**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 58**

**Responding Witness: Christopher M. Garrett**

## C. Cash Working Capital/Lead-Lag Study

Q-58. Cash Working Capital. Provide a reconciliation of total operating expense reflected in the forecasted cost of service (Schedule C.1) to the total expenses lagged in the Companies' requested cash working capital allowances (Schedule B-5.2).

| | Schedule C.1 | Schedule B-5.2 | Difference |
|---|---|---|---|
| | (A) | (B) | (C) |
| KU | | | |
| Total O&M Expenses | 884,639,921 | 877,467,419 | (7,172,503) |
| Total Depreciation and Amortization Expense | 268,954,148 | 347,669,956 | 78,715,807 |
| Total Taxes Other Than Income | 43,682,224 | 45,617,136 | 1,934,912 |
| Total Income Tax Expense | 24,634,790 | 46,746,420 | 22,111,630 |
| | 1,221,911,084 | 1,317,500,930 | 95,589,847 |
| LG&E - Electric | | | |
| Total O&M Expenses | 627,292,494 | 635,106,277 | 7,813,783 |
| Total Depreciation and Amortization Expense | 155,800,380 | 228,887,386 | 73,087,006 |
| Total Taxes Other Than Income | 34,932,925 | 36,773,893 | 1,840,968 |
| Total Income Tax Expense | 24,281,656 | 43,595,949 | 19,314,292 |
| | 842,307,455 | 944,363,505 | 102,056,050 |
| LG&E - Gas | | | |
| Total O&M Expenses | 93,616,747 | 221,950,793 | 128,334,046 |
| Total Depreciation and Amortization Expense | 38,418,048 | 40,461,755 | 2,043,707 |
| Total Taxes Other Than Income | 11,768,640 | 12,584,590 | 815,950 |
| Total Income Tax Expense | 5,322,515 | 7,982,424 | 2,659,909 |
| | 149,125,951 | 282,979,562 | 133,853,612 |

A-58. See attached. The reconciliation includes Jurisdictional Adjustments (Schedule D-2) for Schedule C-1, which remove other rate mechanism amounts not included in base rates. The jurisdictional cash working capital on Schedule B-5.2 removes only applicable other rate mechanism cash working capital amounts (e.g., ECR mechanism).

| KU | Schedule C-1 | Schedule B-5.2 | Difference | Jurisdictional Adjustments Schedule D-2 | Jurisdictional Pro Forma Adjustments to Forecasted Period Schedule D-2.1 | Amortization of Regulatory Assets and Liabilities | Regulatory Debits | Total Reconciliation | Difference |
|---|---|---|---|---|---|---|---|---|---|
| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H)=SUM(D-G) | (I)=(H+C) |
| Total O&M Expenses | 884,639,921 | 877,467,419 | (7,172,503) | 4,699,778 | (994,289) | 3,467,014 | | 7,172,503 | - |
| Total Depreciation and Amortization Expense | 268,954,148 | 347,669,956 | 78,715,807 | (66,754,820) | | (3,467,014) | (8,493,973) | (78,715,807) | - |
| Total Taxes Other Than Income | 43,682,224 | 45,617,136 | 1,934,912 | (1,934,912) | | | | (1,934,912) | - |
| Total Income Tax Expense | 24,634,790 | 46,746,420 | 22,111,630 | (21,991,736) | (119,894) | | | (22,111,630) | - |

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 59**

**Responding Witness: William Steven Seelye**

Q-59. Schedule B-5.1 reports the inclusion of Fuel Stock, Gas Stored Underground, Materials and Supplies, and Prepayments under Other Working Capital Allowances on Schedule B-1. Have the test period operating expenses associated with these items been removed from cash working capital determined under the lead-lag method on Schedule B-5.2?

a. If the response is in the affirmative, explain why there are lagged expenses related to Fuel, Non-Fuel Commodities, Purchased Power, and Purchased Gas in cash working capital, as computed under the lead-lag method.

b. If the response is in the negative,

i. Explain why not removing the related expense from cash working capital under the lead-lag method does not lead to double counting in rate base?

ii. Provide the related expense reflected in each lagged item on Schedule B-5.2 for the forecast test year.

A-59. No.

a. Not applicable.

b.

i. Removing these expense items from the analysis of expense leads would increase cash working capital. For example, for coal expenditures the expense lead was determined as the difference between the time the coal is recorded in inventory and when the payment for the coal clears the Company's bank account. This difference results in positive expense lead days, which reduces cash working capital. Schedule B-5.1 includes inventory and prepayment amounts for which the Company incurs carrying costs until expensed in connection with providing service to customers. Therefore, there is no double counting in rate base because the cash working capital determined from the expense lead calculation in the lead/lag study and the prepayment or inventory items included in rate base measure two different and off-setting timing differences.

ii. Fuel and gas expenses are separately identified on Schedule B-5.2. Information is not readily available to determine the expense amounts attributable to Prepayments and Materials and Supplies.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 60**

**Responding Witness: Christopher M. Garrett / William Steven Seelye**

Q-60. Schedule B-5.2 reflects the inclusion of average balances related to Pension, OPEB, Regulatory Debits, and Regulatory Assets/Liabilities under Additional Cash Working Capital Items. Have the test period operating expenses associated with these items been removed from cash working capital under the lead-lag method?

a. If the response is in the affirmative, explain why there are lagged expenses related to Pension, OPEB, Regulatory Debits, Amortization of Regulatory Assets, and Amortization of Regulatory Liabilities in cash working capital, as computed under the lead-lag method.

b. If the response is in the negative:

i. Explain why not removing the related expense from cash working capital under the lead-lag method does not lead to double counting in rate base.

ii. Provide the related expense reflected in each lagged item on Schedule B-5.2 for the forecasted test year.

A-60. The items referenced received zero expense lead days which has the effect of removing the expenses from the analysis (as mentioned in Question No. 64). Also, see Page 1 for the base period and Page 4 for the forecasted test period of Schedule B-5.2.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 61**

**Responding Witness: Christopher M. Garrett**

Q-61. The adjustment to remove ECR Cash Working Capital is based on the 1/8th principle, rather than the lead-lag method.

a. Provide a justification for the difference in methodology.

b. If the operating expenses proposed in base rates are synchronized with lagged expenses, would it be fair to say the ECR adjustment in cash working capital is unnecessary?

A-61.

a. The Commission approved the ES Forms setting forth the cash working capital methodology for the ECR mechanism which is the 1/8th formula.

b. No. Rate Base computations must correspond to Commission approved methods for base rates and other rate mechanisms.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 62**

**Responding Witness: Christopher M. Garrett**

Q-62. Refer to the direct testimony of witness William Steven Seelye, page 102, wherein he states, "Mr. Garrett provided the balance sheet analyses used for the study of cash working capital based on amounts from the Companies' forecast." Provide a copy of the referenced balance sheet analyses.

A-62. The balance sheet analyses for KU refers to Schedule B-5.2, Pages 2-3 for the base period and Pages 5-6 for the forecasted test period. It is the schedule referenced in Question No. 60 and was provided as part of Tab 55 of the Filing Requirements.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 63**

**Responding Witness: Daniel K. Arbough / William Steven Seelye**

Q-63. Refer to the direct testimony of witness William Steven Seelye, page 104, wherein he indicates the revenue lag includes a "bank lag, which is the period from when the customer payment is received to when the Companies have access to funds."

a. Provide bank documentation or other evidence to support the appropriateness of adding one day to the revenue lag.

b. Do the expense leads measure the bank lag associated with the period from when vendor payments are disbursed to when the Companies no longer have access to the funds?

A-63.

a. See attached.

b. The expense leads measure the time from when the service or expense was incurred to the time when cash payment for such service or expense cleared the Company's bank account (i.e., when the cash was no longer available to the Company). The bank lag is embedded in this time period.

# Your Deposit Account Agreement

&

General Terms & Conditions

Electronic Transfers

Funds Availability

Safe Deposit Box Lease Agreement

U.S. Bank Consumer Reserve Line Agreement

U.S. Bank Business Reserve Line Agreement

Effective November 12th, 2018

Member FDIC

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## Table of Contents

## TERMS APPLICABLE TO ALL ACCOUNTS

### THIS IS AN AGREEMENT

Welcome to U.S. Bank and thank you for opening an account with us. This Agreement provides the general rules that apply to the account(s) you have with **U.S. Bank** described herein. Additional rules will be provided in:

1. disclosures we give you when you open your account for example our *Consumer Pricing Information and Business Pricing Information* brochure(s) and other fee disclosures (Both brochures can be obtained by stopping in a U.S. Bank branch or for the *Consumer Pricing Information* only, call 800.872.2657 to request a copy);
2. disclosures we give to you when you use additional products and services (for example our *Online and Mobile Financial Services Agreement and Fee Guide);*
3. periodic statements;
4. user guides;
5. *Consumer Privacy Pledge* brochure;
6. any appropriate means such as direct mail and notices on or with your statement, including any statements or notices delivered electronically; and
7. disclosures we give you about ATM and Debit Card Overdraft Coverage (applicable to certain consumer accounts, refer to the **Insufficient Funds and Overdrafts** section on page 6 for details).

These things, together, are an agreement between you and **U.S. Bank.**

**Please read this carefully and retain it for future reference. This brochure is revised periodically, so it may include changes from earlier versions.**

**By providing a written or electronic signature on a signature card or other agreement or contract, opening, or continuing to hold an account with us, you agree to the most recent version of this Agreement, which is available to you at your local U.S. Bank branch, at www.usbank.com, or by calling U.S. Bank 24-Hour Banking at a number listed on the last page of this booklet.**

**This Agreement represents the sole and exclusive agreement between you and us regarding the subject matter described herein and supersedes all previous and contemporaneous oral agreements and understandings. If any terms of your signature card, resolution, or certificate of authority are inconsistent with the terms of this Agreement, the terms of this Agreement will control. Any other variations to this Agreement must be acknowledged by us in writing.**

If you have any questions, please call us. Our most commonly used phone numbers are printed on the back of this booklet.

### DEFINITIONS

The following definitions apply in this Agreement except to the extent any term is separately defined for purposes of a specific section. The words **"we," "our,"** and **"us"** mean **U.S. Bank National Association ("U.S. Bank").** We are a national bank. We are owned by **U.S. Bancorp.**

**U.S. Bancorp and U.S. Bank** own or control other companies, directly and indirectly. The members of this family of companies are our **"affiliates."**

The words **"you"** and **"your"** mean each account owner and anyone else with authority to deposit, withdraw, or exercise control over an account. If there is more than one owner, then these words mean each account owner separately, and all account owners jointly.

The term **"account"** means any savings, transaction (for example, checking, NOW Account), and time deposit (for example, certificate of deposit or CD) account or other type of account you have with us, wherever held or maintained.

An **"owner"** is one who has the power to deal with an account in his, her or its own name. An **"agent,"** in contrast, is one whose power to withdraw from an account comes from, or is on behalf of, the owners. Authorized signers, designated corporate officers, trustees, attorneys-in-fact, and convenience signers are examples of agents.

Entities such as corporations, limited liability companies, partnerships, estates, conservatorships, and trusts are not natural persons, and can only act through agents. In such cases, it is the **"entity"** that is the owner.

**"Personal accounts"** are consumer accounts in the names of natural persons (individuals). They are to be distinguished from **"non-personal accounts"** which are accounts in the name of businesses, partnerships, trusts and other entities.

Except where it is clearly inappropriate, words and phrases used in this document should be interpreted so the singular includes the plural and the plural includes the singular.

### CELLULAR PHONE CONTACT POLICY

**By providing us with a telephone number for a cellular phone or other wireless device, including a number that you later convert to a cellular number, you are expressly consenting to receiving communications—including but not limited to prerecorded or artificial voice message calls, text messages, and calls made by an automatic telephone dialing system—from us and our affiliates and agents at that number. This express consent applies to each such telephone number that you provide to us now or in the future and permits such calls for non-marketing purposes. Calls and messages may incur access fees from your cellular provider.**

"you" includes, without limitation, your revocable trust, any partnership in which you are a general partner, any prior or successor entity by way of an entity conversion, and any other series of your series limited liability company (as applicable). In addition to this legal right, you give us and our affiliates the contractual right to apply, without demand or prior notice, all or part of the property (including money, certificates of deposit, securities and other investment property, financial assets, etc.) in your accounts, against any debt any one or more of you owe us or our affiliates. If your account is a joint account, you agree we may consider each joint owner to have an undivided interest in the entire account, so we may exercise our contractual right of setoff against the entire account. This includes, for example, debts that now exist and debts that you may incur later, your obligations under a guaranty, and also includes all fees you owe us or our affiliates. We will not be liable to you if enforcing our rights of setoff against your account(s) leaves insufficient funds to cover outstanding items or other obligations. You agree to hold us harmless from any claim arising as the result of our enforcement of our rights of setoff in, or enforcement of our rights of setoff against, your account(s).

Our contractual right of setoff does not apply:

1. to an account that is an IRA or other tax-deferred retirement account;
2. to a debt that is created by a consumer credit transaction under a credit card plan (but this does not affect our rights under any consensual security interest); or
3. if our records demonstrate to our satisfaction that the right of withdrawal that a depositor/debtor has with us only arises in a representative capacity (for example, only as an authorized signer, attorney-in-fact or a fiduciary) for someone else.

This right of setoff is in addition to any security interest that we or an affiliate of ours might have in your deposit account.

**SECURITY INTEREST IN ACCOUNTS**

You grant to us and our affiliates, a security interest in all your accounts with us, and all property in your accounts (including money, certificates of deposit, securities and other investment property, financial assets, etc.), to secure any amount you owe us or our divisions, department, and affiliates, now or in the future. This includes, for example, debts that now exist and debts that you may incur later, your obligations under a guaranty, and also includes all fees you owe us or our affiliates. For purposes of this section, "account" includes any account you have with us or any of our affiliates (including, without limitation, agency, custody, safekeeping, securities, investment, brokerage, and revocable trust accounts) and "you" includes, without limitation, your revocable trust, any partnership in which you are a general partner, any prior or successor entity by way of an entity conversion, and any other series of your series limited liability company (as applicable). In order to provide us and our affiliates with control over your account and all property in your account for purposes of perfecting the security interest granted above, you agree that we shall comply with any and all order, notices, requests and instructions originated by us or any of our affiliates directing disposition of the funds in your account without any further consent from you, even if such instructions are contrary to your instructions or demands or result in our dishonoring items which are presented for payment.

If your account is a joint account, you agree we may consider each joint owner to have an undivided interest in the entire account, so we may exercise our security interest against the entire account. We may enforce our security interest without demand or prior notice to you. You agree, for purposes of this security interest, that our affiliates may comply with any instructions we give them regarding your accounts held with them, without further consent. You also agree that we may comply with any instructions regarding your accounts that we receive from our affiliates pursuant to a security interest they have in your accounts with us. We will not be liable to you if enforcing our security interest against your account(s) leaves insufficient funds to cover outstanding items or other obligations.

You agree to hold us harmless from any claim arising as the result of our security interest in, or enforcement of our security interest against, your account(s).

**SECURITY**

It is your responsibility to protect the account numbers, including card numbers and electronic access devices (e.g., an ATM card, debit card, username and password or PIN) we provide to you for your account(s). Do not discuss, compare, or share information about your account number(s) with anyone unless you are willing to give him or her full use of your money. An account number can be used by thieves to encode your number on a false demand draft which looks like and functions like an authorized check.

If you furnish your access device and grant actual authority to make transfers to another person (a family member, coworker or employee, for example) who then exceeds that authority, you are liable for the transfers unless we have been notified that transfers by that person are no longer authorized.

Your account number can also be used to electronically remove money from your account. If you provide your account number in response to a telephone solicitation for the purpose of making a transfer (to purchase a service or merchandise, for example), payment can be made from your account even though you did not contact us directly and order the payment.

You must also take precaution in safeguarding your blank checks. Notify us at once if you believe your checks have been lost or stolen. As between you and us, if you are negligent in safeguarding your checks, you must bear the loss entirely yourself or share the loss with us (we may have to share some of the loss if we failed to use ordinary care and if we substantially contributed to the loss).

We reserve the right to place a hold on your account if we suspect irregular, fraudulent, unlawful or other unauthorized activity involved with your account. We may attempt to notify you of such a hold, but we are not required to provide notice prior to placing the hold. You agree that we may maintain such a hold until all claims against you or us to the funds held in your account, whether civil or criminal in nature, have been resolved fully in our sole satisfaction.

**ARBITRATION**

**This section does not apply to any dispute in which the amount in controversy is within the jurisdictional limits of, and is filed in, a small claims court. This Arbitration Provision shall not apply to a party who is a covered borrower under the Military Lending Act. These arbitration provisions shall survive closure of your account or termination of all business with us. If any provision of this section is ruled invalid or unenforceable, this section shall be rendered null and void in its entirety.**

**Arbitration Rules: In the event of a dispute relating to or arising out of your account or this Agreement, you or we may elect to arbitrate the dispute. At your election, the arbitration shall be conducted by either JAMS or the American Arbitration Association ("AAA") (or, if neither of these arbitration organizations will serve, then a comparable substitute arbitration organization agreed upon by the parties or, if the parties cannot agree, chosen by a court of competent jurisdiction). If JAMS is selected, the arbitration will be handled according to its Streamlined Arbitration Rules unless the Claim is for $250,000.00 or more, in which case its Comprehensive Arbitration Rules shall apply. If the AAA is selected, the arbitration will be handled according to its Commercial Arbitration Rules. You may obtain rules and forms for JAMS by contacting JAMS at 1.800.352.5267 or www.jamsadr.com and for the AAA by contacting the AAA at 1.800.778.7879 or www.adr.org. Any arbitration hearing that you attend will take place in the federal judicial district in which you reside. Without regard to which arbitration body is selected to resolve the dispute, any disputes between you and us as to whether your claim falls within the scope of this arbitration clause shall be determined solely by the arbitrator, and not by any court.**

**Arbitration Process: Arbitration involves the review and resolution of the dispute by a neutral party. The arbitrator's decision will generally be final and binding. At your request, for claims made to consumer accounts, we will advance your filing and hearing fees for any claim you may file against us; the arbitrator will decide whether we or you will ultimately be responsible for those fees. Arbitration can only decide our or your dispute and cannot consolidate or join claims of other persons who may have similar claims. There will be no authority or right for any disputes to be arbitrated on a class action basis.**

**Effects of Arbitration: If either of us chooses arbitration, neither of us will have the right to litigate the dispute in court or have a jury trial. In addition, you will not have the right to participate as a representative or member of any class of claimants, or in any other form of representative capacity that seeks monetary or other relief beyond your individual circumstances, pertaining to any dispute subject to arbitration. There shall be no authority for any claims to be arbitrated on a class action or any other form of representative basis. Arbitration can only decide your or our claim, and you may not consolidate or join the claims of other persons who may have similar claims, including without limitation claims for public injunctive or other equitable relief as to our other customers or members of the general public. Any such monetary, injunctive, or other equitable relief shall be limited solely to your accounts, agreements, and transaction with us. Notwithstanding the foregoing, any question as to the validity and effect of this class action waiver shall be decided solely by a court of competent jurisdiction, and not by the arbitrator.**

**ATTORNEY'S FEES**

Where used, "attorney's fees" includes our attorney's fees, court costs, collection costs, and all related costs and expenses. Notwithstanding any provision in this Agreement to the contrary, any provision for attorney's fees in this Agreement shall not be enforceable in any dispute governed by the laws of California or Oregon.

## FUNDS AVAILABILITY: YOUR ABILITY TO WITHDRAW FUNDS – ALL ACCOUNTS

This funds availability policy applies to deposits into a checking or savings account made at a branch or ATM. This policy may not apply to deposits made remotely through a mobile or other electronic device.

Some sections of this disclosure apply to all accounts and all customers. There are special sections for New Accounts, Commercial Accounts, Wealth Management Accounts and Retail Consumer and Business Accounts. We will make that clear in the section headings.

Funds "availability" means your ability to withdraw funds from your account, whether those withdrawals are to be in cash, by check, automatic payment, or any other method we offer you for access to your account. If deposited funds are not "available" to you on a given day, you may not withdraw the funds in cash and we may not use the funds to pay items that you have written or honor other withdrawals you request. If we pay items that you have written or honor other withdrawals before funds are available to you, we may charge a fee for this. Please review the product pricing information brochure for information regarding overdraft fees associated with your accounts.

Please remember that even after the item has "cleared," we have made funds available to you, and you have withdrawn the funds, you are still responsible for items you deposit that are returned to us unpaid and for any other problems involving your deposit. See our **Returned Deposited and Cashed Items** section.

**DETERMINING THE AVAILABILITY OF A DEPOSIT – ALL ACCOUNTS**
The day funds become available is determined by counting business days from the day of your deposit. Every day is a business day except Saturdays, Sundays, and federal holidays. If you make a deposit in person before our "cutoff time" on a business day we are open, we will consider that day to be the day of your deposit for purposes of calculating when your funds will become available. However, if you make a deposit after the cutoff time, or on a day we are not open, we will consider that the deposit was made on the next business day we are open.

**Our cutoff times vary from branch to branch. The earliest cutoff time at any of our branches is 2:00 p.m. (local time at the branch).**

In addition, cutoff times may also vary depending on whether it is a deposit envelope ATM or a no deposit envelope ATM. If you make a deposit before 6:00 p.m. (local time, at the ATM location) for a deposit envelope ATM or before 8:00 p.m. (local time, at the ATM location) for a no deposit envelope ATM on a business day we are open, we will consider that day to be the day of your deposit. If you make a deposit at a deposit envelope ATM on or after 6:00 p.m. (local time), or on or after 8:00 p.m. (local time) for a no deposit envelope ATM or on a day we are not open, we will consider the deposit to be made on the next business day we are open.

Deposits you send by mail are considered deposited on the business day it arrives if it arrives by the cutoff time at the branch of deposit. In all cases, availability of any deposit assumes that a requested withdrawal will not overdraw the account.

**IMMEDIATE AVAILABILITY – ALL ACCOUNTS**
The following types of deposits will usually be available for withdrawal immediately under normal circumstances:

- Cash (if deposited in person to an employee of ours);
- Electronic direct deposits;
- Wire transfers; and
- The first $200.00 from the total of all other deposits made on any given day.

Cash and wire transfer deposits are subject to the **Special Rules for New Accounts** and the $200.00 availability is subject to the rule in the section titled **Longer Delays May Apply.**

**LONGER DELAYS MAY APPLY**

**Government Checks, Cashier's Checks, and Other Types of Special Checks.** If you make a deposit of one of the following items in person to one of our employees, our policy is to make the funds from those deposits available no later than the first business day after the day of deposit:

- State and local government checks that are payable to you;
- Cashier's, certified, and teller's checks that are payable to you; and
- Federal Reserve Checks, Federal Home Loan Checks, and U.S. Postal Money orders that are payable to you.

If you do not make your deposit in person to an employee of the bank (for example, if you mail us the deposit), funds from these deposits may be available no later than the second business day after the day of deposit. However, we may delay funds for a longer period of time, see section titled **Longer Delays May Apply – Safeguard Exceptions.**

**Case-by-Case Delays.** In some cases, we will not make all of the funds that you deposit available to you as provided above. Depending on the type of check that you deposit, funds may not be available until the second business day after the day of your deposit. The first $200.00 of your deposit, however, will be available no later than the first business day after the day of deposit, and usually immediately.

If we are not going to make all of the funds from your deposit available on the first business day, we will notify you at the time you make your deposit. We will also tell you when the funds will be available. If your deposit is not made directly to one of our employees (including a deposit made at an ATM) or if we decide to take this action after you have left the premises, we will mail you the notice by the day after we receive your deposit.

If you will need the funds from a deposit right away, you should ask us when the funds will be available.

**Safeguard Exceptions.** In addition, funds you deposit by check may be delayed for a longer period under the following circumstances:

- We believe a check you deposit will not be paid.
- You deposit checks totaling more than $5,000.00 on any one day.
- You redeposit a check that has been returned unpaid.
- You have overdrawn your account repeatedly in the last six months.
- There is an emergency, such as failure of computer or communications equipment.

We will notify you if we delay your ability to withdraw funds for any of these reasons, and we will tell you when the funds will be available. They will generally be available no later than the seventh business day after the day of your deposit.

**RETAIL CONSUMER, BUSINESS
AND COMMERCIAL ACCOUNTS**
Our general availability policy for these accounts is to make funds available to you on the first business day after the day of deposit. We generally make some portion of a day's deposits available for withdrawal immediately. See the previous section for the types and amounts of deposits that are available immediately.

**WEALTH MANAGEMENT ACCOUNTS**
Our general availability policy for **Private Client Accounts** is to make funds you deposit available to you immediately. This immediate availability policy includes all deposits at any ATM. The section above titled **Longer Delays May Apply** also applies to your accounts. If we impose a delay as provided in that section, then the sections titled **Cashing Checks** and **Other Accounts** may also apply.

**DEPOSITS AT AUTOMATED TELLER MACHINES – RETAIL CONSUMER, BUSINESS AND COMMERCIAL ACCOUNTS**

**Our Machines.** If you make a deposit at an ATM identified as ours with the U.S. Bank name, your deposit will generally be available on the first business day after the day of deposit. However, in certain circumstances, and at U.S. Bank's discretion, the funds may not be available until the second business day after the day of deposit.

**Other Machines.** Generally, deposits at an ATM that is not identified as ours with the U.S. Bank name are not permitted. If we permit a deposit at an ATM that is not identified as ours with the U.S. Bank name, your deposit will not be available until the fifth business day after the day of deposit.

**SPECIAL RULES FOR NEW ACCOUNTS – RETAIL CONSUMER AND BUSINESS ACCOUNTS**
If you are a new customer, the following special rules will apply during the first 30 days your account is open.

Funds from electronic direct deposits and deposits of cash and wire transfers to your account will be available on the day we receive the deposit. The first $5,000.00 of a day's total deposits of cashier's, certified, teller's, traveler's, on-us checks (checks drawn on U.S. Bank), and federal, state and local government checks will be available on the first business day after the day of your deposit if the deposit meets certain conditions. For example, the checks must be payable to you (and you may have to use a special deposit slip). The excess amount over $5,000.00 will be available on the fifth business day after the day of your deposit. If your deposit of these checks (other than a U.S. Treasury check) is not made in person to one of our employees, the first $5,000.00 will not be available until the second business day after the day of your deposit.

Funds from all other check deposits will generally be available on the fifth business day after the day of your deposit. In certain instances, we may hold funds from other check deposits for longer than five business days. For example, if we receive a check that falls within the Safeguard Exception description above, we may delay funds for up to seven business days. If we do so, we will provide you with a hold notice at the time of deposit or when we learn that we will hold the funds from the deposit.

**CASHING CHECKS**
If we cash a check for you that is drawn on another bank, we may withhold the availability of a corresponding amount of funds that are already in your account. Those funds will be available at the time funds from the check we cashed would have been available if you had deposited it.

**OTHER ACCOUNTS**
If we accept for deposit a check that is drawn on another bank, we may make funds from the deposit available for withdrawal immediately but delay your availability to withdraw a corresponding amount of funds that you have on deposit in another account with us. The funds in the other account would then not be available for withdrawal until the day the deposited item would have been available, which will usually be the first business day after the day of deposit.

EFFECTIVE JANUARY 1, 2018

# Business Accounts & Services and Transaction Banking Services

## Disclosure and Agreement

MUFG UnionBank

EFFECTIVE JANUARY 1, 2018

# Business Accounts & Services

## Disclosure and Agreement

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## INTRODUCTION

Welcome to MUFG Union Bank, N.A. ("Union Bank"). Your account is backed by the reputation and resources of one of the largest banks on the West Coast, as well as by coverage of the Federal Deposit Insurance Corporation (FDIC) to permissible limits.

Most accounts may be accessed in person at a Union Bank® branch location, through Online Banking or Telephone Banking, or by using your ATM Card or Union Bank Debit Mastercard BusinessCard® ("Debit Card"). Not all accounts and services are offered at all times at every Union Bank branch for all account types.

This *Business Account & Services and Transaction Banking Services Disclosure and Agreement* also known as *All About Business Account & Services and Transaction Banking Services Disclosure and Agreement*, Bank Depositor Agreement (signature card), applicable fee schedule, other related documents we may provide you, and any amendments contain the terms of our agreement ("Account Agreement") with you for your account and any related services. This Account Agreement supersedes all previous agreements related to its subject matter including any oral or written communication. Except as otherwise stated, this Account Agreement does not alter or amend the terms or conditions of any other agreement you have with us.

### Business Accounts

Business accounts are those accounts used for other than personal, family, or household purposes.

### Customer Identification

To help the government fight money laundering and the funding of terrorism, federal law requires all financial institutions to obtain, verify, and record information that identifies each customer (individual(s) and/or entity(ies)) that opens an account, and to understand the anticipated activity of the account.

*What this means:* When you open an account, we will ask for information on the legal formation for your entity, such as name, address, and a tax identification number. We will ask your name, address, date of birth, and other information that will allow us to identify you and others authorized to use the account. We will ask to see a driver's license or other identifying documents. We may also ask for information about the ownership structure of your entity(ies) such as individuals with ownership and control over the entity.

We may further ask you for specific information regarding the nature of anticipated activity, the sources of your funds, the purposes of transactions, the anticipated frequency of such transactions, the relationship you have with persons to whom you send funds and the persons who send funds to you, the

English. We may decline to process any instruction written in a language other than English, whether issued by you or another person.

### Facsimile Signatures

*What is a facsimile signature:* A facsimile signature is a procedure or mechanism that causes any check to be drawn on your account with a typed signature, facsimile signature, notation, mark, or other form of mechanical symbol, rather than your actual handwritten signature.

*What we require for their use:* You agree not to use facsimile signatures on checks unless you provide us with representative samples and we approve their use.

*About paying facsimile Items:* We may refuse to accept or may pay Items bearing facsimile signatures at our discretion.

*What you're responsible for:*

- You agree to assume full responsibility for any and all payments made by us when we rely on signatures that resemble the actual or facsimile signature(s) you provided (without regard to variation in color or size) in connection with your accounts or services.
- You authorize us to pay any check that appears to bear your authorized facsimile signature, including, but not limited to, Items created by you that display a computer-generated signature (regardless of whether you provided us with a representative sample) without further inquiry.
- You agree to indemnify, defend, and hold us harmless from any and all actions, claims, losses, damages, liabilities, costs, and expenses (including attorneys' fees) arising directly or indirectly from the misuse or the unlawful or unauthorized use or copying of facsimile signatures (whether affixed manually, by stamp, mechanically, electronically, or otherwise).

### Funds Availability Policy

***Your Ability to Withdraw Funds –*** Our policy is to make funds from your cash and check deposits available to you on the 1st Business Day after the Business Day we receive your deposit. Electronic direct deposits will be available on the day we receive the deposit. Once they are available, you can withdraw the funds in cash, and we will use the funds to pay checks that you have written, or other Items presented against your account. Please keep in mind, however, that after we make funds available to you and you have withdrawn the funds, you are still responsible for checks you deposit that are returned to us unpaid.

For determining the availability of your deposits, every day is a Business Day except Saturdays, Sundays, and federal holidays.

If you make a deposit before the close of business on a Business Day that we are open, or otherwise state as our Business Day, we will consider that day to be the day of your deposit. If you make a deposit on a Business Day at one of our ATMs before 9:00 p.m. Pacific Time, we will consider that day to be the day of your deposit. However, if you make a deposit after this hour or on a day that is not considered a Business Day, we will consider that the deposit was made on the next Business Day we are open.

This *Funds Availability Policy* also does not apply to checks deposited other than at a staffed facility at the Bank, at a Union Bank ATM, night depository, lockbox, Express kiosk, or by mail addressed to Union Bank.

This *Funds Availability Policy* does not apply to checks drawn on banks located outside the United States, checks drawn in a foreign currency, or to checks deposited using Mobile Banking or Remote Deposit Service.

***Longer Delays May Apply –*** In some cases, we will not make all of the funds that you deposit by check available to you on the 1st Business Day after the day of your deposit. Depending on the type of check that you deposit, funds may not be available until the 2nd Business Day after the day of your deposit. The first $200 of your deposit, however, will be available on the 1st Business Day after the day of your deposit.

If we are not going to make all of the funds from your deposit available on the 1st Business Day after the day of your deposit, we will notify you at the time you make your deposit. We will also tell you when the funds will be available. If your deposit is not made directly to one of our employees, or if we decide to take this action after you have left the premises, we will mail you the notice by the Business Day after we receive your deposit. If you will need the funds from a deposit right away, you should ask us when the funds will be available.

In addition, some or all of the funds you deposit by check may be delayed for a longer period under the following circumstances:

- We believe a check you deposit will not be paid.
- You deposit checks totaling more than $5,000 on any one day.
- You redeposit a check that has been returned unpaid.
- You have overdrawn your account repeatedly in the last 6 months.
- There is an emergency, such as failure of computer or communications equipment, that prevents us from making your deposit available to you under the timeframes set forth in our *Funds Availability Policy.*

We will notify you if we delay your ability to withdraw funds for any of these reasons, and we will tell you when the funds will be available. They will generally be available no later than the 7th Business Day after the Business Day of your deposit.

***Special Rules for New Accounts –*** If you are a new customer, the following special rules will apply during the first 30 days your account is open.

Funds from electronic direct deposits to your account will be available on the day we receive the deposit. Funds from deposits of cash, wire transfers, and the first $5,000 of a day's total deposits of cashier's, certified and teller's checks, and federal, state and local government checks will be available on the 1st Business Day after the day of your deposit if the deposit meets certain conditions.

For example, the checks must be payable to you. The excess over $5,000 will be available on the 7th Business Day after the day of your deposit. If your deposit of these checks (other than a U.S. Treasury check) is not made in person to one of our employees, the first $5,000 will not be available until the 2nd Business Day after the day of your deposit. Funds from all other check deposits will be available on the 7th Business Day after the day of your deposit.

### Remote Deposit Service

Generally, funds representing a deposit using Remote Deposit Services, will be available for withdrawal the Business Day after deposit if the remote check deposit is made prior to 8:00 p.m. Remote check deposits made on a non-Business Day will generally be available on the 1st Business Day after the Business Day of deposit. However, in some cases, we may delay funds availability up to the 2nd Business Day after the Business Day of your deposit. We will notify you (e.g., by email or text) if we delay availability of your deposit. Funds availability rules set forth in Federal Reserve Regulation CC do not apply to checks deposited using Remote Deposit Services. See the *Business Accounts & Services and Transaction Banking Services Disclosure and Agreement* for more information.

### Mobile Check Deposits

Generally, funds representing a deposit using Mobile Check Deposit will be available to you on the 1st Business Day after the Business Day the deposit is received if the mobile check deposit is made prior to 9:00 p.m., Pacific Time. Mobile check deposits made on a non-Business Day will generally be available on the 1st Business Day after the Business Day the deposit is received. However, in some cases, we may delay funds availability up to the 7th Business Day after the Business Day the deposit is received. We will notify you (e.g., by email or text) if we delay availability of your deposit. Funds availability rules set forth in Federal Reserve Regulation CC do not apply to checks deposited using Mobile Check Deposit. See your *Online Banking Service Agreement* for more information.

We may, at our sole discretion, also hold funds you deposit for any reason necessary that we believe would limit your and/or our losses.



Each check deposited through a mobile device will count as one Combined Transaction.

### Governing Law

To the extent this Account Agreement is subject to the laws of any state, it will be subject to the law of the state where your account is maintained, without regard to its conflict of laws principles. Your accounts and services also will be subject to applicable clearinghouse, Federal Reserve Bank, funds transfer system, image exchange, and correspondent bank rules ("Rules"). You agree that we do not have to notify you of a change in the Rules, except to the extent required by law. If there is any inconsistency between the terms of this Account Agreement and the Rules, the terms of this Account Agreement shall supersede the Rules, unless prohibited by the Rules.

### Inactive Accounts and Unclaimed Property

Accounts become inactive when there has been no transaction or positive contact with us for a certain period of time, as follows:

- 12 consecutive months for transaction (demand deposit) accounts
- 18 consecutive months for savings accounts
- 24 months after the first maturity date or date of last customer contact for time deposit accounts

Positive contact will prevent an account from becoming inactive. Types of positive contact include:

- A deposit or withdrawal performed by you to or from the account. This does not include Bank-initiated transactions, such as service charges, interest payments, or automated deposits and withdrawals.
- Correspondence electronically or in writing concerning the account.
- A signed letter from you relating to the account's disposition.
- An indication from you of your interest in the account, such as contacting us to state your intention to maintain the account, or another record on file with us.

The inactive period begins on the date of the last transaction, last positive contact with us, or first maturity of a time deposit, whichever is latest. We may refuse to post any transactions to an inactive account unless we can confirm that you initiated the transaction. All inactive interest-earning accounts continue to earn interest, except for time deposit accounts that do not automatically renew. Service charges for inactive accounts are the same as those for active accounts. Charges are not reimbursed for inactive accounts that are later reclassified as active. Also, we may change the delivery of account statements for inactive accounts.

You may receive a written notice that your funds may be surrendered to a state government due to inactivity. The requirement to send a notice is based on the account balance

Effective February 2018

# Deposit Agreement and Disclosures

## Facts about corporate and commercial deposit account programs

Welcome to Bank of America Merrill Lynch, and thank you for opening an account with us. When you open a corporate deposit account with us, you agree to the terms and conditions discussed in this publication. Please read this publication carefully and keep it for your records. Throughout this publication, the words "you," "your" and "yours" refer to the accountholder(s). "We," "us" and "our" refer to Bank of America, National Association.

Bank of America Merrill Lynch

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### Foreign currency checks

You may not write checks or give other withdrawal orders on your account, which order payment in foreign currency. If we receive such a check or order, we may refuse to accept or process it without any liability to you.

### Foreign exchange transactions

If we assign a currency exchange rate to your foreign exchange transaction, such exchange rate will be determined by us based upon market conditions. We consider many factors in setting our exchange rates, including and without limitation: exchange rates charged by other parties, desired rates of return, market risk and credit risk. You acknowledge that exchange rates for retail and commercial transactions, and for transactions effected after regular business hours and on weekends, are different from the exchange rates for large inter-bank transactions effected during the business day, as reported in The Wall Street Journal or elsewhere. Exchange rates offered by other dealers, or shown at other sources (including online sources) may be different from our rates. We do not accept any liability if our rates are different from rates offered or reported by third parties, or offered by us at a different time, at a different location, for a different transaction amount, or involving a different payment media (bank-notes, checks, wire transfers, etc.).

### Funds availability: When funds are available for withdrawal

We may negotiate a separate funds availability agreement with you. If we do not do so, then the following funds availability terms will apply to your account.

**Your ability to withdraw funds.** Our policy is to make funds from electronic direct deposits and incoming wire transfers available to you on the day we receive the deposit. Our general policy is to make funds from check deposits available to you no later than the first business day after the day we receive your deposit, when the check is drawn on a financial institution within the same local Federal Reserve district. Check deposits drawn on financial institutions in other districts may be made available on subsequent days. Once they are available, you can withdraw the funds in cash; and we will use the funds to pay checks that you have written. For determining the availability of your deposits, every day is a business day, except Saturdays, Sundays, and federal holidays.

If you make a deposit at a banking center before 2:00 p.m. local time, or such later time as may be posted at that banking center, on a business day that we are open, we consider that day to be the day of your deposit. However, if you make a deposit in a banking center after such time, or on a day when we are not open, we consider that the deposit was made on the next business day we are open.

Other deadlines may apply for deposits made through other channels.

**Government, official and other special types of checks.** If you make a deposit in person to one of our employees, and meet the other conditions noted below, our policy is to make funds from the following types of deposits available no later than the first business day after the day of your deposit:

- U.S. Treasury checks that are payable to you
- State and local government checks that are payable to you and are deposited to an account in the same Federal Reserve District that issued the check
- Cashier's, certified and teller's checks that are payable to you

**Other delays may apply.** There are other situations that may affect funds availability. Depending on the type of check that you deposit, we may place a hold on certain checks and not make funds available until the fifth business day after the day of your deposit. In such a case, we generally notify you at the time you make your deposit. We also tell you when the funds will be available. If your deposit is not made directly to one of our employees, or if we decide to take this action after you have left the premises, we mail you the notice by the next business day after we receive your deposit.

If you need the funds from a deposit right away, you should ask us when the funds will be available.

In addition, we may delay the availability of funds you deposit by check for a longer period under the following circumstances:

- We believe a check you deposit will not be paid.
- You deposit checks totaling more than $5,000 on any one day.
- You redeposit a check that has been returned unpaid.
- You have overdrawn your account repeatedly in the last six months.
- There is an emergency, such as failure of communications or computer equipment.

We will notify you if we delay your ability to withdraw funds for any of these reasons, and we will tell you when the funds will be available. They will generally be available no later than the eleventh business day after the day of your deposit.

**Cash withdrawal limitation.** If we delay availability of your deposit, we place certain limitations on withdrawals in cash or by similar means. In general, $200 of a deposit is available for withdrawal in cash or by similar means no later than the first business day after the day of deposit. In addition, a total of $400 of other funds becoming available on a given day is available for withdrawal in cash or by similar means at or after 5:00 p.m. on that day. Any remaining funds will be available for withdrawal in cash or by similar means on the following business day.

Similar means include electronic payment, issuance of a cashier's or teller's check, certification of a check, or other irrevocable commitment to pay, such as a debit card transaction.

