Service Commission in an Order in Case No. U-15245 dated June 10, 2008. Consumers Energy's Aggregate Peak Demand Provision was not opposed by any party in that proceeding and was supported by Kroger. Testimony in support of Consumer Energy's pilot submitted by Kroger witness Kevin C Higgins in Case No. U-15245 underscores the connection between the competitive environment for electric power in Michigan and the adoption of the pilot:

> The GAP pilot would allow a customer taking service under the General Primary Demand ("GPD") or General Secondary Demand ("GSD") rate schedule with multiple accounts to aggregate its loads for the purpose of determining its monthly peak demand for power supply service. This type of aggregation would allow the customer to capture the diversity within its loads for billing purposes. For example, a customer may have multiple accounts that experience peak demands at different times. Currently, the customer is billed for power supply demand based on each individual account's peak demand during the month. The GAP program would instead bill the customer for power supply demand based on the customer's peak demand for its aggregated load. *This approach is comparable to how the customer's load would be viewed by a competitive supplier*. (Direct Testimony of Kevin C. Higgins on behalf of The Kroger Co., November 6, 2007, p. 4. Emphasis supplied.)

Because retail competition for electric power is allowed in Michigan, the aggregated billing programs adopted by Detroit Edison and Consumers Energy have little or no relevance to KU, which operates in a traditional, regulated environment.

Q. Do you believe that KU met its obligation under the settlement agreement to study conjunctive demand billing?

A. Yes. Although it has not developed a rate that will provide an automatic benefit to Kroger and other multi-site businesses, I believe that the Company has met its obligation under the settlement agreement in the Company's last rate case to study conjunctive demand billing.

Q. Do you agree with Mr. Townsend's recommendation that the Commission require KU to establish a pilot program to test the efficacy of measuring the generation demand for multi-site customers on a conjunctive demand basis?

A. KU does not have any objection to establishing a pilot program to study conjuctive demand billing as long as the generation demand component of the rate is developed on a revenue neutral basis and billed as a coincident peak demand charge. The Company must also recover from program participants any incremental metering and administrative costs for conducting the pilot program. However, the Company does not agree that it would be appropriate to develop a pilot program in which the generation demand component is simply applied to the maximum 15-minute aggregated demands of multi-site customers. Thus, it is unlikely that the Company will agree that Mr. Townsend's version of conjunctive demand billing is appropriate.

IV. MISCELLANEOUS SERVICE CHARGES AND CUSTOMER DEPOSITS

A. LATE PAYMENT FEES

Q. Do you have any comments about modifying the late payment fees?

A. Yes. If the Commission decides to relax the Company's late payment charges, or even eliminate late payment charges altogether, the miscellaneous revenue collected during the test year through though application of the late payment charges will need to be either reduced or eliminated and there will need to be a corresponding increase in the Company's base rate revenues. In developing its proposed rates, late payment charges act as a revenue credit in the determination of base rates. During the test year, pro-forma late payment charge revenues amounted to approximately $9.0 million.[8] If the late payment charge were eliminated, for example, then these revenues would have to be added to the amount of revenue collected through base rates. In other words, the revenues collected through base rates would have to be $9.0 million higher if the late payment charge were eliminated. Of course, this has the effect of shifting revenues *from* customers that do not pay their bills on time *to* customers that do pay their bills on time.

B. CABLE TELEVISION ATTACHMENT CHARGE

Q. Please briefly describe the Company's proposed cable television pole attachment charge.

A. The CATV attachment charge that the Company is proposing in this proceeding is calculated using the same methodology that was approved by the Commission in its Order dated December 21, 1990, in Case No. 90-158, an LG&E rate case, except that, in order to harmonize the LG&E and KU's tariffs, the Company is proposing to apply a

[8] Actual late payment revenues during the test year were $4,398,330. In the updated revenue requirement provided in response to KPSC 4-2, an adjustment was made to include an additional $4,612,907 late payment revenues to reflect implementation of the late payment charge for a full year, resulting in total late payment revenues of $9,011,237.

single charge for attachments rather than to apply two separate charges based on pole size. The methodology approve by the Commission in Case No. 90-158 calculates the annual carrying costs of 35' to 45' poles and assigns a portion of the cost to the CATV attachment charge through the application of a usage space factor (12.24% for two-user poles and 7.59% for three-user poles). The carrying charges are calculated by applying a levelized fixed charge rate to original bare pole costs as recorded in the Company's accounting records. The bare pole costs used in the calculation excludes the cost of both major and minor appurtenances. The cost of major and minor appurtenances are recorded separately in the Company's continuing property records and are therefore not included in the pole costs used to calculate the CATV attachment charge.

Q. KCTA witness Kravtin claims that the Company did not properly exclude appurtenances in the calculation of the CATV attachment charge. Is she correct?

A. No. In developing her proposed CATV attachment charges, Ms. Kravtin reduced pole costs by a 15% factor to account for appurtenances. The 15% factor is arbitrary and not supported by any evidence submitted in this proceeding. As the Company stated in the response to Question No. 30 of KCTA's Supplemental Data Request, dated April 2, 2010, the cost of *all* appurtenances have been excluded from the bare pole costs used to calculate the CATV attachment charge.

Q. Are appurtenances recorded separately in the Company's continuing property records?

A. Yes. All appurtenances charged to Account 364 – Power, Towers and Fixtures are recorded separately in the Company's continuing property records. Attached as

Seelye Rebuttal Exhibit 10 is the Company's response to Question No. 2 of KCTA First Data Request dated March 1, 2010. Appurtenances are recorded separately from bare pole costs and are identified under descriptions labeled "Brackets", "Cross Arms", "Fence", "Guy", and "Platforms". It is important to note that the Company did not use the entire amount of costs recorded in Account 364, as is often done to calculate a CATV attachment charge, even though a strong argument could be made that items such as guy wires and fencing should reasonably be included in the CATV attachment charge.

Q. Are so-called "minor appurtenances" included in the bare pole costs included in the CATV attachment charge?

A. No. Although the term "minor appurtenances" is vague and imprecise, costs such as aerial cable clamps, pole top pins and other such items that relate to connecting conductors to poles are not recorded in Account No. 364 - Poles, but, rather, in Account No. 365 – Overhead Conductor. Items related to connecting transformers to poles are recorded in Account 368 – Transformers. Although these items are not recorded in Account 364 – Poles, Towers and Fixtures, it is important to understand that these minor items would typically account for less than one percent of the cost of a typical project.

Q. Do you agree with Ms. Kravtin that an error was made by applying levelized carrying charge rate to gross investment?

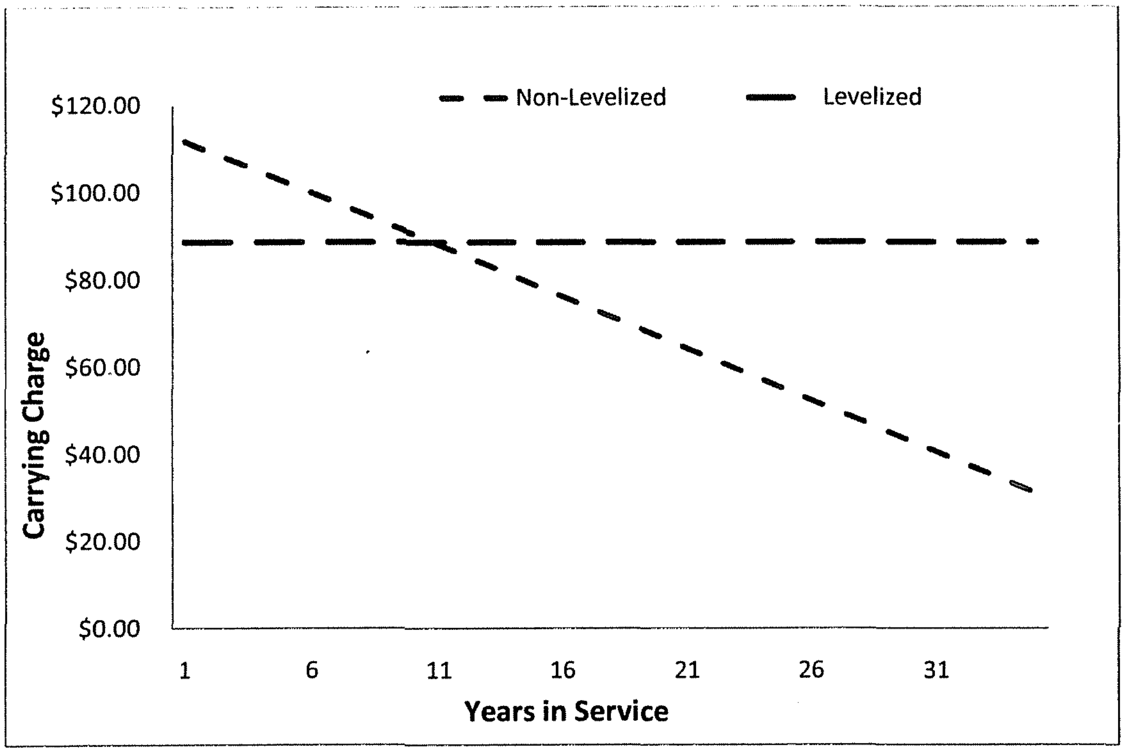
A. No. There are two accepted methodologies for calculating carrying charges – a levelized carrying charge approach and a non-levelized carrying charge approach. Both are standard approaches, both are accepted by the FERC, and, more importantly, both have been routinely accepted by the Commission in Kentucky. It is important to note that either methodology will produce the same result on a present value basis if consistently applied over the life of the investment. But once a particular methodology is selected it is not appropriate to swing back and forth between the two methodologies – selecting whichever method that yields a result that might be desired by one party or another. The reason for this is that during certain periods over the life of an investment a non-levelized carrying charge rate will be higher than a levelized carrying charge rate while during other periods a levelized carrying charge rate will be higher than a non-levelized rate.

Q. Which method was used by the Company the last time the CATV charge was calculated?

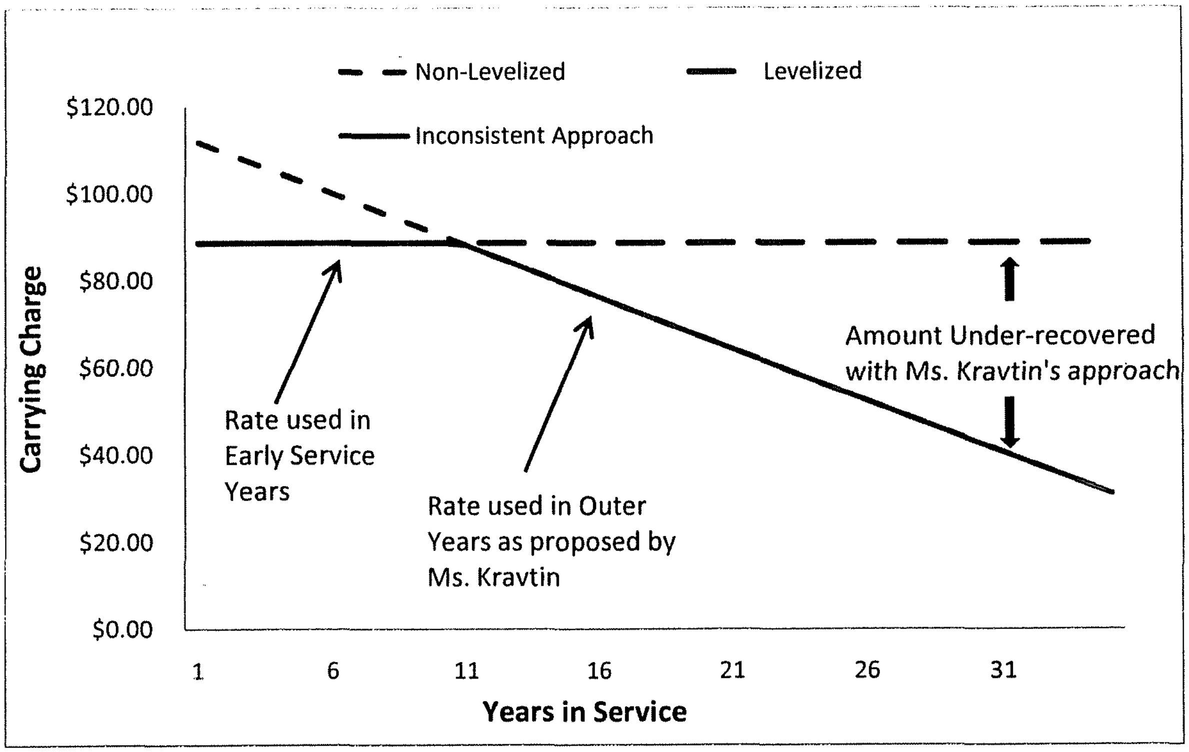
A. We have been unable to locate the workpapers used to calculate KU's CATV charge. Although the methodology used cannot be confirmed with absolute certainty, we believe that the current charge, which was implemented in the early 1980s, was calculated using a levelized carrying charge rate.

Q. Is there anything fundamentally wrong with using a non-levelized carrying charge rate?

A. No, but it is not appropriate to switch back and forth between the two methodologies. As I mentioned, on a present value basis the two methodologies are equivalent over the life of the investment. The economic equivalency of the two methodologies was demonstrated in the Company's response to Question No. 3(a) of the Third Request of Commission Staff dated March 26, 2010, which is included as Seelye Rebuttal Exhibit 11. Particularly, Table I of that response shows that, over the life of an investment, the present value of levelized gross plant carrying charges equal the present value of non-levelized net plant carrying charges. However, at any given point in time the charges will be different. As the name implies, a levelized gross-plant carrying charge is designed to be level over the life of an investment, while a non-levelized net plant carrying charge will change from one year to the next. The following is a graphical comparison of the levelized and non-levelized charges shown in following graph:



As can be seen from this graph, in the early years of an investment, the levelized carrying charge is lower than the non-levelized carrying charges, but later on the levelized carrying charge is higher than the non-levelized charges. Because a levelized carrying charge rate results in a lower rate in the early years but a higher rate in outward years, switching from a levelized rate that has been in place for a long period of time to a non-levelized rate would result in a significant under-recovery of costs over the life of an investment. In other words, it would be inappropriate to use a levelized carrying charge rate during the early years of an investment but switch to a non-levelized charge after the two charges cross over, as illustrated in the following graph:



Q. From the results shown in Table I, can you quantify the impact of switching over from a levelized carrying charge rate to a non-levelized carrying charge rate?

A. Yes. Seelye Rebuttal Exhibit 12 shows the present value calculations from Table I included in the response to the Staff's data request, but a third set of columns has been added that illustrates what happens when a levelized gross plant carrying charge rate is used during the earlier years of an investment but switching over to a non-levelized net plant carrying charge rate at the cross-over point. As can be seen from Seelye Rebuttal Exhibit 12, the present value of the consistently-applied non-levelized carrying charges is equal to the original $1,000 investment used in the example. Likewise, the present value of the consistently-applied non-levelized carrying charges is also equal to the original $1,000 investment. As mentioned earlier, this illustrates the mathematical and economic equivalency of the two methodologies when they are both consistently applied over the life of the investment. But when a levelized carrying charge rate is used in the earlier years but a non-levelized carrying charge rate is used in the outer years, as illustrated in the last two columns of the exhibit, the present value revenue requirement is only $907. Therefore, in this example, an inconsistent blending of the application of a levelized carrying charge rate during the early years with a non-levelized rate during the outer years would result in an under-recovery of costs over the life of the investment.

Q. What is the FERC's policy on switching back and forth between a levelized gross plant carrying charge rate and a non-levelized net plant carrying charge rate?

A. FERC generally does not allow switching back and forth between the two methodologies. In a series of cases involving levelized carrying charges, the FERC rejected attempts to switch from a "net plant" approach to a "levelized" approach in midstream, finding that "allowing Consumers to switch pricing methodologies from the nonlevelized approach ... to the levelized approach ... is inappropriate."

Consumers Energy Co., Opinion No. 429, 85 FERC ¶ 61,100 at 61,366 (1998), *reh'g granted, Opinion No. 429-A,* 89 FERC ¶ 61,138 (1999), *reh'g denied, Opinion No. 429-B*, 95 FERC ¶ 61,084 (2001); *accord Ky. Utils. Co., Opinion No. 432*, 85 FERC ¶ 61,274 at 62,105 (1998). In its *Opinion 432*, the FERC did not allow Kentucky Utilities Company ("KU") to change methodologies, stating as follows:

> In conclusion, we believe that either a levelized gross plant or a non-levelized rate design can produce comparable, reasonable results if they are used consistently. Here, however, KU proposes to switch methods. In supporting such a switch, a utility must prove that its proposed method is reasonable in light of its past recovery of capital costs using a different method. Here, KU has not persuaded us that the switch is appropriate in the circumstances of this case.

In the instant proceeding, Ms. Kravtin has not demonstrated that switching from a methodology that has been utilized for approximately 30 years would be reasonable in light of its past recovery of capital costs.

Q. Even though she proposes to calculate carrying charges using net plant, Ms. Kravtin proposes to continue to utilize sinking fund depreciation. Is this appropriate?

A. No. This is a serious error which significantly understates the cost of providing pole attachment service to CATV companies. It is not appropriate to use a sinking fund depreciation factor in connection with net plant. If a sinking factor is to be utilized, then it should be applied to gross plant, not net plant. As was shown in Seelye Rebuttal Exhibit 11 and Seelye Rebuttal Exhibit 12, carrying charges calculated by applying a levelized carrying charge rate (which included the return plus sinking fund depreciation) is mathematically equivalent on a present value basis to carrying charges calculated using straight line depreciation with net plant.

Ms. Kravtin claims to have corrected the carrying charge calculation to put it on an "apples-to-apples" basis, but she has in fact done the opposite. If net plant is used in calculating carrying charges, then it cannot incorporate the use of sinking fund depreciation. The net plant approach is equivalent to the standard methodology use in any given year, such as the current rate case, to calculate revenue requirements. For example, the revenue requirements calculated in Mr. Rives' exhibits do not use sinking fund depreciation to determine the depreciation element included in revenue requirements. When net plant is used to calculate revenue requirements in a rate case, straight line depreciation rates and not sinking fund depreciation rates are used to determine test-year depreciation expenses.

Q. Ms. Kravtin claims that the Compay improperly included storm related charges in its calculation of the pole attachment charge. Is she correct?

A. No. While the Company inadvertently included storm related charges in Account 593004 in the LG&E pole attachment charge, KU's calculation does not include any storm related expenses. In fact, those storm damages in fact should have been included in the determination of the pole attachment charge, at the same amortization rate as is being proposed in the case. To do otherwise, in effect, provides the cable companies with a "free ride" relative to storm restoration costs.

Specifically, KU incurred a total of $723,980 in expenses charged to Maintenance of Poles, Towers and Fixtures (Subaccount 593001), and $20,243,079 in expenses charged to Tree Trimming of Electric Distribution (Subaccount 593004).

After Commission approval, KU made storm restoration adjustments of $381,066 to Subaccount 593001 and $7,553,655 to Subaccount 593004. These amounts were transferred to a regulatory asset for storm-related costs, resulting in test-year expenses included in revenue requirements of $342,914 (Subaccount 593001) and $12,689,424 (Subaccount 593004), as shown on Seelye Exhibit 8, page 3. Ms. Kravtin claims, on page 23 of her direct testimony, that "KU has taken the expenses it had moved into its regulatory asset and effectively reinserted them into Account 593 for purposes of its pole rate calculations." This is simply not true. However, what KU did not do is include the amortization of the charges to Subaccounts 593001 and 593004 in its pole attachment calculations.

Q. Ms. Kravtin states that in calculating the O&M component of the CATV charge, an incorrect plant in service amount was used for Account 364 in the divisor shown on page 3 of Seelye Exhibit 8. Is she correct?

A. Yes. In calculating the adder to annual carrying charges for O&M expenses, the expenses assigned to poles were divided by $227,809,902, which is an incorrect amount. As pointed out by Ms. Kravtin, the correct plant in service amount for Account 364 as of October 31, 2009, is $244,022,288.

Q. Have you prepared an exhibit correcting these two oversights?

A. Yes. Seelye Rebuttal Exhibit 13 shows a corrected calculation of the CATV charge, which includes the 5-year amortization of the storm-related regulatory asset as a component of Expenses Assigned to Poles and uses the correct amount for Account 364 in calculating the O&M component of the rate.

Q. Who ends up footing the bill if the Commission accepts Ms. Kravtin's other recommendations?

A. All other KU customers would pay the costs. Ms. Kravtin's recommendations will simply lower KU miscellaneous revenue. Lowering these miscellaneous revenues simply shifts the costs that would otherwise be recovered from CATV customers to KU's other customers, particularly residential customers who receive the largest percentage of the revenue credit from CATV attachment charges. From a revenue requirement perspective, lowering CATV attachment charges will therefore not affect the overall revenue that KU collects. Lowering CATV attachment charges will, however, affect KU's other customers. As with making changes to the late payment charges, making changes to lower the CATV charge will result in a larger amount of revenue that must be collected through base rates. Because of the Company's financial neutrality with respect to the level of the CATV attachment charges, KU's position regarding the proper calculation of the charges should be given greater weight by the Commission than the KCTA position, which seeks to obtain lower rates for CATV companies.

V. PRO-FORMA ADJUSTMENTS

A. ELECTRIC TEMPERATURE NORMALIZATION ADJUSTMENT

Q. Do you agree with Mr. Watkins's criticism that the temperature normalization adjustment should not be performed on a month-by-month basis?

A. No. The temperature normalization adjustment should not be performed using seasonal modeling and banding. As long as the analysis encompasses the entire heating and cooling season, the results obtained from performing the adjustment seasonally are not significantly different from the results obtained when the adjustment is performed monthly. However, calculating the electric temperature adjustment on a monthly basis is more consistent with the methodology approved by the Commission to determine the gas temperature normalization adjustment, which is calculated on a monthly basis, and is also more accurate. The reason that it is important to perform a monthly analysis is to avoid problems with non-linearity that can occur when performing a regression analysis across a full season. Performing the analysis across a full season can potentially create two types of non-linearity problems. First, temperature sensitive loads (kWh per degree day) will vary over a fairly wide range of temperatures. Within a relatively small range of temperatures, the response of electric sales to temperature will be practically linear, but over a wide range of temperatures, the response of sales to temperature will not be perfectly linear. Because temperatures tend to be more homogeneous within a single month than over an entire season, accurate monthly models can be developed without resorting to more complicated non-linear regression techniques such as spline regression, kernel regression, or local polynomial fitting.[9] KU specifically developed monthly models so that we could rely on linear regression (using least squares estimation), thus avoiding the need to employ these more complicated non-linear techniques. Obviously, if the regression coefficients (load per degree day) are

[9] See Michael G. Schimek, ed., *Smoothing and Regression: Approaches, Computation, and Application*. (Wiley Series in Probability and Statistics: 2000) Although spline regression, kernel regression, and local polynomial fitting are all excellent techniques, they are significantly more complicated and less standardized than linear regression modeling.

determined using monthly modeling, then the banding approach must also be applied monthly.

Q. Do you agree with Mr. Watkins that May should be considered a shoulder month?

A. No. Mr. Watkins makes an overly simplistic comparison between the average HDDs in May and the average CDDs in May. Although there are 107 HDDs and 88 CDDs during May, Mr. Watkins ignores the fact that the two figures are not comparable. On average, there are 4,598 HDDs on an annual basis, but only 1,226 CDDs on an annual basis. Therefore, the 88 CDDs during May represents a larger proportion of total CDDs than the relationship between the 107 HDDs during May to total HDDs. In addition, system loads during May also exhibit a pattern more representative of a summer month.

B. UNBILLED REVENUES

Q. KIUC witness Kollen recommends against removing unbilled revenues from test-year operating results. What are unbilled revenues?

A. Unbilled revenues represent the estimated revenues corresponding to timing differences that arise between when meters are read and the end of the month. Unbilled revenues arise because meters are read throughout the month on a meter-reading-cycle basis, whereas expenses are recorded on a calendar month basis. Because meters are read and bills are rendered on a billing-cycle basis, at the end of any month the utility will have sold gas or electric energy that the utility has not actually billed to customers, thus giving rise to the concept of "unbilled" revenues. Unbilled revenues represent an attempt to state revenues on a calendar month basis.

Q. How are unbilled revenues estimated?

A. Unbilled revenues are determined each month by developing an estimate of the MWh sales that are unbilled. The unbilled MWh sales are then allocated to the revenue classes on the basis of the as-billed sales for the month. An estimated price is then applied to the allocated MWh unbilled sales to determine unbilled revenues for each revenue class. The estimated unbilled revenues for each revenue class are summed to obtain the unbilled revenues for the month.

Q. What is included in the estimated price applied to the unbilled MWhs?

A. The price used to compute unbilled revenues is an estimate of the *total* price to the consumer. The prices used to estimate unbilled revenues therefore include the fuel adjustment clause component (FAC), the environmental cost recovery surcharge (ECR), and demand-side management component (DSM), as applicable. The price used to estimate the unbilled revenues is thus an all-in price.

Q. Does KU compute unbilled revenues or unbilled MWh sales by rate class?

A. No. Unbilled revenues and unbilled kWh are not estimated for each rate class. The unbilled MWh are estimated for total retail sales and then allocated to the *revenue classes* on the basis of actual sales during the month. Generally, there is little correspondence between the revenue classes reported in FERC Form 1 and other financial statements and the rate classes used to develop rates in a general rate case.

Q. Does KU compute unbilled demand units (kWs) for rate classes that have demand charges?

A. No. Several of KU's rate schedules include demand charges. The technique used to estimate unbilled revenues provides only a high-level estimate of the unbilled kWh. It is not refined enough to develop unbilled demands.

Q. What entries are made to record unbilled revenues during a month?

A. Two entries are made: First, unbilled revenues for the current month are added to actual billed revenues for the current month. Second, the unbilled revenue amount recorded in the previous month is subtracted from the actual billed revenues for the current month. Since the as-billed revenues for the current month includes the unbilled revenues that were recorded in the prior month, this amount needs to be subtracted from actual revenues billed for the current month.

The following table shows the unbilled entries for KU during the test year:

Unbilled Revenues For the 12 Months Ended OCTOBER 2009			
Month	Unbilled Revenue For Current Month	Unbilled Revenue For Previous Month	Net Unbilled Revenues
November 2008	$55,767,000	$50.124,000	$5.643,000
December	$56,638,000	$55.767,000	$871,000
January 2009	$62,420,000	$56,638,000	$5.782,000
February	$53,514,000	$62,420,000	($8.906.000)
March	$57.060,391	$53,514,000	$3.546,391
April	$51,959,141	$57,060,391	($5.101.250)
May	$56,412,661	$51,959,141	$4,453.520
June	$40,626,998	$56,412,661	($15.785.663)
July	$58,311,000	$40,626,998	$17,684,002
August	$59,455,000	$58,311,000	$1,144,000
September	$50,653,000	$59,455,000	($8.802.000)
October	$53.868,529	$50.653,000	$3,215,529
Total Test-Year			$3.744,529

Electric unbilled revenues for the test year, $3,744,529, equals the unbilled revenues for October 2009, the last month of the test year, or $53,868,529, minus the unbilled revenues recorded for October 2008, the month prior to the beginning of the test year, or $50,124,000 (i.e., $53,868,529 – $50,124,000 = $3,744,529).

Q. Did KU make pro-forma adjustments to eliminate unbilled revenues from test-year operating revenues?

A. Yes. Consistent with the two KU rate cases that have been filed since the Company began recording unbilled revenues, (Case No. 2008-00251 and Case No. 2003-00434) and consistent with LG&E's last four rate cases (Case No. 2008-00252, Case No.

2003-00433, Case No. 2000-080 and Case No. 90-158), unbilled revenues were removed from test-year operating results.

Q. Has the subject of removing unbilled revenues been considered in any of these cases?

A. Yes. In Case No. 90-158, LG&E offered testimony by Benjamin A. McKnight, an outside accounting expert, in support of an adjustment to remove unbilled revenue from test-year operating results. After a thorough consideration of the issue, the Commission accepted LG&E's proposed adjustment. (Order in Case No. 90-158, dated December 21, 1990, p. 18.) LG&E proposed an adjustment in Case No. 2000-080 to eliminate unbilled revenues, which was approved in the Commission's Order dated September 27, 2000. LG&E and KU proposed adjustments in Case Nos. 2003-00433 and 2003-00434 to eliminate unbilled revenues. The adjustments to eliminate unbilled revenue were considered extensively in those proceedings. In its Order in Case No. 2003-00433, the Commission stated that the Company's "arguments convince us that any resulting mismatch [between unbilled revenues and expenses] is adequately mitigated by the various normalization adjustments included in its rate application." (Order in Case No. 2003-00433, p. 26.) KU and LG&E also proposed adjustments in Case Nos. 2008-00251 and 2008-00252 to eliminate unbilled revenues. Those rate cases settled.

Q. In this proceeding, have any of the intervenor witnesses offered recommendations regarding the Company's pro-form adjustment?

A. Yes. KIUC witness Kollen simply proposes to leave unbilled revenues in test-year operating results. Mr. Kollen's adjustment would have the effect of increasing revenues by $3,744,529.

Q. Are there any problems with leaving unbilled revenues in test year operating results as proposed by Mr. Kollen?

A. Yes. Besides being contrary to past Commission practice, there are numerous problems with leaving unbilled revenues in test-year operating results. One problem is the unbilled revenues that Mr. Kollen proposes to add to test-year income reflect revenue amounts related to fuel costs, environmental costs, demand-side management costs and other items, all of which have already been removed from test year expenses. Recall that unbilled revenues were computed by applying the all-in price electric energy to the estimated unbilled sales (kWh). These estimated prices include amounts for the FAC, ECR, and DSM. For example, the average price used to compute unbilled revenues for the residential class was $74.39 per MWh for October 2009, which included an ECR component of $7.50 per MWh (based on an 11.2% ECR factor) and an FAC component of $0.71 per MWh. However, the revenues and expenses associated with the ECR and FAC components of the rate have been removed from test-year operating expenses.

Unbilled revenues include amounts for the FAC, ECR, and DSM even though the costs for these components have been eliminated from operating expenses. FAC costs were eliminated from operating expenses through the pro-forma adjustment shown on line 6 of Rives Exhibit 1 (Reference Schedule 1.03). ECR costs were eliminated from operating expenses through the pro-forma adjustment shown on line 8 of Rives Exhibit 1 (Reference Schedule 1.05). DSM costs were eliminated from operating expenses through the pro-forma adjustment shown on line 13 of Rives

Exhibit 1 (Reference Schedule 1.10). Leaving unbilled revenues in test-year operating results seriously distort revenue requirements by double counting these cost components.

Q. Are there any other problems with the unbilled revenue adjustments proposed by Mr. Kollen?

A. Yes. In addition to the unbilled revenues being significantly overstated by the inclusion of FAC, ECR, and DSM revenues, the Mr. Kollen fails to account for the fact that various pro-forma adjustments in the rate case eliminate the need to consider unbilled revenues. Through the proper application of pro-forma adjustments, any need to even consider unbilled revenues disappears. If revenues and expenses are properly constructed in a rate case, there simply will not be any unbilled revenues.

Three major factors account for unbilled revenues during the test year: (1) rate differences due to changes in the FAC, ECR, DSM, etc., (2) changes in the number of customers served, plant closings, and customer rate switching, and (3) changes in temperature. The purpose of making pro-forma adjustments is to develop test-year operating results that account for these and other factors. If the utility's rates did not change (as a result, for example, of changes in gas costs, environmental costs, fuel costs, etc.), if temperatures were normal every year, and if there were no changes in the number and composition of customers, a utility's unbilled revenues would be insignificant. Likewise, if the utility's revenues and expenses are properly adjusted for all relevant factors, consistent with methodologies found reasonable by the Commission, unbilled revenues will have been fully accounted for in the construction of pro-forma operating revenues and expenses.

Q. How do changes in price create unbilled revenues during the test year?

A. As mentioned earlier, unbilled revenues for the test year are calculated by adding the unbilled revenues for October 2009 and subtracting the unbilled revenues for October 2008. If the price in October 2009 is different than it was in October 2008, unbilled revenues would have been created for the test year even if there was no difference in the sales volume for the two months. By eliminating the FAC, ECR, DSM, and other components from revenues and expenses, as was done in KU's rate case application, any unbilled revenues created as a result of changes in the Company's rates have been fully accounted for.

Q. How do changes in the number of customers, plant closings, and customer rate switching create unbilled revenues?

A. If there are more customers served at the end of the test year than there were at the beginning of the test year, then, with everything else being equal, sales volumes and unbilled revenues will be higher for the month that is added (October 2009) than for the month that is subtracted (October 2008) in the computation of unbilled revenues for the year. Similarly, if there is a different customer composition at the beginning of the year than at the end of the year, as a result of plant closings or customer rate switching, then unbilled revenues will be created. Pro-forma adjustments were made to annualize revenues and expenses for year-end numbers of customers (line 15 of Rives Exhibit 1) and to reflect customer billing corrections and rate switching (line 16 of Rives Exhibit 1). Therefore, by making pro-forma adjustments any unbilled revenues created as a result of these factors have been fully accounted for.

Q. How do changes in temperature create unbilled revenues?

A. If there were more degree days during the month for which unbilled revenues are added (October 2009) than there were during the month for which unbilled revenues were subtracted (October 2008) then, with everything else being equal, unbilled revenues would have been created for the test year. A pro-forma adjustment was made to adjust revenues for normal temperature (lines 14 of Rives Exhibit 1). Therefore, any unbilled revenues created as a result of changes in temperature have been eliminated through the temperature normalization adjustment.

Mr. Kollen has not attempted to disentangle (1) the components of unbilled revenues that have been fully accounted for though pro-forma adjustments made in this case *from* (2) the unbilled revenues attributable to changes in temperature, which has already been accounted for in this proceeding.

Q. Are there any other problems with the Mr. Kollen's recommendation of including unbilled revenue adjustments in test year operating results?

A. Yes. Mr. Kollen proposes to eliminate the unbilled revenue adjustment without adjusting the billing determinants used to develop rates in the proceeding. Selectively eliminating the pro-forma adjustment for unbilled revenues, without modifying other key exhibits in the rate case would result in improperly calculated rates.

The billing determinants used to develop the proposed rates in Seelye Exhibit 7 were reconciled back to as-billed revenues, which ***excluded*** unbilled revenues. If unbilled revenues were left in test-year operating results, it would be necessary to develop a fair and equitable methodology for estimating billing determinants that would need to be added to or subtracted from those shown in Seelye Exhibit 7. In compiling the billing determinants used to develop the proposed rates, the rates in effect during the test year were applied to the as-billed billing determinants to test the accuracy of the billing determinants to be used to develop the Company's proposed rates. The results of this reconciliation to as-billed revenues are shown for as-billed revenue in Seelye Exhibit 5. If an adjustment were not made to eliminate unbilled revenues, then a complex and ultimately subjective methodology would need to be developed to reconstruct the billing determinants so that they include the "billing determinants" associated with the unbilled amounts. This would introduce a great deal of subjectivity into the process of developing the proposed rates, and would create another arena for disagreements about whether the approach used to allocate the unbilled revenues and associated billing units among the rate classes was equitable (similar to the disagreements in this proceeding over the methodology used in the cost of service study).

Q. What other exhibits would have to be modified in order to set rates that properly account for unbilled revenues if they were not eliminated from test-year operating results?

A. In addition to modifying the reconstruction of billing determinants in Seelye Exhibits 5 and the development of the proposed rates rate in Seelye Exhibits 7, the year-end adjustment shown in Seelye Exhibits 16 and the temperature normalization adjustments shown in Seelye Exhibit 15 would have to be modified to reflect unbilled revenues. All of these exhibits were prepared on an as-billed basis and would need to be reconstructed on an unbilled basis to properly set rates in this proceeding.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **William Steven Seelye**, being duly sworn, deposes and states that he is a Principal and Senior Analyst with The Prime Group, LLC, that he has personal knowledge of the matters set forth in the foregoing testimony and exhibits, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

W. S. Seelye

William Steven Seelye

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 21st day of May 2010.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 20, 2010

Seelye Rebuttal Exhibit 1

**Production Plant Costs Assigned to Costing Period
in Watkins' Cost of Service Study
For Kentucky Utilities**

	Total	Off-Peak Period	Winter On-Peak Period
Gross Production Plant	$2,373,889,077	$1,901,485,151	$100,890,286
Depreciation Reserve - Production	$1,004,278,601	$804,427,159	$42,681,841
Production Net Plant	$1,369,610,476	$1,097,057,991	$58,208,445
Production Expenses Allocated by Watkins on Production Plant			
502 Steam Exspenses	$11,005,571	$8,815,462	$467,737
505 Electric Expenses	$4,750,212	$3,804,920	$201,884
506 Misc Steam Power Expense	$12,280,840	$9,836,953	$521,936
507 Rents	$874,465	$700,446	$37,165
511 Maintenance of Structures	$4,477,161	$3,586,206	$190,279
536 Water For Power	$0	$0	$0
537 Hydraulic Expenses	$0	$0	$0
538 Electric Expenses	$0	$0	$0
539 Misc Hydraulic Power Expenses	$32,162	$25,762	$1,367
540 Rents	$0	$0	$0
542 Maintenance of Structures	$242,633	$194,349	$10,312
543 Maintenance of Reserves, Dams, & Waterways	$188,214	$150,759	$7,999
546 Operation Supervision & Engineering	$132,803	$106,375	$5,644
548 Generation Expense	$227,067	$181,881	$9,650
549 Misc Other Power Generation	$99,365	$79,591	$4,223
550 Rents	$0	$0	$0
551 Maintenance Supervision & Engineering	$80,702	$64,642	$3,430
552 Maintenance of Structures	$229,542	$183,863	$9,756
553 Maintenance of Gen & Electric Plant	$2,155,168	$1,726,290	$91,595
554 Maintenance of Misc Other Power Generation	$405,749	$325,005	$17,244
555 Purchased Power - Demand	$22,338,727	$17,893,320	$949,396
556 System Control & Load Dispatch	$1,510,099	$1,209,589	$64,179
557 Other Expenses	$801,178	$641,744	$34,050
Sub-Total	$61,831,658	$49,527,158	$2,627,845
Production Depreciation Expense	$75,175,531	$60,215,600	$3,194,960

Production Plant Costs Assigned to Costing Period
in Watkins' Cost of Service Study
For Kentucky Utilities

	Total	**Off-Peak Period**	**Winter On-Peak Period**
Revenue Requirement			
Interest	$29,201,876	$23,390,703	$1,241,080
Equity return	$84,816,553	$67,938,059	$3,604,703
Income Tax	$51,216,411	$41,024,345	$2,176,697
Revenue For Return	165,234,839	$132,353,106	$7,022,481
Production Expenses	$61,831,658	$49,527,158	$2,627,845
Depreciation Expense	$75,175,531	$60,215,600	$3,194,960
Total Plant Related Revenue Requirement	$302,242,028	$242,095,865	$12,845,286
kWh in Costing Period		12,595,732,000	4,843,531,000
Cost per Kwh		$0.019220	$0.002652

	PCT	Cost	WGHT Cost
Debt	46.15%	4.62%	2.13%
Common	53.85%	11.50%	6.19%
Total	100.00%		8.32%

Production Plant Costs Assigned to Costing Period
in Watkins' Cost of Service Study
For Kentucky Utilities

	Gross Plant	Costs Allocated to Off-Peak Period	Costs Allocated to Winter Peak Period	Costs Allocated to Summer Peak Period	Total
Base	$2,889,368	$1,767,698	$810,497	$311,173	$2,889,368
Intermediate	$151,136		$109,208	$41,928	$151,135.937
Peak	$557,018			$557,017.881	$557,017.881
Total	$3,597,521	$1,767,698.207	$919,704.438	$910,118.692	$3,597,521.337
Percentage of Total		49.14%	25.56%	25.30%	

	Hours	Percentage of Total
Off-Peak	5374	61.18%
Winter-Peak	2464	28.05%
Summer-Peak	946	10.77%
Total	8784	100.00%

	Hours	Percentage of Total
Winter-Peak	2464	72.26%
Summer-Peak	946	27.74%
Total	3410	100.00%

Seelye Rebuttal Exhibit 2

Introduction to Linear Regression Analysis

Fourth Edition

DOUGLAS C. MONTGOMERY

Arizona State University
Department of Industrial Engineering
Tempe, AZ

ELIZABETH A. PECK

The Coca-Cola Company (retired)
Atlanta, GA

G. GEOFFREY VINING

Virginia Tech
Department of Statistics
Blacksburg, VA

WILEY-INTERSCIENCE

A JOHN WILEY & SONS, INC. PUBLICATION

Published by John Wiley & Sons, Inc., Hoboken, New Jersey
Published simultaneously in Canada.

Library of Congress Cataloging in Publication Data:

Montgomery, Douglas C.
Introduction to linear regression analysis.–4 th ed. / Douglas C. Montgomery, Elizabeth A. Peck, G. Geoffrey Vining.
p. cm.
Includes bibliographical references and index.
ISBN-13: 978-0-471-75495-4 (cloth)
ISBN-10: 0-471-75495-1 (cloth)
1. Regression analysis. I. Peck, Elizabeth A., 1953- II. Vining, G. Geoffrey, 1954- III. Title.

QA278.2.M65 2006
519.5'36--dc22 005054232

Printed in the United States of America

10 9 8 7 6 5 4 3 2 1

that round-off error is potentially a problem and successive values of α may oscillate wildly unless enough decimal places are carried. Convergence problems may be encountered in cases where the error standard deviation σ is large or when the range of the regressor is very small compared to its mean. This situation implies that the data do not support the need for any transformation.

Example 5.4 The Windmill Data

We will illustrate this procedure using the windmill data in Example 5.2. The scatter diagram in Figure 5.5 suggests that the relationship between DC output (y) and wind speed (x) is not a straight line and that some transformation on x may be appropriate.

We begin with the initial guess $\alpha_0 = 1$ and fit a straight-line model, giving $\hat{y} = 0.1309 + 0.2411x$. Then defining $w = x \ln x$, we fit Eq. (5.8) and obtain

$$\hat{y} = \hat{\beta}_0^* + \hat{\beta}_1^* x + \hat{\gamma} w = -2.4168 + 1.5344x - 0.4626w$$

From Eq. (5.10) we calculate

$$\alpha_1 = \frac{\hat{\gamma}}{\hat{\beta}_1} + 1 = \frac{-0.4626}{0.2411} + 1 = -0.92$$

as the improved estimate of α. Note that this estimate of α is very close to -1, so that the reciprocal transformation on x actually used in Example 5.2 is supported by the Box–Tidwell procedure.

To perform a second iteration, we would define a new regressor variable $x' = x^{-0.92}$ and fit the model

$$\hat{y} = \hat{\beta}_0 + \hat{\beta}_1 x' = 3.1039 - 6.6784x'$$

Then a second regressor $w' = x' \ln x'$ is formed and we fit

$$\hat{y} = \hat{\beta}_0^* + \hat{\beta}_1^* x' + \hat{\gamma} w' = 3.2409 - 6.445x' + 0.5994w'$$

The second-step estimate of α is thus

$$\alpha_2 = \frac{\hat{\gamma}}{\hat{\beta}_1} + \alpha_1 = \frac{0.5994}{-6.6784} + (-0.92) = -1.01$$

which again supports the use of the reciprocal transformation on x.

5.5 GENERALIZED AND WEIGHTED LEAST SQUARES

Linear regression models with nonconstant error variance can also be fitted by the method of **weighted least squares**. In this method of estimation the deviation between the observed and expected values of y_i is multiplied by a **weight** w_i chosen inversely proportional to the variance of y_i. For the case of simple linear regression, the weighted least-squares function is

$$S(\beta_0, \beta_1) = \sum_{i=1}^{n} w_i (y_i - \beta_0 - \beta_1 x_i)^2 \tag{5.11}$$

The resulting least-squares normal equations are

$$\begin{aligned}
\hat{\beta}_0 \sum_{i=1}^{n} w_i + \hat{\beta}_1 \sum_{i=1}^{n} w_i x_i &= \sum_{i=1}^{n} w_i y_i \\
\beta_0 \sum_{i=1}^{n} w_i x_i + \hat{\beta}_1 \sum_{i=1}^{n} w_i x_i^2 &= \sum_{i=1}^{n} w_i x_i y_i
\end{aligned} \tag{5.12}$$

Solving Eq. (5.12) will produce weighted least-squares estimates of β_0 and β_1.

In this section we give a development of weighted least squares for the multiple regression model. We begin by considering a slightly more general situation concerning the structure of the model errors.

5.5.1 Generalized Least Squares

The assumptions usually made concerning the linear regression model $\mathbf{y} = \mathbf{X}\boldsymbol{\beta} + \boldsymbol{\varepsilon}$ are that $E(\boldsymbol{\varepsilon}) = \mathbf{0}$ and that $\mathrm{Var}(\boldsymbol{\varepsilon}) = \sigma^2\mathbf{I}$. As we have observed, sometimes these assumptions are unreasonable, so that we will now consider what modifications to these in the ordinary least-squares procedure are necessary when $\mathrm{Var}(\boldsymbol{\varepsilon}) = \sigma^2\mathbf{V}$, where $\mathbf{V}$ is a known $n \times n$ matrix. This situation has an easy interpretation; if $\mathbf{V}$ is diagonal but with unequal diagonal elements, then the observations $\mathbf{y}$ are **uncorrelated** but have **unequal variances**, while if some of the off-diagonal elements of $\mathbf{V}$ are nonzero, then the observations are **correlated**.

When the model is

$$\begin{gathered}
\mathbf{y} = \mathbf{X}\boldsymbol{\beta} + \boldsymbol{\varepsilon} \\
E(\boldsymbol{\varepsilon}) = \mathbf{0}, \ \mathrm{Var}(\boldsymbol{\varepsilon}) = \sigma^2\mathbf{V}
\end{gathered} \tag{5.13}$$

the ordinary least-squares estimator $\hat{\boldsymbol{\beta}} = (\mathbf{X}'\mathbf{X})^{-1}\mathbf{X}'\mathbf{y}$ is no longer appropriate. We will approach this problem by transforming the model to a new set of observations that satisfy the standard least-squares assumptions. Then we will use ordinary least squares on the transformed data. Since $\sigma^2\mathbf{V}$ is the covariance matrix of the errors, $\mathbf{V}$ must be nonsingular and positive definite, so there exists an $n \times n$ nonsingular symmetric matrix $\mathbf{K}$, where $\mathbf{K}'\mathbf{K} = \mathbf{K}\mathbf{K} = \mathbf{V}$. The matrix $\mathbf{K}$ is often called the **square root** of $\mathbf{V}$. Typically, σ^2 is unknown, in which case $\mathbf{V}$ represents the assumed structure of the variances and covariances among the random errors apart from a constant.

Define the new variables

$$\mathbf{z} = \mathbf{K}^{-1}\mathbf{y}, \quad \mathbf{B} = \mathbf{K}^{-1}\mathbf{X}, \quad \mathbf{g} = \mathbf{K}^{-1}\boldsymbol{\varepsilon} \tag{5.14}$$

so that the regression model $\mathbf{y} = \mathbf{X}\boldsymbol{\beta} + \boldsymbol{\varepsilon}$ becomes $\mathbf{K}^{-1}\mathbf{y} = \mathbf{K}^{-1}\mathbf{X}\boldsymbol{\beta} + \mathbf{K}^{-1}\boldsymbol{\varepsilon}$, or

$$\mathbf{z} = \mathbf{B}\boldsymbol{\beta} + \mathbf{g} \tag{5.15}$$

The errors in this transformed model have zero expectation, that is, $E(\mathbf{g}) = \mathbf{K}^{-1}E(\boldsymbol{\varepsilon}) = \mathbf{0}$. Furthermore, the covariance matrix of $\mathbf{g}$ is

$$\begin{aligned}
\text{Var}(\mathbf{g}) &= \{[\mathbf{g} - E(\mathbf{g})][\mathbf{g} - E(\mathbf{g})]'\} \\
&= E(\mathbf{g}\mathbf{g}') \\
&= E(\mathbf{K}^{-1}\boldsymbol{\varepsilon}\boldsymbol{\varepsilon}'\mathbf{K}^{-1}) \\
&= \mathbf{K}^{-1}E(\boldsymbol{\varepsilon}\boldsymbol{\varepsilon}')\mathbf{K}^{-1} \\
&= \sigma^2\mathbf{K}^{-1}\mathbf{V}\mathbf{K}^{-1} \\
&= \sigma^2\mathbf{K}^{-1}\mathbf{K}\mathbf{K}\mathbf{K}^{-1} \\
&= \sigma^2\mathbf{I}
\end{aligned} \tag{5.16}$$

Thus, the elements of $\mathbf{g}$ have mean zero and constant variance and are uncorrelated. Since the errors $\mathbf{g}$ in the model (5.15) satisfy the usual assumptions, we may apply ordinary least squares. The least-squares function is

$$S(\boldsymbol{\beta}) = \mathbf{g}'\mathbf{g} = \boldsymbol{\varepsilon}'\mathbf{V}^{-1}\boldsymbol{\varepsilon} = (\mathbf{y} - \mathbf{X}\boldsymbol{\beta})'\mathbf{V}^{-1}(\mathbf{y} - \mathbf{X}\boldsymbol{\beta}) \tag{5.17}$$

The least-squares normal equations are

$$(\mathbf{X}'\mathbf{V}^{-1}\mathbf{X})\hat{\boldsymbol{\beta}} = \mathbf{X}'\mathbf{V}^{-1}\mathbf{y} \tag{5.18}$$

and the solution to these equations is

$$\hat{\boldsymbol{\beta}} = (\mathbf{X}'\mathbf{V}^{-1}\mathbf{X})^{-1}\mathbf{X}'\mathbf{V}^{-1}\mathbf{y} \tag{5.19}$$

Here $\hat{\boldsymbol{\beta}}$ is called the **generalized least-squares estimator** of $\boldsymbol{\beta}$.

It is not difficult to show that $\hat{\boldsymbol{\beta}}$ is an unbiased estimator of $\boldsymbol{\beta}$. The covariance matrix of $\hat{\boldsymbol{\beta}}$ is

$$\text{Var}(\hat{\boldsymbol{\beta}}) = \sigma^2(\mathbf{B}'\mathbf{B})^{-1} = \sigma^2(\mathbf{X}'\mathbf{V}^{-1}\mathbf{X})^{-1} \tag{5.20}$$

Appendix C.11 shows that $\hat{\boldsymbol{\beta}}$ is the best linear unbiased estimator of $\boldsymbol{\beta}$. The analysis of variance in terms of generalized least squares is summarized in Table 5.8.

TABLE 5.8 Analysis of Variance for Generalized Least Squares

Source	Sum of Squares	Degrees of Freedom	Mean Square	F_0
Regression	$SS_R = \hat{\boldsymbol{\beta}}'\mathbf{B}'\mathbf{z}$ $= \mathbf{y}'\mathbf{V}^{-1}\mathbf{X}(\mathbf{X}'\mathbf{V}^{-1}\mathbf{X})^{-1}\mathbf{X}'\mathbf{V}^{-1}\mathbf{y}$	p	SS_R/p	MS_R/MS_{Res}
Error	$SS_{Res} = \mathbf{z}'\mathbf{z} - \hat{\boldsymbol{\beta}}'\mathbf{B}'\mathbf{z}$ $= \mathbf{y}'\mathbf{V}^{-1}\mathbf{y}$ $-\mathbf{y}'\mathbf{V}^{-1}\mathbf{X}(\mathbf{X}'\mathbf{V}^{-1}\mathbf{X})^{-1}\mathbf{X}'\mathbf{V}^{-1}\mathbf{y}$	$n - p$	$SS_{Res}/(n-p)$	
Total	$\mathbf{z}'\mathbf{z} = \mathbf{y}'\mathbf{V}^{-1}\mathbf{y}$	n		

5.5.2 Weighted Least Squares

When the errors $\boldsymbol{\varepsilon}$ are uncorrelated but have unequal variances so that the covariance matrix of $\boldsymbol{\varepsilon}$ is

$$\sigma^2\mathbf{V} = \sigma^2\begin{bmatrix} \frac{1}{w_1} & & & 0 \\ & \frac{1}{w_2} & & \\ & & \ddots & \\ 0 & & & \frac{1}{w_n} \end{bmatrix}$$

say, the estimation procedure is usually called **weighted least squares.** Let $\mathbf{W} = \mathbf{V}^{-1}$. Since $\mathbf{V}$ is a diagonal matrix, $\mathbf{W}$ is also diagonal with diagonal elements or **weights** $w_1, w_2, \ldots, w_n$. From Eq. (5.18), the weighted least-squares normal equations are

$$(\mathbf{X}'\mathbf{W}\mathbf{X})\hat{\boldsymbol{\beta}} = \mathbf{X}'\mathbf{W}\mathbf{y}$$

This is the multiple regression analogue of the weighted least-squares normal equations for simple linear regression given in Eq. (5.12). Therefore,

$$\hat{\boldsymbol{\beta}} = (\mathbf{X}'\mathbf{W}\mathbf{X})^{-1}\mathbf{X}'\mathbf{W}\mathbf{y}$$

is the **weighted least-squares estimator.** Note that observations with large variances will have smaller weights than observations with small variances.

Weighted least-squares estimates may be obtained easily from an ordinary least-squares computer program. If we multiply each of the observed values for the ith observation (including the 1 for the intercept) by the square root of the weight for that observation, then we obtain a transformed set of data:

$$\mathbf{B} = \begin{bmatrix} 1\sqrt{w_1} & x_{11}\sqrt{w_1} & \cdots & x_{1k}\sqrt{w_1} \\ 1\sqrt{w_2} & x_{21}\sqrt{w_2} & \cdots & x_{2k}\sqrt{w_2} \\ \vdots & \vdots & & \vdots \\ 1\sqrt{w_n} & x_{n1}\sqrt{w_n} & \cdots & x_{nk}\sqrt{w_n} \end{bmatrix}, \quad \mathbf{z} = \begin{bmatrix} y_1\sqrt{w_1} \\ y_2\sqrt{w_2} \\ \vdots \\ y_n\sqrt{w_n} \end{bmatrix}$$

Now if we apply ordinary least squares to these transformed data, we obtain

$$\hat{\boldsymbol{\beta}} = (\mathbf{B}'\mathbf{B})^{-1}\mathbf{B}'\mathbf{z} = (\mathbf{X}'\mathbf{W}\mathbf{X})^{-1}\mathbf{X}'\mathbf{W}\mathbf{y}$$

the weighted least-squares estimate of $\boldsymbol{\beta}$.

SAS will do weighted least squares. The user must specify a "weight" variable, for example, w. To perform weighted least squares, the user adds the following statement after the model statement:

```
weight w;
```

5.5.3 Some Practical Issues

To use weighted least squares, the weights w_i must be known. Sometimes prior knowledge or experience or information from a theoretical model can be used to determine the weights (for an example of this approach, see Weisberg [1985]). Alternatively, residual analysis may indicate that the variance of the errors may be a function of one of the regressors, say $\text{Var}(\varepsilon_i) = \sigma^2 x_{ij}$, so that $w_i = 1/x_{ij}$. In some cases y_i is actually an average of n_i observations at x_i and if all **original** observations have constant variance σ^2, then the variance of y_i is $\text{Var}(y_i) = \text{Var}(\varepsilon_i) = \sigma^2/n_i$, and we would choose the weights as $w_i = n_i$. Sometimes the primary source of error is measurement error and different observations are measured by different instruments of unequal but known (or well-estimated) accuracy. Then the weights could be chosen inversely proportional to the variances of measurement error. In many practical cases we may have to guess at the weights, perform the analysis, and then reestimate the weights based on the results. Several iterations may be necessary.

Since generalized or weighted least squares requires making additional assumptions regarding the errors, it is of interest to ask what happens when we fail to do this and use ordinary least squares in a situation where $\text{Var}(\boldsymbol{\varepsilon}) = \sigma^2\mathbf{V}$ with $\mathbf{V} \neq \mathbf{I}$. If ordinary least squares is used in this case, the resulting estimator $\hat{\boldsymbol{\beta}} = (\mathbf{X}'\mathbf{X})^{-1}\mathbf{X}'\mathbf{y}$ is still unbiased. However, the ordinary least-squares estimator is no longer a minimum-variance estimator. That is, the covariance matrix of the ordinary least-squares estimator is

$$\text{Var}(\hat{\boldsymbol{\beta}}) = \sigma^2(\mathbf{X}'\mathbf{X})^{-1}\mathbf{X}'\mathbf{V}\mathbf{X}(\mathbf{X}'\mathbf{X})^{-1} \tag{5.21}$$

and the covariance matrix of the generalized least-squares estimator (5.20) gives smaller variances for the regression coefficients. Thus, generalized or weighted least squares is preferable to ordinary least squares whenever $\mathbf{V} \neq \mathbf{I}$.

ICS

Regression Analysis by Example

SAMPRIT CHATTERJEE
BERTRAM PRICE

New York University
New York, New York

JOHN WILEY & SONS
New York • Chichester • Brisbane • Toronto • Singapore

Library of Congress Cataloging in Publication Data:

Chatterjee, Samprit, 1938-
Regression analysis by example.

(Wiley series in probability and mathematical statistics)
Includes bibliographies and index.
1. Regression analysis. I. Price, Bertram, 1939- joint author. II. Title.
QA278.2.C5 519.5'36 77-24510

ISBN 0-471-01521-0

Printed in the United States of America

10 9 8 7

CHAPTER 5

Weighted Least Squares

5.1. INTRODUCTION

In the preceding chapters, 1 through 4, it has been assumed that the underlying correct regression model is of the form

$$Y_i = \beta_0 + \beta_1 X_{1i} + \cdots + \beta_p X_{pi} + u_i, \tag{5.1}$$

where u_i's are random disturbances that are independent and identically distributed (i.i.d.). Various residual plots have been used to check these assumptions. If the residuals are not consistent with the assumptions, it is suggested that either the equation form is inadequate, some additional variables are required, or some of the data observations are outliers.

There has been one exception to this line of analysis. In the example based on the Supervisor data of Chapter 2, it was argued that the underlying model did not have residuals that were i.i.d. In particular, the residuals did not have constant variance. This situation (nonconstant residual variance) is often referred to as heteroscedasticity. The presence of unequal variances violates one of the basic ordinary least squares (OLS) assumptions. If OLS is applied, ignoring heteroscedasticity, the estimated coefficients are still unbiased, but are no longer best in the sense of precision (variance). For the Supervisor data, a transformation was imposed to correct the situation so that better estimates of the original model parameters could be obtained (better than OLS).

In this chapter and the one that follows, we investigate some regression situations where the underlying process implies that the regression residuals are not i.i.d. In the present chapter, heteroscedasticity is discussed. The problem is resolved by applying variations of weighted least squares (WLS). In the next chapter regression models with residuals that are not independent are treated. The approach in both situations is to use a combination of prior knowledge, intuition, and evidence found in the OLS residuals to detect the problem. The solution is usually prescribed as a two-stage procedure. In stage 1, the OLS residuals are used to estimate the parameters of the residual structure. In the second stage, these estimates are used to define a transformation or procedure that corrects for the lack of i.i.d. residuals and to produce estimates of the regression coefficients that usually have more precision than the OLS estimates.

5.2. HETEROSCEDASTIC MODELS

Three different heteroscedastic situations will be distinguished. The first two situations are fairly simple. In these two cases, once the necessity for WLS has been recognized, estimation can be accomplished in one step. The third situation is more complex and requires a two-stage estimation procedure. An example of the first heteroscedastic situation is found in Chapter 2 and will be reviewed here. The second situation is formulated, but no data is analyzed. The third heteroscedastic situation is demonstrated with two examples.

5.3. SUPERVISOR DATA

The first heteroscedastic situation has been treated in Chapter 2. There, data on X, the number of workers in an industrial establishment, and Y, the number of supervisors in the establishment were presented for 27 establishments. The regression model was

$$Y_i = \beta_0 + \beta_1 X_i + u_i. \tag{5.2}$$

It was argued that the variance of u_i depends on the size of the establishment as measured by X; that is, $\sigma_{u_i}^2 = k^2 X_i^2$ where k is a positive constant. (See Chapter 2 for details.) Empirical evidence for this type of heteroscedasticity is obtained by plotting the OLS residuals against X. A plot with the characteristics of Figure 5.1 typifies the situation. If corrective action is not taken and OLS is applied to the raw data, the resulting estimated coefficients will lack precision in a theoretical sense. In addition, for the type of heteroscedasticity present in this data, the estimated standard errors of the regression coefficients are often understated giving a false sense of precision. The problem is resolved by using a version of weighted least squares as described in Chapter 2.

This approach to heteroscedasticity may also be considered in multiple regression models. In Equation (5.1) the variance of the residuals may be affected by only one of the explanatory variables. (The case where the variance is a function of more than one explanatory variable is discussed

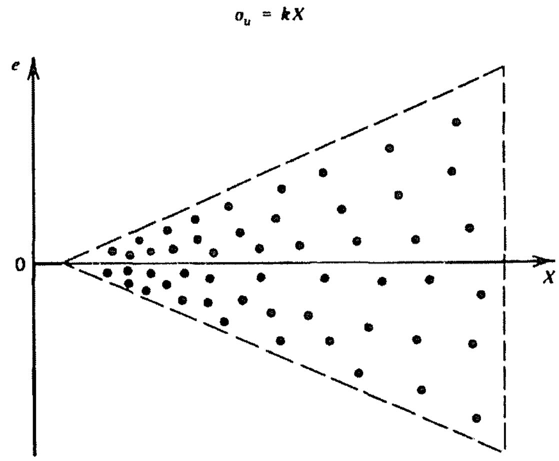


Fig. 5.1. Heteroscedastic residuals.

later.) Empirical evidence is available from the plot of OLS residuals versus the suspected variable and correction is accomplished by extending the method applied in Chapter 2. The resulting estimates are obtained by a transformation of the data. For example, if the original model is given as Equation (5.1) and it is found that $\sigma_{u_i} = kX_{4i}$, then the estimates are produced by regressing Y_i/X_{4i} against $1/X_{4i}, X_{1i}/X_{4i}, \ldots, X_{3i}/X_{4i}, X_{5i}/X_{4i}, \ldots, X_{pi}/X_{4i}$. The resulting coefficient of $1/X_{4i}$ is b_0, an estimate of β_0, the coefficient of X_{1i}/X_{4i} is an estimate of β_1, and so on, and the intercept from the regression is an estimate of β_4. Refer to Chapter 2 for a detailed discussion of this method as applied in simple regression.

5.4. COLLEGE EXPENSE DATA

A second heteroscedastic situation arises frequently with large-scale survey data where measurements on individual sampling units are averaged over a well-defined cluster of units in order to obtain increased stability. Only the average and number of sampling units are reported as data. For example, consider a survey of undergraduate college students (or their parents) that is intended to assess total annual college-related expenses. Assume that the survey is also intended to collect information that will make it possible to relate expenses to characteristics of the institution attended. Regression analysis may be used with a model such as

$$Y_i = \beta_0 + \beta_1 X_{1i} + \beta_2 X_{2i} + \cdots + \beta_6 X_{6i} + u_i. \tag{5.3}$$

The variables are defined in Table 5.1. The data may be collected by selecting a set of schools at random and then interviewing a prescribed number of randomly selected students at each school. The explanatory variables are characteristics of the school with the exception of X_6, which can be taken as an average over the student population. (The logic behind choosing these explanatory variables is left to the imagination of the reader.) Rather than using total expense Y for each student interviewed, the average expense for these students at each institution serves as the dependent variable. The precision of average expenditure is directly proportional to the square root of the sample size on which the average is based. That is, the variance of $\bar{Y}$ is σ^2/n and its standard deviation is $\sigma/\sqrt{n}$. If there are k institutions in the sample and $n_1, n_2, \ldots, n_k$ represent the number of students interviewed at each institution, the standard deviation of u_i in the model (Equation (5.1)) is $\sigma_{u_i} = \sigma/\sqrt{n_i}$ where σ is the standard deviation for annual expense for the population of individual students. Estimation of the regression coefficients is carried out using WLS with weights $w_i = 1/\sigma_{u_i}^2$ as in Chapter 2. Since $\sigma_{u_i}^2 = \sigma^2/n_i$, the regression coefficients are obtained by minimizing the weighted sum of squared residuals,

$$S = \sum_{i=1}^{k} n_i \left(Y_i - \beta_0 - \sum_{j=1}^{6} \beta_j X_{ji} \right)^2. \tag{5.4}$$

Note that the procedure implicitly recognizes that observations from institutions where a large number of students were interviewed are more reliable and should have more weight in determining the regression coefficients than observations from institutions where only a few students were interviewed. The differential precision associated with different observation may be taken as a justification for the weighting scheme.

The estimated coefficients and summary statistics may be computed

Table 5.1. Variables in cost of education survey

Name	Description
Y	Total annual expense (above tuition)
X_1	Size of city or town where school is located
X_2	Distance to nearest urban center
X_3	Type of school—public, private
X_4	Size of student body
X_5	Proportion of entering freshman that graduate
X_6	Distance from home

using a special WLS computer program or by transforming the data and using OLS as in the example in Chapter 2. If both sides of Equation (5.1) are multiplied by $n_i^{1/2}$, the new model will have residuals, $\epsilon_i = u_i \cdot n_i^{1/2}$ and $\sigma_{\epsilon_i} = \sigma$, a constant. That is, the regression model stated in the new variables is

$$Y_i n_i^{1/2} = \beta_0 n_i^{1/2} + \beta_1 X_{1i} n_i^{1/2} + \cdots + \beta_6 X_{6i} n_i^{1/2} + \epsilon_i. \tag{5.5}$$

The residuals in Equation (5.5) satisfy the necessary assumption of constant variance. Regression of $Y_i \cdot n_i^{1/2}$ against the seven new variables consisting of $n_i^{1/2}$, and the six transformed explanatory variables, $X_{ji} n_i^{1/2}$ using OLS will produce the desired estimates of the regression coefficients and their standard errors. Note that the regression with the transformed variables must be carried out with the constant term constrained to be zero. That is, β_0, the intercept of the original model is now the coefficient of $n_i^{1/2}$. Equation (5.5) has no intercept. More details on this point are given with the numerical example in section 5.6.

5.5. TWO-STAGE ESTIMATION

In the two preceding problems heteroscedasticity was expected at the outset. In the first problem the nature of the process under investigation suggests residual variances that increase with the size of the explanatory variable. In the second case, the method of data collection indicates heteroscedasticity. In both cases, homogeneity of variance is accomplished by a transformation. The transformation is constructed directly from information in the raw data. In the problem described in this section, there is also some prior indication that the variances are not equal. But here the exact structure of heteroscedasticity is determined empirically. As a result, estimation of the regression parameters requires two stages.

It is not a simple matter to detect heteroscedasticity in a general multiple regression situation. If present it is often discovered as a result of some good intuition on the part of the analyst on how observations may be grouped or clustered. For multiple regression models, the plot of residuals against $\hat{Y}_i$, the fitted values of the response variable, can serve as a first step. If the magnitude of the residuals appears to vary systematically with $\hat{Y}_i$, heteroscedasticity is suggested. The plot does not necessarily clearly identify the source of the problem. (See the following example.)

One direct method for investigating the presence of nonconstant variance is available when there are replicated measurements on the response variable corresponding to a set of fixed values of the explanatory variables. For example, in the case of one explanatory variable, we may have

NUMERICAL METHODS FOR LEAST SQUARES PROBLEMS

ÅKE BJÖRCK

Linköping University
Linköping, Sweden

siam.
Society for Industrial and Applied Mathematics
Philadelphia

10 9 8 7 6 5 4

Library of Congress Cataloging-in-Publication Data

Björck, Åke, 1934-
Numerical methods for least squares problems / Åke Björck.
p. cm.
Includes bibliographic references (p. -) and index.
ISBN 0-89871-360-9 (pbk.)
1. Equations, Simultaneous—Numerical solutions. 2. Least squares. I Title.
QA214.B56 1996
512.9'42—dc20 96-3908

Portions were adapted with permission from *Handbook of Numerical Analysis, Volume I, Least Squares Methods* by Åke Björck, © 1990, North-Holland, Amsterdam.

the above algorithm is numerically stable. The algorithm can be generalized in a straightforward way to rank deficient A and B. For details see Paige [627, 1979].