**Holds on other funds.** If we cash a check for you that is drawn on another financial institution, we may withhold the availability of a corresponding amount of funds that are already in your account. If we accept for deposit a check that is drawn on another financial institution, we may make funds from the deposit available for withdrawal immediately but delay your ability to withdraw a corresponding amount of funds that you have on deposit in another account with us. In either case, we make these funds available in accordance with our policy described above for the type of check that was cashed or deposited.

**Special rules for new accounts.** If you are a new customer, the following special rules may apply during the first 30 days after the account is open.

Funds from electronic direct deposits to your account are available on the day we receive the deposit. Funds from deposits of cash, wire transfers, and the first $5,000 of a day's total deposits of cashier's, certified, teller's, traveler's, and federal, state and local government checks are available no later than the first business day after the day of your deposit, if the deposit meets certain conditions. For example, the checks must be payable to you and deposited in person to one of our employees. The excess over $5,000 is available by the ninth business day after the day of your deposit. If your deposit of these checks (other than a U.S. Treasury check) is not made in person to one of our employees, the first $5,000 will not be available until the second business day after the day of your deposit. Funds from all other check deposits are generally available by the ninth business day after the day of your deposit. However, we may place longer holds on certain items for other reasons, such as large deposits. (See "Other delays may apply" in this section.)

## Funds transfer services

A funds transfer is the process of carrying out a payment order that leads to paying a beneficiary. The payment order is the set of instructions you give or we receive regarding a funds transfer. The beneficiary is the person who receives the payment.

The following provisions apply to funds transfers you send or receive through us. If you have a specific



agreement with us for these services, these provisions supplement but do not contradict that agreement. The terms "funds transfer," "payment order" and "beneficiary" are used here as they are defined in Article 4A of the Uniform Commercial Code – Funds Transfers, as adopted by the state whose law applies to the account for which the funds transfer service is provided.

We may charge fees for sending or receiving a funds transfer. These fees are described in the list of charges we may make available to you.

If you transfer funds in U.S. dollars to a non-U.S. dollar account, your payment may be converted into the local currency of the non-U.S. dollar account by an intermediary bank or the receiving bank (and we may receive compensation in connection with any such conversion.)

**Fedwire.** Fedwire is the electronic funds transfer system of the U.S. Federal Reserve Banks. When you send a payment order or receive a funds transfer, we or other banks involved in the funds transfer may use Fedwire. If any part of a funds transfer is carried out by Fedwire, your rights and obligations are governed by Regulation J of the U.S. Federal Reserve Board.

**Sending funds transfers.** You may subscribe to certain services we offer, or you may give us other instructions to pay money or have another bank pay money to a beneficiary.

This "Sending funds transfers" section applies to wire transfers and transfers we make between Bank of America accounts. It does not apply to Automated Clearing House ("ACH") system funds transfer services. You may only give us payment orders for ACH system funds transfers (where ACH services are available) if you have a separate agreement with us for these services. For blocking or filtering ACH receipts, see "Automated Clearing House (ACH) blocks and filters services" in this Agreement.

You are solely responsible for ensuring that payment instructions that are sent on your behalf are valid instructions authorized by your organization. While we may in some circumstances implement internal controls to monitor customer payments, including mechanisms that may evaluate the risk of possible fraudulent activity, such monitoring is done solely at our discretion and is not a component of the Security Procedures. You hereby acknowledge that we do not guarantee or ensure that such monitoring will be effective in preventing frauds against your accounts and agree that we may process payments verified by the Security Procedure regardless of the results of transaction monitoring. We will be considered to have acted in good faith and in compliance with the Security Procedures, regardless of the results of transaction monitoring.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 64**

**Responding Witness: William Steven Seelye**

Q-64. Refer to Exhibit WSS-36 which presents the individual revenue lags and expense leads developed for each Company.

a. For each item with an expense lead of 0 (e.g., pension and OPEB expense, depreciation, amortization, and deferred taxes), clarify whether the intention is to reflect an exclusion from cash working capital or an actual expense lead of 0 days in the computation.

b. If the item with an expense lead of 0 should be reflected in the computation as shown in Schedule B-5.2, explain and provide supporting workpapers for the determination of 0 days.

A-64.

a. The intention of including an expense lead of 0 for the referenced items shown on Exhibit WSS-36 is to exclude these items from the calculation of cash working capital.

b. See the response to part a.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 65**

**Responding Witness: Christopher M. Garrett**

Q-65. What is the statutory payment date(s) for the KPSC Assessment?

A-65. The statutory payment date for the KPSC Assessment is July 31st of the KPSC's upcoming fiscal year (July 1st of the current year through June 30th of the following year).

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 66**

**Responding Witness: Christopher M. Garrett**

Q-66. What are the statutory payment dates for sales tax, school tax, and franchise fees?

A-66. Per 103 KAR 25:131 - The sales tax for a large taxpayer, which is defined as averaging a monthly sales and use tax liability exceeding $10,000, is required to be remitted by the 25th of each month.

Per Kentucky Revised Statute 160.615 - The school tax is due and payable monthly on or before the twentieth day of the next succeeding calendar month.

There are no statutory payment dates for franchise fees. The payment dates for franchise fees are agreed upon and specified by each municipality and KU when executing a franchise agreement.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 67**

**Responding Witness:**

Q-67. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO MAINTAIN NUMBERING WITH CASE NO. 2018-00295]

A-67. Not applicable.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 68**

**Responding Witness: Daniel K. Arbough**

## D. Operating Revenues

Q-68. Refer to Schedule C-1, sponsored by Chris M. Garrett, in which "Electric Sales Revenue" is proposed to increase, but "Other Operating Revenues" is proposed to decrease.

a. Explain why it is reasonable to assume Other Operating Revenues will decrease in the forecasted test period.

A-68.

a. It is reasonable to assume that Other Operating Revenues will decrease in the forecasted period based on:

- The initial adjustment to the "Forecasted Adjustments At Current Rates" (Column 2 on Schedule C-1) is a reduction primarily due to the decrease in transmission revenues as a result of the TCJA and the lower historic trending average experienced in these accounts as explained on Schedule D-1 page 1 of 9.

- Furthermore, the reduction reflected in the "Proposed Increase" (Column 4) is primarily related to the proposed change in the late payment charge (see support at Exhibit WSS-14), the reduction in the proposed return check fee (see support at Exhibit WSS-18) and the reduction in the rate for excess facilities (see support at Exhibit WSS-16).

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 69**

**Responding Witness: Christopher M. Garrett**

Q-69. Refer to the direct testimony of Chris M. Garrett, pages 26-27, wherein he discusses the Companies' adjustments to operating revenues "that concerns OSS revenues related to the ECR calculation." Mr. Garret notes that the adjustments were performed "in a manner generally consistent with the methodology" used in the 2009, 2012, 2014 and 2016 base rate cases.

a. Explain what differences exist between previous methodologies used in the past base rate cases cited and the methodology used in these matters.

A-69. The 2009 and 2012 cases used historical test year data and the 2014 and 2016 cases used forecast period data.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 70**

**Responding Witness: Robert M. Conroy**

Q-70. Refer to the direct testimony of Lonnie E. Bellar, page 20, wherein he describes the revenues the Companies derive from the sale of ash.

a. Explain why these revenues are reflected in the environmental surcharge mechanism and not through base rates.

A-70. The revenues related to beneficial reuse projects are included in the environmental surcharge mechanism via 2009 ECR Plan Project 33 as approved by the PSC in Case No. 2009-00197.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 71**

**Responding Witness: Daniel K. Arbough**

Q-71. Refer to the direct testimony of Lonnie E. Bellar, pages 20-21, wherein he discusses refined coal facilities and the actual or anticipated revenues from same.

a. Provide citations to the test year where the revenues or anticipated revenues from the Ghent, Trimble County and Mill Creek stations are incorporated.

b. Explain whether these revenues or anticipated revenues are reflected or anticipated to be reflected in base rates or through the environmental surcharge

A-71.

a. Refer to schedule D-1, page 1 of 8, lines 15-16, and page 2 of 8, line 23. Refined coal revenues for Ghent station are reflected in accounts 454, 456 and as an offset to expense in account 501. See the response to LG&E Case No. 2018-00295, AG Question No. 71, for LG&E station anticipated revenues.

b. Refined coal revenues are anticipated to be reflected in base rates.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 72**

**Responding Witness: David S. Sinclair**

Q-72. Reference the Bellar testimony, p. 21, wherein he discusses refined coal projects at Ghent, Trimble and Mill Creek.

a. Have the Companies been able to quantify any additional savings arising from reduced mercury and NOX emissions? If not, are the Companies aware of whether any other utilities' coal-fired generation stations utilizing similar refined coal systems have been able to achieve any such emission reductions?

b. Have the companies been able to achieve any additional savings through the Section 45 Production Tax Credit? Provide a quantification of any such savings, and indicate where in the application they can be found, and the accounting treatment afforded.

A-72.

a. No. The Companies have not performed any tests to quantify additional savings because performing such tests would be extremely difficult and imprecise in an environment with varying operating conditions (e.g., coal quality, ambient conditions, equipment performance, load levels, etc.). Prior to implementation, the Companies were able to perform tests demonstrating no adverse impacts on facility operations and their costs. The Companies are not aware of any other utilities that are quantifying additional savings.

b. The Companies are not achieving any additional savings through the tax credit.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 73**

**Responding Witness: Christopher M. Garrett**

**E. Operating Expenses**

Q-73. Refer to the direct testimony of Chris M. Garrett, page 32, wherein he discusses advertising expenses.

a. Did the Companies remove all advertising expense, or only that advertising expense that did not produce a "material benefit" to ratepayers.

b. If the response to subpart a., above, indicates the latter, provide the advertising expense not removed for ratemaking purpose, including the rationale for each expense that it produces a "material benefit" for ratepayers. If necessary, break out these expenses and explanations by utility.

A-73.

a. The Companies removed advertising related to institutional and promotional expenses and only included safety and educational advertising.

b.

| Advertising Category | Forecast Period | Benefit |
|---|---|---|
| Customer Newsletters & Direct Mailings | $ 316,400 | The customer newsletter, which is included with the bill, and other direct mailings are the primary way in which KU reaches its customer to explain items related to their service including, but not limited to, safety, saving money, reducing energy, and changes to their service. |
| Customer Education | $ 1,260,000 | KU believes it is important to ensure that customers understand how they can reduce energy and save |

| | | |
|---|---|---|
| | | money on their electric bills. In the absence of many residential demand side management programs that helped customers understand the importance of energy management, KU is educating customers on various techniques they can do on their own to reduce the amount of energy they consume. The education process comes in a variety of forms to ensure we meet our customers in their varied ways they consume information. |
| Telephone Book Listings & Customer Information | $ 225,720 | Telephone book listing and other directory services remain essential to ensuring our customers have the information they need to contact us. |
| Other Safety & Education | $ 57,028 | Safety is our number one priority and educating our customers, beginning at an early age, improves the chances that they will behave safely around electricity. |

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 74**

**Responding Witness: Lonnie E. Bellar / Daniel K. Arbough / Christopher M. Garrett**

Q-74. Refer to the direct testimony of Chris M. Garrett, page 37, wherein he states, "major outages typically occur on an eight-year cycle."

a. Provide evidence that outages occur on an eight-year cycle, rather than a shorter or longer schedule.

b. Provide the historical expenses for years 2013 through 2018 and forecasted expenses for years 2018 through 2024.

c. Explain why amortizing the regulatory deferrals over the same period as the "eight-year major outage cycle" is reasonable.

A-74.

a. See below for a list of the most recent turbine overhaul outage dates for units included in the forecasted test year. Typical time between outages is approximately 8 years, taking into consideration actual run time.

| Unit | Major Outage Dates | |
|---|---|---|
| Brown 3 | 2005 | 2012 |
| Ghent 1 | 2007 | 2015 |
| Ghent 2 | 2004 | 2012 |
| Ghent 3 | 2011 | 2018 |
| Ghent 4 | 2008 | 2014 |
| Trimble 2 | Began Commercial Operation in 2010 | 2018 |

b. See attached for 2013 through 2018 historical expenses and 2018 through 2022 forecasted expenses. Years 2023 and 2024 are outside of the eight-year cycle used to calculate the eight-year average outage expense included in the forecasted test year.

c. Outage expense included in base rates per the Company's last base rate case was set using an eight-year average of outage costs. Amortizing the deferred costs that are less than or exceed the eight-year average over an eight-year cycle is consistent with the ratemaking treatment for outage expense.

| KU Jurisdictional Generator Outage - Not normalized<br>Unit | FERC | 2013<br>Actual | 2014<br>Actual | 2015<br>Actual | 2016<br>Actual | 2017<br>Actual | 2018<br>Actual YTD October |
|---|---|---|---|---|---|---|---|
| 0321 - TRIMBLE COUNTY 2 - GENERATION | 510 | $ - | $ 170,631 | $ - | $ 246,762 | $ - | $ - |
| | 511 | - | - | 2,693 | - | - | 50,193 |
| | 512 | 1,989 | 1,992,060 | 494,326 | 1,121,821 | 1,512,181 | 3,125,979 |
| | 513 | 1,436 | 168,959 | 139,686 | 838,407 | 167,838 | 1,904,619 |
| 5591 - KU GENERATION - COMMON | 510 | 57,941 | (62,537) | - | 442 | - | - |
| | 513 | - | - | - | - | - | - |
| 5613 - GREEN RIVER UNIT 3 [1] | 500 | 13,472 | - | - | - | - | - |
| | 510 | 44,178 | - | - | - | - | - |
| | 511 | 3,813 | 34,979 | 2,722 | - | - | - |
| | 512 | 186,803 | 698,782 | 249,813 | - | - | - |
| | 513 | 12,570 | 84,493 | 7,211 | - | - | - |
| | 514 | - | - | - | - | - | - |
| 5614 - GREEN RIVER UNIT 4 [1] | 500 | 80,138 | - | - | - | - | - |
| | 511 | 24,640 | 42,034 | - | - | - | - |
| | 512 | 834,933 | 652,914 | 686,268 | - | - | - |
| | 513 | 92,316 | 81,101 | 36,934 | - | - | - |
| | 514 | 15,692 | 3,436 | 489 | - | - | - |
| 5621 - E W BROWN UNIT 1 [2] | 510 | 54,019 | - | 234,710 | - | - | 17,581 |
| | 511 | - | - | 28,185 | 2,551 | - | 1,459 |
| | 512 | 314,065 | 342,658 | 770,115 | 424,173 | 170,514 | 165,342 |
| | 513 | 39,697 | 27,379 | 2,814,425 | 746,401 | 66,619 | 56,373 |
| | 514 | | | | | | 395 |
| 5622 - E W BROWN UNIT 2 [2] | 510 | 95,776 | 155,756 | (170,598) | (7,422) | - | 86,647 |
| | 511 | - | 5,310 | - | - | 35 | - |
| | 512 | 688,190 | 519,286 | 177,554 | 524,039 | 319,321 | 146,367 |
| | 513 | 379,582 | 440,069 | 69,033 | 13,200 | 170,328 | 51,853 |
| | 514 | | | | | | 1,050 |
| 5623 - E W BROWN UNIT 3 | 510 | 140,322 | - | - | 224,361 | - | - |
| | 511 | - | - | 1,930 | - | 799 | - |
| | 512 | 352,651 | 1,072,508 | 1,002,174 | 645,014 | 793,360 | 1,222,541 |
| | 513 | 59,679 | 90,586 | 566,909 | 77,949 | 169,502 | 114,587 |
| | 514 | 1,044 | - | 5,676 | 842 | 443 | 3,546 |
| 5624 - E W BROWN UNITS 1 & 2 [2] | 512 | 12,840 | 523 | 2,156 | 1,128 | 567 | - |
| | 513 | 8,839 | - | - | 2,497 | - | - |
| | 514 | 832 | - | - | - | 756 | - |
| 5625 - E W BROWN UNITS 2 & 3 [2] | 512 | - | 8,793 | - | 25,188 | - | - |
| 5630 - E W BROWN STEAM UNITS 1,2,3 SCRUBBER [2] | 512 | 759 | 153,162 | - | 285,730 | 0 | - |
| 5651 - GHENT UNIT 1 | 510 | - | - | 701,055 | - | - | 351,731 |
| | 511 | 41,916 | 15,149 | 288,139 | 82,540 | 27,536 | 91,437 |
| | 512 | 1,967,332 | 2,150,500 | 3,921,111 | 1,365,142 | 1,722,885 | 2,829,518 |
| | 513 | 317,370 | 181,478 | 4,228,284 | 515,167 | 657,717 | 443,029 |
| | 514 | 715 | 79 | 53 | 321 | 227 | - |
| 5652 - GHENT UNIT 2 | 510 | 15,067 | - | 270,844 | 21,862 | - | - |
| | 511 | 9,231 | 24,888 | 38,347 | 44,419 | 117,136 | - |
| | 512 | 532,846 | 1,276,945 | 3,374,848 | 1,661,414 | 1,560,425 | 97,018 |
| | 513 | 99,002 | 358,005 | 748,493 | 596,452 | 582,492 | 34,505 |
| | 514 | - | - | - | - | - | - |

**Case No. 2018-00294**
**Attachment to Response to AG-1 Question No. 74(b)**

**Bellar**

| KU Jurisdictional Generator Outage - Not normalized<br>Unit | FERC | 2013<br>Actual | 2014<br>Actual | 2015<br>Actual | 2016<br>Actual | 2017<br>Actual | 2018<br>Actual YTD October |
|---|---|---|---|---|---|---|---|
| 5653 - GHENT UNIT 3 | 510 | - | 283,560 | - | - | 984 | 441,348 |
| | 511 | 5,100 | 5,342 | 330 | 38,566 | 75,058 | 227,406 |
| | 512 | 864,538 | 3,587,624 | 2,220,256 | 2,282,186 | 1,560,943 | 2,571,243 |
| | 513 | 136,085 | 292,935 | 1,030,676 | 638,626 | 375,552 | 1,615,350 |
| | 514 | - | 144 | 180 | - | - | 567 |
| 5654 - GHENT UNIT 4 | 510 | - | 707,460 | 128,295 | - | (984) | 251,063 |
| | 511 | 409 | 52,774 | 8,577 | 112,854 | 16,550 | 83,750 |
| | 512 | 889,084 | 3,420,107 | (97,614) | 1,932,458 | 1,435,331 | 2,110,098 |
| | 513 | 89,934 | 3,519,889 | 119,526 | 350,705 | 423,903 | 543,382 |
| | 514 | - | 5,325 | - | - | 3,338 | - |
| 5655 - GHENT UNITS 1 & 2 | 511 | - | - | 1,985 | - | - | - |
| | 512 | 20,421 | 8,827 | 988 | - | - | - |
| | 513 | - | 598 | 1,687 | 20,994 | - | - |
| 5656 - GHENT UNITS 3 & 4 | 511 | 129 | - | 49 | 5,884 | - | - |
| | 512 | 1,716 | 5,592 | - | - | - | - |
| | 513 | - | 618 | 769 | 311 | 702 | - |
| 0172 - CANE RUN CC GT 2016 | 549 | - | - | 51,497 | 22 | 158,408 | 20,119 |
| | 551 | - | - | - | - | - | - |
| | 552 | - | - | 5,043 | 65,558 | 116,957 | 87,597 |
| | 553 | - | - | 133,338 | 680,409 | 1,332,856 | 524,255 |
| | 554 | - | - | 56,148 | 212,949 | 247,998 | 276,674 |
| 0432 - PADDYS RUN GT 13 | 553 | 33,788 | 76,980 | 44,366 | 59,562 | 106,504 | 138,890 |
| | 554 | 315 | - | - | - | - | - |
| 0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE | 553 | - | - | - | - | 1,537 | 9,959 |
| 0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE | 553 | - | - | - | - | - | 44,136 |
| 0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE | 553 | - | - | 1,093 | - | 29,220 | 79,193 |
| 0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE | 553 | - | - | - | - | 26,928 | 15,912 |
| 0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE | 553 | - | - | - | - | - | 35,851 |
| 0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE | 553 | - | - | - | - | - | 33,406 |
| 5635 - E W BROWN COMBUSTION TURBINE UNIT 5 | 553 | - | - | - | - | 188,025 | - |
| | 554 | - | - | 12,158 | - | - | 13,673 |
| 5636 - E W BROWN COMBUSTION TURBINE UNIT 6 | 551 | - | - | - | - | - | - |
| | 552 | - | - | - | - | - | - |
| | 553 | 23,019 | 63,267 | 18,187 | 6,492 | (3,094) | - |
| | 554 | - | - | - | - | - | - |
| 5637 - E W BROWN COMBUSTION TURBINE UNIT 7 | 553 | (34,813) | 130,959 | (62,547) | 29,506 | - | - |
| 5638 - E W BROWN COMBUSTION TURBINE UNIT 8 | 553 | - | - | - | - | - | - |
| | 554 | - | - | - | - | - | 541 |
| 5639 - E W BROWN COMBUSTION TURBINE UNIT 9 | 553 | 244,891 | (14,057) | - | - | - | - |
| | 554 | - | 30,555 | - | - | - | - |
| 5640 - E W BROWN COMBUSTION TURBINE UNIT 10 | 553 | - | 23,135 | 274,447 | - | - | - |
| | 554 | - | - | 33,825 | - | - | - |
| 5641 - E W BROWN COMBUSTION TURBINE UNIT 11 | 553 | - | - | - | - | - | 148,099 |
| 5645 - E W BROWN CT UNIT 9 GAS PIPELINE | 554 | - | - | - | 141,017 | 44,490 | - |
| 5693 - HAEFLING UNIT 1 | 553 | 6,033 | 65 | - | - | - | - |
| 5694 - HAEFLING UNIT 2 | 553 | 6,033 | 65 | - | - | - | - |
| 5695 - CLOSED 03/14 - HAEFLING UNIT 3(3) | 553 | 133,418 | - | - | - | - | - |
| **Total** | | **$ 8,921,794** | **$ 22,891,690** | **$ 24,676,845** | **$ 16,038,500** | **$ 14,181,887** | **$ 20,068,282** |

**(1) Green River units 3 and 4 were retired in 2015.**
**(2) E.W. Brown units 1 and 2 are expected to be retired in 2019.**
**(3) Haefling unit 3 was retired in 2013.**

| KU Jurisdictional Generator Outage - Not normalized<br>Unit | FERC | Base<br>Year | Test<br>Year | 2019<br>Plan | 2020<br>Plan | 2021<br>Plan | 2022<br>Plan |
|---|---|---|---|---|---|---|---|
| 0321 - TRIMBLE COUNTY 2 - GENERATION | 510 | $ - | $ 156,257 | $ - | $ 156,257 | $ - | $ - |
| | 511 | 50,193 | - | - | - | - | - |
| | 512 | 2,937,822 | 770,951 | 570,447 | 819,272 | 300,720 | 3,701,050 |
| | 513 | 1,643,247 | 2,537,951 | 814,751 | 2,652,283 | - | 631,015 |
| 5591 - KU GENERATION - COMMON | 510 | - | - | - | - | - | - |
| | 513 | - | - | - | - | - | - |
| 5613 - GREEN RIVER UNIT 3 (1) | 500 | - | - | - | - | - | - |
| | 510 | - | - | - | - | - | - |
| | 511 | - | - | - | - | - | - |
| | 512 | - | - | - | - | - | - |
| | 513 | - | - | - | - | - | - |
| | 514 | - | - | - | - | - | - |
| 5614 - GREEN RIVER UNIT 4 (1) | 500 | - | - | - | - | - | - |
| | 511 | - | - | - | - | - | - |
| | 512 | - | - | - | - | - | - |
| | 513 | - | - | - | - | - | - |
| | 514 | - | - | - | - | - | - |
| 5621 - E W BROWN UNIT 1 (2) | 510 | 24,966 | - | - | - | - | - |
| | 511 | 1,459 | - | - | - | - | - |
| | 512 | 163,293 | - | - | - | - | - |
| | 513 | 56,373 | - | - | - | - | - |
| | 514 | 395 | - | - | | | |
| 5622 - E W BROWN UNIT 2 (2) | 510 | 79,263 | - | - | - | - | - |
| | 511 | - | - | - | - | - | - |
| | 512 | 144,734 | - | - | - | - | - |
| | 513 | 49,205 | - | - | - | - | - |
| | 514 | 1,444 | - | - | | | |
| 5623 - E W BROWN UNIT 3 | 510 | - | - | - | - | 720,199 | - |
| | 511 | - | - | - | - | - | - |
| | 512 | 1,222,614 | 3,498,859 | 2,287,319 | 1,258,413 | 941,743 | 1,328,259 |
| | 513 | 106,175 | 5,338,184 | 5,049,060 | 289,124 | 294,907 | 300,804 |
| | 514 | 255 | - | - | - | - | - |
| 5624 - E W BROWN UNITS 1 & 2 (2) | 512 | - | - | - | - | - | - |
| | 513 | - | - | - | - | - | - |
| | 514 | - | - | - | - | - | - |
| 5625 - E W BROWN UNITS 2 & 3 (2) | 512 | - | - | - | - | - | - |
| 5630 - E W BROWN STEAM UNITS 1,2,3 SCRUBBER (2) | 512 | - | - | - | - | - | - |
| 5651 - GHENT UNIT 1 | 510 | 354,066 | - | - | - | - | 701,493 |
| | 511 | 91,770 | - | - | - | - | - |
| | 512 | 2,760,866 | 3,080,760 | 1,800,952 | 2,946,569 | 8,844,780 | 3,319,529 |
| | 513 | 385,064 | 813,136 | 438,951 | 776,063 | 2,323,927 | 859,642 |
| | 514 | - | - | - | - | - | - |
| 5652 - GHENT UNIT 2 | 510 | - | 1,248,844 | 1,248,844 | - | - | - |
| | 511 | - | - | - | - | - | - |
| | 512 | 1,106,437 | 7,126,213 | 7,126,213 | 2,771,613 | 2,512,956 | 2,439,304 |
| | 513 | 678,317 | 1,982,962 | 1,982,962 | 783,990 | 661,473 | 760,946 |
| | 514 | - | - | - | - | - | - |

| KU Jurisdictional Generator Outage - Not normalized<br>Unit | FERC | Base<br>Year | Test<br>Year | 2019<br>Plan | 2020<br>Plan | 2021<br>Plan | 2022<br>Plan |
|---|---|---|---|---|---|---|---|
| 5653 - GHENT UNIT 3 | 510 | 946,718 | - | - | - | - | 303,980 |
| | 511 | - | - | - | - | - | - |
| | 512 | 2,319,563 | 2,007,930 | 2,007,930 | 2,617,105 | 2,350,678 | 2,785,028 |
| | 513 | 3,966,563 | 774,032 | 774,032 | 915,679 | 811,772 | 1,038,641 |
| | 514 | - | - | - | - | - | - |
| 5654 - GHENT UNIT 4 | 510 | 247,458 | - | - | - | 631,344 | - |
| | 511 | 69,684 | - | - | - | - | - |
| | 512 | 2,139,601 | 5,952,650 | 2,690,356 | 8,171,672 | 2,557,723 | 2,861,034 |
| | 513 | 530,093 | 1,538,959 | 662,448 | 2,098,502 | 705,631 | 661,313 |
| | 514 | - | - | - | - | - | - |
| 5655 - GHENT UNITS 1 & 2 | 511 | - | - | - | - | - | - |
| | 512 | - | - | - | - | - | - |
| | 513 | - | - | - | - | - | - |
| 5656 - GHENT UNITS 3 & 4 | 511 | - | - | - | - | - | - |
| | 512 | - | - | - | - | - | - |
| | 513 | - | - | - | - | - | - |
| 0172 - CANE RUN CC GT 2016 | 549 | 55 | - | - | - | - | - |
| | 551 | - | 456,615 | - | 456,615 | - | - |
| | 552 | 21,014 | - | - | - | - | - |
| | 553 | (99,433) | 3,096,143 | - | 3,096,143 | - | 1,913,522 |
| | 554 | 861,367 | 4,197,360 | 973,463 | 3,223,895 | 922,150 | 1,318,110 |
| 0432 - PADDYS RUN GT 13 | 553 | 61,976 | 105,033 | 105,033 | 71,181 | 109,358 | 74,034 |
| | 554 | - | - | - | - | - | - |
| 0470 - TRIMBLE COUNTY #5 COMBUSTION TURBINE | 553 | 9,959 | 13,985 | 26,746 | 31,276 | 103,763 | 143,664 |
| 0471 - TRIMBLE COUNTY #6 COMBUSTION TURBINE | 553 | 110,482 | 20,635 | 6,832 | 20,635 | 27,285 | 241,421 |
| 0474 - TRIMBLE COUNTY #7 COMBUSTION TURBINE | 553 | 50,993 | 12,410 | 12,410 | 6,509 | 9,459 | 39,554 |
| 0475 - TRIMBLE COUNTY #8 COMBUSTION TURBINE | 553 | 21,737 | 17,130 | 17,130 | 7,689 | 7,689 | 12,410 |
| 0476 - TRIMBLE COUNTY #9 COMBUSTION TURBINE | 553 | 10,745 | 13,590 | 13,590 | 18,310 | 132,197 | 6,509 |
| 0477 - TRIMBLE COUNTY #10 COMBUSTION TURBINE | 553 | 22,192 | 12,410 | 12,410 | 7,689 | 151,080 | 7,689 |
| 5635 - E W BROWN COMBUSTION TURBINE UNIT 5 | 553 | - | - | - | - | - | - |
| | 554 | 13,673 | - | - | - | - | - |
| 5636 - E W BROWN COMBUSTION TURBINE UNIT 6 | 551 | - | - | - | - | - | - |
| | 552 | - | - | - | - | - | - |
| | 553 | 14,919 | 14,664 | 427,274 | 14,664 | 14,884 | 15,107 |
| | 554 | - | - | - | - | - | - |
| 5637 - E W BROWN COMBUSTION TURBINE UNIT 7 | 553 | - | 29,645 | 14,712 | 14,933 | 531,673 | 15,384 |
| 5638 - E W BROWN COMBUSTION TURBINE UNIT 8 | 553 | - | 61,819 | 57,584 | 61,819 | 437,713 | 63,687 |
| | 554 | 541 | - | - | - | - | - |
| 5639 - E W BROWN COMBUSTION TURBINE UNIT 9 | 553 | - | - | - | - | - | - |
| | 554 | - | - | - | - | - | - |
| 5640 - E W BROWN COMBUSTION TURBINE UNIT 10 | 553 | - | - | - | - | - | - |
| | 554 | - | - | - | - | - | - |
| 5641 - E W BROWN COMBUSTION TURBINE UNIT 11 | 553 | 316,710 | - | - | - | - | - |
| 5645 - E W BROWN CT UNIT 9 GAS PIPELINE | 554 | - | - | - | - | - | - |
| 5693 - HAEFLING UNIT 1 | 553 | 4,713 | 5,136 | 5,136 | 5,212 | 5,291 | 5,370 |
| 5694 - HAEFLING UNIT 2 | 553 | 4,713 | 5,136 | 5,136 | 5,212 | 5,291 | 5,370 |
| 5695 - CLOSED 03/14 - HAEFLING UNIT 3[3] | 553 | - | - | - | - | - | - |
| **Total** | | **$ 23,503,993** | **$ 44,889,398** | **$ 29,131,722** | **$ 33,298,325** | **$ 26,115,687** | **$ 25,553,868** |

**(1) Green River units 3 and 4 were retired in 2015.**
**(2) E.W. Brown units 1 and 2 are expected to be retired in 2019.**
**(3) Haefling unit 3 was retired in 2013.**

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 75**

**Responding Witness: Lonnie E. Bellar**

Q-75. Refer to the direct testimony of Lonnie E. Bellar, page 19, wherein he states that "[i]n the calendar year 2018, the Companies have generated more than $11.4 million for the benefit of customers as a result of Off-System Sales ("OSS") of power produced by the Companies' generation facilities.

a. Explain if the $11.4 million amount is the amount of profit in total earned from OSS in 2018, or the amount allocated to customers.

A-75.

a. The $11.4 million amount is the amount that has been allocated to customers for calendar year 2018 through August. The monthly amounts are reported to the Commission as part of the OSS adjustment clause schedule – Page 1 of 3, line 3 as *Customer Share of OSS Margins*.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 76**

**Responding Witness: Elizabeth J. McFarland**

Q-76. Refer to the direct testimony of Lonnie E. Bellar, page 30, wherein he states, "the Companies project operating expenses related to meter readers and field service contracts to significantly increase over current spending on these services." Further reference Schedule C-2.1 Page 4 of 12 and Page 10 of 12.

a. Other than the slight change in jurisdictional percentage, explain and provide support for the increase in METER READING EXPENSES located on line No. 106 on both referenced pages of Schedule C-2.1.

A-76.

a. Meter Reading and Field Service contracts will expire on May 31, 2019. Staffing issues signaled changing market conditions and likely increases in costs for these services. An RFI was issued in May 2018 for both meter reading and field service pricing and six responses were received. An RFP was issued in July 2018. RFP responses have been received and the Company is in the process of evaluating the bidders. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

Attachment pages provided under confidential seal have been removed.

***METER READING LABOR BREAKDOWN for KU TERRITORY***

| Labor Classification | %xDirect labor $ * | **Meter Reader** | | | |
|---|---|---|---|---|---|
| Total Number of Meter Readers | | 76 | | | |
| Estimated Annual Hrs/Meter Readers | | 2,024 | 153,824 | | |
| Base Pay Rate | | 16.00 | | | |
| FICA and M/C | 7.65% | 1.22 | | | |
| SUI | 0.80% | 0.13 | | | |
| FUI | 0.60% | 0.10 | | | |
| Workers Comp. Dollars | 1.64% | 0.26 | | | |
| City Tax | | 0.00 | | | |
| TOTAL REGULATORY | | 1.71 | | | |
| Holiday pay | 2.70% | 0.43 | | 7 days paid | |
| Vacation cost | 4.00% | 0.64 | | | |
| TOTAL BENEFITS | | 1.07 | | | |
| Group Insurance Cost | 7.45% | 1.19 | | | |
| Bonus Dollars | 22.50% | 3.60 | | Yearly retention bonus and accuracy bonus, burdened | |
| Umbrella Ins. | 1.00% | 0.16 | | | |
| General Liability Ins. | 0.50% | 0.08 | | | |
| Small tools | 5.25% | 0.84 | | | |
| Vehicles | | 7.00 | | | |
| Depreciation bldg.(Rent) | | 0.00 | | | |
| *Administrative Cost: (including some penalties)* | 20.60% | 3.30 | | | |
| Local - Payroll | | 0.00 | | | |
| Corp Overheads | | 0.00 | | | |
| Field Supervision/ Superintendent | 21.60% | 3.46 | | Burdened | |
| Lodging/Per Diem | 1.00% | 0.16 | | | |
| Safety training | 4.20% | 0.67 | | | |
| Others (PLEASE LIST ANY OTHER) | | | | | |
| Overtime compensation | 5.60% | 0.90 | | Burdened | |
| Communications | 1.70% | 0.27 | | | |
| Drug test | 1.00% | 0.16 | | | |
| TOTAL OVERHEADS | | 21.79 | | | |
| ***Total Burden Cost per hour*** | | 40.57 | | | |
| ***Total Burden Cost x Annual Hrs (Cell C6)*** | | 82,112.25 | | | |
| ***Total Annual Burden Cost*** | | | | | 6,240,530.91 |
| ***Annual Meters Read*** | | | | | 6,392,028 |
| ***Cost per Meter Read Before Profit*** | | | | | 0.976 |
| ***Profit (%)*** | | | | | 13.5% |
| ***Cost Per Meter Read*** | | | | $ | 1.108 |

**** Note if cost item cannot be calculated as % of direct labor, note how cost calculated***

## *METER READING LABOR BREAKDOWN for KU TERRITORY*

| Labor Classification | %xDirect labor $ | Meter Reader | |
|---|---|---|---|
| Total Number of Meter Readers | | 95 | |
| Estimated Annual Hrs/Meter Readers | | 1,992 | |
| Base Pay Rate | | 13.00 | |
| FICA and M/C | 7.65% | 0.99 | |
| SUI | 5.10% | 0.66 | |
| FUI | 0.60% | 0.08 | |
| Workers Comp. Dollars | 6.43% | 0.84 | |
| City Tax | | 0.00 | |
| TOTAL REGULATORY | | 2.57 | |
| Holiday cost per employee per year | | 747.36 | |
| Vacation cost per employee per year | | 622.80 | |
| TOTAL BENEFITS per employee hour | | 0.69 | |
| Backgrounding, uniform & Other per employee per hour | | 0.94 | |
| Bonus Dollars per employee hour | | 1.00 | |
| General Liability & Umbrella Ins per employee hour | | 0.34 | |
| Small tools per employee hour | | 0.81 | |
| Vehicles per employee hour | | 7.83 | |
| Administrative Cost: | | | |
| Corp Overheads | 22.50% | 2.93 | |
| Field Supervision/Superintendent per employee hour | | 6.68 | |
| Lodging/Per Diem per employee hour | | 0.02 | |
| Safety training per employee hour | | 0.52 | |
| Others (PLEASE LIST ANY OTHER)- Mobilization/Demobilization per employee hour | | 0.23 | |
| TOTAL OVERHEADS | | 21.28 | |
| *Total Burden Cost per hour* | | 24.54 | |
| *Total Burden Cost x Annual Hrs (Cell C6)* | | 48,887.72 | |
| *Total Annual Burden Cost* | | | 48,887.72 |
| *Total Direct Labor Pay* | | | 25,896.00 |
| *Annual Meters Read* | | | 6,200,267 |
| *Cost per Meter Read Before Profit* | | | 1.146 |
| *Profit (%)* | 10.00% | | 0.115 |
| *Cost Per Meter Read* | | | 1.260 |

**** Note if cost item cannot be calculated as % of direct labor, note how cost calculated***

*METER READING LABOR BREAKDOWN for KU TERRITORY*

| Labor Classification | %xDirect labor $ * | Meter Reader | | |
|---|---|---|---|---|
| Total Number of Meter Readers | | 90 | | |
| Estimated Annual Hrs/Meter Readers | | 2,016 | | |
| Base Pay Rate | | 14.50 | | |
| FICA and M/C | 7.65% | 1.11 | | |
| SUI | 2.70% | 0.39 | | |
| FUI | 0.60% | 0.09 | | |
| Workers Comp. Dollars | 4.70% | 0.68 | | |
| City Tax | 0.00% | 0.00 | | |
| TOTAL REGULATORY | | 2.27 | | |
| Holiday pay | 4.37% | 0.63 | | |
| Vacation cost | 3.97% | 0.58 | | |
| TOTAL BENEFITS | | 1.21 | | |
| Group Insurance Cost | 12.00% | 1.74 | | |
| Bonus Dollars | 0.00% | 0.00 | | |
| Umbrella Ins. | 1.67% | 0.24 | | |
| General Liability Ins. | 2.50% | 0.36 | | |
| Small tools | 0.25% | 0.04 | | |
| Vehicles | | | | |
| Depreciation bldg.(Rent) | | 0.00 | | |
| Administrative Cost: | | | | |
| Local - Payroll | 9.22% | 1.34 | | |
| Corp Overheads | 22.77% | 3.30 | | |
| Field Supervision/ Superintendent | 40.42% | 5.86 | | |
| Lodging/Per Diem | 0.00% | 0.00 | | |
| Safety training | 0.81% | 0.12 | | |
| Others: Overtime | 4.96% | 0.72 | | |
| Others: Uniforms, Azuga, GPS | 1.18% | 0.17 | | |
| TOTAL OVERHEADS | | 13.89 | | |
| *Total Burden Cost per hour* | | 31.87 | | |
| *Total Burden Cost x Annual Hrs (Cell C6)* | | 64,241.22 | 5,781,709.58 | |
| *Total Annual Burden Cost* | | | | 5,845,950.80 |
| *Annual Meters Read* | | | | 6,392,028 |
| *Cost per Meter Read Before Profit* | | | | 0.91 |
| *Profit (%)* | | | | 20% |
| *Cost Per Meter Read* | | | | 1.10 |

** Note if cost item cannot be calculated as % of direct labor, note how cost calculated*

| Item No. | Item Name | Quantity | UOM | %age to Wage Rate | Straight Pay Hourly Rate | Overtime Hourly Rate | Total Standard Pay Rate | Total OT Pay Rate |
|---|---|---|---|---|---|---|---|---|
| 1 | HourlyWage Rate | 1 | Each | | 14.000 | 21.000 | | |
| Reg1 | Fica | 1 | Each | 0.077 | 1.071 | 1.607 | | |
| Reg2 | Sui | 1 | Each | 0.051 | 0.714 | 1.071 | | |
| Reg3 | Fui | 1 | Each | 0.006 | 0.084 | 0.126 | | |
| Reg4 | WC | 1 | Each | 0.064 | 0.900 | 0.900 | | |
| Reg 5 | City Tax | 1 | Each | 0.000 | 0.000 | 0.000 | | |
| TotalReg | **TOTAL REGULATORY** | 1 | Each | 0.198 | 2.769 | 3.704 | 2.769 | 3.704 |
| Ben1 | Holiday | 1 | Each | 0.023 | 0.320 | 0.320 | | |
| Ben2 | Vacation | 1 | Each | 0.019 | 0.270 | 0.270 | | |
| Ben3 | Group Insurance | 1 | Each | 0.000 | 0.000 | 0.000 | | |
| Ben4 | 401K | 1 | Each | 0.000 | 0.000 | 0.000 | | |
| Ben 5 | Bonus | 1 | Each | 0.071 | 1.000 | 1.000 | | |
| Ben 6 | Msc. | 1 | Each | 0.953 | 13.341 | 15.861 | | |
| TotalBen | **TOTAL BENEFITS** | 1 | Each | 1.067 | 14.931 | 17.451 | 14.931 | 17.451 |
| Over1 | Liability Insurance | 1 | Each | 0.000 | | | | |
| Over2 | Admin | 1 | Each | 0.000 | | | | |
| Over 3 | Equip & Tools | 1 | Each | 0.000 | | | | |
| Over 4 | Other | 1 | Each | 0.000 | | | | |
| TotalOv | **TOTAL OVERHEAD** | 1 | Each | 0.155 | 2.170 | 3.255 | 2.170 | 3.255 |
| P1 | Profit | 1 | Each | 0.714 | 10.000 | 10.000 | 10.000 | 10.000 |
| TB1 | **Total Burden** | 1 | Each | 2.134 | 29.870 | 34.410 | 29.870 | 34.410 |
| **Billable Rate** | **Billable Rate** | 1 | Each | | | | 43.870 | 55.410 |

| Item No. | Item Name | Quantity | UOM | %age to Wage Rate | Straight Pay Hourly Rate | Overtime Hourly Rate | Total Standard Pay Rate | Total OT Pay Rate |
|---|---|---|---|---|---|---|---|---|
| 1 | HourlyWage Rate | 1 | Each | | 19.000 | 28.500 | | |
| Reg1 | Fica | 1 | Each | 0.076 | 1.450 | 2.180 | | |
| Reg2 | Sui | 1 | Each | 0.009 | 0.174 | 0.000 | | |
| Reg3 | Fui | 1 | Each | 0.002 | 0.040 | 0.000 | | |
| Reg4 | WC | 1 | Each | 0.025 | 0.475 | 0.660 | | |
| Reg 5 | City Tax | 1 | Each | 0.000 | 0.000 | 0.000 | | |
| TotalReg | **TOTAL REGULATORY** | 1 | Each | 0.113 | 2.139 | 2.840 | 2.139 | 2.840 |
| Ben1 | Holiday | 1 | Each | 0.080 | 1.520 | 0.000 | | |
| Ben2 | Vacation | 1 | Each | 0.000 | 0.000 | 0.000 | | |
| Ben3 | Group Insurance | 1 | Each | 0.080 | 1.520 | 0.000 | | |
| Ben4 | 401K | 1 | Each | 0.000 | 0.000 | 0.000 | | |
| Ben 5 | Bonus | 1 | Each | 0.000 | 0.000 | 0.000 | | |
| Ben 6 | Msc. | 1 | Each | 0.000 | 0.000 | 0.000 | | |
| TotalBen | **TOTAL BENEFITS** | 1 | Each | 0.160 | 3.040 | 0.000 | 3.040 | 0.000 |
| Over1 | Liability Insurance | 1 | Each | 0.010 | 0.190 | 0.285 | | |
| Over2 | Admin | 1 | Each | 0.080 | 1.520 | 0.000 | | |
| Over 3 | Equip & Tools | 1 | Each | 0.045 | 0.860 | 0.000 | | |
| Over 4 | Other | 1 | Each | 0.100 | 1.900 | 0.000 | | |
| TotalOv | **TOTAL OVERHEAD** | 1 | Each | 0.155 | 2.945 | 4.418 | 2.945 | 4.418 |
| P1 | Profit | 1 | Each | 0.080 | 1.520 | 2.280 | 1.520 | 2.280 |
| TB1 | **Total Burden** | 1 | Each | 0.508 | 9.644 | 9.538 | 9.644 | 9.538 |
| **Billable Rate** | **Billable Rate** | 1 | Each | | | | 28.644 | 38.038 |

| Item No. | Item Name | Quantity | UOM | %age to Wage Rate | Straight Pay Hourly Rate | Overtime Hourly Rate | Total Standard Pay Rate | Total OT Pay Rate |
|---|---|---|---|---|---|---|---|---|
| 1 | HourlyWage Rate | 1 | Each | | 16.500 | 24.750 | | |
| Reg1 | Fica | 1 | Each | 7.65% | 1.262 | 1.890 | | |
| Reg2 | Sui | 1 | Each | 0.60% | 0.099 | 0.150 | | |
| Reg3 | Fui | 1 | Each | 2.70% | 0.446 | 0.670 | | |
| Reg4 | WC | 1 | Each | 4.70% | 0.776 | 1.160 | | |
| Reg5 | City Tax | 1 | Each | 0.00% | - | - | | |
| Total Reg | **TOTAL REGULATORY** | 1 | Each | 15.65% | 2.583 | 3.870 | | |
| Ben 1 | Holiday | 1 | Each | 4.37% | 0.721 | - | | |
| Ben 2 | Vacation | 1 | Each | 3.97% | 0.655 | - | | |
| Ben 3 | Group Insurance | 1 | Each | 12.00% | 1.980 | - | | |
| Ben 4 | 401K | 1 | Each | 3.00% | 0.495 | 0.740 | | |
| Ben 5 | Bonus | 1 | Each | 0.00% | - | - | | |
| Ben 6 | Msc. | 1 | Each | 0.00% | - | - | | |
| TotalBen | **TOTAL BENEFITS** | 1 | Each | 23.34% | 3.851 | 0.740 | | |
| Over1 | Liability Insurance | 1 | Each | 2.50% | 0.413 | 0.620 | | |
| Over2 | Admin | 1 | Each | 42.93% | 7.083 | - | | |
| Over3 | Equip & Tools | 1 | Each | 5.00% | 0.825 | - | | |
| Over4 | Other | 1 | Each | 70.10% | 11.566 | - | | |
| TotalOver | **TOTAL OVERHEAD** | 1 | Each | 120.53% | 19.887 | 0.620 | | |
| P1 | Profit | 1 | Each | 20.00% | 3.300 | 4.950 | | |
| TB1 | **Total Burden** | 1 | Each | 179.52% | 29.621 | 5.230 | | |
| **Billable Rate** | Billable Rate | 1 | Each | | | | 46.121 | 34.930 |

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 77**

**Responding Witness: Daniel K. Arbough / Lonnie E. Bellar**

Q-77. Vegetation Management: Provide the following information related to Vegetation Management non-storm related O&M and capital expenditures. Provide this information separately for Transmission and Distribution.

a. The accounting policy for each company that determines what Vegetation Management expenditures are charged to Capital and what are charged to O&M.

b. For O&M Expenses:

i. The total dollars budgeted by company, by year, for 2013–2017 and 2018 YTD.

ii. The total dollars spent by company, by year, for 2013–2017 and 2018 YTD.

iii. Please explain over/under variances from budget by company, by year, by functional area (Transmission, Distribution).

c. For Capital:

i. The total dollars budgeted by company, by year, for 2013–2017 and 2018 YTD.

ii. The total dollars spent by company, by year, for 2013–2017 and 2018 YTD.

iii. Please explain over/under variances by company, by year, by functional area (Transmission, Distribution).

d. Explain the Companies' methodologies and policies regarding what level of detail each Company plans and budgets for Vegetation Management.

A-77.

a. LG&E and KU do not have a policy specific to Vegetation Management. The Companies rely on Accounting Policy 650 – Capital – Additions and

Retirements Policy and Procedures to determine what Vegetation Management expenditures are charged to Capital and what are charged to O&M.

Accounting Policy 650 – Capital – Additions and Retirements Policy and Procedures was provided as an attachment to the response to PSC 1-8.

b. See attached for O&M costs for actual and budget for 2013-2017 and 2018 through October, with variance explanations.

c. See attached for Transmission capital costs for actual and budget for 2013-2017 and 2018 through October, with variance explanations. Capital totals for Distribution tree trimming are not readily available as associated costs are charged against numerous reliability improvement or system enhancement capital projects.

d. The Companies plan and budget Distribution Vegetation Management work at the Company level consistent with the Louisville Gas and Electric Company and Kentucky Utilities Company Distribution Vegetation Management Plan filed with the Kentucky Public Service Commission on December 19, 2007. The Companies plan and budget Transmission Vegetation Management work using the expected number of crews and equipment needed to support the vegetation management program. The Company also uses established rates from their long-term vegetation management contractors for planning and budgeting.

**Vegetation Management O&M Expenses**
**Actual vs Budget 2013-2018**
**(000's)**

**Distribution**

| Description | 2013 Actual | 2013 Budget | 2013 Variance (Over)/Under | 2014 Actual | 2014 Budget | 2014 Variance (Over)/Under | 2015 Actual | 2015 Budget | 2015 Variance (Over)/Under | 2016 Actual | 2016 Budget | 2016 Variance (Over)/Under | 2017 Actual | 2017 Budget | 2017 Variance (Over)/Under | YTD 10/31/2018 Actual | YTD 10/31/2018 Budget | YTD 10/31/2018 Variance (Over)/Under |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| KU | 16,494,243 | 16,604,786 | 110,543 [a] | 15,202,401 | 16,856,420 | 1,654,019 [b] | 14,340,571 | 16,248,700 | 1,908,129 [b] | 14,922,723 | 15,533,712 | 610,989 [b] | 13,830,038 | 15,276,000 | 1,445,962 [b] | 13,129,670 | 12,479,564 | (650,106) [b] |

[a] Variances for both companies are due to changes from original budget estimates in order to address hazard trees as appropriate.

[b] Variances for both companies are due to changes from original budget estimates in order to maintain the appropriate trimming cycles and to address hazard trees as appropriate.

**Transmission**

| Description | 2013 Actual | 2013 Budget | 2013 Variance (Over)/Under | 2014 Actual | 2014 Budget | 2014 Variance (Over)/Under | 2015 Actual | 2015 Budget | 2015 Variance (Over)/Under | 2016 Actual | 2016 Budget | 2016 Variance (Over)/Under | 2017 Actual | 2017 Budget | 2017 Variance (Over)/Under | YTD 10/31/2018 Actual | YTD 10/31/2018 Budget | YTD 10/31/2018 Variance (Over)/Under |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| KU | 4,511,675 | 3,886,894 | (624,781) [c] | 5,310,434 | 3,958,239 | (1,352,195) [c] | 5,329,874 | 3,827,558 | (1,502,316) [c] | 5,286,815 | 5,729,553 | 442,738 [c] | 7,985,351 | 7,909,496 | (75,855) | 9,372,566 | 9,257,316 | (115,250) |

[c] Actual vegetation maintenace expenses varied by company and from budget based upon aerial inspections and just in time trimming needs.

**Vegetation Management Capital Expenses - Transmission**
**Actual vs Budget 2013-2018**
**(000's)**

| | 2013 | | | 2014 | | | 2015 | | | 2016 | | | 2017 | | | YTD 10/31/2018 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Description | Actual | Budget | Variance (Over)/Under | Actual | Budget | Variance (Over)/Under | Actual | Budget | Variance (Over)/Under | Actual | Budget | Variance (Over)/Under | Actual | Budget | Variance (Over)/Under | Actual | Budget | Variance (Over)/Under |
| KU | 67,386 | | (67,386) a | 178,804 | | (178,804) a | 216,564 | | (216,564) a | 536,075 | | (536,075) a | 632,093 | | (632,093) a | 1,135,801 | | (1,135,801) a |

a Vegetation Management work is not budgeted as a specific item on a capital projects.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 78**

**Responding Witness: Daniel K. Arbough**

Q-78. Refer to Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(c) I. Page 214 of 235.

a. Explain why the Companies expect a $3.5M increase in "Total O&M Expense – Mgmt. View" between actual 2017 and forecast 2018. Any response should explain the more than $2M increase in "Outside Counsel" between the two periods.

A-78.

a. Labor savings in 2017 were driven by one vacant position in legal that was being held due to assessment of need; and, due to timing of the hiring of the new Executive Vice President -General Counsel. Both of these positions have now been filled.

Outside Counsel spend for 2017 were atypical due to total spend being $1.2 million less than the average of the prior five years. There were extended periods of minimal activity due to timing issues in two litigation matters that were beyond the Company's control.

Outside Services/Legal Expert Fees are significantly higher in 2018 due primarily to two matters.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 79**

**Responding Witness: Daniel K. Arbough**

Q-79. Refer to Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(c) I. Page 215 of 235.

a. Explain the significant increase in "Regulatory" expenses between the actual 2017 expenses and the increase to 2018 forecast and further increase in 2019 and beyond.

b. Explain the doubling of "All Other" expenses for 2018 forecast compared to 2017 actual.

A-79. In 2017, actual spend was atypically lower than actual spend seen in the prior five years.

a. The increase from 2017 Regulatory to 2018 Regulatory is driven by five separate matters forecasted at over $100k each. The increase from 2018 to 2019 is due to six matters forecasted at over $100K (including three matters over $400k each).

b. The increase in All Other for 2018 is driven by a single matter forecasted at over $500k. The remaining increase is spread across over 100 matters.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 80**

**Responding Witness: Daniel K. Arbough**

Q-80. Refer to Attachment to Filing Requirement 807 KAR 5:001 Section 16(7)(c) I. Page 213 of 235, wherein "Major Assumptions" for the 2019 General Counsel Operating Plan states in part:

External Affairs

- Expectation that at least one 2019 legislative issue will require modest outside communications agency spending
- Convergence of legislative, regulatory and legal issues expected to continue (e.g. Solar Share and Planning and Zoning legislation, change in Basic Service Charge and legislations limiting the same, potential change in net metering statute requiring filing of new tariffs, etc.).

a. Are the Companies requesting recovery of anticipated costs of engaging on legislation, including "communications agency spending" in the forecasted period?

A-80.

a. The Companies are not requesting recovery of anticipated costs of engaging on legislation, including "communications agency spending" in the forecasted period. These costs are included in non-recoverable accounts.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 81**

**Responding Witness: Daniel K. Arbough**

Q-81. Directors' and Officers' ("D&O") Liability Insurance: Does the cost of service include any premium costs for D&O insurance either direct charged or allocated? If the response is in the affirmative, provide the following items:

a. Amount included in the base year and forecasted period. If the amount is allocated, provide the allocations.

b. List of officers and directors covered by the insurance.

c. List of acts covered by the insurance.

A-81. Yes, the cost of service includes premium costs for D&O insurance.

a. The amount included in the base year for KU is $283,961. The amount included in the forecasted period for KU is $277,596. One third of the premium is first allocated from PPL to LG&E and KU Energy LLC ("LKE"). LKE further allocates 53% of the LKE portion of the premium to KU.

b. All directors and officers of PPL Corporation and each subsidiary, and employees, regardless of job title, if employee is involved in an outside non-profit board or industry association at the request of PPL Corporation or a subsidiary are covered by this insurance.

c. PPL maintains broad directors and officers liability insurance that is designed to indemnify the directors and officers of PPL Corporation and each of its subsidiaries against any liability (including legal expenses, settlements and judgments) arising out of alleged wrongful acts, errors or omissions committed while managing corporate affairs.

PPL's D&O insurance is comprised of Corporate Indemnification and Side A coverages. Corporate Indemnification coverage will reimburse a company for payments made to directors and officers under the indemnification provisions of the company's bylaws. In situations where a company is unable to indemnify a director or officer, such as in the case of a derivative claim brought on behalf of the company by a third party, or in the case of the company's financial inability to pay, Side A coverage provides, on a direct basis and with no deductible, payments for legal expenses, settlements and judgments.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 82**

**Responding Witness: Robert M. Conroy**

Q-82. Refer to the direct testimony of Paul W. Thompson, page 10, wherein he states the "Companies are long-standing supporters of and leaders in economic development in Kentucky."

a. Do the Companies recover through rates specific expenses, investments, monies, salaries, etc. dedicated exclusively or in part to economic development activities?

b. If the response to 4 (a), above, is in the affirmative, indicate where in the Companies' applications those monies are located.

A-82.

a. Yes.

b. The Company's Economic Development departmental expenses are reflected within account 901 Supervision expense.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 83**

**Responding Witness: Lonnie E. Bellar**

Q-83. Refer to Exhibit LEB-2 to the direct testimony of Lonnie E. Bellar, page 32 of 40, Appendix D, wherein the document discusses the Companies' "plans and processes . . . to address current and future environmental and regulatory requirements."

a. Cite to the portion of the Exhibit where the Companies compared the costs and benefits associated with this variable, particularly where they compared their own "plans and processes" to those that would be administered or adhered to if they were members in an RTO, such as those envisioned by EKPC.

A-83.

a. The Companies have not performed this specific comparison. However, the Companies continually evaluate environmental and regulatory requirements, and regularly review their internal plans processes to address these to ensure that the requirements are met at the least reasonable cost. The Companies also monitor and maintain a working knowledge of the RTOs' plans and processes, evaluate their applicability to the Companies, and reevaluate their internal plans and processes as warranted.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 84**

**Responding Witness: Daniel K. Arbough**

Q-84. Does the Company use credit cards that include rebates? If the response is in the affirmative, provide the following items:

a. Amount of rebate reflected in the cost of service base year and forecasted period. If the amount is allocated, provide the allocations.

b. Actual credit card rebates by year for 2016, 2017, and 2018 YTD. For each year, state the expense accounts where these credit card rebates are reflected and provide a detailed breakdown of those expense accounts.

A-84. Yes.

a. Zero is reflected in the cost of service for the base and forecasted period.

b. The rebate for 2016 was $205,999.93 and the 2017 rebate was $210,764.05. The rebates are recorded in account 921. The rebate for 2018 has not yet been received.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 85**

**Responding Witness: Christopher M. Garrett**

Q-85. Regarding uncollectibles:

a. Explain how the Bad Debt Expense of 0.18% used in the development of Schedule H-1 was derived. Provide the supporting documentation for the derivation.

b. Why is KU and LG&E (gas and electric) bad debt expense used on Schedule H-1 the same if the actual history of bad debt is different as shown in the response to PSC-1-49?

c. Refer to the 2015 Gas Operations % of bad debt to revenue: Explain why the Reserve Account balance was significantly higher in 2015 than the Reserve in 2016 and 2017.

A-85. a. The KU Bad Debt Expense on Schedule H-1 is 0.316%.

| Year | Retail Revenues | Net Charge Offs | Net Charge Off % |
|---|---|---|---|
| 2013 | 1,475,359,565 | 3,690,691 | 0.250% |
| 2014 | 1,595,639,675 | 6,721,700 | 0.421% |
| 2015 | 1,584,248,424 | 5,537,467 | 0.350% |
| 2016 | 1,582,449,743 | 4,426,557 | 0.280% |
| 2017 | 1,561,731,101 | 4,347,134 | 0.278% |
| 5-YR Avg | 7,799,428,508 | 24,723,549 | 0.316% |

b. KU and LG&E (gas and electric) bad debt expense used on Schedule H-1 is not the same. The KU "Uncollectible Accounts Expense" as reported on Schedule H-1 is 0.316% (also shown in item a. above), whereas the LG&E (gas and electric) "Uncollectible Accounts Expense" as reported on Schedule H-1 is 0.182%.

c. Not applicable. KU does not have Gas Operations.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 86**

**Responding Witness: Christopher M. Garrett**

Q-86. Is it possible, based on the cost allocation manual and service agreements in place, for more than one service company (among LKS, PPL Services, and PPL EU Services) to provide the same kind of services to KU and LG&E?

a. If the response is in the affirmative, fully describe the safeguards in place to prevent more than one service company from allocating duplicate charges for the same service.

b. If the response is in the negative, fully explain the delineation and differentiation of services provided by each service company.

A-86. Yes.

a. During the preparation of the annual budget, LKS Financial Planning and Analysis develops an understanding of the specific services to be provided by LKS, PPL Services, and PPL EU Services and whether these services will benefit KU and LG&E. Extra scrutiny is applied to budgeted charges from departments which exist at both LKS and at either of the two PPL service companies to prevent the duplication of services from being charged to KU and LG&E. Charges which do not benefit KU and LG&E (for such reasons as not being specifically identifiable, attributable to other affiliates, or duplicative) are not budgeted or charged to KU and LG&E. The direct charges bills received from PPL Services and PPL EU Services clearly delineate the source departments from which the charges originate. Actual direct charges are reviewed monthly by the LKS Corporate Accounting, Treasury, Forecasting and Budgeting-Corporate, and Budgeting and Forecasting-Distribution Ops/Customer Services Departments to ensure that charges are billed as expected.

b. Not applicable.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 87**

**Responding Witness: Christopher M. Garrett / Robert M. Conroy**

Q-87. Provide a narrative explaining the details and how the amounts were estimated for the categories as shown on the Schedules of Rate Case Preparation Costs (Response to Question No. 59[b]). In the narrative, provide purpose and give examples. For example, regarding the Newspaper Advertising category, explain the purpose and content of the advertising, how many newspapers are involved, how many ads and iterations per paper are required, and what the average cost per ad is.

A-87. The Company is required by 807 KAR 5:11.Tariffs Section 8 (2)(b)3 "Publishing notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area," to notify customers of any change in a charge, fee, condition of service, or rule regarding the provision for service or the quality, delivery, or rendering of customer's service. The Newspaper Advertising expenses listed on the Schedules of Rate Case Preparation Costs depict the costs associated with publishing said notices. The notices provided by the Company were posted in ninety-one (91) newspapers within the Company service territory as ads, and were circulated as required.

Furthermore, the price of placing ads varies per newspaper. For each newspaper, the expenditure ranges from $192.00 to $17,448.96 per week. The Certificate of Completed Notice was filed in the proceeding on November 9, 2018.

In addition, the Companies require the assistance of law firms and consultants in preparation of the rate case application.

See the response to PSC 1- 59(b) for a discussion on the basis of the projections.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 88**

**Responding Witness: Robert M. Conroy**

Q-88. Reference Case No. 2018-00120,[12] in which the named complainants alleged that LG&E-KU paid for certain advertisements regarding House Bill 227 of the 2018 General Assembly, Regular Session (Ky. 2018), for the purpose of promotional, political or institutional advertising as set forth in 807 KAR 5:016.

a. State whether one or both companies are seeking rate recovery for any expenses associated with the running of these advertisements or these type of advertisements. If the response is in the affirmative, provide the amount thereof and identify where in the application these expenses can be found.

A-88.

a. No, the Companies are not seeking rate recovery for any expenses associated with the running of the cited advertisements or similar advertisements.

[12] In re: Complaint of Andy McDonald, et al., vs. Kentucky Utilities and Louisville Gas & Electric. Co.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 89**

**Responding Witness: Lonnie E. Bellar**

Q-89. State whether LG&E-KU considered any alternatives to moving to a cycle-based transmission vegetation management plan. If alternatives were considered, identify the alternatives, discuss their respective merits, and state why the Companies rejected them.

A-89. As described in the Transmission System Improvement Plan (TSIP), LG&E and KU retained Environmental Consultants Inc. (ECI) to conduct a comprehensive assessment of the company's existing vegetation management program and make recommendations to align the companies' program with industry best practices. One of the key recommendations from this assessment was the transition to a cyclical program. LG&E and KU did not consider alternatives to this recommendation beyond the previous approach of just in time clearing. LG&E and KU also described in the TSIP that the just in time approach of clearing based on frequent inspections was no longer sufficient to address the risk of grow-ins or danger trees falling on lines from outside the maintained boundaries of the easement.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 90**

**Responding Witness: Robert M. Conroy**

Q-90. Confirm that in KU rate case 2003-00434, the Commission in its Final Order dated June 30, 2004,[13] relying in part on data broken down by NARUC operating expense category, at p. 44-45 removed 45.35% of KU's dues paid to Edison Electric Institute ("EEI"), for a total exclusion of $67,044, because EEI applied that portion of the dues KU paid toward: (i) legislative advocacy; (ii) regulatory advocacy; and (iii) public relations [hereinafter jointly referred to as "covered activities"].

A-90. The Commission's order speaks for itself. The cited pages contain the information quoted above, but do not refer explicitly to NARUC operating expense categories.

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[13] Accessible at: https://psc.ky.gov/order_vault/Orders_2004/200300434_06302004.pdf

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 91**

**Responding Witness: Christopher M. Garrett**

Q-91. Confirm that since 2007, EEI no longer prepares the same breakout of its activities by NARUC operating expense category.

a. For each rate case since 2007, provide the allocation the Companies utilized in determining the exclusion of particular EEI dues.

b. Provide a narrative explanation of the bases used for each rate case allocation provided in response to subpart a., above.

A-91. KU does not rely upon any NARUC reports or other studies for the exclusion from or inclusion in rates of a portion of any organizations dues. KU relies on information provided on the invoices received from any organization in order to determine the portion of dues that should be excluded from rates.

a. Following are the allocations that KU has used since 2007:

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Per books | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| | 18% | 18% | 22% | 27% | 23% | 20% | 15% | 14% | 14% | 14% |
| Per rate cases | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
| | 18% | | | 27% | | 20% | | 14% | | 14% |

b. The invoices received from EEI are used to determine the allocation used for ratemaking purposes.

## KENTUCKY UTILITIES COMPANY

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 92**

**Responding Witness: Christopher M. Garrett**

Q-92. Reference FR 16(8)(f), Sch. F-1 of the current application.

a. Confirm that in the base period, KU paid $400,967 in jurisdictional dues to EEI, and excluded $64,343.85.

b. Confirm that for the forecasted period, KU seeks to recover $420,215.55 of the jurisdictional dues it believes it will pay to EEI, and to exclude $70,071.48.

c. Confirm that for both the base period and the forecasted test period, EEI has engaged in, and will continue to engage in, inter alia, covered activities.

d. Confirm that all portions of the EEI dues KU proposes to exclude for the forecasted period are non-jurisdictional.

e. If subpart (d), above is so confirmed, explain why the non-recoverable portions of EEI dues identified here are not recoverable in KU's other jurisdictions.

f. Since EEI no longer breaks out its activities by NARUC operating expense category, provide the basis for KU's proposed exclusion of $70,071.48 in EEI dues from the forecasted test period. Provide copies of all documents supporting both the amount of KU's proposed exclusion, and the amounts of EEI dues KU suggests should be included for recovery.

g. Confirm that based on Commission precedent of excluding 45.35% of EEI dues, KU should exclude $190,567.76 from the forecasted period.

A-92.

a. Yes, amounts are confirmed.

b. Yes, amounts are confirmed.

c. KU cannot confirm the activity of EEI, but it is assumed in the forecast they will continue their current activities.

d. Confirmed. The non-recoverable portion of the EEI dues KU excluded for the forecasted period are non-jurisdictional.

e. No, the Company does not agree with this position. KU excluded the appropriate amount of unrecoverable dues based on the information provided on the 2018 invoice from EEI. See the response to Question No. 91(b).

f. Based on the invoice for the EEI membership in 2018, 13% of membership dues and 24% of industry issues should be excluded from the cost of service as those expenses relate to influencing legislation. The combined exclusion of the invoice amount is 14%, which is appropriately applied to the forecasted test period. See the response to Question No. 98 for a copy of the invoice.

   The 2019 estimate was provided by PPL. The amount excluded for the forecasted test period was 14% of the amount provided.

g. No, the Company does not agree with this position. KU excluded the appropriate amount of unrecoverable dues based on the information provided on the 2018 invoice from EEI. See the response to Question No. 91(b).

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 93**

**Responding Witness: Christopher M. Garrett**

Q-93. Reference FR 16(8)(f), Sch. F-1.

h. For the Base Period category, fully identify each vendor falling into the "Various Vendors" and "Other Non-Specific KU Dues" categories, as to both recoverable and not recoverable dues.

i. For both the base and forecasted periods, fully identify all vendors falling in the "Other Non-Specific KU Dues" category.

j. Confirm whether Electric Power Research Institute (EPRI) engages in any one or all of the covered activities. If confirmed as to any one or more of such covered activities, provide the amount of KU dues that EPRI applies to the covered activities, both in dollar terms and percentages of total dues.

k. Confirm that Hunton & Williams, LLP has a lobbying arm/affiliate. Identify the amount of KU dues this organization applies toward covered activities, both in terms of dollars and percentages of total dues.

l. Explain whether North American Transmission Forum engages in covered activities. If so, identify the amount of KU dues this organization applies toward covered activities, both in terms of dollars and percentages of total dues.

m. Explain whether Steptoe & Johnson LLC engages in covered activities. If so, identify the amount of KU dues this organization applies toward covered activities, both in terms of dollars and percentages of total dues.

n. Confirm that the Utility Air Regulatory Group (UAR) engages in covered activities. Identify the amount of KU dues that UAR applies toward covered activities, both in terms of dollars and percentages of total dues.

o. Confirm that the Utility Water Act Group (UWAG) engages in covered activities. Identify the amount of KU dues that UWAG applies toward covered activities, both in terms of dollars and percentages of total dues.

p. Explain whether the Midwest Ozone Group (MOG) engages in covered activities. If so, identify the amount of KU dues MOG applies toward covered activities, both in terms of dollars and percentages of total dues.

q. Explain whether the Utility Solid Waste Activities Group (USWAG) engages in covered activities. If so, identify the amount of KU dues that USWAG applies toward covered activities, both in terms of dollars and percentages of total dues.

A-93.

h. **S**ee attached the breakdown of vendors falling into "Various Vendors" for both recoverable and not recoverable dues. As indicated in FR 16(8)(f), Sch. F-1, portions of the Base Period Recoverable and Non-Recoverable Dues are not completed in specific vendor detail.

i. As indicated in FR 16(8)(f), Sch. F-1, portions of the Forecasted Period Recoverable and Non-Recoverable Dues are not completed in specific vendor detail.

j. Electric Power Research Institute (EPRI) does not engage in any covered activities.

k. Coal Combustion Residuals (CCR) Legal Resources Group and New Source Review (NSR) Legal Resources Group are billed through Hunton & Williams, LLP. Both groups are not engaged in covered activities.

l. North American Transmission Forum does not engage in covered activities.

m. Steptoe & Johnson LLC is an agent of Midwest Ozone Group that engages in covered activities.

n. Utility Air Regulatory Group (UARG) engages in covered activities.

o. Utility Water Act Group (UWAG) engages in covered activities.

p. Midwest Ozone Group (MOG) engages in covered activities.

q. Utility Solid Waste Activities Group (USWAG) engages in covered activities.

**Breakdown of "Various Vendors" - Recoverable**

| Vendor Name | Employee Dues |
|---|---|
| BOSTON COLLEGE | 2,650.00 |
| THE INSTITUTE OF INTERNAL AUDITORS | 2,274.30 |
| LOUISVILLE BAR ASSOCIATION | 1,367.40 |
| BETTER BUSINESS BUREAU | 1,330.00 |
| NORTH AMERICAN ELECTRIC RIALIBILITY CORPORATION | 1,232.92 |
| INSTITUTE OF ELECTRICAL AND ELECTRONICS ENGINEERS (IEEE) | 1,117.12 |
| INDUSTRIAL ASSET MANAGEMENT COUNCIL, INC | 1,052.80 |
| WEATHERBELL ANALYTICS | 970.80 |
| ATD (ASSOCCIATION OF TALENT DEVELOPMENT) | 965.70 |
| ENERGY AND MINERAL LAW | 928.40 |
| WSI CORPORATION | 900.00 |
| PROJECT MANAGEMENT INSTITUTE (PMI) | 877.01 |
| AICPA | 596.85 |
| SOS INT'L LLC | 518.50 |
| SURVEY SITE | 510.00 |
| AMERICAN BAR ASSOCIATION | 495.02 |
| INFORMATION SYSTEMS SECURITY | 468.00 |
| CCIM INSTITUTE | 392.00 |
| INSTITUTE OF MANAGEMENT ACCTOUNTANTS | 379.30 |
| THE LAW CLUB | 318.00 |
| UOFL DELPHI CTR | 314.40 |
| STATE OF INDIANA | 311.72 |
| KENTUCKIANA USERS COUNCIL | 300.00 |
| THE VIRGINIA BAR ASSOCIATION | 300.00 |
| SUBSTANCE ABUSE PROGRAM ADMINISTRATORS ASSOCIATION (SAPAA) | 275.00 |
| PROFESSIONAL ENGINEERING LICENSE RENEWAL | 271.50 |
| AMERICAN BIOGAS COUNCIL | 259.68 |
| PAYROLL PROFESSIONALS OF KENTUCKIANA | 250.00 |
| AIR & WASTE MANAGEMENT ASSOCIATION | 249.60 |
| INTERNATIONAL ENERGY CREDIT ASSOCIATION (IECA) | 244.00 |
| ISACA | 232.80 |
| CGMA & AICPA | 228.25 |
| ENERGY BAR ASSOCIATION | 227.90 |
| THE WALL STREET JOURNAL | 222.40 |
| AMERICAN PAYROLL ASSOCIATION | 219.00 |
| SOCIETY OF HUMAN RESOURCE MANAGEMENT | 191.50 |
| NBMBAA | 175.00 |
| INTERNATIONAL RIGHT OF WAY ASSOCIATION | 145.60 |
| KY ASSOCIATION OF PROFESSIONAL SURVEYORS | 143.00 |
| INDIANA CPA SOCIETY, INC. | 140.45 |
| CLE CENTER | 131.97 |
| WOMEN IN DIGITAL PROFESSIONAL ORGANIZATION | 129.60 |
| LEADERSHIP LOUISVILLE | 129.50 |
| FOREFLIGHT | 129.31 |
| ASSOCIATION OF ENERGY ENGINEERS (AEE ENERGY) | 124.80 |
| ASSOCIATION OF ENERGY ENGINEERS | 124.80 |
| CPA LICENSE RENEWAL | 122.26 |
| TAX EXECUTIVES INSTITUTE | 119.25 |
| SANS INSTITUTE | 113.15 |
| INSTITUTE OF SUPPLY MANAGEMENT | 105.00 |
| NFPA NATL FIRE PROTECT | 105.00 |
| ACFE | 103.35 |

**Breakdown of "Various Vendors" - Recoverable**

| Vendor Name | Employee Dues |
|---|---|
| APICS | 90.00 |
| ASSOCIATION FOR THE ADVANCEMENT OF ARTIFICIAL INTELLIGENCE | 89.90 |
| ARMA (RECORD MANAGEMENT SOCIETY) | 87.50 |
| AEMRICAN SOCIETY OF SAFETY ENGINEERS | 82.61 |
| FORENSIC CPA SOCIETY | 79.50 |
| UTILITY SAFETY & OPS LEADERSHIP NETWORKS (USOLN) | 72.50 |
| ISC2 (CYBERSECURITY AND IT SECURITY PROFESSIONAL ORGANIZATION) | 72.00 |
| AMERICAN SOCIETY OF MECHANICAL ENGINEERS | 71.92 |
| DOWNTOWN HENDERSON PARTNERSHIP | 70.40 |
| INDIANA STATE BOARD OF PROFESSIONAL ENGINEERS | 64.40 |
| CITY OF EARLINGTON | 63.43 |
| SOCIETY OF WOMEN ENGINEERS | 57.95 |
| PVA OF JEFFERSON COUNTY | 56.00 |
| NSPE (NATIONAL SOCIETY OF PROFESSIONAL ENGINEERS) | 52.80 |
| PUBLIC RELATIONS SOCIETY OF AMERICA | 50.40 |
| CERTIFIED INFORMATION SYSTEMS SECURITY PROFESSIONAL (CISSP) | 40.80 |
| KENTUCKY SOCIETY OF PROFESSIONAL ENGINEERS | 34.72 |
| AXOSOFT | 25.97 |
| KENTUCKIANA CHAPTER OF PROJECT MANAGEMENT INSTITUTE (PMI) | 23.04 |
| KENTUCKY STATE TREASURER | 14.85 |
| KENTUCKY STATE BOARD OF LICENSURE FOR PROFESSIONAL ENGINEERS AND LAN | 12.00 |
| KY ASSOCIATION OF MAPPING PROFESSIONALS | 10.75 |
| ASSOCIATED PRESS STYLEBOOK | 8.96 |
| AMAZON | (15.89) |
| Total Employee Dues | 26,700.42 |

| Vendor Name | Company Dues |
|---|---|
| KENTUCKY CLEAN FUELS COALITION | 1,590.00 |
| URBAN LEAGUE OF GREATER CINCINNATI | 1,250.00 |
| HUMAN RESOURCE CERTIFICATION PREPARTION (HRCP) MEMBERSHIP | 847.50 |
| NATIONAL ELECTRICAL MANUFACTURING ASSOCIATION (NEMA) | 806.40 |
| INDIANA COAL COUNCIL INC | 702.00 |
| WORLD TRADE CENTER | 640.00 |
| BELL COUNTY CHAMBER OF COMMERCE | 450.00 |
| FLEMING COUNTY CHAMBER OF COMMERCE | 350.00 |
| MIDCONTINENT INDEPENDENT SYSTEM OPERATOR INC | 333.33 |
| MAYSVILLE MASON COUNTY CHAMBER OF COMMERCE | 250.00 |
| INTERNATIONAL AVAYA USERS GROUP | 192.00 |
| INTERNATIONAL ASSOCIATION OF IT ASSET MANAGERS | 175.20 |
| PLURALSIGHT | 143.52 |
| SURVEY MONKEY | 133.56 |
| INSTITUTE OF HAZARDOUS MATERIALS MANAGEMENT | 102.40 |
| CINCINNATI COAL EXCHANGE | 91.00 |
| PROJECT MANAGEMENT INSTITUTE (PMI) | 76.32 |
| ASCAP | 65.71 |
| THE ELEARNING GUILD | 47.52 |
| NEXMO LTD | 30.79 |
| Total Company Dues | 8,277.25 |
| | |
| Total Employee and Company Dues | 34,977.67 |

**Breakdown of "Various Vendors" - Non-Recoverable**

| Vendor Name | Amount |
|---|---|
| AMERICAN BAR ASSOCIATION | 317.35 |
| ANDERSON CO CHAMBER OF COMMERCE | 200.00 |
| CAMPBELLSVILLE MAIN STREET INC. | 125.00 |
| COMMERCE LEXINGTON INC. | 3,496.95 |
| DANVILLE BOYLE COUNTY | 1,087.00 |
| ENERGY AND MINERAL LAW FOUNDATION | 242.00 |
| GARRARD COUNTY CHAMBER OF COMMERCE | 150.00 |
| GEORGETOWN/SCOTT COUNTY CHAMBER OF COMMERCE | 625.00 |
| GREATER LOUISVILLE INC. | 440.00 |
| GREATER MUHLENBERG CHAMBER OF COMMERCE | 1,512.00 |
| GREENSBURG GREEN COUNTY CHAMBER OF COMMERCE | 200.00 |
| HENRY COUNTY CHAMBER OF COMMERCE INC. | 120.00 |
| INDIANA COAL COUNCIL INC. | 78.00 |
| LOUISVILLE BAR ASSOCIATION | 385.00 |
| OWEN COUNTY CHAMBER OF COMMERCE | 500.00 |
| RICHMOND CHAMBER OF COMMERCE | 544.50 |
| ROCKCASTLE COUNTY CHAMBER OF COMMERCE | 400.00 |
| SPENCER COUNTY TAYLORSVILLE CHAMBER OF COMMERCE INC. | 150.00 |
| THE BUSINESS JOURNALS | 72.87 |
| THE ECONOMIST NEWSPAPER | 83.60 |
| UNION COUNTY FIRST | 500.00 |
| AMERICAN GO ASSOCIATION (USGO) | 275.00 |
| Total | 11,504.27 |

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 94**

**Responding Witness: Robert M. Conroy**

Q-94. Provide copies of the Annual Reports of EEI, EPRI, and of every other organization which require the Companies to pay dues [hereinafter collectively referred to as the "Dues Requiring Organizations"] since the conclusion of the Companies' last rate case.

A-94. The Company does not collect and retain the requested information for its corporate files. The documents requested would require an expensive and burdensome electronic search. The requested information is thus not readily available.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 95**

**Responding Witness:**

Q-95. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO MAINTAIN NUMBERING WITH CASE NO. 2018-00295]

A-95. Not applicable.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 96**

**Responding Witness: Christopher M. Garrett**

Q-96. For each Dues Requiring Organization, provide: (i) the amount of dues the Companies paid during the base period; (ii) the amount they are asking to be recovered from customers during the forecasted period. Provide the complete basis for KU's determination of whether dues should be recoverable or not recoverable.

A-96. See Tab 59 of the Filing Requirements at page 2. Recoverable and non-recoverable dues are trended based on a review of each component of historical dues. Recovery is based on operational benefit to the customer and prior precedent of the Commission.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 97**

**Responding Witness: Christopher M. Garrett**

Q-97. Provide a copy of the formula(s) used to compute, and the actual calculation of the dues the Company paid to each Dues Requiring Organization since the conclusion of the Company's last rate case.

A-97. See attached. Dues are recorded on KU's books based on actual invoices received from such organizations.

| Company | Vendor Name | Dues Calculation Method |
|---|---|---|
| KU | Edison Electric Institute (EEI) | Based on Total Average number of customers served, total revenue, and generation owned capacity |
| KU | Electric Power Research Institute (EPRI) | Based on Generator capacity (coal, gas, hydro, nuclear), peak transmission and thru put on distribution. |
| KU | University of Louisville Research Foundation Inc. | Calculation not available |
| KU | North American Transmission Forum | Load ratio share |
| KU | Hunton and Williams LLP (CCR Legal Resources Group) | Flat annual fee |
| KU | Hunton and Williams LLP (NSR Legal Resources Group) | Flat annual fee |
| KU | Steptoe & Johnson LLC (MOG) | Mega Watts & Size of Company (electric generation capacity only) |
| KU | Utility Air Regulatory Group (UARG) | Mega Watts & Size of Company |
| KU | Utility Water Act Group (UWAG) | Mega Watts & Size of Company (electric generation capacity only) |
| KU | Utility Solid Waste Activities Group (USWAG) | Mega Watts & Size of Company |
| KU | University of Missouri | Calculation not available (annual membership & board appt) |
| KU | Baker Botts LLP (Class of 85 and Cross Cutting Issues) | Flat annual fee |
| KU | Various Vendors and Other non-specific LG&E dues | Calculation not available |

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 98**

**Responding Witness: Christopher M. Garrett**

Q-98. Provide a complete copy of invoices received from each Dues Requiring Organization since the conclusion of the Company's last rate case.