The algorithm above does not take advantage of any special structure the matrix B may have. If B has been obtained from the Cholesky factorization $W = BB^T$ it is of lower triangular form. In this case, and also when W is diagonal, it is advantageous to carry out the two QR decompositions in (4.3.19) and (4.3.21) together, maintaining the lower triangular form throughout. Paige [628, 1979] has given such a variation of the algorithm using a "zero chasing technique," with a careful sequencing of Givens transformations. With fast Givens rotations this requires a total of about $m^2n + 2mn^2 - 4n^3/3$ flops.

REMARK 4.3.2. In some applications, notably from interior point methods, one needs to solve a sequence of problems of the form (4.3.12), with A constant but $B = B_k$, $k = 1, \ldots, p$. The QR decomposition (4.3.19) can then be computed once and for all. In case $m = n$ this reduces the work for solving an additional problem from $5n^3/3$ to n^3.

4.4. Weighted Least Squares Problems

4.4.1. Introduction. In this section we consider the special linear model (4.3.1) where the components in the random error vector ϵ are uncorrelated. In this case the covariance matrix W is a positive diagonal matrix

$$W = \operatorname{diag}(w_1, w_2, \ldots, w_m) > 0.$$

The corresponding least squares problem, $\min_x (Ax - b)^T W^{-1}(Ax - b)$, can be written as a **weighted linear least squares problem**

$$\min_x \|D(Ax - b)\|_2, \tag{4.4.1}$$

where we have introduced the diagonal **weight matrix**

$$D = W^{-1/2} = \operatorname{diag}(d_1, d_2, \ldots, d_m).$$

In many cases it is possible to solve (4.4.1) as a standard linear least squares problem

$$\min_x \|\tilde{A}x - \tilde{b}\|_2, \quad \tilde{A} = DA, \quad \tilde{b} = Db.$$

However, in applications where the weights $d_1, \ldots, d_m$ vary widely in size this is not generally a numerically stable approach.

Note that the weight matrix in (4.4.1) is not unique. Therefore we will in the following assume that the matrix A has been row equilibrated, that is,

$$\max_{1 \le j \le n} |a_{ij}| = 1, \qquad i = 1, \ldots, m.$$

We also assume here and in the following that the rows of A are ordered so that the weights satisfy

$$\infty > d_1 \ge d_2 \ge \cdots \ge d_m > 0. \tag{4.4.2}$$

Then $d_1/d_m = \gamma \gg 1$ corresponds to the case when some components of the error vector in the linear model have much smaller variance than the rest, and we call such weighted problems **stiff**. Note that in the limit when some d_i tend to infinity, the corresponding ith equation becomes a linear constraint.

For stiff problems the condition number $\kappa(DA)$ will be large. An upper bound is given by

$$\kappa(DA) \leq \kappa(D)\kappa(A) = \gamma\kappa(A).$$

It is important to note that this does *not* mean that the problem of computing x from given data $\{D, A, b\}$ is ill-conditioned. For the weighted problem (4.4.1) the perturbations in DA and Db will have a special form, and the normwise perturbation analysis given in Section 1.4.2 is not relevant; see Remark 1.4.3. However, that $\kappa(DA) \gg 1$ correctly warns us that special care may be needed in solving stiff weighted linear least squares problems.

REMARK 4.4.1. Problems with extremely ill-conditioned weight matrices arise, e.g., in electrical networks, certain classes of finite element problems, and interior point methods for constrained optimization. Vavasis [806, 1994] and Hough and Vavasis [474, 1994] have developed special methods for such applications, which satisfy a strong type of stability. ∎

It is easily seen that in general the method of normal equations is not well suited for solving stiff problems. To illustrate this, we consider the important special case where only the first p equations are weighted:

$$\min_x \left\| \begin{pmatrix} \gamma A_1 \\ A_2 \end{pmatrix} x - \begin{pmatrix} \gamma b_1 \\ b_2 \end{pmatrix} \right\|_2^2, \tag{4.4.3}$$

$A_1 \in \mathbf{R}^{p \times n}$ and $A_2 \in \mathbf{R}^{(m-p) \times n}$. Such problems occur, for example, when the method of weighting is used to solve least squares problems with the linear equality constraints $A_1 x = b_1$; see Section 5.1.4. For this problem the matrix of normal equations becomes

$$B = \begin{pmatrix} \gamma A_1^T & A_2^T \end{pmatrix} \begin{pmatrix} \gamma A_1 \\ A_2 \end{pmatrix} = \gamma^2 A_1^T A_1 + A_2^T A_2.$$

If $\gamma > u^{-1/2}$ (u is the unit roundoff) and $A_1^T A_1$ is dense, then $B = A^T A$ will be completely dominated by the first term and the data contained in A_2 may be lost. However, if the number p of very accurate observations is less than n, then the solution depends critically on the less precise data in A_2. (The matrix in Example 2.2.1 is of this type.) We conclude that for weighted least squares problems with $\gamma \gg 1$ the method of normal equations generally is not well behaved.

4.4.2. Methods based on Gaussian elimination. In Section 2.5 several methods based on a preliminary factorization by Gaussian elimination were discussed. In the Peters–Wilkinson method (see Section 2.5.1) A is first reduced by Gaussian elimination to upper triangular form. It was pointed out by Björck and Duff [104, 1980] that this method is suitable for weighted problems.

Assume that $\operatorname{rank}(A_1) = p$, and that p steps of Guassian elimination are performed on the weighted matrix $\tilde{A} = DA$ using row and column pivoting. Then the resulting factorization can be written

$$\Pi_1 \tilde{A} \Pi_2 = L_p D U_p, \tag{4.4.4}$$

where Π_1 and Π_2 are permutation matrices,

$$L_p = \begin{pmatrix} L_{11} & \\ L_{21} & L_{22} \end{pmatrix} \in \mathbf{R}^{m\times n}, \quad U_p = \begin{pmatrix} U_{11} & U_{12} \\ & I \end{pmatrix} \in \mathbf{R}^{n\times n},$$

$L_{11} \in \mathbf{R}^{p\times p}$ is unit lower triangular, and $U_{11} \in \mathbf{R}^{p\times p}$ unit upper triangular. Assuming that $\tilde{A}$ has full rank, D is nonsingular. Then (4.4.1) is equivalent to

$$\min_y \|L_p y - \Pi_1 \tilde{b}\|_2, \qquad U_p \Pi_2^T x = D^{-1} y.$$

This least squares problem is usually well-conditioned, since any ill-conditioning in $\tilde{A}$ is usually reflected in U. We illustrate the method in a simple example.

EXAMPLE 4.4.1. In Example 2.2.1 it was shown that the method of normal equations failed for the problem of Läuchli [517, 1961]. After multiplication with $\gamma = \epsilon^{-1}$ this becomes

$$A = \begin{pmatrix} \gamma & \gamma & \gamma \\ 1 & & \\ & 1 & \\ & & 1 \end{pmatrix}, \qquad b = \begin{pmatrix} \gamma \\ 0 \\ 0 \\ 0 \end{pmatrix},$$

which is of the form (4.4.3) with $p = 1$. After one step of Gaussian elimination we obtain the factorization $A = L_1 D_1 U_1$, where

$$L_1 = \begin{pmatrix} 1 & & \\ \gamma^{-1} & -1 & -1 \\ & 1 & \\ & & 1 \end{pmatrix}, \qquad D_1 U_1 = \begin{pmatrix} \gamma & \gamma & \gamma \\ & 1 & \\ & & 1 \end{pmatrix}.$$

It is easily verified that L_1 is well-conditioned, and the solution can be accurately obtained by solving $L_1^T L_1 y = L_1^T b$, and back-substitution $D_1 U_1 x = y$. ∎

In general, for a problem of the form (4.4.3) the LU factorization (4.4.4) will have the form

$$\begin{pmatrix} \gamma A_1 \\ A_2 \end{pmatrix} = \begin{pmatrix} L_{11} & \\ \frac{1}{\gamma} L_{21} & L_{22} \end{pmatrix} \begin{pmatrix} \gamma U_{11} & \gamma U_{12} \\ & I \end{pmatrix} \equiv L(DU), \tag{4.4.5}$$

where the blocks L_{ij} and U_{ij} are $O(1)$, and $L_{22} \in \mathbf{R}^{(m-p)\times(n-p)}$ is the reduced matrix. The normal equations for $y = (DU)x$ then equal $L^T L y = L^T b$, where

$$\begin{aligned} L^T L &= \begin{pmatrix} L_{11}^T L_{11} + \frac{1}{\gamma^2} L_{21}^T L_{21} & \frac{1}{\gamma} L_{21}^T L_{22} \\ \frac{1}{\gamma} L_{22}^T L_{21} & L_{22}^T L_{22} \end{pmatrix}, \\ L^T b &= \begin{pmatrix} \gamma L_{11}^T b_1 + \frac{1}{\gamma} L_{21}^T b_2 \\ L_{22}^T b_1 \end{pmatrix}. \end{aligned}$$

For $\gamma \gg 1$ the matrix $L^T L$ is almost block diagonal and its condition number is to first approximation independent of γ. If we let R_{11} and R_{22} be the Cholesky factors of $L_{11}^T L_{11}$ and $L_{22}^T L_{22}$, respectively, then the Cholesky factor of $L^T L$ will have the form

$$R = (1 + O(\gamma^{-2})) \begin{pmatrix} R_{11} & \frac{1}{\gamma}(L_{21}R_{11}^{-1})^T L_{22} \\ & R_{22} \end{pmatrix};$$

cf. Stewart [742, 1984]. After solving $RR^T y = L^T b$ the least squares solution is obtained from $DUx = y$, giving

$$x_2 = y_2, \qquad U_{11}x_1 = \frac{1}{\gamma}y_1 - U_{12}y_2.$$

For the weighted least squares problem the augmented system (4.3.16) has the form

$$\begin{pmatrix} \alpha W & A \\ A^T & 0 \end{pmatrix} \begin{pmatrix} \alpha^{-1} r \\ x \end{pmatrix} = \begin{pmatrix} b \\ 0 \end{pmatrix}, \tag{4.4.6}$$

where $W = D^{-2}$. The scaling factor α has been introduced for stability reasons; see Section 2.5.2. As before we assume that D has been chosen so that A is *row equilibrated*, which will tend to lower the condition of A. Further results on the prescaling of A before using the augmented system method are given in Duff [239, 1994]. The system can be solved by using the Bunch–Kaufman factorization described in Section 2.5.2. An advantage with this formulation is that linear constraints can be treated by letting $w_i = 0$ in (4.4.6).

A problem with this approach is that it is not easy to get an a priori estimate of the optimal value of α for stability. A second drawback with the method outlined in this section is that it works with a system of order $m + n$, which may be much larger than n. Therefore, the main use of this method seems to be for sparse problems, where the sparsity of the block I can be taken into account; see Arioli, Duff, and de Rijk [20, 1989].

4.4.3. QR decompositions for weighted problems. We now consider the use of methods based on the QR decomposition of A for solving weighted problems. We first examine the Householder QR method, and show by an example that this method can give poor accuracy for stiff problems unless the algorithm is extended to include *row interchanges*.

EXAMPLE 4.4.2. (See Powell and Reid [670, 1969].) Consider the problem $\min_x \|Ax - b\|_2$, where

$$A = \begin{pmatrix} 0 & 2 & 1 \\ \gamma & \gamma & 0 \\ \gamma & 0 & \gamma \\ 0 & 1 & 1 \end{pmatrix}, \qquad b = \begin{pmatrix} 2 \\ 2\gamma \\ 2\gamma \\ 2 \end{pmatrix},$$

with exact solution equal to $x = (1, 1, 1)$. Using exact arithmetic we obtain after the first step of QR decomposition of A by Householder transformations

(Algorithm 2.4.1) the reduced matrix

$$\tilde{A}^{(2)} = \begin{pmatrix} \frac{1}{2}\gamma - 2^{1/2} & -\frac{1}{2}\gamma - 2^{-1/2} \\ -\frac{1}{2}\gamma - 2^{1/2} & \frac{1}{2}\gamma - 2^{-1/2} \\ 1 & 1 \end{pmatrix}.$$

If $\gamma > u^{-1}$ the terms $-2^{1/2}$ and $-2^{-1/2}$ in the first and second rows are lost. However, this is equivalent to the loss of all information present in the first row of A. This loss is disastrous because the number of rows containing large elements is less than the number of components in x, so there is a substantial dependence of the solution x on the first row of A. (However, compared to the method of normal equations, which fails already when $\gamma > u^{-1/2}$, this is an improvement!) ∎

Van Loan [799, 1985] has given several examples illustrating that solving

$$\min_x \left\| \begin{pmatrix} A_2 \\ \gamma A_1 \end{pmatrix} x - \begin{pmatrix} b_2 \\ \gamma b_1 \end{pmatrix} \right\|_2^2 \tag{4.4.7}$$

instead of (4.4.3) with Householder will give bad accuracy for large values of γ.

It is also essential that *column pivoting* is performed when QR decomposition is used for weighted problems. Van Loan [799, 1985] gives an example of the form (4.4.3), where

$$A_1 = \begin{pmatrix} 1 & 1 & 1 \\ 1 & 1 & -1 \end{pmatrix},$$

to illustrate the need for column pivoting. Stability is lost here without column pivoting because the first two columns of the matrix A_1 are linearly dependent. When column pivoting is introduced this difficulty disappears.

Powell and Reid [670, 1969] extended the Householder algorithm to include *row interchanges*. In each step a pivot column is first selected in the reduced matrix, and then the element of largest absolute value in the pivot column is permuted to the top. Powell and Reid give an error analysis for this algorithm which shows that it has good stability properties for stiff problems as well.

It seems that there is no need to perform row pivoting in Householder QR, provided that the rows are sorted after decreasing row norm before the factorization, so that the weights satisfy (4.4.2). For example, if in Example 4.4.2 the two large rows are permuted to the top of the matrix A, then the Householder algorithm works well.

An approach related to that of Powell and Reid is taken by Gulliksson and Wedin [413, 1992]. They use scaled Householder transformations $\tilde{P}$ which are W invariant, i.e., satisfy

$$\tilde{P} W \tilde{P}^T = W = \operatorname{diag}(w_1, \ldots, w_m). \tag{4.4.8}$$

It is easy to verify that P must have the form

$$P = I - 2Wvv^T/(v^T W v), \qquad P^2 = I,$$

i.e., P is a reflector. Note that $W^{-1/2}PW^{1/2}$ is an orthogonal reflector.

A sequence of W invariant reflectors is used to transform $A\Pi$, where Π is a permutation matrix, to upper triangular form,

$$Q^T A\Pi = \begin{pmatrix} R \\ 0 \end{pmatrix}, \qquad Q^T = P_n \cdots P_2 P_1.$$

This is equivalent to the ordinary QR factorization

$$W^{-1/2}A\Pi = (W^{-1/2}QW^{1/2}) \begin{pmatrix} W^{-1/2}R \\ 0 \end{pmatrix}.$$

When $W > 0$ this method is equivalent to the algorithm of Powell and Reid. However, this approach generalizes simply to the case when W has the form $W = \operatorname{diag}(0, W_2)$, which corresponds to a constrained least squares problem. A backward error analysis of this method has been given by Gulliksson [410, 1995].

In contrast to the Householder QR method, the modified Gram–Schmidt (MGS) method is numerically invariant under row interchanges (except for effects deriving from different summation orders in the computed inner products). In particular, for problems of the special form (4.4.3) MGS will give accurate solutions independent of row ordering if γ is chosen optimally. However, as illustrated by the numerical results by Anda and Park [15, 1996], MGS will lose accuracy for very large values of γ. Gulliksson [411, 1995] has made a detailed study of the numerical stability of MGS for weighted problems.

Anda and Park [15, 1995] have studied the use of Givens QR algorithms for stiff least squares problems, and developed self-scaling fast plane rotations for such problems. They show that both fast and standard Givens rotations produce accurate results regardless of row sorting.

The following example from [15] illustrates the effect of row sorting in Givens rotation. Let $\gamma \gg 1$, and

$$A = \begin{pmatrix} a_{pp} & a_{pq} \\ \gamma a_{qp} & \gamma a_{qq} \end{pmatrix}, \qquad \bar{A} = \begin{pmatrix} \gamma \bar{a}_{pp} & \gamma \bar{a}_{pq} \\ \bar{a}_{qp} & \bar{a}_{qq} \end{pmatrix}.$$

The Givens transformations that zero the elements a'_{qp} and $\bar{a}'_{qp}$ in $A' = GA$, and $\bar{A}' = \bar{G}\bar{A}$, respectively, are (see (2.3.13))

$$G = \frac{1}{\sigma}\begin{pmatrix} a_{pp} & \gamma a_{qp} \\ -\gamma a_{qp} & a_{pp} \end{pmatrix}, \qquad \bar{G} = \frac{1}{\bar{\sigma}}\begin{pmatrix} \gamma \bar{a}_{pp} & \bar{a}_{qp} \\ -\bar{a}_{qp} & \gamma \bar{a}_{pp} \end{pmatrix},$$

where $\sigma = \sqrt{a_{pp}^2 + \gamma^2 a_{qp}^2}$ and $\bar{\sigma} = \sqrt{\gamma^2 \bar{a}_{pp}^2 + \bar{a}_{qp}^2}$. In each case the more heavily weighted row of the resulting matrix GA and $\bar{G}\bar{A}$ is in top position regardless of its initial position. Hence a sequence of rotations will move rows of large norms to the top of the matrix. The numerical results of Anda and Park also showed that the self-scaling rotations maintained high accuracy for extremely large values of γ. Their tests also showed no significant difference in accuracy between different rotation orderings.

ECONOMETRIC METHODS

Third Edition

J. Johnston

University of California, Irvine

McGraw-Hill Book Company

New York St. Louis San Francisco Auckland Bogotá Hamburg Johannesburg London Madrid Mexico Montreal New Delhi Panama Paris São Paulo Singapore Sydney Tokyo Toronto

In Memory of
B. and J.

This book was set in Times Roman by Science Typographers, Inc.
The editors were Patricia A. Mitchell and Scott Amerman;
the cover was designed by Nadja Furlan;
the production supervisor was Phil Galea.
The drawings were done by Burmar.
Halliday Lithograph Corporation was printer and binder.

ECONOMETRIC METHODS

1 2 3 4 5 6 7 8 9 0 HALHAL 8 9 8 7 6 5 4

ISBN 0-07-032685-1

Library of Congress Cataloging in Publication Data

Johnston, J. (John), date
Econometric methods.

Includes bibliographical references and index.
1. Econometrics. I. Title.
HB139.J65 1984 330'.028 83-14899
ISBN 0-07-032685-1

Maximizing $\ln L$ with respect to $\boldsymbol{\beta}$ implies minimizing the weighted sum of squares

$$(\mathbf{y} - \mathbf{X}\boldsymbol{\beta})'\boldsymbol{\Omega}^{-1}(\mathbf{y} - \mathbf{X}\boldsymbol{\beta}) = \mathbf{y}'\boldsymbol{\Omega}^{-1}\mathbf{y} - 2\boldsymbol{\beta}'\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{y} + \boldsymbol{\beta}'\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{X}\boldsymbol{\beta}$$

Differentiating with respect to $\boldsymbol{\beta}$ and equating to zero gives

$$\mathbf{b}_* = (\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{X})^{-1}\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{y}$$

as in Eq. (8-18).

An unbiased estimator of σ^2 may be derived from the application of OLS to Eq. (8-14). It is

$$\begin{aligned} s^2 &= \frac{(\mathbf{Ty} - \mathbf{TXb}_*)'(\mathbf{Ty} - \mathbf{Txb}_*)}{n-k} \\ &= \frac{(\mathbf{y} - \mathbf{Xb}_*)'\mathbf{T}'\mathbf{T}(\mathbf{y} - \mathbf{Xb}_*)}{n-k} \\ &= \frac{(\mathbf{y} - \mathbf{Xb}_*)'\boldsymbol{\Omega}^{-1}(\mathbf{y} - \mathbf{Xb}_*)}{n-k} \\ &= \frac{\mathbf{y}'\boldsymbol{\Omega}^{-1}\mathbf{y} - \mathbf{b}_*'\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{y}}{n-k} \end{aligned} \tag{8-22}$$

On the assumption of normality for the disturbance term all the inference procedures of Chaps. 5 and 6 carry through for this model. Thus the test of

$$H_0: \quad \mathbf{R}\boldsymbol{\beta} = \mathbf{r}$$

is based on

$$F = \frac{(\mathbf{r} - \mathbf{Rb}_*)'\left[\mathbf{R}(\mathbf{X}'\boldsymbol{\Omega}^{-1}\mathbf{X})^{-1}\mathbf{R}'\right]^{-1}(\mathbf{r} - \mathbf{Rb}_*)/q}{s^2}$$

having the $F(q, n-k)$ distribution under the null hypothesis, where $\mathbf{b}_*$ is the GLS estimator defined in Eq. (8-18) and s^2 the variance estimator defined in Eq. (8-22).

The above formulas are only operational if the elements of $\boldsymbol{\Omega}$ are known. In some exceptional cases this may be so, but in most practical cases it is not. We must therefore proceed to the development of operational procedures for such cases, but there is, in fact, no single procedure which is generally applicable. One must look for the procedure which is best suited to the features of each specific problem in turn, and that is done in the remaining sections of this chapter.

8-4 HETEROSCEDASTICITY

We have already mentioned in Sec. 8-1 the possibility of heteroscedastic disturbances in *cross-section* studies. Heteroscedasticity may also arise in dealing with grouped data. Suppose the model is

$$Y_t = \alpha + \beta X_t + u_t \qquad t = 1, \ldots, n$$

where the u_t are homoscedastic with zero covariances. However, suppose we only have access to data which have been averaged within m groups, where n_i indicates the number of observations in the ith group. The form of the model appropriate to the data is now

$$\bar{Y}_i = \alpha + \beta \bar{X}_i + \bar{u}_i$$

and clearly

$$\operatorname{var}(\bar{u}_i) = \frac{\sigma^2}{n_i} \qquad i = 1, \ldots, m$$

Thus

$$\sigma^2 \Omega = \sigma^2 \begin{bmatrix} \frac{1}{n_1} & 0 & \cdots & 0 \\ 0 & \frac{1}{n_2} & \cdots & 0 \\ \cdots & \cdots & \cdots & \cdots \\ 0 & 0 & \cdots & \frac{1}{n_m} \end{bmatrix} \tag{8-23}$$

where Ω is known and the GLS estimator can easily be computed.

Example 8-1 We have taken the same X, Y data as in Example 2-1, only now it is assumed that they relate to group means. The n_i column indicates the number of observations in each group. The overall means are easily computed from

$$\bar{X} = \frac{\Sigma n_i \bar{X}_i}{\Sigma n_i} = \frac{202}{50} = 4.04$$

$$\bar{Y} = \frac{\Sigma n_i \bar{Y}_i}{\Sigma n_i} = \frac{400}{50} = 8.00$$

which are almost identical with the simple means of 4 and 8 in Table 2-1. We assume that Eq. (8-23) is the appropriate assumption about var($\bar{\mathbf{u}}$), that is,

$$\operatorname{var}(\bar{\mathbf{u}}) = \sigma^2 \Omega = \sigma^2 \begin{bmatrix} \frac{1}{n_1} & & & \\ & \frac{1}{n_2} & & \\ & & \ddots & \\ & & & \frac{1}{n_5} \end{bmatrix}$$

Thus

$$\Omega^{-1} = \begin{bmatrix} n_1 & & & \\ & n_2 & & \\ & & \ddots & \\ & & & n_5 \end{bmatrix} = \begin{bmatrix} 12 & & & & \\ & 6 & & & \\ & & 11 & & \\ & & & 10 & \\ & & & & 11 \end{bmatrix}$$

It may then be seen that

$$\mathbf{X}'\Omega^{-1}\mathbf{X} = \begin{bmatrix} 1 & 1 & \cdots & 1 \\ \overline{X}_1 & \overline{X}_2 & \cdots & \overline{X}_5 \end{bmatrix} \begin{bmatrix} n_1 & & & \\ & n_2 & & \\ & & \ddots & \\ & & & n_5 \end{bmatrix} \begin{bmatrix} 1 & \overline{X}_1 \\ 1 & \overline{X}_2 \\ \vdots & \vdots \\ 1 & \overline{X}_5 \end{bmatrix}$$

$$= \begin{bmatrix} \Sigma n_i & \Sigma n_i \overline{X}_i \\ \Sigma n_i \overline{X}_i & \Sigma n_i \overline{X}_i^2 \end{bmatrix}$$

and

$$\mathbf{X}'\Omega^{-1}\mathbf{y} = \begin{bmatrix} \Sigma n_i \overline{Y}_i \\ \Sigma n_i \overline{X}_i \overline{Y}_i \end{bmatrix}$$

Formula (8-18) for the GLS estimator now simplifies to

$$\begin{bmatrix} \Sigma n_i & \Sigma n_i \overline{X}_i \\ \Sigma n_i \overline{X}_i & \Sigma n_i \overline{X}_i^2 \end{bmatrix} \mathbf{b}_* = \begin{bmatrix} \Sigma n_i \overline{Y}_i \\ \Sigma n_i \overline{X}_i \overline{Y}_i \end{bmatrix}$$

which is a form of weighted least squares. Applying the data from Table 8-1 gives

$$50b_{1*} + 202b_{2*} = 400$$

$$202b_{1*} + 1254b_{2*} = 2388$$

with solution $b_{1*} = 0.88$ and $b_{2*} = 1.76$. To obtain the sampling variance of these estimates, substitute for Ω^{-1} from Eq. (8-23) in Eq. (8-22) to obtain for

Table 8-1

$\overline{X}_i$	$\overline{Y}_i$	n_i	$n_i\overline{X}_i$	$n_i\overline{Y}_i$	$n_i\overline{X}_i^2$	$n_i\overline{X}_i\overline{Y}_i$	$n_i\overline{Y}_i^2$
2	4	12	24	48	48	96	192
3	7	6	18	42	54	126	294
1	3	11	11	33	11	33	99
5	9	10	50	90	250	450	810
9	17	11	99	187	891	1683	3179
Sums		50	202	400	1254	2388	4574

this example

$$
\begin{aligned}
(n-k)s^2 &= \Sigma n_i \bar{Y}_i^2 - [b_{1*} \quad b_{2*}] \begin{bmatrix} \Sigma n_i \bar{Y}_i \\ \Sigma n_i \bar{X}_i \bar{Y}_i \end{bmatrix} \\
&= 4574 - [0.8791 \quad 1.7626] \begin{bmatrix} 400 \\ 2388 \end{bmatrix} \\
&= 13.2712
\end{aligned}
$$

Thus
$$s^2 = \frac{13.2712}{3} = 4.4237$$

Notice that the n which occurs in the denominator of the variance formula, Eq. (8-22), is the number of sample points. It is *not* the total number of observations underlying the sample points. In this example, the latter number is $\Sigma n_i = 50$, but $n = 5$. Finally, substitution in Eq. (8-19) gives

$$
\begin{aligned}
\operatorname{var}(\mathbf{b}_*) &= s^2(\mathbf{X}'\mathbf{\Omega}^{-1}\mathbf{X})^{-1} \\
&= 4.4237 \begin{bmatrix} 50 & 202 \\ 202 & 1254 \end{bmatrix}^{-1} \\
&= 4.4237 \begin{bmatrix} 0.057271 & -0.009225 \\ -0.009225 & 0.002284 \end{bmatrix} \\
&= \begin{bmatrix} 0.2533 & -0.0408 \\ -0.0408 & 0.0101 \end{bmatrix}
\end{aligned}
$$

Thus
$$\operatorname{var}(b_{1*}) = 0.2533$$
$$\operatorname{var}(b_{2*}) = 0.0101$$

This example might have been treated equivalently by finding the $\mathbf{T}$ matrix satisfying $\mathbf{T}'\mathbf{T} = \mathbf{\Omega}^{-1}$. Given $\mathbf{\Omega}^{-1}$, the $\mathbf{T}$ matrix is simply

$$
\mathbf{T} = \begin{bmatrix} \sqrt{n_1} & & & \\ & \sqrt{n_2} & & \\ & & \ddots & \\ & & & \sqrt{n_5} \end{bmatrix}
$$

Thus the data of Table 8-1 could have been recorded as

X_i	$2\sqrt{12}$	$3\sqrt{6}$	$1\sqrt{11}$	$5\sqrt{10}$	$9\sqrt{11}$
Y_i	$4\sqrt{12}$	$7\sqrt{6}$	$3\sqrt{11}$	$9\sqrt{10}$	$17\sqrt{11}$

and OLS applied to these five pairs of numbers.

A different variant of a cross-section study is one with *replication* of the Y variable for given values of X. Suppose, for instance, that agronomists are investigating the variation of crop yield in response to varying applications of fertilizer. Let $X_1, \ldots, X_i, \ldots, X_m$ denote the different fertilizer dosages chosen for

Applied Econometrics

Potluri Rao Roger LeRoy Miller
University of Washington

Wadsworth Publishing Company, Inc., Belmont, California

L. C. Cat. Card No.: 71-147193
ISBN-0-534-00031-2
Printed in the United States of America

5 6 7 8 9 10--80 79 78

When the left-out variable is qualitative in nature, it is usually orthogonal to the independent variables and is often detected by the clustering of the residuals.

5.4 Heteroscedastic Residuals

Textbooks in econometrics often recommend plotting the residuals against the independent variables to check for heteroscedasticity. In some cases this may lead to wrong conclusions.

Heteroscedasticity relates to the *variance* of the error terms and not to patterns in the *values* of the error terms. The researcher expects to find the nature of the error of the variance of the error terms from the variance of the residuals. Since the number of residuals (observations) in a typical econometric research project is not large enough to accommodate any powerful techniques of test procedures based on inferences about the true variance, the researcher has to resort to other measures of dispersion.

A common measure in such situations is the range—the difference between minimum and maximum in a given subgroup. When the residuals are arranged according to a sequence believed to have caused heteroscedasticity, the researcher expects the range of the residuals to change when heteroscedasticity actually is present. There are several ways of approaching this problem; a commonly used procedure is to draw the envelope of all the residuals, as shown in Figure 5.3.

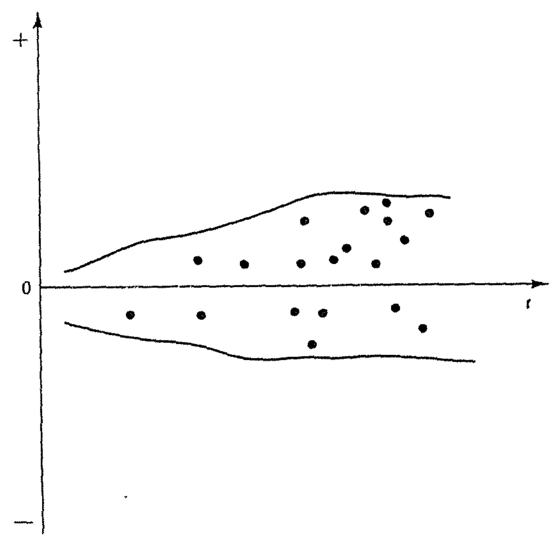


Figure 5.3. Envelope of Residuals

If the envelope expands or contracts systematically with respect to the arrangement of the residuals, then heteroscedasticity may be suspected. But this conclusion is valid only when the observations are reasonably large. In small samples, even though there is no heteroscedasticity in the true error terms, it may often be observed in the residuals arranged with respect to any of the independent variables in the regression that generated them. As we will now show, this is a consequence of the least squares estimation procedure; the researcher should guard against the possible misinterpretation of this phenomenon.

Consider the true relation

$$y_t = \beta x_t + \varepsilon_t, \tag{5.1}$$

where all the error terms (ε's) are randomly generated by the same statistical distribution with mean zero and variance σ_ε^2, and the variables are deviation from the means.

The residuals in the ordinary least squares estimation of (5.1) are

$$e_t = y_t - \hat{\beta} x_t. \tag{5.2}$$

Using (5.1) and the expression for the least squares estimation of $\hat{\beta}$ we obtain

$$e_t = \beta x_t + \varepsilon_t - \left(\sum x_t y_t / \sum x_t^2\right) x_t \tag{5.3}$$

$$= \varepsilon_t - \left(x_t \cdot \sum x_t \varepsilon_t\right) / \sum x_t^2. \tag{5.4}$$

Since the residual e_t has a statistical distribution with mean zero, the variance of the distribution is

$$V(e_t) = E(e_t^2), \tag{5.5}$$

which, by using (5.4), equals

$$E\left[\varepsilon_t^2 + \frac{x_t^2\left(\sum x_t \varepsilon_t\right)^2}{\left(\sum x_t^2\right)^2} - 2 \cdot \frac{x_t \varepsilon_t \left(\sum x_t \varepsilon_t\right)}{\sum x_t^2}\right]. \tag{5.6}$$

Under the assumptions that the errors are serially independent and that the x's are nonstochastic (fixed in repeated samples) we obtain

$$V(e_t) = \sigma_\varepsilon^2 + \frac{x_t^2 \cdot \sigma_\varepsilon^2 \cdot \sum x_t^2}{(\sum x_t^2)^2} - \frac{2x_t^2\sigma_\varepsilon^2}{\sum x_t^2} \tag{5.7}$$

$$= \sigma_\varepsilon^2 \cdot \left\{1 - \frac{x_t^2}{\sum x_t^2}\right\}. \tag{5.8}$$

Realizing that $V(\varepsilon) = \sigma_\varepsilon^2$, we note that the variance of the residuals is not the same as that of error terms; $V(e)$ depends on the values of x:

$$V(e_t) = V(\varepsilon_t) \cdot \left\{1 - \frac{x_t^2}{\sum x_t^2}\right\}. \tag{5.9}$$

If the error terms are homoscedastic and random, the residual corresponding to a given value of x has a statistical distribution with mean zero and variance (5.9). The variance of the residual depends on the value of x, even though the variance of the error term does not. The three-sigma limits for the error term and residuals differ for various values of x, as shown in Figure 5.4. If the researcher interprets the observed behavior of residuals as the behavior of errors, he may reach the wrong conclusion. It is advisable first to draw the expected three-sigma limits for the residuals on the basis of the maximum and the minimum values of the independent variable and on $\sum x_t^2$, before plotting the residuals against an independent variable as a search procedure for locating heteroscedasticity of the error terms.

When $\sum x_t^2$ is very large *compared* to the largest magnitude of observed x, the three-sigma limits for the residuals approach the three-sigma limits for the error terms.

In some empirical work the theory clearly indicates the nature of the variance of the error term. When the theory specifies heteroscedasticity in the error terms then, of course, there is no need to search the residuals. Consider, for example, the case of an investment decision function in the Indian engineering industry (see p. 101 for the notation). For each firm, let the investment decision function be

$$I_j = \beta_0 + \beta_1 S_j + \beta_2 P_j + \varepsilon_j, \tag{5.10}$$

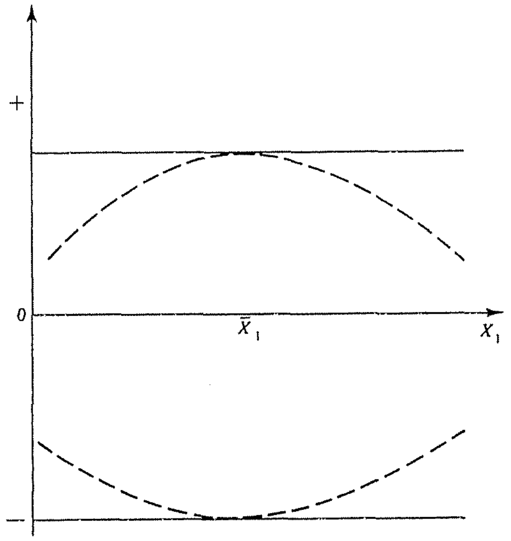


Figure 5.4. Three-Sigma Limits for Error Term and Residuals

where j denotes the jth firm. Let us assume that the variance of the error term for each firm is the same, σ^2.

When data are available for each firm then, of course, there is no problem of heteroscedasticity. But the data in each year relate to aggregates of several numbers of firms, and the number is not the same for all the time periods under investigation. For example there were 54 firms in 1950 and 131 in 1965. Since the data correspond to aggregates, we may express equation (5.10) in terms of the aggregates as

$$\sum_j I_j = \sum_j \beta_0 + \beta_1 \sum_j S_j + \beta_2 \sum_j P_j + \sum_j \varepsilon_j . \tag{5.11}$$

Let N_t be the number of firms for the year t. When the aggregates corresponding to year t are denoted by a subscript t, the investment decision function in terms of the aggregates may be written as

$$I_t = \beta_0 N_t + \beta_1 S_t + \beta_2 P_t + \varepsilon_t . \tag{5.12}$$

Even though equation (5.10) is homoscedastic, equation (5.12) is not. According to the Gauss-Markov theorem, estimation of (5.12) by ordinary least squares does not yield the minimum-variance unbiased estimates of the parameters (β's). However, by a suitable transformation of the variables we may reduce equation (5.12) to a Gauss-Markov case. Consider the variance of the error term ε_t:

$$V(\varepsilon_t) = V(\sum \varepsilon_j) = N_t \cdot \sigma^2, \tag{5.13}$$

since the error terms for each firm are independent of the errors in the other firms.

Suppose we define a new error term ε_t^* as

$$\varepsilon_t^* = \varepsilon_t / \sqrt{N_t}. \tag{5.14}$$

Its variance is

$$V(\varepsilon_t^*) = \sigma^2. \tag{5.15}$$

The transformed error term ε^* has the same variance for all t. Therefore, if we can express equation (5.12) in terms of ε^* the Gauss-Markov theorem holds and we obtain the minimum-variance unbiased estimates of β's by using ordinary least squares. Suppose we divide equation (5.12) by $\sqrt{N_t}$:

$$\frac{I_t}{\sqrt{N_t}} = \beta_0 \frac{N_t}{\sqrt{N_t}} + \beta_1 \frac{S_t}{\sqrt{N_t}} + \beta_2 \frac{P_t}{\sqrt{N_t}} + \frac{\varepsilon_t}{\sqrt{N_t}}. \tag{5.16}$$

By rewriting, (5.16) becomes

$$\frac{I_t}{\sqrt{N_t}} = \beta_0 \sqrt{N_t} + \beta_1 \frac{S_t}{\sqrt{N_t}} + \beta_2 \frac{P_t}{\sqrt{N_t}} + \varepsilon_t^*. \tag{5.17}$$

Equation (5.17) satisfies the Gauss-Markov conditions, hence ordinary least squares estimation of (5.17) provides best linear unbiased estimates.

Since the parameters of (5.12) are the same as those of (5.17), the $\hat{\beta}_0$ from (5.17) is the estimate of the constant term in equation (5.12).

The researcher may note that the general practice for this aggregation problem is to formulate equation (5.10) as though it corresponds to aggregates and then to divide by $\sqrt{N_t}$ to correct for heteroscedasticity. This is a bad practice; even worse, it gives wrong answers.

The investment decision function for the Indian engineering industry, adjusted for heteroscedasticity, is estimated as

$$\underset{}{\frac{I_t}{\sqrt{N_t}}} = \underset{(53.37)}{-\,61.36} + \underset{(7.36)}{7.43\sqrt{N_t}} + \underset{(0.019)}{0.076\left(\frac{S_t}{\sqrt{N_t}}\right)} + \underset{(0.437)}{0.036\left(\frac{P_t}{\sqrt{N_t}}\right)} \qquad R^2 = 0.98. \tag{5.18}$$

Given the level of sales, the movements in profits do not seem to influence the movements in investment. Whether we assume heteroscedasticity or not, we are reaching the same conclusions, for the coefficient of P_t in (4.57) was insignificant also.

In estimating (5.18) we introduced a constant term even though the theoretical specification (5.17) does not provide for it. The constant term in this context has no operational significance. It is there only to allow flexibility in the estimated equation and to simplify the interpretation of the summary statistics (R^2 and standard errors). See the discussion on interpretation of the constant term on page 5.

5.5 *Serial Correlation in Residuals*

In Chapter 3 it was shown that when the error terms are serially dependent the estimates by ordinary least squares are not the minimum-variance unbiased estimates of the parameters. We also studied an alternative estimation procedure (generalized least squares) using an estimate of the parameter (ρ) of serial correlation. Since a theory seldom provides unambiguous information on the serial correlation of the error terms, the researcher wants to infer the nature of serial correlation in the errors from analysis of the residuals with the hope of improving the precision of his estimates.

A point often overlooked by researchers is that correcting for serial correlation does not always give "better" results unless the parameter of serial correlation is known, which is rarely the case. Whenever an estimate of the serial

Seelye Rebuttal Exhibit 3

```
#
#This R code performs weighted least squares analysis
#using the software package R.
#
#As with most other statistical package, R includes an
#option to perform a weighted regression analysis
#
#
#The data is from Seelye Exhibit 25, Page 2 of 4

#capture output in file
sink("f:/WLSQ in R/output.lis")

#Size variable for Overhead Conductor (which is the dependent variable
#in the regression analysis).
#The units are in MCM
size <- c(0.01,0.02,0.19,0.24,0.67,1.31,1.38,1.44,
1.6,1.63,1.8,1.85,3.57,4,0.86,6.95,7,7.5,4,16,16.55)

#Cost variable for Overhead Conductor (average cost per conductor types)
cost<- c(6.53,16.51,26.24,41.74,66.36,83.69,105.6,133.1,167.8,211.6,266,
266.8,300,350,397,500,556,750,795,954,1000)

#Number of units (feet of conductor) used as the weight in the regression
analysis
units <-
c(1515,1212,18421,89519,971519,88940,39898,713507,1954687,112230,288794,
20263,9557,769,265460,7511,919,766,113204,100,331)


#Standard weighted regression model
res <- lm(size ~ cost, weight=units)

res



#In the above, lines beginning with "#" are comments; otherwise the line
is code.
```

```
Call:
lm(formula = size ~ cost, weights = units)

Coefficients:
(Intercept)         cost
   0.756973     0.003659
```

Seelye Rebuttal Exhibit 4

Least-Squares Regression Based on Underlying Individual Unit Cost Data

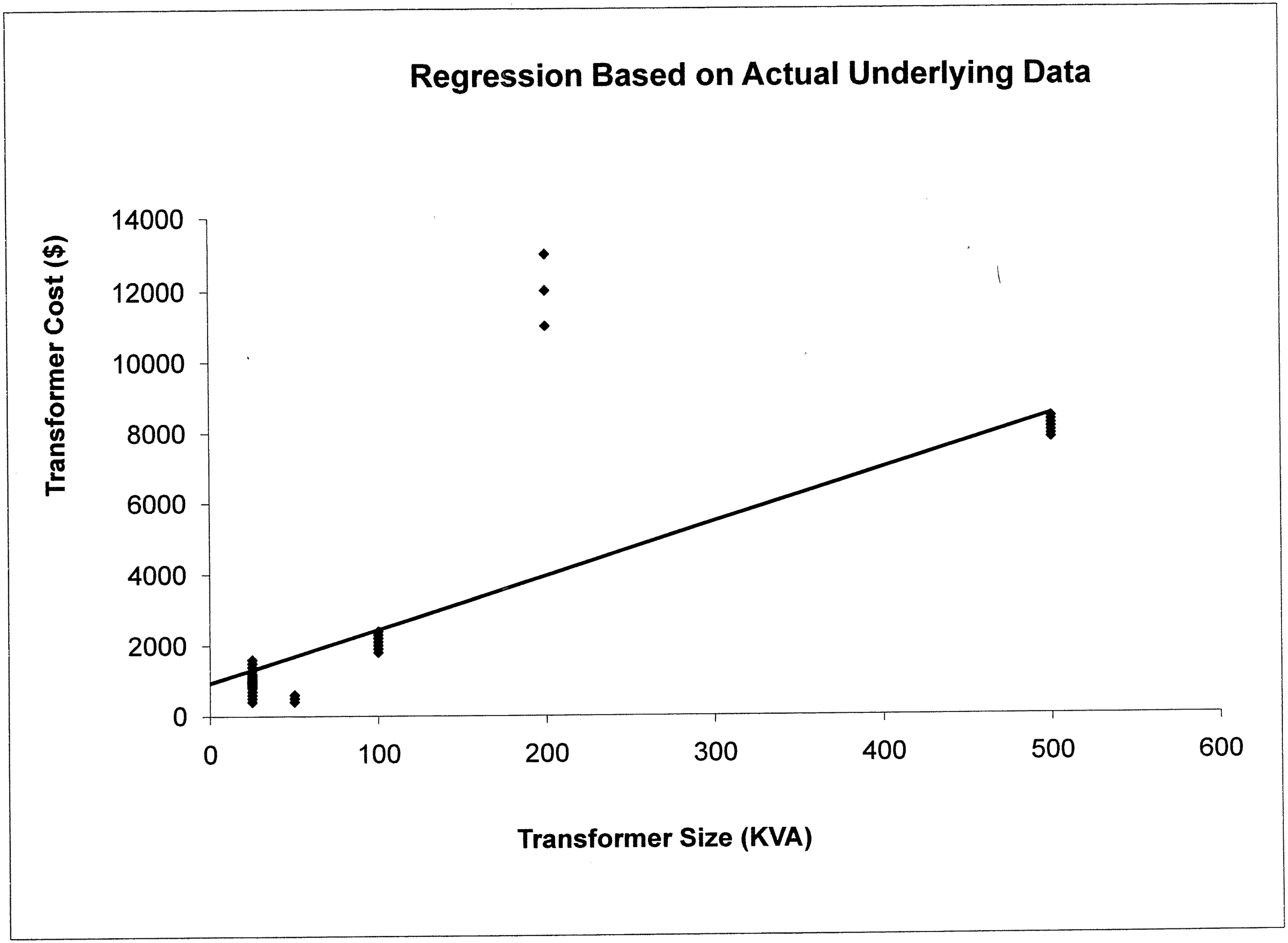
	Cost (y)	Size (x)
1	400	25
2	500	25
3	600	25
4	700	25
5	800	25
6	850	25
7	900	25
8	950	25
9	950	25
10	1000	25
11	1000	25
12	1050	25
13	1050	25
14	1100	25
15	1150	25
16	1200	25
17	1300	25
18	1400	25
19	1500	25
20	1600	25
21	400	50
22	500	50
23	600	50
24	1800	100
25	1800	100
26	1900	100
27	1900	100
28	2000	100
29	2000	100
30	2000	100
31	2100	100
32	2100	100
33	2100	100
34	2100	100
35	2100	100
36	2100	100
37	2200	100
38	2200	100
39	2200	100
40	2300	100

Least-Squares Regression Based on Underlying Individual Unit Cost Data

	Cost (y)	Size (x)
41	2300	100
42	2400	100
43	2400	100
44	11000	200
45	12000	200
46	13000	200
47	7800	500
48	7800	500
49	7900	500
50	7900	500
51	8000	500
52	8000	500
53	8000	500
54	8100	500
55	8100	500
56	8100	500
57	8100	500
58	8100	500
59	8100	500
60	8200	500
61	8200	500
62	8200	500
63	8300	500
64	8300	500
65	8400	500
66	8400	500

Least-Square Regression Results:

Intercept	929.97
Slope	15.10


Regression Based on Actual Underlying Data
Transformer Cost ($)
14000
12000
10000
8000
6000
4000
2000
0
0
100
200
300
400
500
600
Transformer Size (KVA)

Seelye Rebuttal Exhibit 5

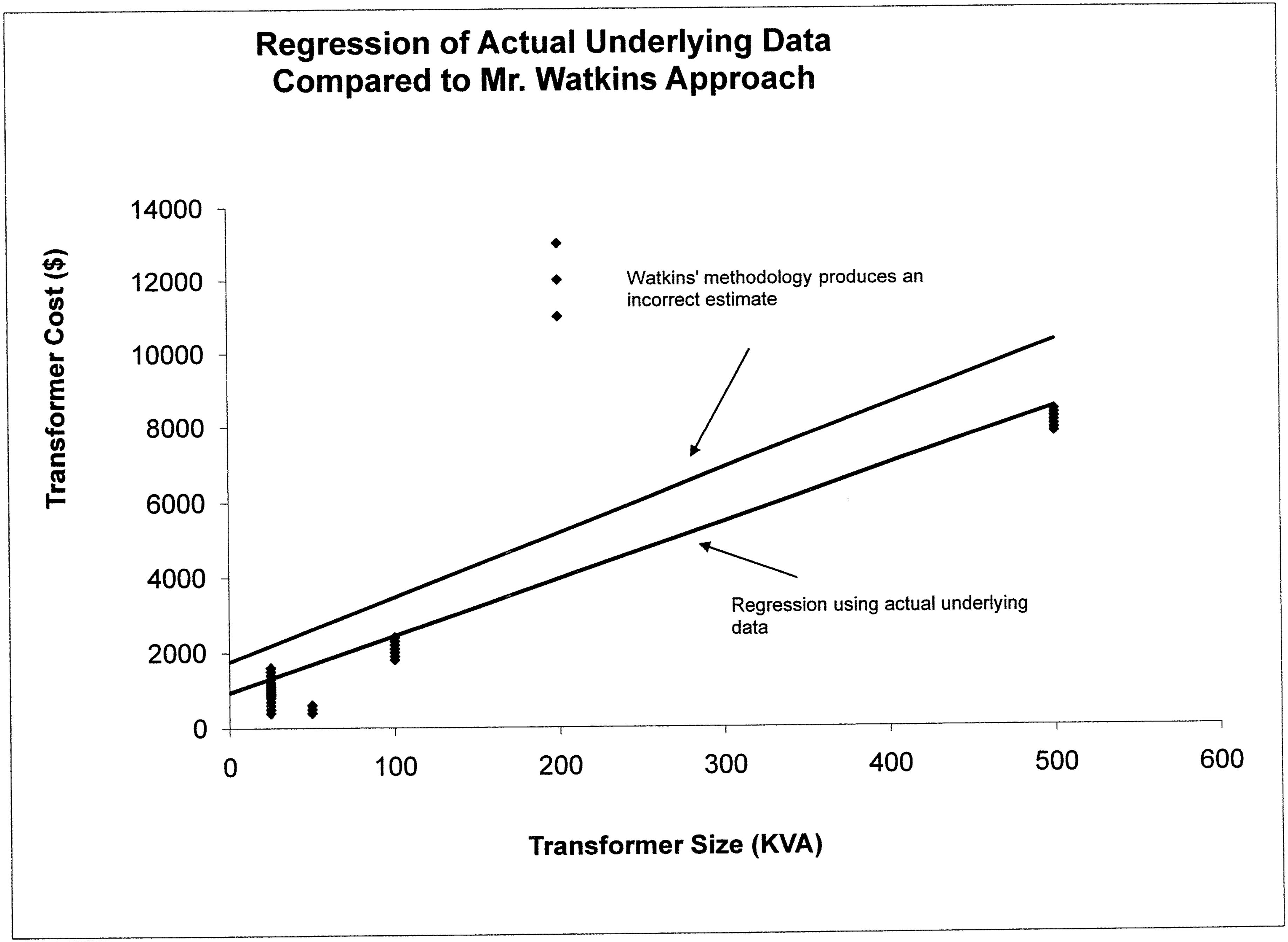
Watkins' Methodology
Unweighted Least-Squares Regression Applied to Summary Data

n	y	x	est y
20	1000	25	2177.5
3	500	50	2604.5833
20	2100	100	3458.75
3	12000	200	5167.0833
20	8100	500	10292.083

Unweighted Least-Squares Regression Results
Applied to Summary Data

Intercept	1,750.42
Slope	17.08

Watkins' methodology produces incorrect results


Regression of Actual Underlying Data
Compared to Mr. Watkins Approach
Transformer Cost ($)
14000
12000
10000
8000
6000
4000
2000
0
0
100
200
300
400
500
600
Transformer Size (KVA)
Watkins' methodology produces an incorrect estimate
Regression using actual underlying data

Seelye Rebuttal Exhibit 6

KU's Methodology

Weighted Least-Squares Regression Applied to Summary Data

n	y	x	y*n^.5	n^.5	xn^.5
20	1000	25	4472.136	4.47	111.8033989
3	500	50	866.0254	1.73	86.60254038
20	2100	100	9391.4855	4.47	447.2135955
3	12000	200	20784.61	1.73	346.4101615
20	8100	500	36224.301	4.47	2236.067977

Unweighted Least-Squares Regression Results
Applied to Summary Data

Intercept	929.97
Slope	15.10

Weighted least-squares regression produces correct results

Seelye Rebuttal Exhibit 7

Recalculation of Watkins' Customer Cost
Adding Back in Costs Classified as Customer Costs
In Watkins' Own Cost of Service Study
For Kentucky Utilities

	Residential	
Gross Plant		
364-365 Overhead Lines - Primary (Customer Cost)	$75,559,084	**<<----Left Out By Watkins**
364-365 Overhead Lines - Secondary (Customer Cost)	$24,197,693	**<<----Left Out By Watkins**
366-367 Underground Lines - Primary (Customer Cost)	$18,834,232	**<<----Left Out By Watkins**
366-367 Underground Lines - Secondary (Customer Cost)	$148,197	**<<----Left Out By Watkins**
368 Transformers - Power Pool (Customer Cost)	$117,605,610	**<<----Left Out By Watkins**
369 Services	$65,820,759	
370 Meters	$40,516,336	
Total Gross Plant	$342,681,911	
Depreciation Reserve		
364-365 Overhead Lines - Primary (Customer Cost)	$31,607,637	**<<----Left Out By Watkins**
364-365 Overhead Lines - Secondary (Customer Cost)	$10,122,302	**<<----Left Out By Watkins**
366-367 Underground Lines - Primary (Customer Cost)	$7,878,676	**<<----Left Out By Watkins**
366-367 Underground Lines - Secondary (Customer Cost)	$61,993	**<<----Left Out By Watkins**
368 Transformers - Power Pool (Customer Cost)	$49,196,406	**<<----Left Out By Watkins**
369 Services	$27,533,931	
370 Meters	$16,948,665	
Total Depreciation Reserve	$143,349,611	
Total Net Plant	$199,332,300	
Operation & Maintenance Expenses		
Distribution Expense - Operating		
580 Operation Supervision & Engineering	$545,567	**<<----Left Out By Watkins**
581 Load Dispatching	$156,284	**<<----Left Out By Watkins**
582 Station Expenses	$259,325	**<<----Left Out By Watkins**
583 Overhead Line Expenses	$587,326	**<<----Left Out By Watkins**
584 Underground Line Expenses	$9,415	**<<----Left Out By Watkins**
586 Meter Expenses	$3,858,065	
588 Miscellaneous Distribution Exp	$1,089,109	**<<----Left Out By Watkins**
589 Rents	$3,767	**<<----Left Out By Watkins**
590 Maintenance Supervision & Engineering	$10,968	**<<----Left Out By Watkins**
592 Maintenance of Station Equipment	$157,309	**<<----Left Out By Watkins**
593 Maintenance of Overhead Lines	$3,791,652	**<<----Left Out By Watkins**
594 Maintenance of Underground Lines	$93,031	**<<----Left Out By Watkins**
595 Maintenance of Line Transformers	-$131,913	**<<----Left Out By Watkins**
598 Miscellaneous Distribution Exp	-$7,786	**<<----Left Out By Watkins**
Sub-total	$10,422,119	
Customer Accounts Expense		
901 Supervision/Customer Accts	$1,408,476	**<<----Left Out By Watkins**
902 Meter Reading Expenses	$2,636,804	
903 Records & Collection	$9,818,212	
904 Uncollectible Accounts	$1,124,027	**<<----Left Out By Watkins**
905 Misc Cust Accounts	$252,292	**<<----Left Out By Watkins**
Sub-total	$15,239,811	
Customer Service & Information Expense		
907 Supervision	$134,510	**<<----Left Out By Watkins**
908 Customer Assistance Expenses	$5,584,474	**<<----Left Out By Watkins**
909 Informational & Instructional	$60,563	**<<----Left Out By Watkins**
910 Miscellaneous Customer Service	$2,281,171	**<<----Left Out By Watkins**
912 Demonstration & Selling Exp	$5,265	**<<----Left Out By Watkins**
913 Advertising Expenses	$43,142	**<<----Left Out By Watkins**
Sub-total	$8,109,125	

Recalculation of Watkins' Customer Cost
Adding Back in Costs Classified as Customer Costs
In Watkins' Own Cost of Service Study
For Kentucky Utilities

	Residential				
General Expenses					
920 Admin & General Salaries	$1,010,740	**<<----Left Out By Watkins**			
921 Office Supplies & Expenses	$321,692	**<<----Left Out By Watkins**			
922 Administrative Expenses Transferred	-$119,024	**<<----Left Out By Watkins**			
923 Outside Services Employed	$448,023	**<<----Left Out By Watkins**			
924 Property Insurance	$154,574	**<<----Left Out By Watkins**			
925 Injuries & Damages - Insurance	$91,415	**<<----Left Out By Watkins**			
926 Employee Benefits	$2,086,709	**<<----Left Out By Watkins**			
928 Regulatory Commission Fees	$36,771	**<<----Left Out By Watkins**			
929 Duplicate Charges	-$193	**<<----Left Out By Watkins**			
930 Miscellaneous General Expenses	$150,391	**<<----Left Out By Watkins**			
931 Rents & Leases	$97,292	**<<----Left Out By Watkins**			
935 Maintenance of General Plant	$476,805	**<<----Left Out By Watkins**			
Sub-total	$4,755,196				
Total Operation & Maintenance Expenses	$38,526,250				
Depreciation Expense					
364-365 Distribution Primary Lines	$7,836,416	**<<----Left Out By Watkins**			
366-367 Distribution Secondary Lines	$2,378,808	**<<----Left Out By Watkins**			
369 Services	$1,834,088				
370 Meters	$1,128,983				
Total Depreciation Expense	$13,178,295				
Revenue Requirement					
Interest	$4,245,778				
Equity return	$12,344,151				
Income Tax	$7,438,142				
Revenue For Return	24,028,071		PCT	Cost	WGHT Cost
		Debt	46.15%	4.62%	2.13%
O & M Expenses	$38,526,250	Common	53.85%	11.50%	6.19%
Depreciation Expense	$13,178,295	Total	100.00%		8.32%
Total Customer Revenue Requirement	$75,732,617				
Number of Bills	$5,019,241				
Monthly Cost	$15.09				

Seelye Rebuttal Exhibit 8

Index	Series A	Series B	Aggregated Value Series A & B
1	70	62	132
2	2	76	78
3	75	49	124
4	26	75	101
5	56	66	122
6	46	10	56
7	77	5	82
8	99	68	167
9	34	33	67
10	35	51	86
11	67	95	162
12	72	44	116
13	95	20	115
14	92	75	167
15	25	81	106
16	96	13	109
17	72	16	88
18	86	74	160
19	56	29	85
20	21	66	87
21	85	57	142
22	69	43	112
23	20	72	92
24	79	80	159
	99	95	167
		Sum of Maximums 194	Maximum of Sums 167

Automatic Savings Under Aggregated Demands 27

Seelye Rebuttal Exhibit 9

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/1/2010	0:15	555.6	715.2	1270.8
1/1/2010	0:30	603	712.8	1315.8
1/1/2010	0:45	603	732	1335
1/1/2010	1:00	614.4	724.8	1339.2
1/1/2010	1:15	619.2	720	1339.2
1/1/2010	1:30	630.6	730.8	1361.4
1/1/2010	1:45	619.8	763.2	1383
1/1/2010	2:00	626.4	740.4	1366.8
1/1/2010	2:15	619.8	729.6	1349.4
1/1/2010	2:30	613.2	732	1345.2
1/1/2010	2:45	562.8	679.8	1242.6
1/1/2010	3:00	562.2	720.6	1282.8
1/1/2010	3:15	586.2	725.4	1311.6
1/1/2010	3:30	740.4	700.8	1441.2
1/1/2010	3:45	784.8	727.8	1512.6
1/1/2010	4:00	741	742.8	1483.8
1/1/2010	4:15	711	749.4	1460.4
1/1/2010	4:30	705	714.6	1419.6
1/1/2010	4:45	726.6	721.8	1448.4
1/1/2010	5:00	749.4	708	1457.4
1/1/2010	5:15	830.4	710.4	1540.8
1/1/2010	5:30	812.4	727.2	1539.6
1/1/2010	5:45	907.2	768	1675.2
1/1/2010	6:00	969	760.2	1729.2
1/1/2010	6:15	1095.6	818.4	1914
1/1/2010	6:30	1077	843.6	1920.6
1/1/2010	6:45	1159.2	813.6	1972.8
1/1/2010	7:00	1237.8	836.4	2074.2
1/1/2010	7:15	1133.4	798	1931.4
1/1/2010	7:30	1109.4	828	1937.4
1/1/2010	7:45	1125	817.2	1942.2
1/1/2010	8:00	1153.8	832.2	1986
1/1/2010	8:15	1136.4	814.8	1951.2
1/1/2010	8:30	1136.4	792.6	1929
1/1/2010	8:45	1190.4	798.6	1989
1/1/2010	9:00	1131.6	774	1905.6
1/1/2010	9:15	1116.6	737.4	1854
1/1/2010	9:30	1140	730.8	1870.8
1/1/2010	9:45	1095	752.4	1847.4
1/1/2010	10:00	1082.4	776.4	1858.8
1/1/2010	10:15	1113.6	819	1932.6
1/1/2010	10:30	1134.6	808.8	1943.4
1/1/2010	10:45	1176.6	811.8	1988.4
1/1/2010	11:00	1207.8	802.2	2010
1/1/2010	11:15	1199.4	810.6	2010
1/1/2010	11:30	1159.2	807	1966.2
1/1/2010	11:45	1152.6	796.2	1948.8
1/1/2010	12:00	1186.8	813.6	2000.4
1/1/2010	12:15	1186.8	817.8	2004.6
1/1/2010	12:30	1168.8	814.8	1983.6
1/1/2010	12:45	1161	810	1971
1/1/2010	13:00	1153.2	822	1975.2
1/1/2010	13:15	1203.6	859.2	2062.8
1/1/2010	13:30	1104.6	867.6	1972.2
1/1/2010	13:45	1084.2	821.4	1905.6
1/1/2010	14:00	1064.4	816	1880.4
1/1/2010	14:15	1069.2	798.6	1867.8
1/1/2010	14:30	1023.6	799.2	1822.8
1/1/2010	14:45	1044	801.6	1845.6
1/1/2010	15:00	1146	784.8	1930.8
1/1/2010	15:15	1159.2	771.6	1930.8
1/1/2010	15:30	1177.8	790.2	1968
1/1/2010	15:45	1174.2	789	1963.2
1/1/2010	16:00	1212.6	819	2031.6
1/1/2010	16:15	1188	805.8	1993.8
1/1/2010	16:30	1185	816	2001
1/1/2010	16:45	1218	811.2	2029.2
1/1/2010	17:00	1205.4	807	2012.4

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/1/2010	17:15	1190.4	802.8	1993.2
1/1/2010	17:30	1205.4	826.8	2032.2
1/1/2010	17:45	1198.2	839.4	2037.6
1/1/2010	18:00	1237.2	833.4	2070.6
1/1/2010	18:15	1221.6	865.8	2087.4
1/1/2010	18:30	1104	801.6	1905.6
1/1/2010	18:45	1056	763.8	1819.8
1/1/2010	19:00	991.2	690	1681.2
1/1/2010	19:15	1003.2	724.2	1727.4
1/1/2010	19:30	1003.8	792.6	1796.4
1/1/2010	19:45	1044	799.8	1843.8
1/1/2010	20:00	1045.8	823.2	1869
1/1/2010	20:15	972	783.6	1755.6
1/1/2010	20:30	910.2	712.2	1622.4
1/1/2010	20:45	878.4	743.4	1621.8
1/1/2010	21:00	919.8	733.2	1653
1/1/2010	21:15	916.2	724.8	1641
1/1/2010	21:30	926.4	711.6	1638
1/1/2010	21:45	835.2	709.2	1544.4
1/1/2010	22:00	803.4	693.6	1497
1/1/2010	22:15	779.4	693	1472.4
1/1/2010	22:30	712.8	679.8	1392.6
1/1/2010	22:45	630.6	653.4	1284
1/1/2010	23:00	605.4	667.2	1272.6
1/1/2010	23:15	588	656.4	1244.4
1/1/2010	23:30	580.2	603.6	1183.8
1/1/2010	23:45	569.4	571.2	1140.6
1/1/2010	24:00:00	565.8	556.2	1122
1/2/2010	0:15	531	508.8	1039.8
1/2/2010	0:30	568.2	500.4	1068.6
1/2/2010	0:45	505.8	498	1003.8
1/2/2010	1:00	491.4	495	986.4
1/2/2010	1:15	479.4	493.8	973.2
1/2/2010	1:30	513.6	495	1008.6
1/2/2010	1:45	540.6	495.6	1036.2
1/2/2010	2:00	570	510	1080
1/2/2010	2:15	565.2	509.4	1074.6
1/2/2010	2:30	546.6	549.6	1096.2
1/2/2010	2:45	553.2	538.2	1091.4
1/2/2010	3:00	567.6	675.6	1243.2
1/2/2010	3:15	576.6	591	1167.6
1/2/2010	3:30	598.8	580.8	1179.6
1/2/2010	3:45	782.4	632.4	1414.8
1/2/2010	4:00	819.6	626.4	1446
1/2/2010	4:15	739.8	635.4	1375.2
1/2/2010	4:30	729.6	637.2	1366.8
1/2/2010	4:45	720	633.6	1353.6
1/2/2010	5:00	747	640.8	1387.8
1/2/2010	5:15	756	654.6	1410.6
1/2/2010	5:30	771.6	657.6	1429.2
1/2/2010	5:45	877.8	688.2	1566
1/2/2010	6:00	976.8	685.2	1662
1/2/2010	6:15	1078.8	693	1771.8
1/2/2010	6:30	1155.6	696	1851.6
1/2/2010	6:45	1066.8	806.4	1873.2
1/2/2010	7:00	1085.4	753	1838.4
1/2/2010	7:15	1091.4	750.6	1842
1/2/2010	7:30	1043.4	739.8	1783.2
1/2/2010	7:45	1044.6	727.8	1772.4
1/2/2010	8:00	1039.2	713.4	1752.6
1/2/2010	8:15	994.2	694.2	1688.4
1/2/2010	8:30	997.2	683.4	1680.6
1/2/2010	8:45	1090.2	702.6	1792.8
1/2/2010	9:00	1088.4	702.6	1791
1/2/2010	9:15	1129.2	687	1816.2
1/2/2010	9:30	1131	689.4	1820.4
1/2/2010	9:45	1108.2	684	1792.2
1/2/2010	10:00	1111.8	685.2	1797