A-98. See attached copies of 2017 and 2018 invoices received from Organization Memberships as presented in FR 16(8)(f), Sch. F-1.

BAKER BOTTS LLP

THE WARNER
1299 PENNSYLVANIA AVE., NW
WASHINGTON, D.C.
20004-2400

TEL +1 202.639.7700
FAX +1 202.639.7890
BakerBotts.com

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SAN FRANCISCO
**WASHINGTON**

December 8, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

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Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of December 2017.

**TOTAL AMOUNT DUE: $2,916.67**

LGE - $1,137.50
KU - $1,779.17

**Please remit to:**

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D.** [redacted]

BAKER BOTTS L.L.P.

THE WARNER
1299 PENNSYLVANIA AVE., NW
WASHINGTON, D.C.
20004-2400

TEL +1 202.639.7700
FAX +1 202.639.7890
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WASHINGTON

December 18, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental
Policy Manager
LG&E and KU Energy LLC
220 West Main Street
PO Box 32010
Louisville, KY 40202

Statement of Fees for Participation in the Class of '85 Regulatory Response Group

**Payment for:**

| | |
|---|---|
| January - December 2018 | $39,600 |
| **TOTAL AMOUNT DUE** | **$39,600*** |

*Please note that if not paid in full by 12/31/2017, the annual fee will increase to $40,800.

LGE - $15,912.00
KU - $24,888.00

**Please remit to:**

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D.** [redacted]

BAKER BOTTS LLP

THE WARNER
1299 PENNSYLVANIA AVE NW
WASHINGTON, D C
20004-2400

TEL +1 202.639.7700
FAX +1 202.639 7890
BakerBotts.com

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January 8, 2018

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

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Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of January 2018.

**TOTAL AMOUNT DUE: $2,916.67**

LGE - $1,137.50
KU - $1,779.17

**Please remit to:**

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D.** [redacted]

35382311.2

**BAKER BOTTS LLP**

THE WARNER
1299 PENNSYLVANIA AVE., NW
WASHINGTON, D C
20004-2400

TEL +1 202 639 7700
FAX +1 202 639.7890
BakerBotts.com

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SAN FRANCISCO
WASHINGTON

February 8, 2018

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

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Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of February 2018.

**TOTAL AMOUNT DUE: $2,916.67**

LGE - $1,137.50
KU - $1,779.17

Please remit to:

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D. [redacted]**

35382311.2

**BAKER BOTTS** L.L.P

THE WARNER
1299 PENNSYLVANIA AVE NW
WASHINGTON, D C
20004-2400

TEL +1 202.639 7700
FAX +1 202 639.7890
BakerBotts.com

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PALO ALTO
RIYADH
SAN FRANCISCO
**WASHINGTON**

March 8, 2018

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

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Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of March 2018.

**TOTAL AMOUNT DUE: $2,916.67**

LGE - $1,137.50
KU - $1,779.17

**Please remit to:**

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D.** [redacted]

35382311.2

**BAKER BOTTS** LLP

THE WARNER
1299 PENNSYLVANIA AVE., NW
WASHINGTON, D.C.
20004-2400

TEL +1 202.639.7700
FAX +1 202.639.7890
BakerBotts.com

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LAW DEPARTMENT

December 14, 2016

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
PO Box 32010
Louisville, KY 40202

Inv. No.
C85-121416

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Statement of Fees for Participation in the Class of '85 Regulatory Response Group

| | |
|---|---|
| December 2016 | $3,200 |
| **TOTAL AMOUNT DUE** | **$3,200** |

**Summary of Activities:** Draft and distribute memoranda and emails to members regarding Clean Air Act issues; review status of EPA and citizen group lawsuits based on various Clean Air Act Programs; send summaries to clients of various Clean Air Act actions; review Federal Register notices and EPA guidance; request clarifications from EPA on various rules; correspondence with EPA staff regarding recent regulatory developments; respond to client questions regarding various Clean Air Act developments.

**Please remit to:**

LGE - $1,216.00

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

KU - $1,984.00

**Taxpayer I.D.** [redacted]

Active 24760494.1

**BAKER BOTTS** LLP

THE WARNER
1299 PENNSYLVANIA AVE., NW
WASHINGTON, D.C.
20004-2400

TEL +1 202.639.7700
FAX +1 202.639.7890
BakerBotts.com

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HOUSTON

LONDON
MOSCOW
NEW YORK
PALO ALTO
RIYADH
SAN FRANCISCO
WASHINGTON

December 14, 2016

Inv. No. ~~[illegible]~~ ~~[illegible]~~

Mr. Robert J. Ehrler
Senior Counsel and Environmental
Policy Manager
LG&E and KU Energy LLC
220 West Main Street
PO Box 32010
Louisville, KY 40202

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Statement of Fees for Participation in the Class of '85 Regulatory Response Group

**Payment for:**

| | |
|---|---|
| January - December 2017 | $38,400 |
| **TOTAL AMOUNT DUE** | **$38,400*** |

*Please note that if not paid in full by 12/31/2016, the annual fee will increase to $39,600.

**Please remit to:**

LGE - $15,048
KU - $24,552

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D.** [redacted]

Active 24760494.2

**BAKER BOTTS LLP**

THE WARNER
1299 PENNSYLVANIA AVE., NW
WASHINGTON, D.C.
20004-2400

TEL +1 202.639.7700
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NEW YORK
PALO ALTO
RIYADH
SAN FRANCISCO
WASHINGTON

January 12, 2017

Invoice #
~~001 011217~~

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

---

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of January 2017

**TOTAL AMOUNT DUE:** **$2,916.66**

LGE - $ 1,108.33
KU - $ 1,808.33

**Please remit to:**

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D** [redacted]

32021375.1

BAKER BOTTS LLP

THE WARNER
1299 PENNSYLVANIA AVE., NW
WASHINGTON, D.C.
20004-2400

TEL +1 202.639.7700
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RIYADH
SAN FRANCISCO
WASHINGTON

BAKERB 02 1017

February 10, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

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Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of February 2017

**TOTAL AMOUNT DUE: $2,916.67**

LGE - $ 1,108.33
KU - $ 1,808.34

**Please remit to:**

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D.** [redacted]

33422162.1

**BAKER BOTTS** LLP

THE WARNER
1299 PENNSYLVANIA AVE., NW
WASHINGTON, D.C.
20004-2400

TEL +1 202.639.7700
FAX +1 202.639.7890
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MOSCOW
NEW YORK
PALO ALTO
RIYADH
SAN FRANCISCO
**WASHINGTON**

March 7, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

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Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of March 2017.

**TOTAL AMOUNT DUE: $2,916.67**

LGE - 1,108.33
KU - 1,808.34

**Please remit to:**

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D.**[redacted]

34284097.1

BAKER BOTTS LLP

THE WARNER
1299 PENNSYLVANIA AVE., NW
WASHINGTON, D.C.
20004-2400

TEL +1 202.639.7700
FAX +1 202.639.7890
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NEW YORK
PALO ALTO
RIYADH
SAN FRANCISCO
WASHINGTON

April 12, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

---

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of April 2017.

**TOTAL AMOUNT DUE: $2,916.67**

LGE - $1,108.33
KU - $1,808.34

**Please remit to:**

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D** [redacted]

35199804.1

BAKER BOTTS LLP

THE WARNER
1299 PENNSYLVANIA AVE., NW
WASHINGTON, D.C.
20004-2400

TEL +1 202.639.7700
FAX +1 202.639.7890
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PALO ALTO
RIYADH
SAN FRANCISCO
WASHINGTON

May 5, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

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Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of May 2017.

**TOTAL AMOUNT DUE: $2,916.67**

LGE - $1,108.33
KU - $1,808.34

**Please remit to:**

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D.**[redacted]

35382163.1

**BAKER BOTTS** LLP

THE WARNER
1299 PENNSYLVANIA AVE., NW
WASHINGTON, D.C.
20004-2400

TEL +1 202.639.7700
FAX +1 202.639.7890
BakerBotts.com

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NEW YORK
PALO ALTO
RIYADH
SAN FRANCISCO
**WASHINGTON**

BAKERB 060577
6/5/17

June 5, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

---

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of June 2017.

**TOTAL AMOUNT DUE: $2,916.67**

LGE - $1,108.33
KU - $1,808.34

**Please remit to:**

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D.** [redacted]

35382294.1

**BAKER BOTTS** L.L.P

THE WARNER
1299 PENNSYLVANIA AVE., NW
WASHINGTON, D.C.
20004-2400

TEL +1 202.639.7700
FAX +1 202.639.7890
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NEW YORK
PALO ALTO
RIYADH
SAN FRANCISCO
WASHINGTON

July 5, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

BAKERB071217

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Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of July 2017.

**TOTAL AMOUNT DUE: $2,916.67**

LGE - $1,108.33
KU - $1,808.34

**Please remit to:**

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D.** [redacted]

35382298.1

**BAKER BOTTS** LLP

THE WARNER
1299 PENNSYLVANIA AVE., NW
WASHINGTON, D.C.
20004-2400

TEL +1 202.639.7700
FAX +1 202.639.7890
BakerBotts.com

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MOSCOW
NEW YORK
PALO ALTO
RIYADH
SAN FRANCISCO
**WASHINGTON**

August 4, 2017

Mr. Robert J. Ehrler
Senior Counsel and Environmental Policy Manager
LG&E and KU Energy LLC
220 West Main Street
Louisville, Kentucky 40202
bob.ehrler@lge-ku.com

---

Statement of Fees for Participation in the Cross-Cutting Issues Group for the month of August 2017.

**TOTAL AMOUNT DUE: $2,916.67**

LGE - $1,108.33
KU - $1,808.34

**Please remit to:**

**Baker Botts L.L.P.**
**P.O. Box 301251**
**Dallas, TX 75303-1251**

**Taxpayer I.D.** [redacted]

35382311.1

# Invoice for Membership Dues

Edison Electric
INSTITUTE

MR. WILLIAM H. SPENCE
CHAIRMAN, PRESIDENT & CEO
PPL CORPORATION
2 N 9TH STREET
ALLENTOWN, PA 18101

| Date | Invoice Number |
|---|---|
| 12/13/2017 | DUES201850 |

***Payment due on or before 1/31/2018***

| Description | Total |
|---|---|
| **2018 EEI Membership Dues for:** | |
| Regular Activities of Edison Electric Institute [1] | $1,171,634 |
| Industry Issues [2] | 117,163 |
| Restoration, Operations, and Crisis Management Program [3] | 15,000 |
| **2018 Contribution to The Edison Foundation, which funds IEI [4]** | A 30,000 |
| **Total** | **$1,333,797** |

1 The portion of 2018 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes, is estimated to be 13%.

2 The portion of the 2018 industry issues support relating to influencing legislation is estimated to be 24%.

3 The Restoration, Operations, and Crisis Management Program is related to improvements to industry-wide responses to major outages (e.g. National Response Event); continuity of industry and business operations; and EEI's all hazards (storms, cyber, etc.) support and coordination of the industry during times of crises. No portion of this assessment is allocable to influencing legislation.

4 The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. Contributions are deductible for federal income tax purposes to the extent provided by law. Please consult your tax advisor with respect to your specific situation.

## PLEASE NOTE INFORMATION FOR ELECTRONIC PAYMENT

The following instructions should be used when transferring funds electronically (ACH or wire) to Edison Electric Institute:

**Beneficiary's Bank:** [redacted]
**Bank's Address:**
**Bank's ABA Number:**
**Beneficiary:**
**Beneficiary's Acct No:**
**Beneficiary's Address:**
**Beneficiary Reference:**

1,333,797
A <30,000>
1,303,797
x .65
847,468.05
LGE * 345,512.7[illegible]
KU * 501,955.30

Please refer any questions to Terri Oliva, EEI Controller: (202) 508-5541 *or* memberdues@eei.org

2

Indirect (CATGB)
2) Office of Chairman

2018

January-December 2018 EEI Membership Dues (invoice attached)
$1,153,181 — This payment will be amortized 1/12 to expense each month at PPL Financial and will be allocated to the Business Lines as a Category B cost.

| | | |
|---|---|---|
| Total for year | $1,303,797 | p4 |
| 65% to Kentucky (Category B) | 65.00% | p7, 9 |
| | 847,468.05 | |
| Jan-Dec 2017 cost to Kentucky for EEI Membership Dues | $847,468.05 | |
| Rounded to | $847,468.00 | p6 |

**Journal Entry Calculation**

2018's EEI Dues allocation % is based on 2018's %

| Allocation | Amount | Company |
|---|---|---|
| p3 40.77% | $ 345,512.70 | LGE p1 |
| 59.23% | $ 501,955.30 | KU |
| Total | $ 847,468.00 | |

| | Total | Calculation of LKE EEI Dues: Non-Lobbying | | Lobbying | | Contribution | |
|---|---|---|---|---|---|---|---|
| Total for year | $1,153,181.00 D | 1,123,365.46 | A | 180,431.54 | B | - | C |
| 1/12 Amortization each month | 8.33% | 8.33% | | 8.33% | | 0 | |
| PPL Financial expense each month | $96,098.42 | $93,613.79 | | $15,035.96 | | $0.00 | |
| 65.00% to Kentucky | 65.0% | 65.00% | | 65.00% | | 65.00% | |
| Estimated cost to Kentucky each month for EEI Membership Dues | $62,463.97 | $60,848.96 | | $9,773.37 | | $0.00 | |
| | | | | | | Expensed not amortized | |
| Estimated Category B cost to Kentucky in 2018 for EEI Membership Dues | $749,567.64 | $730,187.52 | | $117,280.44 | | $0.00 | |

**Amortization Period: January 2018 - December 2018**

| Allocation | Amount | Company | Project | Task | Account | Exp Type | Exp Org |
|---|---|---|---|---|---|---|---|
| 40.77% | $ 24,808.12 | LGE | 119013 | EEI GC | 930272 | 0684 | 026910 |
| 59.23% | $ 36,040.84 | KU | 119012 | EEI-GC | 930272 | 0684 | 026910 |
| 40.77% | $ 3,984.60 | LGE | 119013 | EEI Lobby | 426491 | 0684 | 026910 |
| 59.23% | $ 5,788.77 | KU | 119012 | EEI-Lobby | 426491 | 0684 | 026910 |

Total amount to be amortized per month 62,463.97

| | | |
|---|---|---|
| Rounded to | | 24,808.12 |
| | | 36,040.84 |
| | | 3,984.60 |
| | | 5,788.77 |
| | | 70,622.33 |
| x12 months | LGE | 297,697.44 |
| | KU | 432,490.08 |
| | LGE | 47,815.20 |
| | KU | 69,465.24 |
| | | 847,467.96 |

<- will need true-up at the end of 2018 once recalculation is completed

**Calculation of PPL EEI Dues**

| | | | | |
|---|---|---|---|---|
| | Regular Activities | $ | 1,171,634.00 | p4, 9 |
| p4 – 13% | Lobbying | $ | 152,312.42 | |
| | EEI Dues | $ | 1,019,321.58 | |
| | Industry issues | $ | 117,163.00 | p4 |
| p4 – 24% | Lobbying | $ | 28,119.12 | |
| | EEI Dues | $ | 89,043.88 | |
| | Restore Power | $ | 15,000.00 | p4 |
| | Contribution to Edison Foundation | $ | - | |
| | Lobbying Total | $ | 180,431.54 | B |
| | Contribution Total | $ | - | C |
| | EEI Dues Total | $ | 1,123,365.46 | A |
| | Total Invoice | $ | 1,303,797.00 | D |

p4

# Invoice for Membership Dues

Edison Electric INSTITUTE

MR. WILLIAM H. SPENCE
CHAIRMAN, PRESIDENT & CEO
PPL CORPORATION
2 N 9TH STREET
ALLENTOWN, PA 18101

| Date | Invoice Number |
|---|---|
| 12/07/2016 | DUES201752 |

*Payment due on or before 1/31/2017*

| Description | Total |
|---|---|
| 2017 EEI Membership Dues for: | |
| Regular Activities of Edison Electric Institute [1] | $1,153,181 /2 |
| Industry Issues [2] | 115,318 / |
| Restoration, Operations, and Crisis Management Program [3] | 15,000 / |
| 2017 Contribution to The Edison Foundation, which funds IEI [4] | A ~~30,000~~ e |
| Total | 1,283,499 ~~$1,313,499~~ /2 |

1 The portion of 2017 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes, is estimated to be 13%. /2

2 The portion of the 2017 Industry Issues support relating to influencing legislation is estimated to be 25%. /2

3 The Restoration, Operations, and Crisis Management Program is related to improvements to industry-wide responses to major outages (e.g. National Response Event); continuity of industry and business operations; and EEI's all hazards (storms, cyber, etc.) support and coordination of the industry during times of crises. No portion of this assessment is allocable to influencing legislation.

4 The Edison Foundation is an IRC 501(c)(3) educational and charitable organization. Contributions are deductible for federal income tax purposes to the extent provided by law. Please consult your tax advisor with respect to your specific situation.

## PLEASE NOTE INFORMATION FOR ELECTRONIC PAYMENT

The following instructions should be used when transferring funds electronically (ACH or wire) to Edison Electric Institute:

Beneficiary's Bank: [redacted]
Bank's Address:
Bank's ABA Number:
Beneficiary:
Beneficiary's Acct No:
Beneficiary's Address:
Beneficiary Reference:

1,313,499
<30,000> A
1,283,499
x .66
847,109.34 < LGE * 353,427.04 / KU * 493,681.96

Approved for Payment:

Please refer any questions to Terri Oliva, EEI Controller: (202) 508-5541 *or* memberdues@eei.org

Indirect (CATGB) 2017
2) Office of Chairman

January-December 2017 EEI Membership Dues (invoice attached)
$1,283,499 This payment will be amortized 1/12 to expense each month at PPL Financial and will be allocated to the Business Lines as a Category B cost.

| | | | |
|---|---|---|---|
| Total for year | | 4 | $1,283,499 |
| | 66% to Kentucky (Category B) | 5 | 66.00% |
| | | | 847,109.34 |
| Jan-Dec 2017 cost to Kentucky for EEI Membership Dues | | | $847,109.34 |
| | Rounded to | 5 | 847,109.00 |

**Journal Entry Calculation**

| Allocation | Amount | Company | |
|---|---|---|---|
| 41.72% | $ 353,427.04 | LGE | 1 |
| 58.28% | $ 493,681.96 | KU | 1 |
| Total | $ 847,109.00 | | |

2017's EEI Dues allocation % is based on 2015's %

| | | | Non-Lobbying | Lobbying | Contribution |
|---|---|---|---|---|---|
| | | | **Calculation of LKE EEI Dues** | | |
| Total for year | | $1,283,499.00 D | 1,104,755.97 A | 178,743.03 B | - C |
| | 1/12 Amortization each month | 8.33% | 8.33% | 8.33% | 0 |
| PPL Financial expense each month | | $106,958.25 | $92,063.00 | $14,895.25 | $0.00 |
| | 66.00% to Kentucky | 66.0% | 66.00% | 66.00% | 66.00% |
| Estimated cost to Kentucky each month for EEI Membership Dues | | $70,592.45 | $60,761.58 | $9,830.87 | $0.00 |
| Estimated Category B cost to Kentucky in 2016 for EEI Membership Dues | | $847,109.40 | $729,138.96 | $117,970.44 | $0.00 Expensed not amortized |

**Amortization Period: January 2016 - December 2016**

| Allocation | Amount | Company | Project | Task | Account | Exp Type | Exp Org |
|---|---|---|---|---|---|---|---|
| 41.72% | $ 25,350.68 | LGE | 119013 | EEI GC | 930272 | 0664 | 026910 |
| 58.28% | $ 35,410.90 | KU | 119012 | EEI-GC | 930272 | 0664 | 026910 |
| 41.72% | $ 4,101.59 | LGE | 119013 | EEI Lobby | 426491 | 0664 | 026910 |
| 58.28% | $ 5,729.28 | KU | 119012 | EEI-Lobby | 426491 | 0664 | 026910 |

Total amount to be amortized per month
70,592.45

| | | |
|---|---|---|
| Rounded to | | 25,350.68 |
| | | 35,410.90 |
| | | 4,101.59 |
| | | 5,729.28 |
| | | 70,592.45 |
| | x12 months | |
| | LGE | 304,208.16 |
| | KU | 424,930.80 |
| | LGE | 49,219.08 |
| | KU | 68,751.36 |
| | | 847,109.40 <- will need true-up at the end of 2017 once recalculation is completed |

**Calculation of PPL EEI Dues**

| | | | | |
|---|---|---|---|---|
| | | Regular Activities | $ | 4 1,153,181.00 |
| 4 | 13% | Lobbying | $ | 149,913.53 |
| | | EEI Dues | $ | 1,003,267.47 |
| | | Industry Issues | $ | 4 115,318.00 |
| 4 | 25% | Lobbying | $ | 28,829.50 |
| | | EEI Dues | $ | 86,488.50 |
| | | Restore Power | $ | 4 15,000.00 |
| | | Contribution to Edison Foundation | $ | - |
| | | Lobbying Total | $ | 178,743.03 B |
| | | Contribution Total | $ | - C |
| | | EEI Dues Total | $ | 1,104,755.97 A |
| | | Total Invoice | $ | 1,283,499.00 D |

ELECTRIC POWER RESEARCH INSTITUTE

# INVOICE

Invoice: 90022357
Invoice Date: 01/18/2018
Page: 2 of 2

P.O. Box 10412
Palo Alto CA 94303-0813
USA

Customer No: 30166
Payment Terms: EPRI - Net due in 30 days
Due Date: 02/17/2018
Customer Ref:
EPRI Quotation No: 20008283

Customer: David Link
LG&E and KU Energy LLC
220 W Main St
Louisville KY 40202-1395
USA

For billing questions, please contact:

Telephone: 650-855-2048
Fax: 650-855-2358
Email: accountsreceivable@epri.com

AMOUNT DUE: 3,455,281.35 USD

| | | | | |
|---|---|---|---|---|
| 19 | Protection and Control | 1 | EA | 23,098.48 |
| 20 | Energy Storage and Distributed Generation | 1 | EA | 130,011.15 |
| 21 | Distribution Operations and Planning | 1 | EA | 79,266.77 |
| 22 | Technical Deployment | 1 | EA | 44,470.43 |
| | Deposit Account | | | 247,469.00 |

Subtotal: 3,455,281.35
Amount Due: 3,455,281.35 USD

CPA# 116812 PO# ________________

| Project | Task | Exp Type | $$ or % Split |
|---|---|---|---|
| 133671 | EPRI | 0305 | $ 82,640.21 |
| 133679 | EPRI | 0305 | $ 82,640.21 |
| SRC153955 | I-Prepaid | 0305 | $3,290,000.93 |

KU - 2,039,800.58
LGE - 1,250,200.35

1/30/18
David J. Link, Ph.D. - Manager R&D — Date

1-30-18
David Sinclair - VP Energy Supply and Analysis — Date

Actual amount is $1.51 lower than amount forecasted in Filing Requirement 16(8)(f).

1/30/18
Lonnie Bellar - SVP Operations — Date

1/30/18
Kent Blake - CFO — Date

Please wire funds to:
Bank of America
[redacted]

Please remit check to:
Electric Power Research Institute
13014 Collections Center Drive
Chicago IL 60693
United States

Tax I.D. [redacted]
EPRI is a non-profit United States Corporation.
Please include an invoice copy with your remittance.

ELECTRIC POWER RESEARCH INSTITUTE

# INVOICE

Invoice: 90017191
Invoice Date: 01/17/2017
Page: 2 of 2

P.O. Box 10412
Palo Alto CA 94303-0813
USA

Customer No: 30166
Payment Terms: EPRI - Net due in 30 days
Due Date: 02/16/2017
Customer Ref:
EPRI Quotation No: 20006982

Customer: David Link
LG&E and KU Energy LLC
220 W Main St
Louisville KY 40202-1395
USA

For billing questions, please contact:

Telephone: 650-855-2048
Fax: 650-855-2358
Email: accountsreceivable@epri.com

**AMOUNT DUE: 4,716,825.78 USD**

| | | | | |
|---|---|---|---|---|
| | Environmental Issues | | | |
| 20 | Transmission and Distribution and ROW Environmental Issues | 1 | EA | 107,448.60 |
| 21 | Fish Protection at Electric Generating Facilities | 1 | EA | 129,284.78 |
| 22 | Effluent Guidelines and Water Quality Management | 1 | EA | 121,214.48 |
| 23 | Protection and Control | 1 | EA | 24,591.02 |
| 24 | Electric Transportation | 1 | EA | 109,181.27 |
| 25 | Energy Storage and Distributed Generation | 1 | EA | 116,093.76 |
| 26 | Cyber Security and Privacy | 1 | EA | 131,187.56 |
| | Deposit Account | | | 851,234.00 |
| | | | Subtotal: | 4,716,825.78 |
| | | | **Amount Due:** | **4,716,825.78 USD** |

4,716,825.78
<81,196.94>
<81,196.94>
4,554,431.90 < KU - *2,869,292.10
LGE - *1,685,139.80

Please wire funds to:
Bank of America
[redacted]

Please remit check to:
EPRI
13014 Collections Center Drive
Chicago IL 60693
United States

Tax I.D. [redacted]
EPRI is a non-profit United States Corporation.
Please include an invoice copy with your remittance.

ELECTRIC POWER RESEARCH INSTITUTE

# INVOICE

**Invoice:** 90017191
**Invoice Date:** 01/17/2017
**Page:** 1 of 2

P.O. Box 10412
Palo Alto CA 94303-0813
USA

**Customer No:** 30166
**Payment Terms:** EPRI - Net due in 30 days
**Due Date:** 02/16/2017
**Customer Ref:**
**EPRI Quotation No:** 20006982

Customer: David Link
LG&E and KU Energy LLC
220 W Main St
Louisville KY 40202-1395
USA

For billing questions, please contact:

**Telephone:** 650-855-2048
**Fax:** 650-855-2358
**Email:** accountsreceivable@epri.com

**AMOUNT DUE:** **4,716,825.78 USD**

| Line | Description | Quantity | UOM | Net Amount |
|---|---|---|---|---|
| 1 | Integrated Environmental Controls | 1 | EA | 545,222.51 |
| 2 | Continuous Emissions Monitoring | 1 | EA | 107,209.72 |
| 3 | Heat Rate Improvement | 1 | EA | 87,172.52 |
| 4 | Water Management Technology | 1 | EA | 162,393.87 |
| 5 | Boiler Life and Availability Improvement | 1 | EA | 172,726.19 |
| 6 | Steam Turbines-Generators and Auxiliary Systems | 1 | EA | 137,162.72 |
| 7 | Balance of Plant Systems and Equipment | 1 | EA | 36,829.86 |
| 8 | Boiler and Turbine Steam and Cycle Chemistry | 1 | EA | 103,875.96 |
| 9 | Fossil Materials and Repair | 1 | EA | 155,516.02 |
| 10 | Combined Cycle Turbomachinery | 1 | EA | 306,031.04 |
| 11 | Combined Cycle HRSG and Balance of Plant | 1 | EA | 107,086.21 |
| 12 | Maintenance Management and Technology | 1 | EA | 142,793.57 |
| 13 | Operations Management and Technology | 1 | EA | 127,277.81 |
| 14 | CO2 Capture, Utilization and Storage | 1 | EA | 179,981.32 |
| 15 | Renewables Technology Status, Cost and Performance | 1 | EA | 62,798.67 |
| 16 | Solar | 1 | EA | 116,626.10 |
| 17 | Power Plant Multimedia Toxics Characterization | 1 | EA | 207,200.39 |
| 18 | Assessment of Air Quality Impacts on Human Health | 1 | EA | 202,700.52 |
| 19 | Coal Combustion Products - | 1 | EA | 165,985.31 |

Please wire funds to:
Bank of America
[redacted]

Please remit check to:
EPRI
13014 Collections Center Drive
Chicago IL 60693
United States

Tax I.D. [redacted]
EPRI is a non-profit United States Corporation.
Please include an invoice copy with your remittance.

Detailed Amortization

**EPRI Annual Membership**

Contract Period: 01/01/2017 - 12/31/2017
Contact: Courtney Suyeyasu
Vendor: EPRI
Invoice #: 90017191
Invoice Amt.: $ 4,716,825.78
Invoice Date: 01/17/2017

| Company | Exp Org | Exp Type | Project | Task | Amount | Monthly (January - April 2017 Allocation Method: 124651 I-PREPAID) | KU Amort. | | LGE Amort. (January - April 2017 Allocation Method: 124652 I-PREPAID) | | KU Amort. (May - December 2017 Allocation Method: 124651 I-PREPAID) | | LGE Amort. (May - December 2017 Allocation Method: 124652 I-PREPAID) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 0100 | 008825 | 0375 | 133671 | EPRI | $ 81,196.94 | $ 6,766.41 | $ - | | $ 6,766.41 | | $ - | | $ 6,766.41 | |
| 0100 | 008825 | 0375 | 133679 | EPRI | $ 81,196.94 | $ 6,766.41 | $ - | | $ 6,766.41 | | $ - | | $ 6,766.41 | |
| 0020 | 022070 | 0650 | SRC153955 | EPRI-274 | $ 3,703,197.90 | $ 308,599.83 | $ 194,417.89 | 63.00% | $ 114,181.94 | 37.00% | $ 191,331.89 | 62.00% | $ 117,267.94 | 38.00% |
| 0020 | 022070 | 0650 | SRC153955 | EPRISUP | $ 851,234.00 | $ 70,936.17 | $ 44,689.79 | 63.00% | $ 26,246.38 | 37.00% | $ 43,980.43 | 62.00% | $ 26,955.74 | 38.00% |
| | | | | | 4,716,825.78 | $ 393,068.82 | $ 239,107.68 | | $ 153,961.14 | | $ 235,312.32 | | $ 157,758.50 | |

| | Servco Exp Org | Exp Type | Project | Task | LG&E Exp Org | Exp Type | Project | Task |
|---|---|---|---|---|---|---|---|---|
| Amortization | 022070 | 0650 | SRC124652 | I-PREPAID | 008825 | 0650 | 124652 | I-PREPAID |

| | Prepaid KU | Prepaid LGE | 4 Month Amortization | 4 Month Amortization LGE | Prepaid KU Balance | Prepaid LGE Balance |
|---|---|---|---|---|---|---|
| 3,703,197.90 | 2,333,014.68 | 1,370,183.22 | 777,671.57 | $ 456,727.75 | 1,555,343.11 | 913,455.47 |
| 851,234.00 | 536,277.42 | 314,956.58 | 178,759.15 | $ 104,985.53 | 357,518.27 | 209,971.05 |
| | 2,869,292.10 | 1,685,139.80 | | | 1,912,861.38 | 1,123,426.52 |

HUNTON& WILLIAMS

HUNTON & WILLIAMS LLP
BANK OF AMERICA PLAZA
101 SOUTH TRYON STREET
SUITE 3500
CHARLOTTE, NC 28280

TEL 704 • 378 • 4700
FAX 704 • 378 • 4890

NASH LONG
DIRECT DIAL: 704-378-4728
EMAIL: NLONG@HUNTON.COM

BRENT ROSSER
DIRECT DIAL: 704-378-4707
EMAIL: BROSSER@HUNTON.COM

FILE NO: 86837.000002

December 20, 2017

***Confidential***
***Attorney-Client Privilege***

J. Gregory Cornett
Associate General Counsel
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

**Re: Coal Combustion Residuals Legal Resources Group**

Retainer for services in connection with the
Coal Combustion Residuals Legal Resources Group for 2018 .................$70,000

| |
|---|
| **PLEASE REMIT PAYMENT BY JANUARY 20, 2018**<br>**USE ONE OF THE BELOW METHODS OF PAYMENT** |

**Check Via First-Class Mail**

**Hunton & Williams LLP**
**Attention: Kathy Robinson**
**2200 Pennsylvania Avenue, NW**
**Washington, DC 20037**
**Reference -- 2018 CCR Annual Dues/86837.2**

**Wiring Instructions**

**Bank:** [redacted]
**Account Name:**

**Account No.**
**ABA Transit Routing No.**
**Information with wire**
**Swift Code (Internat'l)**

LGE - $26,600
KU - $43,400

HUNTON& WILLIAMS

HUNTON & WILLIAMS LLP
BANK OF AMERICA PLAZA
101 SOUTH TRYON STREET
SUITE 3500
CHARLOTTE, NC 28280

TEL 704 • 378 • 4700
FAX 704 • 378 • 4890

NASH LONG
DIRECT DIAL: 704-378-4728
EMAIL: NLONG@HUNTON.COM

BRENT ROSSER
DIRECT DIAL: 704-378-4707
EMAIL: BROSSER@HUNTON.COM

FILE NO: 86837.000002

January 3, 2017

***Confidential***
***Attorney-Client Privilege***

J. Gregory Cornett
Associate General Counsel
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202

~~Invoice No. CCR 20~~17

**Re: Coal Combustion Residuals Legal Resources Group**

Retainer for services in connection with the
Coal Combustion Residuals Legal Resources Group for 2017 .................$70,000

**PLEASE REMIT PAYMENT BY JANUARY 20, 2017**
**USE ONE OF THE BELOW METHODS OF PAYMENT**

**Check Via First-Class Mail**

**Hunton & Williams LLP**
**Attention: Kathy Robinson**
**2200 Pennsylvania Avenue, NW**
**Washington, DC 20037**
**Reference -- 2017 CCR Annual Dues/86837.2**

**Wiring Instructions**

**Bank:** [redacted]
**Account Name:**

**Account No.**
**ABA Transit Routing No.**
**Information with wire**
**Swift Code (Internat'l)**

LGE - $26,600
KU - $43,400

HUNTON& WILLIAMS

HUNTON & WILLIAMS LLP
BANK OF AMERICA PLAZA, SUITE 3500
101 SOUTH TRYON STREET
CHARLOTTE, NC 28280

TEL 704 • 378 • 4700
FAX 704 • 378 • 4890

NASH LONG
DIRECT DIAL: 704-378-4728
EMAIL: nlong@hunton.com

BRENT ROSSER
DIRECT DIAL: 704-378-4707
EMAIL: brosser@hunton.com

FILE NO: 54675.000002

December 14, 2017

***Confidential***
***Attorney-Client Privilege***

Robert J. Ehrler, Esq.
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40232

**Re: NSR Legal Resources Group**

Retainer for services in connection with the
NSR Legal Resources Group for 2018 ............................................$35,000

**PLEASE REMIT PAYMENT BY JANUARY 20, 2018**
**USE ONE OF THE BELOW METHODS OF PAYMENT**

**Check Via First-Class Mail**

**Hunton & Williams LLP**
**Attention: Kathy Robinson**
**2200 Pennsylvania Avenue, NW**
**Washington, DC 20037**
**Reference -- 2018 NSR Annual Dues/54675.2**

**Wiring Instructions**

**Bank:** [redacted]
**Account Name:**

**Account No.**
**ABA Transit Routing No**
**Information with wire**
**Swift Code (Internat'l)**

LGE - $12,250
KU - $22,750

HUNTON&
WILLIAMS

HUNTON & WILLIAMS LLP
BANK OF AMERICA PLAZA, SUITE 3500
101 SOUTH TRYON STREET
CHARLOTTE, NC 28280

TEL 704 • 378 • 4700
FAX 704 • 378 • 4890

NASH LONG
DIRECT DIAL: 704-378-4728
EMAIL: nlong@hunton.com

BRENT ROSSER
DIRECT DIAL: 704-378-4707
EMAIL: brosser@hunton.com

FILE NO: 54675.000002

December 16, 2016

Inv. No.
~~NSR 2017~~

***Confidential***
***Attorney-Client Privilege***

Robert J. Ehrler, Esq.
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40232

**Re: NSR Legal Resources Group**

Retainer for services in connection with the
NSR Legal Resources Group for 2017 ....................................................$35,000

**PLEASE REMIT PAYMENT BY JANUARY 20, 2017**
**USE ONE OF THE BELOW METHODS OF PAYMENT**

**Check Via First-Class Mail**

**Hunton & Williams LLP**
**Attention: Kathy Robinson**
**2200 Pennsylvania Avenue, NW**
**Washington, DC 20037**
**Reference -- 2017 NSR Annual Dues/54675.2**

**Wiring Instructions**

**Bank:**
**Account Name:**

**Account No.**
**ABA Transit Routing No.**
**Information with wire**
**Swift Code (Internat'l)**

[redacted]

LGE - $12,250
KU - $22,750

North American Transmission FORUM

North American Transmission Forum, Inc.
9300 Harris Corners Parkway
Suite 300
Charlotte, NC 28269
(704) 945-1900
taldred@natf.net
http://www.natf.net

# INVOICE

**BILL TO**
LGE & KU Energy, LLC
220 W. Main Street
Louisville, KY 40202

**INVOICE #** 1702
**DATE** 10/08/2017
**DUE DATE** 01/31/2018
**TERMS** Net 30

| ACTIVITY | AMOUNT |
|---|---|
| Membership<br>Equal Share 2018 | 22,000.00 |
| Load Ratio Share<br>Load Ratio Share 2018 | 51,165.00 |

**BALANCE DUE** **$73,165.00**

Project 141057 Task I-COMPANYDUES
Exp Org 023000 Exp Type 0650
Amount Approved 73,165.00
Date Approved
Approved by

Chr Bel
2/8/18

LGE - 25,607.75
KU - 47,557.25

V# 70727

North American Transmission FORUM

North American Transmission Forum, Inc.
9300 Harris Corners Parkway
Suite 300
Charlotte, NC 28269
(704) 945-1900
taldred@natf.net
http://www.natf.net

# INVOICE

**BILL TO**
LGE & KU Energy, LLC
220 W. Main Street
Louisville, KY 40202

**INVOICE #** 1605
**DATE** 10/03/2016
**DUE DATE** 12/31/2016
**TERMS** Net 30

| DATE | ACCOUNT SUMMARY | AMOUNT |
|---|---|---|
| 11/09/2015 | Balance Forward | $55,401.00 |
| | Payments and credits between 11/09/2015 and 10/03/2016 | -55,401.00 |
| | New charges (details below) | 61,829.00 |
| | Total Amount Due | $61,829.00 |

| ACTIVITY | AMOUNT |
|---|---|
| **Membership**<br>Equal Share 2017 | 22,000.00 |
| **Load Ratio Share**<br>Load Ratio Share 2017 | 39,829.00 |

| | |
|---|---|
| TOTAL OF NEW CHARGES | 61,829.00 |
| BALANCE DUE | **$61,829.00** |

Invoices are dated with a 12/31/2016 due date. You can pay in 2016 or no later than 1/31/2017. Contact Teresa Aldred @ 704-945-1923 if you need anything changed to process. Email copy was sent on 10/3/16 to Member Reps

LGE - $21,021.86
KU - $40,807.14

RECEIVED
OCT 06 2016
ACCOUNTS PAYABLE

1605, 10/03/2016

PO# 130652

pjm

DATE 12/22/2017

REFERENCE NO. 2018-9

FROM:
PJM INTERCONNECTION, L.L.C.
955 JEFFERSON AVENUE
VALLEY FORGE CORPORATE CENTER
NORRISTOWN, PA 19403-2497
ATTN: Accts Receivable
(610)-666-8800

TO:
LGE/KU

Project 141060 Task I-COMPANYDUES
Exp Org 023005 Exp Type 0650
Amount Approved 11,320.95
Date Approved 1/31/18
Approved by Chris Balmer

2017 Additional Cost Allocation for Eastern Interconnection Planning Collaborative $11,320.95

Payment due within 30 days of invoice receipt

WIRING INSTRUCTIONS:
Account Name:
Account Number:
Bank:
ABA:
[redacted]

LGE - 3,962.33 (under #5K)
KU - 7,358.62

12/22/2017

# MIDWEST OZONE GROUP

## MEMBERSHIP INVOICE

November 27, 2017

LG&E / KU
Attention: Robert Ehrler
220 West Main Street
Louisville, KY 40202

2018 Assessment based upon 1.25 share,
due on or before March 31, 2018

$68,750.00 Current Dues

LGE - $24,062.50
KU - $44,687.50

Please make payment to: Steptoe & Johnson, PLLC
Agent for MOG
c/o David M. Flannery
Post Office Box 1588
Charleston, West Virginia 25326

# MIDWEST OZONE GROUP

## MEMBERSHIP INVOICE

November 4, 2016

Inv. No.

LG&E / KU
Attention: Robert Ehrler
220 West Main Street
Louisville, KY 40202

2017 Assessment based upon 1.25 share,
due on or before March 31, 2017

$68,750.00 Current Dues

LGE - $ 24,062.50
KU - $ 44,687.50

**Please make payment to:** Steptoe & Johnson, PLLC
Agent for MOG
c/o David M. Flannery
Post Office Box 1588
Charleston, West Virginia 25326

EEI

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696
USA
A/R Phone Number . (202) 508 5428
A/R E-Mail accountsreceivable@eei.org

# Invoice

Mr. Gary H. Revlett
Director, Environmental Affairs
LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

Invoice # : 209242
Invoice Date: 12/13/2017
FEIN: [redacted]

| Description | Quantity | Price | Discount | Amount |
|---|---|---|---|---|
| 2018 UARG Membership Dues - Mr. Gary H. Revlett | 1 | $281,841.00 | $0.00 | $281,841.00 |

*This invoice is for your participation in the Utility Air Regulatory Group (UARG) for the calendar year 2018. If you have questions about the program, please contact Andrea Field at 202-955-1558. If you have questions regarding this invoice or to make payment arrangements, please contact Carol Scates, in EEI's Internal Accounting Department, at 202-508-5428.*

| | |
|---|---|
| Invoice Total | $281,841.00 |
| Taxes | $0.00 |
| Amount Paid | $0.00 |
| **PLEASE PAY** | **$281,841.00** |

PLEASE DETACH AND REMIT WITH YOUR PAYMENT

Invoice1 #: 209242

LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

LGE - $109,917.99
KU - $171,923.01

**Payment Method**

Check: Made payable to Edison Electric Institute

ACH/Wiring Instructions:

[redacted]

Please note you are responsible for any ACH or wiring fees.