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/2/2010	10:15	1113	681	1794
1/2/2010	10:30	1102.8	689.4	1792.2
1/2/2010	10:45	1094.4	687.6	1782
1/2/2010	11:00	1117.8	684	1801.8
1/2/2010	11:15	1109.4	690	1799.4
1/2/2010	11:30	1095	691.2	1786.2
1/2/2010	11:45	1093.8	705.6	1799.4
1/2/2010	12:00	1150.8	736.2	1887
1/2/2010	12:15	1140.6	737.4	1878
1/2/2010	12:30	1133.4	737.4	1870.8
1/2/2010	12:45	1141.8	733.2	1875
1/2/2010	13:00	1150.8	737.4	1888.2
1/2/2010	13:15	1145.4	736.8	1882.2
1/2/2010	13:30	1072.2	719.4	1791.6
1/2/2010	13:45	1107.6	708.6	1816.2
1/2/2010	14:00	1083.6	742.8	1826.4
1/2/2010	14:15	1039.8	799.2	1839
1/2/2010	14:30	897.6	759	1656.6
1/2/2010	14:45	731.4	683.4	1414.8
1/2/2010	15:00	675	698.4	1373.4
1/2/2010	15:15	633	695.4	1328.4
1/2/2010	15:30	664.2	716.4	1380.6
1/2/2010	15:45	637.2	732.6	1369.8
1/2/2010	16:00	592.8	699.6	1292.4
1/2/2010	16:15	556.8	640.2	1197
1/2/2010	16:30	532.2	599.4	1131.6
1/2/2010	16:45	539.4	594	1133.4
1/2/2010	17:00	505.8	556.8	1062.6
1/2/2010	17:15	504	603.6	1107.6
1/2/2010	17:30	514.8	611.4	1126.2
1/2/2010	17:45	530.4	565.8	1096.2
1/2/2010	18:00	547.2	581.4	1128.6
1/2/2010	18:15	562.8	603.6	1166.4
1/2/2010	18:30	525.6	540.6	1066.2
1/2/2010	18:45	544.8	502.8	1047.6
1/2/2010	19:00	553.8	505.2	1059
1/2/2010	19:15	537.6	553.2	1090.8
1/2/2010	19:30	540	521.4	1061.4
1/2/2010	19:45	520.8	509.4	1030.2
1/2/2010	20:00	537.6	511.2	1048.8
1/2/2010	20:15	518.4	508.8	1027.2
1/2/2010	20:30	522	512.4	1034.4
1/2/2010	20:45	535.8	512.4	1048.2
1/2/2010	21:00	532.2	508.2	1040.4
1/2/2010	21:15	504.6	500.4	1005
1/2/2010	21:30	481.8	499.2	981
1/2/2010	21:45	484.8	504.6	989.4
1/2/2010	22:00	470.4	504	974.4
1/2/2010	22:15	448.8	580.8	1029.6
1/2/2010	22:30	445.2	559.2	1004.4
1/2/2010	22:45	419.4	523.2	942.6
1/2/2010	23:00	462.6	572.4	1035
1/2/2010	23:15	459	571.2	1030.2
1/2/2010	23:30	449.4	558.6	1008
1/2/2010	23:45	433.2	537	970.2
1/2/2010	24:00:00	457.2	527.4	984.6
1/3/2010	0:15	480	547.8	1027.8
1/3/2010	0:30	489	501.6	990.6
1/3/2010	0:45	531.6	618.6	1150.2
1/3/2010	1:00	523.2	580.8	1104
1/3/2010	1:15	504.6	528.6	1033.2
1/3/2010	1:30	514.8	546.6	1061.4
1/3/2010	1:45	526.2	624.6	1150.8
1/3/2010	2:00	527.4	586.8	1114.2
1/3/2010	2:15	521.4	615	1136.4
1/3/2010	2:30	513	577.2	1090.2
1/3/2010	2:45	510	580.2	1090.2
1/3/2010	3:00	586.2	612.6	1198.8

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/3/2010	3:15	728.4	577.8	1306.2
1/3/2010	3:30	681.6	580.8	1262.4
1/3/2010	3:45	658.2	600	1258.2
1/3/2010	4:00	636.6	594.6	1231.2
1/3/2010	4:15	648.6	579.6	1228.2
1/3/2010	4:30	641.4	591	1232.4
1/3/2010	4:45	654	589.8	1243.8
1/3/2010	5:00	727.2	601.2	1328.4
1/3/2010	5:15	794.4	603.6	1398
1/3/2010	5:30	811.2	628.8	1440
1/3/2010	5:45	891	667.2	1558.2
1/3/2010	6:00	987.6	720.6	1708.2
1/3/2010	6:15	1036.8	785.4	1822.2
1/3/2010	6:30	1071.6	764.4	1836
1/3/2010	6:45	1084.2	815.4	1899.6
1/3/2010	7:00	1033.2	778.8	1812
1/3/2010	7:15	1074.6	730.2	1804.8
1/3/2010	7:30	1106.4	745.2	1851.6
1/3/2010	7:45	1197.6	757.2	1954.8
1/3/2010	8:00	1160.4	739.8	1900.2
1/3/2010	8:15	1195.8	720	1915.8
1/3/2010	8:30	1207.2	745.2	1952.4
1/3/2010	8:45	1153.8	747	1900.8
1/3/2010	9:00	1104	756.6	1860.6
1/3/2010	9:15	1108.2	753.6	1861.8
1/3/2010	9:30	1142.4	751.2	1893.6
1/3/2010	9:45	1120.2	765	1885.2
1/3/2010	10:00	1155.6	785.4	1941
1/3/2010	10:15	1172.4	768.6	1941
1/3/2010	10:30	1162.8	763.2	1926
1/3/2010	10:45	1155.6	754.8	1910.4
1/3/2010	11:00	1092	733.2	1825.2
1/3/2010	11:15	1083	758.4	1841.4
1/3/2010	11:30	1104.6	754.8	1859.4
1/3/2010	11:45	1095.6	760.2	1855.8
1/3/2010	12:00	1062	729.6	1791.6
1/3/2010	12:15	1109.4	736.2	1845.6
1/3/2010	12:30	1081.8	747.6	1829.4
1/3/2010	12:45	1080	735	1815
1/3/2010	13:00	1083	739.2	1822.2
1/3/2010	13:15	1054.2	730.2	1784.4
1/3/2010	13:30	1083	745.2	1828.2
1/3/2010	13:45	1063.8	750.6	1814.4
1/3/2010	14:00	1039.8	732.6	1772.4
1/3/2010	14:15	994.8	716.4	1711.2
1/3/2010	14:30	921	721.2	1642.2
1/3/2010	14:45	860.4	581.4	1441.8
1/3/2010	15:00	833.4	625.2	1458.6
1/3/2010	15:15	857.4	616.8	1474.2
1/3/2010	15:30	819	593.4	1412.4
1/3/2010	15:45	759	615.6	1374.6
1/3/2010	16:00	622.8	595.2	1218
1/3/2010	16:15	618	541.2	1159.2
1/3/2010	16:30	556.8	519	1075.8
1/3/2010	16:45	527.4	518.4	1045.8
1/3/2010	17:00	530.4	556.2	1086.6
1/3/2010	17:15	511.8	547.2	1059
1/3/2010	17:30	544.2	562.8	1107
1/3/2010	17:45	548.4	645.6	1194
1/3/2010	18:00	597.6	574.8	1172.4
1/3/2010	18:15	618	625.2	1243.2
1/3/2010	18:30	588	594.6	1182.6
1/3/2010	18:45	558.6	630.6	1189.2
1/3/2010	19:00	537	549	1086
1/3/2010	19:15	511.8	613.8	1125.6
1/3/2010	19:30	532.8	564.6	1097.4
1/3/2010	19:45	502.2	690.6	1192.8
1/3/2010	20:00	481.2	649.8	1131

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/3/2010	20:15	468	547.8	1015.8
1/3/2010	20:30	430.8	562.8	993.6
1/3/2010	20:45	385.2	514.2	899.4
1/3/2010	21:00	405.6	639	1044.6
1/3/2010	21:15	406.2	577.8	984
1/3/2010	21:30	376.2	566.4	942.6
1/3/2010	21:45	430.8	567.6	998.4
1/3/2010	22:00	438.6	589.2	1027.8
1/3/2010	22:15	430.2	529.8	960
1/3/2010	22:30	396.6	606.6	1003.2
1/3/2010	22:45	457.2	688.2	1145.4
1/3/2010	23:00	449.4	708.6	1158
1/3/2010	23:15	498	702.6	1200.6
1/3/2010	23:30	524.4	767.4	1291.8
1/3/2010	23:45	534	733.8	1267.8
1/3/2010	24:00:00	527.4	726.6	1254
1/4/2010	0:15	533.4	664.2	1197.6
1/4/2010	0:30	524.4	649.2	1173.6
1/4/2010	0:45	520.8	641.4	1162.2
1/4/2010	1:00	543.6	641.4	1185
1/4/2010	1:15	550.2	726	1276.2
1/4/2010	1:30	546.6	709.8	1256.4
1/4/2010	1:45	522.6	691.2	1213.8
1/4/2010	2:00	534.6	682.2	1216.8
1/4/2010	2:15	581.4	773.4	1354.8
1/4/2010	2:30	615.6	769.8	1385.4
1/4/2010	2:45	628.8	754.8	1383.6
1/4/2010	3:00	674.4	778.8	1453.2
1/4/2010	3:15	822.6	785.4	1608
1/4/2010	3:30	760.2	750.6	1510.8
1/4/2010	3:45	710.4	732.6	1443
1/4/2010	4:00	714.6	731.4	1446
1/4/2010	4:15	737.4	749.4	1486.8
1/4/2010	4:30	775.8	743.4	1519.2
1/4/2010	4:45	750	714	1464
1/4/2010	5:00	775.2	723.6	1498.8
1/4/2010	5:15	790.8	721.2	1512
1/4/2010	5:30	802.2	694.8	1497
1/4/2010	5:45	946.2	721.8	1668
1/4/2010	6:00	1043.4	741	1784.4
1/4/2010	6:15	1081.2	750	1831.2
1/4/2010	6:30	1115.4	768.6	1884
1/4/2010	6:45	1185.6	802.8	1988.4
1/4/2010	7:00	1172.4	819.6	1992
1/4/2010	7:15	1162.2	817.2	1979.4
1/4/2010	7:30	1133.4	824.4	1957.8
1/4/2010	7:45	1053.6	796.8	1850.4
1/4/2010	8:00	1094.4	741.6	1836
1/4/2010	8:15	1137.6	778.2	1915.8
1/4/2010	8:30	1099.2	785.4	1884.6
1/4/2010	8:45	1157.4	774	1931.4
1/4/2010	9:00	1230.6	771	2001.6
1/4/2010	9:15	1242	777	2019
1/4/2010	9:30	1261.2	829.8	2091
1/4/2010	9:45	1246.2	804	2050.2
1/4/2010	10:00	1278	804.6	2082.6
1/4/2010	10:15	1253.4	821.4	2074.8
1/4/2010	10:30	1212.6	853.2	2065.8
1/4/2010	10:45	1105.2	832.2	1937.4
1/4/2010	11:00	1118.4	832.8	1951.2
1/4/2010	11:15	1108.8	826.8	1935.6
1/4/2010	11:30	1121.4	819.6	1941
1/4/2010	11:45	1226.4	850.2	2076.6
1/4/2010	12:00	1246.2	862.8	2109
1/4/2010	12:15	1219.8	852	2071.8
1/4/2010	12:30	1213.2	837	2050.2
1/4/2010	12:45	1210.2	837	2047.2
1/4/2010	13:00	1255.8	848.4	2104.2

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/4/2010	13:15	1233.6	837	2070.6
1/4/2010	13:30	1131.6	811.2	1942.8
1/4/2010	13:45	1234.8	822.6	2057.4
1/4/2010	14:00	1226.4	866.4	2092.8
1/4/2010	14:15	1219.2	838.8	2058
1/4/2010	14:30	1159.8	812.4	1972.2
1/4/2010	14:45	1176.6	815.4	1992
1/4/2010	15:00	1227.6	860.4	2088
1/4/2010	15:15	1225.8	879	2104.8
1/4/2010	15:30	1191	900.6	2091.6
1/4/2010	15:45	1227.6	909.6	2137.2
1/4/2010	16:00	1244.4	891	2135.4
1/4/2010	16:15	1255.2	914.4	2169.6
1/4/2010	16:30	1194.6	861.6	2056.2
1/4/2010	16:45	1179	885.6	2064.6
1/4/2010	17:00	1160.4	872.4	2032.8
1/4/2010	17:15	1125	850.2	1975.2
1/4/2010	17:30	1143	781.8	1924.8
1/4/2010	17:45	1068	799.2	1867.2
1/4/2010	18:00	984	775.2	1759.2
1/4/2010	18:15	1002	785.4	1787.4
1/4/2010	18:30	940.8	704.4	1645.2
1/4/2010	18:45	1018.2	697.8	1716
1/4/2010	19:00	1080.6	789	1869.6
1/4/2010	19:15	1113.6	766.2	1879.8
1/4/2010	19:30	1123.8	723.6	1847.4
1/4/2010	19:45	1105.2	686.4	1791.6
1/4/2010	20:00	1031.4	628.2	1659.6
1/4/2010	20:15	970.2	645	1615.2
1/4/2010	20:30	918	556.2	1474.2
1/4/2010	20:45	895.8	646.8	1542.6
1/4/2010	21:00	948.6	649.2	1597.8
1/4/2010	21:15	940.8	670.2	1611
1/4/2010	21:30	906.6	625.8	1532.4
1/4/2010	21:45	840	627.6	1467.6
1/4/2010	22:00	723.6	613.8	1337.4
1/4/2010	22:15	702.6	538.8	1241.4
1/4/2010	22:30	654	556.2	1210.2
1/4/2010	22:45	586.2	570.6	1156.8
1/4/2010	23:00	597.6	592.2	1189.8
1/4/2010	23:15	559.8	569.4	1129.2
1/4/2010	23:30	547.2	525	1072.2
1/4/2010	23:45	492.6	597.6	1090.2
1/4/2010	24:00:00	493.2	529.8	1023
1/5/2010	0:15	588	522	1110
1/5/2010	0:30	589.8	562.8	1152.6
1/5/2010	0:45	596.4	538.2	1134.6
1/5/2010	1:00	561.6	570	1131.6
1/5/2010	1:15	554.4	597	1151.4
1/5/2010	1:30	579.6	524.4	1104
1/5/2010	1:45	610.8	550.2	1161
1/5/2010	2:00	619.8	722.4	1342.2
1/5/2010	2:15	589.8	603	1192.8
1/5/2010	2:30	580.8	606.6	1187.4
1/5/2010	2:45	576.6	615	1191.6
1/5/2010	3:00	592.2	736.2	1328.4
1/5/2010	3:15	567.6	721.2	1288.8
1/5/2010	3:30	602.4	753	1355.4
1/5/2010	3:45	766.8	751.8	1518.6
1/5/2010	4:00	727.2	756.6	1483.8
1/5/2010	4:15	734.4	744	1478.4
1/5/2010	4:30	732	743.4	1475.4
1/5/2010	4:45	758.4	753	1511.4
1/5/2010	5:00	730.8	765.6	1496.4
1/5/2010	5:15	723.6	759	1482.6
1/5/2010	5:30	716.4	778.2	1494.6
1/5/2010	5:45	786	771	1557
1/5/2010	6:00	796.2	772.2	1568.4

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/5/2010	6:15	816	756.6	1572.6
1/5/2010	6:30	840.6	760.2	1600.8
1/5/2010	6:45	730.8	781.8	1512.6
1/5/2010	7:00	750.6	794.4	1545
1/5/2010	7:15	798.6	772.2	1570.8
1/5/2010	7:30	988.8	796.8	1785.6
1/5/2010	7:45	1083	817.8	1900.8
1/5/2010	8:00	1088.4	814.8	1903.2
1/5/2010	8:15	1087.8	817.2	1905
1/5/2010	8:30	1060.2	827.4	1887.6
1/5/2010	8:45	1088.4	848.4	1936.8
1/5/2010	9:00	1039.8	841.8	1881.6
1/5/2010	9:15	1044.6	859.8	1904.4
1/5/2010	9:30	1052.4	833.4	1885.8
1/5/2010	9:45	1027.8	831	1858.8
1/5/2010	10:00	1015.8	800.4	1816.2
1/5/2010	10:15	1039.2	769.2	1808.4
1/5/2010	10:30	1039.2	763.8	1803
1/5/2010	10:45	1127.4	808.2	1935.6
1/5/2010	11:00	1099.2	853.8	1953
1/5/2010	11:15	1059	813.6	1872.6
1/5/2010	11:30	1041.6	741	1782.6
1/5/2010	11:45	1062	762.6	1824.6
1/5/2010	12:00	1036.8	766.8	1803.6
1/5/2010	12:15	981	716.4	1697.4
1/5/2010	12:30	1080	748.2	1828.2
1/5/2010	12:45	1160.4	748.2	1908.6
1/5/2010	13:00	1236.6	777.6	2014.2
1/5/2010	13:15	1209.6	807	2016.6
1/5/2010	13:30	1192.2	860.4	2052.6
1/5/2010	13:45	1236.6	854.4	2091
1/5/2010	14:00	1245	861.6	2106.6
1/5/2010	14:15	1261.2	894	2155.2
1/5/2010	14:30	1267.2	913.2	2180.4
1/5/2010	14:45	1266.6	902.4	2169
1/5/2010	15:00	1252.2	888.6	2140.8
1/5/2010	15:15	1214.4	870	2084.4
1/5/2010	15:30	1218	893.4	2111.4
1/5/2010	15:45	1183.2	895.8	2079
1/5/2010	16:00	1207.8	883.2	2091
1/5/2010	16:15	1213.8	856.8	2070.6
1/5/2010	16:30	1219.2	846	2065.2
1/5/2010	16:45	1233.6	870.6	2104.2
1/5/2010	17:00	1222.8	886.2	2109
1/5/2010	17:15	1182	923.4	2105.4
1/5/2010	17:30	1177.8	905.4	2083.2
1/5/2010	17:45	1184.4	891.6	2076
1/5/2010	18:00	1209	870	2079
1/5/2010	18:15	1227.6	901.8	2129.4
1/5/2010	18:30	1222.2	892.2	2114.4
1/5/2010	18:45	1246.2	924	2170.2
1/5/2010	19:00	1291.8	906	2197.8
1/5/2010	19:15	1275.6	904.2	2179.8
1/5/2010	19:30	1264.8	889.8	2154.6
1/5/2010	19:45	1270.2	899.4	2169.6
1/5/2010	20:00	1205.4	857.4	2062.8
1/5/2010	20:15	1187.4	825.6	2013
1/5/2010	20:30	1244.4	850.8	2095.2
1/5/2010	20:45	1248.6	879.6	2128.2
1/5/2010	21:00	1136.4	895.2	2031.6
1/5/2010	21:15	1150.8	864	2014.8
1/5/2010	21:30	1152	875.4	2027.4
1/5/2010	21:45	1117.2	859.2	1976.4
1/5/2010	22:00	1102.2	800.4	1902.6
1/5/2010	22:15	1063.2	777	1840.2
1/5/2010	22:30	1024.8	786.6	1811.4
1/5/2010	22:45	973.8	745.8	1719.6
1/5/2010	23:00	937.8	661.2	1599

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/5/2010	23:15	915	665.4	1580.4
1/5/2010	23:30	948.6	689.4	1638
1/5/2010	23:45	975.6	684.6	1660.2
1/5/2010	24:00:00	926.4	627	1553.4
1/6/2010	0:15	852.6	609.6	1462.2
1/6/2010	0:30	932.4	595.2	1527.6
1/6/2010	0:45	972.6	634.2	1606.8
1/6/2010	1:00	961.2	633.6	1594.8
1/6/2010	1:15	882	675	1557
1/6/2010	1:30	831	580.2	1411.2
1/6/2010	1:45	757.2	651	1408.2
1/6/2010	2:00	639	590.4	1229.4
1/6/2010	2:15	634.2	600	1234.2
1/6/2010	2:30	691.2	595.8	1287
1/6/2010	2:45	753.6	597.6	1351.2
1/6/2010	3:00	654.6	673.2	1327.8
1/6/2010	3:15	667.2	608.4	1275.6
1/6/2010	3:30	667.2	717.6	1384.8
1/6/2010	3:45	660	640.2	1300.2
1/6/2010	4:00	707.4	654	1361.4
1/6/2010	4:15	771.6	667.8	1439.4
1/6/2010	4:30	793.8	706.8	1500.6
1/6/2010	4:45	864.6	835.8	1700.4
1/6/2010	5:00	906	878.4	1784.4
1/6/2010	5:15	981.6	889.8	1871.4
1/6/2010	5:30	1029	835.2	1864.2
1/6/2010	5:45	1056.6	887.4	1944
1/6/2010	6:00	1066.2	920.4	1986.6
1/6/2010	6:15	1088.4	2	1090.4
1/6/2010	6:30	1107	920.4	2027.4
1/6/2010	6:45	1169.4	906.6	2076
1/6/2010	7:00	1252.8	934.2	2187
1/6/2010	7:15	1225.2	916.8	2142
1/6/2010	7:30	1200.6	911.4	2112
1/6/2010	7:45	1236	972	2208
1/6/2010	8:00	1270.8	976.8	2247.6
1/6/2010	8:15	1308	963	2271
1/6/2010	8:30	1347.6	969.6	2317.2
1/6/2010	8:45	1335.6	954	2289.6
1/6/2010	9:00	1347.6	942.6	2290.2
1/6/2010	9:15	1315.8	949.8	2265.6
1/6/2010	9:30	1321.2	928.2	2249.4
1/6/2010	9:45	1326.6	900.6	2227.2
1/6/2010	10:00	1321.8	879.6	2201.4
1/6/2010	10:15	1290	899.4	2189.4
1/6/2010	10:30	1281	894	2175
1/6/2010	10:45	1273.2	997.2	2270.4
1/6/2010	11:00	1191	997.8	2188.8
1/6/2010	11:15	1132.2	941.4	2073.6
1/6/2010	11:30	1128	949.2	2077.2
1/6/2010	11:45	1144.8	956.4	2101.2
1/6/2010	12:00	1190.4	966	2156.4
1/6/2010	12:15	1216.8	974.4	2191.2
1/6/2010	12:30	1257	23.6	1280.6
1/6/2010	12:45	1249.2	982.8	2232
1/6/2010	13:00	1204.8	942.6	2147.4
1/6/2010	13:15	1173	864.6	2037.6
1/6/2010	13:30	1230.6	924.6	2155.2
1/6/2010	13:45	1159.2	912.6	2071.8
1/6/2010	14:00	1137	875.4	2012.4
1/6/2010	14:15	1192.2	801.6	1993.8
1/6/2010	14:30	1203	860.4	2063.4
1/6/2010	14:45	1132.8	800.4	1933.2
1/6/2010	15:00	1139.4	814.2	1953.6
1/6/2010	15:15	1212	851.4	2063.4
1/6/2010	15:30	1224.6	967.2	2191.8
1/6/2010	15:45	1222.2	880.8	2103
1/6/2010	16:00	1253.4	924.6	2178

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/6/2010	16:15	1269	951	2220
1/6/2010	16:30	1254	926.4	2180.4
1/6/2010	16:45	1262.4	908.4	2170.8
1/6/2010	17:00	1260.6	908.4	2169
1/6/2010	17:15	1250.4	936.6	2187
1/6/2010	17:30	1109.4	907.2	2016.6
1/6/2010	17:45	1125.6	887.4	2013
1/6/2010	18:00	1139.4	888	2027.4
1/6/2010	18:15	1131	907.2	2038.2
1/6/2010	18:30	1095	878.4	1973.4
1/6/2010	18:45	1096.2	892.2	1988.4
1/6/2010	19:00	1128.6	895.8	2024.4
1/6/2010	19:15	1066.8	882	1948.8
1/6/2010	19:30	1132.2	837	1969.2
1/6/2010	19:45	1129.2	856.2	1985.4
1/6/2010	20:00	1122.6	874.2	1996.8
1/6/2010	20:15	1133.4	879	2012.4
1/6/2010	20:30	1195.2	876	2071.2
1/6/2010	20:45	1233.6	877.8	2111.4
1/6/2010	21:00	1134	892.8	2026.8
1/6/2010	21:15	1048.2	820.8	1869
1/6/2010	21:30	1080.6	783.6	1864.2
1/6/2010	21:45	1108.8	796.2	1905
1/6/2010	22:00	1111.8	822	1933.8
1/6/2010	22:15	1101	829.8	1930.8
1/6/2010	22:30	968.4	818.4	1786.8
1/6/2010	22:45	931.2	705.6	1636.8
1/6/2010	23:00	934.2	747.6	1681.8
1/6/2010	23:15	855	742.2	1597.2
1/6/2010	23:30	786.6	697.2	1483.8
1/6/2010	23:45	734.4	697.8	1432.2
1/6/2010	24:00:00	700.2	717.6	1417.8
1/7/2010	0:15	684.6	777.6	1462.2
1/7/2010	0:30	681	787.8	1468.8
1/7/2010	0:45	620.4	702	1322.4
1/7/2010	1:00	631.2	707.4	1338.6
1/7/2010	1:15	631.8	658.8	1290.6
1/7/2010	1:30	676.2	679.2	1355.4
1/7/2010	1:45	618	607.8	1225.8
1/7/2010	2:00	595.8	621.6	1217.4
1/7/2010	2:15	572.4	594.6	1167
1/7/2010	2:30	598.8	600	1198.8
1/7/2010	2:45	555.6	607.8	1163.4
1/7/2010	3:00	555.6	592.2	1147.8
1/7/2010	3:15	620.4	558	1178.4
1/7/2010	3:30	511.8	588	1099.8
1/7/2010	3:45	504	580.2	1084.2
1/7/2010	4:00	583.8	584.4	1168.2
1/7/2010	4:15	619.2	630.6	1249.8
1/7/2010	4:30	652.8	621.6	1274.4
1/7/2010	4:45	658.8	728.4	1387.2
1/7/2010	5:00	654	681.6	1335.6
1/7/2010	5:15	654	637.2	1291.2
1/7/2010	5:30	711.6	724.8	1436.4
1/7/2010	5:45	801.6	710.4	1512
1/7/2010	6:00	873	678.6	1551.6
1/7/2010	6:15	921	690.6	1611.6
1/7/2010	6:30	921.6	702.6	1624.2
1/7/2010	6:45	981.6	739.2	1720.8
1/7/2010	7:00	1092.6	828.6	1921.2
1/7/2010	7:15	1180.2	830.4	2010.6
1/7/2010	7:30	1138.2	817.2	1955.4
1/7/2010	7:45	1182	832.8	2014.8
1/7/2010	8:00	1173	809.4	1982.4
1/7/2010	8:15	1240.8	846.6	2087.4
1/7/2010	8:30	1201.2	875.4	2076.6
1/7/2010	8:45	1188	901.8	2089.8
1/7/2010	9:00	1209	930.6	2139.6

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/7/2010	9:15	1259.4	28.4	1287.8
1/7/2010	9:30	1302	2	1304
1/7/2010	9:45	1287.6	19.4	1307
1/7/2010	10:00	1247.4	34.4	1281.8
1/7/2010	10:15	1228.8	57.2	1286
1/7/2010	10:30	1228.2	47.6	1275.8
1/7/2010	10:45	1245.6	968.4	2214
1/7/2010	11:00	1292.4	936	2228.4
1/7/2010	11:15	1327.2	955.8	2283
1/7/2010	11:30	1311.6	949.2	2260.8
1/7/2010	11:45	1284	947.4	2231.4
1/7/2010	12:00	1301.4	967.2	2268.6
1/7/2010	12:15	1287.6	936	2223.6
1/7/2010	12:30	1249.2	928.2	2177.4
1/7/2010	12:45	1275	938.4	2213.4
1/7/2010	13:00	1245	928.8	2173.8
1/7/2010	13:15	1273.8	903	2176.8
1/7/2010	13:30	1288.2	907.2	2195.4
1/7/2010	13:45	1319.4	915	2234.4
1/7/2010	14:00	1282.8	918	2200.8
1/7/2010	14:15	1263	949.8	2212.8
1/7/2010	14:30	1233.6	894.6	2128.2
1/7/2010	14:45	1234.2	886.2	2120.4
1/7/2010	15:00	1228.2	876.6	2104.8
1/7/2010	15:15	1252.2	886.8	2139
1/7/2010	15:30	1215	859.2	2074.2
1/7/2010	15:45	1237.8	894.6	2132.4
1/7/2010	16:00	1270.2	916.2	2186.4
1/7/2010	16:15	1329	930.6	2259.6
1/7/2010	16:30	1329	943.2	2272.2
1/7/2010	16:45	1317	947.4	2264.4
1/7/2010	17:00	1258.2	948	2206.2
1/7/2010	17:15	1239	907.2	2146.2
1/7/2010	17:30	1260	924	2184
1/7/2010	17:45	1260	946.8	2206.8
1/7/2010	18:00	1287.6	922.2	2209.8
1/7/2010	18:15	1320.6	944.4	2265
1/7/2010	18:30	1246.2	909	2155.2
1/7/2010	18:45	1103.4	807	1910.4
1/7/2010	19:00	1118.4	765	1883.4
1/7/2010	19:15	1180.2	806.4	1986.6
1/7/2010	19:30	1165.2	790.2	1955.4
1/7/2010	19:45	1266.6	804	2070.6
1/7/2010	20:00	1281.6	852	2133.6
1/7/2010	20:15	1228.8	870.6	2099.4
1/7/2010	20:30	1347	916.2	2263.2
1/7/2010	20:45	1342.2	897	2239.2
1/7/2010	21:00	1338.6	893.4	2232
1/7/2010	21:15	1354.2	886.8	2241
1/7/2010	21:30	1278.6	840	2118.6
1/7/2010	21:45	1326	904.8	2230.8
1/7/2010	22:00	1286.4	924	2210.4
1/7/2010	22:15	1225.8	861	2086.8
1/7/2010	22:30	1196.4	843.6	2040
1/7/2010	22:45	1151.4	855.6	2007
1/7/2010	23:00	1047	878.4	1925.4
1/7/2010	23:15	1094.4	837.6	1932
1/7/2010	23:30	1140.6	829.8	1970.4
1/7/2010	23:45	1182	822	2004
1/7/2010	24:00:00	1155.6	804	1959.6
1/8/2010	0:15	1170	745.2	1915.2
1/8/2010	0:30	1197.6	744.6	1942.2
1/8/2010	0:45	1198.2	722.4	1920.6
1/8/2010	1:00	1090.8	732.6	1823.4
1/8/2010	1:15	1090.8	727.2	1818
1/8/2010	1:30	1074.6	708.6	1783.2
1/8/2010	1:45	1182.6	736.8	1919.4
1/8/2010	2:00	1145.4	737.4	1882.8

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/8/2010	2:15	1063.2	687.6	1750.8
1/8/2010	2:30	912.6	557.4	1470
1/8/2010	2:45	876.6	553.2	1429.8
1/8/2010	3:00	828.6	550.2	1378.8
1/8/2010	3:15	724.2	535.8	1260
1/8/2010	3:30	721.2	553.8	1275
1/8/2010	3:45	691.8	585	1276.8
1/8/2010	4:00	660.6	592.2	1252.8
1/8/2010	4:15	726.6	610.8	1337.4
1/8/2010	4:30	706.2	600.6	1306.8
1/8/2010	4:45	682.2	571.2	1253.4
1/8/2010	5:00	731.4	561.6	1293
1/8/2010	5:15	780	600.6	1380.6
1/8/2010	5:30	773.4	759	1532.4
1/8/2010	5:45	800.4	625.8	1426.2
1/8/2010	6:00	867	719.4	1586.4
1/8/2010	6:15	917.4	738.6	1656
1/8/2010	6:30	963	771.6	1734.6
1/8/2010	6:45	1012.2	820.2	1832.4
1/8/2010	7:00	1108.8	826.2	1935
1/8/2010	7:15	1226.4	843	2069.4
1/8/2010	7:30	1221	868.2	2089.2
1/8/2010	7:45	1144.8	868.8	2013.6
1/8/2010	8:00	976.2	855	1831.2
1/8/2010	8:15	1113	843.6	1956.6
1/8/2010	8:30	1125	852	1977
1/8/2010	8:45	1268.4	913.8	2182.2
1/8/2010	9:00	1266.6	907.2	2173.8
1/8/2010	9:15	1234.8	881.4	2116.2
1/8/2010	9:30	1245	891.6	2136.6
1/8/2010	9:45	1318.8	915	2233.8
1/8/2010	10:00	1338	991.8	2329.8
1/8/2010	10:15	1369.8	922.2	2292
1/8/2010	10:30	1138.2	856.8	1995
1/8/2010	10:45	1095.6	844.8	1940.4
1/8/2010	11:00	1285.8	856.2	2142
1/8/2010	11:15	1297.8	897.6	2195.4
1/8/2010	11:30	1294.2	906	2200.2
1/8/2010	11:45	1303.2	902.4	2205.6
1/8/2010	12:00	1265.4	895.8	2161.2
1/8/2010	12:15	1310.4	937.8	2248.2
1/8/2010	12:30	1294.2	915.6	2209.8
1/8/2010	12:45	1276.8	875.4	2152.2
1/8/2010	13:00	1264.2	888.6	2152.8
1/8/2010	13:15	1217.4	869.4	2086.8
1/8/2010	13:30	1280.4	879.6	2160
1/8/2010	13:45	1285.8	899.4	2185.2
1/8/2010	14:00	1244.4	898.2	2142.6
1/8/2010	14:15	1310.4	898.2	2208.6
1/8/2010	14:30	1328.4	886.2	2214.6
1/8/2010	14:45	1336.2	975	2311.2
1/8/2010	15:00	1306.8	931.8	2238.6
1/8/2010	15:15	1321.8	921.6	2243.4
1/8/2010	15:30	1294.8	945	2239.8
1/8/2010	15:45	1281	889.2	2170.2
1/8/2010	16:00	1292.4	871.2	2163.6
1/8/2010	16:15	1248.6	848.4	2097
1/8/2010	16:30	1212.6	858.6	2071.2
1/8/2010	16:45	1309.8	906	2215.8
1/8/2010	17:00	1298.4	933	2231.4
1/8/2010	17:15	1299	919.2	2218.2
1/8/2010	17:30	1232.4	885.6	2118
1/8/2010	17:45	1234.8	940.8	2175.6
1/8/2010	18:00	1234.2	890.4	2124.6
1/8/2010	18:15	1163.4	864.6	2028
1/8/2010	18:30	1162.2	878.4	2040.6
1/8/2010	18:45	1138.8	887.4	2026.2
1/8/2010	19:00	1126.2	880.8	2007

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/8/2010	19:15	1147.8	865.2	2013
1/8/2010	19:30	1237.8	901.8	2139.6
1/8/2010	19:45	1292.4	945	2237.4
1/8/2010	20:00	1273.2	930	2203.2
1/8/2010	20:15	1314	933	2247
1/8/2010	20:30	1305.6	891.6	2197.2
1/8/2010	20:45	1305.6	923.4	2229
1/8/2010	21:00	1282.8	903	2185.8
1/8/2010	21:15	1123.8	912	2035.8
1/8/2010	21:30	1240.8	958.8	2199.6
1/8/2010	21:45	1198.2	963.6	2161.8
1/8/2010	22:00	1190.4	939	2129.4
1/8/2010	22:15	1197	960.6	2157.6
1/8/2010	22:30	1173	924.6	2097.6
1/8/2010	22:45	1181.4	873.6	2055
1/8/2010	23:00	1185	819.6	2004.6
1/8/2010	23:15	1144.8	838.8	1983.6
1/8/2010	23:30	1117.2	798	1915.2
1/8/2010	23:45	1125.6	772.2	1897.8
1/8/2010	24:00:00	1146	780.6	1926.6
1/9/2010	0:15	1074	723	1797
1/9/2010	0:30	993.6	709.2	1702.8
1/9/2010	0:45	958.8	691.2	1650
1/9/2010	1:00	934.2	670.8	1605
1/9/2010	1:15	795.6	639	1434.6
1/9/2010	1:30	788.4	592.2	1380.6
1/9/2010	1:45	685.2	562.8	1248
1/9/2010	2:00	655.8	574.2	1230
1/9/2010	2:15	640.8	549.6	1190.4
1/9/2010	2:30	624.6	516	1140.6
1/9/2010	2:45	613.2	517.2	1130.4
1/9/2010	3:00	607.8	511.2	1119
1/9/2010	3:15	671.4	517.8	1189.2
1/9/2010	3:30	640.8	611.4	1252.2
1/9/2010	3:45	568.2	541.2	1109.4
1/9/2010	4:00	586.2	543.6	1129.8
1/9/2010	4:15	610.2	607.8	1218
1/9/2010	4:30	656.4	555.6	1212
1/9/2010	4:45	638.4	619.2	1257.6
1/9/2010	5:00	633.6	595.2	1228.8
1/9/2010	5:15	660.6	591	1251.6
1/9/2010	5:30	673.2	669	1342.2
1/9/2010	5:45	830.4	682.8	1513.2
1/9/2010	6:00	931.2	772.2	1703.4
1/9/2010	6:15	995.4	754.8	1750.2
1/9/2010	6:30	1027.2	804	1831.2
1/9/2010	6:45	970.8	796.2	1767
1/9/2010	7:00	1070.4	784.8	1855.2
1/9/2010	7:15	1224.6	810	2034.6
1/9/2010	7:30	1171.2	790.8	1962
1/9/2010	7:45	1158.6	798	1956.6
1/9/2010	8:00	1160.4	778.8	1939.2
1/9/2010	8:15	1126.8	773.4	1900.2
1/9/2010	8:30	1151.4	789.6	1941
1/9/2010	8:45	1135.8	790.8	1926.6
1/9/2010	9:00	1134.6	751.8	1886.4
1/9/2010	9:15	1085.4	753.6	1839
1/9/2010	9:30	1110.6	753.6	1864.2
1/9/2010	9:45	1080.6	753	1833.6
1/9/2010	10:00	1083	762.6	1845.6
1/9/2010	10:15	1118.4	762	1880.4
1/9/2010	10:30	1078.8	760.2	1839
1/9/2010	10:45	1105.2	774.6	1879.8
1/9/2010	11:00	993.6	778.8	1772.4
1/9/2010	11:15	934.2	777	1711.2
1/9/2010	11:30	966	777.6	1743.6
1/9/2010	11:45	981	808.8	1789.8
1/9/2010	12:00	1000.2	785.4	1785.6

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/9/2010	12:15	1006.8	804	1810.8
1/9/2010	12:30	1062.6	793.2	1855.8
1/9/2010	12:45	1123.8	783.6	1907.4
1/9/2010	13:00	1141.8	785.4	1927.2
1/9/2010	13:15	1095	792.6	1887.6
1/9/2010	13:30	1083.6	800.4	1884
1/9/2010	13:45	1129.8	798	1927.8
1/9/2010	14:00	1108.8	796.8	1905.6
1/9/2010	14:15	1135.8	792	1927.8
1/9/2010	14:30	1096.2	801.6	1897.8
1/9/2010	14:45	1022.4	798.6	1821
1/9/2010	15:00	964.8	741	1705.8
1/9/2010	15:15	970.8	775.2	1746
1/9/2010	15:30	984	778.2	1762.2
1/9/2010	15:45	980.4	751.2	1731.6
1/9/2010	16:00	949.8	760.2	1710
1/9/2010	16:15	928.8	740.4	1669.2
1/9/2010	16:30	895.2	727.8	1623
1/9/2010	16:45	900.6	728.4	1629
1/9/2010	17:00	888.6	750	1638.6
1/9/2010	17:15	707.4	702.6	1410
1/9/2010	17:30	586.2	615	1201.2
1/9/2010	17:45	501	564.6	1065.6
1/9/2010	18:00	495.6	570	1065.6
1/9/2010	18:15	478.8	559.2	1038
1/9/2010	18:30	451.2	525	976.2
1/9/2010	18:45	447	565.2	1012.2
1/9/2010	19:00	433.8	566.4	1000.2
1/9/2010	19:15	439.2	559.2	998.4
1/9/2010	19:30	431.4	525	956.4
1/9/2010	19:45	436.2	530.4	966.6
1/9/2010	20:00	432	555	987
1/9/2010	20:15	454.8	544.2	999
1/9/2010	20:30	463.2	593.4	1056.6
1/9/2010	20:45	468	567	1035
1/9/2010	21:00	459.6	663	1122.6
1/9/2010	21:15	436.8	591	1027.8
1/9/2010	21:30	436.8	579.6	1016.4
1/9/2010	21:45	450	566.4	1016.4
1/9/2010	22:00	445.8	622.2	1068
1/9/2010	22:15	421.8	529.2	951
1/9/2010	22:30	446.4	573.6	1020
1/9/2010	22:45	474.6	582.6	1057.2
1/9/2010	23:00	462	529.2	991.2
1/9/2010	23:15	453.6	441	894.6
1/9/2010	23:30	490.2	613.2	1103.4
1/9/2010	23:45	464.4	512.4	976.8
1/9/2010	24:00:00	499.2	518.4	1017.6
1/10/2010	0:15	497.4	546.6	1044
1/10/2010	0:30	500.4	505.8	1006.2
1/10/2010	0:45	501	553.2	1054.2
1/10/2010	1:00	497.4	508.2	1005.6
1/10/2010	1:15	511.2	541.8	1053
1/10/2010	1:30	505.2	512.4	1017.6
1/10/2010	1:45	535.8	545.4	1081.2
1/10/2010	2:00	506.4	513.6	1020
1/10/2010	2:15	483.6	507	990.6
1/10/2010	2:30	514.2	502.8	1017
1/10/2010	2:45	473.4	499.2	972.6
1/10/2010	3:00	455.4	492	947.4
1/10/2010	3:15	532.2	488.4	1020.6
1/10/2010	3:30	544.2	487.2	1031.4
1/10/2010	3:45	540.6	499.2	1039.8
1/10/2010	4:00	543.6	586.8	1130.4
1/10/2010	4:15	578.4	526.8	1105.2
1/10/2010	4:30	621.6	599.4	1221
1/10/2010	4:45	671.4	558	1229.4
1/10/2010	5:00	721.8	531.6	1253.4

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/10/2010	5:15	769.2	597	1366.2
1/10/2010	5:30	781.8	631.2	1413
1/10/2010	5:45	876	688.2	1564.2
1/10/2010	6:00	987.6	702	1689.6
1/10/2010	6:15	1133.4	771.6	1905
1/10/2010	6:30	1185	804	1989
1/10/2010	6:45	1197	807.6	2004.6
1/10/2010	7:00	1171.8	801.6	1973.4
1/10/2010	7:15	1182.6	825	2007.6
1/10/2010	7:30	1142.4	808.2	1950.6
1/10/2010	7:45	1158.6	817.8	1976.4
1/10/2010	8:00	1161.6	802.2	1963.8
1/10/2010	8:15	1148.4	779.4	1927.8
1/10/2010	8:30	1131	789	1920
1/10/2010	8:45	1149	799.8	1948.8
1/10/2010	9:00	1147.8	787.2	1935
1/10/2010	9:15	1206.6	814.2	2020.8
1/10/2010	9:30	1172.4	769.2	1941.6
1/10/2010	9:45	1182	801	1983
1/10/2010	10:00	1180.2	796.8	1977
1/10/2010	10:15	1075.8	790.8	1866.6
1/10/2010	10:30	1046.4	757.8	1804.2
1/10/2010	10:45	1138.2	783	1921.2
1/10/2010	11:00	1144.8	796.8	1941.6
1/10/2010	11:15	1153.2	789	1942.2
1/10/2010	11:30	1190.4	787.8	1978.2
1/10/2010	11:45	1167	783.6	1950.6
1/10/2010	12:00	1107.6	781.2	1888.8
1/10/2010	12:15	1119.6	781.8	1901.4
1/10/2010	12:30	1120.8	808.2	1929
1/10/2010	12:45	1123.8	814.2	1938
1/10/2010	13:00	1179.6	794.4	1974
1/10/2010	13:15	1182	790.2	1972.2
1/10/2010	13:30	1174.2	800.4	1974.6
1/10/2010	13:45	1167	797.4	1964.4
1/10/2010	14:00	1057.2	831.6	1888.8
1/10/2010	14:15	931.8	755.4	1687.2
1/10/2010	14:30	916.8	783.6	1700.4
1/10/2010	14:45	960.6	763.2	1723.8
1/10/2010	15:00	925.2	750	1675.2
1/10/2010	15:15	843	750	1593
1/10/2010	15:30	751.8	726	1477.8
1/10/2010	15:45	722.4	700.2	1422.6
1/10/2010	16:00	694.2	696	1390.2
1/10/2010	16:15	649.2	674.4	1323.6
1/10/2010	16:30	591	640.2	1231.2
1/10/2010	16:45	616.2	669.6	1285.8
1/10/2010	17:00	604.8	685.8	1290.6
1/10/2010	17:15	580.2	625.2	1205.4
1/10/2010	17:30	558	596.4	1154.4
1/10/2010	17:45	575.4	614.4	1189.8
1/10/2010	18:00	526.2	592.8	1119
1/10/2010	18:15	535.8	578.4	1114.2
1/10/2010	18:30	519.6	540	1059.6
1/10/2010	18:45	519	568.2	1087.2
1/10/2010	19:00	531	628.8	1159.8
1/10/2010	19:15	545.4	574.8	1120.2
1/10/2010	19:30	573	613.2	1186.2
1/10/2010	19:45	581.4	588.6	1170
1/10/2010	20:00	565.8	597	1162.8
1/10/2010	20:15	518.4	582.6	1101
1/10/2010	20:30	496.2	531.6	1027.8
1/10/2010	20:45	505.8	526.8	1032.6
1/10/2010	21:00	490.2	591.6	1081.8
1/10/2010	21:15	472.8	544.8	1017.6
1/10/2010	21:30	477	524.4	1001.4
1/10/2010	21:45	479.4	522	1001.4
1/10/2010	22:00	482.4	597	1079.4

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/10/2010	22:15	441	601.8	1042.8
1/10/2010	22:30	419.4	565.2	984.6
1/10/2010	22:45	409.2	579.6	988.8
1/10/2010	23:00	430.2	586.2	1016.4
1/10/2010	23:15	457.2	517.8	975
1/10/2010	23:30	450.6	618	1068.6
1/10/2010	23:45	483.6	674.4	1158
1/10/2010	24:00:00	497.4	676.2	1173.6
1/11/2010	0:15	491.4	628.8	1120.2
1/11/2010	0:30	493.8	647.4	1141.2
1/11/2010	0:45	508.8	670.2	1179
1/11/2010	1:00	510	693.6	1203.6
1/11/2010	1:15	532.2	795	1327.2
1/11/2010	1:30	546	735.6	1281.6
1/11/2010	1:45	546.6	810.6	1357.2
1/11/2010	2:00	546	752.4	1298.4
1/11/2010	2:15	616.8	763.2	1380
1/11/2010	2:30	714.6	790.2	1504.8
1/11/2010	2:45	700.8	785.4	1486.2
1/11/2010	3:00	684.6	763.8	1448.4
1/11/2010	3:15	796.8	762	1558.8
1/11/2010	3:30	768.6	744.6	1513.2
1/11/2010	3:45	699.6	838.2	1537.8
1/11/2010	4:00	681.6	854.4	1536
1/11/2010	4:15	751.8	853.2	1605
1/11/2010	4:30	791.4	855.6	1647
1/11/2010	4:45	809.4	855	1664.4
1/11/2010	5:00	835.8	852.6	1688.4
1/11/2010	5:15	889.8	777	1666.8
1/11/2010	5:30	822	790.8	1612.8
1/11/2010	5:45	908.4	782.4	1690.8
1/11/2010	6:00	1060.2	774.6	1834.8
1/11/2010	6:15	1207.8	784.8	1992.6
1/11/2010	6:30	1156.2	803.4	1959.6
1/11/2010	6:45	1087.8	783.6	1871.4
1/11/2010	7:00	1034.4	796.8	1831.2
1/11/2010	7:15	1108.2	810	1918.2
1/11/2010	7:30	1160.4	858	2018.4
1/11/2010	7:45	1245.6	887.4	2133
1/11/2010	8:00	1286.4	885	2171.4
1/11/2010	8:15	1267.2	838.8	2106
1/11/2010	8:30	1309.2	876	2185.2
1/11/2010	8:45	1231.2	895.8	2127
1/11/2010	9:00	1159.2	867.6	2026.8
1/11/2010	9:15	1095.6	832.2	1927.8
1/11/2010	9:30	1164.6	829.2	1993.8
1/11/2010	9:45	1278.6	804.6	2083.2
1/11/2010	10:00	1294.2	808.2	2102.4
1/11/2010	10:15	1186.2	753	1939.2
1/11/2010	10:30	1214.4	768	1982.4
1/11/2010	10:45	1266.6	742.2	2008.8
1/11/2010	11:00	1332	761.4	2093.4
1/11/2010	11:15	1319.4	746.4	2065.8
1/11/2010	11:30	1245	759.6	2004.6
1/11/2010	11:45	1156.2	782.4	1938.6
1/11/2010	12:00	1143.6	840	1983.6
1/11/2010	12:15	1196.4	820.8	2017.2
1/11/2010	12:30	1180.2	802.8	1983
1/11/2010	12:45	1192.2	819	2011.2
1/11/2010	13:00	1183.2	826.8	2010
1/11/2010	13:15	1246.8	819.6	2066.4
1/11/2010	13:30	1225.2	805.2	2030.4
1/11/2010	13:45	1212	769.8	1981.8
1/11/2010	14:00	1257	765	2022
1/11/2010	14:15	1275	777	2052
1/11/2010	14:30	1300.8	837	2137.8
1/11/2010	14:45	1299	830.4	2129.4
1/11/2010	15:00	1270.2	844.8	2115

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/11/2010	15:15	1265.4	856.8	2122.2
1/11/2010	15:30	1282.8	831	2113.8
1/11/2010	15:45	1292.4	826.8	2119.2
1/11/2010	16:00	1346.4	885	2231.4
1/11/2010	16:15	1360.2	860.4	2220.6
1/11/2010	16:30	1318.8	835.8	2154.6
1/11/2010	16:45	1321.2	828.6	2149.8
1/11/2010	17:00	1323.6	806.4	2130
1/11/2010	17:15	1287	784.8	2071.8
1/11/2010	17:30	1290	813.6	2103.6
1/11/2010	17:45	1242	879	2121
1/11/2010	18:00	1265.4	837	2102.4
1/11/2010	18:15	1281.6	831	2112.6
1/11/2010	18:30	1003.2	818.4	1821.6
1/11/2010	18:45	1010.4	808.8	1819.2
1/11/2010	19:00	1070.4	811.8	1882.2
1/11/2010	19:15	1138.2	813.6	1951.8
1/11/2010	19:30	1135.2	793.8	1929
1/11/2010	19:45	1085.4	745.8	1831.2
1/11/2010	20:00	1014	744	1758
1/11/2010	20:15	1033.8	726	1759.8
1/11/2010	20:30	1005.6	711	1716.6
1/11/2010	20:45	1040.4	744.6	1785
1/11/2010	21:00	1038.6	778.2	1816.8
1/11/2010	21:15	1045.2	787.8	1833
1/11/2010	21:30	1061.4	767.4	1828.8
1/11/2010	21:45	1033.8	674.4	1708.2
1/11/2010	22:00	1023	675	1698
1/11/2010	22:15	1030.8	699	1729.8
1/11/2010	22:30	1018.2	718.8	1737
1/11/2010	22:45	1018.2	733.2	1751.4
1/11/2010	23:00	1009.2	729	1738.2
1/11/2010	23:15	962.4	696	1658.4
1/11/2010	23:30	939	696	1635
1/11/2010	23:45	870.6	727.8	1598.4
1/11/2010	24:00:00	751.2	705	1456.2
1/12/2010	0:15	599.4	659.4	1258.8
1/12/2010	0:30	573	672.6	1245.6
1/12/2010	0:45	534.6	677.4	1212
1/12/2010	1:00	544.2	630	1174.2
1/12/2010	1:15	556.8	660.6	1217.4
1/12/2010	1:30	613.8	703.8	1317.6
1/12/2010	1:45	610.8	704.4	1315.2
1/12/2010	2:00	640.2	708	1348.2
1/12/2010	2:15	682.8	812.4	1495.2
1/12/2010	2:30	702	772.2	1474.2
1/12/2010	2:45	643.2	715.8	1359
1/12/2010	3:00	679.8	716.4	1396.2
1/12/2010	3:15	776.4	702.6	1479
1/12/2010	3:30	691.2	675	1366.2
1/12/2010	3:45	628.2	636	1264.2
1/12/2010	4:00	636.6	659.4	1296
1/12/2010	4:15	633	648.6	1281.6
1/12/2010	4:30	645	613.2	1258.2
1/12/2010	4:45	662.4	655.2	1317.6
1/12/2010	5:00	766.2	760.8	1527
1/12/2010	5:15	805.2	730.2	1535.4
1/12/2010	5:30	814.8	751.8	1566.6
1/12/2010	5:45	811.8	782.4	1594.2
1/12/2010	6:00	811.8	759.6	1571.4
1/12/2010	6:15	859.8	769.2	1629
1/12/2010	6:30	895.8	784.2	1680
1/12/2010	6:45	906	796.2	1702.2
1/12/2010	7:00	924	790.8	1714.8
1/12/2010	7:15	1031.4	798.6	1830
1/12/2010	7:30	1126.2	825	1951.2
1/12/2010	7:45	1167	802.2	1969.2
1/12/2010	8:00	1092	792.6	1884.6

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/12/2010	8:15	1054.8	744	1798.8
1/12/2010	8:30	967.8	731.4	1699.2
1/12/2010	8:45	1040.4	735	1775.4
1/12/2010	9:00	1108.8	811.2	1920
1/12/2010	9:15	1170	816.6	1986.6
1/12/2010	9:30	1173.6	821.4	1995
1/12/2010	9:45	1160.4	804.6	1965
1/12/2010	10:00	1195.8	802.2	1998
1/12/2010	10:15	1087.2	835.2	1922.4
1/12/2010	10:30	1017	835.8	1852.8
1/12/2010	10:45	1085.4	832.2	1917.6
1/12/2010	11:00	1309.2	842.4	2151.6
1/12/2010	11:15	1341	839.4	2180.4
1/12/2010	11:30	1326.6	828.6	2155.2
1/12/2010	11:45	1347	848.4	2195.4
1/12/2010	12:00	1314	861	2175
1/12/2010	12:15	1252.2	850.2	2102.4
1/12/2010	12:30	1189.2	876.6	2065.8
1/12/2010	12:45	1072.2	858.6	1930.8
1/12/2010	13:00	1060.2	822	1882.2
1/12/2010	13:15	1186.2	811.8	1998
1/12/2010	13:30	1230	813.6	2043.6
1/12/2010	13:45	1271.4	859.8	2131.2
1/12/2010	14:00	1281.6	871.2	2152.8
1/12/2010	14:15	1198.8	789.6	1988.4
1/12/2010	14:30	1258.8	808.8	2067.6
1/12/2010	14:45	1122.6	803.4	1926
1/12/2010	15:00	1161.6	831.6	1993.2
1/12/2010	15:15	1223.4	802.2	2025.6
1/12/2010	15:30	1201.2	793.2	1994.4
1/12/2010	15:45	1254.6	827.4	2082
1/12/2010	16:00	1309.8	846	2155.8
1/12/2010	16:15	1350.6	843.6	2194.2
1/12/2010	16:30	1289.4	842.4	2131.8
1/12/2010	16:45	1206.6	822	2028.6
1/12/2010	17:00	1156.2	867.6	2023.8
1/12/2010	17:15	1140	850.2	1990.2
1/12/2010	17:30	1150.8	786	1936.8
1/12/2010	17:45	1171.2	799.8	1971
1/12/2010	18:00	1207.2	790.8	1998
1/12/2010	18:15	1242.6	805.8	2048.4
1/12/2010	18:30	1255.8	832.2	2088
1/12/2010	18:45	1237.8	814.8	2052.6
1/12/2010	19:00	1174.8	808.8	1983.6
1/12/2010	19:15	1172.4	817.2	1989.6
1/12/2010	19:30	1145.4	802.2	1947.6
1/12/2010	19:45	1131	799.8	1930.8
1/12/2010	20:00	1131	817.2	1948.2
1/12/2010	20:15	1108.2	840.6	1948.8
1/12/2010	20:30	967.8	781.8	1749.6
1/12/2010	20:45	994.8	750	1744.8
1/12/2010	21:00	1095	783	1878
1/12/2010	21:15	1094.4	786.6	1881
1/12/2010	21:30	1110	772.8	1882.8
1/12/2010	21:45	1029.6	761.4	1791
1/12/2010	22:00	950.4	747	1697.4
1/12/2010	22:15	922.2	750	1672.2
1/12/2010	22:30	859.2	738.6	1597.8
1/12/2010	22:45	880.2	748.8	1629
1/12/2010	23:00	820.2	756.6	1576.8
1/12/2010	23:15	814.2	601.2	1415.4
1/12/2010	23:30	834.6	639	1473.6
1/12/2010	23:45	857.4	667.8	1525.2
1/12/2010	24:00:00	867.6	661.2	1528.8
1/13/2010	0:15	838.8	588	1426.8
1/13/2010	0:30	816	628.2	1444.2
1/13/2010	0:45	814.2	652.2	1466.4
1/13/2010	1:00	793.2	639.6	1432.8

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/13/2010	1:15	772.8	653.4	1426.2
1/13/2010	1:30	826.8	662.4	1489.2
1/13/2010	1:45	828	661.8	1489.8
1/13/2010	2:00	846.6	652.2	1498.8
1/13/2010	2:15	787.2	666.6	1453.8
1/13/2010	2:30	796.8	642.6	1439.4
1/13/2010	2:45	780	642.6	1422.6
1/13/2010	3:00	774.6	624	1398.6
1/13/2010	3:15	795	628.8	1423.8
1/13/2010	3:30	766.2	609.6	1375.8
1/13/2010	3:45	754.8	538.8	1293.6
1/13/2010	4:00	789	604.8	1393.8
1/13/2010	4:15	816	752.4	1568.4
1/13/2010	4:30	839.4	737.4	1576.8
1/13/2010	4:45	897	727.8	1624.8
1/13/2010	5:00	921.6	740.4	1662
1/13/2010	5:15	874.8	733.8	1608.6
1/13/2010	5:30	855.6	712.2	1567.8
1/13/2010	5:45	886.8	729	1615.8
1/13/2010	6:00	1005	741	1746
1/13/2010	6:15	1016.4	756.6	1773
1/13/2010	6:30	1006.2	747.6	1753.8
1/13/2010	6:45	1090.8	773.4	1864.2
1/13/2010	7:00	1097.4	771.6	1869
1/13/2010	7:15	1093.2	759.6	1852.8
1/13/2010	7:30	1137.6	787.2	1924.8
1/13/2010	7:45	1139.4	800.4	1939.8
1/13/2010	8:00	1159.2	816	1975.2
1/13/2010	8:15	1110	871.8	1981.8
1/13/2010	8:30	971.4	786	1757.4
1/13/2010	8:45	1126.2	810.6	1936.8
1/13/2010	9:00	1176.6	826.2	2002.8
1/13/2010	9:15	1180.8	891	2071.8
1/13/2010	9:30	1227	850.8	2077.8
1/13/2010	9:45	1251	883.2	2134.2
1/13/2010	10:00	1137.6	810.6	1948.2
1/13/2010	10:15	1102.8	784.8	1887.6
1/13/2010	10:30	1057.2	754.8	1812
1/13/2010	10:45	1091.4	830.4	1921.8
1/13/2010	11:00	1152.6	907.8	2060.4
1/13/2010	11:15	1167.6	853.2	2020.8
1/13/2010	11:30	1136.4	786.6	1923
1/13/2010	11:45	1106.4	796.2	1902.6
1/13/2010	12:00	1102.8	799.2	1902
1/13/2010	12:15	1128	833.4	1961.4
1/13/2010	12:30	1209.6	870.6	2080.2
1/13/2010	12:45	1171.2	884.4	2055.6
1/13/2010	13:00	1197	32	1229
1/13/2010	13:15	1197.6	963.6	2161.2
1/13/2010	13:30	1139.4	915	2054.4
1/13/2010	13:45	1177.8	912.6	2090.4
1/13/2010	14:00	1245.6	897	2142.6
1/13/2010	14:15	1274.4	880.2	2154.6
1/13/2010	14:30	1223.4	914.4	2137.8
1/13/2010	14:45	1152	916.2	2068.2
1/13/2010	15:00	1032	887.4	1919.4
1/13/2010	15:15	998.4	798.6	1797
1/13/2010	15:30	1047	821.4	1868.4
1/13/2010	15:45	1167	784.8	1951.8
1/13/2010	16:00	1348.8	798.6	2147.4
1/13/2010	16:15	1309.2	806.4	2115.6
1/13/2010	16:30	1162.8	800.4	1963.2
1/13/2010	16:45	1242	820.8	2062.8
1/13/2010	17:00	1275.6	870	2145.6
1/13/2010	17:15	1295.4	812.4	2107.8
1/13/2010	17:30	1268.4	825	2093.4
1/13/2010	17:45	1180.2	843	2023.2
1/13/2010	18:00	1126.2	843.6	1969.8

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/13/2010	18:15	1190.4	806.4	1996.8
1/13/2010	18:30	1192.2	799.2	1991.4
1/13/2010	18:45	1185.6	792.6	1978.2
1/13/2010	19:00	1174.8	791.4	1966.2
1/13/2010	19:15	1181.4	793.8	1975.2
1/13/2010	19:30	1165.2	772.8	1938
1/13/2010	19:45	1071	731.4	1802.4
1/13/2010	20:00	1114.2	754.8	1869
1/13/2010	20:15	1142.4	757.8	1900.2
1/13/2010	20:30	1111.8	764.4	1876.2
1/13/2010	20:45	1102.8	789	1891.8
1/13/2010	21:00	1116.6	803.4	1920
1/13/2010	21:15	1137.6	835.8	1973.4
1/13/2010	21:30	1096.2	801.6	1897.8
1/13/2010	21:45	1044.6	733.2	1777.8
1/13/2010	22:00	1074	792	1866
1/13/2010	22:15	1044.6	775.8	1820.4
1/13/2010	22:30	1014	797.4	1811.4
1/13/2010	22:45	1013.4	753	1766.4
1/13/2010	23:00	976.8	815.4	1792.2
1/13/2010	23:15	867	639.6	1506.6
1/13/2010	23:30	886.2	702.6	1588.8
1/13/2010	23:45	937.8	709.2	1647
1/13/2010	24:00:00	945	681	1626
1/14/2010	0:15	937.8	636	1573.8
1/14/2010	0:30	936	718.8	1654.8
1/14/2010	0:45	915	652.8	1567.8
1/14/2010	1:00	899.4	611.4	1510.8
1/14/2010	1:15	910.8	657	1567.8
1/14/2010	1:30	912	636.6	1548.6
1/14/2010	1:45	771	613.2	1384.2
1/14/2010	2:00	738	679.2	1417.2
1/14/2010	2:15	643.8	631.8	1275.6
1/14/2010	2:30	584.4	641.4	1225.8
1/14/2010	2:45	602.4	699.6	1302
1/14/2010	3:00	599.4	662.4	1261.8
1/14/2010	3:15	759	698.4	1457.4
1/14/2010	3:30	661.8	693.6	1355.4
1/14/2010	3:45	651	711.6	1362.6
1/14/2010	4:00	659.4	751.2	1410.6
1/14/2010	4:15	693.6	697.8	1391.4
1/14/2010	4:30	757.8	711.6	1469.4
1/14/2010	4:45	753	719.4	1472.4
1/14/2010	5:00	783.6	708.6	1492.2
1/14/2010	5:15	810	745.8	1555.8
1/14/2010	5:30	799.2	711.6	1510.8
1/14/2010	5:45	845.4	754.2	1599.6
1/14/2010	6:00	943.8	745.8	1689.6
1/14/2010	6:15	1088.4	775.8	1864.2
1/14/2010	6:30	1102.8	792	1894.8
1/14/2010	6:45	1129.8	802.2	1932
1/14/2010	7:00	1127.4	817.8	1945.2
1/14/2010	7:15	1231.2	858.6	2089.8
1/14/2010	7:30	1232.4	863.4	2095.8
1/14/2010	7:45	1233.6	857.4	2091
1/14/2010	8:00	1197	868.2	2065.2
1/14/2010	8:15	1123.8	806.4	1930.2
1/14/2010	8:30	1170	776.4	1946.4
1/14/2010	8:45	1227.6	820.2	2047.8
1/14/2010	9:00	1209.6	846.6	2056.2
1/14/2010	9:15	1143	817.2	1960.2
1/14/2010	9:30	1069.8	831	1900.8
1/14/2010	9:45	1116	793.8	1909.8
1/14/2010	10:00	1183.2	827.4	2010.6
1/14/2010	10:15	1268.4	883.8	2152.2
1/14/2010	10:30	1227	875.4	2102.4
1/14/2010	10:45	1293	862.2	2155.2
1/14/2010	11:00	1264.8	852	2116.8

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/14/2010	11:15	1260.6	894	2154.6
1/14/2010	11:30	1249.8	891	2140.8
1/14/2010	11:45	1233	895.2	2128.2
1/14/2010	12:00	1253.4	887.4	2140.8
1/14/2010	12:15	1233.6	909	2142.6
1/14/2010	12:30	1195.8	981.6	2177.4
1/14/2010	12:45	1159.8	960	2119.8
1/14/2010	13:00	1167.6	988.2	2155.8
1/14/2010	13:15	1174.2	904.8	2079
1/14/2010	13:30	1175.4	889.8	2065.2
1/14/2010	13:45	1190.4	864	2054.4
1/14/2010	14:00	1172.4	849	2021.4
1/14/2010	14:15	1236.6	837	2073.6
1/14/2010	14:30	1275	861.6	2136.6
1/14/2010	14:45	1315.2	861.6	2176.8
1/14/2010	15:00	1314.6	880.2	2194.8
1/14/2010	15:15	1291.2	875.4	2166.6
1/14/2010	15:30	1328.4	930	2258.4
1/14/2010	15:45	1245	955.8	2200.8
1/14/2010	16:00	1239	908.4	2147.4
1/14/2010	16:15	1273.8	888	2161.8
1/14/2010	16:30	1276.8	905.4	2182.2
1/14/2010	16:45	1287	892.8	2179.8
1/14/2010	17:00	1297.8	898.8	2196.6
1/14/2010	17:15	1193.4	853.2	2046.6
1/14/2010	17:30	1190.4	837.6	2028
1/14/2010	17:45	1200.6	862.2	2062.8
1/14/2010	18:00	1140.6	871.2	2011.8
1/14/2010	18:15	1227.6	848.4	2076
1/14/2010	18:30	1259.4	886.8	2146.2
1/14/2010	18:45	1194	830.4	2024.4
1/14/2010	19:00	1215	791.4	2006.4
1/14/2010	19:15	1179	782.4	1961.4
1/14/2010	19:30	1165.8	754.2	1920
1/14/2010	19:45	1203	775.2	1978.2
1/14/2010	20:00	1228.2	765.6	1993.8
1/14/2010	20:15	1193.4	750.6	1944
1/14/2010	20:30	1102.2	676.2	1778.4
1/14/2010	20:45	1040.4	721.2	1761.6
1/14/2010	21:00	1038	718.2	1756.2
1/14/2010	21:15	1072.8	726.6	1799.4
1/14/2010	21:30	1050	725.4	1775.4
1/14/2010	21:45	929.4	723.6	1653
1/14/2010	22:00	826.2	705	1531.2
1/14/2010	22:15	821.4	659.4	1480.8
1/14/2010	22:30	745.8	698.4	1444.2
1/14/2010	22:45	732.6	712.2	1444.8
1/14/2010	23:00	755.4	669.6	1425
1/14/2010	23:15	774.6	666.6	1441.2
1/14/2010	23:30	772.2	680.4	1452.6
1/14/2010	23:45	726.6	655.2	1381.8
1/14/2010	24:00:00	723	625.8	1348.8
1/15/2010	0:15	780.6	643.2	1423.8
1/15/2010	0:30	740.4	589.2	1329.6
1/15/2010	0:45	738.6	619.8	1358.4
1/15/2010	1:00	744	624.6	1368.6
1/15/2010	1:15	805.2	579.6	1384.8
1/15/2010	1:30	802.2	688.8	1491
1/15/2010	1:45	846	699.6	1545.6
1/15/2010	2:00	830.4	702.6	1533
1/15/2010	2:15	794.4	670.2	1464.6
1/15/2010	2:30	718.8	691.8	1410.6
1/15/2010	2:45	709.8	675.6	1385.4
1/15/2010	3:00	730.2	679.2	1409.4
1/15/2010	3:15	805.8	669	1474.8
1/15/2010	3:30	707.4	695.4	1402.8
1/15/2010	3:45	664.8	700.2	1365
1/15/2010	4:00	703.2	675.6	1378.8

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/15/2010	4:15	786.6	705.6	1492.2
1/15/2010	4:30	802.2	694.2	1496.4
1/15/2010	4:45	795	687.6	1482.6
1/15/2010	5:00	763.8	670.2	1434
1/15/2010	5:15	808.8	682.8	1491.6
1/15/2010	5:30	813.6	693.6	1507.2
1/15/2010	5:45	863.4	703.8	1567.2
1/15/2010	6:00	1027.2	753	1780.2
1/15/2010	6:15	1134	763.2	1897.2
1/15/2010	6:30	1207.2	813.6	2020.8
1/15/2010	6:45	1309.8	853.8	2163.6
1/15/2010	7:00	1323.6	861	2184.6
1/15/2010	7:15	1322.4	893.4	2215.8
1/15/2010	7:30	1223.4	879	2102.4
1/15/2010	7:45	1233.6	865.2	2098.8
1/15/2010	8:00	1159.8	862.2	2022
1/15/2010	8:15	1103.4	852.6	1956
1/15/2010	8:30	1056.6	828.6	1885.2
1/15/2010	8:45	961.8	813.6	1775.4
1/15/2010	9:00	1081.2	803.4	1884.6
1/15/2010	9:15	1212	819	2031
1/15/2010	9:30	1188	887.4	2075.4
1/15/2010	9:45	1173.6	862.8	2036.4
1/15/2010	10:00	1182	824.4	2006.4
1/15/2010	10:15	1161	826.2	1987.2
1/15/2010	10:30	1199.4	859.2	2058.6
1/15/2010	10:45	1173.6	843.6	2017.2
1/15/2010	11:00	1125	810	1935
1/15/2010	11:15	1170	852.6	2022.6
1/15/2010	11:30	1209	849	2058
1/15/2010	11:45	1238.4	868.8	2107.2
1/15/2010	12:00	1258.2	868.8	2127
1/15/2010	12:15	1290	840	2130
1/15/2010	12:30	1290	883.8	2173.8
1/15/2010	12:45	1234.8	892.2	2127
1/15/2010	13:00	1174.2	885.6	2059.8
1/15/2010	13:15	1138.2	892.2	2030.4
1/15/2010	13:30	1098.6	886.8	1985.4
1/15/2010	13:45	1105.2	892.2	1997.4
1/15/2010	14:00	1186.2	949.2	2135.4
1/15/2010	14:15	1212	988.2	2200.2
1/15/2010	14:30	1192.8	948.6	2141.4
1/15/2010	14:45	1218.6	991.8	2210.4
1/15/2010	15:00	1192.8	960	2152.8
1/15/2010	15:15	1202.4	930	2132.4
1/15/2010	15:30	1233.6	978	2211.6
1/15/2010	15:45	1276.2	17	1293.2
1/15/2010	16:00	1261.8	990.6	2252.4
1/15/2010	16:15	1181.4	964.8	2146.2
1/15/2010	16:30	1156.2	919.2	2075.4
1/15/2010	16:45	1148.4	959.4	2107.8
1/15/2010	17:00	1144.8	919.8	2064.6
1/15/2010	17:15	1133.4	871.2	2004.6
1/15/2010	17:30	1065.6	805.2	1870.8
1/15/2010	17:45	1095.6	858.6	1954.2
1/15/2010	18:00	1124.4	884.4	2008.8
1/15/2010	18:15	1062.6	840	1902.6
1/15/2010	18:30	1057.2	792.6	1849.8
1/15/2010	18:45	1071.6	826.8	1898.4
1/15/2010	19:00	1041	817.8	1858.8
1/15/2010	19:15	1032.6	838.2	1870.8
1/15/2010	19:30	946.8	763.8	1710.6
1/15/2010	19:45	922.8	739.8	1662.6
1/15/2010	20:00	927	756.6	1683.6
1/15/2010	20:15	893.4	679.8	1573.2
1/15/2010	20:30	850.2	695.4	1545.6
1/15/2010	20:45	855.6	696	1551.6
1/15/2010	21:00	853.2	685.8	1539

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/15/2010	21:15	888.6	691.2	1579.8
1/15/2010	21:30	789.6	685.2	1474.8
1/15/2010	21:45	764.4	686.4	1450.8
1/15/2010	22:00	717.6	672.6	1390.2
1/15/2010	22:15	681	671.4	1352.4
1/15/2010	22:30	688.8	671.4	1360.2
1/15/2010	22:45	624	664.8	1288.8
1/15/2010	23:00	656.4	645.6	1302
1/15/2010	23:15	621	617.4	1238.4
1/15/2010	23:30	585.6	627.6	1213.2
1/15/2010	23:45	567.6	612	1179.6
1/15/2010	24:00:00	580.2	600	1180.2
1/16/2010	0:15	648	637.2	1285.2
1/16/2010	0:30	631.2	585.6	1216.8
1/16/2010	0:45	611.4	600	1211.4
1/16/2010	1:00	605.4	651.6	1257
1/16/2010	1:15	607.2	599.4	1206.6
1/16/2010	1:30	633	654.6	1287.6
1/16/2010	1:45	680.4	748.2	1428.6
1/16/2010	2:00	656.4	706.8	1363.2
1/16/2010	2:15	642.6	688.8	1331.4
1/16/2010	2:30	631.2	693	1324.2
1/16/2010	2:45	610.8	681.6	1292.4
1/16/2010	3:00	618.6	658.8	1277.4
1/16/2010	3:15	781.8	723.6	1505.4
1/16/2010	3:30	830.4	708	1538.4
1/16/2010	3:45	773.4	669.6	1443
1/16/2010	4:00	738	673.8	1411.8
1/16/2010	4:15	729	687.6	1416.6
1/16/2010	4:30	700.8	704.4	1405.2
1/16/2010	4:45	725.4	710.4	1435.8
1/16/2010	5:00	714	713.4	1427.4
1/16/2010	5:15	762	717.6	1479.6
1/16/2010	5:30	742.2	718.2	1460.4
1/16/2010	5:45	851.4	817.2	1668.6
1/16/2010	6:00	930	800.4	1730.4
1/16/2010	6:15	976.8	801.6	1778.4
1/16/2010	6:30	1081.2	837	1918.2
1/16/2010	6:45	1148.4	838.2	1986.6
1/16/2010	7:00	1181.4	849	2030.4
1/16/2010	7:15	1201.8	844.2	2046
1/16/2010	7:30	1212	839.4	2051.4
1/16/2010	7:45	1230.6	826.2	2056.8
1/16/2010	8:00	1185	805.2	1990.2
1/16/2010	8:15	1090.8	798.6	1889.4
1/16/2010	8:30	1089	793.8	1882.8
1/16/2010	8:45	1065	793.8	1858.8
1/16/2010	9:00	1060.8	798.6	1859.4
1/16/2010	9:15	1033.8	809.4	1843.2
1/16/2010	9:30	1053.6	799.2	1852.8
1/16/2010	9:45	1043.4	770.4	1813.8
1/16/2010	10:00	1048.2	719.4	1767.6
1/16/2010	10:15	1040.4	803.4	1843.8
1/16/2010	10:30	1065.6	811.8	1877.4
1/16/2010	10:45	1206.6	874.2	2080.8
1/16/2010	11:00	1229.4	843	2072.4
1/16/2010	11:15	1245	865.2	2110.2
1/16/2010	11:30	1223.4	860.4	2083.8
1/16/2010	11:45	1228.8	838.8	2067.6
1/16/2010	12:00	1117.2	866.4	1983.6
1/16/2010	12:15	1050.6	799.8	1850.4
1/16/2010	12:30	1008	742.2	1750.2
1/16/2010	12:45	1086	740.4	1826.4
1/16/2010	13:00	1152.6	732.6	1885.2
1/16/2010	13:15	1147.2	745.2	1892.4
1/16/2010	13:30	1095.6	789.6	1885.2
1/16/2010	13:45	993	712.2	1705.2
1/16/2010	14:00	945.6	804.6	1750.2

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/16/2010	14:15	955.8	736.2	1692
1/16/2010	14:30	906.6	771	1677.6
1/16/2010	14:45	864.6	895.2	1759.8
1/16/2010	15:00	848.4	776.4	1624.8
1/16/2010	15:15	870	779.4	1649.4
1/16/2010	15:30	814.2	790.2	1604.4
1/16/2010	15:45	851.4	759.6	1611
1/16/2010	16:00	736.8	713.4	1450.2
1/16/2010	16:15	655.2	647.4	1302.6
1/16/2010	16:30	615	651	1266
1/16/2010	16:45	566.4	652.2	1218.6
1/16/2010	17:00	547.2	655.8	1203
1/16/2010	17:15	543.6	614.4	1158
1/16/2010	17:30	496.8	631.8	1128.6
1/16/2010	17:45	462	646.2	1108.2
1/16/2010	18:00	488.4	632.4	1120.8
1/16/2010	18:15	495.6	609	1104.6
1/16/2010	18:30	510	633	1143
1/16/2010	18:45	537.6	632.4	1170
1/16/2010	19:00	581.4	630.6	1212
1/16/2010	19:15	571.2	636.6	1207.8
1/16/2010	19:30	550.2	614.4	1164.6
1/16/2010	19:45	549.6	604.2	1153.8
1/16/2010	20:00	510.6	620.4	1131
1/16/2010	20:15	498	607.8	1105.8
1/16/2010	20:30	521.4	583.8	1105.2
1/16/2010	20:45	529.2	574.2	1103.4
1/16/2010	21:00	504.6	592.2	1096.8
1/16/2010	21:15	489	562.8	1051.8
1/16/2010	21:30	487.8	598.2	1086
1/16/2010	21:45	481.2	588	1069.2
1/16/2010	22:00	478.2	574.2	1052.4
1/16/2010	22:15	496.2	554.4	1050.6
1/16/2010	22:30	481.2	601.2	1082.4
1/16/2010	22:45	460.2	591	1051.2
1/16/2010	23:00	397.2	603.6	1000.8
1/16/2010	23:15	392.4	550.8	943.2
1/16/2010	23:30	401.4	556.2	957.6
1/16/2010	23:45	433.2	547.2	980.4
1/16/2010	24:00:00	435	561	996
1/17/2010	0:15	458.4	544.8	1003.2
1/17/2010	0:30	463.2	547.2	1010.4
1/17/2010	0:45	490.8	593.4	1084.2
1/17/2010	1:00	487.2	628.2	1115.4
1/17/2010	1:15	504.6	653.4	1158
1/17/2010	1:30	532.2	655.8	1188
1/17/2010	1:45	519.6	634.2	1153.8
1/17/2010	2:00	528.6	630	1158.6
1/17/2010	2:15	526.8	612	1138.8
1/17/2010	2:30	527.4	618.6	1146
1/17/2010	2:45	550.8	651.6	1202.4
1/17/2010	3:00	616.8	675.6	1292.4
1/17/2010	3:15	799.8	672	1471.8
1/17/2010	3:30	708.6	665.4	1374
1/17/2010	3:45	679.2	672.6	1351.8
1/17/2010	4:00	677.4	669.6	1347
1/17/2010	4:15	670.2	664.8	1335
1/17/2010	4:30	670.8	676.2	1347
1/17/2010	4:45	693	663	1356
1/17/2010	5:00	700.2	657.6	1357.8
1/17/2010	5:15	674.4	685.8	1360.2
1/17/2010	5:30	678	714.6	1392.6
1/17/2010	5:45	765.6	675.6	1441.2
1/17/2010	6:00	880.2	696	1576.2
1/17/2010	6:15	970.2	720	1690.2
1/17/2010	6:30	1039.8	727.8	1767.6
1/17/2010	6:45	1084.8	729.6	1814.4
1/17/2010	7:00	1084.2	735	1819.2

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/17/2010	7:15	1123.8	812.4	1936.2
1/17/2010	7:30	1128.6	780.6	1909.2
1/17/2010	7:45	1161	805.2	1966.2
1/17/2010	8:00	1230.6	874.8	2105.4
1/17/2010	8:15	1247.4	864	2111.4
1/17/2010	8:30	1216.8	874.2	2091
1/17/2010	8:45	1216.8	875.4	2092.2
1/17/2010	9:00	1224.6	853.8	2078.4
1/17/2010	9:15	1218.6	862.2	2080.8
1/17/2010	9:30	1219.8	846	2065.8
1/17/2010	9:45	1191	817.8	2008.8
1/17/2010	10:00	1210.2	803.4	2013.6
1/17/2010	10:15	1218	826.8	2044.8
1/17/2010	10:30	1212	822	2034
1/17/2010	10:45	1191	820.2	2011.2
1/17/2010	11:00	1213.8	831.6	2045.4
1/17/2010	11:15	1209	817.2	2026.2
1/17/2010	11:30	1185.6	838.8	2024.4
1/17/2010	11:45	1171.8	847.8	2019.6
1/17/2010	12:00	1183.8	844.2	2028
1/17/2010	12:15	1180.8	826.8	2007.6
1/17/2010	12:30	1210.2	835.8	2046
1/17/2010	12:45	1190.4	844.8	2035.2
1/17/2010	13:00	1150.8	820.2	1971
1/17/2010	13:15	1211.4	819	2030.4
1/17/2010	13:30	1227	844.8	2071.8
1/17/2010	13:45	1183.8	828.6	2012.4
1/17/2010	14:00	1208.4	806.4	2014.8
1/17/2010	14:15	1114.2	826.8	1941
1/17/2010	14:30	969.6	795	1764.6
1/17/2010	14:45	970.2	766.8	1737
1/17/2010	15:00	1019.4	790.8	1810.2
1/17/2010	15:15	961.8	681	1642.8
1/17/2010	15:30	842.4	672.6	1515
1/17/2010	15:45	751.8	681.6	1433.4
1/17/2010	16:00	655.8	653.4	1309.2
1/17/2010	16:15	619.8	691.2	1311
1/17/2010	16:30	655.8	670.8	1326.6
1/17/2010	16:45	628.8	703.2	1332
1/17/2010	17:00	610.2	666.6	1276.8
1/17/2010	17:15	611.4	624	1235.4
1/17/2010	17:30	588	639	1227
1/17/2010	17:45	615.6	620.4	1236
1/17/2010	18:00	673.8	645.6	1319.4
1/17/2010	18:15	643.8	648.6	1292.4
1/17/2010	18:30	627	613.2	1240.2
1/17/2010	18:45	610.8	644.4	1255.2
1/17/2010	19:00	577.8	639.6	1217.4
1/17/2010	19:15	556.8	642	1198.8
1/17/2010	19:30	583.8	649.2	1233
1/17/2010	19:45	575.4	654.6	1230
1/17/2010	20:00	541.2	726	1267.2
1/17/2010	20:15	509.4	619.2	1128.6
1/17/2010	20:30	489.6	631.8	1121.4
1/17/2010	20:45	494.4	662.4	1156.8
1/17/2010	21:00	470.4	649.8	1120.2
1/17/2010	21:15	474.6	676.2	1150.8
1/17/2010	21:30	475.2	686.4	1161.6
1/17/2010	21:45	498	696.6	1194.6
1/17/2010	22:00	496.8	670.2	1167
1/17/2010	22:15	492	652.2	1144.2
1/17/2010	22:30	505.8	640.2	1146
1/17/2010	22:45	474	631.2	1105.2
1/17/2010	23:00	458.4	648	1106.4
1/17/2010	23:15	445.8	592.2	1038
1/17/2010	23:30	447.6	675	1122.6
1/17/2010	23:45	446.4	701.4	1147.8
1/17/2010	24:00:00	455.4	710.4	1165.8

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/18/2010	0:15	511.2	687	1198.2
1/18/2010	0:30	510	683.4	1193.4
1/18/2010	0:45	502.8	787.2	1290
1/18/2010	1:00	513	726.6	1239.6
1/18/2010	1:15	556.8	777	1333.8
1/18/2010	1:30	570	745.8	1315.8
1/18/2010	1:45	540	787.8	1327.8
1/18/2010	2:00	543.6	756.6	1300.2
1/18/2010	2:15	622.8	795	1417.8
1/18/2010	2:30	660	775.2	1435.2
1/18/2010	2:45	666	781.2	1447.2
1/18/2010	3:00	674.4	779.4	1453.8
1/18/2010	3:15	844.2	782.4	1626.6
1/18/2010	3:30	780	819	1599
1/18/2010	3:45	764.4	801.6	1566
1/18/2010	4:00	744.6	796.8	1541.4
1/18/2010	4:15	785.4	796.2	1581.6
1/18/2010	4:30	817.8	779.4	1597.2
1/18/2010	4:45	838.2	772.8	1611
1/18/2010	5:00	861.6	801.6	1663.2
1/18/2010	5:15	801	779.4	1580.4
1/18/2010	5:30	805.8	781.2	1587
1/18/2010	5:45	795.6	741	1536.6
1/18/2010	6:00	829.2	741	1570.2
1/18/2010	6:15	918	732	1650
1/18/2010	6:30	1039.8	836.4	1876.2
1/18/2010	6:45	1119.6	826.8	1946.4
1/18/2010	7:00	1156.2	841.8	1998
1/18/2010	7:15	1119	831.6	1950.6
1/18/2010	7:30	1102.8	839.4	1942.2
1/18/2010	7:45	1192.8	852	2044.8
1/18/2010	8:00	1222.2	898.8	2121
1/18/2010	8:15	1206	900	2106
1/18/2010	8:30	1197.6	912	2109.6
1/18/2010	8:45	1235.4	922.8	2158.2
1/18/2010	9:00	1263.6	919.8	2183.4
1/18/2010	9:15	1306.8	885.6	2192.4
1/18/2010	9:30	1350	910.2	2260.2
1/18/2010	9:45	1307.4	886.8	2194.2
1/18/2010	10:00	1305	823.8	2128.8
1/18/2010	10:15	1276.8	825	2101.8
1/18/2010	10:30	1235.4	771	2006.4
1/18/2010	10:45	1200	766.2	1966.2
1/18/2010	11:00	1149.6	730.2	1879.8
1/18/2010	11:15	1000.8	708	1708.8
1/18/2010	11:30	886.8	639.6	1526.4
1/18/2010	11:45	857.4	705.6	1563
1/18/2010	12:00	854.4	667.2	1521.6
1/18/2010	12:15	1023.6	679.8	1703.4
1/18/2010	12:30	1107	797.4	1904.4
1/18/2010	12:45	1102.2	673.2	1775.4
1/18/2010	13:00	1164.6	867.6	2032.2
1/18/2010	13:15	1294.8	840.6	2135.4
1/18/2010	13:30	1310.4	876.6	2187
1/18/2010	13:45	1293.6	885.6	2179.2
1/18/2010	14:00	1280.4	895.8	2176.2
1/18/2010	14:15	1321.8	896.4	2218.2
1/18/2010	14:30	1291.8	871.8	2163.6
1/18/2010	14:45	1285.8	907.2	2193
1/18/2010	15:00	1299	902.4	2201.4
1/18/2010	15:15	1303.2	907.8	2211
1/18/2010	15:30	1273.8	912.6	2186.4
1/18/2010	15:45	1232.4	897	2129.4
1/18/2010	16:00	1280.4	903	2183.4
1/18/2010	16:15	1276.2	909	2185.2
1/18/2010	16:30	1237.8	899.4	2137.2
1/18/2010	16:45	1239.6	887.4	2127
1/18/2010	17:00	1244.4	894.6	2139

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/18/2010	17:15	1323	902.4	2225.4
1/18/2010	17:30	1287.6	869.4	2157
1/18/2010	17:45	1285.2	888.6	2173.8
1/18/2010	18:00	1268.4	887.4	2155.8
1/18/2010	18:15	1335.6	886.8	2222.4
1/18/2010	18:30	1335	885.6	2220.6
1/18/2010	18:45	1288.2	885	2173.2
1/18/2010	19:00	1118.4	855	1973.4
1/18/2010	19:15	1146.6	853.8	2000.4
1/18/2010	19:30	1160.4	843.6	2004
1/18/2010	19:45	1185.6	855	2040.6
1/18/2010	20:00	1200.6	872.4	2073
1/18/2010	20:15	1143.6	857.4	2001
1/18/2010	20:30	1068	849.6	1917.6
1/18/2010	20:45	1056	832.2	1888.2
1/18/2010	21:00	974.4	841.8	1816.2
1/18/2010	21:15	872.4	839.4	1711.8
1/18/2010	21:30	828	714.6	1542.6
1/18/2010	21:45	846	750.6	1596.6
1/18/2010	22:00	877.8	720	1597.8
1/18/2010	22:15	875.4	676.2	1551.6
1/18/2010	22:30	810	672.6	1482.6
1/18/2010	22:45	838.2	681.6	1519.8
1/18/2010	23:00	832.8	699.6	1532.4
1/18/2010	23:15	819	682.8	1501.8
1/18/2010	23:30	836.4	672	1508.4
1/18/2010	23:45	822	701.4	1523.4
1/18/2010	24:00:00	834	649.2	1483.2
1/19/2010	0:15	817.8	647.4	1465.2
1/19/2010	0:30	816.6	652.2	1468.8
1/19/2010	0:45	793.8	667.2	1461
1/19/2010	1:00	759.6	679.2	1438.8
1/19/2010	1:15	743.4	675	1418.4
1/19/2010	1:30	732.6	654	1386.6
1/19/2010	1:45	619.2	675	1294.2
1/19/2010	2:00	643.8	693	1336.8
1/19/2010	2:15	645.6	682.2	1327.8
1/19/2010	2:30	677.4	687	1364.4
1/19/2010	2:45	640.8	790.2	1431
1/19/2010	3:00	661.8	795	1456.8
1/19/2010	3:15	647.4	765	1412.4
1/19/2010	3:30	638.4	735.6	1374
1/19/2010	3:45	675	738.6	1413.6
1/19/2010	4:00	723.6	777.6	1501.2
1/19/2010	4:15	881.4	772.2	1653.6
1/19/2010	4:30	816	779.4	1595.4
1/19/2010	4:45	772.8	772.8	1545.6
1/19/2010	5:00	755.4	778.8	1534.2
1/19/2010	5:15	816	810.6	1626.6
1/19/2010	5:30	876	813.6	1689.6
1/19/2010	5:45	911.4	833.4	1744.8
1/19/2010	6:00	910.2	831	1741.2
1/19/2010	6:15	915.6	814.2	1729.8
1/19/2010	6:30	936.6	811.2	1747.8
1/19/2010	6:45	1042.2	852	1894.2
1/19/2010	7:00	981.6	866.4	1848
1/19/2010	7:15	1012.8	858.6	1871.4
1/19/2010	7:30	1099.2	856.2	1955.4
1/19/2010	7:45	1165.2	898.2	2063.4
1/19/2010	8:00	1206	900.6	2106.6
1/19/2010	8:15	1209.6	862.8	2072.4
1/19/2010	8:30	1200.6	873	2073.6
1/19/2010	8:45	1192.2	880.8	2073
1/19/2010	9:00	1065.6	863.4	1929
1/19/2010	9:15	956.4	878.4	1834.8
1/19/2010	9:30	955.8	886.8	1842.6
1/19/2010	9:45	1206.6	895.8	2102.4
1/19/2010	10:00	1313.4	913.8	2227.2

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/19/2010	10:15	1340.4	14.6	1355
1/19/2010	10:30	1274.4	994.2	2268.6
1/19/2010	10:45	1320	972	2292
1/19/2010	11:00	1264.2	947.4	2211.6
1/19/2010	11:15	1193.4	961.2	2154.6
1/19/2010	11:30	1200.6	988.2	2188.8
1/19/2010	11:45	1198.8	947.4	2146.2
1/19/2010	12:00	1230.6	958.8	2189.4
1/19/2010	12:15	1332.6	965.4	2298
1/19/2010	12:30	1314	9.8	1323.8
1/19/2010	12:45	1296	975	2271
1/19/2010	13:00	1204.8	961.2	2166
1/19/2010	13:15	1201.2	938.4	2139.6
1/19/2010	13:30	1309.8	50	1359.8
1/19/2010	13:45	1221.6	43.4	1265
1/19/2010	14:00	1183.8	0.2	1184
1/19/2010	14:15	1181.4	865.8	2047.2
1/19/2010	14:30	1217.4	910.8	2128.2
1/19/2010	14:45	1240.2	921	2161.2
1/19/2010	15:00	1261.2	900	2161.2
1/19/2010	15:15	1276.8	912.6	2189.4
1/19/2010	15:30	1291.2	937.2	2228.4
1/19/2010	15:45	1356.6	29	1385.6
1/19/2010	16:00	1320	997.2	2317.2
1/19/2010	16:15	1244.4	952.2	2196.6
1/19/2010	16:30	1178.4	935.4	2113.8
1/19/2010	16:45	1102.8	961.2	2064
1/19/2010	17:00	1132.8	972	2104.8
1/19/2010	17:15	1130.4	952.2	2082.6
1/19/2010	17:30	1178.4	946.2	2124.6
1/19/2010	17:45	1195.8	971.4	2167.2
1/19/2010	18:00	1171.8	946.8	2118.6
1/19/2010	18:15	1080	862.8	1942.8
1/19/2010	18:30	1024.8	886.2	1911
1/19/2010	18:45	1049.4	862.8	1912.2
1/19/2010	19:00	1012.8	824.4	1837.2
1/19/2010	19:15	980.4	806.4	1786.8
1/19/2010	19:30	978.6	847.2	1825.8
1/19/2010	19:45	946.2	760.2	1706.4
1/19/2010	20:00	972	750.6	1722.6
1/19/2010	20:15	960	750.6	1710.6
1/19/2010	20:30	881.4	769.2	1650.6
1/19/2010	20:45	890.4	735	1625.4
1/19/2010	21:00	890.4	725.4	1615.8
1/19/2010	21:15	865.8	770.4	1636.2
1/19/2010	21:30	847.2	768.6	1615.8
1/19/2010	21:45	819.6	822	1641.6
1/19/2010	22:00	798	793.8	1591.8
1/19/2010	22:15	742.8	728.4	1471.2
1/19/2010	22:30	684	688.8	1372.8
1/19/2010	22:45	644.4	679.2	1323.6
1/19/2010	23:00	630.6	681.6	1312.2
1/19/2010	23:15	630	706.2	1336.2
1/19/2010	23:30	622.8	717.6	1340.4
1/19/2010	23:45	578.4	720.6	1299
1/19/2010	24:00:00	618.6	709.2	1327.8
1/20/2010	0:15	604.8	684	1288.8
1/20/2010	0:30	600	679.8	1279.8
1/20/2010	0:45	587.4	670.2	1257.6
1/20/2010	1:00	595.2	686.4	1281.6
1/20/2010	1:15	600	670.8	1270.8
1/20/2010	1:30	625.8	716.4	1342.2
1/20/2010	1:45	656.4	799.8	1456.2
1/20/2010	2:00	635.4	688.2	1323.6
1/20/2010	2:15	616.8	776.4	1393.2
1/20/2010	2:30	685.2	808.2	1493.4
1/20/2010	2:45	673.2	778.8	1452
1/20/2010	3:00	687	714	1401

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/20/2010	3:15	829.8	793.2	1623
1/20/2010	3:30	749.4	810	1559.4
1/20/2010	3:45	701.4	777.6	1479
1/20/2010	4:00	718.2	764.4	1482.6
1/20/2010	4:15	706.2	756.6	1462.8
1/20/2010	4:30	706.2	793.8	1500
1/20/2010	4:45	739.2	788.4	1527.6
1/20/2010	5:00	709.8	789	1498.8
1/20/2010	5:15	742.8	799.8	1542.6
1/20/2010	5:30	766.8	818.4	1585.2
1/20/2010	5:45	846.6	812.4	1659
1/20/2010	6:00	964.2	891	1855.2
1/20/2010	6:15	978	878.4	1856.4
1/20/2010	6:30	946.2	841.8	1788
1/20/2010	6:45	983.4	880.8	1864.2
1/20/2010	7:00	987.6	898.8	1886.4
1/20/2010	7:15	1029	892.2	1921.2
1/20/2010	7:30	1173.6	908.4	2082
1/20/2010	7:45	1146	915.6	2061.6
1/20/2010	8:00	1176	898.8	2074.8
1/20/2010	8:15	1183.2	879	2062.2
1/20/2010	8:30	1149.6	878.4	2028
1/20/2010	8:45	1137.6	887.4	2025
1/20/2010	9:00	1169.4	897.6	2067
1/20/2010	9:15	1192.2	924.6	2116.8
1/20/2010	9:30	1159.2	921	2080.2
1/20/2010	9:45	1242.6	921	2163.6
1/20/2010	10:00	1252.8	962.4	2215.2
1/20/2010	10:15	1229.4	934.2	2163.6
1/20/2010	10:30	1240.8	909	2149.8
1/20/2010	10:45	1289.4	921.6	2211
1/20/2010	11:00	1270.8	964.8	2235.6
1/20/2010	11:15	1252.8	975.6	2228.4
1/20/2010	11:30	1240.8	981.6	2222.4
1/20/2010	11:45	1142.4	936.6	2079
1/20/2010	12:00	1157.4	912	2069.4
1/20/2010	12:15	1122	920.4	2042.4
1/20/2010	12:30	1093.8	969	2062.8
1/20/2010	12:45	1098	945.6	2043.6
1/20/2010	13:00	1105.2	872.4	1977.6
1/20/2010	13:15	1164	885	2049
1/20/2010	13:30	1148.4	861.6	2010
1/20/2010	13:45	1191.6	833.4	2025
1/20/2010	14:00	1200	885.6	2085.6
1/20/2010	14:15	1134.6	850.2	1984.8
1/20/2010	14:30	1120.8	840	1960.8
1/20/2010	14:45	1143.6	862.8	2006.4
1/20/2010	15:00	1181.4	905.4	2086.8
1/20/2010	15:15	1148.4	897.6	2046
1/20/2010	15:30	1236	865.8	2101.8
1/20/2010	15:45	1272.6	966.6	2239.2
1/20/2010	16:00	1231.2	949.2	2180.4
1/20/2010	16:15	1309.8	937.2	2247
1/20/2010	16:30	1248	954.6	2202.6
1/20/2010	16:45	1195.2	979.2	2174.4
1/20/2010	17:00	1178.4	21.2	1199.6
1/20/2010	17:15	1099.8	964.8	2064.6
1/20/2010	17:30	1032	911.4	1943.4
1/20/2010	17:45	1030.8	900	1930.8
1/20/2010	18:00	1019.4	913.2	1932.6
1/20/2010	18:15	998.4	832.8	1831.2
1/20/2010	18:30	1021.2	799.2	1820.4
1/20/2010	18:45	1002.6	790.2	1792.8
1/20/2010	19:00	879	784.8	1663.8
1/20/2010	19:15	864.6	774	1638.6
1/20/2010	19:30	895.2	718.8	1614
1/20/2010	19:45	906.6	682.8	1589.4
1/20/2010	20:00	886.2	744.6	1630.8

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/20/2010	20:15	895.8	753.6	1649.4
1/20/2010	20:30	931.2	751.2	1682.4
1/20/2010	20:45	875.4	699	1574.4
1/20/2010	21:00	857.4	705.6	1563
1/20/2010	21:15	895.8	733.8	1629.6
1/20/2010	21:30	910.8	684.6	1595.4
1/20/2010	21:45	928.2	712.8	1641
1/20/2010	22:00	872.4	706.2	1578.6
1/20/2010	22:15	814.8	682.8	1497.6
1/20/2010	22:30	704.4	710.4	1414.8
1/20/2010	22:45	680.4	651.6	1332
1/20/2010	23:00	699	669	1368
1/20/2010	23:15	649.8	622.8	1272.6
1/20/2010	23:30	621.6	662.4	1284
1/20/2010	23:45	636	630	1266
1/20/2010	24:00:00	642.6	678	1320.6
1/21/2010	0:15	646.2	643.8	1290
1/21/2010	0:30	662.4	750	1412.4
1/21/2010	0:45	687.6	746.4	1434
1/21/2010	1:00	668.4	698.4	1366.8
1/21/2010	1:15	666	687	1353
1/21/2010	1:30	696	706.8	1402.8
1/21/2010	1:45	708.6	690.6	1399.2
1/21/2010	2:00	700.8	700.8	1401.6
1/21/2010	2:15	671.4	706.8	1378.2
1/21/2010	2:30	704.4	703.2	1407.6
1/21/2010	2:45	763.8	717.6	1481.4
1/21/2010	3:00	798.6	808.2	1606.8
1/21/2010	3:15	757.8	769.8	1527.6
1/21/2010	3:30	832.2	799.8	1632
1/21/2010	3:45	897	810	1707
1/21/2010	4:00	830.4	819.6	1650
1/21/2010	4:15	817.2	793.2	1610.4
1/21/2010	4:30	904.8	835.2	1740
1/21/2010	4:45	913.2	826.2	1739.4
1/21/2010	5:00	886.8	865.2	1752
1/21/2010	5:15	944.4	852	1796.4
1/21/2010	5:30	915.6	863.4	1779
1/21/2010	5:45	883.8	860.4	1744.2
1/21/2010	6:00	997.2	850.8	1848
1/21/2010	6:15	1114.2	866.4	1980.6
1/21/2010	6:30	1107	868.8	1975.8
1/21/2010	6:45	1144.8	859.8	2004.6
1/21/2010	7:00	1176.6	859.8	2036.4
1/21/2010	7:15	1212.6	904.8	2117.4
1/21/2010	7:30	1238.4	928.2	2166.6
1/21/2010	7:45	1246.8	949.8	2196.6
1/21/2010	8:00	1209	935.4	2144.4
1/21/2010	8:15	1250.4	927	2177.4
1/21/2010	8:30	1353.6	942	2295.6
1/21/2010	8:45	1273.2	951.6	2224.8
1/21/2010	9:00	1156.2	902.4	2058.6
1/21/2010	9:15	1245	863.4	2108.4
1/21/2010	9:30	1222.8	851.4	2074.2
1/21/2010	9:45	1234.8	844.8	2079.6
1/21/2010	10:00	1169.4	862.2	2031.6
1/21/2010	10:15	1049.4	765	1814.4
1/21/2010	10:30	1044.6	840.6	1885.2
1/21/2010	10:45	1096.8	863.4	1960.2
1/21/2010	11:00	1192.2	922.8	2115
1/21/2010	11:15	1269.6	982.2	2251.8
1/21/2010	11:30	1300.2	28.4	1328.6
1/21/2010	11:45	1268.4	14	1282.4
1/21/2010	12:00	1235.4	972.6	2208
1/21/2010	12:15	1252.2	17	1269.2
1/21/2010	12:30	1244.4	949.8	2194.2
1/21/2010	12:45	1295.4	921.6	2217
1/21/2010	13:00	1285.8	908.4	2194.2

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/21/2010	13:15	1258.2	907.8	2166
1/21/2010	13:30	1162.2	903	2065.2
1/21/2010	13:45	1216.8	914.4	2131.2
1/21/2010	14:00	1288.2	951	2239.2
1/21/2010	14:15	1216.8	978.6	2195.4
1/21/2010	14:30	1207.8	920.4	2128.2
1/21/2010	14:45	1186.2	949.8	2136
1/21/2010	15:00	1110	936	2046
1/21/2010	15:15	1105.2	903	2008.2
1/21/2010	15:30	1098.6	900	1998.6
1/21/2010	15:45	1116	928.8	2044.8
1/21/2010	16:00	1133.4	990	2123.4
1/21/2010	16:15	1110.6	954.6	2065.2
1/21/2010	16:30	1126.2	922.2	2048.4
1/21/2010	16:45	1077.6	934.8	2012.4
1/21/2010	17:00	1073.4	965.4	2038.8
1/21/2010	17:15	1098	950.4	2048.4
1/21/2010	17:30	1129.8	958.8	2088.6
1/21/2010	17:45	1074.6	946.8	2021.4
1/21/2010	18:00	1117.8	862.8	1980.6
1/21/2010	18:15	1164.6	893.4	2058
1/21/2010	18:30	1061.4	874.8	1936.2
1/21/2010	18:45	1066.8	850.8	1917.6
1/21/2010	19:00	1051.8	854.4	1906.2
1/21/2010	19:15	1029	864	1893
1/21/2010	19:30	1050.6	886.8	1937.4
1/21/2010	19:45	1054.8	879	1933.8
1/21/2010	20:00	1048.8	912	1960.8
1/21/2010	20:15	1011.6	902.4	1914
1/21/2010	20:30	907.8	770.4	1678.2
1/21/2010	20:45	888.6	789.6	1678.2
1/21/2010	21:00	919.8	825	1744.8
1/21/2010	21:15	930.6	812.4	1743
1/21/2010	21:30	871.2	781.8	1653
1/21/2010	21:45	888.6	714.6	1603.2
1/21/2010	22:00	896.4	739.8	1636.2
1/21/2010	22:15	896.4	733.2	1629.6
1/21/2010	22:30	880.2	745.8	1626
1/21/2010	22:45	850.2	751.8	1602
1/21/2010	23:00	837	737.4	1574.4
1/21/2010	23:15	821.4	715.8	1537.2
1/21/2010	23:30	833.4	718.8	1552.2
1/21/2010	23:45	822	720.6	1542.6
1/21/2010	24:00:00	823.8	729	1552.8
1/22/2010	0:15	805.8	733.2	1539
1/22/2010	0:30	764.4	747.6	1512
1/22/2010	0:45	720	742.2	1462.2
1/22/2010	1:00	726.6	700.8	1427.4
1/22/2010	1:15	763.8	718.2	1482
1/22/2010	1:30	748.8	690.6	1439.4
1/22/2010	1:45	744.6	727.2	1471.8
1/22/2010	2:00	759.6	691.2	1450.8
1/22/2010	2:15	752.4	705	1457.4
1/22/2010	2:30	778.8	728.4	1507.2
1/22/2010	2:45	799.2	732	1531.2
1/22/2010	3:00	783	724.8	1507.8
1/22/2010	3:15	857.4	739.8	1597.2
1/22/2010	3:30	805.8	733.8	1539.6
1/22/2010	3:45	807.6	741.6	1549.2
1/22/2010	4:00	813.6	727.2	1540.8
1/22/2010	4:15	825.6	730.2	1555.8
1/22/2010	4:30	896.4	731.4	1627.8
1/22/2010	4:45	856.2	768.6	1624.8
1/22/2010	5:00	805.8	790.8	1596.6
1/22/2010	5:15	825.6	768	1593.6
1/22/2010	5:30	922.2	814.8	1737
1/22/2010	5:45	1006.8	869.4	1876.2
1/22/2010	6:00	1083.6	869.4	1953

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/22/2010	6:15	1149	894.6	2043.6
1/22/2010	6:30	1171.2	912	2083.2
1/22/2010	6:45	1278.6	24.2	1302.8
1/22/2010	7:00	1283.4	958.8	2242.2
1/22/2010	7:15	1299	69.8	1368.8
1/22/2010	7:30	1255.8	68	1323.8
1/22/2010	7:45	1326	39.8	1365.8
1/22/2010	8:00	1365.6	15.8	1381.4
1/22/2010	8:15	1306.8	967.8	2274.6
1/22/2010	8:30	1258.2	983.4	2241.6
1/22/2010	8:45	1229.4	976.8	2206.2
1/22/2010	9:00	1288.2	973.8	2262
1/22/2010	9:15	1279.2	9.8	1289
1/22/2010	9:30	1218.6	976.8	2195.4
1/22/2010	9:45	1283.4	937.8	2221.2
1/22/2010	10:00	1261.2	930.6	2191.8
1/22/2010	10:15	1194	913.2	2107.2
1/22/2010	10:30	1023	907.8	1930.8
1/22/2010	10:45	1109.4	900.6	2010
1/22/2010	11:00	1236	952.2	2188.2
1/22/2010	11:15	1226.4	937.8	2164.2
1/22/2010	11:30	1330.2	969	2299.2
1/22/2010	11:45	1227.6	934.2	2161.8
1/22/2010	12:00	1207.2	915.6	2122.8
1/22/2010	12:15	1168.8	930	2098.8
1/22/2010	12:30	1173.6	960	2133.6
1/22/2010	12:45	1261.8	945.6	2207.4
1/22/2010	13:00	1203	959.4	2162.4
1/22/2010	13:15	1186.2	891.6	2077.8
1/22/2010	13:30	1171.8	883.2	2055
1/22/2010	13:45	1187.4	856.8	2044.2
1/22/2010	14:00	1275	858.6	2133.6
1/22/2010	14:15	1213.2	868.2	2081.4
1/22/2010	14:30	1229.4	868.8	2098.2
1/22/2010	14:45	1291.8	916.2	2208
1/22/2010	15:00	1302.6	915	2217.6
1/22/2010	15:15	1259.4	981	2240.4
1/22/2010	15:30	1242	963	2205
1/22/2010	15:45	1183.2	930	2113.2
1/22/2010	16:00	1215	897	2112
1/22/2010	16:15	1180.2	879.6	2059.8
1/22/2010	16:30	1198.8	900.6	2099.4
1/22/2010	16:45	1189.2	895.8	2085
1/22/2010	17:00	1219.2	925.8	2145
1/22/2010	17:15	1217.4	930	2147.4
1/22/2010	17:30	1115.4	946.8	2062.2
1/22/2010	17:45	1158.6	912	2070.6
1/22/2010	18:00	1219.8	942	2161.8
1/22/2010	18:15	1132.8	870.6	2003.4
1/22/2010	18:30	1132.2	868.2	2000.4
1/22/2010	18:45	1162.8	869.4	2032.2
1/22/2010	19:00	1139.4	851.4	1990.8
1/22/2010	19:15	1120.8	819	1939.8
1/22/2010	19:30	1085.4	817.8	1903.2
1/22/2010	19:45	1084.2	789.6	1873.8
1/22/2010	20:00	1092.6	772.8	1865.4
1/22/2010	20:15	989.4	767.4	1756.8
1/22/2010	20:30	931.2	736.2	1667.4
1/22/2010	20:45	870.6	721.2	1591.8
1/22/2010	21:00	862.8	764.4	1627.2
1/22/2010	21:15	837.6	726.6	1564.2
1/22/2010	21:30	841.8	729.6	1571.4
1/22/2010	21:45	904.2	774.6	1678.8
1/22/2010	22:00	846.6	764.4	1611
1/22/2010	22:15	805.8	727.8	1533.6
1/22/2010	22:30	760.2	666	1426.2
1/22/2010	22:45	726.6	675.6	1402.2
1/22/2010	23:00	726	688.2	1414.2

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/22/2010	23:15	691.2	718.2	1409.4
1/22/2010	23:30	762	710.4	1472.4
1/22/2010	23:45	802.8	701.4	1504.2
1/22/2010	24:00:00	799.2	720	1519.2
1/23/2010	0:15	809.4	702	1511.4
1/23/2010	0:30	851.4	736.2	1587.6
1/23/2010	0:45	839.4	699.6	1539
1/23/2010	1:00	799.2	682.8	1482
1/23/2010	1:15	814.2	721.2	1535.4
1/23/2010	1:30	842.4	725.4	1567.8
1/23/2010	1:45	854.4	769.8	1624.2
1/23/2010	2:00	838.8	815.4	1654.2
1/23/2010	2:15	830.4	787.8	1618.2
1/23/2010	2:30	808.2	778.8	1587
1/23/2010	2:45	798	787.8	1585.8
1/23/2010	3:00	781.8	770.4	1552.2
1/23/2010	3:15	871.2	732	1603.2
1/23/2010	3:30	885	763.2	1648.2
1/23/2010	3:45	832.2	751.2	1583.4
1/23/2010	4:00	904.2	815.4	1719.6
1/23/2010	4:15	946.2	805.8	1752
1/23/2010	4:30	929.4	812.4	1741.8
1/23/2010	4:45	1007.4	843.6	1851
1/23/2010	5:00	1026.6	866.4	1893
1/23/2010	5:15	982.2	844.8	1827
1/23/2010	5:30	1056.6	853.8	1910.4
1/23/2010	5:45	1144.8	855.6	2000.4
1/23/2010	6:00	1270.2	886.2	2156.4
1/23/2010	6:15	1239.6	879.6	2119.2
1/23/2010	6:30	1222.2	888.6	2110.8
1/23/2010	6:45	1266.6	893.4	2160
1/23/2010	7:00	1264.2	892.2	2156.4
1/23/2010	7:15	1258.8	879	2137.8
1/23/2010	7:30	1265.4	880.8	2146.2
1/23/2010	7:45	1168.2	881.4	2049.6
1/23/2010	8:00	1117.8	856.8	1974.6
1/23/2010	8:15	1120.8	818.4	1939.2
1/23/2010	8:30	1132.8	821.4	1954.2
1/23/2010	8:45	1113.6	839.4	1953
1/23/2010	9:00	1154.4	824.4	1978.8
1/23/2010	9:15	1216.2	835.2	2051.4
1/23/2010	9:30	1256.4	847.8	2104.2
1/23/2010	9:45	1248	887.4	2135.4
1/23/2010	10:00	1258.8	875.4	2134.2
1/23/2010	10:15	1252.8	847.2	2100
1/23/2010	10:30	1257	864	2121
1/23/2010	10:45	1243.8	849	2092.8
1/23/2010	11:00	1254	862.8	2116.8
1/23/2010	11:15	1206	874.8	2080.8
1/23/2010	11:30	1174.2	856.2	2030.4
1/23/2010	11:45	1136.4	796.2	1932.6
1/23/2010	12:00	1131.6	816.6	1948.2
1/23/2010	12:15	1053.6	778.8	1832.4
1/23/2010	12:30	1053	816.6	1869.6
1/23/2010	12:45	995.4	792.6	1788
1/23/2010	13:00	826.8	710.4	1537.2
1/23/2010	13:15	775.8	661.8	1437.6
1/23/2010	13:30	808.8	659.4	1468.2
1/23/2010	13:45	789.6	669	1458.6
1/23/2010	14:00	810.6	636	1446.6
1/23/2010	14:15	832.8	691.8	1524.6
1/23/2010	14:30	822.6	703.8	1526.4
1/23/2010	14:45	814.8	685.2	1500
1/23/2010	15:00	789	653.4	1442.4
1/23/2010	15:15	736.2	706.8	1443
1/23/2010	15:30	733.2	691.8	1425
1/23/2010	15:45	758.4	691.8	1450.2
1/23/2010	16:00	634.8	660.6	1295.4

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/23/2010	16:15	584.4	653.4	1237.8
1/23/2010	16:30	582.6	633.6	1216.2
1/23/2010	16:45	575.4	627	1202.4
1/23/2010	17:00	516.6	629.4	1146
1/23/2010	17:15	460.8	607.2	1068
1/23/2010	17:30	396.6	635.4	1032
1/23/2010	17:45	360.6	506.4	867
1/23/2010	18:00	361.8	356.4	718.2
1/23/2010	18:15	318	337.2	655.2
1/23/2010	18:30	299.4	302.4	601.8
1/23/2010	18:45	294	303	597
1/23/2010	19:00	289.2	297.6	586.8
1/23/2010	19:15	322.8	291.6	614.4
1/23/2010	19:30	302.4	305.4	607.8
1/23/2010	19:45	300.6	469.2	769.8
1/23/2010	20:00	316.2	532.2	848.4
1/23/2010	20:15	346.8	457.8	804.6
1/23/2010	20:30	405	463.8	868.8
1/23/2010	20:45	450	466.8	916.8
1/23/2010	21:00	474	466.8	940.8
1/23/2010	21:15	507	522.6	1029.6
1/23/2010	21:30	498.6	548.4	1047
1/23/2010	21:45	489	527.4	1016.4
1/23/2010	22:00	478.8	530.4	1009.2
1/23/2010	22:15	480.6	544.2	1024.8
1/23/2010	22:30	489	589.8	1078.8
1/23/2010	22:45	486	615.6	1101.6
1/23/2010	23:00	472.8	604.8	1077.6
1/23/2010	23:15	458.4	589.2	1047.6
1/23/2010	23:30	448.2	590.4	1038.6
1/23/2010	23:45	441	578.4	1019.4
1/23/2010	24:00:00	445.2	559.8	1005
1/24/2010	0:15	462.6	594	1056.6
1/24/2010	0:30	446.4	601.8	1048.2
1/24/2010	0:45	469.2	606	1075.2
1/24/2010	1:00	475.2	648	1123.2
1/24/2010	1:15	463.8	619.2	1083
1/24/2010	1:30	471.6	652.2	1123.8
1/24/2010	1:45	474.6	654.6	1129.2
1/24/2010	2:00	499.8	638.4	1138.2
1/24/2010	2:15	541.8	582.6	1124.4
1/24/2010	2:30	528.6	583.2	1111.8
1/24/2010	2:45	615.6	710.4	1326
1/24/2010	3:00	604.2	643.8	1248
1/24/2010	3:15	661.2	647.4	1308.6
1/24/2010	3:30	737.4	663	1400.4
1/24/2010	3:45	675.6	634.2	1309.8
1/24/2010	4:00	718.8	618	1336.8
1/24/2010	4:15	714	678	1392
1/24/2010	4:30	702	651	1353
1/24/2010	4:45	729.6	668.4	1398
1/24/2010	5:00	652.8	670.2	1323
1/24/2010	5:15	657.6	595.2	1252.8
1/24/2010	5:30	693	588	1281
1/24/2010	5:45	825.6	684	1509.6
1/24/2010	6:00	954.6	690.6	1645.2
1/24/2010	6:15	1068	693.6	1761.6
1/24/2010	6:30	1048.8	724.2	1773
1/24/2010	6:45	1071	838.2	1909.2
1/24/2010	7:00	1082.4	832.8	1915.2
1/24/2010	7:15	1108.2	810.6	1918.8
1/24/2010	7:30	1116	838.2	1954.2
1/24/2010	7:45	1141.2	814.2	1955.4
1/24/2010	8:00	1131.6	823.2	1954.8
1/24/2010	8:15	1176.6	828	2004.6
1/24/2010	8:30	1221.6	794.4	2016
1/24/2010	8:45	1216.8	793.8	2010.6
1/24/2010	9:00	1162.2	811.2	1973.4

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/24/2010	9:15	1181.4	793.8	1975.2
1/24/2010	9:30	1165.2	834	1999.2
1/24/2010	9:45	1158.6	829.8	1988.4
1/24/2010	10:00	1148.4	841.2	1989.6
1/24/2010	10:15	1134.6	840.6	1975.2
1/24/2010	10:30	1129.2	868.2	1997.4
1/24/2010	10:45	1112.4	861.6	1974
1/24/2010	11:00	1119.6	846	1965.6
1/24/2010	11:15	1150.8	846	1996.8
1/24/2010	11:30	1125.6	850.8	1976.4
1/24/2010	11:45	1150.8	825	1975.8
1/24/2010	12:00	1147.8	853.8	2001.6
1/24/2010	12:15	1129.8	823.8	1953.6
1/24/2010	12:30	1020	788.4	1808.4
1/24/2010	12:45	874.2	732.6	1606.8
1/24/2010	13:00	829.2	734.4	1563.6
1/24/2010	13:15	713.4	627.6	1341
1/24/2010	13:30	662.4	637.8	1300.2
1/24/2010	13:45	622.2	661.2	1283.4
1/24/2010	14:00	572.4	665.4	1237.8
1/24/2010	14:15	555	649.2	1204.2
1/24/2010	14:30	603	640.2	1243.2
1/24/2010	14:45	617.4	649.8	1267.2
1/24/2010	15:00	635.4	633	1268.4
1/24/2010	15:15	640.8	619.8	1260.6
1/24/2010	15:30	597.6	648	1245.6
1/24/2010	15:45	615	638.4	1253.4
1/24/2010	16:00	582	630.6	1212.6
1/24/2010	16:15	565.2	606	1171.2
1/24/2010	16:30	570	646.2	1216.2
1/24/2010	16:45	601.8	625.8	1227.6
1/24/2010	17:00	580.2	615.6	1195.8
1/24/2010	17:15	611.4	627	1238.4
1/24/2010	17:30	609.6	688.2	1297.8
1/24/2010	17:45	586.2	705	1291.2
1/24/2010	18:00	576.6	694.8	1271.4
1/24/2010	18:15	565.2	720.6	1285.8
1/24/2010	18:30	507.6	720	1227.6
1/24/2010	18:45	492	680.4	1172.4
1/24/2010	19:00	471.6	693.6	1165.2
1/24/2010	19:15	456	633.6	1089.6
1/24/2010	19:30	445.2	687.6	1132.8
1/24/2010	19:45	426.6	661.2	1087.8
1/24/2010	20:00	417.6	666	1083.6
1/24/2010	20:15	426.6	783.6	1210.2
1/24/2010	20:30	414	732	1146
1/24/2010	20:45	387	705.6	1092.6
1/24/2010	21:00	381.6	706.8	1088.4
1/24/2010	21:15	408.6	702.6	1111.2
1/24/2010	21:30	397.8	694.8	1092.6
1/24/2010	21:45	399	639.6	1038.6
1/24/2010	22:00	402.6	638.4	1041
1/24/2010	22:15	404.4	658.8	1063.2
1/24/2010	22:30	405	701.4	1106.4
1/24/2010	22:45	399	685.2	1084.2
1/24/2010	23:00	398.4	705.6	1104
1/24/2010	23:15	403.2	688.8	1092
1/24/2010	23:30	409.8	711.6	1121.4
1/24/2010	23:45	514.8	685.2	1200
1/24/2010	24:00:00	493.2	698.4	1191.6
1/25/2010	0:15	514.8	754.8	1269.6
1/25/2010	0:30	545.4	829.8	1375.2
1/25/2010	0:45	525	819.6	1344.6
1/25/2010	1:00	561.6	825	1386.6
1/25/2010	1:15	590.4	824.4	1414.8
1/25/2010	1:30	598.8	811.2	1410
1/25/2010	1:45	606	811.8	1417.8
1/25/2010	2:00	592.2	795	1387.2

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/25/2010	2:15	578.4	781.8	1360.2
1/25/2010	2:30	572.4	787.2	1359.6
1/25/2010	2:45	577.8	841.2	1419
1/25/2010	3:00	541.8	843.6	1385.4
1/25/2010	3:15	533.4	849	1382.4
1/25/2010	3:30	735	853.2	1588.2
1/25/2010	3:45	680.4	844.2	1524.6
1/25/2010	4:00	616.8	932.4	1549.2
1/25/2010	4:15	663	837	1500
1/25/2010	4:30	675.6	756.6	1432.2
1/25/2010	4:45	662.4	780.6	1443
1/25/2010	5:00	776.4	810.6	1587
1/25/2010	5:15	851.4	808.2	1659.6
1/25/2010	5:30	807	783	1590
1/25/2010	5:45	972.6	807.6	1780.2
1/25/2010	6:00	1130.4	862.8	1993.2
1/25/2010	6:15	1260.6	870.6	2131.2
1/25/2010	6:30	1275.6	881.4	2157
1/25/2010	6:45	1211.4	881.4	2092.8
1/25/2010	7:00	1246.8	859.8	2106.6
1/25/2010	7:15	1265.4	867.6	2133
1/25/2010	7:30	1284.6	878.4	2163
1/25/2010	7:45	1327.8	909	2236.8
1/25/2010	8:00	1264.8	903.6	2168.4
1/25/2010	8:15	1163.4	882.6	2046
1/25/2010	8:30	1174.2	862.8	2037
1/25/2010	8:45	1208.4	855.6	2064
1/25/2010	9:00	1308	861.6	2169.6
1/25/2010	9:15	1269.6	865.2	2134.8
1/25/2010	9:30	1246.2	831	2077.2
1/25/2010	9:45	1284.6	835.2	2119.8
1/25/2010	10:00	1085.4	799.8	1885.2
1/25/2010	10:15	1050	666.6	1716.6
1/25/2010	10:30	1021.8	642.6	1664.4
1/25/2010	10:45	1126.8	665.4	1792.2
1/25/2010	11:00	1183.8	684.6	1868.4
1/25/2010	11:15	1177.2	757.2	1934.4
1/25/2010	11:30	1146	684	1830
1/25/2010	11:45	1170.6	727.2	1897.8
1/25/2010	12:00	1214.4	860.4	2074.8
1/25/2010	12:15	1185	830.4	2015.4
1/25/2010	12:30	1185	831	2016
1/25/2010	12:45	1183.2	841.2	2024.4
1/25/2010	13:00	1248.6	836.4	2085
1/25/2010	13:15	1201.8	873.6	2075.4
1/25/2010	13:30	1232.4	874.8	2107.2
1/25/2010	13:45	1263.6	888	2151.6
1/25/2010	14:00	1285.8	877.2	2163
1/25/2010	14:15	1299.6	870.6	2170.2
1/25/2010	14:30	1282.8	849.6	2132.4
1/25/2010	14:45	1285.2	861	2146.2
1/25/2010	15:00	1284.6	855	2139.6
1/25/2010	15:15	1253.4	863.4	2116.8
1/25/2010	15:30	1269	866.4	2135.4
1/25/2010	15:45	1299.6	869.4	2169
1/25/2010	16:00	1272.6	889.2	2161.8
1/25/2010	16:15	1147.8	799.8	1947.6
1/25/2010	16:30	1113.6	798	1911.6
1/25/2010	16:45	1100.4	792	1892.4
1/25/2010	17:00	1078.8	798	1876.8
1/25/2010	17:15	1081.8	753.6	1835.4
1/25/2010	17:30	1165.2	819	1984.2
1/25/2010	17:45	1195.8	850.8	2046.6
1/25/2010	18:00	1134	825	1959
1/25/2010	18:15	1212.6	748.2	1960.8
1/25/2010	18:30	1180.8	715.8	1896.6
1/25/2010	18:45	1109.4	690.6	1800
1/25/2010	19:00	1141.8	728.4	1870.2

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/25/2010	19:15	1194	731.4	1925.4
1/25/2010	19:30	1120.8	767.4	1888.2
1/25/2010	19:45	1146	705.6	1851.6
1/25/2010	20:00	1188.6	708	1896.6
1/25/2010	20:15	1213.2	711.6	1924.8
1/25/2010	20:30	1163.4	708	1871.4
1/25/2010	20:45	1030.2	678.6	1708.8
1/25/2010	21:00	1029.6	654	1683.6
1/25/2010	21:15	1018.2	733.2	1751.4
1/25/2010	21:30	997.2	753	1750.2
1/25/2010	21:45	958.8	728.4	1687.2
1/25/2010	22:00	858	681	1539
1/25/2010	22:15	839.4	670.8	1510.2
1/25/2010	22:30	849.6	716.4	1566
1/25/2010	22:45	722.4	690.6	1413
1/25/2010	23:00	592.2	717	1309.2
1/25/2010	23:15	582	663	1245
1/25/2010	23:30	633	661.2	1294.2
1/25/2010	23:45	606.6	624	1230.6
1/25/2010	24:00:00	552	598.8	1150.8
1/26/2010	0:15	567.6	609.6	1177.2
1/26/2010	0:30	592.8	601.8	1194.6
1/26/2010	0:45	625.8	615.6	1241.4
1/26/2010	1:00	610.2	621	1231.2
1/26/2010	1:15	606	601.8	1207.8
1/26/2010	1:30	606.6	655.2	1261.8
1/26/2010	1:45	612.6	643.2	1255.8
1/26/2010	2:00	612	696.6	1308.6
1/26/2010	2:15	639.6	695.4	1335
1/26/2010	2:30	618.6	677.4	1296
1/26/2010	2:45	705	699	1404
1/26/2010	3:00	744	706.8	1450.8
1/26/2010	3:15	724.8	717	1441.8
1/26/2010	3:30	861	826.8	1687.8
1/26/2010	3:45	789.6	757.8	1547.4
1/26/2010	4:00	722.4	705.6	1428
1/26/2010	4:15	727.8	753	1480.8
1/26/2010	4:30	742.2	880.2	1622.4
1/26/2010	4:45	763.2	918.6	1681.8
1/26/2010	5:00	811.2	901.2	1712.4
1/26/2010	5:15	873	892.8	1765.8
1/26/2010	5:30	839.4	823.8	1663.2
1/26/2010	5:45	833.4	828.6	1662
1/26/2010	6:00	754.8	803.4	1558.2
1/26/2010	6:15	803.4	711.6	1515
1/26/2010	6:30	845.4	743.4	1588.8
1/26/2010	6:45	879.6	747.6	1627.2
1/26/2010	7:00	985.8	827.4	1813.2
1/26/2010	7:15	1076.4	751.8	1828.2
1/26/2010	7:30	1210.8	798.6	2009.4
1/26/2010	7:45	1259.4	932.4	2191.8
1/26/2010	8:00	1213.2	889.8	2103
1/26/2010	8:15	1216.8	897	2113.8
1/26/2010	8:30	1204.2	890.4	2094.6
1/26/2010	8:45	1192.8	798	1990.8
1/26/2010	9:00	1131	820.8	1951.8
1/26/2010	9:15	1119.6	883.8	2003.4
1/26/2010	9:30	1222.2	873.6	2095.8
1/26/2010	9:45	1238.4	855	2093.4
1/26/2010	10:00	1259.4	898.2	2157.6
1/26/2010	10:15	1179	849	2028
1/26/2010	10:30	1072.8	768.6	1841.4
1/26/2010	10:45	1194	819.6	2013.6
1/26/2010	11:00	1264.8	813.6	2078.4
1/26/2010	11:15	1207.2	821.4	2028.6
1/26/2010	11:30	1198.8	767.4	1966.2
1/26/2010	11:45	1158.6	846.6	2005.2
1/26/2010	12:00	1203	890.4	2093.4

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/26/2010	12:15	1148.4	892.2	2040.6
1/26/2010	12:30	1123.2	879.6	2002.8
1/26/2010	12:45	1184.4	892.2	2076.6
1/26/2010	13:00	1228.8	887.4	2116.2
1/26/2010	13:15	1237.2	878.4	2115.6
1/26/2010	13:30	1215	880.8	2095.8
1/26/2010	13:45	1299.6	882	2181.6
1/26/2010	14:00	1317.6	904.8	2222.4
1/26/2010	14:15	1228.8	18.2	1247
1/26/2010	14:30	1245	936.6	2181.6
1/26/2010	14:45	1251.6	956.4	2208
1/26/2010	15:00	1227.6	936.6	2164.2
1/26/2010	15:15	1230.6	898.8	2129.4
1/26/2010	15:30	1309.2	930	2239.2
1/26/2010	15:45	1376.4	942.6	2319
1/26/2010	16:00	1318.8	941.4	2260.2
1/26/2010	16:15	1299.6	892.8	2192.4
1/26/2010	16:30	1327.8	880.2	2208
1/26/2010	16:45	1285.8	883.2	2169
1/26/2010	17:00	1260.6	920.4	2181
1/26/2010	17:15	1177.8	880.2	2058
1/26/2010	17:30	1153.2	876.6	2029.8
1/26/2010	17:45	1170	892.8	2062.8
1/26/2010	18:00	1184.4	877.8	2062.2
1/26/2010	18:15	1177.8	864	2041.8
1/26/2010	18:30	1186.2	910.2	2096.4
1/26/2010	18:45	1168.2	888.6	2056.8
1/26/2010	19:00	1170.6	897	2067.6
1/26/2010	19:15	1192.2	897	2089.2
1/26/2010	19:30	1193.4	871.8	2065.2
1/26/2010	19:45	1112.4	865.2	1977.6
1/26/2010	20:00	1053.6	832.8	1886.4
1/26/2010	20:15	1089	773.4	1862.4
1/26/2010	20:30	1047	598.2	1645.2
1/26/2010	20:45	1057.2	673.8	1731
1/26/2010	21:00	1074	683.4	1757.4
1/26/2010	21:15	1117.2	688.2	1805.4
1/26/2010	21:30	1063.8	681.6	1745.4
1/26/2010	21:45	1012.8	698.4	1711.2
1/26/2010	22:00	888	657	1545
1/26/2010	22:15	729	616.2	1345.2
1/26/2010	22:30	667.2	616.8	1284
1/26/2010	22:45	663	626.4	1289.4
1/26/2010	23:00	657	636.6	1293.6
1/26/2010	23:15	647.4	622.2	1269.6
1/26/2010	23:30	655.2	633	1288.2
1/26/2010	23:45	619.8	630	1249.8
1/26/2010	24:00:00	606.6	629.4	1236
1/27/2010	0:15	620.4	622.2	1242.6
1/27/2010	0:30	586.2	626.4	1212.6
1/27/2010	0:45	531	640.2	1171.2
1/27/2010	1:00	546.6	595.8	1142.4
1/27/2010	1:15	608.4	608.4	1216.8
1/27/2010	1:30	618.6	784.8	1403.4
1/27/2010	1:45	620.4	733.8	1354.2
1/27/2010	2:00	622.2	734.4	1356.6
1/27/2010	2:15	628.8	707.4	1336.2
1/27/2010	2:30	638.4	732.6	1371
1/27/2010	2:45	673.8	624.6	1298.4
1/27/2010	3:00	676.2	737.4	1413.6
1/27/2010	3:15	643.8	768.6	1412.4
1/27/2010	3:30	643.8	841.2	1485
1/27/2010	3:45	666.6	742.8	1409.4
1/27/2010	4:00	678	817.8	1495.8
1/27/2010	4:15	676.2	779.4	1455.6
1/27/2010	4:30	675	727.2	1402.2
1/27/2010	4:45	758.4	778.2	1536.6
1/27/2010	5:00	783	752.4	1535.4

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/27/2010	5:15	861	703.2	1564.2
1/27/2010	5:30	843.6	810.6	1654.2
1/27/2010	5:45	883.8	838.8	1722.6
1/27/2010	6:00	1048.8	863.4	1912.2
1/27/2010	6:15	1136.4	915	2051.4
1/27/2010	6:30	1154.4	901.8	2056.2
1/27/2010	6:45	1156.8	877.2	2034
1/27/2010	7:00	1273.2	902.4	2175.6
1/27/2010	7:15	1381.8	961.2	2343
1/27/2010	7:30	1371.6	948	2319.6
1/27/2010	7:45	1324.8	946.8	2271.6
1/27/2010	8:00	1327.8	951	2278.8
1/27/2010	8:15	1254.6	921	2175.6
1/27/2010	8:30	1229.4	854.4	2083.8
1/27/2010	8:45	1237.8	832.2	2070
1/27/2010	9:00	1179.6	804	1983.6
1/27/2010	9:15	1204.2	805.8	2010
1/27/2010	9:30	1202.4	815.4	2017.8
1/27/2010	9:45	1181.4	811.2	1992.6
1/27/2010	10:00	1155	817.2	1972.2
1/27/2010	10:15	1227	902.4	2129.4
1/27/2010	10:30	1251.6	867.6	2119.2
1/27/2010	10:45	1293	892.2	2185.2
1/27/2010	11:00	1331.4	913.2	2244.6
1/27/2010	11:15	1316.4	907.2	2223.6
1/27/2010	11:30	1274.4	898.2	2172.6
1/27/2010	11:45	1296.6	832.8	2129.4
1/27/2010	12:00	1239	828.6	2067.6
1/27/2010	12:15	1218	680.4	1898.4
1/27/2010	12:30	1201.8	724.2	1926
1/27/2010	12:45	1154.4	724.8	1879.2
1/27/2010	13:00	1126.8	799.8	1926.6
1/27/2010	13:15	1137	783.6	1920.6
1/27/2010	13:30	1142.4	803.4	1945.8
1/27/2010	13:45	1188	860.4	2048.4
1/27/2010	14:00	1279.8	873.6	2153.4
1/27/2010	14:15	1297.8	890.4	2188.2
1/27/2010	14:30	1318.8	876	2194.8
1/27/2010	14:45	1282.8	872.4	2155.2
1/27/2010	15:00	1255.2	876.6	2131.8
1/27/2010	15:15	1290.6	846.6	2137.2
1/27/2010	15:30	1275	875.4	2150.4
1/27/2010	15:45	1249.2	921.6	2170.8
1/27/2010	16:00	1248	958.8	2206.8
1/27/2010	16:15	1231.8	927	2158.8
1/27/2010	16:30	1175.4	890.4	2065.8
1/27/2010	16:45	1179	893.4	2072.4
1/27/2010	17:00	1160.4	921.6	2082
1/27/2010	17:15	1154.4	859.8	2014.2
1/27/2010	17:30	1187.4	876.6	2064
1/27/2010	17:45	1178.4	877.8	2056.2
1/27/2010	18:00	1165.2	888.6	2053.8
1/27/2010	18:15	1259.4	903	2162.4
1/27/2010	18:30	1292.4	884.4	2176.8
1/27/2010	18:45	1308.6	935.4	2244
1/27/2010	19:00	1296.6	915	2211.6
1/27/2010	19:15	1337.4	885.6	2223
1/27/2010	19:30	1347.6	888.6	2236.2
1/27/2010	19:45	1284	880.2	2164.2
1/27/2010	20:00	1177.2	886.8	2064
1/27/2010	20:15	1168.8	870.6	2039.4
1/27/2010	20:30	1207.8	870	2077.8
1/27/2010	20:45	1203.6	837.6	2041.2
1/27/2010	21:00	1113.6	795.6	1909.2
1/27/2010	21:15	1076.4	784.8	1861.2
1/27/2010	21:30	1069.8	780	1849.8
1/27/2010	21:45	1046.4	829.8	1876.2
1/27/2010	22:00	971.4	827.4	1798.8