EEI

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696
USA
A/R Phone Number : (202) 508 5428
A/R E-Mail : accountsreceivable@eei.org

Mr. Gary H. Revlett
LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

# Invoice

Invoice # : 192522
Invoice Date: 12/01/2016
FEIN: [redacted]

| Description | Quantity | Price | Discount | Amount |
|---|---|---|---|---|
| 2017 UARG Membership Dues -- **ACTUAL DUES AMOUNT** | 1 | $268,376.00 | $0.00 | $268,376.00 |

LGE - $ 101,982.88
KU - $ 166,393.12

This invoice is for your participation in the Utility Air Regulatory Group (UARG) for the calendar year 2017. If you have questions about the program, please contact Andrea Field at 202-955-1558. If you have questions regarding this invoice or to make payment arrangements, please contact Carol Ray, in EEI's Internal Accounting Department, at 202-508-5428.

| | |
|---|---|
| Invoice Total | $268,376.00 |
| Taxes | $0.00 |
| Amount Paid | $0.00 |
| **PLEASE PAY** | **$268,376.00** |

PLEASE DETACH AND REMIT WITH YOUR PAYMENT

Invoice #: 192522

LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

**Payment Method**

Check: Made payable to Edison Electric Institute

[redacted]

Please note you are responsible for any ACH or wiring fees.

Robert J. Ehrler, Esq.
Senior Counsel & Environmental Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

IN ACCOUNT WITH
Hunton & Williams LLP
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102128134
November 29, 2017
29142.050001

## Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through October 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 78.22 |
| Legal Fees and Expenses | $ | 8,799.77 |
| Credit | $ | 0 |
| **TOTAL DUE** | **$** | **8,877.99** |

LGE - $ 3,462.42
KU - $ 5,415.57

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102129784
December 19, 2017
29142.050001

## Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through November 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 0.00 |
| Legal Fees and Expenses | $ | 8,391.66 |
| Credit | $ | 0 |
| **TOTAL DUE** | **$** | **8,391.66** |

LGE - $ 3,272.75
KU - $ 5,118.91

EIVED
06 2018
PAYABLE

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102131210
January 26, 2018
29142.050001

**Utility Water Act Group**

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through December 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 882.82 |
| Legal Fees and Expenses | $ | 8,612.29 |
| Credit | $ | 0 |
| **TOTAL DUE** | **$** | **9,495.11** |

LGE - $ 3,703.09
KU - $ 5,792.02

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102132441
February 21, 2018
29142.050001

**Utility Water Act Group**

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through January 2018 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | |
| Legal Fees and Expenses | $ | 8,105.17 |
| Credit | $ | 0 |
| **TOTAL DUE** | **$** | **8,105.17** |

LGE - $3,161.02
KU - $4,944.15

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

Invoice #102134496
March 16, 2018
29142.050001

**Utility Water Act Group**

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through February 2018 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | |
| Legal Fees and Expenses | $ | 8,695.21 |
| Credit | $ | () |
| **TOTAL DUE** | **$** | **8,695.21** |

LGE - $3,391.13
KU - $5,304.08

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102108220B
August 25, 2016
29142.050001

## Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through July 2016 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 82.53 |
| Legal Fees and Expenses | $ | 9,591.19 |
| Total Due | $ | 9,673.72 |
| Amount Paid | $ | (7,255.29) |
| **BALANCE DUE** | **$** | **2,418.43** |

LGE - 894.82

KU - 1,523.61

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

Invoice #102113260
December 15, 2016
29142.050001

**Utility Water Act Group**

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through November 2016 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 122.17 |
| Legal Fees and Expenses | $ | 6,609.67 |
| Credit | $ | 0 |
| **TOTAL DUE** | **$** | **6,731.84** |

LGE - 2,558.10
KU - 4,173.74

RECEIVED
JAN 20 2017
ACCOUNTS PAYABLE

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102114903
January 31, 2017
29142.050001

**Utility Water Act Group**

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through December 2016 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 123.02 |
| Legal Fees and Expenses | $ | 19,119.79 |
| Credit | $ | 0 |
| **TOTAL DUE** | **$** | **19,242.81** |

ACCOUNTS PAYABLE
FEB 07 2017
RECEIVED

LGE - 7,119.84
Ku - 12,122.97

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102116294
February 28, 2017
29142.050001

## Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through January 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 0.00 |
| Legal Fees and Expenses | $ | 7,413.77 |
| Credit | $ | 0 |
| **TOTAL DUE** | **$** | **7,413.77** |

LGE - 2,743.09
KU - 4,670.68

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102116911
March 16, 2017
29142.050001

## Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through February 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 0.00 |
| Legal Fees and Expenses | $ | 9,109.63 |
| Credit | $ | 0 |
| **TOTAL DUE** | **$** | **9,109.63** |

LGE - 3,370.56
KU - 5,739.07

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102118542
April 25, 2017
29142.050001

## Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through March 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 0.00 |
| Legal Fees and Expenses | $ | 7,196.26 |
| Credit | $ | 0 |
| **TOTAL DUE** | **$** | **7,196.26** |

LGE - 2,662.62
KU - 4,533.64

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102119593
May 22, 2017
29142.050001

## Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through April 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 0.00 |
| Legal Fees and Expenses | $ | 10,258.59 |
| Credit | $ | 0 |
| **TOTAL DUE** | **$** | **10,258.59** |

LGE - 3,898.26

KU - 6,360.33

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
P. O. Box 32010
Louisville, KY 40202

Invoice #102121047
June 26, 2017
29142.050001

**Utility Water Act Group**

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through May 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 193.86 |
| Legal Fees and Expenses | $ | 8,899.94 |
| Credit | $ | 0 |
| **TOTAL DUE** | **$** | **9,093.80** |

LGE - 3,455.64
KU - 5,638.16

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102122602
July 28, 2017
29142.050001

## Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through June 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 0.00 |
| Legal Fees and Expenses | $ | 8,288.56 |
| Credit from May Invoice | $ | (124.47) |
| **TOTAL DUE** | **$** | **8,164.09** |

LGE - 3,102.35

KU - 5,061.74

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102124457
August 30, 2017
29142.050001

## Utility Water Act Group

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through July 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 0.00 |
| Legal Fees and Expenses | $ | 9,698.13 |
| Credit | $ | () |
| **TOTAL DUE** | **$** | **9,698.13** |

LGE - 3,782.27

KU - 5,915.86

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074
TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Robert J. Ehrler, Esq.
Senior Counsel & Environmental
Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

Invoice #102125945
October 2, 2017
29142.050001

**Utility Water Act Group**

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through August 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 0.00 |
| Legal Fees and Expenses | $ | 11,016.42 |
| Credit | $ | 0 |
| **TOTAL DUE** | **$** | **11,016.42** |

LGE - 4,296.40
KU - 6,720.02

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

Robert J. Ehrler, Esq.
Senior Counsel & Environmental Policy Manager
LG&E and KU Energy
Environmental Affairs
Louisville, KY 40202

IN ACCOUNT WITH
**Hunton & Williams LLP**
ATTORNEYS AT LAW
RIVERFRONT PLAZA, EAST TOWER
951 EAST BYRD STREET
RICHMOND, VIRGINIA 23219-4074

TEL 804 • 788 • 8200
FAX 804 • 788 • 8218

Invoice #102127227
October 26, 2017
29142.050001

**Utility Water Act Group**

FOR MEMBERSHIP DUES, based on services rendered by Hunton & Williams, and charges associated with those services, through September 2017 in connection with the regulation of the electric utility industry by the Environmental Protection Agency.

| | | |
|---|---|---|
| Consultant Charges | $ | 0.00 |
| Legal Fees and Expenses | $ | 10,791.88 |
| Credit | $ | 0 |
| **TOTAL DUE** | **$** | **10,791.88** |

LGE - 4,208.83
KU - 6,583.05

Please include our file number with your remittance. Mail your check, payable to Hunton & Williams LLP, to: **Hunton & Williams LLP, Accounting Department, UWAG Payment, Riverfront Plaza-East Tower, 951 East Byrd Street, Richmond, VA 23219-4074.**

UNIVERSITY OF LOUISVILLE RESEARCH FOUNDATION
SPONSORED PROGRAMS FINANCIAL ADMINISTRATION
**INVOICE**

UNIVERSITY OF LOUISVILLE.

**Invoice Detail:**
Invoice ID: LG&E INV2018-001
Invoice Date: 2018-02-21
Payment Terms: IMMED

**Bill To:**
Jessi J. Logsdon
Sourcing Leader, Corporate Purchasing
LG&E and KU Services Company
820 E. Broadway
Louisville, KY 40202

**Project Detail:**
UofL Ref: OGMB160808P
PI: Prater, Glen
Project: Industry/University Cooperative Research Center for Efficient Vehicles and Sustainable transportation Systems (EV-STS)
NSF EV-STS I/U CRC

**Current Amount Due:** $50,000.00

**Invoiced Items:**

FY 2018-2019 EV-STS Membership Dues Currently Payable: $50,000.00

With payment of this invoice, LG&E and KU Services Company will have an EV-STS Membership through 06/30/2019. EV-STS Membership Agreement signed by Stephanie R. Pryer on 04/20/17 (Sponsorship Effective 07/01/17).

Please make payment in US Dollars, and include a copy of this invoice with payment.
Remit To: University of Louisville Research Foundation, Inc.
Office of Sponsored Programs Administration

Attention: Andrea Welch
300 East Market Street, Suite 300
Louisville, KY 40202-1959

LGE - $19,000
KU - $31,000

Andrea Welch
Andrea Welch
Grant Management Accountant

CPA# ____ PO# ____

| Project | Task | Exp Type | $$ or % Split |
|---|---|---|---|
| SRC153955 | UNIVERSITY | 0650 | 100% |

Proponent (up to $1k) ____ Date 2/23/18
~~Group/ Team Leader (up to $10k)~~ ~~Date~~ ____
Manager (up to $100k) ____ Date 2/26/18

F ED

MAR 07 2018

AC S AYABLE

FRI

FINANCIAL RESEARCH INSTITUTE

University of Missouri-Columbia
Phone: 573-882-3800

ENTERED

March 1, 2018

Invoice Number: 18-1018

| | |
|---|---|
| Project: | SRV21440 |
| Task: | DUES COMPANY |
| Expense Type: | 0650 |
| Expense Org: | 021440 |
| Signature | |
| Approval Signature | |
| Approval Date | 3/5/18 |

Robert Conroy
Vice President, State Regulation & Rates
LG&E & KU Energy
220 West Main Street
Louisville, KY 40202

| Financial Research Institute / Public Utility Division Advisory Board Appointment | |
|---|---|
| **Appointment Term** | **Amount Due** |
| May 1, 2018 – April 30, 2019 | **$10,000.00** |

Please make your check payable to: **University of Missouri-FRI/PUD**

The University of Missouri/FRI's tax identification number is [redacted]

LGE - $4,500 (under $5M
KU - $5,500

Mail payment to: Financial Research Institute/Public Utility Division
Trulaske College of Business
401A Cornell Hall
Columbia, MO 65211

**PLEASE REMIT PAYMENT ON OR BEFORE APRIL 15, 2018**

EEI

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696
USA
A/R Phone Number : (202) 508 5428
A/R E-Mail : accountsreceivable@eei.org

Mr. William Paul Puckett
Sr. Environmental Engineer
LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

## Invoice

Invoice # : 210212
Invoice Date: 01/16/2018
FEIN: [redacted]

| Description | Quantity | Price | Discount | Amount |
|---|---|---|---|---|
| 2018 USWAG Membership Dues - Mr. William Paul Puckett | 1 | $68,175.00 | $0.00 | $68,175.00 |

RECEIVED
JAN 26 2018
ACCOUNTS PAYABLE

*This Invoice is for the 2018 Utility Solid Waste Activities Group (USWAG) Membership Dues. The portion of 2018 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes is estimated to be 3%. If you have questions concerning the USWAG program, please contact Jim Roewer, at 202-508-5645. If you have questions regarding payment for this invoice, please contact Carol Scates, in EEI's Internal Accounting Department, at 202-508-5428.*

| | |
|---|---|
| Invoice Total | $68,175.00 |
| Taxes | $0.00 |
| Amount Paid | $0.00 |
| PLEASE PAY | $68,175.00 |

PLEASE DETACH AND REMIT WITH YOUR PAYMENT

Invoice1 #: 210212

LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

LGE - # 26,588.25
KU - # 41,586.75

**Payment Method**

Check: Made payable to Edison Electric Institute

[redacted]

Please note you are responsible for any ACH or wiring fees.

EEI

Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, DC 20004-2696
USA
A/R Phone Number : (202) 508 5428
A/R E-Mail : accountsreceivable@eei.org

Mr. W. Michael Winkler
LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

## Invoice

Invoice # : 194276
Invoice Date: 01/25/2017
FEIN: [redacted]

| Description | Quantity | Price | Discount | Amount |
|---|---|---|---|---|
| 2017 USWAG Membership Dues | 1 | $67,500.00 | $0.00 | $67,500.00 |

This invoice is for the 2017 Utility Solid Waste Activities Group (USWAG) Membership Dues. The portion of 2017 membership dues relating to influencing legislation, which is not deductible for federal income tax purposes is estimated to be 3%. If you have questions concerning the USWAG program, please contact Gayle Novak, at 202-508-5654. If you have questions regarding payment for this invoice, please contact Carol Ray, in EEI's Internal Accounting Department, at 202-508-5428.

| | |
|---|---|
| Invoice Total | $67,500.00 |
| Taxes | $0.00 |
| Amount Paid | $0.00 |
| PLEASE PAY | $67,500.00 |

PLEASE DETACH AND REMIT WITH YOUR PAYMENT

Invoice #: 194276

LG&E and KU Energy
220 W Main Street
Louisville, KY 40202-0000

LGE - $21,600
KU - $45,900

**Payment Method**

Check: Made payable to Edison Electric Institute

[redacted]

Please note you are responsible for any ACH or wiring fees.

# ACAA 2018 Membership Dues Invoice

Make payment to "ACAA" - 38800 Country Club Drive, Farmington Hills, MI 48331 – Phone: (720) 870-7897

RECEIVED
OCT 16 2017

**Member Primary Point of Contact:**

**LG&E and KU Services Company**
Kenneth Tapp
By-Products Coordinator
220 West Main Street, 4th Floor
Louisville KY 40202

Phone: (502) 627-3154

Email: kenny.tapp@lge-ku.com

RECEIVED
OCT 16 2017
By [signature]

**Billing Contact (If other than Primary POC):**

Billing POC:

Invoice Date: 11/1/2017 Processing Rep: ajb ACAA Tax ID: [redacted] Invoice Number: lg&e2018

**Invoice Detail:**

| | | | |
|---|---|---|---|
| Unadjusted Dues: | $15,000.00 | Dues For: | Utility 2018 Category U Member Dues |
| Discount (If Applied) | 0.00% | Terms: | On Receipt |
| Total Due: | $15,000.00 | Invoice Comments: | |
| Paid To Date: | $0.00 | | |
| Balance Remaining: | $15,000.00 | DatePaid (ACAA Use Only) | |

**Thank you for your continuing support of ACAA and the CCP Industry!**

LGE - 7,200
KU - 7,800

Members are encouraged to consider making a tax deductible donation to the ACAA Educational Foundation (501(c)(3)). The Foundation promotes the sponsorship of educational conferences and scholarships and support of educational and scientific publications and activities related to the beneficial use of coal combustion products.

Donations to the Foundation should be made out to: "ACAA Educational Foundation" and mailed to the ACAA office.

Donation Amount: ______________________

A receipt for your donation will be sent to your organization's primary point of contact addressed above unless you request otherwise.

Advancing the management and use of coal combustion products.

ACAA American Coal Ash Association

October 2017

To All ACAA Members:

It is time to renew your membership in the American Coal Ash Association. We thank you for your support in 2017 and ask for your continued support in 2018. As you consider your investment in the mission of the ACAA we ask you to consider the following facts.

- The markets for beneficial use of coal combustion products (CCP) continue to improve. The most recent data available indicates strong recovery in some markets from the regulatory threat from the U.S. Environmental Protection Agency (EPA). In total, beneficial use is now over 50%. At the beginning of this century the beneficial use rate was just over 29%. The progress is real and substantial.
- As the use of coal as a fuel for generating electricity stabilizes in the 30% to 35% range, availability of CCP is stabilizing as well. Investment in the infrastructure needed to meet market demand is beginning to make a difference. Some increased activity in CCP imports has been noted. Increased interest in reclaiming CCP from surface impoundments and landfills has the potential to meeting the growing demand for CCP. The ACAA has been working hard to inform user groups as to the future availability of the materials that have proven to be so important to our economy.
- With a new administration taking over the federal government in 2017, the ACAA has been actively involved with new management at the EPA to unwind some of the actions of previous management that have been so damaging to our members. Great progress has been made. We are committed to building on this momentum in 2018.
- The 2017 World of Coal Ash was a record-setting event by any standard. Attendance and technical content was well beyond previous records. The strength of this event speaks to the importance and interest in our industry.

In 2018 the ACAA will mark its 50th anniversary. Incorporated in Washington, D.C. on March 8, 1968 as the National Ash Association, the ACAA has served as the voice for the beneficial use industry helping to divert hundreds of millions of tons of CCP from disposal units to uses that are *environmentally responsible, technically appropriate, commercially competitive, and supportive of a more sustainable society.* Our mission remains unchanged and is more important than ever.

We hope you will elect to renew your ACAA membership and help us to continue to advance our mission.

Sincerely,

Thomas H Adams

Thomas H. Adams, Executive Director

38800 Country Club Drive, Farmington Hills, Michigan 48331-3439
Office: 720-870-7897 Fax: 720-870-7889 Email: info@ACAA-USA.org Website: http://www.ACAA-USA.org

September 13, 2017

# Carbon Utilization Research Council

1050 Thomas Jefferson Street, NW; Suite 700; Washington, DC 20007

## INVOICE

Ms. Caryl Pfeiffer
Director, Corporate Fuels & By-Products
LG&E and KU
220 West Main Street
P.O. Box 32030
Louisville, KY 40202

Enclosed are 2018 membership dues to the Carbon Utilization Research Council in the amount of:

- 2018 Full Council Membership $30,000

<15,000>

15,000

Please make check payable to:
**Carbon Utilization Research Council**

And remit to:

LGE - $7,200

KU - $7,800

Judy Bernstein
**Carbon Utilization Research Council**
1050 Thomas Jefferson Street, NW, Suite 700
Washington, DC 20007-3877

**Notification Regarding Nondeductibility of the Portion of Dues Payment Allocable to Lobbying Activities**

The Reconciliation Act that was enacted in 1993 eliminated the deduction for lobbying expenses previously available to certain taxpayers under section 162(e) of the Internal Revenue Code, effective for expenses incurred after December 31, 1993. A portion of 2018 dues of the Carbon Utilization Research Council will be allocable to lobbying activities carried on by the council, and therefore will be nondeductible. For 2018, the percentage of each dues payment estimated to be allocable to lobbying expenditures is 50 percent.

# CORE MEMBERSHIP RENEWAL FORM

Utilities Technology Council™

**Current Expiration Date: 9/30/2017**

LG&E and KU Services Company
John Pulliam, Telecom Engineer
820 W Broadway,
Louisville, KY 40202-2218

**Membership Renewal Notice**
**UTC's 2018 membership year runs from October 1, 2017 through December 31, 2018.** UTC membership fees are based on total gross annual revenues from the most recent fiscal year. Calculate your annual fee based on the table shown below.

| ANNUAL REVENUE | MEMBERSHIP DUES |
|---|---|
| Revenue < $15 | $625 |
| $15< ≤ Revenue ≤ $25M | $938 |
| $25M ≤ Revenue ≤ $50M | $1,875 |
| $50M < Revenue ≤ $100M | $3,125 |
| $100M < Revenue ≤ $250M | $4,688 |
| $250M < Revenue ≤ $500M | $6,250 |
| $500M < Revenue ≤ $750M | $9,375 |
| $750M < Revenue ≤ $1.25B | $12,500 |
| $1.25B < Revenue ≤ $5B | $18,750 |
| $5B < Revenue ≤ $10B | $25,000 |
| Revenue > $10B | $37,500 |

*Please note: Dues are calculated for 15 months of membership for 2018 only. Contributions or gifts to UTC are not deductible as charitable contributions for Federal income tax purposes. However, they may be tax deductible as ordinary and necessary business expenses. For these purposes, UTC estimates that 5% of your membership fee will be allocable to nondeductible lobbying activities during the ensuing fiscal year.* **UTC offers three effortless ways to renew your organization's membership in the association.**

**BY MAIL:** UTC Membership
P.O. Box 79358
Baltimore, MD 21279-0358 USA

[redacted]

*Please detach lower portion and remit with payment.*

Utilities Technology Council™

## *Core Membership Renewal: 2017-2018*

**15 month Dues Calculation:**
**12 months (*15000*) + 3 months (*3750*) = Amount Due: $ *18750***

LGE - 9,750
KU - 9,000

**Amount Enclosed = $**________

**If paying by credit card, please indicate card type:** ☐ Visa ☐ MasterCard ☐ American Express

Cardholder's Name | Card Number | Expiration Date

Billing Address | City/State | Zip/Postal Code | Cardholder's Signature

**PLEASE SEND A COPY OF THE INVOICE W ITH YOUR PAYMENT**

PLEASE MAKE CORRECTIONS TO PRIMARY CONTACT NFORMATION BELOW IF NECESSARY.

**Name** John Pulliam **Title** Telecom Engineer

**Company** LG&E and KU Services Company

**Address** 820 W Broadway Louisville, KY 40202-2218

**Phone:** **E-mail Address** john.pulliam@lge-ku.com

*Questions? Please contact Tiffany Bennett, Membership Manager, at 1.202.833.6822 or* tiffany.bennett@utc.org

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 99**

**Responding Witness: Christopher M. Garrett**

Q-99. Provide any and all documents in the Companies' possession that depict how each Dues Requiring Organization spends the dues it collects, including the percentage that applies to all covered activities.

A-99. See the responses to Question Nos. 94 and 98.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 100**

**Responding Witness: Christopher M. Garrett**

Q-100. Provide a detailed description of the services each Dues Requiring Organization provided to the Company since the conclusion of the Company's last rate case. Of these services or benefits, state which benefits accrue to ratepayers, and how.

A-100. Company employees participate in various industry associations and organizations as presented in FR 16(8)(f), Sch. F-1 to gain knowledge, training, timely information and experience throughout the industry to allow for the Company to provide service to its customers in the most economical, cost effective, safe and reliable manner. The gaining of industry knowledge through these associations benefits customers through the use of best practices in providing services.

Edison Electric Institute (EEI): The Edison Electric Institute (EEI) is the association that represents all U.S. investor-owned electric companies. EEI provides public policy leadership, strategic business intelligence, and essential conferences and forums.

Electric Power Research Institute (EPRI): EPRI is a non-profit research consortium providing science and technology solutions for the benefit of utility members, their customers, and society. Funding annual Technology Research and Analysis activities is an expected and prudent activity recognized by the Kentucky Public Service Commission. EPRI has organized and provided this activity for member utilities since its founding in 1973. EPRI provides a collaborative research model that provides LG&E and KU leverage on their investment of approximately 20:1. Cutting edge research keeps LG&E and KU aware of significant technology changes and applications to improve operations.

Coal Combustion Residuals (CCR) Legal Resources Group and New Source Review (NSR) Legal Resources Group: This is a group of utilities which have retained common counsel that monitor developments and assess potential liability in the areas of coal combustion residuals and new source review.

Midwest Ozone Group (MOG) and Steptoe & Johnson LLC (agent of MOG): The Midwest Ozone Group (MOG) is an affiliation of companies, trade organizations, and associations which have drawn upon their collective resources to advance the objective of seeking solutions to the development of a legally and technically sound national ambient air quality program. It is the primary goal of MOG to work with policy makers in evaluating air quality policies by encouraging the use of sound science. As members of the business community, the MOG membership also has a keen interest in assuring that policy makers are appropriately assessing the data and information required to accurately evaluate its emission control strategies.

Utility Air Regulatory Group (UARG): UARG is a not-for-profit association of individual electric generating companies and national trade associations. UARG participates on behalf of its members collectively in Clean Air Act ("CAA") administrative proceedings that affect electric generators and in litigation arising from those proceedings.

Class of 85 represented by Baker Botts LLP: This group participates on behalf of its members collectively in Clean Air Act ("CAA") administrative proceedings that affect electric generators and in litigation arising from those proceedings

Utility Water Act Group (UWAG): UWAG is a voluntary, non-profit, unincorporated group of 147 individual energy companies and three national trade associations of energy companies: the Edison Electric Institute, the National Rural Electric Cooperative Association, and the American Public Power Association. The individual energy companies operate power plants and other facilities that generate, transmit, and distribute electricity to residential, commercial, industrial, and institutional customers. UWAG's purpose is to participate on behalf of its members in EPA's rulemakings under the Clean Water Act and in litigation arising from those rulemakings.

Utility Solid Waste Activities Group (USWAG): USWAG is responsible for addressing solid and hazardous waste issues on behalf of the utility industry. USWAG was formed in 1978, and is a trade association of over 110 utility operating companies, energy companies and industry associations, including the Edison Electric Institute (EEI), the National Rural Electric Cooperative Association (NRECA), the American Public Power Association (APPA), and the American Gas Association (AGA). USWAG engages in regulatory advocacy pertaining to RCRA, TSCA, and HMTA. USWAG's mission is to address the regulation of utility wastes, byproducts and materials in a manner that protects human health and the environment and is consistent with the business needs of its members.

North American Transmission Forum (NATF) services include:

- Peer Reviews: NATF peer reviews help members improve operations. Review teams comprise subject matter experts from other utility members and staff that review selected practice areas and cross-functional topics at the utility hosting the review. The teams' final reports include noteworthy positives that are shared with other members and improvement recommendations for the host utility to implement.

- Assistance: Assistance is tailored to a particular member's request or needs by leveraging one or more NATF programs or offerings. NATF subject-matter experts and staff work with host companies to help them develop action plans to improve on selected topics or issues.
- Practices: Groups of subject-matter experts hold monthly web meetings and annual workshops, and write NATF practices and principles of excellence. Groups include: • Compliance • Equipment Performance & Maintenance • Human Performance Improvement • Modeling and Planning • Operator Training • Cyber Security • Physical Security • System Operations • System Protection • Vegetation Management
- Reliability Initiatives: The NATF coordinates activities related to select established or emerging reliability topics in a project based format. Currently there are initiatives on resilience, supply chain risk management, and human performance near-miss database.
- Knowledge Management: The NATF supports the exchange and management of operating experience and reliability data. Secure, effective program tools (databases, scorecards, performance reports, surveys, lessons learned summaries, and operating experience library) and regular working group meetings help facilitate internal peer benchmarking, dissemination of objective performance information, and awareness of key reliability trends and risks.
- Training: The NATF offers web-based resources on select topics chosen and prioritized by members.

<u>University of Louisville Research Foundation Inc.:</u> LG&E and KU Technology Research and Analysis utilizes the research conducted by Efficient Vehicles and Sustainable transportation Systems (EV-STS) to better understand future electric vehicle technologies and needs for supporting Electric Vehicles (EV) charging infrastructure.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 101**

**Responding Witness: Christopher M. Garrett**

Q-101. Provide a list of all presentations, webinar recordings, briefing books, policy memos, and white papers that each Dues Requiring Organization provided to the Companies since the conclusion of their last rate cases.

A-101. The Company objects to this question because it is overly broad and unduly burdensome. Many employees participate in Organization Memberships as presented in FR 16(8)(f), Sch. F. Many of these employees receive almost daily email communications from the organizations. Creating a list of all materials that each of the Organization Memberships provided to the Companies would be unduly burdensome and require an electronic search of emails and electronic files of many custodians, resulting in significant expense.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 102**

**Responding Witness: Christopher M. Garrett**

Q-102. Has the Company included in operating expenses any amount for: (i) EEI Media Communications, and (ii) any similar division of any other Dues Requiring Organization?

a. If so, state the amount, indicate in which account this has been recorded, and provide a citation to any and all Commission Orders or other authority upon which the Companies are relying for the inclusion of such expense in the test period.

b. If not, provide an estimate of how much of the Company's dues are being spent on media or public relations work.

A-102. As stated in the response to Question No. 92, the Company has excluded the appropriate amount of unrecoverable dues based on the information provided on the 2018 invoice from EEI.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 103**

**Responding Witness: Christopher M. Garrett**

Q-103. State whether the Company is aware whether any portion of the dues it pays to any Dues Requiring Organization are utilized to pay for any of the following expenditures, and if so, provide complete details:

a. Influencing federal or Kentucky legislation;

b. Any media advertising campaigns backing the Companies' or the Dues Requiring Organization's position on net metering;

c. Expenditures on "We Stand For Energy," or "Defend My Dividend," public relations, advocacy efforts or other covered activities;

d. Contributions from EEI, EPRI or other Dues Requiring Organizations to third-party organizations and contractors including any of the expenditures identified in a. – c., above.

A-103. The Company has excluded the appropriate amount of unrecoverable dues based on the information provided on the 2018 invoice from EEI. EPRI does not engage in any covered activities.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 104**

**Responding Witness: Robert M. Conroy**

Q-104. Since the conclusion of the Company's last rate case, how much has EEI paid for its efforts to "rebrand" the utility industry? Include in your response payments to external public relations firms as well as the associated salary to any EEI staff involved in contracting, coordinating with, or promulgating internally or externally the rebranding campaign effort.[14]

A-104. KU does not collect and retain the requested information for its corporate files. See the response to Question No. 98.

[14] See, e.g., https://www.huffingtonpost.com/entry/messaging-utilities-solar-power_us_56f45cd6e4b014d3fe22b572

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 105**

**Responding Witness: Robert M. Conroy**

Q-105. Do the Company's EEI dues contribute to the salary, benefits and expenses of the EEI Executive Vice President for Public Policy and External Affairs, or any other EEI officer or employee who has led an effort EEI undertook to rebrand the utility industry?

A-105. KU does not collect and retain the requested information for its corporate files. See the response to Question No. 98.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 106**

**Responding Witness: Daniel K. Arbough**

Q-106. List all travel and entertainment expenses that Company employees incurred in the base period and are included in the forecast period, or that are expected to be incurred and included in the forecast period, in relation to Dues Requiring Organization activities. Show accounts, amounts, descriptions, person, job title and reason for the expense. Provide a copy of applicable employee time and expense reports and invoices documenting such expenses.

A-106. In general the request seeks information that the Company does not identify and retain in the categories requested. Travel expenses are not organized according to attendance at seminars and training events held by the various professional organizations. The request requires a significant amount of original work and cannot be completed within the time provided for the response. Entertainment expenses are typically not reimbursable and if so are booked below the line.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 107**

**Responding Witness: Christopher M. Garrett**

Q-107. Is the Company relying upon any NARUC reports or other studies for the exclusion from or inclusion in rates of a portion of its dues payable to EEI, or to any other Dues Requiring Organization? If so, provide a copy of such report and indicate how the report's recommendations have been included in its filing.

A-107. See the response to Question No. 91.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 108**

**Responding Witness: Christopher M. Garrett**

Q-108. Do any of the Company's personnel actively participate on Committees and/or perform any other work for any Dues Requiring Organization or any other industry organization to which the Company belongs, including but not limited to EEI?

a. If so, state specifically which employees participate, how they are compensated for their time (amount and source of compensation), and the purpose and accomplishments of any such association related work.

b. List any and all reimbursements received from industry associations, for work performed for such organizations by Company employees.

A-108. Company employees participate in various industry associations and organizations to gain knowledge, training, timely information and experience throughout the industry to allow for the Company to provide service to its customers in the most economical, cost effective, safe and reliable manner. The gaining of industry knowledge through these associations benefits customers through the use of best practices in providing services.

a. With one limited exception relating to contractual work for EPRI, employees are not compensated by industry organizations for participation on committees. See the response to part b.

b. With regard to the EPRI work referenced in part a. above, since 2016, the Company has been reimbursed by EPRI for work paid to three regular, full-time employees beyond their normal compensation. Reimbursement from EPRI was also received for work paid to a temporary employee.

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**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 109**

**Responding Witness:**

Q-109. [THIS REQUEST INTENTIONALLY LEFT BLANK IN ORDER TO MAINTAIN NUMBERING WITH CASE NO. 2018-00295]

A-109. Not applicable.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 110**

**Responding Witness: Gregory J. Meiman**

**F. Compensation**

Q-110. Refer to the direct testimony of Lonnie E. Bellar, page 27, wherein he discusses the starting pay for the Companies' Customer Representatives.

a. Under what category of employees (i.e. hourly, exempt, salary, etc.) do Customer Representatives fall under in reference to wages in rate case applications?

A-110. Customer Representatives fall under the non-exempt category.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 111**

**Responding Witness: Daniel K. Arbough**

Q-111. Refer to the direct testimony of Lonnie E. Bellar, page 28, wherein he discusses the hourly wage increases for Customers Representatives.

a. Where is this adjustment located in the application?

A-111.

a. The effect of the hourly wage increases is included within account numbers 901 (Customer Accts Supervision) and 903 (Customer Records and Collection Expenses), from the Schedule D-1, page 6 of 8, lines 105 and 107.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 112**

**Responding Witness: Gregory J. Meiman**

Q-112. Regarding findings of the Willis Towers Watson ("WTW") Target Total Cash Compensation Study, the direct testimony of Gregory J. Meiman, page 10, states, "The Companies' use of base salary and target incentive compensation as its primary pay vehicles for employees is consistent and aligned with market pay vehicles used by utility and general industry peers."

a. Identify the list of utility peers used in the comparison.

b. Identify the criteria for the "utility peers" that WTW used to qualify them as peers for the study's comparative purposes.

A-112.

a. The attached files contain participant lists of the four utility industry focused compensation surveys used in completing the benchmarking study for KU and LG&E. Attachment 1 contains two WTW Energy Services compensation survey participant lists. Attachments 2 and 3 contain two compensation survey participant lists being filed pursuant to a Petition for Confidential Protection.

b. The selection criteria used in leveraging these surveys for completing the compensation benchmarking analysis are as follows:

- Readily available, published compensation surveys covering utility/energy services benchmark positions similar to KU/LGE positions
- Compensation surveys predominantly focused on regulated utilities and the national US market that cover all major components of compensation

# Lousville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU)

### 2017 Willis Towers Watson CDB Energy Services Executive Compensation Survey

### Participant List

AES Corporation
ALLETE
Alliant Energy
Ameren
American Electric Power
Aqua America
Areva
AREVA Nuclear Materials
ATC Management
Atmos Energy
AVANGRID
Avista
Berkshire Hathaway Energy
Black Hills
Blue Ridge Electric Membership
Boardwalk Pipeline Partners
BWX Technologies
California Independent System Operator
Calpine
CenterPoint Energy
CH Energy Group
Cheniere Energy
Chesapeake Utilities
Citizens Energy Group
CLEAResult
Cleco
CMS Energy
Colorado Springs Utilities
Covanta Corporation
CPS Energy
DCP Midstream
Direct Energy
Dominion Energy
Duke Energy
Duquesne Light
Dynegy
Edison International
ElectriCities of North Carolina
Electric Power Research Institute
El Paso Electric
Enable Midstream Partners
Energy Northwest
Energy Transfer Partners
EnLink Midstream
Entergy
EQT Corporation
ERCOT
Lower Colorado River Authority
McDermott International
MDU Resources
Midwest Independent Transmission System Operator
Monroe Energy
MRC Global, Inc.
National Grid USA
New York Power Authority
NextEra Energy, Inc.
NiSource
NorthWestern Energy
NOVA Chemicals
NRG Energy
Nuscale Power
NW Natural
OGE Energy
Oglethorpe Power
Old Dominion Electric
Omaha Public Power
Oncor Electric Delivery
ONE Gas
ONEOK
Orlando Utilities Commission
Otter Tail
Pacific Gas & Electric
Peoples Natural Gas
Pinnacle West Capital
PJM Interconnection
PNM Resources
Portland General Electric
PPL
Public Service Enterprise Group
Puget Sound Energy
Salt River Project
Santee Cooper
SCANA
Sempra Energy
South Central Connecticut Regional Water Authority
Southern Company Services
Southern Maryland Electric Cooperative
South Jersey Industries
Southwest Gas
Spectra Energy
Spire
STP Nuclear Operating
Summit Midstream
Talen Energy

# Lousville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU)

## 2017 Willis Towers Watson CDB Energy Services Executive Compensation Survey

### Participant List

Eversource Energy
Exelon
FirstEnergy
First Solar
Frank's International
Genesis Energy
Great River Energy
ICF International
Idaho Power
ISO New England
ITC Holdings
JEA
Kinder Morgan
Knoxville Utilities Board
LG&E and KU Energy
TECO Energy
Tennessee Valley Authority
Texas Reliability Entity, Inc.
TransCanada
UGI
Unitil
UNS Energy
URENCO
Vectren
Vistra Energy
Westar Energy
Williams Companies
Wisconsin Energy
Wolf Creek Nuclear
Xcel Energy

# Lousville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU)

**2017 Willis Towers Watson CDB Energy Services Middle Management, Professional and Support Compensation Survey**

**Participant List**

ALLETE
Alliant Energy
Alyeska Pipeline Service
Ameren
American Electric Power
Areva
AREVA Nuclear Materials
Associated Electric Cooperative
ATC Management
Atlantic Trading & Marketing
Atmos Energy
AVANGRID
Avista
Bechtel Marine Propulsion - Bettis
Bechtel Nuclear, Security & Environmental
Black Hills
Blattner Energy
Boardwalk Pipeline Partners
BWX Technologies
California Independent System Operator
Calpine
Capital Power
CenterPoint Energy
Centrus Energy Corp
Chelan County Public Utility District
CH Energy Group
Cheniere Energy
Chesapeake Utilities
CLEAResult
Cleco
CMS Energy
Colorado Springs Utilities
Crestwood Equity Partners
DCP Midstream
Direct Energy
DNV GL
Dominion Energy
DTE Energy
Duke Energy
Duquesne Light
Dynegy
EDF Trading
Edison International
Electric Boat Corporation
ElectriCities of North Carolina
El Paso Electric
Enable Midstream Partners
Kinder Morgan
Knoxville Utilities Board
LG&E and KU Energy
Lower Colorado River Authority
Midwest Independent Transmission System Operator
Monroe Energy
National Grid USA
Nebraska Public Power District
Newport News Shipbuilding
New York Power Authority
NextEra Energy, Inc.
NiSource
Noble Energy
NorthWestern Energy
NOVA Chemicals
NRG Energy
Nuscale Power
NuStar Energy
NW Natural
Oak Ridge National Laboratory
OGE Energy
Oglethorpe Power
Old Dominion Electric
Omaha Public Power
Oncor Electric Delivery
ONE Gas
ONEOK
Orlando Utilities Commission
Pacific Gas & Electric
Peoples Natural Gas
Pinnacle West Capital
PJM Interconnection
Platte River Power Authority
PNM Resources
Portland General Electric
PPL
Public Service Enterprise Group
Puget Sound Energy
Saipem
Salt River Project
Santee Cooper
SCANA
Sempra Energy
Sharyland Utilities
Sonnedix
South Central Connecticut Regional Water Authority
Southern Company Services

## Lousville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU)

**2017 Willis Towers Watson CDB Energy Services Middle Management, Professional and Support Compensation Survey**

**Participant List**

Enbridge Energy
Energy Northwest
Energy Transfer Partners
ENI US Operating Company
EnLink Midstream
Entergy
Enterprise Products Operating LLP
EPCOR Utilities
EQT Corporation
ERCOT
Eversource Energy
Exelon
FirstEnergy
First Solar
Frank's International
GE Energy
Great Plains Energy
Great River Energy
ICF International
Idaho National Laboratory
Idaho Power
ISO New England
ITC Holdings
JEA
Southern Maryland Electric Cooperative
South Jersey Industries
Southwestern Energy
Southwest Gas
Spire
STP Nuclear Operating
Talen Energy
Targa Resources
T.D. Williamson
TECO Energy
Tennessee Valley Authority
TransCanada
Tri-State Generation & Transmission
Unitil
UNS Energy
URENCO
Vectren
Vistra Energy
Washington Gas
WEC Energy Group
Westar Energy
Williams Companies
Wolf Creek Nuclear
Xcel Energy

## Lousville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU)

### 2017 American Gas Association Compensation Survey

### Participant List

[redacted]

# Lousville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU)

## 2017 EAP Data Information Solutions Energy Technical Craft Clerical Compensation Survey

### Participant List

[redacted]

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 113**

**Responding Witness: Gregory J. Meiman**

Q-113. Refer to the direct testimony of Gregory J. Meiman, page 6, wherein he testifies that costs to train call center reps is $16,000 per person. Provide a detailed breakdown for how this cost was derived. Include all workpapers in Excel format, with formulas intact and cells unprotected and with all columns and rows accessible.