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/27/2010	22:15	834.6	771.6	1606.2
1/27/2010	22:30	837	799.2	1636.2
1/27/2010	22:45	831	802.8	1633.8
1/27/2010	23:00	821.4	784.2	1605.6
1/27/2010	23:15	744	658.2	1402.2
1/27/2010	23:30	716.4	622.2	1338.6
1/27/2010	23:45	681.6	628.8	1310.4
1/27/2010	24:00:00	626.4	587.4	1213.8
1/28/2010	0:15	681.6	607.2	1288.8
1/28/2010	0:30	695.4	613.2	1308.6
1/28/2010	0:45	709.2	606	1315.2
1/28/2010	1:00	660.6	610.2	1270.8
1/28/2010	1:15	681	575.4	1256.4
1/28/2010	1:30	659.4	577.8	1237.2
1/28/2010	1:45	664.8	604.8	1269.6
1/28/2010	2:00	630.6	588	1218.6
1/28/2010	2:15	622.8	616.2	1239
1/28/2010	2:30	576	646.8	1222.8
1/28/2010	2:45	597.6	629.4	1227
1/28/2010	3:00	619.8	639	1258.8
1/28/2010	3:15	746.4	660.6	1407
1/28/2010	3:30	622.8	743.4	1366.2
1/28/2010	3:45	589.8	638.4	1228.2
1/28/2010	4:00	581.4	696.6	1278
1/28/2010	4:15	634.8	792.6	1427.4
1/28/2010	4:30	733.2	847.8	1581
1/28/2010	4:45	739.8	856.2	1596
1/28/2010	5:00	777	846	1623
1/28/2010	5:15	861	844.2	1705.2
1/28/2010	5:30	884.4	838.2	1722.6
1/28/2010	5:45	974.4	848.4	1822.8
1/28/2010	6:00	1070.4	849	1919.4
1/28/2010	6:15	1151.4	843	1994.4
1/28/2010	6:30	1208.4	897	2105.4
1/28/2010	6:45	1273.2	886.8	2160
1/28/2010	7:00	1241.4	903.6	2145
1/28/2010	7:15	1237.2	876	2113.2
1/28/2010	7:30	1272.6	896.4	2169
1/28/2010	7:45	1269.6	909.6	2179.2
1/28/2010	8:00	1250.4	921	2171.4
1/28/2010	8:15	1147.2	833.4	1980.6
1/28/2010	8:30	1150.2	779.4	1929.6
1/28/2010	8:45	1081.2	784.2	1865.4
1/28/2010	9:00	1086.6	789.6	1876.2
1/28/2010	9:15	1150.2	885.6	2035.8
1/28/2010	9:30	1170.6	864.6	2035.2
1/28/2010	9:45	1176.6	870	2046.6
1/28/2010	10:00	1236.6	897	2133.6
1/28/2010	10:15	1293	885.6	2178.6
1/28/2010	10:30	1321.2	902.4	2223.6
1/28/2010	10:45	1323.6	909	2232.6
1/28/2010	11:00	1307.4	889.2	2196.6
1/28/2010	11:15	1348.2	912	2260.2
1/28/2010	11:30	1363.8	901.8	2265.6
1/28/2010	11:45	1296	903.6	2199.6
1/28/2010	12:00	1338	896.4	2234.4
1/28/2010	12:15	1307.4	906	2213.4
1/28/2010	12:30	1294.8	898.2	2193
1/28/2010	12:45	1260.6	894.6	2155.2
1/28/2010	13:00	1311	916.8	2227.8
1/28/2010	13:15	1299	906.6	2205.6
1/28/2010	13:30	1327.8	884.4	2212.2
1/28/2010	13:45	1349.4	917.4	2266.8
1/28/2010	14:00	1325.4	910.2	2235.6
1/28/2010	14:15	1269.6	843.6	2113.2
1/28/2010	14:30	1270.8	721.2	1992
1/28/2010	14:45	1286.4	819.6	2106
1/28/2010	15:00	1279.8	782.4	2062.2

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/28/2010	15:15	1245	756	2001
1/28/2010	15:30	1087.2	756.6	1843.8
1/28/2010	15:45	1167	789.6	1956.6
1/28/2010	16:00	1288.8	873	2161.8
1/28/2010	16:15	1306.2	836.4	2142.6
1/28/2010	16:30	1272	799.2	2071.2
1/28/2010	16:45	1294.8	898.8	2193.6
1/28/2010	17:00	1297.2	886.2	2183.4
1/28/2010	17:15	1294.2	883.2	2177.4
1/28/2010	17:30	1289.4	898.8	2188.2
1/28/2010	17:45	1270.2	873	2143.2
1/28/2010	18:00	1281	869.4	2150.4
1/28/2010	18:15	1272	888	2160
1/28/2010	18:30	1182	861.6	2043.6
1/28/2010	18:45	1190.4	823.8	2014.2
1/28/2010	19:00	1046.4	804.6	1851
1/28/2010	19:15	1087.8	777	1864.8
1/28/2010	19:30	1153.8	772.8	1926.6
1/28/2010	19:45	1141.8	777.6	1919.4
1/28/2010	20:00	1058.4	777	1835.4
1/28/2010	20:15	969	774	1743
1/28/2010	20:30	946.2	763.2	1709.4
1/28/2010	20:45	1026.6	747	1773.6
1/28/2010	21:00	1075.2	793.2	1868.4
1/28/2010	21:15	1082.4	765	1847.4
1/28/2010	21:30	1062.6	746.4	1809
1/28/2010	21:45	1007.4	759	1766.4
1/28/2010	22:00	1012.8	750.6	1763.4
1/28/2010	22:15	1039.2	746.4	1785.6
1/28/2010	22:30	928.2	714.6	1642.8
1/28/2010	22:45	767.4	613.2	1380.6
1/28/2010	23:00	669.6	623.4	1293
1/28/2010	23:15	673.8	533.4	1207.2
1/28/2010	23:30	630.6	583.8	1214.4
1/28/2010	23:45	644.4	602.4	1246.8
1/28/2010	24:00:00	688.8	562.2	1251
1/29/2010	0:15	671.4	553.2	1224.6
1/29/2010	0:30	669.6	550.2	1219.8
1/29/2010	0:45	657	557.4	1214.4
1/29/2010	1:00	645	538.2	1183.2
1/29/2010	1:15	618	559.2	1177.2
1/29/2010	1:30	586.8	535.8	1122.6
1/29/2010	1:45	667.2	541.2	1208.4
1/29/2010	2:00	658.2	538.8	1197
1/29/2010	2:15	660.6	585.6	1246.2
1/29/2010	2:30	621	561.6	1182.6
1/29/2010	2:45	613.8	613.2	1227
1/29/2010	3:00	584.4	644.4	1228.8
1/29/2010	3:15	637.8	636.6	1274.4
1/29/2010	3:30	671.4	640.2	1311.6
1/29/2010	3:45	634.2	680.4	1314.6
1/29/2010	4:00	649.2	684	1333.2
1/29/2010	4:15	738	691.2	1429.2
1/29/2010	4:30	819	820.8	1639.8
1/29/2010	4:45	814.2	791.4	1605.6
1/29/2010	5:00	768	763.8	1531.8
1/29/2010	5:15	797.4	718.2	1515.6
1/29/2010	5:30	839.4	729	1568.4
1/29/2010	5:45	913.2	781.2	1694.4
1/29/2010	6:00	1098	800.4	1898.4
1/29/2010	6:15	1188	773.4	1961.4
1/29/2010	6:30	1214.4	811.8	2026.2
1/29/2010	6:45	1164.6	795.6	1960.2
1/29/2010	7:00	1171.2	796.8	1968
1/29/2010	7:15	1191.6	814.2	2005.8
1/29/2010	7:30	1265.4	853.2	2118.6
1/29/2010	7:45	1337.4	852.6	2190
1/29/2010	8:00	1296.6	867.6	2164.2

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/29/2010	8:15	1215	881.4	2096.4
1/29/2010	8:30	1144.2	885.6	2029.8
1/29/2010	8:45	1174.2	839.4	2013.6
1/29/2010	9:00	1206	850.8	2056.8
1/29/2010	9:15	1233	848.4	2081.4
1/29/2010	9:30	1228.2	855	2083.2
1/29/2010	9:45	1203	889.8	2092.8
1/29/2010	10:00	1258.8	910.8	2169.6
1/29/2010	10:15	1321.2	921.6	2242.8
1/29/2010	10:30	1344	915.6	2259.6
1/29/2010	10:45	1326	921.6	2247.6
1/29/2010	11:00	1333.2	916.8	2250
1/29/2010	11:15	1330.8	882	2212.8
1/29/2010	11:30	1306.8	869.4	2176.2
1/29/2010	11:45	1308.6	881.4	2190
1/29/2010	12:00	1341.6	914.4	2256
1/29/2010	12:15	1277.4	902.4	2179.8
1/29/2010	12:30	1270.2	914.4	2184.6
1/29/2010	12:45	1320.6	913.2	2233.8
1/29/2010	13:00	1211.4	899.4	2110.8
1/29/2010	13:15	1150.8	824.4	1975.2
1/29/2010	13:30	1206	811.2	2017.2
1/29/2010	13:45	1224	840	2064
1/29/2010	14:00	1195.8	831.6	2027.4
1/29/2010	14:15	1248	827.4	2075.4
1/29/2010	14:30	1171.2	831	2002.2
1/29/2010	14:45	1239	883.8	2122.8
1/29/2010	15:00	1251.6	899.4	2151
1/29/2010	15:15	1270.2	904.8	2175
1/29/2010	15:30	1283.4	899.4	2182.8
1/29/2010	15:45	1306.8	896.4	2203.2
1/29/2010	16:00	1314	892.8	2206.8
1/29/2010	16:15	1320.6	889.2	2209.8
1/29/2010	16:30	1327.8	888.6	2216.4
1/29/2010	16:45	1276.8	879.6	2156.4
1/29/2010	17:00	1152	874.2	2026.2
1/29/2010	17:15	1102.2	801	1903.2
1/29/2010	17:30	1157.4	801.6	1959
1/29/2010	17:45	1207.2	815.4	2022.6
1/29/2010	18:00	1194	823.8	2017.8
1/29/2010	18:15	1221	806.4	2027.4
1/29/2010	18:30	1206	800.4	2006.4
1/29/2010	18:45	1207.8	861.6	2069.4
1/29/2010	19:00	1196.4	838.8	2035.2
1/29/2010	19:15	1216.8	824.4	2041.2
1/29/2010	19:30	1134.6	815.4	1950
1/29/2010	19:45	1127.4	802.2	1929.6
1/29/2010	20:00	1088.4	792	1880.4
1/29/2010	20:15	1067.4	738	1805.4
1/29/2010	20:30	1071	755.4	1826.4
1/29/2010	20:45	1067.4	796.8	1864.2
1/29/2010	21:00	1056.6	765	1821.6
1/29/2010	21:15	1080.6	766.8	1847.4
1/29/2010	21:30	1002.6	735	1737.6
1/29/2010	21:45	948	714	1662
1/29/2010	22:00	950.4	703.2	1653.6
1/29/2010	22:15	928.8	639.6	1568.4
1/29/2010	22:30	877.8	641.4	1519.2
1/29/2010	22:45	802.8	610.8	1413.6
1/29/2010	23:00	745.8	553.8	1299.6
1/29/2010	23:15	712.2	585.6	1297.8
1/29/2010	23:30	686.4	581.4	1267.8
1/29/2010	23:45	591	518.4	1109.4
1/29/2010	24:00:00	562.8	559.2	1122
1/30/2010	0:15	510	531	1041
1/30/2010	0:30	457.2	516.6	973.8
1/30/2010	0:45	465	547.8	1012.8
1/30/2010	1:00	490.8	498.6	989.4

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/30/2010	1:15	498	519	1017
1/30/2010	1:30	541.2	580.8	1122
1/30/2010	1:45	540.6	541.2	1081.8
1/30/2010	2:00	532.2	581.4	1113.6
1/30/2010	2:15	535.8	585	1120.8
1/30/2010	2:30	540.6	538.2	1078.8
1/30/2010	2:45	550.8	558	1108.8
1/30/2010	3:00	554.4	581.4	1135.8
1/30/2010	3:15	548.4	589.2	1137.6
1/30/2010	3:30	559.2	556.8	1116
1/30/2010	3:45	733.8	580.8	1314.6
1/30/2010	4:00	689.4	586.8	1276.2
1/30/2010	4:15	658.2	592.2	1250.4
1/30/2010	4:30	732	594.6	1326.6
1/30/2010	4:45	775.2	681.6	1456.8
1/30/2010	5:00	758.4	634.2	1392.6
1/30/2010	5:15	797.4	610.8	1408.2
1/30/2010	5:30	801	634.8	1435.8
1/30/2010	5:45	910.8	666.6	1577.4
1/30/2010	6:00	1038.6	682.8	1721.4
1/30/2010	6:15	1175.4	696	1871.4
1/30/2010	6:30	1164	695.4	1859.4
1/30/2010	6:45	1160.4	696	1856.4
1/30/2010	7:00	1162.8	700.2	1863
1/30/2010	7:15	1198.2	736.2	1934.4
1/30/2010	7:30	1155.6	765.6	1921.2
1/30/2010	7:45	1163.4	733.2	1896.6
1/30/2010	8:00	1126.8	739.2	1866
1/30/2010	8:15	1080.6	723.6	1804.2
1/30/2010	8:30	1040.4	753	1793.4
1/30/2010	8:45	1024.2	742.2	1766.4
1/30/2010	9:00	1015.2	732.6	1747.8
1/30/2010	9:15	1000.2	729.6	1729.8
1/30/2010	9:30	1021.2	729	1750.2
1/30/2010	9:45	1041.6	730.2	1771.8
1/30/2010	10:00	1066.8	742.2	1809
1/30/2010	10:15	1137	766.2	1903.2
1/30/2010	10:30	1131.6	755.4	1887
1/30/2010	10:45	1101	759.6	1860.6
1/30/2010	11:00	1084.2	762.6	1846.8
1/30/2010	11:15	1095	751.8	1846.8
1/30/2010	11:30	1074	735	1809
1/30/2010	11:45	1067.4	746.4	1813.8
1/30/2010	12:00	1101.6	766.2	1867.8
1/30/2010	12:15	1105.2	762.6	1867.8
1/30/2010	12:30	1098.6	768	1866.6
1/30/2010	12:45	1090.2	765	1855.2
1/30/2010	13:00	1086	769.8	1855.8
1/30/2010	13:15	1064.4	762	1826.4
1/30/2010	13:30	943.8	729.6	1673.4
1/30/2010	13:45	843.6	658.8	1502.4
1/30/2010	14:00	918.6	680.4	1599
1/30/2010	14:15	882	565.8	1447.8
1/30/2010	14:30	895.2	563.4	1458.6
1/30/2010	14:45	966	596.4	1562.4
1/30/2010	15:00	867.6	555	1422.6
1/30/2010	15:15	750.6	523.2	1273.8
1/30/2010	15:30	727.2	542.4	1269.6
1/30/2010	15:45	661.8	547.8	1209.6
1/30/2010	16:00	616.2	554.4	1170.6
1/30/2010	16:15	618	517.2	1135.2
1/30/2010	16:30	610.2	509.4	1119.6
1/30/2010	16:45	553.2	514.2	1067.4
1/30/2010	17:00	564.6	515.4	1080
1/30/2010	17:15	558	509.4	1067.4
1/30/2010	17:30	510	434.4	944.4
1/30/2010	17:45	464.4	415.8	880.2
1/30/2010	18:00	456	393.6	849.6

DATE	TIME	Store A KW	Store B KW	Store A + B KW
1/30/2010	18:15	452.4	380.4	832.8
1/30/2010	18:30	406.2	373.8	780
1/30/2010	18:45	388.8	389.4	778.2
1/30/2010	19:00	344.4	378	722.4
1/30/2010	19:15	354	384.6	738.6
1/30/2010	19:30	370.2	381.6	751.8
1/30/2010	19:45	360.6	371.4	732
1/30/2010	20:00	361.2	371.4	732.6
1/30/2010	20:15	354.6	422.4	777
1/30/2010	20:30	357.6	461.4	819
1/30/2010	20:45	349.8	457.2	807
1/30/2010	21:00	351.6	453.6	805.2
1/30/2010	21:15	359.4	448.8	808.2
1/30/2010	21:30	351.6	468	819.6
1/30/2010	21:45	349.8	453.6	803.4
1/30/2010	22:00	346.8	457.2	804
1/30/2010	22:15	348.6	453.6	802.2
1/30/2010	22:30	360	459	819
1/30/2010	22:45	341.4	461.4	802.8
1/30/2010	23:00	342	453.6	795.6
1/30/2010	23:15	363.6	429	792.6
1/30/2010	23:30	352.8	431.4	784.2
1/30/2010	23:45	346.2	433.8	780
1/30/2010	24:00:00	354	427.2	781.2
1/31/2010	0:15	353.4	432.6	786
1/31/2010	0:30	346.2	442.8	789
1/31/2010	0:45	344.4	439.2	783.6
1/31/2010	1:00	432.6	448.8	881.4
1/31/2010	1:15	399.6	444.6	844.2
1/31/2010	1:30	391.8	444.6	836.4
1/31/2010	1:45	486.6	444.6	931.2
1/31/2010	2:00	538.8	450	988.8
1/31/2010	2:15	544.2	494.4	1038.6
1/31/2010	2:30	538.2	510.6	1048.8
1/31/2010	2:45	534	497.4	1031.4
1/31/2010	3:00	514.2	588	1102.2
1/31/2010	3:15	785.4	580.8	1366.2
1/31/2010	3:30	705.6	536.4	1242
1/31/2010	3:45	687	644.4	1331.4
1/31/2010	4:00	661.8	578.4	1240.2
1/31/2010	4:15	664.8	573.6	1238.4
1/31/2010	4:30	658.2	571.8	1230
1/31/2010	4:45	699.6	569.4	1269
1/31/2010	5:00	741.6	568.8	1310.4
1/31/2010	5:15	741.6	581.4	1323
1/31/2010	5:30	820.2	610.2	1430.4
1/31/2010	5:45	900.6	625.2	1525.8
1/31/2010	6:00	996	646.2	1642.2
1/31/2010	6:15	1091.4	670.8	1762.2
1/31/2010	6:30	1062.6	687	1749.6
1/31/2010	6:45	1043.4	697.2	1740.6
1/31/2010	7:00	1065	774	1839
1/31/2010	7:15	1099.2	737.4	1836.6
1/31/2010	7:30	1098	742.8	1840.8
1/31/2010	7:45	1160.4	752.4	1912.8
1/31/2010	8:00	1160.4	754.8	1915.2
1/31/2010	8:15	1141.8	742.8	1884.6
1/31/2010	8:30	1138.2	746.4	1884.6
1/31/2010	8:45	1119.6	761.4	1881
1/31/2010	9:00	1159.8	757.2	1917
1/31/2010	9:15	1169.4	745.8	1915.2
1/31/2010	9:30	1152.6	758.4	1911
1/31/2010	9:45	1138.8	776.4	1915.2
1/31/2010	10:00	1119.6	762.6	1882.2
1/31/2010	10:15	1053	765	1818
1/31/2010	10:30	1047	747	1794
1/31/2010	10:45	1057.2	745.8	1803
1/31/2010	11:00	1090.8	771.6	1862.4

		Store A	Store B	Store A + B
DATE	TIME	KW	KW	KW
1/31/2010	11:15	1159.2	772.2	1931.4
1/31/2010	11:30	1158.6	764.4	1923
1/31/2010	11:45	1136.4	760.8	1897.2
1/31/2010	12:00	1114.2	764.4	1878.6
1/31/2010	12:15	1045.2	758.4	1803.6
1/31/2010	12:30	1020	784.8	1804.8
1/31/2010	12:45	1013.4	771.6	1785
1/31/2010	13:00	1009.8	738	1747.8
1/31/2010	13:15	1018.8	733.2	1752
1/31/2010	13:30	1001.4	729	1730.4
1/31/2010	13:45	991.8	733.2	1725
1/31/2010	14:00	964.8	736.8	1701.6
1/31/2010	14:15	891	678	1569
1/31/2010	14:30	917.4	667.8	1585.2
1/31/2010	14:45	882.6	667.8	1550.4
1/31/2010	15:00	805.8	636.6	1442.4
1/31/2010	15:15	696.6	619.2	1315.8
1/31/2010	15:30	604.2	612.6	1216.8
1/31/2010	15:45	579	619.2	1198.2
1/31/2010	16:00	588	609.6	1197.6
1/31/2010	16:15	529.2	564	1093.2
1/31/2010	16:30	496.8	549.6	1046.4
1/31/2010	16:45	537.6	556.8	1094.4
1/31/2010	17:00	542.4	559.8	1102.2
1/31/2010	17:15	548.4	544.2	1092.6
1/31/2010	17:30	565.2	550.2	1115.4
1/31/2010	17:45	547.2	548.4	1095.6
1/31/2010	18:00	531	560.4	1091.4
1/31/2010	18:15	571.2	546	1117.2
1/31/2010	18:30	543.6	515.4	1059
1/31/2010	18:45	551.4	541.2	1092.6
1/31/2010	19:00	543	573	1116
1/31/2010	19:15	529.2	543.6	1072.8
1/31/2010	19:30	523.8	526.8	1050.6
1/31/2010	19:45	526.2	549.6	1075.8
1/31/2010	20:00	495.6	495.6	991.2
1/31/2010	20:15	465	574.2	1039.2
1/31/2010	20:30	427.8	574.8	1002.6
1/31/2010	20:45	442.8	536.4	979.2
1/31/2010	21:00	394.2	547.8	942
1/31/2010	21:15	387	553.8	940.8
1/31/2010	21:30	406.8	567.6	974.4
1/31/2010	21:45	404.4	568.8	973.2
1/31/2010	22:00	391.2	610.2	1001.4
1/31/2010	22:15	408	577.2	985.2
1/31/2010	22:30	419.4	613.2	1032.6
1/31/2010	22:45	511.2	627.6	1138.8
1/31/2010	23:00	480	610.8	1090.8
1/31/2010	23:15	456	583.2	1039.2
1/31/2010	23:30	487.2	646.8	1134
1/31/2010	23:45	480.6	673.2	1153.8
1/31/2010	24:00:00	543	804	1347
Maximum Demand		**1381.80** (1)	**997.80** (2)	**2343.00**

2379.60
(1) + (2)

Automatic Savings 36.60

Seelye Rebuttal Exhibit 10

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	19-Jul-09	BRACKET	2	$ 25
E364.00-Poles, Towers, and Fixtures	31-Jul-09	BRACKET	12	771
E364.00-Poles, Towers, and Fixtures	1-Aug-09	BRACKET	4,143	278,728
E364.00-Poles, Towers, and Fixtures	10-Aug-09	BRACKET	1,252	57,828
E364.00-Poles, Towers, and Fixtures	1-Sep-09	BRACKET	5,796	299,791
E364.00-Poles, Towers, and Fixtures	28-Sep-09	BRACKET	6,875	444,034
E364.00-Poles, Towers, and Fixtures	29-Sep-09	BRACKET	2,668	227,561
E364.00-Poles, Towers, and Fixtures	30-Sep-09	BRACKET	9	267
E364.00-Poles, Towers, and Fixtures	1-Oct-09	BRACKET	58	4,097
E364.00-Poles, Towers, and Fixtures	19-Oct-09	BRACKET	4	2,830
E364.00-Poles, Towers, and Fixtures	1-Nov-09	BRACKET	9,244	671,975
E364.00-Poles, Towers, and Fixtures	19-Nov-09	BRACKET	2,262	165,538
E364.00-Poles, Towers, and Fixtures	1-Jan-32	CROSS ARMS	1,246	1,447
E364.00-Poles, Towers, and Fixtures	1-Jan-41	CROSS ARMS	5,618	24,908
E364.00-Poles, Towers, and Fixtures	31-Dec-41	CROSS ARMS	2	22
E364.00-Poles, Towers, and Fixtures	31-Dec-41	CROSS ARMS	2	28
E364.00-Poles, Towers, and Fixtures	31-Dec-41	CROSS ARMS	6	73
E364.00-Poles, Towers, and Fixtures	31-Dec-41	CROSS ARMS	14	31
E364.00-Poles, Towers, and Fixtures	31-Dec-41	CROSS ARMS	16	746
E364.00-Poles, Towers, and Fixtures	31-Dec-41	CROSS ARMS	231	4,059
E364.00-Poles, Towers, and Fixtures	1-Jan-42	CROSS ARMS	194	415
E364.00-Poles, Towers, and Fixtures	31-Dec-42	CROSS ARMS	1	16
E364.00-Poles, Towers, and Fixtures	31-Dec-42	CROSS ARMS	2	44
E364.00-Poles, Towers, and Fixtures	31-Dec-42	CROSS ARMS	18	330
E364.00-Poles, Towers, and Fixtures	1-Jan-43	CROSS ARMS	107	209
E364.00-Poles, Towers, and Fixtures	31-Dec-43	CROSS ARMS	1	44
E364.00-Poles, Towers, and Fixtures	31-Dec-43	CROSS ARMS	2	111
E364.00-Poles, Towers, and Fixtures	31-Dec-43	CROSS ARMS	3	59
E364.00-Poles, Towers, and Fixtures	31-Dec-43	CROSS ARMS	3	162
E364.00-Poles, Towers, and Fixtures	31-Dec-43	CROSS ARMS	41	1,870
E364.00-Poles, Towers, and Fixtures	1-Jan-44	CROSS ARMS	371	1,615
E364.00-Poles, Towers, and Fixtures	31-Dec-44	CROSS ARMS	2	54
E364.00-Poles, Towers, and Fixtures	31-Dec-44	CROSS ARMS	14	561
E364.00-Poles, Towers, and Fixtures	1-Jan-45	CROSS ARMS	224	589
E364.00-Poles, Towers, and Fixtures	31-Dec-45	CROSS ARMS	5	348
E364.00-Poles, Towers, and Fixtures	31-Dec-45	CROSS ARMS	31	1,621
E364.00-Poles, Towers, and Fixtures	1-Jan-46	CROSS ARMS	224	540
E364.00-Poles, Towers, and Fixtures	31-Dec-46	CROSS ARMS	1	65
E364.00-Poles, Towers, and Fixtures	31-Dec-46	CROSS ARMS	15	653
E364.00-Poles, Towers, and Fixtures	1-Jan-47	CROSS ARMS	231	602
E364.00-Poles, Towers, and Fixtures	31-Dec-47	CROSS ARMS	3	319
E364.00-Poles, Towers, and Fixtures	31-Dec-47	CROSS ARMS	11	866
E364.00-Poles, Towers, and Fixtures	31-Dec-47	CROSS ARMS	19	469
E364.00-Poles, Towers, and Fixtures	31-Dec-47	CROSS ARMS	25	2,282
E364.00-Poles, Towers, and Fixtures	1-Jan-48	CROSS ARMS	3,605	13,562
E364.00-Poles, Towers, and Fixtures	31-Dec-48	CROSS ARMS	1	83
E364.00-Poles, Towers, and Fixtures	31-Dec-48	CROSS ARMS	1	125
E364.00-Poles, Towers, and Fixtures	31-Dec-48	CROSS ARMS	2	63
E364.00-Poles, Towers, and Fixtures	31-Dec-48	CROSS ARMS	3	208
E364.00-Poles, Towers, and Fixtures	31-Dec-48	CROSS ARMS	5	260
E364.00-Poles, Towers, and Fixtures	31-Dec-48	CROSS ARMS	6	420
E364.00-Poles, Towers, and Fixtures	31-Dec-48	CROSS ARMS	7	115
E364.00-Poles, Towers, and Fixtures	31-Dec-48	CROSS ARMS	25	296
E364.00-Poles, Towers, and Fixtures	1-Jan-49	CROSS ARMS	5,568	21,630
E364.00-Poles, Towers, and Fixtures	31-Dec-49	CROSS ARMS	1	137

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-49	CROSS ARMS	2	91
E364.00-Poles, Towers, and Fixtures	31-Dec-49	CROSS ARMS	3	191
E364.00-Poles, Towers, and Fixtures	31-Dec-49	CROSS ARMS	4	274
E364.00-Poles, Towers, and Fixtures	31-Dec-49	CROSS ARMS	5	28
E364.00-Poles, Towers, and Fixtures	31-Dec-49	CROSS ARMS	9	83
E364.00-Poles, Towers, and Fixtures	31-Dec-49	CROSS ARMS	21	722
E364.00-Poles, Towers, and Fixtures	1-Jan-50	CROSS ARMS	5,416	22,069
E364.00-Poles, Towers, and Fixtures	31-Dec-50	CROSS ARMS	2	166
E364.00-Poles, Towers, and Fixtures	31-Dec-50	CROSS ARMS	16	2,196
E364.00-Poles, Towers, and Fixtures	31-Dec-50	CROSS ARMS	20	210
E364.00-Poles, Towers, and Fixtures	1-Jan-51	CROSS ARMS	4,922	23,182
E364.00-Poles, Towers, and Fixtures	31-Dec-51	CROSS ARMS	1	20
E364.00-Poles, Towers, and Fixtures	31-Dec-51	CROSS ARMS	1	92
E364.00-Poles, Towers, and Fixtures	31-Dec-51	CROSS ARMS	2	128
E364.00-Poles, Towers, and Fixtures	31-Dec-51	CROSS ARMS	4	348
E364.00-Poles, Towers, and Fixtures	31-Dec-51	CROSS ARMS	61	914
E364.00-Poles, Towers, and Fixtures	1-Jan-52	CROSS ARMS	5,584	28,643
E364.00-Poles, Towers, and Fixtures	31-Dec-52	CROSS ARMS	1	36
E364.00-Poles, Towers, and Fixtures	31-Dec-52	CROSS ARMS	1	94
E364.00-Poles, Towers, and Fixtures	31-Dec-52	CROSS ARMS	5	398
E364.00-Poles, Towers, and Fixtures	31-Dec-52	CROSS ARMS	5	559
E364.00-Poles, Towers, and Fixtures	31-Dec-52	CROSS ARMS	10	1,264
E364.00-Poles, Towers, and Fixtures	31-Dec-52	CROSS ARMS	20	152
E364.00-Poles, Towers, and Fixtures	1-Jan-53	CROSS ARMS	3,361	19,706
E364.00-Poles, Towers, and Fixtures	31-Dec-53	CROSS ARMS	1	94
E364.00-Poles, Towers, and Fixtures	31-Dec-53	CROSS ARMS	3	255
E364.00-Poles, Towers, and Fixtures	31-Dec-53	CROSS ARMS	59	864
E364.00-Poles, Towers, and Fixtures	31-Dec-54	CROSS ARMS	1	46
E364.00-Poles, Towers, and Fixtures	31-Dec-54	CROSS ARMS	1	86
E364.00-Poles, Towers, and Fixtures	31-Dec-54	CROSS ARMS	1	170
E364.00-Poles, Towers, and Fixtures	31-Dec-54	CROSS ARMS	2	45
E364.00-Poles, Towers, and Fixtures	31-Dec-54	CROSS ARMS	186	1,540
E364.00-Poles, Towers, and Fixtures	1-Jan-55	CROSS ARMS	2,421	14,205
E364.00-Poles, Towers, and Fixtures	31-Dec-55	CROSS ARMS	2	74
E364.00-Poles, Towers, and Fixtures	31-Dec-55	CROSS ARMS	2	213
E364.00-Poles, Towers, and Fixtures	31-Dec-55	CROSS ARMS	3	482
E364.00-Poles, Towers, and Fixtures	31-Dec-55	CROSS ARMS	4	345
E364.00-Poles, Towers, and Fixtures	31-Dec-55	CROSS ARMS	4	863
E364.00-Poles, Towers, and Fixtures	31-Dec-55	CROSS ARMS	6	1,204
E364.00-Poles, Towers, and Fixtures	31-Dec-55	CROSS ARMS	138	2,693
E364.00-Poles, Towers, and Fixtures	1-Jan-56	CROSS ARMS	10,119	95,816
E364.00-Poles, Towers, and Fixtures	31-Dec-56	CROSS ARMS	1	282
E364.00-Poles, Towers, and Fixtures	31-Dec-56	CROSS ARMS	3	570
E364.00-Poles, Towers, and Fixtures	31-Dec-56	CROSS ARMS	11	88
E364.00-Poles, Towers, and Fixtures	31-Dec-56	CROSS ARMS	16	2,225
E364.00-Poles, Towers, and Fixtures	31-Dec-56	CROSS ARMS	19	2,149
E364.00-Poles, Towers, and Fixtures	31-Dec-56	CROSS ARMS	32	4,093
E364.00-Poles, Towers, and Fixtures	31-Dec-56	CROSS ARMS	85	1,598
E364.00-Poles, Towers, and Fixtures	1-Jan-57	CROSS ARMS	10,343	108,505
E364.00-Poles, Towers, and Fixtures	31-Dec-57	CROSS ARMS	1	43
E364.00-Poles, Towers, and Fixtures	31-Dec-57	CROSS ARMS	562	9,383
E364.00-Poles, Towers, and Fixtures	1-Jan-58	CROSS ARMS	5,465	62,600
E364.00-Poles, Towers, and Fixtures	31-Dec-58	CROSS ARMS	1	64
E364.00-Poles, Towers, and Fixtures	31-Dec-58	CROSS ARMS	1	100
E364.00-Poles, Towers, and Fixtures	31-Dec-58	CROSS ARMS	2	343

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-58	CROSS ARMS	235	3,622
E364.00-Poles, Towers, and Fixtures	1-Jan-59	CROSS ARMS	9,225	102,255
E364.00-Poles, Towers, and Fixtures	31-Dec-59	CROSS ARMS	1	139
E364.00-Poles, Towers, and Fixtures	31-Dec-59	CROSS ARMS	2	59
E364.00-Poles, Towers, and Fixtures	31-Dec-59	CROSS ARMS	2	218
E364.00-Poles, Towers, and Fixtures	31-Dec-59	CROSS ARMS	4	437
E364.00-Poles, Towers, and Fixtures	31-Dec-59	CROSS ARMS	5	195
E364.00-Poles, Towers, and Fixtures	31-Dec-59	CROSS ARMS	112	1,780
E364.00-Poles, Towers, and Fixtures	1-Jan-60	CROSS ARMS	1,139	13,453
E364.00-Poles, Towers, and Fixtures	31-Dec-60	CROSS ARMS	1	63
E364.00-Poles, Towers, and Fixtures	31-Dec-60	CROSS ARMS	2	258
E364.00-Poles, Towers, and Fixtures	31-Dec-60	CROSS ARMS	37	974
E364.00-Poles, Towers, and Fixtures	1-Jan-61	CROSS ARMS	8,595	93,451
E364.00-Poles, Towers, and Fixtures	31-Dec-61	CROSS ARMS	1	38
E364.00-Poles, Towers, and Fixtures	31-Dec-61	CROSS ARMS	1	82
E364.00-Poles, Towers, and Fixtures	31-Dec-61	CROSS ARMS	1	101
E364.00-Poles, Towers, and Fixtures	31-Dec-61	CROSS ARMS	2	312
E364.00-Poles, Towers, and Fixtures	31-Dec-61	CROSS ARMS	3	566
E364.00-Poles, Towers, and Fixtures	31-Dec-61	CROSS ARMS	5	1,050
E364.00-Poles, Towers, and Fixtures	31-Dec-61	CROSS ARMS	192	4,408
E364.00-Poles, Towers, and Fixtures	1-Jan-62	CROSS ARMS	8,371	93,197
E364.00-Poles, Towers, and Fixtures	31-Dec-62	CROSS ARMS	1	190
E364.00-Poles, Towers, and Fixtures	31-Dec-62	CROSS ARMS	3	932
E364.00-Poles, Towers, and Fixtures	31-Dec-62	CROSS ARMS	4	135
E364.00-Poles, Towers, and Fixtures	31-Dec-62	CROSS ARMS	5	541
E364.00-Poles, Towers, and Fixtures	31-Dec-62	CROSS ARMS	188	3,610
E364.00-Poles, Towers, and Fixtures	1-Jan-63	CROSS ARMS	16,149	135,766
E364.00-Poles, Towers, and Fixtures	31-Dec-63	CROSS ARMS	1	39
E364.00-Poles, Towers, and Fixtures	31-Dec-63	CROSS ARMS	1	263
E364.00-Poles, Towers, and Fixtures	31-Dec-63	CROSS ARMS	3	190
E364.00-Poles, Towers, and Fixtures	31-Dec-63	CROSS ARMS	3	525
E364.00-Poles, Towers, and Fixtures	31-Dec-63	CROSS ARMS	5	1,535
E364.00-Poles, Towers, and Fixtures	31-Dec-63	CROSS ARMS	6	871
E364.00-Poles, Towers, and Fixtures	31-Dec-63	CROSS ARMS	10	1,200
E364.00-Poles, Towers, and Fixtures	31-Dec-63	CROSS ARMS	228	3,644
E364.00-Poles, Towers, and Fixtures	1-Jan-64	CROSS ARMS	24,155	161,649
E364.00-Poles, Towers, and Fixtures	31-Dec-64	CROSS ARMS	1	169
E364.00-Poles, Towers, and Fixtures	31-Dec-64	CROSS ARMS	3	287
E364.00-Poles, Towers, and Fixtures	31-Dec-64	CROSS ARMS	7	245
E364.00-Poles, Towers, and Fixtures	31-Dec-64	CROSS ARMS	80	1,775
E364.00-Poles, Towers, and Fixtures	1-Jan-65	CROSS ARMS	21,887	157,668
E364.00-Poles, Towers, and Fixtures	31-Dec-65	CROSS ARMS	2	818
E364.00-Poles, Towers, and Fixtures	31-Dec-65	CROSS ARMS	4	1,148
E364.00-Poles, Towers, and Fixtures	31-Dec-65	CROSS ARMS	5	145
E364.00-Poles, Towers, and Fixtures	31-Dec-65	CROSS ARMS	132	2,914
E364.00-Poles, Towers, and Fixtures	1-Jan-66	CROSS ARMS	25,068	187,977
E364.00-Poles, Towers, and Fixtures	31-Dec-66	CROSS ARMS	5	215
E364.00-Poles, Towers, and Fixtures	31-Dec-66	CROSS ARMS	12	567
E364.00-Poles, Towers, and Fixtures	31-Dec-66	CROSS ARMS	137	2,390
E364.00-Poles, Towers, and Fixtures	1-Jan-67	CROSS ARMS	25,407	201,590
E364.00-Poles, Towers, and Fixtures	31-Dec-67	CROSS ARMS	1	40
E364.00-Poles, Towers, and Fixtures	31-Dec-67	CROSS ARMS	1	119
E364.00-Poles, Towers, and Fixtures	31-Dec-67	CROSS ARMS	2	76
E364.00-Poles, Towers, and Fixtures	31-Dec-67	CROSS ARMS	19	3,731
E364.00-Poles, Towers, and Fixtures	31-Dec-67	CROSS ARMS	54	1,107

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-68	CROSS ARMS	24,464	211,844
E364.00-Poles, Towers, and Fixtures	31-Dec-68	CROSS ARMS	1	123
E364.00-Poles, Towers, and Fixtures	31-Dec-68	CROSS ARMS	2	69
E364.00-Poles, Towers, and Fixtures	31-Dec-68	CROSS ARMS	3	233
E364.00-Poles, Towers, and Fixtures	31-Dec-68	CROSS ARMS	4	214
E364.00-Poles, Towers, and Fixtures	31-Dec-68	CROSS ARMS	4	298
E364.00-Poles, Towers, and Fixtures	31-Dec-68	CROSS ARMS	5	432
E364.00-Poles, Towers, and Fixtures	31-Dec-68	CROSS ARMS	49	1,096
E364.00-Poles, Towers, and Fixtures	1-Jan-69	CROSS ARMS	24,987	192,928
E364.00-Poles, Towers, and Fixtures	31-Dec-69	CROSS ARMS	1	42
E364.00-Poles, Towers, and Fixtures	31-Dec-69	CROSS ARMS	272	5,842
E364.00-Poles, Towers, and Fixtures	1-Jan-70	CROSS ARMS	15,329	116,676
E364.00-Poles, Towers, and Fixtures	31-Dec-70	CROSS ARMS	1	136
E364.00-Poles, Towers, and Fixtures	31-Dec-70	CROSS ARMS	4	86
E364.00-Poles, Towers, and Fixtures	31-Dec-70	CROSS ARMS	7	1,253
E364.00-Poles, Towers, and Fixtures	31-Dec-70	CROSS ARMS	108	2,626
E364.00-Poles, Towers, and Fixtures	1-Jan-71	CROSS ARMS	7	284
E364.00-Poles, Towers, and Fixtures	1-Jan-71	CROSS ARMS	31,975	294,668
E364.00-Poles, Towers, and Fixtures	31-Dec-71	CROSS ARMS	1	157
E364.00-Poles, Towers, and Fixtures	31-Dec-71	CROSS ARMS	1	362
E364.00-Poles, Towers, and Fixtures	31-Dec-71	CROSS ARMS	1	425
E364.00-Poles, Towers, and Fixtures	31-Dec-71	CROSS ARMS	1	1,063
E364.00-Poles, Towers, and Fixtures	31-Dec-71	CROSS ARMS	8	383
E364.00-Poles, Towers, and Fixtures	31-Dec-71	CROSS ARMS	71	1,680
E364.00-Poles, Towers, and Fixtures	1-Jan-72	CROSS ARMS	27,520	235,284
E364.00-Poles, Towers, and Fixtures	31-Dec-72	CROSS ARMS	1	127
E364.00-Poles, Towers, and Fixtures	31-Dec-72	CROSS ARMS	2	92
E364.00-Poles, Towers, and Fixtures	31-Dec-72	CROSS ARMS	49	1,286
E364.00-Poles, Towers, and Fixtures	1-Jan-73	CROSS ARMS	28,735	272,881
E364.00-Poles, Towers, and Fixtures	31-Dec-73	CROSS ARMS	1	158
E364.00-Poles, Towers, and Fixtures	31-Dec-73	CROSS ARMS	1	363
E364.00-Poles, Towers, and Fixtures	31-Dec-73	CROSS ARMS	3	485
E364.00-Poles, Towers, and Fixtures	31-Dec-73	CROSS ARMS	24	2,903
E364.00-Poles, Towers, and Fixtures	31-Dec-73	CROSS ARMS	227	7,933
E364.00-Poles, Towers, and Fixtures	1-Jan-74	CROSS ARMS	26,881	279,487
E364.00-Poles, Towers, and Fixtures	31-Dec-74	CROSS ARMS	1	92
E364.00-Poles, Towers, and Fixtures	31-Dec-74	CROSS ARMS	1	450
E364.00-Poles, Towers, and Fixtures	31-Dec-74	CROSS ARMS	1	495
E364.00-Poles, Towers, and Fixtures	31-Dec-74	CROSS ARMS	1	647
E364.00-Poles, Towers, and Fixtures	31-Dec-74	CROSS ARMS	2	407
E364.00-Poles, Towers, and Fixtures	31-Dec-74	CROSS ARMS	2	477
E364.00-Poles, Towers, and Fixtures	31-Dec-74	CROSS ARMS	2	1,115
E364.00-Poles, Towers, and Fixtures	31-Dec-74	CROSS ARMS	16	1,840
E364.00-Poles, Towers, and Fixtures	31-Dec-74	CROSS ARMS	79	4,138
E364.00-Poles, Towers, and Fixtures	1-Jan-75	CROSS ARMS	16,737	194,842
E364.00-Poles, Towers, and Fixtures	31-Dec-75	CROSS ARMS	1	146
E364.00-Poles, Towers, and Fixtures	31-Dec-75	CROSS ARMS	38	4,234
E364.00-Poles, Towers, and Fixtures	31-Dec-75	CROSS ARMS	179	7,955
E364.00-Poles, Towers, and Fixtures	1-Jan-76	CROSS ARMS	21,829	241,157
E364.00-Poles, Towers, and Fixtures	31-Dec-76	CROSS ARMS	7	687
E364.00-Poles, Towers, and Fixtures	31-Dec-76	CROSS ARMS	53	3,243
E364.00-Poles, Towers, and Fixtures	1-Jan-77	CROSS ARMS	22,701	270,559
E364.00-Poles, Towers, and Fixtures	31-Dec-77	CROSS ARMS	4	491
E364.00-Poles, Towers, and Fixtures	31-Dec-77	CROSS ARMS	29	1,300
E364.00-Poles, Towers, and Fixtures	1-Jan-78	CROSS ARMS	21,528	294,853

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-78	CROSS ARMS	1	727
E364.00-Poles, Towers, and Fixtures	31-Dec-78	CROSS ARMS	7	650
E364.00-Poles, Towers, and Fixtures	31-Dec-78	CROSS ARMS	45	2,648
E364.00-Poles, Towers, and Fixtures	1-Jan-79	CROSS ARMS	27,373	445,171
E364.00-Poles, Towers, and Fixtures	31-Dec-79	CROSS ARMS	1	172
E364.00-Poles, Towers, and Fixtures	31-Dec-79	CROSS ARMS	1	294
E364.00-Poles, Towers, and Fixtures	31-Dec-79	CROSS ARMS	2	461
E364.00-Poles, Towers, and Fixtures	31-Dec-79	CROSS ARMS	26	2,736
E364.00-Poles, Towers, and Fixtures	31-Dec-79	CROSS ARMS	29	2,670
E364.00-Poles, Towers, and Fixtures	1-Jan-80	CROSS ARMS	22,914	472,685
E364.00-Poles, Towers, and Fixtures	31-Dec-80	CROSS ARMS	2	3,670
E364.00-Poles, Towers, and Fixtures	31-Dec-80	CROSS ARMS	4	2,535
E364.00-Poles, Towers, and Fixtures	31-Dec-80	CROSS ARMS	4	16,637
E364.00-Poles, Towers, and Fixtures	31-Dec-80	CROSS ARMS	5	1,621
E364.00-Poles, Towers, and Fixtures	31-Dec-80	CROSS ARMS	17	3,415
E364.00-Poles, Towers, and Fixtures	31-Dec-80	CROSS ARMS	81	4,970
E364.00-Poles, Towers, and Fixtures	1-Jan-81	CROSS ARMS	25,414	521,424
E364.00-Poles, Towers, and Fixtures	31-Dec-81	CROSS ARMS	1	638
E364.00-Poles, Towers, and Fixtures	31-Dec-81	CROSS ARMS	2	1,556
E364.00-Poles, Towers, and Fixtures	31-Dec-81	CROSS ARMS	3	913
E364.00-Poles, Towers, and Fixtures	31-Dec-81	CROSS ARMS	6	2,897
E364.00-Poles, Towers, and Fixtures	31-Dec-81	CROSS ARMS	9	5,764
E364.00-Poles, Towers, and Fixtures	31-Dec-81	CROSS ARMS	45	9,063
E364.00-Poles, Towers, and Fixtures	31-Dec-81	CROSS ARMS	135	9,807
E364.00-Poles, Towers, and Fixtures	1-Jan-82	CROSS ARMS	25,877	628,986
E364.00-Poles, Towers, and Fixtures	31-Dec-82	CROSS ARMS	1	3,722
E364.00-Poles, Towers, and Fixtures	31-Dec-82	CROSS ARMS	12	3,289
E364.00-Poles, Towers, and Fixtures	31-Dec-82	CROSS ARMS	52	4,129
E364.00-Poles, Towers, and Fixtures	1-Jan-83	CROSS ARMS	27,531	687,640
E364.00-Poles, Towers, and Fixtures	31-Dec-83	CROSS ARMS	1	1,240
E364.00-Poles, Towers, and Fixtures	31-Dec-83	CROSS ARMS	1	2,292
E364.00-Poles, Towers, and Fixtures	31-Dec-83	CROSS ARMS	3	1,956
E364.00-Poles, Towers, and Fixtures	31-Dec-83	CROSS ARMS	89	6,471
E364.00-Poles, Towers, and Fixtures	1-Jan-84	CROSS ARMS	23,064	564,338
E364.00-Poles, Towers, and Fixtures	31-Dec-84	CROSS ARMS	1	518
E364.00-Poles, Towers, and Fixtures	31-Dec-84	CROSS ARMS	6	1,811
E364.00-Poles, Towers, and Fixtures	31-Dec-84	CROSS ARMS	12	1,734
E364.00-Poles, Towers, and Fixtures	1-Jan-85	CROSS ARMS	21,831	551,060
E364.00-Poles, Towers, and Fixtures	31-Dec-85	CROSS ARMS	1	445
E364.00-Poles, Towers, and Fixtures	31-Dec-85	CROSS ARMS	7	1,232
E364.00-Poles, Towers, and Fixtures	31-Dec-85	CROSS ARMS	17	2,931
E364.00-Poles, Towers, and Fixtures	1-Jan-86	CROSS ARMS	28,923	796,610
E364.00-Poles, Towers, and Fixtures	31-Dec-86	CROSS ARMS	9	1,911
E364.00-Poles, Towers, and Fixtures	31-Dec-86	CROSS ARMS	22	2,218
E364.00-Poles, Towers, and Fixtures	31-Dec-86	CROSS ARMS	55	15,707
E364.00-Poles, Towers, and Fixtures	1-Jan-87	CROSS ARMS	33,604	927,715
E364.00-Poles, Towers, and Fixtures	31-Dec-87	CROSS ARMS	1	861
E364.00-Poles, Towers, and Fixtures	31-Dec-87	CROSS ARMS	1	1,414
E364.00-Poles, Towers, and Fixtures	31-Dec-87	CROSS ARMS	2	2,796
E364.00-Poles, Towers, and Fixtures	31-Dec-87	CROSS ARMS	3	1,848
E364.00-Poles, Towers, and Fixtures	31-Dec-87	CROSS ARMS	3	2,222
E364.00-Poles, Towers, and Fixtures	31-Dec-87	CROSS ARMS	3	5,032
E364.00-Poles, Towers, and Fixtures	31-Dec-87	CROSS ARMS	6	1,730
E364.00-Poles, Towers, and Fixtures	31-Dec-87	CROSS ARMS	123	37,310
E364.00-Poles, Towers, and Fixtures	31-Dec-87	CROSS ARMS	396	47,453

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-88	CROSS ARMS	29,008	876,750
E364.00-Poles, Towers, and Fixtures	31-Dec-88	CROSS ARMS	1	3,592
E364.00-Poles, Towers, and Fixtures	31-Dec-88	CROSS ARMS	3	4,069
E364.00-Poles, Towers, and Fixtures	31-Dec-88	CROSS ARMS	3	6,345
E364.00-Poles, Towers, and Fixtures	31-Dec-88	CROSS ARMS	8	2,880
E364.00-Poles, Towers, and Fixtures	31-Dec-88	CROSS ARMS	33	5,169
E364.00-Poles, Towers, and Fixtures	1-Jan-89	CROSS ARMS	32,164	1,029,750
E364.00-Poles, Towers, and Fixtures	31-Dec-89	CROSS ARMS	1	308
E364.00-Poles, Towers, and Fixtures	31-Dec-89	CROSS ARMS	62	9,273
E364.00-Poles, Towers, and Fixtures	1-Jan-90	CROSS ARMS	30,345	998,004
E364.00-Poles, Towers, and Fixtures	31-Dec-90	CROSS ARMS	1	555
E364.00-Poles, Towers, and Fixtures	31-Dec-90	CROSS ARMS	2	1,152
E364.00-Poles, Towers, and Fixtures	31-Dec-90	CROSS ARMS	11	4,192
E364.00-Poles, Towers, and Fixtures	31-Dec-90	CROSS ARMS	30	5,466
E364.00-Poles, Towers, and Fixtures	1-Jan-91	CROSS ARMS	27,126	889,788
E364.00-Poles, Towers, and Fixtures	31-Dec-91	CROSS ARMS	1	19
E364.00-Poles, Towers, and Fixtures	31-Dec-91	CROSS ARMS	2	1,276
E364.00-Poles, Towers, and Fixtures	31-Dec-91	CROSS ARMS	5	2,027
E364.00-Poles, Towers, and Fixtures	31-Dec-91	CROSS ARMS	64	9,729
E364.00-Poles, Towers, and Fixtures	1-Jan-92	CROSS ARMS	31,414	1,098,147
E364.00-Poles, Towers, and Fixtures	31-Dec-92	CROSS ARMS	1	555
E364.00-Poles, Towers, and Fixtures	31-Dec-92	CROSS ARMS	1	609
E364.00-Poles, Towers, and Fixtures	31-Dec-92	CROSS ARMS	8	2,690
E364.00-Poles, Towers, and Fixtures	31-Dec-92	CROSS ARMS	9	2,555
E364.00-Poles, Towers, and Fixtures	31-Dec-92	CROSS ARMS	38	9,440
E364.00-Poles, Towers, and Fixtures	1-Jan-93	CROSS ARMS	27,446	975,097
E364.00-Poles, Towers, and Fixtures	31-Dec-93	CROSS ARMS	10	3,992
E364.00-Poles, Towers, and Fixtures	31-Dec-93	CROSS ARMS	59	10,656
E364.00-Poles, Towers, and Fixtures	1-Jan-94	CROSS ARMS	32,520	1,222,572
E364.00-Poles, Towers, and Fixtures	31-Dec-94	CROSS ARMS	2	706
E364.00-Poles, Towers, and Fixtures	31-Dec-94	CROSS ARMS	6	4,349
E364.00-Poles, Towers, and Fixtures	31-Dec-94	CROSS ARMS	65	11,182
E364.00-Poles, Towers, and Fixtures	1-Jan-95	CROSS ARMS	34,873	1,625,363
E364.00-Poles, Towers, and Fixtures	31-Dec-95	CROSS ARMS	1	2,006
E364.00-Poles, Towers, and Fixtures	31-Dec-95	CROSS ARMS	5	1,842
E364.00-Poles, Towers, and Fixtures	31-Dec-95	CROSS ARMS	7	1,055
E364.00-Poles, Towers, and Fixtures	31-Dec-95	CROSS ARMS	31	19,084
E364.00-Poles, Towers, and Fixtures	31-Dec-95	CROSS ARMS	208	39,985
E364.00-Poles, Towers, and Fixtures	1-Jan-96	CROSS ARMS	28,885	1,586,072
E364.00-Poles, Towers, and Fixtures	31-Dec-96	CROSS ARMS	1	(0)
E364.00-Poles, Towers, and Fixtures	31-Dec-96	CROSS ARMS	5	1,636
E364.00-Poles, Towers, and Fixtures	1-Jan-97	CROSS ARMS	26,674	1,339,085
E364.00-Poles, Towers, and Fixtures	31-Oct-97	CROSS ARMS	36	9,284
E364.00-Poles, Towers, and Fixtures	31-Dec-97	CROSS ARMS	1	1,174
E364.00-Poles, Towers, and Fixtures	31-Dec-97	CROSS ARMS	2	3,362
E364.00-Poles, Towers, and Fixtures	31-Dec-97	CROSS ARMS	5	1,012
E364.00-Poles, Towers, and Fixtures	31-Dec-97	CROSS ARMS	10	10,390
E364.00-Poles, Towers, and Fixtures	1-Jan-98	CROSS ARMS	23,447	1,160,473
E364.00-Poles, Towers, and Fixtures	31-Mar-98	CROSS ARMS	105	19,436
E364.00-Poles, Towers, and Fixtures	31-Dec-98	CROSS ARMS	9	2,615
E364.00-Poles, Towers, and Fixtures	1-Jan-99	CROSS ARMS	4,450	511,085
E364.00-Poles, Towers, and Fixtures	30-Apr-99	CROSS ARMS	1	2,878
E364.00-Poles, Towers, and Fixtures	30-Apr-99	CROSS ARMS	1	3,167
E364.00-Poles, Towers, and Fixtures	30-Apr-99	CROSS ARMS	1	3,948
E364.00-Poles, Towers, and Fixtures	30-Apr-99	CROSS ARMS	2	7,201

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-00	CROSS ARMS	21,249	1,884,728
E364.00-Poles, Towers, and Fixtures	30-Sep-00	CROSS ARMS	2	3,530
E364.00-Poles, Towers, and Fixtures	30-Sep-00	CROSS ARMS	3	10,147
E364.00-Poles, Towers, and Fixtures	30-Sep-00	CROSS ARMS	4	18,604
E364.00-Poles, Towers, and Fixtures	1-Jan-01	CROSS ARMS	21,664	1,089,337
E364.00-Poles, Towers, and Fixtures	28-Feb-01	CROSS ARMS	1	1,394
E364.00-Poles, Towers, and Fixtures	31-Oct-01	CROSS ARMS	1	(5,604)
E364.00-Poles, Towers, and Fixtures	31-Oct-01	CROSS ARMS	2	5,096
E364.00-Poles, Towers, and Fixtures	31-Oct-01	CROSS ARMS	2	30,745
E364.00-Poles, Towers, and Fixtures	31-Dec-01	CROSS ARMS	1	1
E364.00-Poles, Towers, and Fixtures	1-Jan-02	CROSS ARMS	19,756	1,426,842
E364.00-Poles, Towers, and Fixtures	30-Apr-02	CROSS ARMS	2	3,888
E364.00-Poles, Towers, and Fixtures	30-Apr-02	CROSS ARMS	4	6,739
E364.00-Poles, Towers, and Fixtures	31-May-02	CROSS ARMS	2	5
E364.00-Poles, Towers, and Fixtures	31-Jul-02	CROSS ARMS	1	4,376
E364.00-Poles, Towers, and Fixtures	31-Jul-02	CROSS ARMS	1	7,594
E364.00-Poles, Towers, and Fixtures	31-Jul-02	CROSS ARMS	2	3,631
E364.00-Poles, Towers, and Fixtures	31-Jul-02	CROSS ARMS	2	12,391
E364.00-Poles, Towers, and Fixtures	31-Jul-02	CROSS ARMS	3	3,620
E364.00-Poles, Towers, and Fixtures	31-Jul-02	CROSS ARMS	3	4,702
E364.00-Poles, Towers, and Fixtures	31-Jul-02	CROSS ARMS	4	1,883
E364.00-Poles, Towers, and Fixtures	31-Jul-02	CROSS ARMS	4	10,443
E364.00-Poles, Towers, and Fixtures	31-Jul-02	CROSS ARMS	5	14,409
E364.00-Poles, Towers, and Fixtures	31-Jul-02	CROSS ARMS	7	11,910
E364.00-Poles, Towers, and Fixtures	31-Jul-02	CROSS ARMS	12	4,856
E364.00-Poles, Towers, and Fixtures	31-Jul-02	CROSS ARMS	12	22,179
E364.00-Poles, Towers, and Fixtures	30-Sep-02	CROSS ARMS	4	5,626
E364.00-Poles, Towers, and Fixtures	30-Sep-02	CROSS ARMS	6	1,240
E364.00-Poles, Towers, and Fixtures	1-Jan-03	CROSS ARMS	16,777	1,362,866
E364.00-Poles, Towers, and Fixtures	31-Mar-03	CROSS ARMS	4	4,822
E364.00-Poles, Towers, and Fixtures	31-May-03	CROSS ARMS	1	2,002
E364.00-Poles, Towers, and Fixtures	30-Jun-03	CROSS ARMS	1	263
E364.00-Poles, Towers, and Fixtures	30-Jun-03	CROSS ARMS	9	2,461
E364.00-Poles, Towers, and Fixtures	31-Dec-03	CROSS ARMS	1	3,138
E364.00-Poles, Towers, and Fixtures	31-Dec-03	CROSS ARMS	3	1,450
E364.00-Poles, Towers, and Fixtures	1-Jan-04	CROSS ARMS	8,617	877,861
E364.00-Poles, Towers, and Fixtures	31-Aug-04	CROSS ARMS	4	8,020
E364.00-Poles, Towers, and Fixtures	1-Jan-05	CROSS ARMS	1,430	171,358
E364.00-Poles, Towers, and Fixtures	1-Dec-05	CROSS ARMS	2	11,217
E364.00-Poles, Towers, and Fixtures	1-Jan-06	CROSS ARMS	1,708	55,757
E364.00-Poles, Towers, and Fixtures	31-Dec-06	CROSS ARMS	6	1,140
E364.00-Poles, Towers, and Fixtures	1-Jan-07	CROSS ARMS	8,425	895,512
E364.00-Poles, Towers, and Fixtures	26-Feb-07	CROSS ARMS	77	(0)
E364.00-Poles, Towers, and Fixtures	30-Sep-07	CROSS ARMS	12	58,293
E364.00-Poles, Towers, and Fixtures	1-Oct-07	CROSS ARMS	54	(100)
E364.00-Poles, Towers, and Fixtures	14-Nov-07	CROSS ARMS	18	5,598
E364.00-Poles, Towers, and Fixtures	25-Nov-07	CROSS ARMS	18	4,487
E364.00-Poles, Towers, and Fixtures	30-Nov-07	CROSS ARMS	163	37,434
E364.00-Poles, Towers, and Fixtures	31-Dec-07	CROSS ARMS	35	26,443
E364.00-Poles, Towers, and Fixtures	1-Jan-08	CROSS ARMS	1,985	495,001
E364.00-Poles, Towers, and Fixtures	7-Apr-08	CROSS ARMS	3	177
E364.00-Poles, Towers, and Fixtures	31-May-08	CROSS ARMS	63	21,791
E364.00-Poles, Towers, and Fixtures	9-Jun-08	CROSS ARMS	292	106,763
E364.00-Poles, Towers, and Fixtures	31-Jul-08	CROSS ARMS	7	597
E364.00-Poles, Towers, and Fixtures	1-Aug-08	CROSS ARMS	100	10,520

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Aug-08	CROSS ARMS	152	64,329
E364.00-Poles, Towers, and Fixtures	24-Sep-08	CROSS ARMS	11	3,941
E364.00-Poles, Towers, and Fixtures	30-Sep-08	CROSS ARMS	266	84,108
E364.00-Poles, Towers, and Fixtures	1-Oct-08	CROSS ARMS	18	3,876
E364.00-Poles, Towers, and Fixtures	15-Oct-08	CROSS ARMS	10	3,843
E364.00-Poles, Towers, and Fixtures	31-Oct-08	CROSS ARMS	169	65,505
E364.00-Poles, Towers, and Fixtures	30-Nov-08	CROSS ARMS	63	15,046
E364.00-Poles, Towers, and Fixtures	31-Dec-08	CROSS ARMS	293	206,854
E364.00-Poles, Towers, and Fixtures	31-Jan-09	CROSS ARMS	29	30,630
E364.00-Poles, Towers, and Fixtures	1-Feb-09	CROSS ARMS	114	22,129
E364.00-Poles, Towers, and Fixtures	20-Apr-09	CROSS ARMS	10	67,050
E364.00-Poles, Towers, and Fixtures	16-Jun-09	CROSS ARMS	219	40,525
E364.00-Poles, Towers, and Fixtures	22-Jul-09	CROSS ARMS	6	0
E364.00-Poles, Towers, and Fixtures	27-Jul-09	CROSS ARMS	1	293
E364.00-Poles, Towers, and Fixtures	29-Jul-09	CROSS ARMS	3	1,053
E364.00-Poles, Towers, and Fixtures	30-Jul-09	CROSS ARMS	24	7,612
E364.00-Poles, Towers, and Fixtures	31-Jul-09	CROSS ARMS	34	8,113
E364.00-Poles, Towers, and Fixtures	1-Aug-09	CROSS ARMS	87	18,266
E364.00-Poles, Towers, and Fixtures	3-Aug-09	CROSS ARMS	8	0
E364.00-Poles, Towers, and Fixtures	4-Aug-09	CROSS ARMS	4	2,250
E364.00-Poles, Towers, and Fixtures	6-Aug-09	CROSS ARMS	76	37,275
E364.00-Poles, Towers, and Fixtures	7-Aug-09	CROSS ARMS	7	2,560
E364.00-Poles, Towers, and Fixtures	10-Aug-09	CROSS ARMS	13	2,824
E364.00-Poles, Towers, and Fixtures	30-Sep-09	CROSS ARMS	6	2,087
E364.00-Poles, Towers, and Fixtures	1-Oct-09	CROSS ARMS	2	243
E364.00-Poles, Towers, and Fixtures	2-Oct-09	CROSS ARMS	12	8,398
E364.00-Poles, Towers, and Fixtures	5-Oct-09	CROSS ARMS	27	10,002
E364.00-Poles, Towers, and Fixtures	8-Oct-09	CROSS ARMS	1	254
E364.00-Poles, Towers, and Fixtures	13-Oct-09	CROSS ARMS	35	9,619
E364.00-Poles, Towers, and Fixtures	14-Oct-09	CROSS ARMS	13	5,796
E364.00-Poles, Towers, and Fixtures	15-Oct-09	CROSS ARMS	3	547
E364.00-Poles, Towers, and Fixtures	16-Oct-09	CROSS ARMS	4	384
E364.00-Poles, Towers, and Fixtures	20-Oct-09	CROSS ARMS	1	1,962
E364.00-Poles, Towers, and Fixtures	21-Oct-09	CROSS ARMS	406	130,139
E364.00-Poles, Towers, and Fixtures	23-Oct-09	CROSS ARMS	21	(132)
E364.00-Poles, Towers, and Fixtures	26-Oct-09	CROSS ARMS	65	18,790
E364.00-Poles, Towers, and Fixtures	30-Oct-09	CROSS ARMS	9	653
E364.00-Poles, Towers, and Fixtures	31-Oct-09	CROSS ARMS	183	11,894
E364.00-Poles, Towers, and Fixtures	2-Nov-09	CROSS ARMS	30	3,289
E364.00-Poles, Towers, and Fixtures	3-Nov-09	CROSS ARMS	34	4,664
E364.00-Poles, Towers, and Fixtures	4-Nov-09	CROSS ARMS	6	83
E364.00-Poles, Towers, and Fixtures	9-Nov-09	CROSS ARMS	4	211
E364.00-Poles, Towers, and Fixtures	10-Nov-09	CROSS ARMS	1	963
E364.00-Poles, Towers, and Fixtures	12-Nov-09	CROSS ARMS	5	654
E364.00-Poles, Towers, and Fixtures	16-Nov-09	CROSS ARMS	4	1,296
E364.00-Poles, Towers, and Fixtures	17-Nov-09	CROSS ARMS	29	9,034
E364.00-Poles, Towers, and Fixtures	19-Nov-09	CROSS ARMS	499	109,568
E364.00-Poles, Towers, and Fixtures	23-Nov-09	CROSS ARMS	230	45,552
E364.00-Poles, Towers, and Fixtures	24-Nov-09	CROSS ARMS	285	104,907
E364.00-Poles, Towers, and Fixtures	30-Nov-09	CROSS ARMS	1,050	308,139
E364.00-Poles, Towers, and Fixtures	1-Dec-09	CROSS ARMS	462	214,397
E364.00-Poles, Towers, and Fixtures	2-Dec-09	CROSS ARMS	4,138	1,183,404
E364.00-Poles, Towers, and Fixtures	3-Dec-09	CROSS ARMS	91	20,037
E364.00-Poles, Towers, and Fixtures	4-Dec-09	CROSS ARMS	24	10,217
E364.00-Poles, Towers, and Fixtures	7-Dec-09	CROSS ARMS	93	12,714

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	8-Dec-09	CROSS ARMS	1,130	312,663
E364.00-Poles, Towers, and Fixtures	9-Dec-09	CROSS ARMS	176	81,450
E364.00-Poles, Towers, and Fixtures	16-Dec-09	CROSS ARMS	6	12,052
E364.00-Poles, Towers, and Fixtures	19-Dec-09	CROSS ARMS	14	5,306
E364.00-Poles, Towers, and Fixtures	31-Dec-09	CROSS ARMS	197	34,731
E364.00-Poles, Towers, and Fixtures	1-Jan-47	FENCE	1	0
E364.00-Poles, Towers, and Fixtures	1-Jan-48	FENCE	40	88
E364.00-Poles, Towers, and Fixtures	1-Jan-50	FENCE	100	108
E364.00-Poles, Towers, and Fixtures	1-Jan-55	FENCE	56	271
E364.00-Poles, Towers, and Fixtures	1-Jan-58	FENCE	1	422
E364.00-Poles, Towers, and Fixtures	1-Jan-59	FENCE	494	2,903
E364.00-Poles, Towers, and Fixtures	1-Jan-61	FENCE	188	1,066
E364.00-Poles, Towers, and Fixtures	1-Jan-63	FENCE	176	1,013
E364.00-Poles, Towers, and Fixtures	1-Jan-64	FENCE	116	699
E364.00-Poles, Towers, and Fixtures	1-Jan-65	FENCE	262	1,345
E364.00-Poles, Towers, and Fixtures	1-Jan-66	FENCE	148	785
E364.00-Poles, Towers, and Fixtures	1-Jan-67	FENCE	91	3,123
E364.00-Poles, Towers, and Fixtures	1-Jan-68	FENCE	656	2,047
E364.00-Poles, Towers, and Fixtures	1-Jan-69	FENCE	160	947
E364.00-Poles, Towers, and Fixtures	1-Jan-70	FENCE	460	3,024
E364.00-Poles, Towers, and Fixtures	1-Jan-71	FENCE	415	2,106
E364.00-Poles, Towers, and Fixtures	1-Jan-72	FENCE	90	462
E364.00-Poles, Towers, and Fixtures	1-Jan-74	FENCE	114	605
E364.00-Poles, Towers, and Fixtures	1-Jan-75	FENCE	76	1,097
E364.00-Poles, Towers, and Fixtures	1-Jan-81	FENCE	240	828
E364.00-Poles, Towers, and Fixtures	1-Jan-83	FENCE	73	416
E364.00-Poles, Towers, and Fixtures	1-Jan-87	FENCE	132	2,210
E364.00-Poles, Towers, and Fixtures	1-Jan-88	FENCE	1	447
E364.00-Poles, Towers, and Fixtures	1-Jan-89	FENCE	240	4,115
E364.00-Poles, Towers, and Fixtures	1-Jan-90	FENCE	84	1,526
E364.00-Poles, Towers, and Fixtures	1-Jan-02	FENCE	200	18,093
E364.00-Poles, Towers, and Fixtures	1-Jan-41	GUY	15	0
E364.00-Poles, Towers, and Fixtures	31-Dec-41	GUY	53	2,625
E364.00-Poles, Towers, and Fixtures	1-Jan-42	GUY	68	168
E364.00-Poles, Towers, and Fixtures	31-Dec-42	GUY	5	18
E364.00-Poles, Towers, and Fixtures	1-Jan-43	GUY	24	108
E364.00-Poles, Towers, and Fixtures	31-Dec-43	GUY	9	52
E364.00-Poles, Towers, and Fixtures	1-Jan-44	GUY	25	209
E364.00-Poles, Towers, and Fixtures	31-Dec-44	GUY	4	35
E364.00-Poles, Towers, and Fixtures	1-Jan-45	GUY	45	462
E364.00-Poles, Towers, and Fixtures	31-Dec-45	GUY	26	255
E364.00-Poles, Towers, and Fixtures	1-Jan-46	GUY	17	142
E364.00-Poles, Towers, and Fixtures	1-Jan-46	GUY	2,839	15,267
E364.00-Poles, Towers, and Fixtures	31-Dec-46	GUY	19	356
E364.00-Poles, Towers, and Fixtures	1-Jan-47	GUY	45	585
E364.00-Poles, Towers, and Fixtures	31-Dec-47	GUY	132	1,673
E364.00-Poles, Towers, and Fixtures	31-Dec-48	GUY	224	3,434
E364.00-Poles, Towers, and Fixtures	31-Dec-49	GUY	91	3,045
E364.00-Poles, Towers, and Fixtures	1-Jan-50	GUY	3,398	29,892
E364.00-Poles, Towers, and Fixtures	31-Dec-50	GUY	363	11,277
E364.00-Poles, Towers, and Fixtures	1-Jan-51	GUY	7,495	76,369
E364.00-Poles, Towers, and Fixtures	31-Dec-51	GUY	178	8,207
E364.00-Poles, Towers, and Fixtures	1-Jan-52	GUY	7,610	79,618
E364.00-Poles, Towers, and Fixtures	31-Dec-52	GUY	114	2,380
E364.00-Poles, Towers, and Fixtures	1-Jan-53	GUY	4,338	61,207

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-53 GUY		94	3,103
E364.00-Poles, Towers, and Fixtures	1-Jan-54 GUY		566	7,593
E364.00-Poles, Towers, and Fixtures	31-Dec-54 GUY		181	5,886
E364.00-Poles, Towers, and Fixtures	1-Jan-55 GUY		3,292	46,822
E364.00-Poles, Towers, and Fixtures	31-Dec-55 GUY		130	5,334
E364.00-Poles, Towers, and Fixtures	1-Jan-56 GUY		3,984	62,636
E364.00-Poles, Towers, and Fixtures	31-Dec-56 GUY		203	13,447
E364.00-Poles, Towers, and Fixtures	1-Jan-57 GUY		5,701	84,401
E364.00-Poles, Towers, and Fixtures	1-Jan-57 GUY		1,680	0
E364.00-Poles, Towers, and Fixtures	31-Dec-57 GUY		211	6,486
E364.00-Poles, Towers, and Fixtures	1-Jan-58 GUY		3,515	70,263
E364.00-Poles, Towers, and Fixtures	1-Jan-58 GUY		3,202	9,690
E364.00-Poles, Towers, and Fixtures	31-Dec-58 GUY		130	5,220
E364.00-Poles, Towers, and Fixtures	1-Jan-59 GUY		6,484	214,781
E364.00-Poles, Towers, and Fixtures	1-Jan-59 GUY		8,423	0
E364.00-Poles, Towers, and Fixtures	31-Dec-59 GUY		34	1,320
E364.00-Poles, Towers, and Fixtures	1-Jan-60 GUY		683	12,489
E364.00-Poles, Towers, and Fixtures	31-Dec-60 GUY		242	9,209
E364.00-Poles, Towers, and Fixtures	1-Jan-61 GUY		5,969	112,098
E364.00-Poles, Towers, and Fixtures	31-Dec-61 GUY		56	1,900
E364.00-Poles, Towers, and Fixtures	1-Jan-62 GUY		5,054	94,685
E364.00-Poles, Towers, and Fixtures	31-Dec-62 GUY		229	12,387
E364.00-Poles, Towers, and Fixtures	1-Jan-63 GUY		5,512	110,056
E364.00-Poles, Towers, and Fixtures	31-Dec-63 GUY		143	7,754
E364.00-Poles, Towers, and Fixtures	1-Jan-64 GUY		6,344	127,482
E364.00-Poles, Towers, and Fixtures	31-Dec-64 GUY		41	542
E364.00-Poles, Towers, and Fixtures	1-Jan-65 GUY		6,826	137,182
E364.00-Poles, Towers, and Fixtures	31-Dec-65 GUY		34	820
E364.00-Poles, Towers, and Fixtures	1-Jan-66 GUY		7,498	157,533
E364.00-Poles, Towers, and Fixtures	31-Dec-66 GUY		15	738
E364.00-Poles, Towers, and Fixtures	1-Jan-67 GUY		7,157	156,279
E364.00-Poles, Towers, and Fixtures	31-Dec-67 GUY		55	2,164
E364.00-Poles, Towers, and Fixtures	1-Jan-68 GUY		6,196	143,523
E364.00-Poles, Towers, and Fixtures	31-Dec-68 GUY		43	1,358
E364.00-Poles, Towers, and Fixtures	1-Jan-69 GUY		7,381	169,068
E364.00-Poles, Towers, and Fixtures	31-Dec-69 GUY		131	6,835
E364.00-Poles, Towers, and Fixtures	1-Jan-70 GUY		4,871	118,463
E364.00-Poles, Towers, and Fixtures	31-Dec-70 GUY		52	4,207
E364.00-Poles, Towers, and Fixtures	1-Jan-71 GUY		1	21
E364.00-Poles, Towers, and Fixtures	1-Jan-71 GUY		9,219	260,463
E364.00-Poles, Towers, and Fixtures	31-Dec-71 GUY		68	3,263
E364.00-Poles, Towers, and Fixtures	1-Jan-72 GUY		8,003	213,228
E364.00-Poles, Towers, and Fixtures	31-Dec-72 GUY		30	2,107
E364.00-Poles, Towers, and Fixtures	1-Jan-73 GUY		8,664	252,073
E364.00-Poles, Towers, and Fixtures	31-Dec-73 GUY		208	13,805
E364.00-Poles, Towers, and Fixtures	1-Jan-74 GUY		8,613	258,332
E364.00-Poles, Towers, and Fixtures	31-Dec-74 GUY		71	5,964
E364.00-Poles, Towers, and Fixtures	1-Jan-75 GUY		5,284	167,529
E364.00-Poles, Towers, and Fixtures	31-Dec-75 GUY		105	6,351
E364.00-Poles, Towers, and Fixtures	1-Jan-76 GUY		6,722	216,315
E364.00-Poles, Towers, and Fixtures	31-Dec-76 GUY		20	1,168
E364.00-Poles, Towers, and Fixtures	1-Jan-77 GUY		7,397	246,457
E364.00-Poles, Towers, and Fixtures	31-Dec-77 GUY		50	3,817
E364.00-Poles, Towers, and Fixtures	1-Jan-78 GUY		6,647	241,060
E364.00-Poles, Towers, and Fixtures	31-Dec-78 GUY		11	491

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-79 GUY		8,250	328,344
E364.00-Poles, Towers, and Fixtures	31-Dec-79 GUY		46	4,476
E364.00-Poles, Towers, and Fixtures	1-Jan-80 GUY		9,691	399,895
E364.00-Poles, Towers, and Fixtures	31-Dec-80 GUY		49	6,099
E364.00-Poles, Towers, and Fixtures	1-Jan-81 GUY		6,160	356,536
E364.00-Poles, Towers, and Fixtures	31-Dec-81 GUY		104	15,049
E364.00-Poles, Towers, and Fixtures	1-Jan-82 GUY		6,527	427,963
E364.00-Poles, Towers, and Fixtures	31-Dec-82 GUY		25	3,514
E364.00-Poles, Towers, and Fixtures	1-Jan-83 GUY		6,867	515,561
E364.00-Poles, Towers, and Fixtures	31-Dec-83 GUY		8	1,356
E364.00-Poles, Towers, and Fixtures	1-Jan-84 GUY		5,738	436,014
E364.00-Poles, Towers, and Fixtures	31-Dec-84 GUY		11	1,021
E364.00-Poles, Towers, and Fixtures	1-Jan-85 GUY		6,312	516,410
E364.00-Poles, Towers, and Fixtures	31-Dec-85 GUY		62	9,181
E364.00-Poles, Towers, and Fixtures	1-Jan-86 GUY		7,372	662,077
E364.00-Poles, Towers, and Fixtures	31-Dec-86 GUY		32	5,923
E364.00-Poles, Towers, and Fixtures	1-Jan-87 GUY		8,489	805,868
E364.00-Poles, Towers, and Fixtures	31-Dec-87 GUY		155	24,394
E364.00-Poles, Towers, and Fixtures	1-Jan-88 GUY		7,300	754,611
E364.00-Poles, Towers, and Fixtures	31-Dec-88 GUY		8	1,300
E364.00-Poles, Towers, and Fixtures	1-Jan-89 GUY		7,838	742,559
E364.00-Poles, Towers, and Fixtures	31-Dec-89 GUY		7	1,116
E364.00-Poles, Towers, and Fixtures	1-Jan-90 GUY		7,502	737,552
E364.00-Poles, Towers, and Fixtures	31-Dec-90 GUY		30	4,513
E364.00-Poles, Towers, and Fixtures	1-Jan-91 GUY		6,880	709,153
E364.00-Poles, Towers, and Fixtures	31-Dec-91 GUY		67	13,674
E364.00-Poles, Towers, and Fixtures	1-Jan-92 GUY		8,048	820,372
E364.00-Poles, Towers, and Fixtures	31-Dec-92 GUY		11	1,840
E364.00-Poles, Towers, and Fixtures	1-Jan-93 GUY		7,638	831,392
E364.00-Poles, Towers, and Fixtures	31-Dec-93 GUY		34	6,810
E364.00-Poles, Towers, and Fixtures	1-Jan-94 GUY		8,709	953,093
E364.00-Poles, Towers, and Fixtures	31-Dec-94 GUY		62	249,685
E364.00-Poles, Towers, and Fixtures	1-Jan-95 GUY		10,224	1,130,599
E364.00-Poles, Towers, and Fixtures	31-Dec-95 GUY		33	6,763
E364.00-Poles, Towers, and Fixtures	1-Jan-96 GUY		7,723	1,003,209
E364.00-Poles, Towers, and Fixtures	31-Dec-96 GUY		17	3,617
E364.00-Poles, Towers, and Fixtures	1-Jan-97 GUY		7,589	941,062
E364.00-Poles, Towers, and Fixtures	30-Apr-97 GUY		12	1,307
E364.00-Poles, Towers, and Fixtures	31-Oct-97 GUY		26	7,161
E364.00-Poles, Towers, and Fixtures	1-Jan-98 GUY		6,607	822,201
E364.00-Poles, Towers, and Fixtures	31-Mar-98 GUY		28	8,783
E364.00-Poles, Towers, and Fixtures	1-Jan-99 GUY		1,736	260,433
E364.00-Poles, Towers, and Fixtures	30-Apr-99 GUY		27	15,724
E364.00-Poles, Towers, and Fixtures	31-May-99 GUY		4	1,537
E364.00-Poles, Towers, and Fixtures	1-Jan-00 GUY		6,286	753,334
E364.00-Poles, Towers, and Fixtures	30-Sep-00 GUY		5	4,614
E364.00-Poles, Towers, and Fixtures	1-Jan-01 GUY		15,494	768,683
E364.00-Poles, Towers, and Fixtures	31-Jul-01 GUY		1	281
E364.00-Poles, Towers, and Fixtures	31-Oct-01 GUY		5	1,033
E364.00-Poles, Towers, and Fixtures	1-Jan-02 GUY		30,391	517,870
E364.00-Poles, Towers, and Fixtures	1-Jan-02 GUY		7	413
E364.00-Poles, Towers, and Fixtures	30-Apr-02 GUY		2	2,359
E364.00-Poles, Towers, and Fixtures	30-Apr-02 GUY		2	9,377
E364.00-Poles, Towers, and Fixtures	30-Apr-02 GUY		32	26,631
E364.00-Poles, Towers, and Fixtures	31-Jul-02 GUY		32	23,079

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	30-Sep-02 GUY		2	2,913
E364.00-Poles, Towers, and Fixtures	1-Jan-03 GUY		3,443	131,533
E364.00-Poles, Towers, and Fixtures	1-Jan-03 GUY		16	2,303
E364.00-Poles, Towers, and Fixtures	31-Dec-03 GUY		7	2,122
E364.00-Poles, Towers, and Fixtures	1-Jan-04 GUY		2,396	97,687
E364.00-Poles, Towers, and Fixtures	1-Jan-04 GUY		23	2,298
E364.00-Poles, Towers, and Fixtures	30-Jun-04 GUY		3	4,923
E364.00-Poles, Towers, and Fixtures	30-Jun-04 GUY		5	2,982
E364.00-Poles, Towers, and Fixtures	1-Jan-05 GUY		1,660	(1,259)
E364.00-Poles, Towers, and Fixtures	1-Jan-05 GUY		287	16,425
E364.00-Poles, Towers, and Fixtures	1-Jan-06 GUY		368	1,270
E364.00-Poles, Towers, and Fixtures	1-Jan-06 GUY		446	13,062
E364.00-Poles, Towers, and Fixtures	1-Jan-07 GUY		114	0
E364.00-Poles, Towers, and Fixtures	1-Jan-07 GUY		631	21,109
E364.00-Poles, Towers, and Fixtures	1-Oct-07 GUY		2,099	(116)
E364.00-Poles, Towers, and Fixtures	25-Nov-07 GUY		14	117
E364.00-Poles, Towers, and Fixtures	1-Jan-08 GUY		5	0
E364.00-Poles, Towers, and Fixtures	1-Jan-08 GUY		19	1,628
E364.00-Poles, Towers, and Fixtures	31-May-08 GUY		48	3,647
E364.00-Poles, Towers, and Fixtures	1-Aug-08 GUY		52	1,084
E364.00-Poles, Towers, and Fixtures	31-Aug-08 GUY		209	18,535
E364.00-Poles, Towers, and Fixtures	30-Sep-08 GUY		338	60,777
E364.00-Poles, Towers, and Fixtures	31-Oct-08 GUY		303	48,084
E364.00-Poles, Towers, and Fixtures	30-Nov-08 GUY		86	9,395
E364.00-Poles, Towers, and Fixtures	31-Dec-08 GUY		922	88,800
E364.00-Poles, Towers, and Fixtures	31-Jan-09 GUY		3	77
E364.00-Poles, Towers, and Fixtures	20-Apr-09 GUY		62	51,793
E364.00-Poles, Towers, and Fixtures	19-Jul-09 GUY		4	0
E364.00-Poles, Towers, and Fixtures	22-Jul-09 GUY		42	31
E364.00-Poles, Towers, and Fixtures	27-Jul-09 GUY		12	408
E364.00-Poles, Towers, and Fixtures	29-Jul-09 GUY		16	334
E364.00-Poles, Towers, and Fixtures	30-Jul-09 GUY		2	32
E364.00-Poles, Towers, and Fixtures	31-Jul-09 GUY		29	5,906
E364.00-Poles, Towers, and Fixtures	1-Aug-09 GUY		456	8,981
E364.00-Poles, Towers, and Fixtures	3-Aug-09 GUY		7	2,333
E364.00-Poles, Towers, and Fixtures	4-Aug-09 GUY		8	216
E364.00-Poles, Towers, and Fixtures	7-Aug-09 GUY		29	1,781
E364.00-Poles, Towers, and Fixtures	10-Aug-09 GUY		15	169
E364.00-Poles, Towers, and Fixtures	1-Sep-09 GUY		4	123
E364.00-Poles, Towers, and Fixtures	28-Sep-09 GUY		3	0
E364.00-Poles, Towers, and Fixtures	29-Sep-09 GUY		5	4,481
E364.00-Poles, Towers, and Fixtures	1-Oct-09 GUY		31	2,168
E364.00-Poles, Towers, and Fixtures	2-Oct-09 GUY		12	418
E364.00-Poles, Towers, and Fixtures	5-Oct-09 GUY		80	8,202
E364.00-Poles, Towers, and Fixtures	7-Oct-09 GUY		8	(3,719)
E364.00-Poles, Towers, and Fixtures	8-Oct-09 GUY		4	53
E364.00-Poles, Towers, and Fixtures	9-Oct-09 GUY		17	(19)
E364.00-Poles, Towers, and Fixtures	12-Oct-09 GUY		19	1,494
E364.00-Poles, Towers, and Fixtures	13-Oct-09 GUY		22	4,457
E364.00-Poles, Towers, and Fixtures	14-Oct-09 GUY		4	103
E364.00-Poles, Towers, and Fixtures	16-Oct-09 GUY		35	9,352
E364.00-Poles, Towers, and Fixtures	19-Oct-09 GUY		1	0
E364.00-Poles, Towers, and Fixtures	20-Oct-09 GUY		2	19
E364.00-Poles, Towers, and Fixtures	21-Oct-09 GUY		4	118
E364.00-Poles, Towers, and Fixtures	22-Oct-09 GUY		2	0

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	23-Oct-09	GUY	1	0
E364.00-Poles, Towers, and Fixtures	26-Oct-09	GUY	19	213
E364.00-Poles, Towers, and Fixtures	27-Oct-09	GUY	5	72
E364.00-Poles, Towers, and Fixtures	29-Oct-09	GUY	33	19,832
E364.00-Poles, Towers, and Fixtures	30-Oct-09	GUY	17	138
E364.00-Poles, Towers, and Fixtures	31-Oct-09	GUY	27	367
E364.00-Poles, Towers, and Fixtures	2-Nov-09	GUY	9	(39)
E364.00-Poles, Towers, and Fixtures	3-Nov-09	GUY	27	460
E364.00-Poles, Towers, and Fixtures	4-Nov-09	GUY	813	19,334
E364.00-Poles, Towers, and Fixtures	6-Nov-09	GUY	10	986
E364.00-Poles, Towers, and Fixtures	9-Nov-09	GUY	535	7,861
E364.00-Poles, Towers, and Fixtures	10-Nov-09	GUY	62	1,583
E364.00-Poles, Towers, and Fixtures	11-Nov-09	GUY	3	3,822
E364.00-Poles, Towers, and Fixtures	12-Nov-09	GUY	22	4,780
E364.00-Poles, Towers, and Fixtures	13-Nov-09	GUY	10	252
E364.00-Poles, Towers, and Fixtures	16-Nov-09	GUY	12	303
E364.00-Poles, Towers, and Fixtures	17-Nov-09	GUY	60	3,478
E364.00-Poles, Towers, and Fixtures	19-Nov-09	GUY	66	11,403
E364.00-Poles, Towers, and Fixtures	20-Nov-09	GUY	10	209
E364.00-Poles, Towers, and Fixtures	21-Nov-09	GUY	5	150
E364.00-Poles, Towers, and Fixtures	23-Nov-09	GUY	135	9,713
E364.00-Poles, Towers, and Fixtures	24-Nov-09	GUY	6	139
E364.00-Poles, Towers, and Fixtures	25-Nov-09	GUY	257	6,983
E364.00-Poles, Towers, and Fixtures	30-Nov-09	GUY	1,242	73,765
E364.00-Poles, Towers, and Fixtures	1-Dec-09	GUY	465	20,869
E364.00-Poles, Towers, and Fixtures	2-Dec-09	GUY	125	3,866
E364.00-Poles, Towers, and Fixtures	3-Dec-09	GUY	1,675	36,931
E364.00-Poles, Towers, and Fixtures	4-Dec-09	GUY	6	142
E364.00-Poles, Towers, and Fixtures	7-Dec-09	GUY	202	9,850
E364.00-Poles, Towers, and Fixtures	8-Dec-09	GUY	1,778	402,424
E364.00-Poles, Towers, and Fixtures	9-Dec-09	GUY	227	19,299
E364.00-Poles, Towers, and Fixtures	16-Dec-09	GUY	215	39,277
E364.00-Poles, Towers, and Fixtures	31-Dec-09	GUY	152	4,096
E364.00-Poles, Towers, and Fixtures	1-Jan-32	PLATFORMS NEW (05491)	413	5,509
E364.00-Poles, Towers, and Fixtures	1-Jan-46	PLATFORMS NEW (05491)	2	129
E364.00-Poles, Towers, and Fixtures	1-Jan-47	PLATFORMS NEW (05491)	3	212
E364.00-Poles, Towers, and Fixtures	1-Jan-48	PLATFORMS NEW (05491)	2	202
E364.00-Poles, Towers, and Fixtures	1-Jan-49	PLATFORMS NEW (05491)	2	149
E364.00-Poles, Towers, and Fixtures	1-Jan-50	PLATFORMS NEW (05491)	2	137
E364.00-Poles, Towers, and Fixtures	1-Jan-53	PLATFORMS NEW (05491)	1	161
E364.00-Poles, Towers, and Fixtures	1-Jan-56	PLATFORMS NEW (05491)	1	141
E364.00-Poles, Towers, and Fixtures	1-Jan-57	PLATFORMS NEW (05491)	8	874
E364.00-Poles, Towers, and Fixtures	1-Jan-58	PLATFORMS NEW (05491)	1	233
E364.00-Poles, Towers, and Fixtures	1-Jan-59	PLATFORMS NEW (05491)	2	424
E364.00-Poles, Towers, and Fixtures	1-Jan-60	PLATFORMS NEW (05491)	6	1,528
E364.00-Poles, Towers, and Fixtures	1-Jan-61	PLATFORMS NEW (05491)	1	135
E364.00-Poles, Towers, and Fixtures	1-Jan-62	PLATFORMS NEW (05491)	1	396
E364.00-Poles, Towers, and Fixtures	1-Jan-63	PLATFORMS NEW (05491)	15	4,456
E364.00-Poles, Towers, and Fixtures	1-Jan-64	PLATFORMS NEW (05491)	6	1,499
E364.00-Poles, Towers, and Fixtures	1-Jan-65	PLATFORMS NEW (05491)	11	2,896
E364.00-Poles, Towers, and Fixtures	1-Jan-66	PLATFORMS NEW (05491)	8	2,467
E364.00-Poles, Towers, and Fixtures	1-Jan-67	PLATFORMS NEW (05491)	8	2,122
E364.00-Poles, Towers, and Fixtures	1-Jan-68	PLATFORMS NEW (05491)	21	6,079
E364.00-Poles, Towers, and Fixtures	1-Jan-69	PLATFORMS NEW (05491)	6	1,665
E364.00-Poles, Towers, and Fixtures	1-Jan-70	PLATFORMS NEW (05491)	17	4,889

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-71	PLATFORMS NEW (05491)	20	4,681
E364.00-Poles, Towers, and Fixtures	1-Jan-72	PLATFORMS NEW (05491)	21	7,467
E364.00-Poles, Towers, and Fixtures	1-Jan-73	PLATFORMS NEW (05491)	26	8,600
E364.00-Poles, Towers, and Fixtures	1-Jan-74	PLATFORMS NEW (05491)	19	6,431
E364.00-Poles, Towers, and Fixtures	1-Jan-75	PLATFORMS NEW (05491)	11	4,451
E364.00-Poles, Towers, and Fixtures	1-Jan-76	PLATFORMS NEW (05491)	7	2,669
E364.00-Poles, Towers, and Fixtures	1-Jan-77	PLATFORMS NEW (05491)	11	4,559
E364.00-Poles, Towers, and Fixtures	1-Jan-78	PLATFORMS NEW (05491)	7	3,281
E364.00-Poles, Towers, and Fixtures	1-Jan-79	PLATFORMS NEW (05491)	10	6,037
E364.00-Poles, Towers, and Fixtures	1-Jan-80	PLATFORMS NEW (05491)	2	889
E364.00-Poles, Towers, and Fixtures	1-Jan-81	PLATFORMS NEW (05491)	2	1,286
E364.00-Poles, Towers, and Fixtures	1-Jan-82	PLATFORMS NEW (05491)	10	7,622
E364.00-Poles, Towers, and Fixtures	1-Jan-83	PLATFORMS NEW (05491)	3	2,185
E364.00-Poles, Towers, and Fixtures	1-Jan-84	PLATFORMS NEW (05491)	7	7,360
E364.00-Poles, Towers, and Fixtures	1-Jan-86	PLATFORMS NEW (05491)	5	1,824
E364.00-Poles, Towers, and Fixtures	1-Jan-87	PLATFORMS NEW (05491)	17	19,428
E364.00-Poles, Towers, and Fixtures	1-Jan-88	PLATFORMS NEW (05491)	7	8,182
E364.00-Poles, Towers, and Fixtures	1-Jan-89	PLATFORMS NEW (05491)	9	10,865
E364.00-Poles, Towers, and Fixtures	1-Jan-90	PLATFORMS NEW (05491)	14	25,609
E364.00-Poles, Towers, and Fixtures	1-Jan-91	PLATFORMS NEW (05491)	4	6,515
E364.00-Poles, Towers, and Fixtures	1-Jan-92	PLATFORMS NEW (05491)	13	19,995
E364.00-Poles, Towers, and Fixtures	1-Jan-93	PLATFORMS NEW (05491)	7	13,203
E364.00-Poles, Towers, and Fixtures	1-Jan-94	PLATFORMS NEW (05491)	13	21,793
E364.00-Poles, Towers, and Fixtures	1-Jan-95	PLATFORMS NEW (05491)	13	23,011
E364.00-Poles, Towers, and Fixtures	1-Jan-96	PLATFORMS NEW (05491)	16	28,776
E364.00-Poles, Towers, and Fixtures	1-Jan-97	PLATFORMS NEW (05491)	7	14,238
E364.00-Poles, Towers, and Fixtures	1-Jan-98	PLATFORMS NEW (05491)	9	21,236
E364.00-Poles, Towers, and Fixtures	1-Jan-99	PLATFORMS NEW (05491)	5	18,792
E364.00-Poles, Towers, and Fixtures	1-Jan-00	PLATFORMS NEW (05491)	5	21,790
E364.00-Poles, Towers, and Fixtures	1-Jan-01	PLATFORMS NEW (05491)	5	45,420
E364.00-Poles, Towers, and Fixtures	1-Jan-02	PLATFORMS NEW (05491)	3	20,162
E364.00-Poles, Towers, and Fixtures	1-Jan-03	PLATFORMS NEW (05491)	2	60,601
E364.00-Poles, Towers, and Fixtures	1-Jan-04	PLATFORMS NEW (05491)	3	27,860
E364.00-Poles, Towers, and Fixtures	1-Jan-06	PLATFORMS NEW (05491)	1	11,280
E364.00-Poles, Towers, and Fixtures	30-Nov-07	PLATFORMS NEW (05491)	1	9,485
E364.00-Poles, Towers, and Fixtures	31-Dec-08	PLATFORMS NEW (05491)	1	5,722
E364.00-Poles, Towers, and Fixtures	1-Oct-09	PLATFORMS NEW (05491)	3	35,803
E364.00-Poles, Towers, and Fixtures	14-Oct-09	PLATFORMS NEW (05491)	2	15,342
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 100 FT	2	83,833
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 105 FT	1	7,588
E364.00-Poles, Towers, and Fixtures	1-Jan-32	POLE WOOD 20 FT	42	637
E364.00-Poles, Towers, and Fixtures	1-Jan-41	POLE WOOD 20 FT	680	7,009
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 20 FT	2	28
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 20 FT	12	244
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 20 FT	16	243
E364.00-Poles, Towers, and Fixtures	1-Jan-42	POLE WOOD 20 FT	8	78
E364.00-Poles, Towers, and Fixtures	1-Jan-44	POLE WOOD 20 FT	9	146
E364.00-Poles, Towers, and Fixtures	31-Dec-44	POLE WOOD 20 FT	1	28
E364.00-Poles, Towers, and Fixtures	1-Jan-45	POLE WOOD 20 FT	6	114
E364.00-Poles, Towers, and Fixtures	1-Jan-46	POLE WOOD 20 FT	39	470
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD 20 FT	6	104
E364.00-Poles, Towers, and Fixtures	1-Jan-48	POLE WOOD 20 FT	14	275
E364.00-Poles, Towers, and Fixtures	1-Jan-49	POLE WOOD 20 FT	6	127
E364.00-Poles, Towers, and Fixtures	31-Dec-49	POLE WOOD 20 FT	2	247
E364.00-Poles, Towers, and Fixtures	1-Jan-50	POLE WOOD 20 FT	10	139

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 20 FT	2	61
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 20 FT	2	302
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 20 FT	4	114
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 20 FT	5	157
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 20 FT	14	3,082
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 20 FT	24	1,491
E364.00-Poles, Towers, and Fixtures	1-Jan-51	POLE WOOD 20 FT	1	21
E364.00-Poles, Towers, and Fixtures	31-Dec-51	POLE WOOD 20 FT	1	182
E364.00-Poles, Towers, and Fixtures	1-Jan-52	POLE WOOD 20 FT	3	61
E364.00-Poles, Towers, and Fixtures	31-Dec-52	POLE WOOD 20 FT	4	543
E364.00-Poles, Towers, and Fixtures	31-Dec-53	POLE WOOD 20 FT	1	73
E364.00-Poles, Towers, and Fixtures	31-Dec-53	POLE WOOD 20 FT	1	145
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 20 FT	2	277
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 20 FT	1	180
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 20 FT	4	575
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 20 FT	5	1,018
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 20 FT	13	1,523
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 20 FT	1	144
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 20 FT	1	167
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 20 FT	1	193
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 20 FT	9	1,107
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 20 FT	2	335
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 20 FT	6	841
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 20 FT	7	2,143
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 20 FT	13	1,128
E364.00-Poles, Towers, and Fixtures	1-Jan-58	POLE WOOD 20 FT	2	35
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 20 FT	1	243
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 20 FT	7	721
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 20 FT	8	1,400
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 20 FT	19	4,758
E364.00-Poles, Towers, and Fixtures	1-Jan-59	POLE WOOD 20 FT	3	119
E364.00-Poles, Towers, and Fixtures	31-Dec-59	POLE WOOD 20 FT	2	334
E364.00-Poles, Towers, and Fixtures	31-Dec-59	POLE WOOD 20 FT	2	407
E364.00-Poles, Towers, and Fixtures	31-Dec-59	POLE WOOD 20 FT	17	1,991
E364.00-Poles, Towers, and Fixtures	1-Jan-60	POLE WOOD 20 FT	2	91
E364.00-Poles, Towers, and Fixtures	31-Dec-60	POLE WOOD 20 FT	2	521
E364.00-Poles, Towers, and Fixtures	1-Jan-61	POLE WOOD 20 FT	4	212
E364.00-Poles, Towers, and Fixtures	31-Dec-61	POLE WOOD 20 FT	4	640
E364.00-Poles, Towers, and Fixtures	31-Dec-61	POLE WOOD 20 FT	13	2,644
E364.00-Poles, Towers, and Fixtures	31-Dec-61	POLE WOOD 20 FT	13	3,451
E364.00-Poles, Towers, and Fixtures	31-Dec-61	POLE WOOD 20 FT	15	2,702
E364.00-Poles, Towers, and Fixtures	31-Dec-61	POLE WOOD 20 FT	26	2,947
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 20 FT	2	243
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 20 FT	5	881
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 20 FT	7	662
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 20 FT	1	39
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 20 FT	1	0
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 20 FT	1	80
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 20 FT	7	1,142
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 20 FT	8	823
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 20 FT	12	1,655
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 20 FT	13	3,141
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 20 FT	28	7,383
E364.00-Poles, Towers, and Fixtures	1-Jan-64	POLE WOOD 20 FT	5	198
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 20 FT	1	104

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 20 FT	1	180
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 20 FT	2	464
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 20 FT	1	43
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 20 FT	1	199
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 20 FT	2	208
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 20 FT	3	264
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 20 FT	4	531
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 20 FT	9	1,664
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 20 FT	3	141
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 20 FT	1	176
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 20 FT	1	208
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 20 FT	3	334
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 20 FT	5	750
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 20 FT	1	29
E364.00-Poles, Towers, and Fixtures	31-Dec-67	POLE WOOD 20 FT	6	897
E364.00-Poles, Towers, and Fixtures	31-Dec-68	POLE WOOD 20 FT	2	343
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 20 FT	2	92
E364.00-Poles, Towers, and Fixtures	31-Dec-69	POLE WOOD 20 FT	1	255
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 20 FT	1	245
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 20 FT	1	304
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 20 FT	1	428
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 20 FT	2	326
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 20 FT	5	703
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 20 FT	2	102
E364.00-Poles, Towers, and Fixtures	31-Dec-71	POLE WOOD 20 FT	1	100
E364.00-Poles, Towers, and Fixtures	31-Dec-71	POLE WOOD 20 FT	1	150
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 20 FT	1	51
E364.00-Poles, Towers, and Fixtures	31-Dec-72	POLE WOOD 20 FT	1	81
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 20 FT	3	163
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 20 FT	1	136
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 20 FT	1	175
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 20 FT	1	357
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 20 FT	1	72
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 20 FT	1	1,147
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 20 FT	1	1,676
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 20 FT	3	1,766
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 20 FT	6	8,488
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 20 FT	7	5,554
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 20 FT	9	7,237
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 20 FT	1	339
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 20 FT	2	417
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 20 FT	1	54
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 20 FT	3	657
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 20 FT	3	1,012
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 20 FT	1	127
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 20 FT	1	241
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 20 FT	1	310
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 20 FT	1	394
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 20 FT	1	496
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 20 FT	2	1,435
E364.00-Poles, Towers, and Fixtures	31-Dec-78	POLE WOOD 20 FT	1	124
E364.00-Poles, Towers, and Fixtures	31-Dec-78	POLE WOOD 20 FT	1	241
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 20 FT	2	201
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 20 FT	1	267
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 20 FT	2	1,581

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 20 FT	2	4,253
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 20 FT	3	3,557
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 20 FT	3	7,553
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 20 FT	2	218
E364.00-Poles, Towers, and Fixtures	31-Dec-80	POLE WOOD 20 FT	1	774
E364.00-Poles, Towers, and Fixtures	31-Dec-80	POLE WOOD 20 FT	1	1,222
E364.00-Poles, Towers, and Fixtures	31-Dec-80	POLE WOOD 20 FT	2	587
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 20 FT	1	70
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 20 FT	1	1,075
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 20 FT	2	1,700
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 20 FT	3	2,106
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 20 FT	5	1,657
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 20 FT	6	2,763
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 20 FT	2	173
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 20 FT	3	1,132
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 20 FT	5	2,619
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 20 FT	1	131
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 20 FT	1	797
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 20 FT	1	1,255
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 20 FT	4	3,970
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 20 FT	6	2,763
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 20 FT	7	4,672
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 20 FT	2	238
E364.00-Poles, Towers, and Fixtures	31-Dec-84	POLE WOOD 20 FT	2	1,001
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 20 FT	1	996
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 20 FT	1	1,468
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 20 FT	2	1,206
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 20 FT	2	4,465
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 20 FT	4	1,782
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 20 FT	1	824
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 20 FT	1	991
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 20 FT	1	1,501
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 20 FT	2	974
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 20 FT	2	287
E364.00-Poles, Towers, and Fixtures	31-Dec-87	POLE WOOD 20 FT	1	440
E364.00-Poles, Towers, and Fixtures	31-Dec-87	POLE WOOD 20 FT	1	2,154
E364.00-Poles, Towers, and Fixtures	31-Dec-87	POLE WOOD 20 FT	2	3,295
E364.00-Poles, Towers, and Fixtures	31-Dec-88	POLE WOOD 20 FT	2	1,138
E364.00-Poles, Towers, and Fixtures	31-Dec-89	POLE WOOD 20 FT	1	697
E364.00-Poles, Towers, and Fixtures	31-Dec-89	POLE WOOD 20 FT	1	942
E364.00-Poles, Towers, and Fixtures	31-Dec-89	POLE WOOD 20 FT	1	1,424
E364.00-Poles, Towers, and Fixtures	31-Dec-89	POLE WOOD 20 FT	2	41
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 20 FT	1	447
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 20 FT	1	506
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 20 FT	1	1,232
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 20 FT	2	4,249
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 20 FT	1	1,047
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 20 FT	2	4,831
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 20 FT	3	7,072
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 20 FT	4	2,555
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 20 FT	7	5,341
E364.00-Poles, Towers, and Fixtures	31-Dec-92	POLE WOOD 20 FT	1	1,418
E364.00-Poles, Towers, and Fixtures	31-Dec-92	POLE WOOD 20 FT	1	1,708
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 20 FT	1	529
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 20 FT	1	788

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 20 FT	3	2,851
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 20 FT	4	5,139
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 20 FT	1	1,419
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 20 FT	1	2,014
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 20 FT	2	2,050
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 20 FT	1	1,146
E364.00-Poles, Towers, and Fixtures	31-Dec-96	POLE WOOD 20 FT	1	2,721
E364.00-Poles, Towers, and Fixtures	30-Apr-97	POLE WOOD 20 FT	1	1,716
E364.00-Poles, Towers, and Fixtures	30-Apr-97	POLE WOOD 20 FT	2	432
E364.00-Poles, Towers, and Fixtures	30-Apr-97	POLE WOOD 20 FT	2	4,810
E364.00-Poles, Towers, and Fixtures	31-May-97	POLE WOOD 20 FT	2	12,754
E364.00-Poles, Towers, and Fixtures	31-May-97	POLE WOOD 20 FT	2	15,551
E364.00-Poles, Towers, and Fixtures	31-May-97	POLE WOOD 20 FT	3	32,513
E364.00-Poles, Towers, and Fixtures	31-Dec-97	POLE WOOD 20 FT	4	1,129
E364.00-Poles, Towers, and Fixtures	31-Dec-98	POLE WOOD 20 FT	1	1,019
E364.00-Poles, Towers, and Fixtures	31-Dec-98	POLE WOOD 20 FT	1	1,620
E364.00-Poles, Towers, and Fixtures	31-Dec-98	POLE WOOD 20 FT	1	2,486
E364.00-Poles, Towers, and Fixtures	31-May-02	POLE WOOD 20 FT	1	5
E364.00-Poles, Towers, and Fixtures	1-Jan-41	POLE WOOD 25 FT	932	12,854
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 25 FT	1	14
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 25 FT	3	42
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 25 FT	3	60
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 25 FT	6	324
E364.00-Poles, Towers, and Fixtures	31-Dec-42	POLE WOOD 25 FT	2	78
E364.00-Poles, Towers, and Fixtures	1-Jan-43	POLE WOOD 25 FT	77	1,072
E364.00-Poles, Towers, and Fixtures	31-Dec-43	POLE WOOD 25 FT	39	1,858
E364.00-Poles, Towers, and Fixtures	1-Jan-44	POLE WOOD 25 FT	123	2,430
E364.00-Poles, Towers, and Fixtures	31-Dec-44	POLE WOOD 25 FT	12	580
E364.00-Poles, Towers, and Fixtures	31-Dec-44	POLE WOOD 25 FT	56	2,331
E364.00-Poles, Towers, and Fixtures	1-Jan-45	POLE WOOD 25 FT	365	8,196
E364.00-Poles, Towers, and Fixtures	31-Dec-45	POLE WOOD 25 FT	2	73
E364.00-Poles, Towers, and Fixtures	1-Jan-46	POLE WOOD 25 FT	1,017	22,480
E364.00-Poles, Towers, and Fixtures	31-Dec-46	POLE WOOD 25 FT	41	2,968
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD 25 FT	534	12,265
E364.00-Poles, Towers, and Fixtures	31-Dec-47	POLE WOOD 25 FT	19	1,189
E364.00-Poles, Towers, and Fixtures	31-Dec-47	POLE WOOD 25 FT	33	3,243
E364.00-Poles, Towers, and Fixtures	31-Dec-47	POLE WOOD 25 FT	34	1,595
E364.00-Poles, Towers, and Fixtures	1-Jan-48	POLE WOOD 25 FT	275	6,439
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 25 FT	1	35
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 25 FT	2	172
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 25 FT	3	168
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 25 FT	4	180
E364.00-Poles, Towers, and Fixtures	1-Jan-49	POLE WOOD 25 FT	255	5,479
E364.00-Poles, Towers, and Fixtures	31-Dec-49	POLE WOOD 25 FT	1	78
E364.00-Poles, Towers, and Fixtures	31-Dec-49	POLE WOOD 25 FT	1	2,945
E364.00-Poles, Towers, and Fixtures	31-Dec-49	POLE WOOD 25 FT	6	425
E364.00-Poles, Towers, and Fixtures	1-Jan-50	POLE WOOD 25 FT	165	3,946
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 25 FT	1	33
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 25 FT	1	56
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 25 FT	5	223
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 25 FT	7	596
E364.00-Poles, Towers, and Fixtures	1-Jan-51	POLE WOOD 25 FT	111	2,879
E364.00-Poles, Towers, and Fixtures	31-Dec-51	POLE WOOD 25 FT	1	83
E364.00-Poles, Towers, and Fixtures	31-Dec-51	POLE WOOD 25 FT	1	136
E364.00-Poles, Towers, and Fixtures	31-Dec-51	POLE WOOD 25 FT	2	168

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-51	POLE WOOD 25 FT	3	203
E364.00-Poles, Towers, and Fixtures	31-Dec-51	POLE WOOD 25 FT	7	434
E364.00-Poles, Towers, and Fixtures	1-Jan-52	POLE WOOD 25 FT	98	2,517
E364.00-Poles, Towers, and Fixtures	31-Dec-52	POLE WOOD 25 FT	2	123
E364.00-Poles, Towers, and Fixtures	31-Dec-52	POLE WOOD 25 FT	2	187
E364.00-Poles, Towers, and Fixtures	31-Dec-52	POLE WOOD 25 FT	2	408
E364.00-Poles, Towers, and Fixtures	31-Dec-52	POLE WOOD 25 FT	7	549
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 25 FT	39	1,635
E364.00-Poles, Towers, and Fixtures	31-Dec-53	POLE WOOD 25 FT	2	73
E364.00-Poles, Towers, and Fixtures	31-Dec-53	POLE WOOD 25 FT	12	1,537
E364.00-Poles, Towers, and Fixtures	31-Dec-53	POLE WOOD 25 FT	14	1,282
E364.00-Poles, Towers, and Fixtures	31-Dec-53	POLE WOOD 25 FT	20	3,192
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 25 FT	2	542
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 25 FT	4	567
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 25 FT	5	283
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 25 FT	5	945
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 25 FT	5	1,777
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 25 FT	7	1,034
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 25 FT	8	739
E364.00-Poles, Towers, and Fixtures	1-Jan-55	POLE WOOD 25 FT	43	1,397
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 25 FT	2	378
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 25 FT	4	540
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 25 FT	4	722
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 25 FT	6	409
E364.00-Poles, Towers, and Fixtures	1-Jan-56	POLE WOOD 25 FT	29	855
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 25 FT	1	105
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 25 FT	6	513
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 25 FT	80	2,528
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 25 FT	1	65
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 25 FT	2	258
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 25 FT	4	348
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 25 FT	8	772
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 25 FT	8	2,056
E364.00-Poles, Towers, and Fixtures	1-Jan-58	POLE WOOD 25 FT	39	1,459
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 25 FT	1	62
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 25 FT	1	98
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 25 FT	1	291
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 25 FT	5	632
E364.00-Poles, Towers, and Fixtures	1-Jan-59	POLE WOOD 25 FT	80	1,609
E364.00-Poles, Towers, and Fixtures	31-Dec-59	POLE WOOD 25 FT	1	117
E364.00-Poles, Towers, and Fixtures	31-Dec-59	POLE WOOD 25 FT	2	322
E364.00-Poles, Towers, and Fixtures	31-Dec-59	POLE WOOD 25 FT	2	865
E364.00-Poles, Towers, and Fixtures	31-Dec-59	POLE WOOD 25 FT	3	551
E364.00-Poles, Towers, and Fixtures	1-Jan-60	POLE WOOD 25 FT	24	1,046
E364.00-Poles, Towers, and Fixtures	31-Dec-60	POLE WOOD 25 FT	2	206
E364.00-Poles, Towers, and Fixtures	31-Dec-60	POLE WOOD 25 FT	2	251
E364.00-Poles, Towers, and Fixtures	31-Dec-60	POLE WOOD 25 FT	6	562
E364.00-Poles, Towers, and Fixtures	1-Jan-61	POLE WOOD 25 FT	32	1,383
E364.00-Poles, Towers, and Fixtures	1-Jan-62	POLE WOOD 25 FT	18	735
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 25 FT	1	92
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 25 FT	2	407
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 25 FT	3	327
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 25 FT	3	1,042
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 25 FT	11	454
E364.00-Poles, Towers, and Fixtures	1-Jan-64	POLE WOOD 25 FT	7	275

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 25 FT	1	85
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 25 FT	2	588
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 25 FT	2	1,035
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 25 FT	6	240
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 25 FT	160	341
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 25 FT	3	128
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 25 FT	1	136
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 25 FT	4	166
E364.00-Poles, Towers, and Fixtures	31-Dec-67	POLE WOOD 25 FT	2	113
E364.00-Poles, Towers, and Fixtures	31-Dec-67	POLE WOOD 25 FT	4	340
E364.00-Poles, Towers, and Fixtures	31-Dec-68	POLE WOOD 25 FT	1	68
E364.00-Poles, Towers, and Fixtures	31-Dec-68	POLE WOOD 25 FT	1	123
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 25 FT	3	150
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 25 FT	8	284
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 25 FT	3	199
E364.00-Poles, Towers, and Fixtures	31-Dec-72	POLE WOOD 25 FT	1	312
E364.00-Poles, Towers, and Fixtures	31-Dec-72	POLE WOOD 25 FT	1	359
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 25 FT	4	198
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 25 FT	1	838
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 25 FT	1	1,114
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 25 FT	2	1,090
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 25 FT	2	1,517
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 25 FT	1	53
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 25 FT	1	197
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 25 FT	3	262
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 25 FT	2	639
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 25 FT	1	141
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 25 FT	3	387
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 25 FT	1	696
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 25 FT	1	1,062
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 25 FT	2	939
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 25 FT	4	2,327
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 25 FT	3	21
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 25 FT	1	532
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 25 FT	1	1,328
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 25 FT	2	2,110
E364.00-Poles, Towers, and Fixtures	31-Dec-92	POLE WOOD 25 FT	1	292
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 25 FT	1	900
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 25 FT	1	1,022
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 25 FT	1	1,284
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 25 FT	2	1,345
E364.00-Poles, Towers, and Fixtures	30-Sep-98	POLE WOOD 25 FT	4	6,112
E364.00-Poles, Towers, and Fixtures	31-Dec-98	POLE WOOD 25 FT	2	506
E364.00-Poles, Towers, and Fixtures	31-Dec-98	POLE WOOD 25 FT	3	3,679
E364.00-Poles, Towers, and Fixtures	1-Jan-41	POLE WOOD 30 FT	2	0
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 30 FT	14	760
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 30 FT	14	778
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 30 FT	15	745
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 30 FT	42	2,338
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 30 FT	82	631
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 30 FT	96	3,670
E364.00-Poles, Towers, and Fixtures	1-Jan-42	POLE WOOD 30 FT	9	106
E364.00-Poles, Towers, and Fixtures	31-Dec-42	POLE WOOD 30 FT	1	17
E364.00-Poles, Towers, and Fixtures	31-Dec-42	POLE WOOD 30 FT	22	256
E364.00-Poles, Towers, and Fixtures	1-Jan-43	POLE WOOD 30 FT	2	21

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-44	POLE WOOD 30 FT	1	69
E364.00-Poles, Towers, and Fixtures	31-Dec-44	POLE WOOD 30 FT	2	95
E364.00-Poles, Towers, and Fixtures	31-Dec-44	POLE WOOD 30 FT	4	71
E364.00-Poles, Towers, and Fixtures	31-Dec-44	POLE WOOD 30 FT	12	148
E364.00-Poles, Towers, and Fixtures	31-Dec-44	POLE WOOD 30 FT	22	999
E364.00-Poles, Towers, and Fixtures	31-Dec-44	POLE WOOD 30 FT	47	2,103
E364.00-Poles, Towers, and Fixtures	1-Jan-46	POLE WOOD 30 FT	1,062	26,249
E364.00-Poles, Towers, and Fixtures	31-Dec-46	POLE WOOD 30 FT	2	180
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD 30 FT	1,928	124,863
E364.00-Poles, Towers, and Fixtures	31-Dec-47	POLE WOOD 30 FT	5	56
E364.00-Poles, Towers, and Fixtures	31-Dec-47	POLE WOOD 30 FT	5	142
E364.00-Poles, Towers, and Fixtures	31-Dec-47	POLE WOOD 30 FT	5	293
E364.00-Poles, Towers, and Fixtures	1-Jan-48	POLE WOOD 30 FT	1,727	120,577
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 30 FT	1	37
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 30 FT	4	223
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 30 FT	14	642
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 30 FT	21	236
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 30 FT	42	1,067
E364.00-Poles, Towers, and Fixtures	1-Jan-49	POLE WOOD 30 FT	2,009	56,433
E364.00-Poles, Towers, and Fixtures	1-Jan-50	POLE WOOD 30 FT	2,021	59,864
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 30 FT	1	53
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 30 FT	2	111
E364.00-Poles, Towers, and Fixtures	1-Jan-51	POLE WOOD 30 FT	1,333	42,565
E364.00-Poles, Towers, and Fixtures	31-Dec-51	POLE WOOD 30 FT	1	62
E364.00-Poles, Towers, and Fixtures	1-Jan-52	POLE WOOD 30 FT	1,410	45,372
E364.00-Poles, Towers, and Fixtures	31-Dec-52	POLE WOOD 30 FT	1	54
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 30 FT	148	8,810
E364.00-Poles, Towers, and Fixtures	1-Jan-54	POLE WOOD 30 FT	1	38
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 30 FT	1	46
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 30 FT	2	65
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 30 FT	2	131
E364.00-Poles, Towers, and Fixtures	1-Jan-55	POLE WOOD 30 FT	60	2,434
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 30 FT	1	124
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 30 FT	2	21
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 30 FT	3	178
E364.00-Poles, Towers, and Fixtures	1-Jan-56	POLE WOOD 30 FT	19	747
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 30 FT	2	119
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 30 FT	2	182
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 30 FT	4	122
E364.00-Poles, Towers, and Fixtures	1-Jan-61	POLE WOOD 30 FT	540	25,607
E364.00-Poles, Towers, and Fixtures	31-Dec-61	POLE WOOD 30 FT	2	34
E364.00-Poles, Towers, and Fixtures	1-Jan-62	POLE WOOD 30 FT	636	29,879
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 30 FT	1	114
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 30 FT	1	133
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 30 FT	10	1,419
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 30 FT	1,137	54,316
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 30 FT	2	135
E364.00-Poles, Towers, and Fixtures	1-Jan-64	POLE WOOD 30 FT	1,618	77,623
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 30 FT	2	28
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 30 FT	1,331	63,690
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 30 FT	1	45
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 30 FT	2	46
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 30 FT	2	77
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 30 FT	2	281
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 30 FT	1,858	97,180

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 30 FT	1	60
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 30 FT	2	38
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 30 FT	7	302
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 30 FT	1,762	97,141
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 30 FT	1,555	93,642
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 30 FT	1,891	117,216
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 30 FT	241	16,291
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 30 FT	1	23
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 30 FT	1	163
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 30 FT	2,826	194,038
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 30 FT	2,724	200,677
E364.00-Poles, Towers, and Fixtures	31-Dec-72	POLE WOOD 30 FT	1	117
E364.00-Poles, Towers, and Fixtures	31-Dec-72	POLE WOOD 30 FT	6	283
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 30 FT	2,843	231,071
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 30 FT	2,559	209,471
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 30 FT	1,787	158,990
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 30 FT	1	176
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 30 FT	2,535	243,054
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 30 FT	1	1,294
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 30 FT	1	2,552
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 30 FT	2	476
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 30 FT	3	1,244
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 30 FT	2,469	244,541
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 30 FT	2	98
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 30 FT	5	280
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 30 FT	2,045	219,535
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 30 FT	2,150	261,300
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 30 FT	1	164
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 30 FT	1	221
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 30 FT	2	460
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 30 FT	2,026	260,562
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 30 FT	2,118	300,972
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 30 FT	1,846	302,884
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 30 FT	1	304
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 30 FT	7	2,633
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 30 FT	11	107
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 30 FT	12	688
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 30 FT	13	6,046
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 30 FT	27	2,948
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 30 FT	39	11,880
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 30 FT	1,781	363,751
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 30 FT	1,411	271,844
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 30 FT	1,258	252,080
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 30 FT	1,465	316,241
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 30 FT	1,480	326,143
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 30 FT	1,318	319,829
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 30 FT	1,352	318,445
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 30 FT	1,352	341,358
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 30 FT	1	271
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 30 FT	1	489
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 30 FT	1,342	361,750
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 30 FT	1,339	345,440
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 30 FT	1,497	430,302
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 30 FT	1,536	449,906
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 30 FT	1,555	477,058

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 30 FT	1	267
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 30 FT	1	1,181
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 30 FT	1	1,430
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 30 FT	1	1,696
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 30 FT	1,319	491,398
E364.00-Poles, Towers, and Fixtures	31-Dec-96	POLE WOOD 30 FT	1	520
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 30 FT	1,303	470,694
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 30 FT	1,282	474,870
E364.00-Poles, Towers, and Fixtures	31-Jan-98	POLE WOOD 30 FT	1	99
E364.00-Poles, Towers, and Fixtures	31-Jan-98	POLE WOOD 30 FT	1	948
E364.00-Poles, Towers, and Fixtures	31-Jan-98	POLE WOOD 30 FT	2	2,765
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 30 FT	58	46,739
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 30 FT	1,054	387,805
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 30 FT	686	127,194
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 30 FT	906	365,333
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 30 FT	1,322	569,451
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 30 FT	691	548,408
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 30 FT	67	24,786
E364.00-Poles, Towers, and Fixtures	1-Dec-05	POLE WOOD 30 FT	1	1,062
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 30 FT	25	7,209
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 30 FT	290	239,412
E364.00-Poles, Towers, and Fixtures	30-Sep-07	POLE WOOD 30 FT	1	11,796
E364.00-Poles, Towers, and Fixtures	30-Nov-07	POLE WOOD 30 FT	6	5,480
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 30 FT	307	212,135
E364.00-Poles, Towers, and Fixtures	22-Feb-08	POLE WOOD 30 FT	20	25,759
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 30 FT	1	367
E364.00-Poles, Towers, and Fixtures	30-Sep-08	POLE WOOD 30 FT	9	4,295
E364.00-Poles, Towers, and Fixtures	31-Oct-08	POLE WOOD 30 FT	56	53,990
E364.00-Poles, Towers, and Fixtures	30-Nov-08	POLE WOOD 30 FT	24	29,324
E364.00-Poles, Towers, and Fixtures	31-Dec-08	POLE WOOD 30 FT	124	115,110
E364.00-Poles, Towers, and Fixtures	31-Jan-09	POLE WOOD 30 FT	5	1,451
E364.00-Poles, Towers, and Fixtures	16-Jun-09	POLE WOOD 30 FT	24	11,888
E364.00-Poles, Towers, and Fixtures	22-Jul-09	POLE WOOD 30 FT	1	0
E364.00-Poles, Towers, and Fixtures	27-Jul-09	POLE WOOD 30 FT	2	5,598
E364.00-Poles, Towers, and Fixtures	28-Jul-09	POLE WOOD 30 FT	13	12,712
E364.00-Poles, Towers, and Fixtures	29-Jul-09	POLE WOOD 30 FT	1	223
E364.00-Poles, Towers, and Fixtures	1-Aug-09	POLE WOOD 30 FT	233	171,678
E364.00-Poles, Towers, and Fixtures	4-Aug-09	POLE WOOD 30 FT	14	10,859
E364.00-Poles, Towers, and Fixtures	10-Aug-09	POLE WOOD 30 FT	42	13,470
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 30 FT	132	44,608
E364.00-Poles, Towers, and Fixtures	1-Oct-09	POLE WOOD 30 FT	126	96,324
E364.00-Poles, Towers, and Fixtures	13-Oct-09	POLE WOOD 30 FT	1	219
E364.00-Poles, Towers, and Fixtures	16-Oct-09	POLE WOOD 30 FT	5	1,872
E364.00-Poles, Towers, and Fixtures	19-Oct-09	POLE WOOD 30 FT	1	254
E364.00-Poles, Towers, and Fixtures	20-Oct-09	POLE WOOD 30 FT	2	35
E364.00-Poles, Towers, and Fixtures	26-Oct-09	POLE WOOD 30 FT	1	1,139
E364.00-Poles, Towers, and Fixtures	27-Oct-09	POLE WOOD 30 FT	4	6,886
E364.00-Poles, Towers, and Fixtures	29-Oct-09	POLE WOOD 30 FT	3	4,607
E364.00-Poles, Towers, and Fixtures	31-Oct-09	POLE WOOD 30 FT	133	59,219
E364.00-Poles, Towers, and Fixtures	5-Nov-09	POLE WOOD 30 FT	1	(106)
E364.00-Poles, Towers, and Fixtures	9-Nov-09	POLE WOOD 30 FT	165	54,114
E364.00-Poles, Towers, and Fixtures	10-Nov-09	POLE WOOD 30 FT	4	9,691
E364.00-Poles, Towers, and Fixtures	19-Nov-09	POLE WOOD 30 FT	144	68,025
E364.00-Poles, Towers, and Fixtures	21-Nov-09	POLE WOOD 30 FT	87	44,828
E364.00-Poles, Towers, and Fixtures	23-Nov-09	POLE WOOD 30 FT	1	117

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	25-Nov-09	POLE WOOD 30 FT	99	80,159
E364.00-Poles, Towers, and Fixtures	30-Nov-09	POLE WOOD 30 FT	680	392,276
E364.00-Poles, Towers, and Fixtures	2-Dec-09	POLE WOOD 30 FT	759	386,007
E364.00-Poles, Towers, and Fixtures	3-Dec-09	POLE WOOD 30 FT	1	654
E364.00-Poles, Towers, and Fixtures	7-Dec-09	POLE WOOD 30 FT	35	26,930
E364.00-Poles, Towers, and Fixtures	9-Dec-09	POLE WOOD 30 FT	1	258
E364.00-Poles, Towers, and Fixtures	17-Dec-09	POLE WOOD 30 FT	5	7,941
E364.00-Poles, Towers, and Fixtures	22-Dec-09	POLE WOOD 30 FT	1	1,219
E364.00-Poles, Towers, and Fixtures	31-Dec-09	POLE WOOD 30 FT	1	418
E364.00-Poles, Towers, and Fixtures	1-Jan-41	POLE WOOD 35 FT	3	39
E364.00-Poles, Towers, and Fixtures	1-Jan-41	POLE WOOD 35 FT	112	2,676
E364.00-Poles, Towers, and Fixtures	1-Jan-42	POLE WOOD 35 FT	202	10,443
E364.00-Poles, Towers, and Fixtures	1-Jan-43	POLE WOOD 35 FT	15	624
E364.00-Poles, Towers, and Fixtures	1-Jan-44	POLE WOOD 35 FT	36	2,394
E364.00-Poles, Towers, and Fixtures	1-Jan-45	POLE WOOD 35 FT	19	525
E364.00-Poles, Towers, and Fixtures	1-Jan-46	POLE WOOD 35 FT	469	15,006
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD 35 FT	454	21,017
E364.00-Poles, Towers, and Fixtures	1-Jan-48	POLE WOOD 35 FT	693	33,164
E364.00-Poles, Towers, and Fixtures	1-Jan-49	POLE WOOD 35 FT	4,896	282,062
E364.00-Poles, Towers, and Fixtures	1-Jan-50	POLE WOOD 35 FT	6,543	378,195
E364.00-Poles, Towers, and Fixtures	1-Jan-51	POLE WOOD 35 FT	4,844	315,028
E364.00-Poles, Towers, and Fixtures	1-Jan-52	POLE WOOD 35 FT	5,424	356,684
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 35 FT	2,419	220,825
E364.00-Poles, Towers, and Fixtures	1-Jan-54	POLE WOOD 35 FT	299	15,654
E364.00-Poles, Towers, and Fixtures	1-Jan-55	POLE WOOD 35 FT	1,246	60,219
E364.00-Poles, Towers, and Fixtures	1-Jan-56	POLE WOOD 35 FT	1,236	63,798
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 35 FT	1,957	221,193
E364.00-Poles, Towers, and Fixtures	1-Jan-58	POLE WOOD 35 FT	1,619	160,605
E364.00-Poles, Towers, and Fixtures	1-Jan-59	POLE WOOD 35 FT	1,089	79,251
E364.00-Poles, Towers, and Fixtures	1-Jan-61	POLE WOOD 35 FT	1,621	94,716
E364.00-Poles, Towers, and Fixtures	1-Jan-62	POLE WOOD 35 FT	1,724	105,338
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 35 FT	1,807	117,726
E364.00-Poles, Towers, and Fixtures	1-Jan-64	POLE WOOD 35 FT	2,187	142,550
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 35 FT	1,609	103,152
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 35 FT	1,874	124,856
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 35 FT	1,950	142,884
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 35 FT	1,651	126,094
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 35 FT	1,759	151,365
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 35 FT	1,048	86,657
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 35 FT	2,128	182,953
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 35 FT	1,859	170,929
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 35 FT	2,021	212,015
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 35 FT	1,828	200,990
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 35 FT	1,490	197,689
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 35 FT	1,654	212,707
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 35 FT	1,552	204,122
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 35 FT	1,296	182,468
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 35 FT	1,611	257,746
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 35 FT	1,170	206,542
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 35 FT	1,126	220,127
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 35 FT	1,052	232,693
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 35 FT	1,283	334,424
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 35 FT	941	226,468
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 35 FT	850	206,880
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 35 FT	1,192	322,314

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 35 FT	1,178	315,713
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 35 FT	921	279,899
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 35 FT	1,080	306,340
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 35 FT	1,143	355,834
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 35 FT	1,139	347,966
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 35 FT	1,175	370,932
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 35 FT	1,284	453,131
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 35 FT	1,308	461,346
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 35 FT	1,213	455,191
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 35 FT	1,023	490,115
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 35 FT	1,070	485,467
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 35 FT	972	433,573
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 35 FT	102	128,153
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 35 FT	878	498,243
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 35 FT	591	210,985
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 35 FT	574	391,491
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 35 FT	666	855,591
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 35 FT	557	580,729
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 35 FT	47	41,885
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 35 FT	20	21,519
E364.00-Poles, Towers, and Fixtures	6-Dec-06	POLE WOOD 35 FT	2	3,012
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 35 FT	510	622,257
E364.00-Poles, Towers, and Fixtures	31-Aug-07	POLE WOOD 35 FT	1	5,159
E364.00-Poles, Towers, and Fixtures	1-Oct-07	POLE WOOD 35 FT	3	(19)
E364.00-Poles, Towers, and Fixtures	25-Nov-07	POLE WOOD 35 FT	1	488
E364.00-Poles, Towers, and Fixtures	30-Nov-07	POLE WOOD 35 FT	1	331
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 35 FT	266	349,542
E364.00-Poles, Towers, and Fixtures	22-Feb-08	POLE WOOD 35 FT	15	16,728
E364.00-Poles, Towers, and Fixtures	13-Mar-08	POLE WOOD 35 FT	2	2,439
E364.00-Poles, Towers, and Fixtures	3-Apr-08	POLE WOOD 35 FT	1	8
E364.00-Poles, Towers, and Fixtures	1-Aug-08	POLE WOOD 35 FT	2	665
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 35 FT	8	10,994
E364.00-Poles, Towers, and Fixtures	30-Sep-08	POLE WOOD 35 FT	22	18,543
E364.00-Poles, Towers, and Fixtures	1-Oct-08	POLE WOOD 35 FT	3	4,873
E364.00-Poles, Towers, and Fixtures	31-Oct-08	POLE WOOD 35 FT	82	101,824
E364.00-Poles, Towers, and Fixtures	30-Nov-08	POLE WOOD 35 FT	12	13,680
E364.00-Poles, Towers, and Fixtures	31-Dec-08	POLE WOOD 35 FT	68	121,639
E364.00-Poles, Towers, and Fixtures	31-Jan-09	POLE WOOD 35 FT	3	25,825
E364.00-Poles, Towers, and Fixtures	16-Jun-09	POLE WOOD 35 FT	12	15,286
E364.00-Poles, Towers, and Fixtures	19-Jul-09	POLE WOOD 35 FT	1	643
E364.00-Poles, Towers, and Fixtures	22-Jul-09	POLE WOOD 35 FT	1	0
E364.00-Poles, Towers, and Fixtures	27-Jul-09	POLE WOOD 35 FT	1	1,108
E364.00-Poles, Towers, and Fixtures	28-Jul-09	POLE WOOD 35 FT	2	1,654
E364.00-Poles, Towers, and Fixtures	29-Jul-09	POLE WOOD 35 FT	3	1,662
E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 35 FT	5	3,828
E364.00-Poles, Towers, and Fixtures	1-Aug-09	POLE WOOD 35 FT	72	85,689
E364.00-Poles, Towers, and Fixtures	3-Aug-09	POLE WOOD 35 FT	2	0
E364.00-Poles, Towers, and Fixtures	4-Aug-09	POLE WOOD 35 FT	2	4,108
E364.00-Poles, Towers, and Fixtures	7-Aug-09	POLE WOOD 35 FT	3	2,383
E364.00-Poles, Towers, and Fixtures	10-Aug-09	POLE WOOD 35 FT	5	2,231
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 35 FT	22	11,264
E364.00-Poles, Towers, and Fixtures	6-Oct-09	POLE WOOD 35 FT	1	(11,264)
E364.00-Poles, Towers, and Fixtures	7-Oct-09	POLE WOOD 35 FT	2	(7,415)
E364.00-Poles, Towers, and Fixtures	13-Oct-09	POLE WOOD 35 FT	7	4,744
E364.00-Poles, Towers, and Fixtures	14-Oct-09	POLE WOOD 35 FT	2	2,396