A-113. The call center study turnover cost analysis provides a timeline of all costs of hire and training incurred when replacing call center positions attributed to turnover. The study begins with the costs associated with advertising for open positions through the total training costs associated with each new hire.

The Excel spreadsheet is being filed pursuant to a Petition for Confidential Protection.

The attachment is Confidential and provided under seal in a separate file in Excel format.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 114**

**Responding Witness: Gregory J. Meiman**

Q-114. Refer to the direct testimony of Gregory J. Meiman, page 6, wherein he testifies that the three-year average turnover rate in the call center was 13.4%, excluding retirements. Mr. Meiman also testifies that the Companies determined compensation paid to those individuals was below market (page 6, line 17) and that adjusting their wages "to become market competitive . . . will reduce turnover costs and allow for uninterrupted service for our customers."

a. Explain in detail how Mr. Meiman determined that call center employees' pay was below market. Provide all supporting documentation.

b. Explain how Mr. Meiman determined that the below-market compensation was the cause of the turnover rate (e.g., exit interviews or surveys)? Any response should provide all supporting documentation.

A-114.

a. Below is the assessment of the Companies' starting pay rates:

| Key | Business Information | Location | Advertised Hourly Pay Rate | Other Information |
|---|---|---|---|---|
| 1 | Global outsourcer call center | Lexington | $12.00 | |
| 2 | LKE Current Offer | Lexington & Louisville | $12.00 | |
| 3 | Retail & foodservice | Lexington & Louisville | $12.00 | |
| 4 | Global outsourcer call center | Louisville | $13.00 | |
| 5 | National utility call center | Louisville | $14.00 | Free/Discounted on company provided services |
| 6 | Utility outsourcer call center | Lexington | $14.00 | |
| 7 | Medical collections call center | Louisville | $15.50 | bonus averaging $1.000/month and $0.50 increase every 6 months |
| 8 | Recommended LKE Salary Offer | | $16.00 | |
| 9 | Regional utility call center | Plainfield. IN | $16.00 | |
| 10 | Large retail call center | New Albany, IN | $16.45 | |
| 11 | Local utility call center | Louisville | $18.00 | |

Corresponding adjustments were made to maintain internal equity and assist in retention of existing employees.

b. The exit interview scores (1-5, with 5 the highest) for the Call Center area are reflected below:

| | Call Center Pay | LKE Pay |
|---|---|---|
| **2017** | 2.50 | 3.55 |
| **2016** | 3.17 | 4.23 |
| **2015** | 3.25 | 4.16 |

As illustrated above, satisfaction with pay decreases over the period. Additionally, the Call Center scores are lower than the rest of the company for pay.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 115**

**Responding Witness: Gregory J. Meiman**

Q-115. Refer to the direct testimony of Gregory J. Meiman, pages 6-7, wherein he explains the Companies' compensation philosophy. In that discussion, he states that the policy has been in effect since 1997, regularly reviewed, and used for compensation decisions, which are supported by various levels of approval. Mr. Meiman concludes that the policy results in "ensuring base salaries are competitive based on the nature and responsibilities of the employee's position and are fair relative to the pay for other similarly-situated positions within the organization."

a. If the Companies' compensation philosophy ensures competitive and fair pay as stated in testimony, provide the reason that the call center employee compensation had been below market for three years, as stated on page 6.

A-115. We consistently apply our philosophy of targeting our base compensation salary range midpoints at the $50^{th}$ percentile of national market. Salary range minimums and maximums are based on 70% and 130% of the established $50^{th}$ percentile midpoint.

While the compensation of the call center employees was within this competitive range, the monitoring of our recruitment and retention experiences prompted further assessment of our Call Center starting pay rates (see the response to Question No. 114a) and determined that an adjustment was appropriate.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 116**

**Responding Witness: Gregory J. Meiman**

Q-116. Refer to the direct testimony of Gregory J. Meiman, page 7, wherein he testifies that job pay midpoints are established using external market compensation data "of the national general or utility industry."

a. What determines whether the Companies use the national general compensation data as opposed to the utility industry compensation data?

b. Specifically which positions or groups of positions use national general compensation data as opposed to utility industry compensation data?

c. Is the compensation data used to establish job pay midpoints based on a set of criteria limiting the comparison to similar utilities (e.g., within the region)? If the response is in the negative, explain.

d. If compensation data comparison is limited to similar utilities, what is the criteria for types of industries included in the national general compensation data?

e. If compensation data comparison is limited to similar utilities, what is the criteria for utility peers to be included in the utility industry compensation data?

A-116.

a. For jobs that we can recruit from any industry and don't require energy or utility specific experience, we use general industry compensation survey data. For jobs that require energy or utility specific experience and we can only recruit internally or from within the energy or utility industry, we use utility industry compensation survey data.

b. The attachment is being provided under seal pursuant to a petition for confidential protection.

c. No, job pay midpoints are established using the $50^{th}$ percentile of the national total sample scope regardless if we use general industry or energy services surveys.

d. Not applicable. See the response to part c.

e. Not applicable. See the response to part c.

CONFIDENTIAL INFORMATION REDACTED



Jobs that use national general industry compensation data:

| Job Code | Job Title |
| --- | --- |
| [redacted] | |

CONFIDENTIAL INFORMATION REDACTED



Jobs that use national general industry compensation data:

| Job Code | Job Title |
| --- | --- |
| [redacted] | |

CONFIDENTIAL INFORMATION REDACTED



Jobs that use national general industry compensation data:

| Job Code | Job Title |
| --- | --- |
| [redacted] | [redacted] |

CONFIDENTIAL INFORMATION REDACTED



Jobs that use national general industry compensation data:

| Job Code | Job Title |
|---|---|
| [redacted] | [redacted] |

Jobs that use national general industry compensation data:

| Job Code | Job Title |
|---|---|
| [redacted] | |

CONFIDENTIAL INFORMATION REDACTED



Jobs that use national general industry compensation data:

| Job Code | Job Title |
|---|---|
| [redacted] | |

CONFIDENTIAL INFORMATION REDACTED



Jobs that use national general industry compensation data:

| Job Code | Job Title |
| --- | --- |
| [redacted] | |

Jobs that use national general industry compensation data:

| Job Code | Job Title |
| --- | --- |
| [redacted] | |

Jobs that use national general industry compensation data:

| Job Code | Job Title |
|---|---|
| [redacted] | [redacted] |

Jobs that use national general industry compensation data:

| Job Code | Job Title |
| --- | --- |
| [redacted] | |

CONFIDENTIAL INFORMATION REDACTED



Jobs that use national general industry compensation data:

| Job Code | Job Title |
| --- | --- |
| [redacted] | [redacted] |

CONFIDENTIAL INFORMATION REDACTED



Jobs that use national general industry compensation data:

| Job Code | Job Title |
|---|---|
| [redacted] | [redacted] |

CONFIDENTIAL INFORMATION REDACTED



Jobs that use national general industry compensation data:

| Job Code | Job Title |
|---|---|
| [redacted] | |

CONFIDENTIAL INFORMATION REDACTED



Jobs that use national general industry compensation data:

| Job Code | Job Title |
|---|---|
| [redacted] | |

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 117**

**Responding Witness: Gregory J. Meiman**

Q-117. Refer to the direct testimony of Gregory J. Meiman, page 12, wherein he testifies that the Team Incentive Award ("TIA") Plan removed ties to financial performance, e.g., earnings per share and net income.

a. Provide examples of former incentive criteria for positions in which performance ties to financial performance existed, and also provide current adjusted incentive criteria for those same positions.

b. Provide the Individual and Team Effectiveness criteria for the TIA Plan for all Senior Managers in Electric Distribution and Energy Supply and Analysis.

c. Indicate whether any incentive awards or other compensation provided for any employees who are part of the TIA Plan receive stock-based awards. If so, indicate specific type of stock (e.g., restricted).

d. Explain whether any employees receive stock-based compensation, restricted or otherwise, in their base compensation.

A-117.

a. In 2016, there was incentive criteria tied to financial performance. Net income was measured as income after all expenses and all taxes have been deducted.

| **2016 TIA Measures and Weightings** |
| --- |
| 15% – Corporate Safety<br>15% – Customer Satisfaction<br>30% – Net Income<br>40% – Individual/Team Effectiveness |

In 2017 and 2018 the measures and weightings were as follows:

| **TIA Measures and Weightings** |
|---|
| 15% – Corporate Safety<br>15% – Customer Satisfaction<br>15% – Cost Control<br>15% – Customer Reliability<br>40% – Individual/Team Effectiveness |

b. Measures for individual Senior Managers in Electric Distribution and Energy Supply and Analysis are established each year to ensure achievement of strategic business goals. Goals vary by individual and by department and support respective department business objectives.

c. Senior Managers participating in the TIA are eligible for restricted stock units (RSUs) which are not subject to rate recovery.

d. No employees received stock-based compensation, restricted or otherwise, in their base compensation.

# KENTUCKY UTILITIES COMPANY

## Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018

## Case No. 2018-00294

## Question No. 118

## Responding Witness: Gregory J. Meiman

Q-118. Do the Companies or LKE have any other incentive award programs besides the TIA? If the response is in the affirmative, provide the following items:

a. Amount included in the base year and forecasted amount. If the amount is allocated, provide the allocations;

b. Copy of plan documents;

c. List of participates and awards made for 2016, 2017, and 2018 YTD; and

d. The performance objectives and actual performance results upon which the awards were based for 2016, 2017, and 2018 YTD

A-118.

a. Other than the TIA plan, the only other offering of incentive awards included in the revenue requirement is for employees working in the Customer Services Contact Center. Details of those incentive awards are set forth below.

| KU | Base Year | Forecast Test Year |
|---|---|---|
| **Residential Service Center (46% LG&E - 54% KU)** | $92,000 | $83,000 |
| **Business Offices (44% LG&E - 56% KU)** | $23,000 | $69,000 |
| **Business Service Center (36% LG&E - 64% KU)** | $10,000 | $22,000 |
| **Grand Total** | **$125,000** | **$175,000** |

b. See attached.

c. A total for each job family has been provided instead of a listing of participant names to protect employee privacy. There were no incentive awards made in 2016 or 2017 since the plan was implemented in 2018.

| **Job Family** | **Total YTD (Jan-Oct) 2018 Award** |
|---|---:|
| Area Retail Operations Managers | $400 |
| Billing Analysis Associates | $1,440 |
| Business Center Representatives | $7,675 |
| Business Center Specialists | $1,025 |
| CC Performance Ops Representatives (RPM) | $3,060 |
| Customer Care Coaches | $10,724 |
| Customer Care Representatives | $128,668 |
| Customer Interaction Quality Analysts | $1,010 |
| Customer Representatives | $20,500 |
| **Grand Total** | **$174,502** |

d. See the responses to parts b and c.

**Customer Services & Marketing**
**Contact Center**
**2018 Incentive Plan**

This document is a formalized incentive plan that explains the incentive programs for each contact center. Incentives may be based and awarded on team and/or individual accomplishments. While various situations are identified, flexibility is important as it is rarely pre-determined when it needs to be executed. Each instance of an incentive payout will be documented (as further defined in this document) with the following information: description of the situation, incentive to be provided, team/individuals eligible for the incentive, the period of the incentive, the eligibility for the incentive and effectiveness measurement.

Prior to the start of any incentive program, the following must be done:

- Communication provided to those individuals eligible to participate in the program. The communication will provide the individual with the following information: description of the incentive situation, period for the incentive program, incentive to be provided, eligibility for the incentive and eligibility measurement.
- Documentation of the communication will be maintained. If the communication is delivered verbally, the communication shall be documented and contain the signatures of the employees the communication was delivered to.

Upon completion of the incentive program, the following must be done:

- Employees eligible for awards will be documented in a spreadsheet. An example of an Eligible Employee spreadsheet is contained in Appendix A.
- Spreadsheet should include the effectiveness evaluation for the incentive – did it accomplish the intended goal.
- Spreadsheet will be approved by the team leader (BSC), AROM (BO), or Operation Manager (RSC) and obtain a one over approval by the appropriate department manager.

All monetary incentive awards will be reported to payroll to be included in the recipient's paycheck. All tax considerations will be addressed through the normal payroll process.

This plan will be reviewed annually in order to determine effectiveness of incentives. This review will provide insight into any necessary adjustments to the plan for the following year. The plan will be updated annually and approved by the managers and director.

**Business Service Center**
**Budgeted Amount $43,000**

| Situation | Description | Frequency | Incentive | Team/Individual | Eligibility | Effectiveness Measurement |
|---|---|---|---|---|---|---|
| Service Level | When monthly SL goal is in jeopardy | Monthly | $25-$75 bonus on paycheck | Team (CR, Specialist and Lead) | Meeting or exceeding service level goal | SL Goal Achieved |
| Attendance | When call volume expected to be high or attendance low | Daily or monthly | $25-$75 bonus on paycheck | Individual or Team (CR) | All Reps that are in attendance on selected time period | Lower shrinkage than forecasted |
| Average Handle Time | Total call time including talk time, hold time, and ACW | Monthly or Quarterly | $25-$50 bonus on paycheck | Individual or Team (CR) | All Reps when AHT within departmental goals | AHT lower and within goal |
| Schedule Adherence | Improvement to schedule adherence | Monthly or Quarterly | $25-$50 bonus on paycheck | Individual (CR) | >= 95% Adherence | Enhances availability around scheduled breaks and lunches |
| Quality Assurance Score | Random calls selected for evaluation | Monthly | $100 bonus on paycheck | Individual (CR) | All calls for reps scored for the month receiving a 100% | Enhances consistency and accuracy |
| First Contact Resolution | FCR scores based on transactional surveys by third party | Monthly or Quarterly | $25-$75 bonus or logo item | Team (CR, Specialist) | Everyone based on survey results of => FCR target | FCR increases from previous month and above target |
| Top Rep Performance | Top rep per scorecard performance | Quarterly | $100 bonus on paycheck | Individual (CR) | One winner per site of All reps | Highest productivity compared to peers |
| Customer Experience Score | CE scores based on transactional surveys by third party | Monthly or Quarterly | $25-$75 bonus on paycheck or logo item | Team (CR, Specialist, Lead) | Everyone based on survey results of => CE target as reported by third party surveys | CE score increases from previous month |
| Customer Service Week | Celebration activities to recognize CS employees | October | Logo wear | Team (CR, Specialist, Lead) | Everyone | N/A |
| Other business need as appropriate | Other focus based on business need | TBD | $25-150 bonus on paycheck/ logo item | TBD | TBD | TBD |

**Business Office**
**Budgeted Amount $85,000**

| Situation | Description | Frequency | Incentive | Team/Individual | Eligibility | Effectiveness Measurement |
|---|---|---|---|---|---|---|
| Attendance | Adherence to attendance policy | Quarterly | $50 Bonus on paycheck | Individual (CRs) | No more than 1 unscheduled occurrence within each quarter | Occurrence guideline |
| Cash Desk Outages | Cash management performance | Quarterly | $50 Bonus on paycheck | Individual (CRs) | No more than 2 cash desk outages of any dollar amount (Net zero correction does not count as additional outage) | Cash desk outages |
| Off in Errors (ZHONs) | CCS performance as its related to off in errors | Quarterly | $50 Bonus on paycheck | Individual (CRs) | Zero ZHONs | Zero ZHONs |
| Customer Experience Scores | CE scores based on transactional surveys by third party | Quarterly | $50 Bonus on paycheck | Team (CRs, Leads and AROMs) | Overall CE score of 8.8 or above each month of the quarter | Independent of each quarter |
| Customer Service Week | National Customer Service week. Recognition of our Customer Service Reps | October | Logo item | Team (CR's, Leads and AROMS) | Everyone | N/A |
| Other business need as appropriate | Other focus based on business need | TBD | $25-150 bonus on paycheck/ logo item | TBD | TBD | TBD |
| Other business need as appropriate | Other focus based on business need | TBD | $25-150 bonus on paycheck/ logo item | TBD | TBD | TBD |

**Residential Service Center**
**Budgeted Amount $210,000**

| Situation | Description | Frequency | Incentive | Team/Individual | Eligibility | Effectiveness Measurement |
|---|---|---|---|---|---|---|
| Service Level | Monthly SL is in jeopardy | Monthly | $75-150 bonus on paycheck/ logo item | Team (CR's, Coaches and Ops Manager) | Meet Monthly SL goal | Goal Achieved |
| Attendance | High Call Volume/Absenteeism expected | Daily or monthly | $50-150 bonus on paycheck/ logo item | Individual or Team (CR's and Coaches) | Work 100% of Scheduled time/No Off Duty | Amount Baseline is exceeded |
| Average Handle Time | Need to increase the # of calls per agent | Daily | $25-75 bonus on paycheck/ logo item | Individual (CR's) | AHT 10% below goal | Amount Baseline is exceeded |
| After Call Work | Increase efficiency during ACW | Daily | $25-50 bonus on paycheck/ logo item | Individual (CR's) | ACW below target | Amount Baseline is exceeded |
| Schedule Adherence | Higher adherence to schedules needed | Daily | $50-150 bonus on paycheck/ logo item | Individual (CR's) | Adherence > 97% | Amount Baseline is exceeded |
| Quality Assurance Score | New Process Introduced - Awareness of new rules needed | Monthly | $50 bonus on paycheck/ logo item | Individual or Team (CR's and Coaches) | Successful QA monitor by individual or group under new process | Increased percentage of adoption |
| Quarterly Performance Incentive | A quarterly performance incentive that focuses on 1 or more areas of performance | Quarterly | $150-250 bonus on paycheck/ logo item | Individual (CR's) | Meet specific performance targets | Baselined measures such as ACW, attendance or quality |
| Customer Experience | QA/Survey Scores declining | Monthly or Quarterly | $50-100 bonus on paycheck/ logo item | Individual or Team (CR's, Coaches and Ops Managers) | CE > 8.5 QA Average >85 | Amount Baseline is exceeded |
| Customer Service Week | National Customer Service week. Recognition of our Customer Service Reps | October | Logo item | Team (CR's, Coaches and Ops Manager) | Everyone | N/A |
| Other business need as appropriate | Other focus based on business need | TBD | $25-150 bonus on paycheck/ logo item | TBD | TBD | TBD |

David A. Daniel 7-10-18

**David Daniel** **Date**
**Manager Business Service Center**

Debbie Leist 7/10/18

**Debbie Leist** **Date**
**Director Customer Service & Marketing**

Lora Huff Aria 7/9/18

**Lora Aria** **Date**
**Manager Business Offices**

7/9/2018

**Darius Lepp** **Date**
**Manager Residential Service Center**

Appendix A: Example of Eligible Employee(s) Incentives Template

**Paid Incentives - amounts are paid out on employee's paycheck**

| Employee ID (e.g. "E012345") | Name | Project | Task | Time Code (a) | Amount | Date of Incentive | Start Date (b) | End Date (b) | Comments |
|---|---|---|---|---|---|---|---|---|---|
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**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 119**

**Responding Witness: Gregory J. Meiman**

Q-119. Indicate whether any award of executive compensation (e.g., incentive pay) is in the form of stock.

a. If so, indicate the specific type of stock (e.g., restricted).

b. If so, indicate the amount (by type of stock) included in the revenue requirement.

A-119. Yes.

a. Executives are eligible to receive grants of restricted stock units and performance stock units.

b. All stock based incentives are excluded from the revenue requirement.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 120**

**Responding Witness: Gregory J. Meiman**

Q-120. Refer to the direct testimony of Gregory J. Meiman, page 22, wherein he refers to "Mercer's comparator group." Identify those companies making up the comparator group and provide the criteria by which they are identified as peers of the Companies.

A-120. The requested entities are identified at page 10 of 13 of the study provided by Mercer which is attached as Attachment 4 to Tab 60 to the Application. These entities were selected based on their similar customer size to the Companies and/or a local presence.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 121**

**Responding Witness: Gregory J. Meiman**

Q-121. Provide a list of severance payments included in the base year, including the amount, reason, and position of employee involved.

A-121. The Company does not budget severance payments. As such, no severance amounts were included in the cost of service or revenue requirement.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 122**

**Responding Witness: Gregory J. Meiman**

Q-122. Long Term Incentive Plans ("LTIP"): Does the cost of service include any long-term incentive plan costs, either direct charged or allocated? If the response is in the affirmative, provide the following items:

a. The amount included in the base year and forecasted period. If the amount is allocated, provide the allocations.

b. A list of the officers, directors, and key employees and the amounts of LTIP awarded to each for 2016, 2017, and 2018 YTD.

c. The performance objectives and actual performance results upon which the awards were based for 2016, 2017, and 2018 YTD.

d. A copy of the LTIP plan documents and explain how the awards are made.

A-122. No, the cost of service does not include any long-term incentive plan costs, neither direct charged nor allocated.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 123**

**Responding Witness: Gregory J. Meiman**

Q-123. Supplemental Executive Retirement Plan ("SERP"): Does the cost of service include any SERP either direct charged or allocated? If the response is in the affirmative, provide the following item:

a. The amount included in the base year and forecasted amount. If the amount is allocated, provide the allocations.

A-123.

a. SERP expense is not included in the Company's cost of service.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 124**

**Responding Witness: Gregory J. Meiman**

Q-124. Supplemental Executive Retirement Program (SERP).

a. Provide the comparable SERP expense for each calendar year 2015, 2016, and 2017.

b. Provide the most recent three actuarial reports for SERP.

c. Provide all actuarial studies, reports, and estimates used for SERP for the rate effective period, as to both Companies.

d. If different for affiliated SERP costs charged or allocated to KU, also answer parts a-e above for each affiliate that incurred SERP costs that were charged or allocated to KU.

A-124.

a. SERP expense was not included in the Company's cost of service for calendar years 2015, 2016, and 2017.

b. Not applicable, as SERP expense is not included in the Company's cost of service.

c. Not applicable, as SERP expense is not included in the Company's cost of service.

d. Not applicable.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 125**

**Responding Witness: Christopher M. Garrett**

**G. Taxes**

Q-125. Refer to the direct testimony of Chris M. Garrett, pages 32-35, and Schedule E-1 sponsored by Mr. Garrett. Mr. Garrett notes that the "TCJA retains the corporate deduction for state income taxes and the interest deductibility for utilities."

a. Are these two deductions taken into account in setting the Companies' rates?

b. If the response to subpart a., above, is in the affirmative, provide a citation to the application where the deductions are evidenced.

A-125.

a. Yes, the two deductions are included.

b. The state income tax and interest expense deductions can be seen on Schedule E-1, lines 2 and 15.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 126**

**Responding Witness: Christopher M. Garrett**

Q-126. Refer to the direct testimony of Kent W. Blake, pages 4-5, wherein he described the Offer and Acceptance of Satisfaction as filed in Case No. 2018-00034, as "Commission-approved."

a. Is it the position of the Companies that the Commission approved the referenced Offer and Acceptance of Satisfaction? If the response is in the affirmative, provide support for same.

A-126.

a. In Case No. 2018-00034, the Commission approved, with modifications that did not impact the termination date of the TCJA Surcredit, the *Offer and Acceptance of Satisfaction* in its Order dated March 20, 2018. In the Commission's Order dated September 28, 2018, the Commission noted that the *Offer and Acceptance of Satisfaction* became non-unanimous after the AG's withdrawal, but did not alter the termination date of the TCJA Surcredit.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 127**

**Responding Witness: Christopher M. Garrett**

Q-127. Tax Cuts and Jobs Act. Notwithstanding the regulatory treatment in Case No. 2018-00034, confirm that IRS normalization requirements for excess accumulated deferred income taxes ("ADIT") apply to only accelerated federal tax method-life depreciation, and that they do not apply to excess ADIT on other book-tax temporary differences, regardless of whether they have a basis in plant.

A-127. Confirmed. The normalization requirements apply to ADIT and excess ADIT attributable to differences in the method of computing depreciation and/or the depreciable life of an asset (method-life differences) used for federal income tax purposes versus those used for financial purposes. Federal ADIT and excess ADIT attributable to method-life differences are subject to the normalization rules and are generally referred to as "protected items." There is no prohibition against any other basis adjustments being treated in the same way (normalized) as method-life differences. The Company has, with past regulatory approval, consistently treated plant related basis adjustments arising from other than method-life differences as protected items. Furthermore, the Companies have classified net operating loss carryforward excess ADITs as "protected."

In this case customers actually benefit by including the other basis adjustments as protected items. The other basis adjustments are a net deferred income tax asset or additional "costs" to customers (rather than a deferred income tax liability that is refunded to customers) due to the income tax rate change. The customers benefit because they are "paying back" this deferred tax asset over a longer period of time as a protected item versus an unprotected item.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 128**

**Responding Witness: Christopher M. Garrett**

Q-128. Tax Cuts and Jobs Act. The Companies' FERC Form 1's for 2017 state the following at page 123.22:

KU
Regulatory liabilities associated with net deferred taxes represent the future revenue impact from the adjustment of deferred income taxes required primarily for excess deferred taxes and unamortized investment tax credits. At December 31, 2017, excess deferred taxes recorded as a result of the TCJA were $634 million, which includes the gross-up associated with the excess deferred taxes.

LG&E
Regulatory liabilities associated with net deferred taxes represent the future revenue impact from the adjustment of deferred income taxes required primarily for excess deferred taxes and unamortized investment tax credits. At December 31, 2017, excess deferred taxes recorded as a result of the TCJA were $532 million, which includes the gross-up associated with the excess deferred taxes.

a. Provide a reconciliation of the Companies' excess deferred tax balances, before and after the referenced gross-up.

b. What is the purpose of the gross-up and why is it necessary?

c. Considering the excess deferred taxes are amortized, how is the gross up reflected in cost of service as the excess deferred taxes is amortized?

A-128.

a. See attached.

b. The gross-up represents the future tax consequence of refunding excess deferred tax back to customers. As the Company refunds excess deferred tax back to customers in rates, the refund results in lower future revenue (and taxable income) to the Company and therefore lower future income tax expense. This future decrease in income tax is an additional amount that is to be distributed to customers.

c. The gross-up is part of the revenue requirement calculation on Schedule A, line 7, Tab 54 of the Filing Requirements. The excess deferred tax that is amortized per Schedule E, Tab 58 of the Filing Requirement does not include the gross-up.

**Kentucky Utilities Company**
**Louisville Gas and Electric Company**
Regulatory Movement - TCJA
Balances as of 12/31/17

| | KU | LG&E |
|---|---|---|
| ***Excess Deferred Taxes on Timing Differences*** | | |
| Cumulative Federal Timing Differences, including NOLs | (3,497,577,603) | (2,975,451,192) |
| Federal Rate Change | 14.00% | 14.00% |
| Excess Deferred Tax | (489,660,864) | (416,563,167) |
| Cumulative State Timing Differences | (2,462,775,281) | (2,048,290,331) |
| Fed Benefit Rate Change | -0.84% | -0.84% |
| Excess Deferred Tax | 20,687,312 | 17,205,639 |
| Total Excess Deferred Tax before Gross-up | (468,973,552) | (399,357,528) |
| Gross-up Factor | 1.3466 | 1.3466 |
| Net Regulatory Movement | (631,529,157) | (537,782,828) |
| ***Change in Gross-up Factor on Existing Regulatory Adjustments*** | | |
| Excess Deferred Tax Balance - Prior rate changes | (4,755,068) | (7,163,617) |
| Unamortized ITC Balance | (93,857,853) | (35,252,005) |
| ITC Basis Adjustments | 89,034,136 | 21,735,503 |
| AFUDC Equity Balance | 17,870,543 | - |
| Subtotal | 8,291,758 | (20,680,119) |
| Reduction in Gross-up Factor | (0.2900) | (0.2900) |
| Reduction to Existing Regulatory Adjustments | (2,404,952) | 5,998,087 |
| **Total Regulatory Movement** | **(633,934,109)** | **(531,784,741)** |

| | Old Tax Rates | New Tax Rates | Change in Rates |
|---|---|---|---|
| Federal | 35.00% | 21.00% | -14.00% |
| State | 6.00% | 6.00% | 0.00% |
| Fed Benefit | -2.10% | -1.26% | 0.84% |
| Composite | 38.90% | 25.74% | -13.16% |
| Gross-up Factor (1/(1 - tax rate)) | 1.6367 | 1.3466 | -0.2900 |

Note: Tax Rates are based on enacted tax law as of 12/31/17. The reduction to the Kentucky state tax rate was enacted per HB 487 in April 2018 and is not reflected in the balances above.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 129**

**Responding Witness: Christopher M. Garrett**

Q-129. State Tax Reform. Refer to the direct testimony of Chris M. Garrett, page 35, wherein he states, "Prior to the implementation of H.B. 487, the Companies paid a state corporate income tax rate of 6%. For taxable years beginning on or after January 1, 2018, the state corporate income tax will be imposed at a 5% tax rate."

a. What are the estimated savings from the corporate rate reduction and estimated increases in sales tax resulting from state tax reform for the period between January 1, 2018, and April 30, 2019?

A-129.

a. See Exhibit 2 from Case No. 2018-00304 which provides an annual estimate for income tax savings, excess ADIT amortization, and offsets for the loss of the Kentucky domestic production activities deduction and the increase in sales tax attributable to the total Company (including rate mechanisms).

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 130**

**Responding Witness: Christopher M. Garrett**

Q-130. State Tax Reform. Refer to the direct testimony of Chris M. Garrett, page 35, wherein he states, "In a separate filing earlier this month, the Companies requested permission to establish regulatory liabilities by the end of the year for the excess ADIT created by the reduction in the state corporate income tax rate."

a. How are the regulatory liabilities reflected in the base and forecasted test years?

A-130.

a. The Company has assumed that the regulatory liability treatment will be granted and has included the Kentucky excess ADIT regulatory liability in rate base in both the base and forecasted test period. See the response to Question No. 131 for the associated Kentucky excess ADIT amortization on Schedule E.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 131**

**Responding Witness: Christopher M. Garrett**

Q-131. State Tax Reform. Refer to the direct testimony of Chris M. Garrett, page 38, wherein he states, "Included in the forecasted test year is approximately $1.0 million for KU, $0.5 million for LG&E Electric, and $0.1 million for LG&E Gas of additional excess ADIT amortization associated with Kentucky state tax reform."

a. Reconcile the referenced amortizations to the excess ADIT adjustments in the Companies' respective Schedule Es.

A-131.

a. See reconciliation below.

| KU Forecasted Test Year | |
|---|---|
| Schedule E-1, Line 107 – Excess Deferreds – Protected | $(1,433,013) |
| Schedule E-1, Line 108 – Excess Deferreds – Unprotected | (54,672) |
| Total state excess ADIT amortization - forecasted test year | (1,487,685) |
| Less state excess ADIT amortization - prior rate changes | (283,333) |
| Excess ADIT amortization - Kentucky state tax reform | $(1,204,352) |
| | |
| Net of federal tax offset [$1,204,352 * (1 - .21%)] | $ (951,438) |

For LG&E's Electric and Gas reconciliations, refer to Case No. 2018-00295 response to AG 1-131.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 132**

**Responding Witness: Christopher M. Garrett**

Q-132. State Tax Reform. Refer to the direct testimony of Chris M. Garrett, page 35, wherein he states, "Like the Companies' treatment of the TCJA, KU and LG&E will account for the state corporate tax rate reduction by amortizing all protected excess ADIT using the Average Rate Assumption Method ("ARAM") and amortizing all unprotected excess ADIT over a 15-year amortization period. The Companies will continue to treat all property-related excess ADIT as protected."

a. Cite the Kentucky law or tax code that defines "protected" excess ADIT.

b. Cite the Kentucky law or tax code that requires using ARAM to amortize "protected" excess ADIT consistent with IRS requirements for electing federal accelerated depreciation.

A-132.

a. Effective for tax years beginning on or after January 1, 2018, House Bill 366 section 53(14) amends Kentucky's income tax provisions for conformity to the Internal Revenue Code that was in effect on December 31, 2017 (includes Tax Cuts and Jobs Act and normalization section). However, Kentucky will continue to decouple from the full expensing deduction allowed for federal purposes under Internal Revenue Code Section 168(k). House Bill 366 was adopted in its entirety into House Bill 487.

b. See the response to part a.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 133**

**Responding Witness: Christopher M. Garrett**

Q-133. State Tax Reform. Refer to the direct testimony of Chris M. Garrett, page 35, wherein he states, "The amortization of the unprotected excess ADIT will begin when new base rates go into effect."

a. Discuss when the "protected" excess ADIT amortizations under the ARAM method begin.

b. If they do not begin when new base rates go into effect, will the benefit of the "protected" excess ADIT amortizations from January 1, 2018, through April 30, 2019, ever accrue to customers?

A-133.

a. The Company began amortizing its Kentucky "protected" excess ADIT under the ARAM effective January 1, 2018. This approach is consistent with the approach taken in the previous two Kentucky state tax reform cases, Case No. 2005-00181 and Case No. 2006-00456.

b. Unlike with the much larger federal Tax Cuts and Jobs Act, no separate cases were initiated nor Orders issued to address state tax reform from its inception. The base rates set forth in this proceeding, however, do provide customers the benefit of the forecast test year amortization of the "protected" excess ADIT on an ongoing basis. Whether benefits embedded in the calculation of base rates will ultimately be greater or less than the cumulative excess ADIT amortization will depend on the timing of rate cases during the life of the underlying assets giving rise to the excess ADIT balances.

**KENTUCKY UTILITIES COMPANY**

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**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 134**

**Responding Witness: Christopher M. Garrett**

Q-134. State Tax Reform. The Kentucky corporate income tax rate was previously reduced from 7 percent to 6 percent, effective in 2008, and from 8.25 percent to 7 percent, effective in 2006.

a. Were the excess ADIT's in connection with the previous tax rate reductions amortized consistently with the Companies' proposed ratemaking treatment in the instant case? If the response is in the negative, explain the differences.

b. Do the Companies have remaining excess ADIT balances on their books from the previous tax rate reductions? If the response is in the affirmative, provide the forecasted balances as of December 31, 2018, and April 30, 2019.

A-134.

a. The protected excess deferred income tax was amortized consistent with the approach in Case No. 2005-00181 and Case No. 2006-00456. For the unprotected excess deferred tax in both of the previous cases the Company immediately reduced income tax expense in the year of the tax rate reduction due to the de minimis amount of the adjustment ($185,000 in 2005 and $80,000 in 2006).

b. Yes. The Company does have "protected" ADIT balances from the previous tax rate reductions that continue to amortize. The forecasted balances as of December 31, 2018, and April 30, 2019 are $5.7 million and $5.6 million, respectfully.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 135**

**Responding Witness: Christopher M. Garrett**

Q-135. Property Tax. Refer to Filing Requirement 807 KAR 5:001 Section 16(7)(c), Item A, wherein the Companies describe the financial planning modeling process. Page 13 of 19 states the following:

Property taxes are estimated annually based on net book asset values, including CWIP, as of December 31 of the previous year and include several current asset balances such as; fuel inventory and materials and supplies. The expense accrual is spread evenly over twelve months while cash payments are based on historic trends, which normally result in large cash payments during the fourth quarter of a calendar year.

The primary source of data used to calculate the estimates is within the UI report labeled "KY Plant Account". The plant account assignment determines the property classification (real estate, manufacturing machinery, other tangible) and then the appropriate tax rates are applied to those balances. State and local tax rates are based on prior year settlements with an assumed increase to local tax rates of two percent per year.

a. Provide the computation supporting monthly property tax expense for 2019 and 2020. The computation should reflect:

   i. Net book asset values, including CWIP, as of December 31 of the previous year and current asset balances such as; fuel inventory and materials and supplies.

   ii. Rates applied to those balances.

b. Reconcile the state and local tax rates based on prior year settlements with the assumed increase to local tax rates of two percent per year going back to 2017.

A-135.

a. See the attachment to the response to KIUC 1-54.

b. The Kentucky Department of Revenue releases an "Average Local Property Tax Rates" schedule each year which supports the assumed increase to local tax rates of two percent. State tax rates remain unchanged. See attached.

# TABLE II
# AVERAGE LOCAL PROPERTY TAX RATES

**Tax rates are expressed in cents per $100 of assessed value.**

| TYPE OF DISTRICT<br>CLASS OF PROPERTY | TAX RATE * | NO. DISTRICTS REPORTING | % Increase |
|---|---|---|---|
| **COUNTIES** | | | |
| Average Real Estate Rate | 33.0544 | 120 | 3% |
| Average Tangible Rate | 39.4471 | 120 | 2% |
| Average Motor Vehicle Rate | 25.0962 | 120 | 1% |
| **CITIES** | | | |
| Average Real Estate Rate(Zero Rates Excluded) | 22.5847 | 403 | 0% |
| Average Real Estate Rate(Zero Rates Included) | 22.4179 | 406 | 1% |
| Average Tangible Rate(Zero Rates Excluded) | 29.1876 | 298 | 3% |
| Average Tangible Rate(Zero Rates Included) | 21.4234 | 406 | 4% |
| Average Motor Vehicle Rate(Zero Rates Excluded) | 24.9731 | 273 | 0% |
| Average Motor Vehicle Rate(Zero Rates Included) | 16.7922 | 406 | 1% |
| **SCHOOL DISTRICTS** | | | |
| Average Real Estate Rate | 64.8006 | 178 | 3% |
| Average Tangible Rate | 64.8927 | 178 | 3% |
| Average Motor Vehicle Rate | 56.1073 | 178 | 0% |
| **SPECIAL TAX DISTRICTS** | | | |
| Average Real Estate Rate(Zero Rates Excluded) | 10.415 | 243 | 1% |
| Average Real Estate Rate(Zero Rates Included) | 10.33 | 245 | 1% |
| Average Tangible Rate(Zero Rates Excluded) | 10.6932 | 158 | 1% |
| Average Tangible Rate(Zero Rates Included) | 6.896 | 245 | 2% |
| Average Motor Vehicle Rate(Zero Rates Excluded) | 10.1796 | 152 | 1% |
| Average Motor Vehicle Rate(Zero Rates Included) | 6.3155 | 245 | 1% |

2017 Property Tax Rate Book

# TABLE II

# AVERAGE LOCAL PROPERTY TAX RATES

Tax rates are expressed in cents per $100 of assessed value.

| TYPE OF DISTRICT<br>CLASS OF PROPERTY | TAX RATE * | NO. DISTRICTS REPORTING |
|---|---|---|
| **COUNTIES** | | |
| Average Real Estate Rate | 31.9487 | 120 |
| Average Tangible Rate | 38.5832 | 120 |
| Average Motor Vehicle Rate | 24.9274 | 120 |
| **CITIES** | | |
| Average Real Estate Rate(Zero Rates Excluded) | 22.5454 | 403 |
| Average Real Estate Rate(Zero Rates Included) | 22.1605 | 410 |
| Average Tangible Rate(Zero Rates Excluded) | 28.4638 | 298 |
| Average Tangible Rate(Zero Rates Included) | 20.6883 | 410 |
| Average Motor Vehicle Rate(Zero Rates Excluded) | 24.9011 | 274 |
| Average Motor Vehicle Rate(Zero Rates Included) | 16.6412 | 410 |
| **SCHOOL DISTRICTS** | | |
| Average Real Estate Rate | 63.0714 | 178 |
| Average Tangible Rate | 63.2248 | 178 |
| Average Motor Vehicle Rate | 56.0843 | 178 |
| **SPECIAL TAX DISTRICTS** | | |
| Average Real Estate Rate(Zero Rates Excluded) | 10.3065 | 243 |
| Average Real Estate Rate(Zero Rates Included) | 10.2224 | 245 |
| Average Tangible Rate(Zero Rates Excluded) | 10.558 | 157 |
| Average Tangible Rate(Zero Rates Included) | 6.7657 | 245 |
| Average Motor Vehicle Rate(Zero Rates Excluded) | 10.0983 | 151 |
| Average Motor Vehicle Rate(Zero Rates Included) | 6.2239 | 245 |

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 136**

**Responding Witness: Christopher M. Garrett**

Q-136. Tax Depreciation. Refer to the Companies' response to PSC Data Request No. 1-65.

a. Provide the tax depreciation rates for each line item in Att_KU_PSC_1-65_Depreciation_Exp_Wkpr.

b. Reconcile the book-tax timing differences to accumulated deferred income taxes in rate base for the forecast period.

A-136.

a. See attached.

b. See the response to PSC 2-51(b).