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	16-Oct-09	POLE WOOD 35 FT	4	2,205
E364.00-Poles, Towers, and Fixtures	20-Oct-09	POLE WOOD 35 FT	2	1,037
E364.00-Poles, Towers, and Fixtures	21-Oct-09	POLE WOOD 35 FT	1	240
E364.00-Poles, Towers, and Fixtures	26-Oct-09	POLE WOOD 35 FT	1	(258)
E364.00-Poles, Towers, and Fixtures	29-Oct-09	POLE WOOD 35 FT	1	1,261
E364.00-Poles, Towers, and Fixtures	30-Oct-09	POLE WOOD 35 FT	1	241
E364.00-Poles, Towers, and Fixtures	31-Oct-09	POLE WOOD 35 FT	136	95,320
E364.00-Poles, Towers, and Fixtures	5-Nov-09	POLE WOOD 35 FT	10	11,839
E364.00-Poles, Towers, and Fixtures	6-Nov-09	POLE WOOD 35 FT	1	3,078
E364.00-Poles, Towers, and Fixtures	9-Nov-09	POLE WOOD 35 FT	319	234,718
E364.00-Poles, Towers, and Fixtures	12-Nov-09	POLE WOOD 35 FT	14	20,915
E364.00-Poles, Towers, and Fixtures	13-Nov-09	POLE WOOD 35 FT	7	3,404
E364.00-Poles, Towers, and Fixtures	16-Nov-09	POLE WOOD 35 FT	3	5,677
E364.00-Poles, Towers, and Fixtures	17-Nov-09	POLE WOOD 35 FT	4	2,801
E364.00-Poles, Towers, and Fixtures	19-Nov-09	POLE WOOD 35 FT	114	86,187
E364.00-Poles, Towers, and Fixtures	20-Nov-09	POLE WOOD 35 FT	1	285
E364.00-Poles, Towers, and Fixtures	21-Nov-09	POLE WOOD 35 FT	77	67,846
E364.00-Poles, Towers, and Fixtures	30-Nov-09	POLE WOOD 35 FT	75	114,247
E364.00-Poles, Towers, and Fixtures	1-Dec-09	POLE WOOD 35 FT	79	88,813
E364.00-Poles, Towers, and Fixtures	2-Dec-09	POLE WOOD 35 FT	505	437,077
E364.00-Poles, Towers, and Fixtures	4-Dec-09	POLE WOOD 35 FT	7	7,810
E364.00-Poles, Towers, and Fixtures	7-Dec-09	POLE WOOD 35 FT	10	11,074
E364.00-Poles, Towers, and Fixtures	8-Dec-09	POLE WOOD 35 FT	17	20,103
E364.00-Poles, Towers, and Fixtures	9-Dec-09	POLE WOOD 35 FT	2	2,022
E364.00-Poles, Towers, and Fixtures	16-Dec-09	POLE WOOD 35 FT	134	88,199
E364.00-Poles, Towers, and Fixtures	29-Dec-09	POLE WOOD 35 FT	1	3,336
E364.00-Poles, Towers, and Fixtures	1-Jan-41	POLE WOOD 40 FT	10	251
E364.00-Poles, Towers, and Fixtures	1-Jan-42	POLE WOOD 40 FT	4	0
E364.00-Poles, Towers, and Fixtures	1-Jan-43	POLE WOOD 40 FT	4	0
E364.00-Poles, Towers, and Fixtures	1-Jan-44	POLE WOOD 40 FT	33	1,698
E364.00-Poles, Towers, and Fixtures	1-Jan-45	POLE WOOD 40 FT	29	1,371
E364.00-Poles, Towers, and Fixtures	1-Jan-46	POLE WOOD 40 FT	42	1,855
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD 40 FT	37	2,363
E364.00-Poles, Towers, and Fixtures	1-Jan-50	POLE WOOD 40 FT	787	34,179
E364.00-Poles, Towers, and Fixtures	1-Jan-51	POLE WOOD 40 FT	1,479	73,389
E364.00-Poles, Towers, and Fixtures	1-Jan-52	POLE WOOD 40 FT	1,790	92,290
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 40 FT	580	37,858
E364.00-Poles, Towers, and Fixtures	1-Jan-54	POLE WOOD 40 FT	472	87,520
E364.00-Poles, Towers, and Fixtures	1-Jan-55	POLE WOOD 40 FT	1,140	157,358
E364.00-Poles, Towers, and Fixtures	1-Jan-56	POLE WOOD 40 FT	1,383	173,125
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 40 FT	1,443	101,844
E364.00-Poles, Towers, and Fixtures	1-Jan-58	POLE WOOD 40 FT	785	57,740
E364.00-Poles, Towers, and Fixtures	1-Jan-59	POLE WOOD 40 FT	1,372	101,651
E364.00-Poles, Towers, and Fixtures	1-Jan-60	POLE WOOD 40 FT	510	83,001
E364.00-Poles, Towers, and Fixtures	1-Jan-61	POLE WOOD 40 FT	1,794	237,743
E364.00-Poles, Towers, and Fixtures	1-Jan-62	POLE WOOD 40 FT	1,362	183,804
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 40 FT	2,150	278,878
E364.00-Poles, Towers, and Fixtures	1-Jan-64	POLE WOOD 40 FT	2,466	313,905
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 40 FT	2,585	330,171
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 40 FT	2,479	350,568
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 40 FT	2,563	357,163
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 40 FT	3,092	450,095
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 40 FT	3,124	466,212
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 40 FT	2,556	410,679
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 40 FT	2,906	493,695

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 40 FT	3,449	656,596
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 40 FT	3,380	746,993
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 40 FT	3,174	738,795
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 40 FT	2,448	586,636
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 40 FT	2,789	719,300
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 40 FT	3,244	842,799
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 40 FT	2,745	791,670
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 40 FT	2,980	1,021,787
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 40 FT	3,067	1,062,792
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 40 FT	2,807	1,064,093
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 40 FT	2,749	1,159,162
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 40 FT	3,290	1,861,038
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 40 FT	2,572	1,273,693
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 40 FT	2,711	1,372,504
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 40 FT	3,072	1,672,247
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 40 FT	3,462	1,865,759
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 40 FT	3,013	1,822,863
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 40 FT	3,331	1,935,954
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 40 FT	3,269	1,988,193
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 40 FT	3,240	2,079,475
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 40 FT	3,833	2,448,471
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 40 FT	3,569	2,667,164
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 40 FT	4,122	3,235,740
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 40 FT	4,126	3,430,457
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 40 FT	2,958	3,217,843
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 40 FT	3,316	3,382,737
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 40 FT	2,608	2,805,758
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 40 FT	341	488,576
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 40 FT	2,053	2,479,762
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 40 FT	1,527	1,005,340
E364.00-Poles, Towers, and Fixtures	28-Feb-01	POLE WOOD 40 FT	1	6,179
E364.00-Poles, Towers, and Fixtures	31-Oct-01	POLE WOOD 40 FT	1	1,157
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 40 FT	1,751	2,141,003
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 40 FT	2,465	2,997,762
E364.00-Poles, Towers, and Fixtures	31-May-03	POLE WOOD 40 FT	1	13,324
E364.00-Poles, Towers, and Fixtures	30-Jun-03	POLE WOOD 40 FT	1	1,542
E364.00-Poles, Towers, and Fixtures	31-Aug-03	POLE WOOD 40 FT	1	6,888
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 40 FT	1,500	2,481,118
E364.00-Poles, Towers, and Fixtures	31-Dec-04	POLE WOOD 40 FT	1	2,217
E364.00-Poles, Towers, and Fixtures	31-Dec-04	POLE WOOD 40 FT	2	205
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 40 FT	159	225,968
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 40 FT	58	75,741
E364.00-Poles, Towers, and Fixtures	30-Nov-06	POLE WOOD 40 FT	1	4,348
E364.00-Poles, Towers, and Fixtures	6-Dec-06	POLE WOOD 40 FT	1	2,457
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 40 FT	1,623	2,656,450
E364.00-Poles, Towers, and Fixtures	26-Feb-07	POLE WOOD 40 FT	1	0
E364.00-Poles, Towers, and Fixtures	1-Oct-07	POLE WOOD 40 FT	29	(290)
E364.00-Poles, Towers, and Fixtures	14-Nov-07	POLE WOOD 40 FT	1	2,783
E364.00-Poles, Towers, and Fixtures	25-Nov-07	POLE WOOD 40 FT	3	2,403
E364.00-Poles, Towers, and Fixtures	30-Nov-07	POLE WOOD 40 FT	30	31,441
E364.00-Poles, Towers, and Fixtures	31-Dec-07	POLE WOOD 40 FT	13	76,236
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 40 FT	1,171	2,302,666
E364.00-Poles, Towers, and Fixtures	22-Feb-08	POLE WOOD 40 FT	104	313,442
E364.00-Poles, Towers, and Fixtures	1-Aug-08	POLE WOOD 40 FT	1	683
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 40 FT	36	79,773

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	30-Sep-08	POLE WOOD 40 FT	87	145,422
E364.00-Poles, Towers, and Fixtures	1-Oct-08	POLE WOOD 40 FT	7	20,322
E364.00-Poles, Towers, and Fixtures	15-Oct-08	POLE WOOD 40 FT	2	5,650
E364.00-Poles, Towers, and Fixtures	31-Oct-08	POLE WOOD 40 FT	53	196,192
E364.00-Poles, Towers, and Fixtures	30-Nov-08	POLE WOOD 40 FT	47	132,503
E364.00-Poles, Towers, and Fixtures	31-Dec-08	POLE WOOD 40 FT	454	1,065,257
E364.00-Poles, Towers, and Fixtures	31-Jan-09	POLE WOOD 40 FT	13	120,293
E364.00-Poles, Towers, and Fixtures	1-Feb-09	POLE WOOD 40 FT	2	2,143
E364.00-Poles, Towers, and Fixtures	16-Jun-09	POLE WOOD 40 FT	75	96,161
E364.00-Poles, Towers, and Fixtures	17-Jul-09	POLE WOOD 40 FT	4	10,286
E364.00-Poles, Towers, and Fixtures	19-Jul-09	POLE WOOD 40 FT	3	6,444
E364.00-Poles, Towers, and Fixtures	22-Jul-09	POLE WOOD 40 FT	3	0
E364.00-Poles, Towers, and Fixtures	27-Jul-09	POLE WOOD 40 FT	20	43,543
E364.00-Poles, Towers, and Fixtures	28-Jul-09	POLE WOOD 40 FT	1	656
E364.00-Poles, Towers, and Fixtures	29-Jul-09	POLE WOOD 40 FT	12	14,047
E364.00-Poles, Towers, and Fixtures	30-Jul-09	POLE WOOD 40 FT	2	954
E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 40 FT	16	20,995
E364.00-Poles, Towers, and Fixtures	1-Aug-09	POLE WOOD 40 FT	159	259,276
E364.00-Poles, Towers, and Fixtures	3-Aug-09	POLE WOOD 40 FT	10	27,461
E364.00-Poles, Towers, and Fixtures	4-Aug-09	POLE WOOD 40 FT	11	23,814
E364.00-Poles, Towers, and Fixtures	6-Aug-09	POLE WOOD 40 FT	2	1,259
E364.00-Poles, Towers, and Fixtures	7-Aug-09	POLE WOOD 40 FT	18	30,406
E364.00-Poles, Towers, and Fixtures	10-Aug-09	POLE WOOD 40 FT	13	11,578
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 40 FT	1	908
E364.00-Poles, Towers, and Fixtures	29-Sep-09	POLE WOOD 40 FT	1	1,867
E364.00-Poles, Towers, and Fixtures	1-Oct-09	POLE WOOD 40 FT	1	2,314
E364.00-Poles, Towers, and Fixtures	5-Oct-09	POLE WOOD 40 FT	38	38,299
E364.00-Poles, Towers, and Fixtures	7-Oct-09	POLE WOOD 40 FT	1	36,832
E364.00-Poles, Towers, and Fixtures	12-Oct-09	POLE WOOD 40 FT	1	756
E364.00-Poles, Towers, and Fixtures	13-Oct-09	POLE WOOD 40 FT	1	1,950
E364.00-Poles, Towers, and Fixtures	14-Oct-09	POLE WOOD 40 FT	9	13,988
E364.00-Poles, Towers, and Fixtures	16-Oct-09	POLE WOOD 40 FT	4	4,239
E364.00-Poles, Towers, and Fixtures	20-Oct-09	POLE WOOD 40 FT	29	221,915
E364.00-Poles, Towers, and Fixtures	23-Oct-09	POLE WOOD 40 FT	1	(46)
E364.00-Poles, Towers, and Fixtures	26-Oct-09	POLE WOOD 40 FT	12	12,475
E364.00-Poles, Towers, and Fixtures	27-Oct-09	POLE WOOD 40 FT	3	7,055
E364.00-Poles, Towers, and Fixtures	29-Oct-09	POLE WOOD 40 FT	1	1,736
E364.00-Poles, Towers, and Fixtures	31-Oct-09	POLE WOOD 40 FT	379	513,400
E364.00-Poles, Towers, and Fixtures	2-Nov-09	POLE WOOD 40 FT	48	55,751
E364.00-Poles, Towers, and Fixtures	3-Nov-09	POLE WOOD 40 FT	8	13,753
E364.00-Poles, Towers, and Fixtures	4-Nov-09	POLE WOOD 40 FT	1	4,988
E364.00-Poles, Towers, and Fixtures	5-Nov-09	POLE WOOD 40 FT	3	1,214
E364.00-Poles, Towers, and Fixtures	6-Nov-09	POLE WOOD 40 FT	9	7,111
E364.00-Poles, Towers, and Fixtures	9-Nov-09	POLE WOOD 40 FT	6	21,388
E364.00-Poles, Towers, and Fixtures	10-Nov-09	POLE WOOD 40 FT	8	25,114
E364.00-Poles, Towers, and Fixtures	11-Nov-09	POLE WOOD 40 FT	126	192,121
E364.00-Poles, Towers, and Fixtures	12-Nov-09	POLE WOOD 40 FT	2	9,909
E364.00-Poles, Towers, and Fixtures	13-Nov-09	POLE WOOD 40 FT	7	5,251
E364.00-Poles, Towers, and Fixtures	16-Nov-09	POLE WOOD 40 FT	6	17,990
E364.00-Poles, Towers, and Fixtures	17-Nov-09	POLE WOOD 40 FT	4	15,227
E364.00-Poles, Towers, and Fixtures	19-Nov-09	POLE WOOD 40 FT	23	44,903
E364.00-Poles, Towers, and Fixtures	23-Nov-09	POLE WOOD 40 FT	155	289,391
E364.00-Poles, Towers, and Fixtures	24-Nov-09	POLE WOOD 40 FT	1	4,712
E364.00-Poles, Towers, and Fixtures	30-Nov-09	POLE WOOD 40 FT	299	418,339
E364.00-Poles, Towers, and Fixtures	1-Dec-09	POLE WOOD 40 FT	223	455,953

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	2-Dec-09	POLE WOOD 40 FT	1,842	2,465,130
E364.00-Poles, Towers, and Fixtures	3-Dec-09	POLE WOOD 40 FT	5	8,684
E364.00-Poles, Towers, and Fixtures	4-Dec-09	POLE WOOD 40 FT	33	65,391
E364.00-Poles, Towers, and Fixtures	7-Dec-09	POLE WOOD 40 FT	235	468,442
E364.00-Poles, Towers, and Fixtures	8-Dec-09	POLE WOOD 40 FT	312	487,990
E364.00-Poles, Towers, and Fixtures	9-Dec-09	POLE WOOD 40 FT	19	(44,730)
E364.00-Poles, Towers, and Fixtures	16-Dec-09	POLE WOOD 40 FT	268	397,518
E364.00-Poles, Towers, and Fixtures	19-Dec-09	POLE WOOD 40 FT	6	9,574
E364.00-Poles, Towers, and Fixtures	31-Dec-09	POLE WOOD 40 FT	12	127,747
E364.00-Poles, Towers, and Fixtures	1-Jan-42	POLE WOOD 45 FT	3	89
E364.00-Poles, Towers, and Fixtures	1-Jan-44	POLE WOOD 45 FT	3	137
E364.00-Poles, Towers, and Fixtures	1-Jan-48	POLE WOOD 45 FT	68	3,582
E364.00-Poles, Towers, and Fixtures	1-Jan-49	POLE WOOD 45 FT	81	4,377
E364.00-Poles, Towers, and Fixtures	1-Jan-50	POLE WOOD 45 FT	432	23,444
E364.00-Poles, Towers, and Fixtures	1-Jan-51	POLE WOOD 45 FT	393	24,290
E364.00-Poles, Towers, and Fixtures	1-Jan-52	POLE WOOD 45 FT	443	27,993
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 45 FT	87	8,958
E364.00-Poles, Towers, and Fixtures	1-Jan-54	POLE WOOD 45 FT	72	5,801
E364.00-Poles, Towers, and Fixtures	1-Jan-55	POLE WOOD 45 FT	243	17,511
E364.00-Poles, Towers, and Fixtures	1-Jan-56	POLE WOOD 45 FT	369	29,413
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 45 FT	379	32,446
E364.00-Poles, Towers, and Fixtures	1-Jan-58	POLE WOOD 45 FT	173	15,326
E364.00-Poles, Towers, and Fixtures	1-Jan-59	POLE WOOD 45 FT	287	25,578
E364.00-Poles, Towers, and Fixtures	1-Jan-60	POLE WOOD 45 FT	121	11,017
E364.00-Poles, Towers, and Fixtures	1-Jan-61	POLE WOOD 45 FT	355	28,909
E364.00-Poles, Towers, and Fixtures	1-Jan-62	POLE WOOD 45 FT	340	29,784
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 45 FT	706	65,292
E364.00-Poles, Towers, and Fixtures	1-Jan-64	POLE WOOD 45 FT	558	52,318
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 45 FT	667	62,659
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 45 FT	563	58,543
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 45 FT	672	71,211
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 45 FT	841	96,489
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 45 FT	738	85,573
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 45 FT	734	88,306
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 45 FT	1,087	141,277
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 45 FT	811	112,368
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 45 FT	913	138,925
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 45 FT	909	147,555
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 45 FT	490	92,323
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 45 FT	587	116,351
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 45 FT	699	144,657
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 45 FT	695	156,909
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 45 FT	931	241,293
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 45 FT	899	261,580
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 45 FT	814	256,583
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 45 FT	882	302,659
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 45 FT	921	371,386
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 45 FT	750	297,944
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 45 FT	887	374,802
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 45 FT	1,117	471,990
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 45 FT	1,211	528,927
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 45 FT	1,237	583,863
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 45 FT	1,299	599,394
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 45 FT	1,421	696,256
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 45 FT	1,214	614,701

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 45 FT	1,633	820,459
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 45 FT	1,805	1,010,066
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 45 FT	2,196	1,250,019
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 45 FT	2,390	1,574,104
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 45 FT	2,032	1,498,101
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 45 FT	1,963	1,364,043
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 45 FT	1,883	1,555,023
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 45 FT	527	1,306,308
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 45 FT	2,095	2,195,179
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 45 FT	1,498	1,443,616
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 45 FT	1,328	2,334,102
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 45 FT	2,254	3,246,237
E364.00-Poles, Towers, and Fixtures	31-Aug-03	POLE WOOD 45 FT	1	12,777
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 45 FT	1,963	4,041,380
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 45 FT	439	593,142
E364.00-Poles, Towers, and Fixtures	1-Dec-05	POLE WOOD 45 FT	2	3,187
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 45 FT	300	283,547
E364.00-Poles, Towers, and Fixtures	31-Dec-06	POLE WOOD 45 FT	1	1,217
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 45 FT	4,263	3,311,156
E364.00-Poles, Towers, and Fixtures	26-Feb-07	POLE WOOD 45 FT	16	0
E364.00-Poles, Towers, and Fixtures	1-Oct-07	POLE WOOD 45 FT	21	(264)
E364.00-Poles, Towers, and Fixtures	14-Nov-07	POLE WOOD 45 FT	1	3,422
E364.00-Poles, Towers, and Fixtures	25-Nov-07	POLE WOOD 45 FT	11	10,858
E364.00-Poles, Towers, and Fixtures	30-Nov-07	POLE WOOD 45 FT	55	88,142
E364.00-Poles, Towers, and Fixtures	31-Dec-07	POLE WOOD 45 FT	3	16,333
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 45 FT	1,707	2,817,282
E364.00-Poles, Towers, and Fixtures	3-Apr-08	POLE WOOD 45 FT	7	27,191
E364.00-Poles, Towers, and Fixtures	31-May-08	POLE WOOD 45 FT	6	6,135
E364.00-Poles, Towers, and Fixtures	9-Jun-08	POLE WOOD 45 FT	64	160,075
E364.00-Poles, Towers, and Fixtures	1-Aug-08	POLE WOOD 45 FT	55	47,436
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 45 FT	56	166,507
E364.00-Poles, Towers, and Fixtures	30-Sep-08	POLE WOOD 45 FT	123	256,308
E364.00-Poles, Towers, and Fixtures	1-Oct-08	POLE WOOD 45 FT	6	6,843
E364.00-Poles, Towers, and Fixtures	15-Oct-08	POLE WOOD 45 FT	3	9,138
E364.00-Poles, Towers, and Fixtures	31-Oct-08	POLE WOOD 45 FT	227	485,879
E364.00-Poles, Towers, and Fixtures	30-Nov-08	POLE WOOD 45 FT	20	47,593
E364.00-Poles, Towers, and Fixtures	31-Dec-08	POLE WOOD 45 FT	214	562,466
E364.00-Poles, Towers, and Fixtures	31-Jan-09	POLE WOOD 45 FT	4	18,706
E364.00-Poles, Towers, and Fixtures	1-Feb-09	POLE WOOD 45 FT	38	50,887
E364.00-Poles, Towers, and Fixtures	28-Feb-09	POLE WOOD 45 FT	2	8,976
E364.00-Poles, Towers, and Fixtures	20-Apr-09	POLE WOOD 45 FT	5	25,798
E364.00-Poles, Towers, and Fixtures	16-Jun-09	POLE WOOD 45 FT	24	33,099
E364.00-Poles, Towers, and Fixtures	17-Jul-09	POLE WOOD 45 FT	2	47,128
E364.00-Poles, Towers, and Fixtures	19-Jul-09	POLE WOOD 45 FT	1	1,292
E364.00-Poles, Towers, and Fixtures	22-Jul-09	POLE WOOD 45 FT	3	0
E364.00-Poles, Towers, and Fixtures	27-Jul-09	POLE WOOD 45 FT	1	2,201
E364.00-Poles, Towers, and Fixtures	29-Jul-09	POLE WOOD 45 FT	2	3,258
E364.00-Poles, Towers, and Fixtures	30-Jul-09	POLE WOOD 45 FT	19	24,186
E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 45 FT	17	30,480
E364.00-Poles, Towers, and Fixtures	1-Aug-09	POLE WOOD 45 FT	80	171,894
E364.00-Poles, Towers, and Fixtures	3-Aug-09	POLE WOOD 45 FT	2	0
E364.00-Poles, Towers, and Fixtures	4-Aug-09	POLE WOOD 45 FT	4	19,223
E364.00-Poles, Towers, and Fixtures	7-Aug-09	POLE WOOD 45 FT	9	21,167
E364.00-Poles, Towers, and Fixtures	10-Aug-09	POLE WOOD 45 FT	7	7,791
E364.00-Poles, Towers, and Fixtures	30-Sep-09	POLE WOOD 45 FT	1	674

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	2-Oct-09	POLE WOOD 45 FT	6	40,197
E364.00-Poles, Towers, and Fixtures	7-Oct-09	POLE WOOD 45 FT	8	(319,435)
E364.00-Poles, Towers, and Fixtures	8-Oct-09	POLE WOOD 45 FT	1	2,090
E364.00-Poles, Towers, and Fixtures	13-Oct-09	POLE WOOD 45 FT	6	12,712
E364.00-Poles, Towers, and Fixtures	14-Oct-09	POLE WOOD 45 FT	4	8,389
E364.00-Poles, Towers, and Fixtures	15-Oct-09	POLE WOOD 45 FT	3	2,587
E364.00-Poles, Towers, and Fixtures	16-Oct-09	POLE WOOD 45 FT	5	1,609
E364.00-Poles, Towers, and Fixtures	21-Oct-09	POLE WOOD 45 FT	5	10,912
E364.00-Poles, Towers, and Fixtures	26-Oct-09	POLE WOOD 45 FT	25	46,048
E364.00-Poles, Towers, and Fixtures	29-Oct-09	POLE WOOD 45 FT	1	7,834
E364.00-Poles, Towers, and Fixtures	30-Oct-09	POLE WOOD 45 FT	10	6,432
E364.00-Poles, Towers, and Fixtures	31-Oct-09	POLE WOOD 45 FT	120	302,384
E364.00-Poles, Towers, and Fixtures	2-Nov-09	POLE WOOD 45 FT	8	8,440
E364.00-Poles, Towers, and Fixtures	3-Nov-09	POLE WOOD 45 FT	26	39,771
E364.00-Poles, Towers, and Fixtures	4-Nov-09	POLE WOOD 45 FT	154	311,543
E364.00-Poles, Towers, and Fixtures	5-Nov-09	POLE WOOD 45 FT	16	37,274
E364.00-Poles, Towers, and Fixtures	9-Nov-09	POLE WOOD 45 FT	154	346,993
E364.00-Poles, Towers, and Fixtures	11-Nov-09	POLE WOOD 45 FT	99	181,831
E364.00-Poles, Towers, and Fixtures	12-Nov-09	POLE WOOD 45 FT	2	10,722
E364.00-Poles, Towers, and Fixtures	13-Nov-09	POLE WOOD 45 FT	113	125,789
E364.00-Poles, Towers, and Fixtures	17-Nov-09	POLE WOOD 45 FT	24	90,746
E364.00-Poles, Towers, and Fixtures	23-Nov-09	POLE WOOD 45 FT	73	141,116
E364.00-Poles, Towers, and Fixtures	24-Nov-09	POLE WOOD 45 FT	1	26
E364.00-Poles, Towers, and Fixtures	30-Nov-09	POLE WOOD 45 FT	182	457,598
E364.00-Poles, Towers, and Fixtures	1-Dec-09	POLE WOOD 45 FT	123	305,576
E364.00-Poles, Towers, and Fixtures	3-Dec-09	POLE WOOD 45 FT	722	1,579,825
E364.00-Poles, Towers, and Fixtures	4-Dec-09	POLE WOOD 45 FT	52	99,790
E364.00-Poles, Towers, and Fixtures	7-Dec-09	POLE WOOD 45 FT	80	91,007
E364.00-Poles, Towers, and Fixtures	8-Dec-09	POLE WOOD 45 FT	286	697,345
E364.00-Poles, Towers, and Fixtures	9-Dec-09	POLE WOOD 45 FT	104	68,545
E364.00-Poles, Towers, and Fixtures	28-Dec-09	POLE WOOD 45 FT	246	407,274
E364.00-Poles, Towers, and Fixtures	31-Dec-09	POLE WOOD 45 FT	3	2,991
E364.00-Poles, Towers, and Fixtures	1-Jan-41	POLE WOOD 50 FT	115	2,331
E364.00-Poles, Towers, and Fixtures	1-Jan-42	POLE WOOD 50 FT	32	186
E364.00-Poles, Towers, and Fixtures	1-Jan-43	POLE WOOD 50 FT	5	101
E364.00-Poles, Towers, and Fixtures	1-Jan-44	POLE WOOD 50 FT	1	0
E364.00-Poles, Towers, and Fixtures	1-Jan-45	POLE WOOD 50 FT	24	1,551
E364.00-Poles, Towers, and Fixtures	1-Jan-46	POLE WOOD 50 FT	22	1,004
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD 50 FT	41	2,586
E364.00-Poles, Towers, and Fixtures	1-Jan-48	POLE WOOD 50 FT	227	14,744
E364.00-Poles, Towers, and Fixtures	1-Jan-49	POLE WOOD 50 FT	101	7,032
E364.00-Poles, Towers, and Fixtures	1-Jan-50	POLE WOOD 50 FT	61	4,530
E364.00-Poles, Towers, and Fixtures	1-Jan-51	POLE WOOD 50 FT	76	7,222
E364.00-Poles, Towers, and Fixtures	1-Jan-52	POLE WOOD 50 FT	54	5,129
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 50 FT	2	162
E364.00-Poles, Towers, and Fixtures	1-Jan-54	POLE WOOD 50 FT	2	202
E364.00-Poles, Towers, and Fixtures	1-Jan-56	POLE WOOD 50 FT	103	10,969
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 50 FT	51	5,793
E364.00-Poles, Towers, and Fixtures	1-Jan-58	POLE WOOD 50 FT	32	3,778
E364.00-Poles, Towers, and Fixtures	1-Jan-59	POLE WOOD 50 FT	37	4,288
E364.00-Poles, Towers, and Fixtures	1-Jan-60	POLE WOOD 50 FT	7	741
E364.00-Poles, Towers, and Fixtures	1-Jan-61	POLE WOOD 50 FT	48	5,139
E364.00-Poles, Towers, and Fixtures	1-Jan-62	POLE WOOD 50 FT	121	14,519
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 50 FT	180	24,247
E364.00-Poles, Towers, and Fixtures	1-Jan-64	POLE WOOD 50 FT	168	20,576

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 50 FT	192	22,916
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 50 FT	103	14,230
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 50 FT	123	17,456
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 50 FT	70	10,190
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 50 FT	76	11,723
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 50 FT	106	16,344
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 50 FT	143	22,449
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 50 FT	120	20,687
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 50 FT	100	19,088
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 50 FT	188	38,385
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 50 FT	85	20,733
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 50 FT	66	16,042
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 50 FT	86	22,188
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 50 FT	68	18,054
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 50 FT	77	25,212
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 50 FT	190	68,678
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 50 FT	126	49,652
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 50 FT	123	52,492
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 50 FT	120	64,021
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 50 FT	104	52,172
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 50 FT	121	62,389
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 50 FT	179	100,423
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 50 FT	211	123,964
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 50 FT	166	102,748
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 50 FT	216	126,370
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 50 FT	199	124,305
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 50 FT	175	112,087
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 50 FT	234	145,083
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 50 FT	280	193,145
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 50 FT	443	294,693
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 50 FT	676	473,636
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 50 FT	464	392,467
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 50 FT	466	440,315
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 50 FT	428	391,184
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 50 FT	309	326,052
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 50 FT	554	781,703
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 50 FT	438	740,905
E364.00-Poles, Towers, and Fixtures	28-Feb-01	POLE WOOD 50 FT	1	1,276
E364.00-Poles, Towers, and Fixtures	28-Feb-01	POLE WOOD 50 FT	1	7,429
E364.00-Poles, Towers, and Fixtures	28-Feb-01	POLE WOOD 50 FT	2	4,848
E364.00-Poles, Towers, and Fixtures	28-Feb-01	POLE WOOD 50 FT	21	8,058
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 50 FT	374	738,399
E364.00-Poles, Towers, and Fixtures	30-Sep-02	POLE WOOD 50 FT	1	12
E364.00-Poles, Towers, and Fixtures	30-Sep-02	POLE WOOD 50 FT	1	2,166
E364.00-Poles, Towers, and Fixtures	30-Sep-02	POLE WOOD 50 FT	2	504
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 50 FT	633	1,068,739
E364.00-Poles, Towers, and Fixtures	31-Mar-03	POLE WOOD 50 FT	1	16,921
E364.00-Poles, Towers, and Fixtures	31-Mar-03	POLE WOOD 50 FT	1	29,773
E364.00-Poles, Towers, and Fixtures	30-Jun-03	POLE WOOD 50 FT	1	2,745
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 50 FT	405	1,555,965
E364.00-Poles, Towers, and Fixtures	30-Sep-04	POLE WOOD 50 FT	1	6,320
E364.00-Poles, Towers, and Fixtures	30-Sep-04	POLE WOOD 50 FT	2	11,664
E364.00-Poles, Towers, and Fixtures	30-Sep-04	POLE WOOD 50 FT	5	5,394
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 50 FT	77	151,256
E364.00-Poles, Towers, and Fixtures	31-Jan-05	POLE WOOD 50 FT	1	1,985

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Jan-05	POLE WOOD 50 FT	1	3,542
E364.00-Poles, Towers, and Fixtures	31-Jan-05	POLE WOOD 50 FT	2	641
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 50 FT	86	83,807
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 50 FT	1,832	1,015,268
E364.00-Poles, Towers, and Fixtures	26-Feb-07	POLE WOOD 50 FT	21	0
E364.00-Poles, Towers, and Fixtures	1-Oct-07	POLE WOOD 50 FT	14	(196)
E364.00-Poles, Towers, and Fixtures	14-Nov-07	POLE WOOD 50 FT	1	3,751
E364.00-Poles, Towers, and Fixtures	25-Nov-07	POLE WOOD 50 FT	10	9,896
E364.00-Poles, Towers, and Fixtures	31-Dec-07	POLE WOOD 50 FT	6	15,902
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 50 FT	424	639,460
E364.00-Poles, Towers, and Fixtures	7-Apr-08	POLE WOOD 50 FT	2	1,218
E364.00-Poles, Towers, and Fixtures	31-May-08	POLE WOOD 50 FT	24	28,065
E364.00-Poles, Towers, and Fixtures	31-Jul-08	POLE WOOD 50 FT	17	53,507
E364.00-Poles, Towers, and Fixtures	1-Aug-08	POLE WOOD 50 FT	13	14,074
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 50 FT	34	83,785
E364.00-Poles, Towers, and Fixtures	30-Sep-08	POLE WOOD 50 FT	32	48,366
E364.00-Poles, Towers, and Fixtures	31-Oct-08	POLE WOOD 50 FT	27	75,298
E364.00-Poles, Towers, and Fixtures	30-Nov-08	POLE WOOD 50 FT	1	6,333
E364.00-Poles, Towers, and Fixtures	31-Dec-08	POLE WOOD 50 FT	28	66,393
E364.00-Poles, Towers, and Fixtures	31-Jan-09	POLE WOOD 50 FT	2	2,290
E364.00-Poles, Towers, and Fixtures	1-Feb-09	POLE WOOD 50 FT	3	4,373
E364.00-Poles, Towers, and Fixtures	12-Feb-09	POLE WOOD 50 FT	2	8,253
E364.00-Poles, Towers, and Fixtures	16-Jun-09	POLE WOOD 50 FT	12	18,171
E364.00-Poles, Towers, and Fixtures	22-Jul-09	POLE WOOD 50 FT	9	13,145
E364.00-Poles, Towers, and Fixtures	28-Jul-09	POLE WOOD 50 FT	1	772
E364.00-Poles, Towers, and Fixtures	29-Jul-09	POLE WOOD 50 FT	1	958
E364.00-Poles, Towers, and Fixtures	30-Jul-09	POLE WOOD 50 FT	3	4,739
E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 50 FT	19	40,068
E364.00-Poles, Towers, and Fixtures	1-Aug-09	POLE WOOD 50 FT	11	5,898
E364.00-Poles, Towers, and Fixtures	6-Aug-09	POLE WOOD 50 FT	11	273,463
E364.00-Poles, Towers, and Fixtures	7-Aug-09	POLE WOOD 50 FT	4	9,194
E364.00-Poles, Towers, and Fixtures	10-Aug-09	POLE WOOD 50 FT	1	1,223
E364.00-Poles, Towers, and Fixtures	29-Sep-09	POLE WOOD 50 FT	1	6,787
E364.00-Poles, Towers, and Fixtures	30-Sep-09	POLE WOOD 50 FT	2	7,761
E364.00-Poles, Towers, and Fixtures	5-Oct-09	POLE WOOD 50 FT	13	35,694
E364.00-Poles, Towers, and Fixtures	8-Oct-09	POLE WOOD 50 FT	1	2,726
E364.00-Poles, Towers, and Fixtures	13-Oct-09	POLE WOOD 50 FT	1	874
E364.00-Poles, Towers, and Fixtures	14-Oct-09	POLE WOOD 50 FT	3	5,568
E364.00-Poles, Towers, and Fixtures	19-Oct-09	POLE WOOD 50 FT	13	8,022
E364.00-Poles, Towers, and Fixtures	20-Oct-09	POLE WOOD 50 FT	31	77,280
E364.00-Poles, Towers, and Fixtures	22-Oct-09	POLE WOOD 50 FT	1	13,119
E364.00-Poles, Towers, and Fixtures	23-Oct-09	POLE WOOD 50 FT	10	(742)
E364.00-Poles, Towers, and Fixtures	26-Oct-09	POLE WOOD 50 FT	2	3,103
E364.00-Poles, Towers, and Fixtures	30-Oct-09	POLE WOOD 50 FT	1	213
E364.00-Poles, Towers, and Fixtures	31-Oct-09	POLE WOOD 50 FT	34	72,109
E364.00-Poles, Towers, and Fixtures	9-Nov-09	POLE WOOD 50 FT	14	23,891
E364.00-Poles, Towers, and Fixtures	11-Nov-09	POLE WOOD 50 FT	41	100,102
E364.00-Poles, Towers, and Fixtures	16-Nov-09	POLE WOOD 50 FT	2	6,529
E364.00-Poles, Towers, and Fixtures	23-Nov-09	POLE WOOD 50 FT	1	231
E364.00-Poles, Towers, and Fixtures	30-Nov-09	POLE WOOD 50 FT	175	345,261
E364.00-Poles, Towers, and Fixtures	1-Dec-09	POLE WOOD 50 FT	13	45,185
E364.00-Poles, Towers, and Fixtures	3-Dec-09	POLE WOOD 50 FT	4	8,527
E364.00-Poles, Towers, and Fixtures	7-Dec-09	POLE WOOD 50 FT	16	40,748
E364.00-Poles, Towers, and Fixtures	8-Dec-09	POLE WOOD 50 FT	97	50,232
E364.00-Poles, Towers, and Fixtures	9-Dec-09	POLE WOOD 50 FT	15	42,807

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-09	POLE WOOD 50 FT	1	2,471
E364.00-Poles, Towers, and Fixtures	1-Jan-41	POLE WOOD 55 FT	190	8,172
E364.00-Poles, Towers, and Fixtures	1-Jan-42	POLE WOOD 55 FT	17	780
E364.00-Poles, Towers, and Fixtures	1-Jan-43	POLE WOOD 55 FT	4	385
E364.00-Poles, Towers, and Fixtures	1-Jan-44	POLE WOOD 55 FT	10	723
E364.00-Poles, Towers, and Fixtures	1-Jan-45	POLE WOOD 55 FT	9	686
E364.00-Poles, Towers, and Fixtures	1-Jan-46	POLE WOOD 55 FT	2	146
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD 55 FT	30	2,026
E364.00-Poles, Towers, and Fixtures	1-Jan-48	POLE WOOD 55 FT	41	3,153
E364.00-Poles, Towers, and Fixtures	1-Jan-49	POLE WOOD 55 FT	18	1,703
E364.00-Poles, Towers, and Fixtures	1-Jan-50	POLE WOOD 55 FT	22	2,188
E364.00-Poles, Towers, and Fixtures	1-Jan-51	POLE WOOD 55 FT	26	2,987
E364.00-Poles, Towers, and Fixtures	1-Jan-52	POLE WOOD 55 FT	25	3,174
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 55 FT	12	2,727
E364.00-Poles, Towers, and Fixtures	1-Jan-55	POLE WOOD 55 FT	6	822
E364.00-Poles, Towers, and Fixtures	1-Jan-56	POLE WOOD 55 FT	21	2,759
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 55 FT	10	1,495
E364.00-Poles, Towers, and Fixtures	1-Jan-58	POLE WOOD 55 FT	1	174
E364.00-Poles, Towers, and Fixtures	1-Jan-59	POLE WOOD 55 FT	4	560
E364.00-Poles, Towers, and Fixtures	1-Jan-61	POLE WOOD 55 FT	53	6,944
E364.00-Poles, Towers, and Fixtures	1-Jan-62	POLE WOOD 55 FT	40	6,099
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 55 FT	70	11,338
E364.00-Poles, Towers, and Fixtures	1-Jan-64	POLE WOOD 55 FT	63	9,939
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 55 FT	34	5,428
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 55 FT	22	3,965
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 55 FT	28	4,712
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 55 FT	27	4,600
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 55 FT	26	5,660
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 55 FT	22	4,226
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 55 FT	52	11,055
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 55 FT	19	4,247
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 55 FT	24	6,009
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 55 FT	30	8,120
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 55 FT	32	10,526
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 55 FT	28	9,533
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 55 FT	28	9,662
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 55 FT	8	3,130
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 55 FT	39	16,602
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 55 FT	43	23,983
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 55 FT	32	16,783
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 55 FT	34	20,000
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 55 FT	32	21,436
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 55 FT	29	18,795
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 55 FT	56	38,360
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 55 FT	40	28,936
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 55 FT	54	39,663
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 55 FT	36	29,964
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 55 FT	53	42,223
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 55 FT	56	46,791
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 55 FT	41	34,459
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 55 FT	65	53,493
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 55 FT	50	44,216
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 55 FT	98	85,649
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 55 FT	140	113,003
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 55 FT	175	173,804

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 55 FT	93	95,154
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 55 FT	54	59,964
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 55 FT	41	57,282
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 55 FT	137	213,082
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 55 FT	71	135,807
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 55 FT	70	245,939
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 55 FT	81	290,995
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 55 FT	56	233,163
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 55 FT	16	42,761
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 55 FT	17	25,592
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 55 FT	289	171,827
E364.00-Poles, Towers, and Fixtures	26-Feb-07	POLE WOOD 55 FT	4	0
E364.00-Poles, Towers, and Fixtures	1-Oct-07	POLE WOOD 55 FT	1	(20)
E364.00-Poles, Towers, and Fixtures	25-Nov-07	POLE WOOD 55 FT	2	1,365
E364.00-Poles, Towers, and Fixtures	31-Dec-07	POLE WOOD 55 FT	1	2,920
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 55 FT	44	79,932
E364.00-Poles, Towers, and Fixtures	31-May-08	POLE WOOD 55 FT	5	7,603
E364.00-Poles, Towers, and Fixtures	31-Aug-08	POLE WOOD 55 FT	3	4,528
E364.00-Poles, Towers, and Fixtures	24-Sep-08	POLE WOOD 55 FT	1	90
E364.00-Poles, Towers, and Fixtures	30-Sep-08	POLE WOOD 55 FT	10	6,315
E364.00-Poles, Towers, and Fixtures	31-Oct-08	POLE WOOD 55 FT	5	15,811
E364.00-Poles, Towers, and Fixtures	31-Dec-08	POLE WOOD 55 FT	3	8,193
E364.00-Poles, Towers, and Fixtures	22-Jul-09	POLE WOOD 55 FT	5	67
E364.00-Poles, Towers, and Fixtures	30-Jul-09	POLE WOOD 55 FT	2	4,374
E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 55 FT	1	3,704
E364.00-Poles, Towers, and Fixtures	1-Aug-09	POLE WOOD 55 FT	3	11,667
E364.00-Poles, Towers, and Fixtures	3-Aug-09	POLE WOOD 55 FT	3	0
E364.00-Poles, Towers, and Fixtures	6-Aug-09	POLE WOOD 55 FT	1	22,225
E364.00-Poles, Towers, and Fixtures	7-Aug-09	POLE WOOD 55 FT	2	15,555
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 55 FT	7	15,426
E364.00-Poles, Towers, and Fixtures	1-Oct-09	POLE WOOD 55 FT	14	27,066
E364.00-Poles, Towers, and Fixtures	13-Oct-09	POLE WOOD 55 FT	1	2,973
E364.00-Poles, Towers, and Fixtures	14-Oct-09	POLE WOOD 55 FT	12	35,712
E364.00-Poles, Towers, and Fixtures	22-Oct-09	POLE WOOD 55 FT	1	12,859
E364.00-Poles, Towers, and Fixtures	31-Oct-09	POLE WOOD 55 FT	7	13,807
E364.00-Poles, Towers, and Fixtures	2-Nov-09	POLE WOOD 55 FT	29	80,701
E364.00-Poles, Towers, and Fixtures	4-Nov-09	POLE WOOD 55 FT	1	4,977
E364.00-Poles, Towers, and Fixtures	13-Nov-09	POLE WOOD 55 FT	8	19,496
E364.00-Poles, Towers, and Fixtures	30-Nov-09	POLE WOOD 55 FT	4	15,399
E364.00-Poles, Towers, and Fixtures	8-Dec-09	POLE WOOD 55 FT	12	(74,399)
E364.00-Poles, Towers, and Fixtures	9-Dec-09	POLE WOOD 55 FT	2	7,534
E364.00-Poles, Towers, and Fixtures	1-Jan-41	POLE WOOD 60 FT	1	0
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 60 FT	3	185
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 60 FT	11	104
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 60 FT	17	156
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 60 FT	31	443
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 60 FT	58	1,285
E364.00-Poles, Towers, and Fixtures	31-Dec-42	POLE WOOD 60 FT	1	367
E364.00-Poles, Towers, and Fixtures	1-Jan-43	POLE WOOD 60 FT	24	1,764
E364.00-Poles, Towers, and Fixtures	31-Dec-43	POLE WOOD 60 FT	1	325
E364.00-Poles, Towers, and Fixtures	1-Jan-44	POLE WOOD 60 FT	2	144
E364.00-Poles, Towers, and Fixtures	31-Dec-44	POLE WOOD 60 FT	35	937
E364.00-Poles, Towers, and Fixtures	1-Jan-45	POLE WOOD 60 FT	4	423
E364.00-Poles, Towers, and Fixtures	31-Dec-45	POLE WOOD 60 FT	11	266
E364.00-Poles, Towers, and Fixtures	31-Dec-45	POLE WOOD 60 FT	21	525

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-45	POLE WOOD 60 FT	33	2,372
E364.00-Poles, Towers, and Fixtures	1-Jan-46	POLE WOOD 60 FT	2	164
E364.00-Poles, Towers, and Fixtures	31-Dec-46	POLE WOOD 60 FT	1	16
E364.00-Poles, Towers, and Fixtures	31-Dec-46	POLE WOOD 60 FT	1	23
E364.00-Poles, Towers, and Fixtures	31-Dec-46	POLE WOOD 60 FT	1	25
E364.00-Poles, Towers, and Fixtures	31-Dec-46	POLE WOOD 60 FT	10	204
E364.00-Poles, Towers, and Fixtures	31-Dec-46	POLE WOOD 60 FT	111	6,555
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD 60 FT	10	883
E364.00-Poles, Towers, and Fixtures	31-Dec-47	POLE WOOD 60 FT	4	158
E364.00-Poles, Towers, and Fixtures	31-Dec-47	POLE WOOD 60 FT	4	2,779
E364.00-Poles, Towers, and Fixtures	31-Dec-47	POLE WOOD 60 FT	9	209
E364.00-Poles, Towers, and Fixtures	1-Jan-48	POLE WOOD 60 FT	7	684
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 60 FT	1	31
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 60 FT	1	456
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 60 FT	3	68
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 60 FT	7	169
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 60 FT	15	1,641
E364.00-Poles, Towers, and Fixtures	31-Dec-48	POLE WOOD 60 FT	72	10,538
E364.00-Poles, Towers, and Fixtures	1-Jan-49	POLE WOOD 60 FT	19	2,411
E364.00-Poles, Towers, and Fixtures	31-Dec-49	POLE WOOD 60 FT	2	79
E364.00-Poles, Towers, and Fixtures	31-Dec-49	POLE WOOD 60 FT	14	1,108
E364.00-Poles, Towers, and Fixtures	1-Jan-50	POLE WOOD 60 FT	4	393
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 60 FT	2	69
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 60 FT	3	277
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 60 FT	8	430
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 60 FT	19	1,506
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 60 FT	96	3,683
E364.00-Poles, Towers, and Fixtures	1-Jan-51	POLE WOOD 60 FT	12	1,597
E364.00-Poles, Towers, and Fixtures	31-Dec-51	POLE WOOD 60 FT	2	133
E364.00-Poles, Towers, and Fixtures	31-Dec-51	POLE WOOD 60 FT	11	1,685
E364.00-Poles, Towers, and Fixtures	31-Dec-51	POLE WOOD 60 FT	12	673
E364.00-Poles, Towers, and Fixtures	31-Dec-51	POLE WOOD 60 FT	19	3,397
E364.00-Poles, Towers, and Fixtures	31-Dec-51	POLE WOOD 60 FT	22	2,583
E364.00-Poles, Towers, and Fixtures	1-Jan-52	POLE WOOD 60 FT	5	721
E364.00-Poles, Towers, and Fixtures	31-Dec-52	POLE WOOD 60 FT	11	1,239
E364.00-Poles, Towers, and Fixtures	31-Dec-52	POLE WOOD 60 FT	24	919
E364.00-Poles, Towers, and Fixtures	31-Dec-52	POLE WOOD 60 FT	36	5,588
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 60 FT	1	261
E364.00-Poles, Towers, and Fixtures	31-Dec-53	POLE WOOD 60 FT	3	94
E364.00-Poles, Towers, and Fixtures	31-Dec-53	POLE WOOD 60 FT	8	512
E364.00-Poles, Towers, and Fixtures	31-Dec-53	POLE WOOD 60 FT	21	2,772
E364.00-Poles, Towers, and Fixtures	31-Dec-53	POLE WOOD 60 FT	42	1,773
E364.00-Poles, Towers, and Fixtures	1-Jan-54	POLE WOOD 60 FT	1	0
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 60 FT	2	136
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 60 FT	23	982
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 60 FT	23	5,260
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 60 FT	31	2,818
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 60 FT	37	2,023
E364.00-Poles, Towers, and Fixtures	31-Dec-54	POLE WOOD 60 FT	38	2,376
E364.00-Poles, Towers, and Fixtures	1-Jan-55	POLE WOOD 60 FT	15	2,481
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 60 FT	3	137
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 60 FT	9	891
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 60 FT	22	4,171
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 60 FT	27	1,483
E364.00-Poles, Towers, and Fixtures	1-Jan-56	POLE WOOD 60 FT	10	1,683

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 60 FT	1	107
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 60 FT	8	788
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 60 FT	22	2,134
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 60 FT	44	5,628
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD 60 FT	1	202
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 60 FT	10	1,805
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 60 FT	13	1,897
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 60 FT	20	2,314
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 60 FT	24	1,926
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 60 FT	44	4,261
E364.00-Poles, Towers, and Fixtures	31-Dec-57	POLE WOOD 60 FT	216	14,244
E364.00-Poles, Towers, and Fixtures	1-Jan-58	POLE WOOD 60 FT	1	179
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 60 FT	1	39
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 60 FT	1	50
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 60 FT	2	312
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 60 FT	8	1,020
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 60 FT	29	2,948
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 60 FT	84	8,798
E364.00-Poles, Towers, and Fixtures	31-Dec-58	POLE WOOD 60 FT	87	6,140
E364.00-Poles, Towers, and Fixtures	1-Jan-59	POLE WOOD 60 FT	6	1,079
E364.00-Poles, Towers, and Fixtures	31-Dec-59	POLE WOOD 60 FT	1	188
E364.00-Poles, Towers, and Fixtures	31-Dec-59	POLE WOOD 60 FT	3	398
E364.00-Poles, Towers, and Fixtures	31-Dec-59	POLE WOOD 60 FT	20	2,073
E364.00-Poles, Towers, and Fixtures	31-Dec-59	POLE WOOD 60 FT	23	1,211
E364.00-Poles, Towers, and Fixtures	31-Dec-59	POLE WOOD 60 FT	33	3,473
E364.00-Poles, Towers, and Fixtures	1-Jan-60	POLE WOOD 60 FT	1	147
E364.00-Poles, Towers, and Fixtures	31-Dec-60	POLE WOOD 60 FT	3	544
E364.00-Poles, Towers, and Fixtures	31-Dec-60	POLE WOOD 60 FT	4	467
E364.00-Poles, Towers, and Fixtures	31-Dec-60	POLE WOOD 60 FT	4	600
E364.00-Poles, Towers, and Fixtures	31-Dec-60	POLE WOOD 60 FT	7	481
E364.00-Poles, Towers, and Fixtures	31-Dec-60	POLE WOOD 60 FT	8	755
E364.00-Poles, Towers, and Fixtures	31-Dec-60	POLE WOOD 60 FT	13	1,048
E364.00-Poles, Towers, and Fixtures	1-Jan-61	POLE WOOD 60 FT	67	10,178
E364.00-Poles, Towers, and Fixtures	31-Dec-61	POLE WOOD 60 FT	1	114
E364.00-Poles, Towers, and Fixtures	31-Dec-61	POLE WOOD 60 FT	1	143
E364.00-Poles, Towers, and Fixtures	31-Dec-61	POLE WOOD 60 FT	1	168
E364.00-Poles, Towers, and Fixtures	31-Dec-61	POLE WOOD 60 FT	3	122
E364.00-Poles, Towers, and Fixtures	31-Dec-61	POLE WOOD 60 FT	7	900
E364.00-Poles, Towers, and Fixtures	31-Dec-61	POLE WOOD 60 FT	29	4,631
E364.00-Poles, Towers, and Fixtures	31-Dec-61	POLE WOOD 60 FT	36	1,958
E364.00-Poles, Towers, and Fixtures	1-Jan-62	POLE WOOD 60 FT	17	3,097
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 60 FT	1	513
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 60 FT	2	327
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 60 FT	13	2,335
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 60 FT	25	1,763
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 60 FT	32	4,713
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 60 FT	45	3,987
E364.00-Poles, Towers, and Fixtures	31-Dec-62	POLE WOOD 60 FT	47	5,611
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 60 FT	23	8,678
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 60 FT	3	313
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 60 FT	4	625
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 60 FT	6	672
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 60 FT	7	864
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 60 FT	8	672
E364.00-Poles, Towers, and Fixtures	31-Dec-63	POLE WOOD 60 FT	11	747

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-64	POLE WOOD 60 FT	17	3,429
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 60 FT	1	192
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 60 FT	3	65
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 60 FT	8	135
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 60 FT	9	508
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 60 FT	14	766
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 60 FT	28	665
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 60 FT	13	2,758
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 60 FT	4	455
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 60 FT	8	527
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 60 FT	10	548
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 60 FT	10	745
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 60 FT	17	3,356
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 60 FT	1	44
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 60 FT	1	57
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 60 FT	2	213
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 60 FT	2	295
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 60 FT	6	1,898
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 60 FT	7	521
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 60 FT	9	2,421
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 60 FT	12	1,096
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 60 FT	13	2,553
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 60 FT	29	5,636
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 60 FT	14	2,838
E364.00-Poles, Towers, and Fixtures	31-Dec-67	POLE WOOD 60 FT	1	346
E364.00-Poles, Towers, and Fixtures	31-Dec-67	POLE WOOD 60 FT	3	436
E364.00-Poles, Towers, and Fixtures	31-Dec-67	POLE WOOD 60 FT	5	497
E364.00-Poles, Towers, and Fixtures	31-Dec-67	POLE WOOD 60 FT	5	660
E364.00-Poles, Towers, and Fixtures	31-Dec-67	POLE WOOD 60 FT	6	422
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 60 FT	11	2,009
E364.00-Poles, Towers, and Fixtures	31-Dec-68	POLE WOOD 60 FT	1	67
E364.00-Poles, Towers, and Fixtures	31-Dec-68	POLE WOOD 60 FT	1	190
E364.00-Poles, Towers, and Fixtures	31-Dec-68	POLE WOOD 60 FT	1	233
E364.00-Poles, Towers, and Fixtures	31-Dec-68	POLE WOOD 60 FT	3	362
E364.00-Poles, Towers, and Fixtures	31-Dec-68	POLE WOOD 60 FT	4	350
E364.00-Poles, Towers, and Fixtures	31-Dec-68	POLE WOOD 60 FT	6	975
E364.00-Poles, Towers, and Fixtures	31-Dec-68	POLE WOOD 60 FT	11	1,504
E364.00-Poles, Towers, and Fixtures	31-Dec-68	POLE WOOD 60 FT	52	13,818
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 60 FT	38	10,651
E364.00-Poles, Towers, and Fixtures	31-Dec-69	POLE WOOD 60 FT	1	324
E364.00-Poles, Towers, and Fixtures	31-Dec-69	POLE WOOD 60 FT	5	2,847
E364.00-Poles, Towers, and Fixtures	31-Dec-69	POLE WOOD 60 FT	10	1,226
E364.00-Poles, Towers, and Fixtures	31-Dec-69	POLE WOOD 60 FT	11	1,058
E364.00-Poles, Towers, and Fixtures	31-Dec-69	POLE WOOD 60 FT	11	5,120
E364.00-Poles, Towers, and Fixtures	31-Dec-69	POLE WOOD 60 FT	12	2,270
E364.00-Poles, Towers, and Fixtures	31-Dec-69	POLE WOOD 60 FT	13	1,943
E364.00-Poles, Towers, and Fixtures	31-Dec-69	POLE WOOD 60 FT	17	4,092
E364.00-Poles, Towers, and Fixtures	31-Dec-69	POLE WOOD 60 FT	32	9,404
E364.00-Poles, Towers, and Fixtures	31-Dec-69	POLE WOOD 60 FT	38	20,785
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 60 FT	11	2,898
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 60 FT	1	108
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 60 FT	2	753
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 60 FT	3	434
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 60 FT	5	1,189
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 60 FT	5	1,482

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 60 FT	7	1,445
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 60 FT	15	2,108
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 60 FT	17	4,204
E364.00-Poles, Towers, and Fixtures	31-Dec-71	POLE WOOD 60 FT	1	171
E364.00-Poles, Towers, and Fixtures	31-Dec-71	POLE WOOD 60 FT	1	176
E364.00-Poles, Towers, and Fixtures	31-Dec-71	POLE WOOD 60 FT	1	524
E364.00-Poles, Towers, and Fixtures	31-Dec-71	POLE WOOD 60 FT	3	712
E364.00-Poles, Towers, and Fixtures	31-Dec-71	POLE WOOD 60 FT	4	1,735
E364.00-Poles, Towers, and Fixtures	31-Dec-71	POLE WOOD 60 FT	6	2,789
E364.00-Poles, Towers, and Fixtures	31-Dec-71	POLE WOOD 60 FT	7	1,159
E364.00-Poles, Towers, and Fixtures	31-Dec-71	POLE WOOD 60 FT	10	5,388
E364.00-Poles, Towers, and Fixtures	31-Dec-71	POLE WOOD 60 FT	11	1,185
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 60 FT	5	1,371
E364.00-Poles, Towers, and Fixtures	31-Dec-72	POLE WOOD 60 FT	1	291
E364.00-Poles, Towers, and Fixtures	31-Dec-72	POLE WOOD 60 FT	2	581
E364.00-Poles, Towers, and Fixtures	31-Dec-72	POLE WOOD 60 FT	2	820
E364.00-Poles, Towers, and Fixtures	31-Dec-72	POLE WOOD 60 FT	3	554
E364.00-Poles, Towers, and Fixtures	31-Dec-72	POLE WOOD 60 FT	5	493
E364.00-Poles, Towers, and Fixtures	31-Dec-72	POLE WOOD 60 FT	11	1,827
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 60 FT	12	3,412
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 60 FT	1	164
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 60 FT	2	2,080
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 60 FT	6	977
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 60 FT	7	1,159
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 60 FT	7	2,960
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 60 FT	8	3,693
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 60 FT	21	15,999
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 60 FT	39	39,927
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 60 FT	54	28,457
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 60 FT	14	4,833
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 60 FT	2	341
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 60 FT	2	891
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 60 FT	5	611
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 60 FT	5	945
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 60 FT	5	1,432
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 60 FT	8	5,121
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 60 FT	19	11,788
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 60 FT	12	5,205
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 60 FT	4	1,513
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 60 FT	7	5,881
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 60 FT	12	3,776
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 60 FT	19	3,295
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 60 FT	22	4,902
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 60 FT	26	5,741
E364.00-Poles, Towers, and Fixtures	31-Dec-75	POLE WOOD 60 FT	26	21,151
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 60 FT	6	2,230
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 60 FT	1	301
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 60 FT	2	278
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 60 FT	2	535
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 60 FT	2	1,568
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 60 FT	3	529
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 60 FT	3	1,213
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 60 FT	4	1,836
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 60 FT	1	131
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 60 FT	2	443

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 60 FT	2	1,593
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 60 FT	5	2,314
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 60 FT	2	1,098
E364.00-Poles, Towers, and Fixtures	31-Dec-78	POLE WOOD 60 FT	1	109
E364.00-Poles, Towers, and Fixtures	31-Dec-78	POLE WOOD 60 FT	2	306
E364.00-Poles, Towers, and Fixtures	31-Dec-78	POLE WOOD 60 FT	2	570
E364.00-Poles, Towers, and Fixtures	31-Dec-78	POLE WOOD 60 FT	2	1,477
E364.00-Poles, Towers, and Fixtures	31-Dec-78	POLE WOOD 60 FT	4	1,116
E364.00-Poles, Towers, and Fixtures	31-Dec-78	POLE WOOD 60 FT	4	2,517
E364.00-Poles, Towers, and Fixtures	31-Dec-78	POLE WOOD 60 FT	4	3,555
E364.00-Poles, Towers, and Fixtures	31-Dec-78	POLE WOOD 60 FT	12	15,145
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 60 FT	7	3,815
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 60 FT	1	157
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 60 FT	3	767
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 60 FT	3	993
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 60 FT	3	3,070
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 60 FT	3	3,956
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 60 FT	6	1,556
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 60 FT	6	2,309
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 60 FT	10	6,518
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 60 FT	14	11,854
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 60 FT	15	9,336
E364.00-Poles, Towers, and Fixtures	31-Dec-80	POLE WOOD 60 FT	1	462
E364.00-Poles, Towers, and Fixtures	31-Dec-80	POLE WOOD 60 FT	2	387
E364.00-Poles, Towers, and Fixtures	31-Dec-80	POLE WOOD 60 FT	2	627
E364.00-Poles, Towers, and Fixtures	31-Dec-80	POLE WOOD 60 FT	3	2,428
E364.00-Poles, Towers, and Fixtures	31-Dec-80	POLE WOOD 60 FT	8	4,751
E364.00-Poles, Towers, and Fixtures	31-Dec-80	POLE WOOD 60 FT	19	5,913
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 60 FT	12	8,586
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 60 FT	1	173
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 60 FT	2	624
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 60 FT	2	1,283
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 60 FT	2	3,828
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 60 FT	3	2,117
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 60 FT	6	1,992
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 60 FT	6	6,667
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 60 FT	7	2,621
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 60 FT	8	10,824
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 60 FT	13	9,875
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 60 FT	24	30,699
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 60 FT	19	15,443
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 60 FT	2	743
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 60 FT	2	2,566
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 60 FT	5	3,158
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 60 FT	5	3,714
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 60 FT	6	1,437
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 60 FT	8	2,504
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 60 FT	8	9,533
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 60 FT	9	8,852
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 60 FT	1	29
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 60 FT	1	623
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 60 FT	1	773
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 60 FT	1	1,095
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 60 FT	2	1,883
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 60 FT	6	2,786

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 60 FT	13	6,335
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 60 FT	16	4,931
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 60 FT	13	10,605
E364.00-Poles, Towers, and Fixtures	31-Dec-84	POLE WOOD 60 FT	1	244
E364.00-Poles, Towers, and Fixtures	31-Dec-84	POLE WOOD 60 FT	1	737
E364.00-Poles, Towers, and Fixtures	31-Dec-84	POLE WOOD 60 FT	2	894
E364.00-Poles, Towers, and Fixtures	31-Dec-84	POLE WOOD 60 FT	2	2,140
E364.00-Poles, Towers, and Fixtures	31-Dec-84	POLE WOOD 60 FT	8	3,007
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 60 FT	6	5,109
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 60 FT	1	287
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 60 FT	1	1,447
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 60 FT	2	5,270
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 60 FT	3	718
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 60 FT	3	1,701
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 60 FT	3	1,818
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 60 FT	3	12,345
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 60 FT	4	3,932
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 60 FT	19	17,476
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 60 FT	2	33,537
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 60 FT	3	2,357
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 60 FT	4	1,453
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 60 FT	4	4,438
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 60 FT	8	4,694
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 60 FT	8	8,065
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 60 FT	8	12,717
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 60 FT	8	14,368
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 60 FT	15	7,232
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 60 FT	32	31,019
E364.00-Poles, Towers, and Fixtures	31-Dec-87	POLE WOOD 60 FT	1	259
E364.00-Poles, Towers, and Fixtures	31-Dec-87	POLE WOOD 60 FT	1	2,245
E364.00-Poles, Towers, and Fixtures	31-Dec-87	POLE WOOD 60 FT	1	2,343
E364.00-Poles, Towers, and Fixtures	31-Dec-87	POLE WOOD 60 FT	7	8,872
E364.00-Poles, Towers, and Fixtures	31-Dec-87	POLE WOOD 60 FT	13	11,175
E364.00-Poles, Towers, and Fixtures	31-Dec-87	POLE WOOD 60 FT	24	16,906
E364.00-Poles, Towers, and Fixtures	31-Dec-87	POLE WOOD 60 FT	46	60,417
E364.00-Poles, Towers, and Fixtures	31-Dec-87	POLE WOOD 60 FT	48	26,506
E364.00-Poles, Towers, and Fixtures	31-Dec-87	POLE WOOD 60 FT	54	25,337
E364.00-Poles, Towers, and Fixtures	31-Dec-87	POLE WOOD 60 FT	63	24,064
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 60 FT	11	13,301
E364.00-Poles, Towers, and Fixtures	31-Dec-88	POLE WOOD 60 FT	1	1,155
E364.00-Poles, Towers, and Fixtures	31-Dec-88	POLE WOOD 60 FT	2	752
E364.00-Poles, Towers, and Fixtures	31-Dec-88	POLE WOOD 60 FT	2	1,970
E364.00-Poles, Towers, and Fixtures	31-Dec-88	POLE WOOD 60 FT	2	2,815
E364.00-Poles, Towers, and Fixtures	31-Dec-88	POLE WOOD 60 FT	4	3,107
E364.00-Poles, Towers, and Fixtures	31-Dec-88	POLE WOOD 60 FT	4	4,961
E364.00-Poles, Towers, and Fixtures	31-Dec-88	POLE WOOD 60 FT	7	3,301
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 60 FT	21	20,260
E364.00-Poles, Towers, and Fixtures	31-Dec-89	POLE WOOD 60 FT	1	461
E364.00-Poles, Towers, and Fixtures	31-Dec-89	POLE WOOD 60 FT	1	2,032
E364.00-Poles, Towers, and Fixtures	31-Dec-89	POLE WOOD 60 FT	3	2,074
E364.00-Poles, Towers, and Fixtures	31-Dec-89	POLE WOOD 60 FT	5	6,708
E364.00-Poles, Towers, and Fixtures	31-Dec-89	POLE WOOD 60 FT	6	5,611
E364.00-Poles, Towers, and Fixtures	31-Dec-89	POLE WOOD 60 FT	8	4,617
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 60 FT	17	17,103
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 60 FT	1	494

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 60 FT	1	2,043
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 60 FT	1	2,348
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 60 FT	2	2,008
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 60 FT	2	2,178
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 60 FT	3	4,540
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 60 FT	4	9,930
E364.00-Poles, Towers, and Fixtures	31-Dec-90	POLE WOOD 60 FT	6	3,327
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 60 FT	7	7,687
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 60 FT	1	858
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 60 FT	3	1,599
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 60 FT	3	8,708
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 60 FT	4	7,397
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 60 FT	8	18,084
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 60 FT	10	36,693
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 60 FT	12	13,460
E364.00-Poles, Towers, and Fixtures	31-Dec-92	POLE WOOD 60 FT	1	894
E364.00-Poles, Towers, and Fixtures	31-Dec-92	POLE WOOD 60 FT	1	953
E364.00-Poles, Towers, and Fixtures	31-Dec-92	POLE WOOD 60 FT	2	995
E364.00-Poles, Towers, and Fixtures	31-Dec-92	POLE WOOD 60 FT	5	2,717
E364.00-Poles, Towers, and Fixtures	31-Dec-92	POLE WOOD 60 FT	6	3,787
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 60 FT	26	29,871
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 60 FT	1	871
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 60 FT	1	2,138
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 60 FT	1	2,532
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 60 FT	2	743
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 60 FT	5	4,095
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 60 FT	5	8,354
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 60 FT	6	18,963
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 60 FT	11	7,078
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 60 FT	27	32,388
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 60 FT	1	703
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 60 FT	1	3,197
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 60 FT	3	4,719
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 60 FT	4	3,908
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 60 FT	5	10,085
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 60 FT	6	5,986
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 60 FT	9	8,582
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 60 FT	26	20,463
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 60 FT	46	54,423
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 60 FT	5	9,291
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 60 FT	5	10,327
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 60 FT	6	4,484
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 60 FT	8	5,783
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 60 FT	8	6,681
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 60 FT	9	5,960
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 60 FT	9	10,150
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 60 FT	47	61,152
E364.00-Poles, Towers, and Fixtures	31-Dec-96	POLE WOOD 60 FT	1	1,628
E364.00-Poles, Towers, and Fixtures	31-Dec-96	POLE WOOD 60 FT	1	4,209
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 60 FT	25	32,761
E364.00-Poles, Towers, and Fixtures	31-Oct-97	POLE WOOD 60 FT	1	2,530
E364.00-Poles, Towers, and Fixtures	31-Oct-97	POLE WOOD 60 FT	1	3,104
E364.00-Poles, Towers, and Fixtures	31-Oct-97	POLE WOOD 60 FT	1	3,568
E364.00-Poles, Towers, and Fixtures	31-Oct-97	POLE WOOD 60 FT	3	2,761
E364.00-Poles, Towers, and Fixtures	31-Oct-97	POLE WOOD 60 FT	4	7,596