**Kentucky Utilities Company**
**Depreciation Calculation**

| Description | Current Rate | Proposed Rate eff. May-2019 | Tax Depr Rate |
|---|---|---|---|
| KU-130100- KY Organization | 0.00% | 0.00% | KU MISC INTANGIBLE 5 SL |
| KU-130100- VA Organization | 0.00% | 0.00% | KU MISC INTANGIBLE 5 SL |
| KU-130200-Franchises and Consents | 3.63% | 3.63% | KU MISC INTANGIBLE 5 SL |
| KU-130200-Licensed Project Franchi | 3.63% | 3.63% | KU MISC INTANGIBLE 5 SL |
| KU-130300-Misc Intangible Plant | 20.96% | 20.96% | KU MISC INTANGIBLE 5 SL |
| KU-130310-CCS Software | 10.06% | 10.06% | KU MISC INTANGIBLE 5 SL |
| KU-131020-EWB 1 Land | 0.00% | 0.00% | NA |
| KU-131020-EWB 3 Land | 0.00% | 0.00% | NA |
| KU-131020-EWB 3 Land ECR 2011 | 0.00% | 0.00% | NA |
| KU-131020-GH 1 Land | 0.00% | 0.00% | NA |
| KU-131020-GH 4 Land ECR 2009 | 0.00% | 0.00% | NA |
| KU-131020-GH 4 Land ECR 2016 | 0.00% | 0.00% | NA |
| KU-131020-GR 1&2 Land | 0.00% | 0.00% | NA |
| KU-131020-PI 1&2 Land | 0.00% | 0.00% | NA |
| KU-131020-PI 3 Land | 0.00% | 0.00% | NA |
| KU-131020-TC 2 Land | 0.00% | 0.00% | NA |
| KU-131020-TC 2 Land ECR 2009 | 0.00% | 0.00% | NA |
| KU-131020-TY 3 Land | 0.00% | 0.00% | NA |
| KU-131100-EWB 1 Structures and Imp | 0.05% | 0.04% | KU STEAM PROD MACRS 20 |
| KU-131100-EWB 2 Structures and Imp | 0.67% | 0.63% | KU STEAM PROD MACRS 20 |
| KU-131100-EWB 3 Struc | 1.80% | 3.17% | KU STEAM PROD MACRS 20 |
| KU-131100-EWB 3 Struc ECR 2005 | 0.00% | 3.17% | KU STEAM PROD MACRS 20 |
| KU-131100-EWB 3 Struc ECR 2009 | 1.80% | 3.17% | KU STEAM PROD MACRS 20 |
| KU-131100-EWB 3 Struc ECR 2011 | 1.80% | 3.17% | KU STEAM PROD MACRS 20 |
| KU-131100-EWB3 FGD Struc | 4.83% | 4.54% | KU STEAM PROD MACRS 20 |
| KU-131100-EWB3 FGD Struc ECR 2005 | 0.00% | 4.54% | KU STEAM PROD MACRS 20 |
| KU-131100-GH 1 Struc | 0.32% | 1.68% | KU STEAM PROD MACRS 20 |
| KU-131100-GH 1 Struc ECR 2006 | 0.00% | 1.68% | KU STEAM PROD MACRS 20 |
| KU-131100-GH 1SC Structures and Im | 1.16% | 1.14% | KU STEAM PROD MACRS 20 |
| KU-131100-GH 2 Structures and Impr | 0.88% | 1.31% | KU STEAM PROD MACRS 20 |
| KU-131100-GH 3 Struc | 1.47% | 2.15% | KU STEAM PROD MACRS 20 |
| KU-131100-GH 3 Struc ECR 2006 | 0.00% | 2.15% | KU STEAM PROD MACRS 20 |
| KU-131100-GH 3 Struc ECR 2011 | 1.47% | 2.15% | KU STEAM PROD MACRS 20 |
| KU-131100-GH 4 Struc | 2.49% | 3.44% | KU STEAM PROD MACRS 20 |
| KU-131100-GH 4 Struc ECR 2005 | 0.00% | 3.44% | KU STEAM PROD MACRS 20 |
| KU-131100-GH 4 Struc ECR 2006 | 0.00% | 3.44% | KU STEAM PROD MACRS 20 |
| KU-131100-GH 4 Struc ECR 2009 | 2.49% | 3.44% | KU STEAM PROD MACRS 20 |
| KU-131100-GH2 FGD Structures and I | 1.20% | 1.16% | KU STEAM PROD MACRS 20 |
| KU-131100-GH3 FGD Structures and I | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131100-GH4 FGD Structures and I | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131100-GR 1-2 Structures and Im | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131100-GR 3 Structures and Impr | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131100-GR 4 Structures and Impr | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131100-PI 1-2 Structures and Imp | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131100-PI 3 Structures and Impr | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131100-SL Structures and Improv | 1.12% | 1.54% | KU STEAM PROD MACRS 20 |
| KU-131100-TC 2 FGD Struc & Improv | 1.44% | 1.21% | KU STEAM PROD MACRS 20 |
| KU-131100-TC2 Struct | 2.05% | 1.81% | KU STEAM PROD MACRS 20 |
| KU-131100-TC2 Struct ECR 2006 | 0.00% | 1.81% | KU STEAM PROD MACRS 20 |
| KU-131100-TC2 Struct ECR 2009 | 2.05% | 1.81% | KU STEAM PROD MACRS 20 |
| KU-131100-TY 1&2 Structures and Im | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131100-TY 3 Structures and Impr | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131101-AROP EWB 1 Struct & Imp | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131101-AROP EWB 3 ECR 2009 | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131101-AROP EWB 3 Struct & Imp | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |

**Kentucky Utilities Company**
**Depreciation Calculation**

| Description | Current Rate | Proposed Rate eff. May-2019 | Tax Depr Rate |
|---|---|---|---|
| KU-131101-AROP GH 1 Struct & Imp | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131101-AROP GR 1-2 Struct & Imp | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131101-AROP GR 4 Struct & Impr | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131101-AROP TC2 Struct ECR 2009 | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131101-AROP TY 3 Struct & Impr | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 1 Boil | 3.16% | 3.21% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 1 Boil - Ash Pond | 0.00% | 24.68% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 1 Boil ECR 2005 | 3.16% | 3.21% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 1 Boil ECR 2011 | 0.00% | 3.21% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 2 Boil | 2.98% | 3.08% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 2 Boil ECR 2005 | 2.98% | 3.08% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 2 Boil ECR 2006 | 2.98% | 3.08% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 2 Boil ECR 2011 | 0.00% | 3.08% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 3 Boil | 2.65% | 5.19% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 3 Boil Ash Pond | 0.00% | 24.68% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 3 Boil ECR 2005 | 2.65% | 5.19% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 3 Boil ECR 2006 | 2.65% | 5.19% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 3 Boil ECR 2009 | 2.65% | 5.19% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 3 Boil ECR 2011 | 2.65% | 5.19% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 3 ECR 2016 Plan | 2.65% | 5.19% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB 3 ECR 2018 Plan | 2.65% | 5.19% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB ECR Future Plan | 2.65% | 5.19% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB3 FGD Boil | 4.81% | 4.92% | KU STEAM PROD MACRS 20 |
| KU-131200-EWB3 FGD Boil ECR 2005 | 0.00% | 4.92% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 1 Boil | 2.93% | 4.83% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 1 Boil - Ash Pond | 0.00% | 0.26% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 1 Boil ECR 2005 | 0.00% | 4.83% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 1 Boil ECR 2006 | 0.00% | 4.83% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 1 Boil ECR 2011 | 2.93% | 4.83% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 1 Boil ECR 2016 | 2.93% | 4.83% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 1 SC Boil - Ash Pond | 0.00% | 0.23% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 1SC Boil | 4.17% | 4.16% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 1SC Boil ECR 2005 | 0.00% | 4.16% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 1SC Boil ECR 2016 | 4.17% | 4.16% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 2 Boil | 1.65% | 5.10% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 2 Boil ECR 2005 | 0.00% | 5.10% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 2 Boil ECR 2011 | 1.65% | 5.10% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 2 Boil ECR 2016 | 1.65% | 5.10% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 2 SC Boil - Ash Pond | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 2SC Boil | 2.38% | 1.19% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 2SC Boil ECR 2005 | 0.00% | 1.19% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 2SC Boil ECR 2016 | 2.38% | 1.19% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 3 Boil | 2.26% | 3.54% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 3 Boil ECR 2006 | 0.00% | 3.54% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 3 Boil ECR 2011 | 2.26% | 3.54% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 3 Boil ECR 2016 | 2.26% | 3.54% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 4 Boil | 2.60% | 4.35% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 4 Boil - Ash Pond | 0.00% | 14.06% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 4 Boil ECR 2005 | 0.00% | 4.35% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 4 Boil ECR 2006 | 0.00% | 4.35% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 4 Boil ECR 2009 | 2.60% | 4.35% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 4 Boil ECR 2011 | 2.60% | 4.35% | KU STEAM PROD MACRS 20 |
| KU-131200-GH 4 Boil ECR 2016 | 2.60% | 4.35% | KU STEAM PROD MACRS 20 |
| KU-131200-GH3 FGD Boil | 3.89% | 3.99% | KU STEAM PROD MACRS 20 |
| KU-131200-GH3 FGD Boil ECR 2005 | 3.89% | 3.99% | KU STEAM PROD MACRS 20 |

**Kentucky Utilities Company**
**Depreciation Calculation**

| Description | Current Rate | Proposed Rate eff. May-2019 | Tax Depr Rate |
|---|---|---|---|
| KU-131200-GH3 FGD Boil ECR 2016 | 3.89% | 3.99% | KU STEAM PROD MACRS 20 |
| KU-131200-GH4 FGD Boil | 4.01% | 3.57% | KU STEAM PROD MACRS 20 |
| KU-131200-GH4 FGD Boil ECR 2005 | 4.01% | 3.57% | KU STEAM PROD MACRS 20 |
| KU-131200-GH4 FGD Boil ECR 2016 | 4.01% | 3.57% | KU STEAM PROD MACRS 20 |
| KU-131200-Ghent ECR 2018 Plan | 2.60% | 4.35% | KU STEAM PROD MACRS 20 |
| KU-131200-Ghent ECR Future Plan | 2.60% | 4.35% | KU STEAM PROD MACRS 20 |
| KU-131200-GR 1-2 Boiler Plant Equi | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-GR 3 Boil | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-GR 3 Boil - Ash Pond | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-GR 3 Boil ECR 2006 | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-GR 4 Boil | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-GR 4 Boil ECR 2006 | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-GR 4 Boil ECR 2016 | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-GR ECR Future Plan | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-PI 1-2 Boiler Plant Equip | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-PI 3 Boil - Ash Pond | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-PI 3 Boiler Plant Equipm | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-PI ECR 2016 | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-PI ECR Future Plan | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-TC 2 Boil | 2.37% | 2.17% | KU STEAM PROD MACRS 20 |
| KU-131200-TC 2 Boil - Ash Pond | 0.00% | 7.48% | KU STEAM PROD MACRS 20 |
| KU-131200-TC 2 Boil ECR 2006 | 2.37% | 2.17% | KU STEAM PROD MACRS 20 |
| KU-131200-TC 2 Boil ECR 2009 | 2.37% | 2.17% | KU STEAM PROD MACRS 20 |
| KU-131200-TC 2 Boil ECR 2009-Ash Po | 0.00% | 7.48% | KU STEAM PROD MACRS 20 |
| KU-131200-TC 2 Boil ECR 2016 | 2.37% | 2.17% | KU STEAM PROD MACRS 20 |
| KU-131200-TC ECR 2018 Plan | 2.37% | 2.17% | KU STEAM PROD MACRS 20 |
| KU-131200-TC ECR Future Plan | 2.37% | 2.17% | KU STEAM PROD MACRS 20 |
| KU-131200-TC2 FGD Boil ECR 2006 | 2.22% | 1.96% | KU STEAM PROD MACRS 20 |
| KU-131200-TC2 FGD Boil ECR 2006 | 2.22% | 1.96% | KU STEAM PROD MACRS 20 |
| KU-131200-TY 1&2 Boiler Plant Equi | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-TY 3 Boil | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-TY 3 Boil - Ash Pond | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-TY 3 Boil ECR 2006 | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-TY 3 Boil ECR 2016 | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131200-TY ECR Future Plan | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131201-AROP EWB 1 Boiler Plt Eqp | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131201-AROP EWB 3 Boiler Plt Eqp | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131201-AROP GH 1 Boiler Plt Equp | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131201-AROP GH 1SC Boiler Plt Eq | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131201-AROP GH 2 Boiler Plt Equp | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131201-AROP GH 4 Boiler Plt Equp | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131201-AROP GR 1-2 Boiler Plt Eq | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131201-AROP GR 4 Boiler Plt Equp | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131201-AROP TY 1-2 Boiler Plt Eq | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131201-AROP TY 3 Boiler Plt Equp | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131400-EWB 1 Turbogenerator Uni | 2.68% | 2.52% | KU STEAM PROD MACRS 20 |
| KU-131400-EWB 2 Turbogenerator Uni | 1.73% | 1.62% | KU STEAM PROD MACRS 20 |
| KU-131400-EWB 3 Turbogenerator Uni | 1.73% | 5.29% | KU STEAM PROD MACRS 20 |
| KU-131400-GH 1 Turbogenerator Unit | 2.60% | 3.34% | KU STEAM PROD MACRS 20 |
| KU-131400-GH 2 Turbogenerator Unit | 2.11% | 2.62% | KU STEAM PROD MACRS 20 |
| KU-131400-GH 3 Turbogenerator Unit | 1.97% | 2.12% | KU STEAM PROD MACRS 20 |
| KU-131400-GH 4 Turbogenerator Unit | 2.39% | 2.64% | KU STEAM PROD MACRS 20 |
| KU-131400-GR 1&2 Turbogenerator Un | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131400-GR 3 Turbogenerator Unit | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131400-GR 4 Turbogenerator Unit | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |

**Kentucky Utilities Company**
**Depreciation Calculation**

| Description | Current Rate | Proposed Rate eff. May-2019 | Tax Depr Rate |
|---|---|---|---|
| KU-131400-PI 1-2 Turbogenerator Uni | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131400-PI 3 Turbogenerator Unit | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131400-TC 2 Turbogenerator Unit | 2.37% | 2.14% | KU STEAM PROD MACRS 20 |
| KU-131400-TY 1&2 Turbogenerator Un | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131400-TY 3 Turbogenerator Unit | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131401-AROP TY 3 Turbogenerator | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131500-EWB 1 Accessory Electric | 1.33% | 1.24% | KU STEAM PROD MACRS 20 |
| KU-131500-EWB 2 Acc | 2.13% | 2.00% | KU STEAM PROD MACRS 20 |
| KU-131500-EWB 2 Acc ECR 2005 | 2.13% | 2.00% | KU STEAM PROD MACRS 20 |
| KU-131500-EWB 3 Acc | 1.34% | 3.74% | KU STEAM PROD MACRS 20 |
| KU-131500-EWB 3 Acc ECR 2005 | 1.34% | 3.74% | KU STEAM PROD MACRS 20 |
| KU-131500-EWB 3 Acc ECR 2011 | 1.34% | 3.74% | KU STEAM PROD MACRS 20 |
| KU-131500-EWB 3 FGD Acc | 4.79% | 4.75% | KU STEAM PROD MACRS 20 |
| KU-131500-EWB3 FGD Acc ECR 2005 | 4.79% | 4.75% | KU STEAM PROD MACRS 20 |
| KU-131500-GH 1 Access ECR 2011 | 0.60% | 2.37% | KU STEAM PROD MACRS 20 |
| KU-131500-GH 1 Accessory Electric | 0.60% | 2.37% | KU STEAM PROD MACRS 20 |
| KU-131500-GH 1SC Acc ECR 2005 | 4.04% | 3.69% | KU STEAM PROD MACRS 20 |
| KU-131500-GH 1SC Acc ECR 2005 | 4.04% | 3.69% | KU STEAM PROD MACRS 20 |
| KU-131500-GH 2 Acc ECR 2011 | 1.49% | 1.66% | KU STEAM PROD MACRS 20 |
| KU-131500-GH 2 Accessory Electric | 1.49% | 1.66% | KU STEAM PROD MACRS 20 |
| KU-131500-GH 2SC Acc ECR 2005 | 4.94% | 4.85% | KU STEAM PROD MACRS 20 |
| KU-131500-GH 2SC Acc ECR 2005 | 4.94% | 4.85% | KU STEAM PROD MACRS 20 |
| KU-131500-GH 3 Acc ECR 2011 | 1.45% | 1.73% | KU STEAM PROD MACRS 20 |
| KU-131500-GH 3 Accessory Electric | 1.45% | 1.73% | KU STEAM PROD MACRS 20 |
| KU-131500-GH 4 Acc ECR 2009 | 1.67% | 3.56% | KU STEAM PROD MACRS 20 |
| KU-131500-GH 4 Acc ECR 2011 | 1.67% | 3.56% | KU STEAM PROD MACRS 20 |
| KU-131500-GH 4 Accessory Electric | 1.67% | 3.56% | KU STEAM PROD MACRS 20 |
| KU-131500-GH3 FGD Acc ECR 2005 | 3.91% | 3.66% | KU STEAM PROD MACRS 20 |
| KU-131500-GH3 FGD Acc ECR 2005 | 3.91% | 3.66% | KU STEAM PROD MACRS 20 |
| KU-131500-GH4 FGD Acc ECR 2005 | 4.05% | 4.15% | KU STEAM PROD MACRS 20 |
| KU-131500-GH4 FGD Acc ECR 2005 | 4.05% | 4.15% | KU STEAM PROD MACRS 20 |
| KU-131500-GR 1&2 Accessory Electri | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131500-GR 3 Accessory Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131500-GR 4 Accessory Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131500-PI 1-2 Accessory Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131500-PI 3 Accessory Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131500-TC 2 Acc | 2.18% | 1.99% | KU STEAM PROD MACRS 20 |
| KU-131500-TC 2 Acc ECR 2006 | 2.18% | 1.99% | KU STEAM PROD MACRS 20 |
| KU-131500-TC 2 Acc ECR 2009 | 2.18% | 1.99% | KU STEAM PROD MACRS 20 |
| KU-131500-TC 2 FGD Accessory Equip | 1.66% | 1.42% | KU STEAM PROD MACRS 20 |
| KU-131500-TY 1&2 Accessory Electri | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131500-TY 3 Accessory Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131501-AROP EWB 1 Acc  Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131501-AROP EWB 2 Acc Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131501-AROP EWB 3 Acc Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131501-AROP GH 1 Acc  Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131501-AROP GH 2 Acc  Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131501-AROP GH 3 Acc Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131501-AROP GH 4 Acc  Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131501-AROP GR 4 Acc Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131501-AROP TY 3 Acc  Electric | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131600-EWB 1 Misc Power Plant E | 1.60% | 1.52% | KU STEAM PROD MACRS 20 |
| KU-131600-EWB 2 Misc Power Plant E | 0.06% | 0.06% | KU STEAM PROD MACRS 20 |
| KU-131600-EWB 3 Misc Power Plant E | 2.35% | 3.36% | KU STEAM PROD MACRS 20 |
| KU-131600-GH 1 Misc Power Plant Eq | 0.78% | 1.06% | KU STEAM PROD MACRS 20 |

**Kentucky Utilities Company**
**Depreciation Calculation**

| Description | Current Rate | Proposed Rate eff. May-2019 | Tax Depr Rate |
|---|---|---|---|
| KU-131600-GH 1SC Misc Power Plant | 1.27% | 0.90% | KU STEAM PROD MACRS 20 |
| KU-131600-GH 2 Misc Power Plant Eq | 0.65% | 0.89% | KU STEAM PROD MACRS 20 |
| KU-131600-GH 3 Misc Power Plant Eq | 1.20% | 2.17% | KU STEAM PROD MACRS 20 |
| KU-131600-GH 3 Misc PwrPlt ECR 2011 | 1.20% | 2.17% | KU STEAM PROD MACRS 20 |
| KU-131600-GH 4 Misc Power Plant Eq | 3.03% | 3.53% | KU STEAM PROD MACRS 20 |
| KU-131600-GR 1&2 Misc Power Plant | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131600-GR 3 Misc Power Plant Eq | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131600-GR 4 Misc Power Plant Eq | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131600-PI 1-2 Misc Power Plant E | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131600-PI 3 Misc Power Plant Eq | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131600-SL Misc Power Plant Equi | 3.04% | 3.46% | KU STEAM PROD MACRS 20 |
| KU-131600-TC 2 Misc Power Plant Equ | 2.51% | 2.26% | KU STEAM PROD MACRS 20 |
| KU-131600-TY 1&2 Misc Power Plant | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-131600-TY 3 Misc Power Plant Eq | 0.00% | 0.00% | KU STEAM PROD MACRS 20 |
| KU-133010-DD Land Rights | 0.00% | 0.00% | NA |
| KU-133100-DD Structures and Improv | 2.48% | 2.48% | KU HYDRO PROD MACRS 20 |
| KU-133200-DD Reservoirs, Dams, and | 2.61% | 2.61% | KU HYDRO PROD MACRS 20 |
| KU-133300-DD Water Wheels, Turbine | 3.86% | 3.86% | KU HYDRO PROD MACRS 20 |
| KU-133400-DD Accessory Electric Eq | 3.81% | 3.81% | KU HYDRO PROD MACRS 20 |
| KU-133400-L7 Accessory Electric Eq | 0.00% | 0.00% | KU HYDRO PROD MACRS 20 |
| KU-133500-DD Misc Power Plant Equi | 3.76% | 3.76% | KU HYDRO PROD MACRS 20 |
| KU-133500-L7 Misc Power Plant Equi | 0.00% | 0.00% | KU HYDRO PROD MACRS 20 |
| KU-133600-DD Roads, Railroads, and | 3.33% | 3.33% | KU HYDRO PROD MACRS 20 |
| KU-134020-EWB 8 Land | 0.00% | 0.00% | NA |
| KU-134020-EWB Solar Facility Land | 0.00% | 0.00% | NA |
| KU-134020-Land | 0.00% | 0.00% | NA |
| KU-134100-CR 7 Structures and Impr | 3.03% | 3.03% | KU OTHER PROD MACRS 20 |
| KU-134100-EWB 10 Structures and Im | 2.92% | 2.92% | KU OTHER PROD MACRS 15 |
| KU-134100-EWB 11 Structures and Im | 4.32% | 4.32% | KU OTHER PROD MACRS 15 |
| KU-134100-EWB 5 Structures and Im | 3.94% | 3.94% | KU OTHER PROD MACRS 15 |
| KU-134100-EWB 6 Structures and Imp | 4.34% | 4.34% | KU OTHER PROD MACRS 15 |
| KU-134100-EWB 7 Structures and Imp | 4.33% | 4.33% | KU OTHER PROD MACRS 15 |
| KU-134100-EWB 8 Structures and Imp | 3.97% | 3.97% | KU OTHER PROD MACRS 15 |
| KU-134100-EWB 9 Structures and Imp | 2.76% | 2.76% | KU OTHER PROD MACRS 15 |
| KU-134100-EWB Solar Struc and Imp | 4.24% | 4.24% | KU OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ |
| KU-134100-HA 1,2,&3 Structures and | 19.17% | 19.17% | KU OTHER PROD MACRS 15 |
| KU-134100-PR 13 Structures and Imp | 4.16% | 4.16% | KU OTHER PROD MACRS 15 |
| KU-134100-TC 10 Structures and Imp | 3.79% | 3.79% | KU OTHER PROD MACRS 15 |
| KU-134100-TC 5 Structures and Impr | 3.87% | 3.87% | KU OTHER PROD MACRS 15 |
| KU-134100-TC 6 Structures and Impr | 3.86% | 3.86% | KU OTHER PROD MACRS 15 |
| KU-134100-TC 7 Structures and Impr | 3.78% | 3.78% | KU OTHER PROD MACRS 15 |
| KU-134100-TC 8 Structures and Impr | 3.78% | 3.78% | KU OTHER PROD MACRS 15 |
| KU-134100-TC 9 Structures and Impr | 3.79% | 3.79% | KU OTHER PROD MACRS 15 |
| KU-134200-CR 7 Fuel Holders, Produ | 3.10% | 3.10% | KU OTHER PROD MACRS 20 |
| KU-134200-EWB 10 Fuel Holders, Pro | 5.43% | 5.43% | KU OTHER PROD MACRS 15 |
| KU-134200-EWB 11 Fuel Holders, Pro | 7.39% | 7.39% | KU OTHER PROD MACRS 15 |
| KU-134200-EWB 5 Fuel Holders, Prod | 5.00% | 5.00% | KU OTHER PROD MACRS 15 |
| KU-134200-EWB 6 Fuel Holders, Prod | 6.96% | 6.96% | KU OTHER PROD MACRS 15 |
| KU-134200-EWB 7 Fuel Holders, Prod | 6.99% | 6.99% | KU OTHER PROD MACRS 15 |
| KU-134200-EWB 8 Fuel Holders, Prod | 6.53% | 6.53% | KU OTHER PROD MACRS 15 |
| KU-134200-EWB 9 Fuel Holders, Prod | 4.65% | 4.65% | KU OTHER PROD MACRS 15 |
| KU-134200-HA 1,2,&3 Fuel Holders, | 15.74% | 15.74% | KU OTHER PROD MACRS 15 |
| KU-134200-PR 13 Fuel Holders, Prod | 3.89% | 3.89% | KU OTHER PROD MACRS 15 |
| KU-134200-TC 10 Fuel Holders, Prod | 3.85% | 3.85% | KU OTHER PROD MACRS 15 |
| KU-134200-TC 5 Fuel Holders, Produ | 3.90% | 3.90% | KU OTHER PROD MACRS 15 |

**Kentucky Utilities Company**
**Depreciation Calculation**

| Description | Current Rate | Proposed Rate eff. May-2019 | Tax Depr Rate |
|---|---|---|---|
| KU-134200-TC 6 Fuel Holders, Produ | 3.90% | 3.90% | KU OTHER PROD MACRS 15 |
| KU-134200-TC 7 Fuel Holders, Produ | 3.82% | 3.82% | KU OTHER PROD MACRS 15 |
| KU-134200-TC 8 Fuel Holders, Produ | 3.82% | 3.82% | KU OTHER PROD MACRS 15 |
| KU-134200-TC 9 Fuel Holders, Produ | 3.83% | 3.83% | KU OTHER PROD MACRS 15 |
| KU-134201-AROP EWB 9 Turbogenerator | 0.00% | 0.00% | KU OTHER PROD MACRS 15 |
| KU-134300-Cane Run 7 Prime Movers | 3.57% | 3.57% | KU OTHER PROD MACRS 20 |
| KU-134300-EWB 10 Prime Movers | 4.94% | 4.94% | KU OTHER PROD MACRS 15 |
| KU-134300-EWB 11 Prime Movers | 4.82% | 4.82% | KU OTHER PROD MACRS 15 |
| KU-134300-EWB 5 Prime Movers | 4.41% | 4.41% | KU OTHER PROD MACRS 15 |
| KU-134300-EWB 6 Prime Movers | 5.42% | 5.42% | KU OTHER PROD MACRS 15 |
| KU-134300-EWB 7 Prime Movers | 5.28% | 5.28% | KU OTHER PROD MACRS 15 |
| KU-134300-EWB 8 Prime Movers | 5.81% | 5.81% | KU OTHER PROD MACRS 15 |
| KU-134300-EWB 9 Prime Movers | 4.74% | 4.74% | KU OTHER PROD MACRS 15 |
| KU-134300-Green River CC GT | 0.00% | 0.00% | KU OTHER PROD MACRS 20 |
| KU-134300-PR 13 Prime Movers | 5.53% | 5.53% | KU OTHER PROD MACRS 15 |
| KU-134300-TC 10 Prime Movers | 4.49% | 4.49% | KU OTHER PROD MACRS 15 |
| KU-134300-TC 5 Prime Movers | 4.58% | 4.58% | KU OTHER PROD MACRS 15 |
| KU-134300-TC 6 Prime Movers | 4.50% | 4.50% | KU OTHER PROD MACRS 15 |
| KU-134300-TC 7 Prime Movers | 4.52% | 4.52% | KU OTHER PROD MACRS 15 |
| KU-134300-TC 8 Prime Movers | 4.57% | 4.57% | KU OTHER PROD MACRS 15 |
| KU-134300-TC 9 Prime Movers | 4.48% | 4.48% | KU OTHER PROD MACRS 15 |
| KU-134400-CR 7 Generators | 2.89% | 2.89% | KU OTHER PROD MACRS 20 |
| KU-134400-EWB 10 Generators | 2.94% | 2.94% | KU OTHER PROD MACRS 15 |
| KU-134400-EWB 11 Generators | 5.55% | 5.55% | KU OTHER PROD MACRS 15 |
| KU-134400-EWB 5 Generators | 3.98% | 3.98% | KU OTHER PROD MACRS 15 |
| KU-134400-EWB 6 Generators | 4.02% | 4.02% | KU OTHER PROD MACRS 15 |
| KU-134400-EWB 7 Generators | 4.08% | 4.08% | KU OTHER PROD MACRS 15 |
| KU-134400-EWB 8 Generators | 4.04% | 4.04% | KU OTHER PROD MACRS 15 |
| KU-134400-EWB 9 Generators | 2.77% | 2.77% | KU OTHER PROD MACRS 15 |
| KU-134400-EWB Solar Generators | 4.61% | 4.61% | KU OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ |
| KU-134400-HA 1,2,&3 Generators | 5.37% | 5.37% | KU OTHER PROD MACRS 15 |
| KU-134400-PR 13 Generators | 4.21% | 4.21% | KU OTHER PROD MACRS 15 |
| KU-134400-TC 10 Generators | 3.76% | 3.76% | KU OTHER PROD MACRS 15 |
| KU-134400-TC 5 Generators | 3.85% | 3.85% | KU OTHER PROD MACRS 15 |
| KU-134400-TC 6 Generators | 3.85% | 3.85% | KU OTHER PROD MACRS 15 |
| KU-134400-TC 7 Generators | 3.75% | 3.75% | KU OTHER PROD MACRS 15 |
| KU-134400-TC 8 Generators | 3.75% | 3.75% | KU OTHER PROD MACRS 15 |
| KU-134400-TC 9 Generators | 3.76% | 3.76% | KU OTHER PROD MACRS 15 |
| KU-134500-CR 7 Accessory Electric | 2.96% | 2.96% | KU OTHER PROD MACRS 20 |
| KU-134500-EWB 10 Accessory Electri | 3.77% | 3.77% | KU OTHER PROD MACRS 15 |
| KU-134500-EWB 11 Accessory Electri | 4.92% | 4.92% | KU OTHER PROD MACRS 15 |
| KU-134500-EWB 5 Accessory Electric | 4.23% | 4.23% | KU OTHER PROD MACRS 15 |
| KU-134500-EWB 6 Accessory Electric | 4.44% | 4.44% | KU OTHER PROD MACRS 15 |
| KU-134500-EWB 7 Accessory Electric | 4.45% | 4.45% | KU OTHER PROD MACRS 15 |
| KU-134500-EWB 8 Accessory Electric | 5.84% | 5.84% | KU OTHER PROD MACRS 15 |
| KU-134500-EWB 9 Accessory Electric | 3.64% | 3.64% | KU OTHER PROD MACRS 15 |
| KU-134500-EWB Solar Accessory Elec | 4.36% | 4.36% | KU OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ |
| KU-134500-HA 1,2,&3 Accessory Elec | 22.16% | 22.16% | KU OTHER PROD MACRS 15 |
| KU-134500-PR 13 Accessory Electric | 4.01% | 4.01% | KU OTHER PROD MACRS 15 |
| KU-134500-TC 10 Acessory Electric | 4.04% | 4.04% | KU OTHER PROD MACRS 15 |
| KU-134500-TC 5 Accessory Electric | 4.18% | 4.18% | KU OTHER PROD MACRS 15 |
| KU-134500-TC 6 Accessory Electric | 4.25% | 4.25% | KU OTHER PROD MACRS 15 |
| KU-134500-TC 7 Accessory Electric | 4.13% | 4.13% | KU OTHER PROD MACRS 15 |
| KU-134500-TC 8 Accessory Electric | 3.79% | 3.79% | KU OTHER PROD MACRS 15 |
| KU-134500-TC 9 Accessory Electric | 3.91% | 3.91% | KU OTHER PROD MACRS 15 |

**Kentucky Utilities Company**
**Depreciation Calculation**

| **Description** | **Current Rate** | **Proposed Rate eff. May-2019** | **Tax Depr Rate** |
|---|---|---|---|
| KU-134501-AROP EWB 10 Acc Electri | 0.00% | 0.00% | KU OTHER PROD MACRS 15 |
| KU-134501-AROP EWB 11 Acc Electric | 0.00% | 0.00% | KU OTHER PROD MACRS 15 |
| KU-134501-AROP EWB 5 Acc Electric | 0.00% | 0.00% | KU OTHER PROD MACRS 15 |
| KU-134501-AROP EWB 6 Acc Electric | 0.00% | 0.00% | KU OTHER PROD MACRS 15 |
| KU-134501-AROP EWB 7 Acc Electric | 0.00% | 0.00% | KU OTHER PROD MACRS 15 |
| KU-134501-AROP EWB 8 Acc Electric | 0.00% | 0.00% | KU OTHER PROD MACRS 15 |
| KU-134501-AROP EWB 9 Acc Electric | 0.00% | 0.00% | KU OTHER PROD MACRS 15 |
| KU-134501-AROP TC 7 Acc Electric | 0.00% | 0.00% | KU OTHER PROD MACRS 15 |
| KU-134501-AROP TC 8 Acc Electric | 0.00% | 0.00% | KU OTHER PROD MACRS 15 |
| KU-134600-CR 7 Misc. Power Plant E | 3.32% | 3.32% | KU OTHER PROD MACRS 20 |
| KU-134600-EWB 10 Misc Power Plant | 3.26% | 3.26% | KU OTHER PROD MACRS 15 |
| KU-134600-EWB 11 Misc Power Plant | 5.22% | 5.22% | KU OTHER PROD MACRS 15 |
| KU-134600-EWB 5 Misc Power Plant E | 4.01% | 4.01% | KU OTHER PROD MACRS 15 |
| KU-134600-EWB 6 Misc Power Plant E | 6.22% | 6.22% | KU OTHER PROD MACRS 15 |
| KU-134600-EWB 7 Misc Power Plant E | 6.24% | 6.24% | KU OTHER PROD MACRS 15 |
| KU-134600-EWB 8 Misc Power Plant E | 4.98% | 4.98% | KU OTHER PROD MACRS 15 |
| KU-134600-EWB 9 Misc Power Plant E | 3.31% | 3.31% | KU OTHER PROD MACRS 15 |
| KU-134600-EWB Solar Misc Power Plt | 4.25% | 4.25% | KU OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ |
| KU-134600-HA 1,2,&3 Misc Power Pla | 17.75% | 17.75% | KU OTHER PROD MACRS 15 |
| KU-134600-PR 13 Misc Power Plant E | 3.93% | 3.93% | KU OTHER PROD MACRS 15 |
| KU-134600-TC 10 Misc Power Plant E | 4.61% | 4.61% | KU OTHER PROD MACRS 15 |
| KU-134600-TC 5 Misc. Power Plant E | 4.04% | 4.04% | KU OTHER PROD MACRS 15 |
| KU-134600-TC 6 Misc. Power Plant E | 0.00% | 0.00% | KU OTHER PROD MACRS 15 |
| KU-134600-TC 7 Misc. Power Plant E | 3.89% | 3.89% | KU OTHER PROD MACRS 15 |
| KU-134600-TC 8 Misc. Power Plant E | 3.89% | 3.89% | KU OTHER PROD MACRS 15 |
| KU-134600-TC 9 Misc. Power Plant E | 3.91% | 3.91% | KU OTHER PROD MACRS 15 |
| KU-135010- KY Land Rights | 0.86% | 0.86% | NA |
| KU-135010- TN Land Rights | 0.86% | 0.86% | NA |
| KU-135010- VA Land Rights | 0.86% | 0.86% | NA |
| KU-135010-Licensed Project Land Ri | 0.86% | 0.86% | NA |
| KU-135020- KY Land | 0.00% | 0.00% | NA |
| KU-135020- VA Land | 0.00% | 0.00% | NA |
| KU-135210- KY Licensed Proj Str & I | 1.66% | 1.66% | KU TRANS MACRS 15 |
| KU-135210- KY Struc & Imprv-Non Sys | 1.66% | 1.66% | KU TRANS MACRS 15 |
| KU-135210- KY Struc NonSys Dix Ctrl | 1.66% | 1.66% | KU TRANS MACRS 15 |
| KU-135210- VA Struc & Imprv-Non Sys | 1.66% | 1.66% | KU TRANS VA MACRS 15 |
| KU-135220-Struct & Improve-System | 1.83% | 1.83% | KU TRANS MACRS 15 |
| KU-135310- KY Licensed Proj Sta Eq- | 1.90% | 1.90% | KU TRANS MACRS 15 |
| KU-135310- KY Station Equip -Non Sy | 1.90% | 1.90% | KU TRANS MACRS 15 |
| KU-135310- VA Station Equip -Non Sy | 1.90% | 1.90% | KU TRANS VA MACRS 15 |
| KU-135311-AROP Station Equip Non S | 1.67% | 1.67% | KU TRANS MACRS 15 |
| KU-135320-Station Equipment-System | 0.00% | 0.00% | KU TRANS MACRS 15 |
| KU-135400- KY Towers Fix | 1.69% | 1.69% | KU TRANS MACRS 15 |
| KU-135400- KY Towers Fix ECR 2005 | 1.69% | 1.69% | KU TRANS MACRS 15 |
| KU-135400- VA Towers and Fixtures | 1.69% | 1.69% | KU TRANS VA MACRS 15 |
| KU-135500- KY Licensed Proj Poles a | 2.93% | 2.93% | KU TRANS MACRS 15 |
| KU-135500- KY Poles | 2.93% | 2.93% | KU TRANS MACRS 15 |
| KU-135500- KY Poles ECR 2005 | 2.93% | 2.93% | KU TRANS MACRS 15 |
| KU-135500- TN Poles and Fixtures | 2.93% | 2.93% | KU TRANS MACRS 15 |
| KU-135500- VA Poles and Fixtures | 2.93% | 2.93% | KU TRANS VA MACRS 15 |
| KU-135600- KY Licensed Proj Ohd Con | 2.54% | 2.54% | KU TRANS MACRS 15 |
| KU-135600- TN Overhead Conductors | 2.54% | 2.54% | KU TRANS MACRS 15 |
| KU-135600- VA Overhead Conductors | 2.54% | 2.54% | KU TRANS VA MACRS 15 |
| KU-135600-KY OH Cond | 2.54% | 2.54% | KU TRANS MACRS 15 |
| KU-135600-KY OH Cond ECR 2005 | 2.54% | 2.54% | KU TRANS MACRS 15 |

**Kentucky Utilities Company**
**Depreciation Calculation**

| Description | Current Rate | Proposed Rate eff. May-2019 | Tax Depr Rate |
|---|---|---|---|
| KU-135700- KY Underground Conduit | 1.70% | 1.70% | KU TRANS MACRS 15 |
| KU-135700- VA Underground Conduit | 1.70% | 1.70% | KU TRANS VA MACRS 15 |
| KU-135800- KY Undergrd Conductors a | 0.74% | 0.74% | KU TRANS MACRS 15 |
| KU-135800- VA Undergrd Conductors a | 0.74% | 0.74% | KU TRANS VA MACRS 15 |
| KU-136010- KY Land Rights | 0.64% | 0.64% | NA |
| KU-136010- KY Licensed Proj Land Ri | 0.64% | 0.64% | NA |
| KU-136010- TN Land Rights | 0.64% | 0.64% | NA |
| KU-136010- VA Land Rights | 0.64% | 0.64% | NA |
| KU-136020-KY Land | 0.00% | 0.00% | NA |
| KU-136020-TN Land | 0.00% | 0.00% | NA |
| KU-136020-VA Land | 0.00% | 0.00% | NA |
| KU-136025-VA Land | 0.00% | 0.00% | NA |
| KU-136100- KY Struct and Improv | 2.15% | 2.15% | KU DISTR MACRS 20 |
| KU-136100- TN Struct and Improv | 2.15% | 2.15% | KU DISTR MACRS 20 |
| KU-136100- VA Struct and Improv | 2.15% | 2.15% | KU DISTR VA MACRS 20 |
| KU-136200- KY Station Equipment | 2.29% | 2.29% | KU DISTR MACRS 20 |
| KU-136200- TN Station Equipment | 2.29% | 2.29% | KU DISTR MACRS 20 |
| KU-136200- VA Station Equipment | 2.29% | 2.29% | KU DISTR VA MACRS 20 |
| KU-136400-KY Ghent Transpt ECR 2009 | 2.67% | 2.67% | KU DISTR MACRS 20 |
| KU-136400-KY Licensed Project Pole | 2.67% | 2.67% | KU DISTR MACRS 20 |
| KU-136400-KY Poles, Towers, and Fix | 2.67% | 2.67% | KU DISTR MACRS 20 |
| KU-136400-TN Poles, Towers, and Fix | 2.67% | 2.67% | KU DISTR MACRS 20 |
| KU-136400-VA Poles, Towers, and Fix | 2.67% | 2.67% | KU DISTR VA MACRS 20 |
| KU-136500- KY Licensed Proj Ohd Con | 2.47% | 2.47% | KU DISTR MACRS 20 |
| KU-136500- KY Overhead Conductor | 2.47% | 2.47% | KU DISTR MACRS 20 |
| KU-136500- TN Overhead Conductor | 2.47% | 2.47% | KU DISTR MACRS 20 |
| KU-136500- VA Overhead Conductor | 2.47% | 2.47% | KU DISTR VA MACRS 20 |
| KU-136500-KY Ghent Transpt ECR 2009 | 2.47% | 2.47% | KU DISTR MACRS 20 |
| KU-136600- KY Underground Conduit | 2.32% | 2.32% | KU DISTR MACRS 20 |
| KU-136600- TN Underground Conduit | 2.32% | 2.32% | KU DISTR MACRS 20 |
| KU-136600- VA Underground Conduit | 2.32% | 2.32% | KU DISTR VA MACRS 20 |
| KU-136600-KY Ghent Transpt ECR 2009 | 2.32% | 2.32% | KU DISTR MACRS 20 |
| KU-136700- KY Undergrnd Conductors | 2.43% | 2.43% | KU DISTR MACRS 20 |
| KU-136700- TN Undergrnd Conductors | 2.43% | 2.43% | KU DISTR MACRS 20 |
| KU-136700- VA Undergrnd Conductors | 2.43% | 2.43% | KU DISTR VA MACRS 20 |
| KU-136700-KY Ghent Transpt ECR 2009 | 2.43% | 2.43% | KU DISTR MACRS 20 |
| KU-136800- KY Line Transformers | 1.79% | 1.79% | KU DISTR MACRS 20 |
| KU-136800- TN Line Transformers | 1.79% | 1.79% | KU DISTR MACRS 20 |
| KU-136800- VA Line Transformers | 1.79% | 1.79% | KU DISTR VA MACRS 20 |
| KU-136900- KY Services | 1.63% | 1.63% | KU DISTR MACRS 20 |
| KU-136900- TN Services | 1.63% | 1.63% | KU DISTR MACRS 20 |
| KU-136900- VA Services | 1.63% | 1.63% | KU DISTR VA MACRS 20 |
| KU-137000- KY Meters | 3.51% | 3.51% | KU DISTR MACRS 20 |
| KU-137000- TN Meters | 3.51% | 3.51% | KU DISTR MACRS 20 |
| KU-137000- VA Meters | 3.51% | 3.51% | KU DISTR VA MACRS 20 |
| KU-137001- KY DSM Meters | 6.85% | 6.85% | KU DISTR MACRS 20 |
| KU-137002- KY Meter Asset Management | 6.85% | 6.85% | KU DISTR MACRS 20 |
| KU-137002- VA Meter Asset Management | 6.85% | 6.85% | KU DISTR VA MACRS 20 |
| KU-137020- KY Meters - CT and PT | 4.29% | 4.29% | KU DISTR MACRS 20 |
| KU-137020- TN Meters - CT and PT | 4.29% | 4.29% | KU DISTR MACRS 20 |
| KU-137020- VA Meters - CT and PT | 4.29% | 4.29% | KU DISTR VA MACRS 20 |
| KU-137100- KY Install on Customers | 0.53% | 0.53% | KU DISTR MACRS 20 |
| KU-137100- TN Install on Customers | 0.53% | 0.53% | KU DISTR MACRS 20 |
| KU-137100- VA Install on Customers | 0.53% | 0.53% | KU DISTR VA MACRS 20 |
| KU-137101- KY Install Charging Sta | 10.00% | 10.00% | KU DISTR MACRS 20 |