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Oct-97	POLE WOOD 60 FT	4	12,685
E364.00-Poles, Towers, and Fixtures	31-Oct-97	POLE WOOD 60 FT	5	4,909
E364.00-Poles, Towers, and Fixtures	31-Dec-97	POLE WOOD 60 FT	1	790
E364.00-Poles, Towers, and Fixtures	31-Dec-97	POLE WOOD 60 FT	1	1,771
E364.00-Poles, Towers, and Fixtures	31-Dec-97	POLE WOOD 60 FT	1	2,082
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 60 FT	16	22,697
E364.00-Poles, Towers, and Fixtures	31-Mar-98	POLE WOOD 60 FT	1	643
E364.00-Poles, Towers, and Fixtures	31-Mar-98	POLE WOOD 60 FT	2	2,359
E364.00-Poles, Towers, and Fixtures	31-Mar-98	POLE WOOD 60 FT	2	3,212
E364.00-Poles, Towers, and Fixtures	31-Mar-98	POLE WOOD 60 FT	5	11,912
E364.00-Poles, Towers, and Fixtures	31-Mar-98	POLE WOOD 60 FT	7	10,100
E364.00-Poles, Towers, and Fixtures	31-Mar-98	POLE WOOD 60 FT	12	30,184
E364.00-Poles, Towers, and Fixtures	31-May-98	POLE WOOD 60 FT	1	1,081
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 60 FT	14	20,790
E364.00-Poles, Towers, and Fixtures	31-May-99	POLE WOOD 60 FT	2	3,346
E364.00-Poles, Towers, and Fixtures	31-May-99	POLE WOOD 60 FT	2	5,615
E364.00-Poles, Towers, and Fixtures	31-May-99	POLE WOOD 60 FT	4	5,933
E364.00-Poles, Towers, and Fixtures	31-May-99	POLE WOOD 60 FT	5	3,672
E364.00-Poles, Towers, and Fixtures	31-May-99	POLE WOOD 60 FT	9	9,215
E364.00-Poles, Towers, and Fixtures	31-May-99	POLE WOOD 60 FT	11	19,388
E364.00-Poles, Towers, and Fixtures	31-May-99	POLE WOOD 60 FT	37	6,565
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 60 FT	34	55,158
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 60 FT	21	69,319
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 60 FT	16	40,642
E364.00-Poles, Towers, and Fixtures	31-May-02	POLE WOOD 60 FT	1	861
E364.00-Poles, Towers, and Fixtures	31-May-02	POLE WOOD 60 FT	1	6,960
E364.00-Poles, Towers, and Fixtures	31-May-02	POLE WOOD 60 FT	2	1,553
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 60 FT	29	188,116
E364.00-Poles, Towers, and Fixtures	30-Jun-03	POLE WOOD 60 FT	8	53,169
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 60 FT	17	85,299
E364.00-Poles, Towers, and Fixtures	30-Sep-04	POLE WOOD 60 FT	1	441
E364.00-Poles, Towers, and Fixtures	30-Sep-04	POLE WOOD 60 FT	3	2,025
E364.00-Poles, Towers, and Fixtures	30-Sep-04	POLE WOOD 60 FT	5	4,225
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLE WOOD 60 FT	5	15,611
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 60 FT	5	8,891
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 60 FT	126	68,803
E364.00-Poles, Towers, and Fixtures	1-Jan-08	POLE WOOD 60 FT	7	22,372
E364.00-Poles, Towers, and Fixtures	1-Aug-08	POLE WOOD 60 FT	1	1,481
E364.00-Poles, Towers, and Fixtures	30-Sep-08	POLE WOOD 60 FT	2	473
E364.00-Poles, Towers, and Fixtures	31-Jan-09	POLE WOOD 60 FT	1	1,571
E364.00-Poles, Towers, and Fixtures	16-Jun-09	POLE WOOD 60 FT	3	2,686
E364.00-Poles, Towers, and Fixtures	19-Jul-09	POLE WOOD 60 FT	1	3,323
E364.00-Poles, Towers, and Fixtures	31-Jul-09	POLE WOOD 60 FT	2	12,329
E364.00-Poles, Towers, and Fixtures	1-Sep-09	POLE WOOD 60 FT	8	27,784
E364.00-Poles, Towers, and Fixtures	16-Oct-09	POLE WOOD 60 FT	1	406
E364.00-Poles, Towers, and Fixtures	31-Oct-09	POLE WOOD 60 FT	4	8,055
E364.00-Poles, Towers, and Fixtures	2-Nov-09	POLE WOOD 60 FT	40	266,359
E364.00-Poles, Towers, and Fixtures	30-Nov-09	POLE WOOD 60 FT	3	6,216
E364.00-Poles, Towers, and Fixtures	1-Jan-41	POLE WOOD 65 FT	6	0
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 65 FT	5	301
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 65 FT	25	1,232
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 65 FT	211	2,556
E364.00-Poles, Towers, and Fixtures	31-Dec-41	POLE WOOD 65 FT	251	9,069
E364.00-Poles, Towers, and Fixtures	1-Jan-43	POLE WOOD 65 FT	1	0
E364.00-Poles, Towers, and Fixtures	31-Dec-43	POLE WOOD 65 FT	4	225

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	31-Dec-43	POLE WOOD 65 FT	7	317
E364.00-Poles, Towers, and Fixtures	1-Jan-44	POLE WOOD 65 FT	1	71
E364.00-Poles, Towers, and Fixtures	1-Jan-45	POLE WOOD 65 FT	2	212
E364.00-Poles, Towers, and Fixtures	1-Jan-46	POLE WOOD 65 FT	6	410
E364.00-Poles, Towers, and Fixtures	31-Dec-47	POLE WOOD 65 FT	1	243
E364.00-Poles, Towers, and Fixtures	1-Jan-48	POLE WOOD 65 FT	4	545
E364.00-Poles, Towers, and Fixtures	1-Jan-49	POLE WOOD 65 FT	18	2,798
E364.00-Poles, Towers, and Fixtures	31-Dec-49	POLE WOOD 65 FT	1	200
E364.00-Poles, Towers, and Fixtures	1-Jan-50	POLE WOOD 65 FT	12	1,602
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 65 FT	1	32
E364.00-Poles, Towers, and Fixtures	31-Dec-50	POLE WOOD 65 FT	1	209
E364.00-Poles, Towers, and Fixtures	1-Jan-51	POLE WOOD 65 FT	16	3,209
E364.00-Poles, Towers, and Fixtures	1-Jan-52	POLE WOOD 65 FT	2	325
E364.00-Poles, Towers, and Fixtures	1-Jan-55	POLE WOOD 65 FT	7	1,332
E364.00-Poles, Towers, and Fixtures	31-Dec-55	POLE WOOD 65 FT	1	77
E364.00-Poles, Towers, and Fixtures	1-Jan-56	POLE WOOD 65 FT	8	1,508
E364.00-Poles, Towers, and Fixtures	31-Dec-56	POLE WOOD 65 FT	1	97
E364.00-Poles, Towers, and Fixtures	1-Jan-58	POLE WOOD 65 FT	4	1,054
E364.00-Poles, Towers, and Fixtures	1-Jan-59	POLE WOOD 65 FT	2	410
E364.00-Poles, Towers, and Fixtures	1-Jan-60	POLE WOOD 65 FT	9	1,811
E364.00-Poles, Towers, and Fixtures	31-Dec-60	POLE WOOD 65 FT	4	699
E364.00-Poles, Towers, and Fixtures	1-Jan-61	POLE WOOD 65 FT	27	4,862
E364.00-Poles, Towers, and Fixtures	1-Jan-62	POLE WOOD 65 FT	1	214
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 65 FT	17	10,697
E364.00-Poles, Towers, and Fixtures	1-Jan-64	POLE WOOD 65 FT	3	770
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 65 FT	1	114
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 65 FT	4	875
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 65 FT	8	4,328
E364.00-Poles, Towers, and Fixtures	31-Dec-64	POLE WOOD 65 FT	62	1,208
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 65 FT	23	4,843
E364.00-Poles, Towers, and Fixtures	31-Dec-65	POLE WOOD 65 FT	6	1,049
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 65 FT	11	3,307
E364.00-Poles, Towers, and Fixtures	31-Dec-66	POLE WOOD 65 FT	1	11
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 65 FT	5	1,218
E364.00-Poles, Towers, and Fixtures	31-Dec-67	POLE WOOD 65 FT	12	404
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 65 FT	1	254
E364.00-Poles, Towers, and Fixtures	31-Dec-68	POLE WOOD 65 FT	8	365
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 65 FT	43	13,272
E364.00-Poles, Towers, and Fixtures	31-Dec-69	POLE WOOD 65 FT	7	422
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 65 FT	4	1,453
E364.00-Poles, Towers, and Fixtures	31-Dec-70	POLE WOOD 65 FT	3	203
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 65 FT	12	3,614
E364.00-Poles, Towers, and Fixtures	31-Dec-71	POLE WOOD 65 FT	2	485
E364.00-Poles, Towers, and Fixtures	31-Dec-71	POLE WOOD 65 FT	6	831
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 65 FT	3	987
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 65 FT	14	5,964
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 65 FT	2	532
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 65 FT	2	2,005
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 65 FT	6	624
E364.00-Poles, Towers, and Fixtures	31-Dec-73	POLE WOOD 65 FT	7	175
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 65 FT	11	4,710
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 65 FT	1	334
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 65 FT	2	69
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 65 FT	2	1,002
E364.00-Poles, Towers, and Fixtures	31-Dec-74	POLE WOOD 65 FT	3	247

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-75	POLE WOOD 65 FT	6	3,403
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 65 FT	5	3,049
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 65 FT	4	974
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 65 FT	5	4,154
E364.00-Poles, Towers, and Fixtures	31-Dec-76	POLE WOOD 65 FT	10	1,273
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 65 FT	6	3,524
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 65 FT	1	79
E364.00-Poles, Towers, and Fixtures	31-Dec-77	POLE WOOD 65 FT	4	482
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 65 FT	5	2,833
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 65 FT	9	5,233
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 65 FT	1	301
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 65 FT	2	1,869
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 65 FT	3	1,821
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 65 FT	4	1,317
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 65 FT	8	487
E364.00-Poles, Towers, and Fixtures	31-Dec-79	POLE WOOD 65 FT	22	4,730
E364.00-Poles, Towers, and Fixtures	1-Jan-80	POLE WOOD 65 FT	4	2,974
E364.00-Poles, Towers, and Fixtures	31-Dec-80	POLE WOOD 65 FT	6	533
E364.00-Poles, Towers, and Fixtures	31-Dec-80	POLE WOOD 65 FT	7	1,979
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 65 FT	6	4,874
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 65 FT	2	155
E364.00-Poles, Towers, and Fixtures	31-Dec-81	POLE WOOD 65 FT	6	1,042
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 65 FT	10	11,354
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 65 FT	1	384
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 65 FT	2	158
E364.00-Poles, Towers, and Fixtures	31-Dec-82	POLE WOOD 65 FT	3	1,356
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 65 FT	1	949
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 65 FT	1	92
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 65 FT	1	363
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 65 FT	4	1,796
E364.00-Poles, Towers, and Fixtures	31-Dec-83	POLE WOOD 65 FT	10	1,264
E364.00-Poles, Towers, and Fixtures	31-Dec-84	POLE WOOD 65 FT	2	1,057
E364.00-Poles, Towers, and Fixtures	31-Dec-84	POLE WOOD 65 FT	2	1,537
E364.00-Poles, Towers, and Fixtures	31-Dec-84	POLE WOOD 65 FT	2	1,914
E364.00-Poles, Towers, and Fixtures	31-Dec-84	POLE WOOD 65 FT	3	1,316
E364.00-Poles, Towers, and Fixtures	31-Dec-84	POLE WOOD 65 FT	5	6,629
E364.00-Poles, Towers, and Fixtures	31-Dec-84	POLE WOOD 65 FT	8	2,784
E364.00-Poles, Towers, and Fixtures	31-Dec-84	POLE WOOD 65 FT	25	2,787
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 65 FT	1	944
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 65 FT	12	8,037
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 65 FT	14	7,991
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 65 FT	22	11,455
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 65 FT	42	5,888
E364.00-Poles, Towers, and Fixtures	31-Dec-85	POLE WOOD 65 FT	94	27,634
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 65 FT	5	6,568
E364.00-Poles, Towers, and Fixtures	31-Dec-86	POLE WOOD 65 FT	1	93
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 65 FT	11	14,000
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 65 FT	1	1,349
E364.00-Poles, Towers, and Fixtures	31-Dec-88	POLE WOOD 65 FT	2	683
E364.00-Poles, Towers, and Fixtures	31-Dec-88	POLE WOOD 65 FT	4	1,673
E364.00-Poles, Towers, and Fixtures	31-Dec-88	POLE WOOD 65 FT	7	1,210
E364.00-Poles, Towers, and Fixtures	31-Dec-88	POLE WOOD 65 FT	8	2,465
E364.00-Poles, Towers, and Fixtures	31-Dec-88	POLE WOOD 65 FT	27	5,210
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 65 FT	8	9,715
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 65 FT	2	2,718

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 65 FT	1	1,778
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 65 FT	1	810
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 65 FT	2	183
E364.00-Poles, Towers, and Fixtures	31-Dec-91	POLE WOOD 65 FT	2	199
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 65 FT	7	10,436
E364.00-Poles, Towers, and Fixtures	31-Dec-92	POLE WOOD 65 FT	1	139
E364.00-Poles, Towers, and Fixtures	31-Dec-92	POLE WOOD 65 FT	1	607
E364.00-Poles, Towers, and Fixtures	31-Dec-92	POLE WOOD 65 FT	2	300
E364.00-Poles, Towers, and Fixtures	31-Dec-92	POLE WOOD 65 FT	4	2,601
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 65 FT	12	20,311
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 65 FT	6	819
E364.00-Poles, Towers, and Fixtures	31-Dec-93	POLE WOOD 65 FT	9	3,344
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 65 FT	4	6,927
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 65 FT	1	473
E364.00-Poles, Towers, and Fixtures	31-Dec-94	POLE WOOD 65 FT	1	591
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 65 FT	9	17,572
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 65 FT	1	1,981
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 65 FT	2	2,370
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 65 FT	4	3,487
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 65 FT	5	8,249
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 65 FT	9	6,307
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 65 FT	14	2,189
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 65 FT	26	17,651
E364.00-Poles, Towers, and Fixtures	31-Dec-95	POLE WOOD 65 FT	67	41,111
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 65 FT	19	29,953
E364.00-Poles, Towers, and Fixtures	31-Dec-96	POLE WOOD 65 FT	1	1,055
E364.00-Poles, Towers, and Fixtures	31-Dec-96	POLE WOOD 65 FT	2	1,180
E364.00-Poles, Towers, and Fixtures	31-Dec-96	POLE WOOD 65 FT	2	1,431
E364.00-Poles, Towers, and Fixtures	31-Dec-96	POLE WOOD 65 FT	7	1,084
E364.00-Poles, Towers, and Fixtures	31-Dec-96	POLE WOOD 65 FT	10	9,856
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 65 FT	14	24,610
E364.00-Poles, Towers, and Fixtures	31-May-97	POLE WOOD 65 FT	3	2,503
E364.00-Poles, Towers, and Fixtures	31-May-97	POLE WOOD 65 FT	6	1,074
E364.00-Poles, Towers, and Fixtures	31-May-97	POLE WOOD 65 FT	6	9,902
E364.00-Poles, Towers, and Fixtures	31-May-97	POLE WOOD 65 FT	11	2,635
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 65 FT	12	23,127
E364.00-Poles, Towers, and Fixtures	31-Jan-98	POLE WOOD 65 FT	1	224
E364.00-Poles, Towers, and Fixtures	31-Jul-98	POLE WOOD 65 FT	1	675
E364.00-Poles, Towers, and Fixtures	31-Jul-98	POLE WOOD 65 FT	1	813
E364.00-Poles, Towers, and Fixtures	31-Jul-98	POLE WOOD 65 FT	3	1,892
E364.00-Poles, Towers, and Fixtures	31-Jul-98	POLE WOOD 65 FT	4	1,764
E364.00-Poles, Towers, and Fixtures	31-Jul-98	POLE WOOD 65 FT	129	3,781
E364.00-Poles, Towers, and Fixtures	30-Sep-98	POLE WOOD 65 FT	1	3,379
E364.00-Poles, Towers, and Fixtures	30-Sep-98	POLE WOOD 65 FT	6	20,191
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 65 FT	5	10,295
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 65 FT	7	19,023
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 65 FT	7	96,547
E364.00-Poles, Towers, and Fixtures	31-Aug-01	POLE WOOD 65 FT	1	2,537
E364.00-Poles, Towers, and Fixtures	31-Aug-01	POLE WOOD 65 FT	2	2,241
E364.00-Poles, Towers, and Fixtures	31-Aug-01	POLE WOOD 65 FT	2	3,365
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 65 FT	4	13,149
E364.00-Poles, Towers, and Fixtures	30-Apr-02	POLE WOOD 65 FT	1	2,214
E364.00-Poles, Towers, and Fixtures	30-Apr-02	POLE WOOD 65 FT	1	4,707
E364.00-Poles, Towers, and Fixtures	30-Apr-02	POLE WOOD 65 FT	1	5,814
E364.00-Poles, Towers, and Fixtures	30-Apr-02	POLE WOOD 65 FT	1	10,622

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	30-Apr-02	POLE WOOD 65 FT	1	15,934
E364.00-Poles, Towers, and Fixtures	30-Apr-02	POLE WOOD 65 FT	1	18,016
E364.00-Poles, Towers, and Fixtures	30-Apr-02	POLE WOOD 65 FT	2	34,151
E364.00-Poles, Towers, and Fixtures	30-Apr-02	POLE WOOD 65 FT	4	48,608
E364.00-Poles, Towers, and Fixtures	30-Apr-02	POLE WOOD 65 FT	9	83,861
E364.00-Poles, Towers, and Fixtures	30-Apr-02	POLE WOOD 65 FT	10	38,802
E364.00-Poles, Towers, and Fixtures	30-Apr-02	POLE WOOD 65 FT	79	65,657
E364.00-Poles, Towers, and Fixtures	30-Jun-02	POLE WOOD 65 FT	1	1,523
E364.00-Poles, Towers, and Fixtures	30-Jun-02	POLE WOOD 65 FT	4	668
E364.00-Poles, Towers, and Fixtures	30-Jun-02	POLE WOOD 65 FT	4	23,228
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 65 FT	9	52,085
E364.00-Poles, Towers, and Fixtures	31-Aug-03	POLE WOOD 65 FT	1	1,062
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 65 FT	5	62,621
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 65 FT	3	11,391
E364.00-Poles, Towers, and Fixtures	30-Sep-08	POLE WOOD 65 FT	4	2,660
E364.00-Poles, Towers, and Fixtures	16-Jun-09	POLE WOOD 65 FT	1	1,760
E364.00-Poles, Towers, and Fixtures	31-Oct-09	POLE WOOD 65 FT	9	59,665
E364.00-Poles, Towers, and Fixtures	1-Jan-41	POLE WOOD 70 FT	3	0
E364.00-Poles, Towers, and Fixtures	1-Jan-49	POLE WOOD 70 FT	5	0
E364.00-Poles, Towers, and Fixtures	1-Jan-51	POLE WOOD 70 FT	2	0
E364.00-Poles, Towers, and Fixtures	1-Jan-52	POLE WOOD 70 FT	3	0
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD 70 FT	1	0
E364.00-Poles, Towers, and Fixtures	1-Jan-55	POLE WOOD 70 FT	1	225
E364.00-Poles, Towers, and Fixtures	1-Jan-56	POLE WOOD 70 FT	2	471
E364.00-Poles, Towers, and Fixtures	1-Jan-58	POLE WOOD 70 FT	1	320
E364.00-Poles, Towers, and Fixtures	1-Jan-59	POLE WOOD 70 FT	4	1,345
E364.00-Poles, Towers, and Fixtures	1-Jan-60	POLE WOOD 70 FT	1	276
E364.00-Poles, Towers, and Fixtures	1-Jan-61	POLE WOOD 70 FT	4	855
E364.00-Poles, Towers, and Fixtures	1-Jan-62	POLE WOOD 70 FT	3	803
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 70 FT	11	6,912
E364.00-Poles, Towers, and Fixtures	1-Jan-64	POLE WOOD 70 FT	1	0
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 70 FT	3	977
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD 70 FT	1	279
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 70 FT	1	400
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD 70 FT	3	1,406
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 70 FT	21	8,669
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 70 FT	1	416
E364.00-Poles, Towers, and Fixtures	1-Jan-76	POLE WOOD 70 FT	1	307
E364.00-Poles, Towers, and Fixtures	1-Jan-77	POLE WOOD 70 FT	2	2,997
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 70 FT	7	8,233
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 70 FT	5	6,258
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 70 FT	1	1,262
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 70 FT	1	1,262
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 70 FT	10	15,219
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 70 FT	1	1,870
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 70 FT	5	9,208
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 70 FT	6	9,196
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 70 FT	1	1,630
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 70 FT	2	4,863
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 70 FT	2	3,671
E364.00-Poles, Towers, and Fixtures	1-Jan-93	POLE WOOD 70 FT	1	2,073
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 70 FT	6	12,445
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 70 FT	9	20,775
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 70 FT	1	2,267
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 70 FT	7	17,203

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-98	POLE WOOD 70 FT	3	7,139
E364.00-Poles, Towers, and Fixtures	1-Jan-99	POLE WOOD 70 FT	4	12,690
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 70 FT	3	13,474
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 70 FT	2	25,754
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 70 FT	1	2,211
E364.00-Poles, Towers, and Fixtures	30-Apr-02	POLE WOOD 70 FT	2	19,843
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 70 FT	5	102,091
E364.00-Poles, Towers, and Fixtures	31-Mar-03	POLE WOOD 70 FT	2	12,145
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 70 FT	1	50,307
E364.00-Poles, Towers, and Fixtures	1-Jan-07	POLE WOOD 70 FT	2	7,944
E364.00-Poles, Towers, and Fixtures	31-Jan-09	POLE WOOD 70 FT	1	30,087
E364.00-Poles, Towers, and Fixtures	31-Oct-09	POLE WOOD 70 FT	1	7,764
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 75 FT	1	875
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 75 FT	7	2,153
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 75 FT	8	3,905
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD 75 FT	1	715
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 75 FT	5	2,135
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 75 FT	1	512
E364.00-Poles, Towers, and Fixtures	1-Jan-74	POLE WOOD 75 FT	1	742
E364.00-Poles, Towers, and Fixtures	1-Jan-78	POLE WOOD 75 FT	1	54
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 75 FT	5	4,470
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 75 FT	1	1,483
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 75 FT	1	2,379
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 75 FT	1	1,396
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 75 FT	1	1,442
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 75 FT	10	15,985
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 75 FT	6	0
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 75 FT	1	2,473
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 75 FT	6	10,844
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 75 FT	4	7,804
E364.00-Poles, Towers, and Fixtures	1-Jan-96	POLE WOOD 75 FT	1	2,889
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 75 FT	4	16,126
E364.00-Poles, Towers, and Fixtures	1-Jan-02	POLE WOOD 75 FT	2	7,013
E364.00-Poles, Towers, and Fixtures	31-Mar-03	POLE WOOD 75 FT	2	14,768
E364.00-Poles, Towers, and Fixtures	1-Jan-04	POLE WOOD 75 FT	3	103,359
E364.00-Poles, Towers, and Fixtures	1-Jan-06	POLE WOOD 75 FT	4	16,239
E364.00-Poles, Towers, and Fixtures	1-Jan-61	POLE WOOD 80 FT	1	307
E364.00-Poles, Towers, and Fixtures	1-Jan-63	POLE WOOD 80 FT	1	377
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD 80 FT	2	0
E364.00-Poles, Towers, and Fixtures	1-Jan-67	POLE WOOD 80 FT	6	2,828
E364.00-Poles, Towers, and Fixtures	1-Jan-69	POLE WOOD 80 FT	1	565
E364.00-Poles, Towers, and Fixtures	1-Jan-71	POLE WOOD 80 FT	1	520
E364.00-Poles, Towers, and Fixtures	1-Jan-72	POLE WOOD 80 FT	1	562
E364.00-Poles, Towers, and Fixtures	1-Jan-73	POLE WOOD 80 FT	1	600
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 80 FT	1	1,727
E364.00-Poles, Towers, and Fixtures	1-Jan-84	POLE WOOD 80 FT	1	1,800
E364.00-Poles, Towers, and Fixtures	1-Jan-85	POLE WOOD 80 FT	1	1,633
E364.00-Poles, Towers, and Fixtures	1-Jan-86	POLE WOOD 80 FT	2	4,043
E364.00-Poles, Towers, and Fixtures	1-Jan-88	POLE WOOD 80 FT	3	6,232
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 80 FT	3	6,157
E364.00-Poles, Towers, and Fixtures	1-Jan-90	POLE WOOD 80 FT	1	2,805
E364.00-Poles, Towers, and Fixtures	1-Jan-92	POLE WOOD 80 FT	4	8,839
E364.00-Poles, Towers, and Fixtures	1-Jan-00	POLE WOOD 80 FT	1	2,098
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 80 FT	3	62,485
E364.00-Poles, Towers, and Fixtures	1-Jan-79	POLE WOOD 85 FT	1	1,114

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	1-Jan-83	POLE WOOD 85 FT	1	2,498
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD 85 FT	1	2,294
E364.00-Poles, Towers, and Fixtures	1-Jan-97	POLE WOOD 85 FT	1	3,602
E364.00-Poles, Towers, and Fixtures	1-Jan-01	POLE WOOD 85 FT	1	2,643
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 85 FT	9	210,128
E364.00-Poles, Towers, and Fixtures	1-Jan-87	POLE WOOD 90 FT	1	5,441
E364.00-Poles, Towers, and Fixtures	1-Jan-91	POLE WOOD 90 FT	1	1,201
E364.00-Poles, Towers, and Fixtures	1-Jan-94	POLE WOOD 90 FT	3	11,612
E364.00-Poles, Towers, and Fixtures	1-Jan-95	POLE WOOD 90 FT	1	3,966
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 90 FT	1	38,476
E364.00-Poles, Towers, and Fixtures	1-Jan-81	POLE WOOD 95 FT	1	1,601
E364.00-Poles, Towers, and Fixtures	1-Jan-82	POLE WOOD 95 FT	1	2,164
E364.00-Poles, Towers, and Fixtures	1-Jan-03	POLE WOOD 95 FT	2	95,305
E364.00-Poles, Towers, and Fixtures	1-Jan-32	POLE WOOD UNDER 20 FT	8	121
E364.00-Poles, Towers, and Fixtures	1-Jan-41	POLE WOOD UNDER 20 FT	139	1,146
E364.00-Poles, Towers, and Fixtures	1-Jan-42	POLE WOOD UNDER 20 FT	26	200
E364.00-Poles, Towers, and Fixtures	1-Jan-43	POLE WOOD UNDER 20 FT	20	176
E364.00-Poles, Towers, and Fixtures	1-Jan-44	POLE WOOD UNDER 20 FT	81	1,012
E364.00-Poles, Towers, and Fixtures	1-Jan-45	POLE WOOD UNDER 20 FT	2	38
E364.00-Poles, Towers, and Fixtures	1-Jan-46	POLE WOOD UNDER 20 FT	18	0
E364.00-Poles, Towers, and Fixtures	1-Jan-47	POLE WOOD UNDER 20 FT	6	80
E364.00-Poles, Towers, and Fixtures	1-Jan-48	POLE WOOD UNDER 20 FT	3	62
E364.00-Poles, Towers, and Fixtures	1-Jan-49	POLE WOOD UNDER 20 FT	3	45
E364.00-Poles, Towers, and Fixtures	1-Jan-50	POLE WOOD UNDER 20 FT	11	146
E364.00-Poles, Towers, and Fixtures	1-Jan-52	POLE WOOD UNDER 20 FT	3	82
E364.00-Poles, Towers, and Fixtures	1-Jan-53	POLE WOOD UNDER 20 FT	5	60
E364.00-Poles, Towers, and Fixtures	1-Jan-54	POLE WOOD UNDER 20 FT	4	100
E364.00-Poles, Towers, and Fixtures	1-Jan-55	POLE WOOD UNDER 20 FT	4	105
E364.00-Poles, Towers, and Fixtures	1-Jan-56	POLE WOOD UNDER 20 FT	8	196
E364.00-Poles, Towers, and Fixtures	1-Jan-57	POLE WOOD UNDER 20 FT	1	59
E364.00-Poles, Towers, and Fixtures	1-Jan-59	POLE WOOD UNDER 20 FT	2	62
E364.00-Poles, Towers, and Fixtures	1-Jan-64	POLE WOOD UNDER 20 FT	1	36
E364.00-Poles, Towers, and Fixtures	1-Jan-65	POLE WOOD UNDER 20 FT	5	152
E364.00-Poles, Towers, and Fixtures	1-Jan-66	POLE WOOD UNDER 20 FT	1	39
E364.00-Poles, Towers, and Fixtures	1-Jan-68	POLE WOOD UNDER 20 FT	1	39
E364.00-Poles, Towers, and Fixtures	1-Jan-70	POLE WOOD UNDER 20 FT	3	121
E364.00-Poles, Towers, and Fixtures	1-Jan-89	POLE WOOD UNDER 20 FT	1	134
E364.00-Poles, Towers, and Fixtures	1-Jan-05	POLES, MOD	1	329
E364.00-Poles, Towers, and Fixtures	1-Jan-32	STEEL POLES	2	888
E364.00-Poles, Towers, and Fixtures	1-Jan-41	STEEL POLES	94	42,298
E364.00-Poles, Towers, and Fixtures	1-Jan-42	STEEL POLES	1	450
E364.00-Poles, Towers, and Fixtures	1-Jan-80	STEEL POLES	1	655
E364.00-Poles, Towers, and Fixtures	1-Jan-88	STEEL POLES	1	10,372
E364.00-Poles, Towers, and Fixtures	1-Jan-91	STEEL POLES	2	18,837
E364.00-Poles, Towers, and Fixtures	1-Jan-94	STEEL POLES	2	9,648
E364.00-Poles, Towers, and Fixtures	1-Jan-95	STEEL POLES	2	19,491
E364.00-Poles, Towers, and Fixtures	1-Jan-96	STEEL POLES	49	69,896
E364.00-Poles, Towers, and Fixtures	1-Jan-97	STEEL POLES	198	149,438
E364.00-Poles, Towers, and Fixtures	1-Jan-98	STEEL POLES	252	167,035
E364.00-Poles, Towers, and Fixtures	1-Jan-99	STEEL POLES	132	156,016
E364.00-Poles, Towers, and Fixtures	1-Jan-00	STEEL POLES	128	219,361
E364.00-Poles, Towers, and Fixtures	1-Jan-01	STEEL POLES	107	104,765
E364.00-Poles, Towers, and Fixtures	1-Jan-02	STEEL POLES	24	21,529
E364.00-Poles, Towers, and Fixtures	30-Apr-02	STEEL POLES	1	14,173
E364.00-Poles, Towers, and Fixtures	30-Apr-02	STEEL POLES	1	39,034

Kentucky Utilities Company
Plant Account 364 - Poles, Towers, and Fixtures
As of October 31, 2009

Account	In-Service Date	Description	Quantity	Cost
E364.00-Poles, Towers, and Fixtures	30-Apr-02	STEEL POLES	1	42,121
E364.00-Poles, Towers, and Fixtures	1-Jan-03	STEEL POLES	53	96,300
E364.00-Poles, Towers, and Fixtures	1-Jan-04	STEEL POLES	20	19,880
E364.00-Poles, Towers, and Fixtures	1-Jan-06	STEEL POLES	1	669
E364.00-Poles, Towers, and Fixtures	25-Apr-06	STEEL POLES	2	0
E364.00-Poles, Towers, and Fixtures	26-Apr-06	STEEL POLES	1	0
E364.00-Poles, Towers, and Fixtures	1-Jan-07	STEEL POLES	2	7,490
E364.00-Poles, Towers, and Fixtures	1-Jan-08	STEEL POLES	3	2,131
E364.00-Poles, Towers, and Fixtures	30-Sep-08	STEEL POLES	1	1,656
E364.00-Poles, Towers, and Fixtures	31-Oct-08	STEEL POLES	1	2,101
E364.00-Poles, Towers, and Fixtures	31-Dec-08	STEEL POLES	1	2,243
E364.00-Poles, Towers, and Fixtures	30-Jul-09	STEEL POLES	1	1,841
E364.00-Poles, Towers, and Fixtures	31-Jul-09	STEEL POLES	2	4,567
E364.00-Poles, Towers, and Fixtures	12-Aug-09	STEEL POLES	3	6,413
E364.00-Poles, Towers, and Fixtures	1-Sep-09	STEEL POLES	13	22,518
E364.00-Poles, Towers, and Fixtures	1-Oct-09	STEEL POLES	6	19,422
E364.00-Poles, Towers, and Fixtures	16-Oct-09	STEEL POLES	2	254
E364.00-Poles, Towers, and Fixtures	31-Oct-09	STEEL POLES	2	5,529
E364.00-Poles, Towers, and Fixtures	10-Nov-09	STEEL POLES	1	2,521
E364.00-Poles, Towers, and Fixtures	31-Dec-41	TOWERS	1	3,110
E364.00-Poles, Towers, and Fixtures	31-Dec-41	TOWERS	2	2,291
E364.00-Poles, Towers, and Fixtures	31-Dec-56	TOWERS	1,870	255
E364.00-Poles, Towers, and Fixtures	31-Dec-60	TOWERS	150	45
E364.00-Poles, Towers, and Fixtures	31-Dec-72	TOWERS	100	42
E364.00-Poles, Towers, and Fixtures	31-Dec-81	TOWERS	2	42,088
E364.00-Poles, Towers, and Fixtures	1-Jan-99	TOWERS	2	5,838,921
E364.00-Poles, Towers, and Fixtures	1-Jan-00	TOWERS	4	298
E364.00-Poles, Towers, and Fixtures	1-Jan-04	TOWERS	1	116
Total				$ 244,022,288

Seelye Rebuttal Exhibit 11

KENTUCKY UTILITIES COMPANY

CASE NO. 2009-00548

Response to Third Data Request of Commission Staff
Dated March 26, 2010

Question No. 3

Responding Witness: William Steven Seelye

Q-3. Refer to Seelye Exhibit 8, the response to Item 96 of Commission Staffs Second Data Request ("Staffs Second Request") and KU's response to Item 27 of the Initial Data Request of the Kentucky Cable Telecommunications Association.

a. With regard to the response to Item 96, explain in detail the difference between a levelized and non-levelized charge.

b. Recalculate the cable TV attachment charges with the only change being the use of net plant investment costs and provide an updated Exhibit 8.

c. The response to Item 27 discusses the calculation of the operation and maintenance expenses used in the calculation of the CATV charges.

(1) Starting with the rates as calculated in the application, recalculate the CATV rates if tree trimming expenses related to services and overhead conductors is excluded from the calculation of the adder for operation and maintenance expenses. If the expenses related to services and overhead conductors cannot be excluded from account 593004, Tree Trimming of Electric Distribution, recalculate the CATV rates if the adder for operation and maintenance expenses is calculated by dividing the Expenses Assigned to Poles of $13,966,333 by the net book value of Accounts 364, 365, and 369. Include an updated Exhibit 8 in the response.

(2) Starting with the rates as calculated in response to Item b above, recalculate the CATV rates if tree trimming expenses related to services and overhead conductors is excluded from the calculation of the adder for operation and maintenance expenses. If the expenses related to services and overhead conductors cannot be excluded from account 593004, Tree Trimming of Electric Distribution, recalculate the CATV rates if the adder for operation and maintenance expenses is calculated- by dividing the Expenses Assigned to Poles of $13,966,333 by the net book value of Accounts 364, 365, and 369. Include an updated Exhibit 8 in the response.

A-3. a. A *levelized carrying* charge is a uniform series of payments calculated by applying a uniform series capital recovery factor to the gross original cost investment. A capital recovery factor is equal to the rate of return plus sinking fund depreciation. The calculation of a levelized carrying charge rate is identical to the calculation of a conventional mortgage payment on a home. In calculating a levelized carrying charge -- or a mortgage payment -- a capital recovery factor is applied to the original, un-depreciated investment ("gross investment"). Without considering income taxes, a levelized carrying charge (LCC) is therefore calculated by applying the return on investment (ROR) plus the sinking fund depreciation to the gross investment, as follows:

LCC = Gross Investment x [ROR + Sinking Fund Depreciation Rate]

Mathematically, it is not appropriate to apply a capital recovery factor (which is equal to rate of return plus sinking fund depreciation) to the depreciated investment ("net investment"). In the context of the proposed CATV attachment charge, applying a capital recovery factor – which reflects *sinking fund depreciation* as opposed to *straight line depreciation* – to net investment would result in a significant under-recovery of costs and would thus inappropriately shift these costs onto other customers.

A *non-levelized carrying charge* (NLCC) is a non-uniform series of payments calculated by applying the rate of return to net investment and then adding straight-line depreciation, as follows:

NLCC = Net Investment x ROR + Straight Line Depreciation

A non-levelized carrying charge calculation corresponds to the methodology used to determine revenue requirements in a rate case. Importantly, in a rate case *straight line depreciation* rather than *sinking fund depreciation* is used to calculate revenue requirements.

On a present value basis, levelized carrying charges are equivalent to non-levelized carrying charges over the life of the investment. This can be seen in the following attachment (Table I) which compares the present-value non-levelized carrying charges on a $1,000 investment to the present-value levelized carrying charges on the same $1,000 investment. Please note that for both calculations, the sum of present value revenue carrying charges is equal to the original $1,000 investment.

But if sinking fund depreciation rather than straight-line depreciation is applied to net investment then an incorrect result is obtained. As seen in Table II, calculating carrying charges by applying a *sinking fund depreciation* rate to the *net investment* results in significant under-recovery of carrying costs. When the levelized and non-levelized carrying charges are properly calculated, the sum of the present-value carrying charges for each series is equal to $1,000. But when sinking fund depreciation is applied to net investment, the sum of the present value carrying charges is only equal to $721.54. What this means is that if carrying charges are miscalculated in this manner, only 72.15% of cost will be recovered over the life of the investment.

The conclusion reached is that either methodology – either a levelized fixed charge calculation or non-levelized fixed charge calculation – is reasonable assuming that the methodologies are properly applied *and* assuming that the same methodology is consistently applied over time. While on a present value basis both methodologies will yield the same result over the life of the investment, during any particular year the carrying charges will likely be different. For this reason, generally it is not appropriate to switch back and forth between the two methodologies. While LG&E does not have a fundamental objection with using a non-levelized carrying charge calculation to determine the CATV attachment charges *as long as straight-line depreciation is used in the calculation*, the Company does not believe that it is appropriate to switch back and forth between the two methodologies.

The use of levelized versus non-levelized carrying charge rates has been considered extensively by the Federal Energy Regulatory Commission ("FERC"). The FERC will allow the application of a levelized carrying charge rate (with sinking fund depreciation) to gross plant – which it calls the "levelized gross plant method" -- or the application of a non-levelized carrying charge rate (with straight-line depreciation) to net plant – which it calls "nonlevelized net plant method". The FERC, however, is reluctant to allow a utility to switch back and forth between the two methodologies. In a series of cases involving levelized carrying charges, the FERC rejected attempts to switch from a "net plant" approach to a "levelized" approach in midstream, finding that "allowing Consumers to switch pricing methodologies from the nonlevelized approach … to the levelized approach … is inappropriate." *Consumers Energy Co., Opinion No. 429*, 85 FERC ¶ 61,100 at 61,366 (1998), *reh'g granted, Opinion No. 429-A*, 89 FERC ¶ 61,138 (1999), *reh'g denied, Opinion No. 429-B*, 95 FERC ¶ 61,084 (2001); *accord Ky. Utils. Co., Opinion No. 432*, 85 FERC ¶ 61,274 at 62,105 (1998). In the *Opinion 432*, the FERC did not allow Kentucky Utilities Company ("KU") to change methodologies, stating as follows:

> In conclusion, we believe that either a levelized gross plant or a non-levelized rate design can produce comparable, reasonable results if they are used consistently. Here, however, KU proposes

> to switch methods. In supporting such a switch, a utility must prove that its proposed method is reasonable in light of its past recovery of capital costs using a different method. Here, KU has not persuaded us that the switch is appropriate in the circumstances of this case.

Regarding CATV attachment charges, considering the historical practice of calculating the charges using the levelized gross plant methodology, the Company maintains that the historical practice should be continued in the current proceeding.

b. As indicated in response to LG&E KCTA-1 Question 8, the Company does not have information concerning the net plant costs related to the types of poles (35 foot, 40 foot, and 45 foot poles) used to calculate the proposed CATV attachment charge. A *rough estimate* can be developed by applying the ratio of net plant to gross plant for Account 364 – Poles, Towers and Fixtures to the applicable gross plant unit costs for 35, 40, and 45 foot poles. As explained above, using net plant necessitates the application of straight line depreciation rather than sinking fund depreciation. A non-levelized carrying charge calculation using *roughly estimated* net plant data is attached.

c. (1) Expenses related to services and overhead conductors cannot be excluded from account 593004. Attached is a recalculation of Seelye Exhibit 11 with the operation and maintenance expense adder calculated by dividing the Expenses Assigned to Poles by the *net* book value of Accounts 364, 365, and 369. Because the operation and maintenance expense adder is applied to *gross* plant costs in Seelye Exhibit 11, a recalculation of Seelye Exhibit 11 is also attached, with the operation and maintenance expense adder calculated by dividing the Expenses Assigned to Poles by the *gross* book value of Accounts 364, 365, and 369.

(2) Attached is a recalculation of the attachment to the response to sub-part b of this Question, with the operation and maintenance expense adder calculated by dividing the Expenses Assigned to Poles by the *net* book value of Accounts 364, 365, and 369.

Table I

(a)	*Book Life*	*35 Years*
(b)	Straight Line Depreciation (1/(a))	2.86%
(c)	Sinking-Fund Depreciation (see formula)	0.54%
(d)	Rate of Return	8.32%
(e)	Capital Recovery Factor (CFR) [(c) + (d)]	8.86%

	Non-Levelized Carrying Charges					Levelized Carrying Charges		
Year (1)	Net Investment (2)	Return (3)	Straight Line Depreciation (4)	Non-Levelized Carrying Charges (5)	Present Value at 8.32% ROR (6)	Gross Investment (7)	Non-Levelized Carrying Charges (8) [(e) x (7)]	Present Value at 8.32% ROR (6)
1	$1,000.00	$83.20	$28.57	$111.77	$103.19	$1,000.00	$88.60	$81.80
2	971.43	80.82	28.57	109.39	93.23	1,000.00	88.60	75.51
3	942.86	78.45	28.57	107.02	84.20	1,000.00	88.60	69.71
4	914.29	76.07	28.57	104.64	76.01	1,000.00	88.60	64.36
5	885.71	73.69	28.57	102.26	68.58	1,000.00	88.60	59.42
6	857.14	71.31	28.57	99.89	61.84	1,000.00	88.60	54.85
7	828.57	68.94	28.57	97.51	55.73	1,000.00	88.60	50.64
8	800.00	66.56	28.57	95.13	50.19	1,000.00	88.60	46.75
9	771.43	64.18	28.57	92.75	45.18	1,000.00	88.60	43.16
10	742.86	61.81	28.57	90.38	40.64	1,000.00	88.60	39.84
11	714.29	59.43	28.57	88.00	36.53	1,000.00	88.60	36.78
12	685.71	57.05	28.57	85.62	32.82	1,000.00	88.60	33.96
13	657.14	54.67	28.57	83.25	29.45	1,000.00	88.60	31.35
14	628.57	52.30	28.57	80.87	26.42	1,000.00	88.60	28.94
15	600.00	49.92	28.57	78.49	23.67	1,000.00	88.60	26.72
16	571.43	47.54	28.57	76.11	21.19	1,000.00	88.60	24.67
17	542.86	45.17	28.57	73.74	18.95	1,000.00	88.60	22.77
18	514.29	42.79	28.57	71.36	16.93	1,000.00	88.60	21.02
19	485.71	40.41	28.57	68.98	15.11	1,000.00	88.60	19.41
20	457.14	38.03	28.57	66.61	13.47	1,000.00	88.60	17.92
21	428.57	35.66	28.57	64.23	11.99	1,000.00	88.60	16.54
22	400.00	33.28	28.57	61.85	10.66	1,000.00	88.60	15.27
23	371.43	30.90	28.57	59.47	9.46	1,000.00	88.60	14.10
24	342.86	28.53	28.57	57.10	8.39	1,000.00	88.60	13.01
25	314.29	26.15	28.57	54.72	7.42	1,000.00	88.60	12.02
26	285.71	23.77	28.57	52.34	6.55	1,000.00	88.60	11.09
27	257.14	21.39	28.57	49.97	5.77	1,000.00	88.60	10.24
28	228.57	19.02	28.57	47.59	5.08	1,000.00	88.60	9.45
29	200.00	16.64	28.57	45.21	4.45	1,000.00	88.60	8.73
30	171.43	14.26	28.57	42.83	3.90	1,000.00	88.60	8.06
31	142.86	11.89	28.57	40.46	3.40	1,000.00	88.60	7.44
32	114.29	9.51	28.57	38.08	2.95	1,000.00	88.60	6.87
33	85.71	7.13	28.57	35.70	2.55	1,000.00	88.60	6.34
34	57.14	4.75	28.57	33.33	2.20	1,000.00	88.60	5.85
35	28.57	2.38	28.57	30.95	1.89	1,000.00	88.60	5.40
Sum of Present Value Carrying Charges					$1,000.00			$1,000.00

Table II

(a)	Book Life	35 Years
(b)	Straight Line Depreciation (1/(a))	2.86%
(c)	Sinking-Fund Depreciation (see formula)	0.54%
(d)	Rate of Return	8.32%
(e)	Capital Recovery Factor (CFR) [(c) + (d)]	8.86%

	Non-Levelized Carrying Charges					*Misapplied* Levelized Carrying Charges		
Year (1)	Net Investment (2)	Return (3)	Straight Line Depreciation (4)	Non-Levelized Carrying Charges (5)	Present Value at 8.32% ROR (6)	Net Investment (7)	Non-Levelized Carrying Charges (8) [(e) x (7)]	Present Value at 8.32% ROR (6)
1	$1,000.00	$83.20	$28.57	$111.77	$103.19	$1,000.00	$88.60	$81.80
2	971.43	80.82	28.57	109.39	93.23	971.43	86.07	73.36
3	942.86	78.45	28.57	107.02	84.20	942.86	83.54	65.73
4	914.29	76.07	28.57	104.64	76.01	914.29	81.01	58.84
5	885.71	73.69	28.57	102.26	68.58	885.71	78.48	52.63
6	857.14	71.31	28.57	99.89	61.84	857.14	75.95	47.02
7	828.57	68.94	28.57	97.51	55.73	828.57	73.41	41.96
8	800.00	66.56	28.57	95.13	50.19	800.00	70.88	37.40
9	771.43	64.18	28.57	92.75	45.18	771.43	68.35	33.29
10	742.86	61.81	28.57	90.38	40.64	742.86	65.82	29.60
11	714.29	59.43	28.57	88.00	36.53	714.29	63.29	26.27
12	685.71	57.05	28.57	85.62	32.82	685.71	60.76	23.29
13	657.14	54.67	28.57	83.25	29.45	657.14	58.22	20.60
14	628.57	52.30	28.57	80.87	26.42	628.57	55.69	18.19
15	600.00	49.92	28.57	78.49	23.67	600.00	53.16	16.03
16	571.43	47.54	28.57	76.11	21.19	571.43	50.63	14.10
17	542.86	45.17	28.57	73.74	18.95	542.86	48.10	12.36
18	514.29	42.79	28.57	71.36	16.93	514.29	45.57	10.81
19	485.71	40.41	28.57	68.98	15.11	485.71	43.04	9.43
20	457.14	38.03	28.57	66.61	13.47	457.14	40.50	8.19
21	428.57	35.66	28.57	64.23	11.99	428.57	37.97	7.09
22	400.00	33.28	28.57	61.85	10.66	400.00	35.44	6.11
23	371.43	30.90	28.57	59.47	9.46	371.43	32.91	5.24
24	342.86	28.53	28.57	57.10	8.39	342.86	30.38	4.46
25	314.29	26.15	28.57	54.72	7.42	314.29	27.85	3.78
26	285.71	23.77	28.57	52.34	6.55	285.71	25.32	3.17
27	257.14	21.39	28.57	49.97	5.77	257.14	22.78	2.63
28	228.57	19.02	28.57	47.59	5.08	228.57	20.25	2.16
29	200.00	16.64	28.57	45.21	4.45	200.00	17.72	1.75
30	171.43	14.26	28.57	42.83	3.90	171.43	15.19	1.38
31	142.86	11.89	28.57	40.46	3.40	142.86	12.66	1.06
32	114.29	9.51	28.57	38.08	2.95	114.29	10.13	0.78
33	85.71	7.13	28.57	35.70	2.55	85.71	7.59	0.54
34	57.14	4.75	28.57	33.33	2.20	57.14	5.06	0.33
35	28.57	2.38	28.57	30.95	1.89	28.57	2.53	0.15
Sum of Present Value Carrying Charges					$1,000.00			$721.54

KENTUCKY UTILITIES COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Gross Installed Cost		Gross Average Installed Cost	Net / Gross Factor for Account 364	Estimate of Net Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2009						
35'	93,558	$ 17,458,914		$ 186.61	0.44445787	$ 82.94
40'	142,251	78,741,981		553.54	0.44445787	246.03
	235,809	96,200,895		407.96		181.32
Three-User Poles						
40'	142,251	$ 78,741,981		$ 553.54	0.44445787	$ 335.30
45'	63,914	48,216,502		754.40	0.44445787	273.70
	206,165	126,958,484		615.81		316.20

	Estimated Number of Attachments	Weighted Cost
Two-User Pole Cost		
$181.32 x .1224 Usage Space Factor = $ 22.19		
$ 22.19 x .2115 Annual Carrying Charge = $ 4.69	30,517	$ 143,269
Three-User Pole Cost		
$316.20 x .0759 Usage Space Factor = $24.00		
$ 24.00 x .2115 Annual Carrying Charge = $5.08	118,345	600,817
Weighted Total	148,862	$ 744,087
Weighted Average Monthly Cost		5.00

KENTUCKY UTILITIES COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	8.32%
Depreciation - Straight Line	2.86%
Income Tax (1)	3.63%
Property Tax and Insurance	0.22%
Operation and Maintenance (Page 3)	6.13%
Total	21.15%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Common	53.85%	11.50%	6.19%
Preferred	0.00%	0.00%	0.00%
Total Equity	53.85%		6.19%
Debt	46.15%	4.61%	2.13%
Total Capitalization	100.00%		8.32%

Composite Federal and State Income Taxes rate = 36.93%

Income Tax = (0.3693/(1-0.3693) x 0.0619 = 3.63%

KENTUCKY UTILITIES COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2009

(1) Labor Charged to 593001- Maint of Poles, Towers and Fixtures Subaccount	$225,691	
- Tree Trimming	635,116	
		$860,808
Total Labor		$71,018,516
Total Administrative and General Expenses		$77,056,654

Assignment of a Portion of A.& G Expenses to Poles

($860,808/$71,018,516) x $77,056,654 = $933,995

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 342,914
Tree Trimming of Electric Distribution Routes 593004	12,689,424
A & G Expenses Assigned to Poles	$933,995
Total	$ 13,966,333

Adder to Annual Carrying Charges for O & M Expenses

$ 13,966,333	Expenses Assigned to Poles	=	6.13%
227,809,902	Plant in Service - Account 364		

Net Plant to Gross Plant Ratio for Account 364

Gross Plant	Depreciation	Net Plant	Net to Gross Ratio
$ 227,809,902	$ 126,557,999	$ 101,251,903	44.446%

KENTUCKY UTILITIES COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost	Average Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2009			
35'	93,558	$ 17,458,914	$ 186.61
40'	142,251	78,741,981	553.54
	235,809	96,200,895	407.96
Three-User Poles			
40'	142,251	$ 78,741,981	$ 553.54
45'	63,914	48,216,502	754.40
	206,165	126,958,484	615.81

	Estimated Number of Attachments	Weighted Cost
Two-User Pole Cost		
\$407.96 x .1224 Usage Space Factor = \$ 49.93		
\$ 49.93 x .1517 Annual Carrying Charge = \$ 7.58	30,517	$ 231,192
Three-User Pole Cost		
\$615.81 x .0759 Usage Space Factor = \$46.74		
\$ 46.74 x .1517 Annual Carrying Charge = \$7.09	118,345	839,219
Weighted Total	148,862	$ 1,070,411
Weighted Average Monthly Cost		7.19

KENTUCKY UTILITIES COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	8.32%
Depreciation - Sinking Fund	0.54%
Income Tax (1)	3.63%
Property Tax and Insurance	0.22%
Operation and Maintenance (Page 3)	2.47%
Total	15.17%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Common	53.85%	11.50%	6.19%
Preferred	0.00%	0.00%	0.00%
Total Equity	53.85%		6.19%
Debt	46.15%	4.61%	2.13%
Total Capitalization	100.00%		8.32%

Composite Federal and State Income Taxes rate = 36.93%

Income Tax = (0.3693/(1-0.3693) x 0.0619 = 3.63%

KENTUCKY UTILITIES COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2009

(1) Labor Charged to 593001- Maint of Poles, Towers and Fixtures Subaccount	$225,691	
- Tree Trimming	635,116	
		$860,808
Total Labor		$71,018,516
Total Administrative and General Expenses		$77,056,654

Assignment of a Portion of A & G Expenses to Poles

($860,808/$71,018,516) x $77,056,654 = $933,995

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 342,914
Tree Trimming of Electric Distribution Routes 593004	12,689,424
A & G Expenses Assigned to Poles	$933,995
Total	$ 13,966,333

Adder to Annual Carrying Charges for O & M Expenses

$$\frac{\$\ 13{,}966{,}333 \quad \text{Expenses Assigned to Poles}}{566{,}433{,}038 \quad \text{Plant in Service - 364 , 365, and 369}} = 2.47\%$$

Net Plant to Gross Plant Ratio for Accounts 364,365 and 369

Gross Plant	Depreciation	Net Plant	Net to Gross Ratio
$ 566,433,038	$ 173,586,068	$ 392,846,970	69.355%

KENTUCKY UTILITIES COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost	Average Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2009			
35'	93,558	$ 17,458,914	$ 186.61
40'	142,251	78,741,981	553.54
	235,809	96,200,895	407.96
Three-User Poles			
40'	142,251	$ 78,741,981	$ 553.54
45'	63,914	48,216,502	754.40
	206,165	126,958,484	615.81

	Estimated Number of Attachments	Weighted Cost
Two-User Pole Cost		
$407.96 x .1224 Usage Space Factor = $ 49.93		
$ 49.93 x .1800 Annual Carrying Charge = $ 8.99	30,517	$ 274,235
Three-User Pole Cost		
$615.81 x .0759 Usage Space Factor = $46.74		
$ 46.74 x .1800 Annual Carrying Charge = $8.41	118,345	995,461
Weighted Total	148,862	$ 1,269,695
Weighted Average Monthly Cost		8.53

KENTUCKY UTILITIES COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	8.32%
Depreciation - Sinking Fund	0.54%
Income Tax (1)	3.63%
Property Tax and Insurance	0.22%
Operation and Maintenance (Page 3)	5.29%
Total	18.00%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Common	53.85%	11.50%	6.19%
Preferred	0.00%	0.00%	0.00%
Total Equity	53.85%		6.19%
Debt	46.15%	4.61%	2.13%
Total Capitalization	100.00%		8.32%

Composite Federal and State Income Taxes rate = 36.93%

Income Tax = (0.3693/(1-0.3693) x 0.0619 = 3.63%

KENTUCKY UTILITIES COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2009

(1) Labor Charged to 593001- Maint of Poles, Towers and Fixtures Subaccount	$225,691	
- Tree Trimming	635,116	
		$860,808
Total Labor		$71,018,516
Total Administrative and General Expenses		$77,056,654

Assignment of a Portion of A & G Expenses to Poles

($860,808/$71,018,516) x $77,056,654 = $933,995

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 342,914
Tree Trimming of Electric Distribution Routes 593004	12,689,424
A & G Expenses Assigned to Poles	$933,995
Total	$ 13,966,333

Adder to Annual Carrying Charges for O & M Expenses

$ 13,966,333	Expenses Assigned to Poles	=	5.29%
264,000,387	Plant in Service - 364, 365, and 369		

Net Plant to Gross Plant Ratio for Accounts 364,365 and 369

Gross Plant	Depreciation	Net Plant	Net to Gross Ratio
$ 566,433,038	$ 302,432,651	$ 264,000,387	46.608%

KENTUCKY UTILITIES COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost	Average Installed Cost	Net Gross Factor for Account 364	Estimate of Net Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2009					
35'	93,558	$ 17,458,914	$ 186.61	0.46607519	$ 86.97
40'	142,251	78,741,981	553.54	0.46607519	257.99
	235,809	96,200,895	407.96		190 14
Three-User Poles					
40'	142,251	$ 78,741,981	$ 553.54	0.46607519	$ 257.99
45'	63,914	48,216,502	754.40	0.46607519	351.61
	206,165	126,958,484	615 81		431 59

	Estimated Number of Attachments	Weighted Cost
Two-User Pole Cost		
$190.14 x .1224 Usage Space Factor = $ 23.27		
$ 23.27 x .2031 Annual Carrying Charge = $ 4.73	30,517	$ 144,269
Three-User Pole Cost		
$431.59 x .0759 Usage Space Factor = $32.76		
$ 32.76 x .2031 Annual Carrying Charge = $6.65	118,345	787,480
Weighted Total	148,862	$ 931,749
Weighted Average Monthly Cost		6.26

KENTUCKY UTILITIES COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	8.32%
Depreciation - Straight Line	2.86%
Income Tax (1)	3.63%
Property Tax and Insurance	0.22%
Operation and Maintenance (Page 3)	5.29%
Total	20.31%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Common	53.85%	11.50%	6.19%
Preferred	0.00%	0.00%	0.00%
Total Equity	53.85%		6.19%
Debt	46.15%	4.61%	2.13%
Total Capitalization	100.00%		8.32%

Composite Federal and State Income Taxes rate = 36.93%

Income Tax = (0.3693/(1-0.3693) x 0.0619 = 3.63%

KENTUCKY UTILITIES COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2009

(1) Labor Charged to 593001- Maint of Poles, Towers and Fixtures Subaccount	$225,691	
- Tree Trimming	635,116	
		$860,808
Total Labor		$71,018,516
Total Administrative and General Expenses		$77,056,654

Assignment of a Portion of A & G Expenses to Poles

($860,808/$71,018,516) x $77,056,654 = $933,995

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 342,914
Tree Trimming of Electric Distribution Routes 593004	12,689,424
A & G Expenses Assigned to Poles	$933,995
Total	$ 13,966,333

Adder to Annual Carrying Charges for O & M Expenses

$ 13,966,333	Expenses Assigned to Poles	=	5.29%
264,000,387	Plant in Service - 364 , 365, and 369		

Net Plant to Gross Plant Ratio for Accounts 364,365 and 369

Gross Plant	Depreciation	Net Plant	Net to Gross Ratio
$ 566,433,038	$ 302,432,651	$ 264,000,387	46.608%

Seelye Rebuttal Exhibit 12

(a)	Book Life	35	Years
(b)	Straight Line Depreciation (1/(a))	2.86%	
(c)	Sinking-Fund Depreciation (see formula)	0.54%	
(d)	Rate of Return	8.32%	
(e)	Capital Recovery Factor (CFR) [(c) + (d)]	8.86%	

	Non-Levelized Carrying Charges					Levelized Carrying Charges			Ms. Kravtin's Inconsistent Approach		
Year (1)	Net Investment (2)	Return (3)	Straight Line Depreciation (4)	Non-Levelized Carrying Charges (5)	Present Value at 8.32% ROR (6)	Gross Investment (7)	Levelized Carrying Charges (8)	Present Value at 8.32% ROR (9)	Choosing the Charge that Results in the Lowest Rate (10)	Difference From Consistently Applied Levelized Approach (11)	Present Value Difference at 8.32% ROR
							[(e) x (7)]			(10) - (8)	
1	$1,000.00	$83.20	$28.57	$111.77	$103.19	$1,000.00	$88.60	$81.80	$88.60	$0.00	$81.80
2	971.43	80.82	28.57	109.39	93.23	1,000.00	88.60	75.51	$88.60	$0.00	$75.51
3	942.86	78.45	28.57	107.02	84.20	1,000.00	88.60	69.71	$88.60	$0.00	$69.71
4	914.29	76.07	28.57	104.64	76.01	1,000.00	88.60	64.36	$88.60	$0.00	$64.36
5	885.71	73.69	28.57	102.26	68.58	1,000.00	88.60	59.42	$88.60	$0.00	$59.42
6	857.14	71.31	28.57	99.89	61.84	1,000.00	88.60	54.85	$88.60	$0.00	$54.85
7	828.57	68.94	28.57	97.51	55.73	1,000.00	88.60	50.64	$88.60	$0.00	$50.64
8	800.00	66.56	28.57	95.13	50.19	1,000.00	88.60	46.75	$88.60	$0.00	$46.75
9	771.43	64.18	28.57	92.75	45.18	1,000.00	88.60	43.16	$88.60	$0.00	$43.16
10	742.86	61.81	28.57	90.38	40.64	1,000.00	88.60	39.84	$88.60	$0.00	$39.84
11	714.29	59.43	28.57	88.00	36.53	1,000.00	88.60	36.78	$88.00	($0.60)	$36.53
12	685.71	57.05	28.57	85.62	32.82	1,000.00	88.60	33.96	$85.62	($2.98)	$32.82
13	657.14	54.67	28.57	83.25	29.45	1,000.00	88.60	31.35	$83.25	($5.36)	$29.45
14	628.57	52.30	28.57	80.87	26.42	1,000.00	88.60	28.94	$80.87	($7.73)	$26.42
15	600.00	49.92	28.57	78.49	23.67	1,000.00	88.60	26.72	$78.49	($10.11)	$23.67
16	571.43	47.54	28.57	76.11	21.19	1,000.00	88.60	24.67	$76.11	($12.49)	$21.19
17	542.86	45.17	28.57	73.74	18.95	1,000.00	88.60	22.77	$73.74	($14.87)	$18.95
18	514.29	42.79	28.57	71.36	16.93	1,000.00	88.60	21.02	$71.36	($17.24)	$16.93
19	485.71	40.41	28.57	68.98	15.11	1,000.00	88.60	19.41	$68.98	($19.62)	$15.11
20	457.14	38.03	28.57	66.61	13.47	1,000.00	88.60	17.92	$66.61	($22.00)	$13.47
21	428.57	35.66	28.57	64.23	11.99	1,000.00	88.60	16.54	$64.23	($24.37)	$11.99
22	400.00	33.28	28.57	61.85	10.66	1,000.00	88.60	15.27	$61.85	($26.75)	$10.66
23	371.43	30.90	28.57	59.47	9.46	1,000.00	88.60	14.10	$59.47	($29.13)	$9.46
24	342.86	28.53	28.57	57.10	8.39	1,000.00	88.60	13.01	$57.10	($31.51)	$8.39
25	314.29	26.15	28.57	54.72	7.42	1,000.00	88.60	12.02	$54.72	($33.88)	$7.42
26	285.71	23.77	28.57	52.34	6.55	1,000.00	88.60	11.09	$52.34	($36.26)	$6.55
27	257.14	21.39	28.57	49.97	5.77	1,000.00	88.60	10.24	$49.97	($38.64)	$5.77
28	228.57	19.02	28.57	47.59	5.08	1,000.00	88.60	9.45	$47.59	($41.01)	$5.08
29	200.00	16.64	28.57	45.21	4.45	1,000.00	88.60	8.73	$45.21	($43.39)	$4.45
30	171.43	14.26	28.57	42.83	3.90	1,000.00	88.60	8.06	$42.83	($45.77)	$3.90
31	142.86	11.89	28.57	40.46	3.40	1,000.00	88.60	7.44	$40.46	($48.15)	$3.40
32	114.29	9.51	28.57	38.08	2.95	1,000.00	88.60	6.87	$38.08	($50.52)	$2.95
33	85.71	7.13	28.57	35.70	2.55	1,000.00	88.60	6.34	$35.70	($52.90)	$2.55
34	57.14	4.75	28.57	33.33	2.20	1,000.00	88.60	5.85	$33.33	($55.28)	$2.20
35	28.57	2.38	28.57	30.95	1.89	1,000.00	88.60	5.40	$30.95	($57.65)	$1.89
Sum of Present Value Carrying Charges					$1,000.00			$1,000.00			$907.26

Seelye Rebuttal Exhibit 13

KENTUCKY UTILITIES COMPANY

Calculation Of Attachment Charges for CATV

Pole Size	Quantity	Installed Cost		Average Installed Cost
Weighted Average Bare Pole Cost as of 10/31/2009				
35'	93,470	$ 17,215,691		$ 184.18
40'	142,334	77,391,311		543.73
	235,804	94,607,002		401.21
Three-User Poles				
40'	142,334	$ 77,391,311		$ 543.73
45'	63,153	45,668,509		723.14
	205,487	123,059,820		598.87

	Estimated Number of Attachments	Weighted Cost
Two-User Pole Cost		
$401.21 x .1224 Usage Space Factor = $ 49.11		
$ 49.11 x .1908 Annual Carrying Charge = $ 9.37	30,517	$ 285,934
Three-User Pole Cost		
$598.87 x .0759 Usage Space Factor = $45.45		
$ 45.45 x .1908 Annual Carrying Charge = $8.67	118,345	1,026,357
Weighted Total	148,862	$ 1,312,291
Weighted Average Monthly Cost		$ 8.82

KENTUCKY UTILITIES COMPANY

Calculation Of Annual Carrying Charge

Proposed Rate of Return	8.32%
Depreciation - Sinking Fund	0.54%
Income Tax (1)	3.63%
Property Tax and Insurance	0.22%
Operation and Maintenance (Page 3)	6.37%
Total	19.08%

(1) Derived from rates of equity capital

	Capitalization Ratio	Annual Rate	Composite Rate
Common	53.85%	11.50%	6.19%
Preferred	0.00%	0.00%	0.00%
Total Equity	53.85%		6.19%
Debt	46.15%	4.61%	2.13%
Total Capitalization	100.00%		8.32%

Composite Federal and State Income Taxes rate = 36.93%

Income Tax = (0.3693/(1-0.3693) x 0.0619 = 3.63%

KENTUCKY UTILITIES COMPANY

Operation and Maintenance Expenses for
the 12 Months Ended October 31, 2009

(1) Labor Charged to 593001- Maint of Poles, Towers and Fixtures Subaccount	$225,691	
- Tree Trimming	635,116	
		$860,808
Total Labor		$71,018,516
Total Administrative and General Expenses		$77,056,654

Assignment of a Portion of A & G Expenses to Poles

($860,808/$71,018,516) x $77,056,654 = $933,995

Expenses Assigned to Poles

Maintenance of Poles, Towers, and Fixtures Subaccount 593001	$ 419,127
Tree Trimming of Electric Distribution Routes 593004	14,200,155
A & G Expenses Assigned to Poles	$933,995
Total	$ 15,553,277

Adder to Annual Carrying Charges for O & M Expenses

$$\frac{\$\ 15{,}553{,}277 \text{ Expenses Assigned to Poles}}{244{,}022{,}288 \text{ Plant in Service - Account 364}} = 6.37\%$$