**Kentucky Utilities Company**
**Depreciation Calculation**

| Description | Current Rate | Proposed Rate eff. May-2019 | Tax Depr Rate |
|---|---|---|---|
| KU-137300- KY Str Lighting and Sign | 4.00% | 4.00% | KU STREET LIGHTS MACRS 7 |
| KU-137300- VA Str Lighting and Sign | 4.00% | 4.00% | KU STREET LIGHTS VA MACRS 7 |
| KU-138920- KY Land | 0.00% | 0.00% | NA |
| KU-138920- VA Land | 0.00% | 0.00% | NA |
| KU-139010- KY Structures & Improv | 2.43% | 2.43% | KU STRUCTURES MACRS 39 |
| KU-139010- VA Structures & Improv | 2.43% | 2.43% | KU STRUCTURES MACRS 39 |
| KU-139010-KY Stru Pinevll Joint Own | 2.43% | 2.43% | KU STRUCTURES MACRS 39 |
| KU-139010-KY Struc Morganfield Offi | 2.43% | 2.43% | KU STRUCTURES MACRS 39 |
| KU-139010-KY Struc One Quality Bldg | 2.43% | 2.43% | KU STRUCTURES MACRS 39 |
| KU-139010-Pinevlle Storerm Owned | 2.43% | 2.43% | KU STRUCTURES MACRS 39 |
| KU-139020- VA Pennington Gap Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020- VA Wise Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Carlisle Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Coeburn Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Columbia Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Corbin Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Earlington Pole Yard | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Eddyville Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Ewing Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Flemingsburg Storeroom | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Henderson Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Lexington Northside Offic | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Liberty Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Livermore Storeroom | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-London Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Manchester Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Morehead Storeroom | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Richmond Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Somerset Pole Yard | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-St Paul Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Tates Creek Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Taylorsville Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Versailles Storeroom | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139020-Whitley City Office | 1.43% | 1.43% | KU STRUCTURES MACRS 39 |
| KU-139110- KY Office Equipment | 4.36% | 4.36% | KU GENERAL OTHER MACRS 7 |
| KU-139110- VA Office Equipment | 4.36% | 4.36% | KU GENERAL OTHER MACRS 7 |
| KU-139120-KY Non PC Computer Equip | 11.69% | 11.69% | KU GENERAL OTHER MACRS 7 |
| KU-139120-VA Non PC Computer Equip | 11.69% | 11.69% | KU GENERAL OTHER MACRS 7 |
| KU-139130-Cash Processing Equipmen | 0.00% | 0.00% | KU GENERAL OTHER MACRS 7 |
| KU-139131-Personal Computers | 25.02% | 25.02% | KU GENERAL OTHER MACRS 7 |
| KU-139200- KY - Ghent 4 ECR 2009 | 1.97% | 1.97% | KU CARS TRUCKS MACRS 5 |
| KU-139300- KY Stores Equipment | 4.40% | 4.40% | KU GENERAL OTHER MACRS 7 |
| KU-139300- VA Stores Equipment | 4.40% | 4.40% | KU GENERAL OTHER MACRS 7 |
| KU-139400- KY Tools, Shop, Garage | 4.02% | 4.02% | KU GENERAL OTHER MACRS 7 |
| KU-139400- VA Tools, Shop, Garage | 4.02% | 4.02% | KU GENERAL OTHER MACRS 7 |
| KU-139500-KY Laboratory Equipment | 0.00% | 0.00% | KU GENERAL OTHER MACRS 7 |
| KU-139500-VA Laboratory Equipment | 0.00% | 0.00% | KU GENERAL OTHER MACRS 7 |
| KU-139600-KY Power Op Equip | 0.00% | 0.00% | KU GENERAL OTHER MACRS 7 |
| KU-139600-VA Power Op Equip | 0.00% | 0.00% | KU CARS TRUCKS MACRS 5 |
| KU-139700-KY DSM Communication | 4.90% | 4.90% | KU GENERAL OTHER MACRS 7 |
| KU-139700-KY Microwave,Fiber,Other | 4.90% | 4.90% | KU GENERAL OTHER MACRS 7 |
| KU-139700-VA Microwave,Fiber,Other | 4.90% | 4.90% | KU GENERAL OTHER MACRS 7 |
| KU-139710- KY Radios and Telephone | 10.84% | 10.84% | KU GENERAL OTHER MACRS 7 |
| KU-139710- VA Radios and Telephone | 10.84% | 10.84% | KU GENERAL OTHER MACRS 7 |
| KU-139720- DSM Equipment | 14.08% | 14.08% | KU GENERAL OTHER MACRS 7 |

**Kentucky Utilities Company**
**Depreciation Calculation**

| Description | Current Rate | Proposed Rate eff. May-2019 | Tax Depr Rate |
|---|---|---|---|
| KU-139800- KY Miscellaneous Equip | 0.00% | 0.00% | KU GENERAL OTHER MACRS 7 |
| KU-139800- VA Miscellaneous Equip | 0.00% | 0.00% | KU GENERAL OTHER MACRS 7 |
| KU-312104-Nonutility Prop - Misc L | 0.00% | 0.00% | KU GENERAL OTHER MACRS 7 |
| KU-312105-Nonutility Prop-Misc Str | 0.00% | 0.00% | KU GENERAL OTHER MACRS 7 |
| KU-312106-Nonutility-Misc Land Rig | 0.00% | 0.00% | KU GENERAL OTHER MACRS 7 |
| KU-139620-KY Power Op Equip - Other | 5.65% | 5.65% | KU GENERAL OTHER MACRS 7 |
| KU-134020-Simpson Solar Share Land | 0.00% | 0.00% | KU OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ |
| KU-134100-Simp Solar A1 Struc & Imp | 4.24% | 4.24% | KU OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ |
| KU-134400-Simp Solar A1 Generators | 4.61% | 4.61% | KU OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ |
| KU-134500-Simp Solar A1 Access Elec | 4.36% | 4.36% | KU OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ |
| KU-134600-Simp Solar A1 Misc Pwr Pl | 4.25% | 4.25% | KU OTHER PROD MACRS 5 - 15% DEPR BASIS ADJ |

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 137**

**Responding Witness: David S. Sinclair**

**X. COST OF SERVICE/RATE DESIGN/TARIFFS**

Q-137. With regard to Mr. Seelye's Loss of Load Probability ("LOLP") study, he indicates that hourly loads were utilized for individual classes. In this respect, provide:

a. a detailed narrative description of how class hourly loads were developed;

b. each class hourly load for the forecasted test year (or the period utilized by Mr. Seelye within his CCOSS). Because of the joint dispatch of the Companies' generation facilities, include both KU and LG&E classes (showing KU and LG&E classes separately). In addition, also include each non-jurisdictional class;

c. a detailed explanation of how curtailable load or curtailable load credits are reflected within the class hourly loads;

d. all workpapers, analyses, spreadsheets, etc. showing the development of each hourly load for each class; and,

e. an explanation of whether the hourly loads provided in (b) are measured at the meter or generation level.

Provide all data in executable electronic format, preferably in native Excel format, with all formulas intact and cells unprotected and with all columns and rows accessible. If data is not available in Excel format, contact counsel for the Attorney General to provide the data in ASCII comma-delimited format with all fields defined.

A-137.

a. See Case Nos. 2018-00294 and 2018-00295 Attachment to Filing Requirement 807 KAR 5:001 Sec. 16(7)(c) E.

b. See the attachment being provided in Excel format.

c. The class hourly load forecasts reflect forecasted reductions due to the Companies' Direct Load Control program but not the Curtailable Service Rider ("CSR"). Load reductions associated with CSR are modeled as a supply-side resource.

d. See the attachments being provided in Excel format.

e. The hourly loads provided in response to part b are measured at the generation level.

The attachments are being provided in separate files in Excel format.

# KENTUCKY UTILITIES COMPANY

## Response to Attorney General's Initial Data Requests for Information
## Dated November 13, 2018

## Case No. 2018-00294

## Question No. 138

## Responding Witness: David S. Sinclair

Q-138. For each of the last two years (or most recent 24-months available), provide actual class hourly loads for both KU and LG&E for every hour during the 24-month period. If the requested data for every hour and every class is not available, provide the most detailed information available.

A-138. The attachment, which is provided in Excel format, contains class hourly loads for the 12-month period from May 2017 to April 2018. Class hourly loads are estimated based on sample recorder data. The Companies have not estimated class hourly loads for the 12 months prior to May 2017.

The attachment is being provided in a separate file in Excel format.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 139**

**Responding Witness: David S. Sinclair**

Q-139. With regard to Mr. Seelye's LOLP study, he indicates that hourly characteristics of LG&E and KU's generating facilities were utilized. In this respect, provide:

a. A detailed narrative description of how hourly generation output was developed;

b. Each hourly generation output (by unit) for the forecasted test year (or the period utilized by Mr. Seelye within his CCOSS). Because of the joint dispatch of the Companies' generation facilities, include both KU and LG&E generation resources. For facilities jointly-owned exclusively by LG&E and KU, provide total unit output by hour. For facilities partially owned by LG&E and KU combined, provide KU and LG&E (combined) percentage output;

c. Hourly purchases of electricity (KU and LG&E combined); and,

d. Hourly wholesale sales of electricity (KU and LG&E combined).

Provide all data in executable electronic format, preferably in native Excel format, with all formulas intact and cells unprotected and with all columns and rows accessible. If data is not available in Excel format, contact counsel for the Attorney General to provide the data in ASCII comma-delimited format with all fields defined.

A-139.

a. See attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. The LOLP study is a statistical calculation of hourly LOLP based on the Companies' forecasted resource characteristics and load at an hourly level, however it does not involve developing an hourly dispatch model.

For a general discussion of how the Companies model hourly generation for business planning, see the "Annual Generation Forecast Process" attached at Tab 16 of the Filing Requirements, Section 16(7)(c), Item G.

b. Hourly generation outputs are not produced by the LOLP analysis. See the response to part (a).

c. Hourly purchases outputs are not produced by the LOLP analysis. See the response to part (a).

d. Market off-system sales are not produced by the LOLP analysis. However, wholesale sales to the non-departing municipals are included in the Companies' load obligation. See the response to part (a).

The entire attachment is Confidential and provided separately under seal.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 140**

**Responding Witness: David S. Sinclair**

Q-140. With regard to Mr. Seelye's LOLP study, provide a detailed explanation along with all mathematical formulae showing how hourly LOLP was calculated. In this response, specifically explain how off-system sales, wholesale purchases of power, curtailment capabilities, reserve margin requirements, and outage rates are considered, evaluated, and quantified in developing hourly LOLP.

A-140. See the response to Question No. 139. No off-system sales were modeled in the LOLP study. In addition to the Companies' firm supply-side capacity resources, the analysis assumed that the Companies could purchase up to 558 MW of energy in an hour and could curtail up to 141 MW of CSR-related load. The generation resources in the LOLP study reflect the characteristics of the Companies' existing resources that were acquired to meet the Companies' forecasted load obligations, based on the reserve margin target range developed in the Companies' 2014 Integrated Resource Plan ("IRP"). The Companies' 2018 IRP target reserve margin range resulted in no changes to the Companies' generation portfolio. Forecasted outage rates are included in the generating unit characteristics considered in the LOLP analysis.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 141**

**Responding Witness: David S. Sinclair**

Q-141. With regard to Mr. Seelye's LOLP study, provide all analyses, workpapers, spreadsheets, etc. showing the following:

a. hourly system Loss of Load Probability;

b. hourly system load (MW);

c. hourly forced outage MW (by unit as available);

d. hourly planned outage MW (by unit as available);

e. available generation production from KU/LG&E-owned facilities;

f. wholesale sales (if applicable or utilized in determining hourly LOLP);

g. wholesale purchased power (if applicable or utilized in determining hourly LOLP); and,

h. required reserve margin (percent or MW as applicable)

i. curtailable load available (MW)

j. curtailable load actually curtailed (MW).

In this response, provide all data and formulae necessary to replicate each hourly system Loss of Load Probability. Provide all data in executable electronic format, preferably in native Excel format, with all formulas intact and cells unprotected and with all columns and rows accessible. If data is not available in Excel format, contact counsel for the Attorney General to provide the data in ASCII comma-delimited format with all fields defined.

A-141.

a. See the attachment being provided in Excel format.

b. See the response to part (a).

c. PROSYM's process for calculating LOLP does not simulate forced outages for each unit on an hourly basis. See the response to Question No. 139.

d. Planned outages were not considered in the LOLP calculation.

e. See the attachment being provided in Excel format. Note that maximum capacity in the outage rate table varies by month.

f. See the response to Question No. 140.

g. See the response to Question No. 140.

h. See the response to Question No. 142(a).

i. The sum of the expected curtailment achievable by the Companies' CSR customers is 141 MW.

j. No hourly data regarding the curtailment of CSR customers are produced as a result of the LOLP analysis. See the response to Question No. 139(a).

In addition, a number of PROSYM files are being provided in response to this request. The Company is providing them on separate electronic storage media subject to a motion to deviate because the files cannot be uploaded to the Commission's website. The Company will supply copies on electronic storage media to the Commission, the Attorney General, and all parties who have already requested copies of all responses filed. The Company will provide the files to any other party to this proceeding upon request.

The attachments are being provided in separate files in Excel format.

The attachments are being provided in separate files.

## KENTUCKY UTILITIES COMPANY

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 142**

**Responding Witness: David S. Sinclair**

Q-142. Provide LG&E and KU individual and combined generation reserve margins for the following:

a. fully forecasted test year;

b. most recent actual period available; and,

c. as of December 31, 2017.

A-142. The Companies develop a target reserve margin range for planning sufficient supply resources to reliably meet the combined Companies' anticipated peak hour load obligation and account for resource outage risk and load variability at every moment of the year. At any point in time, the Companies take actions to address momentary demand and system operational issues. The planning reserve margin is designed to allow the combined Companies to reliably address these uncertainties at the lowest reasonable cost. For further information regarding the development of the Companies' target reserve margin, see the Companies' 2018 Integrated Resource Plan. Because the Companies jointly plan the combined system, the Companies do not develop a target reserve margin range or a planning reserve margin for each individual company on a standalone basis. Although a comparison of each company's allocated supply resources and forecasted summer peak load can be performed, there is no target reserve margin range to which these figures can be compared.

a. The planning reserve margin for the forecasted test period is 23.5 percent for the combined Companies. The capacity of the supply resources that have been allocated to each company over the years is higher than the forecasted summer peak demand in the forecasted test period by 33.5 percent for KU and by 9.7 percent for LG&E.

b. The planning reserve margin for 2018 was 24.7 percent for the combined Companies. The capacity of the supply resources that have been allocated to each company over the years was higher than the 2018 forecasted summer peak by 30.3 percent for KU and by 16.4 percent for LG&E.

c. The planning reserve margin for 2017 was 21.6 percent for the combined Companies. The Companies have not developed historical calculations for the individual Companies.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 143**

**Responding Witness: David S. Sinclair / William Steven Seelye**

Q-143. Provide all workpapers, analyses, spreadsheets, etc. showing the development of each class' weighted LOLP as shown in Exhibit WSS-19. Provide all data in executable electronic format, preferably in native Excel format, with all formulas intact and cells unprotected and with all columns and rows accessible. If data is not available in Excel format, contact counsel for the Attorney General to provide the data in ASCII comma-delimited format with all fields defined.

A-143. See the responses to Question No. 137, part b and Question No. 141.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 144**

**Responding Witness: David S. Sinclair**

Q-144. For each of the last ten years, provide the following:

a. annual winter system peak demand (KU and LG&E combined);

b. annual winter native load (jurisdictional) peak demand (KU and LG&E combined);

c. annual summer system peak demand (KU and LG&E combined); and,

d. annual summer native load (jurisdictional) peak demand (KU and LG&E combined).

A-144. See attached.

| Year | Maximum Winter System Demand* |
|---|---|
| 2008 | 6,357 |
| 2009 | 6,555 |
| 2010 | 6,340 |
| 2011 | 6,017 |
| 2012 | 5,704 |
| 2013 | 5,907 |
| 2014 | 7,114 |
| 2015 | 7,079 |
| 2016 | 6,223 |
| 2017 | 5,679 |
| 2018 | 6,699 |

| Year | Maximum Summer System Demand* |
|---|---|
| 2008 | 6,352 |
| 2009 | 6,367 |
| 2010 | 7,175 |
| 2011 | 6,756 |
| 2012 | 6,856 |
| 2013 | 6,434 |
| 2014 | 6,313 |
| 2015 | 6,392 |
| 2016 | 6,458 |
| 2017 | 6,503 |
| 2018 | 6,490 |

| Year | Maximum Winter Jurisdictional Demand* |
|---|---|
| 2008 | Not Available |
| 2009 | Not Available |
| 2010 | 5,725 |
| 2011 | 5,477 |
| 2012 | 5,179 |
| 2013 | 5,368 |
| 2014 | 6,482 |
| 2015 | 6,402 |
| 2016 | 5,653 |
| 2017 | 5,201 |
| 2018 | 6,100 |

*Winter defined as November through April
*Jurisdictional removes ODP and Muni Loads

| Year | Maximum Summer Jurisdictional Demand* |
|---|---|
| 2008 | Not Available |
| 2009 | Not Available |
| 2010 | 6,622 |
| 2011 | 6,221 |
| 2012 | 6,333 |
| 2013 | 5,955 |
| 2014 | 5,845 |
| 2015 | 5,923 |
| 2016 | 5,983 |
| 2017 | 6,048 |
| 2018 | 6,053 |

*Summer defined as May through October

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 145**

**Responding Witness: Christopher M. Garrett**

Q-145. For each KU and LG&E generating unit owned individually, jointly, or partially, provide the following for the most recent actual 12-month period available:

a. names of owners (and ownership percentages);

b. type of fuel(s);

c. total nameplate (rated) capacity (MW);

d. total and individual company gross investment at the end of the period;

e. total individual company depreciation reserve at the end of the period;

f. total and individual company annual book depreciation expense;

g. gross KWh produced during the period; and,

h. net (less station use) KWh produced during the period.

Provide in executable electronic (Excel) format with all formulas intact and cells unprotected and with all columns and rows accessible.

A-145. See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 146**

**Responding Witness: Daniel K. Arbough / David S. Sinclair**

Q-146. For each KU and LG&E generating unit owned individually, jointly, or partially, provide the following for the fully forecasted test year ending April 30, 2020:

a. names of owners (and ownership percentages);

b. type of fuel(s);

c. total nameplate (rated) capacity (MW);

d. total and individual company gross investment at the end of the period;

e. total individual company depreciation reserve at the end of the period;

f. total and individual company annual book depreciation expense;

g. gross KWh produced during the period; and,

h. net (less station use) KWh produced during the period.

Provide in executable electronic (Excel) format with all formulas intact and cells unprotected and with all columns and rows accessible.

A-146.

a. See the attachment being provided in Excel format.

b. See the response to part a.

c. See the response to part a.

d. KU does not maintain gross investment information in the forecasted test period at generating unit level.

e. KU does not maintain depreciation reserve information in the forecasted test period at a generating unit level.

f. KU does not maintain book depreciation expense in the forecasted test period at a generating unit level.

g. The Companies do not produce a forecast of gross generation.

h. See the response to part a.

The attachment is being provided in a separate file in Excel format.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 147**

**Responding Witness: David S. Sinclair**

Q-147. Provide the combined KU and LG&E generating order of dispatch by unit and the basis for this order of dispatch.

A-147. The Companies' dispatch order as of November 2018 is provided in the table below. It is ranked in ascending order by average generating cost at maximum load, inclusive of variable fuel, emission allowances, and operating and maintenance costs. The dispatch order will vary depending on the price of natural gas and coal and other variables.

| Dispatch Order (Lowest Cost to Highest Cost) | Unit | Dispatch Order (Lowest Cost to Highest Cost) | Unit |
|---|---|---|---|
| 1 | Brown Solar | 20 | Trimble County 7 |
| 2 | Hydro (Ohio Falls and Dix Dam) | 21 | Trimble County 8 |
| 3 | Trimble County 2 | 22 | Trimble County 9 |
| 4 | Cane Run 7 | 23 | Trimble County 10 |
| 5 | Ghent 2 | 24 | Paddy's Run 13 |
| 6 | Mill Creek 4 | 25 | Bluegrass |
| 7 | Trimble County 1 | 26 | Brown 6 |
| 8 | Mill Creek 1 | 27 | Brown 7 |
| 9 | Mill Creek 2 | 28 | Brown 5 |
| 10 | Mill Creek 3 | 29 | Brown 9 |
| 11 | Brown 2 | 30 | Brown 10 |
| 12 | Ghent 1 | 31 | Brown 8 |
| 13 | Ghent 4 | 32 | Brown 11 |
| 14 | Brown 1 | 33 | Cane Run 11 |
| 15 | Ghent 3 | 34 | Paddy's Run 11 |
| 16 | Brown 3 | 35 | Paddy's Run 12 |
| 17 | OVEC | 36 | Zorn 1 |
| 18 | Trimble County 5 | 37 | Haefling |
| 19 | Trimble County 6 | | |

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
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**Case No. 2018-00294**

**Question No. 148**

**Responding Witness: Christopher M. Garrett**

Q-148. For each KU and LG&E generating unit, provide average monthly and annual fuel costs per KWh during the most recent 12-months available. Provide in executable electronic (Excel) format with all formulas intact and unprotected and with all columns and rows accessible.

A-148. See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 149**

**Responding Witness: David S. Sinclair**

Q-149. For each KU and LG&E generating unit, provide forecasted average monthly and annual fuel costs per KWh for the fully forecasted test year ending April 30, 2020. Provide in executable electronic (Excel) format with all formulas intact and cells unprotected and with all columns and rows accessible.

A-149. See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 150**

**Responding Witness: David S. Sinclair**

Q-150. With regard to wholesale sales, resale sales, and all other non-jurisdictional sales of electricity, provide the following for each customer for the fully forecasted test year for KU and LG&E separately:

a. identification of customer;

b. sales of electricity revenue;

c. KWh at meter;

d. maximum peak demand;

e. maximum contract demand; and,

f. voltage level at delivered service.

A-150. See attached.

**Forecasted Test Year**

| Customer | Sales of electricity revenue | kWh at meter | Max peak kW demand | Max contract demand | Voltage level |
|---|---|---|---|---|---|
| 1 | $ 12,585,764.56 | 210,545,136 | 40,508 | N/A** | Primary |
| 2 | $ 12,271,453.18 | 211,477,892 | 39,610 | N/A** | Transmission |
| ODP | $ 71,170,172.62 | 704,786,454 | N/A* | N/A** | Transmission, Primary, Secondary |

*Max peak demand forecasted for KU company as a whole; ODP is not broken out.

**Not applicable

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
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**Case No. 2018-00294**

**Question No. 151**

**Responding Witness: William Steven Seelye**

Q-151. Explain why sales for resale customers are not allocated any costs in Mr. Seelye's cost of service study, but rather, revenues are credited back to jurisdictional customers. In this regard, also explain how the loads associated with sales for resale are considered and reflected in Mr. Seelye's LOLP method.

A-151. Sales-for-resale revenues and costs for full-requirements customers are jurisdictionally assigned to the FERC jurisdiction in KU's jurisdictional separation study. Sales-for-resale revenues for opportunity sales are credited back through the Off-System Sales Adjustment Clause (OSS) which are excluded from the determination of revenue requirements in this case.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 152**

**Responding Witness: William Steven Seelye**

Q-152. With regard to the curtailable load credits reflected in the fully forecasted test year and Mr. Seelye's class cost of service study, provide the level (megawatts) of curtailable load embedded in the revenue credit separately by each rate schedule and by CR-1 and CR-2.

A-152. The requested information is provided in attachment Att_KU_PSC_1-53_ElecScheduleM_Forecasted.xlsx (tab Sch M-2.3 (2)) provided in response to PSC 1-53.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 153**

**Responding Witness: David S. Sinclair**

Q-153. Provide a detailed itemization of each requested curtailment during the last five years. In this response, provide the date, duration, requested load curtailment by individual customer and by CR-1 and CR-2, along with the amount of load actually curtailed.

A-153. The current CSR-1 and CSR-2 tariffs have been in place since Case Nos. 2016-00370 and 2016-00371. Prior to 7/1/17 there was a single Curtailable Service Rider (CSR) which had different parameters (e.g., no buy through option) and was in place from 7/1/15 through 6/30/17. Prior to 7/1/15, there were two riders in place, CSR-10 and CSR-30, also with different parameters (e.g. 10 minute notice and 30 minute notice).

KU has not requested physical load curtailment for CSR-1 or CSR-2 since their inception on July 1, 2017. As detailed in the table below, KU requested curtailment under the buy-through option of the tariffs on four days in January 2018.

| *Customer* | *Start Date/Time* | *End Date/Time* | Hours | Type |
|---|---|---|---|---|
| 13 | 01/04/2018 08:00 | 01/04/2018 22:00 | 14 | Buy Through Option |
| 6 | 01/04/2018 08:00 | 01/04/2018 22:00 | 14 | Buy Through Option |
| 7 | 01/04/2018 08:00 | 01/04/2018 22:00 | 14 | Buy Through Option |
| 8 | 01/04/2018 08:00 | 01/04/2018 22:00 | 14 | Buy Through Option |
| 4 | 01/04/2018 08:00 | 01/04/2018 22:00 | 14 | Buy Through Option |
| 9 | 01/04/2018 08:00 | 01/04/2018 22:00 | 14 | Buy Through Option |
| 10 | 01/04/2018 08:00 | 01/04/2018 22:00 | 14 | Buy Through Option |
| 11 | 01/04/2018 08:00 | 01/04/2018 22:00 | 14 | Buy Through Option |
| 12 | 01/04/2018 08:00 | 01/04/2018 22:00 | 14 | Buy Through Option |
| 13 | 01/05/2018 09:00 | 01/05/2018 23:00 | 14 | Buy Through Option |
| 6 | 01/05/2018 09:00 | 01/05/2018 23:00 | 14 | Buy Through Option |
| 7 | 01/05/2018 09:00 | 01/05/2018 23:00 | 14 | Buy Through Option |
| 8 | 01/05/2018 09:00 | 01/05/2018 23:00 | 14 | Buy Through Option |
| 4 | 01/05/2018 09:00 | 01/05/2018 23:00 | 14 | Buy Through Option |
| 9 | 01/05/2018 09:00 | 01/05/2018 23:00 | 14 | Buy Through Option |
| 10 | 01/05/2018 09:00 | 01/05/2018 23:00 | 14 | Buy Through Option |
| 11 | 01/05/2018 09:00 | 01/05/2018 23:00 | 14 | Buy Through Option |
| 12 | 01/05/2018 09:00 | 01/05/2018 23:00 | 14 | Buy Through Option |
| 13 | 01/16/2018 10:00 | 01/16/2018 23:00 | 13 | Buy Through Option |
| 6 | 01/16/2018 10:00 | 01/16/2018 23:00 | 13 | Buy Through Option |
| 7 | 01/16/2018 10:00 | 01/16/2018 23:00 | 13 | Buy Through Option |
| 8 | 01/16/2018 10:00 | 01/16/2018 23:00 | 13 | Buy Through Option |
| 4 | 01/16/2018 10:00 | 01/16/2018 23:00 | 13 | Buy Through Option |
| 9 | 01/16/2018 10:00 | 01/16/2018 23:00 | 13 | Buy Through Option |
| 10 | 01/16/2018 10:00 | 01/16/2018 23:00 | 13 | Buy Through Option |
| 11 | 01/16/2018 10:00 | 01/16/2018 23:00 | 13 | Buy Through Option |
| 12 | 01/16/2018 10:00 | 01/16/2018 23:00 | 13 | Buy Through Option |
| 13 | 01/17/2018 09:00 | 01/17/2018 23:00 | 14 | Buy Through Option |
| 6 | 01/17/2018 09:00 | 01/17/2018 23:00 | 14 | Buy Through Option |
| 7 | 01/17/2018 09:00 | 01/17/2018 23:00 | 14 | Buy Through Option |
| 8 | 01/17/2018 09:00 | 01/17/2018 23:00 | 14 | Buy Through Option |
| 4 | 01/17/2018 09:00 | 01/17/2018 23:00 | 14 | Buy Through Option |
| 9 | 01/17/2018 09:00 | 01/17/2018 23:00 | 14 | Buy Through Option |
| 10 | 01/17/2018 09:00 | 01/17/2018 23:00 | 14 | Buy Through Option |
| 11 | 01/17/2018 09:00 | 01/17/2018 23:00 | 14 | Buy Through Option |
| 12 | 01/17/2018 09:00 | 01/17/2018 23:00 | 14 | Buy Through Option |

Below is a table detailing the curtailments for the past five years (November 1, 2013 thru November 14, 2018) under the curtailable service rider(s) applicable at the time.

| *Customer* | *Start Date/Time* | *End Date/Time* | *Hours* | *Type* | *Contract/CSR Firm or CSR Reduction* | *Load Not Compliant (kVA)* |
|---|---|---|---|---|---|---|
| 4 | 01/06/2014 18:30 | 01/06/2014 19:41 | 1.18 | Physical Curtailment | 150 MVA contract; 4,000 kW firm | 0 |
| 4 | 01/07/2014 07:14 | 01/07/2014 10:00 | 2.77 | Physical Curtailment | 150 MVA contract; 4,000 kW firm | 0 |
| 5 | 01/07/2014 07:20 | 01/07/2014 10:00 | 2.67 | Physical Curtailment | 5,000 kVA contract; 3,500 kW firm | 5,129.8 |
| 6 | 01/07/2014 07:40 | 01/07/2014 10:00 | 2.33 | Physical Curtailment | 2,000 kVA reduction | 0 |
| 4 | 01/30/2014 07:36 | 01/30/2014 08:06 | 0.50 | Physical Curtailment | 150 MVA contract; 4,000 kW firm | 39,184.8 |
| 5 | 01/30/2014 07:37 | 01/30/2014 08:07 | 0.50 | Physical Curtailment | 5,000 kVA contract; 3,500 kW firm | 5,157.5 |

Note: The applicable CSR tariff required a “contract firm demand” or a CSR reduction commitment. In the case of contract firm demand, it is not possible to identify the amount of load actually curtailed, only the amount of load in excess of the contract amount during the CSR curtailment. For reduction commitments, the table notes if any part of the reduction commitment was not achieved.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 154**

**Responding Witness: David S. Sinclair**

Q-154. Explain in detail how each, KU and LG&E (acting alone or in conjunction with affiliates), treats interruptible/curtailable load in:

a. developing its long-run load forecast;

b. determining its long-run need for future supply-side resources;

c. determining its need for operating reserve capacity;

d. providing ancillary services; and,

e. determining whether such load qualifies as spinning reserve.

A-154.

a. The Companies incorporate an expected hourly-integrated impact of the Direct Load Control program into the peak load forecast.

b. The Companies treat interruptible CSR customers as a supply-side resource. Long-term resource plans include an expected hourly-integrated impact of CSR interruptions as a component of the Companies' generating portfolio.

c-e. Curtailable load under the CSR tariffs does not affect operating reserves, which consist of spinning reserves and non-spinning (supplemental) reserves. Both spinning and non-spinning reserves must be available to serve load within a 15 minute period. For curtailable load to qualify as operating reserves, the curtailable load must be fully removable from system load within a 15 minute period. The execution of a CSR event requires a 60 minute notice. Therefore, CSR does not qualify as an operating reserve and is not considered when determining the need for operating reserve capacity. Similar limitations also exist for considering CSR capacity for contingency and regulating reserves. Contingency reserves must be available within 15 minutes and regulating reserves must be immediately reactive to Automatic Generation Control to provide normal regulating margin.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 155**

**Responding Witness: Robert M. Conroy / William Steven Seelye**

Q-155. Explain in detail how KU and LG&E treat curtailment buy-through revenues in setting base rates and/or modifying its Fuel Adjustment Clause.

A-155. The Companies did not include any curtailment buy-through revenues in the forecasted test year for determining base rates in this proceeding. Regardless, curtailment buy-through revenues are recorded to fuel revenues and therefore would not affect the determination of base rates.

For Fuel Adjustment Clause purposes, buy-through revenues are credited to monthly fuel costs for determining the FAC factor. LG&E and KU decrease the total fuel costs represented by F(m) by the excess of the curtailment buy-through revenues over the revenues received from the CSR customer's standard rate schedule billings. The latter recovers the CSR customer's portion of the actual fuel and purchase power costs incurred by the Company from the CSR customer.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 156**

**Responding Witness: Robert M. Conroy / William Steven Seelye**

Q-156. Identify and explain in detail how KU and LG&E treats test-year curtailment buy-through revenue in the electric cost-of-service study filed in this case. This request refers to the methodology that KU and LG&E would use even if it received no test-year CSR buy-through revenue.

A-156. The Companies did not include any curtailment buy-through revenues in the forecasted test year in this proceeding. Buy-through revenues are credited to Kentucky retail customers through the fuel adjustment clause. See also the response to Question No. 155.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 157**

**Responding Witness: William Steven Seelye**

Q-157. Provide the most recent loss factors for energy and demand separated by voltage level; i.e., transmission, sub-transmission, primary, secondary.

A-157. See the attachment to the response to KIUC 1-7, part c.

**KENTUCKY UTILITIES COMPANY**

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**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 158**

**Responding Witness: Elizabeth J. McFarland**

Q-158. Provide the current number of customers (accounts) by rate schedule for each zip code within the Company's service area. Note: street lighting accounts may be excluded from this data set. Provide in executable electronic (Excel) format with all formulas intact and cells unprotected and with all columns and rows accessible.

A-158. See the attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 159**

**Responding Witness: William Steven Seelye**

Q-159. With regard to the Company's CCOSS, explain why Rate PS-Secondary, Rate TOD-Secondary, and Outdoor Sports Lighting (OSL) are not allocated any secondary line (overhead or underground) costs.

A-159. It is the Company's practice not to install secondary conductor runs for customers served on the Rate PS-Secondary, TOD-Secondary, and Outdoor Sports Lighting rate schedules.

**KENTUCKY UTILITIES COMPANY**

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**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 160**

**Responding Witness: William Steven Seelye**

Q-160. Provide references to each instance known to Mr. Seelye that the LOLP method has been proposed before State regulatory commissions to allocate generation plant for retail class cost allocations purposes. In this response, provide the name of the utility, year, jurisdiction, docket number, and proposing party as available. Further, indicate whether the State regulatory commission that the LOLP was proposed to explicitly found the LOLP method to be reasonable to CCOSS purposes.

A-160. See the response to KIUC 1-15.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 161**

**Responding Witness: William Steven Seelye**

Q-161. Provide an itemized list as well as a copy of all investor-owned electric utility testimony prepared by Mr. Seelye and provided to a regulatory commission on issues concerning class cost of service during the last five years. If such testimony is available electronically on Commission websites, simply provide a link to the respective testimony.

A-161. See testimony filed by William Steven Seelye in KU's and LG&E's most recent base rate proceedings (Case No. 2016-00370 and Case No. 2016-00371, respectively).

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
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**Case No. 2018-00294**

**Question No. 162**

**Responding Witness: Robert M. Conroy**

Q-162. Refer to the direct testimony of William Steven Seelye, page 15, wherein he states "The Companies want customers, stakeholders, and employees to be aware that two types of costs are included in the energy charge for Rate RS and other rates that have a two-part rate structure consisting of a Basic Service Charge and an Energy Charge."

a. Why do the Companies want customers, stakeholders and employees to be aware that the energy charge includes these two types of costs?

A-162.

a. The reasons for separating the current energy charge into a fixed-cost component (Infrastructure Energy Charge) and a variable-cost component (Variable Energy Charge) are explained in detail on pages 17-20 of the testimony of Mr. Conroy and pages 15-20 of the testimony of Mr. Seelye.

**KENTUCKY UTILITIES COMPANY**

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**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 163**

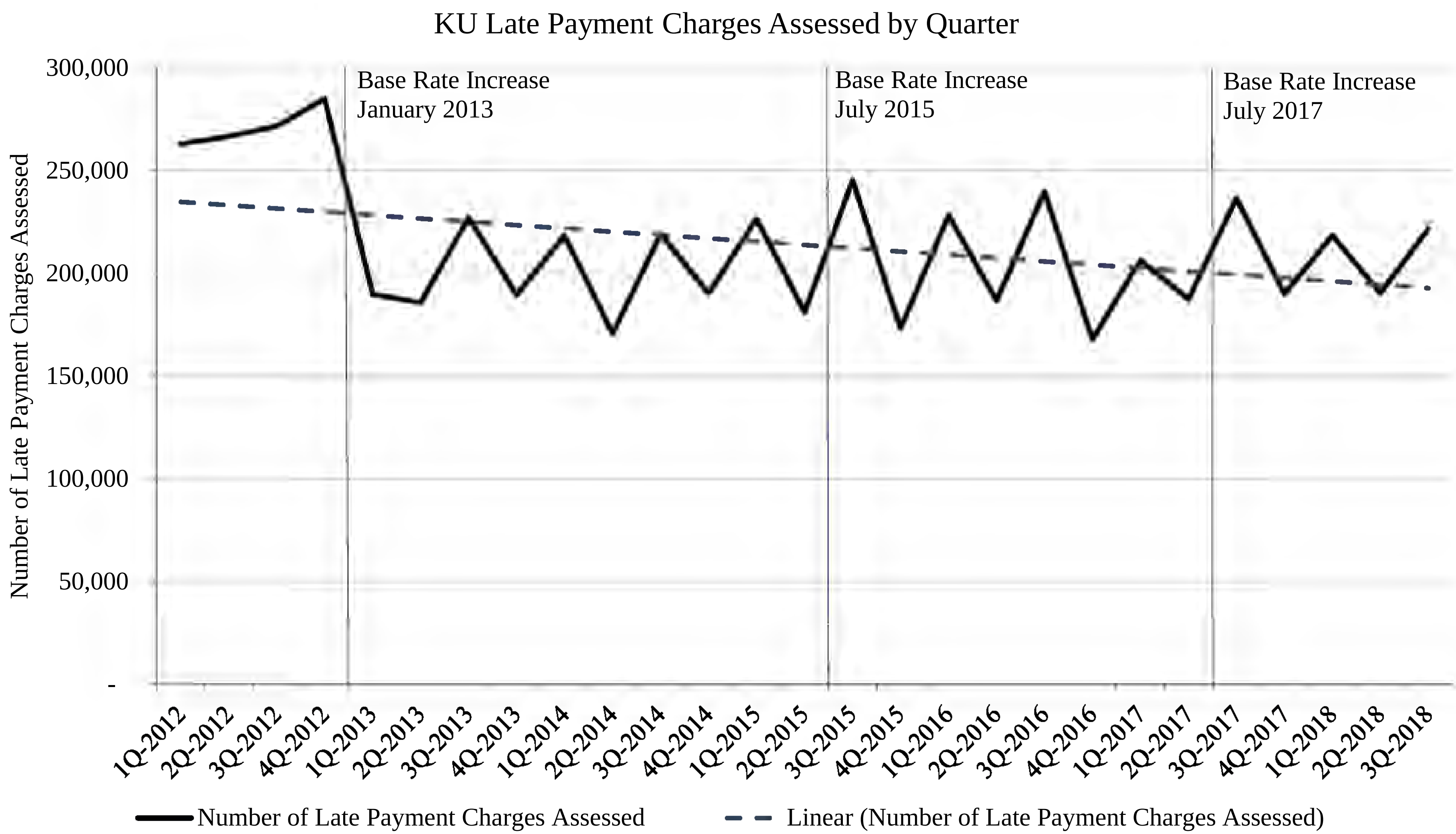
**Responding Witness: Elizabeth J. McFarland**

Q-163. Refer to the direct testimony of William Steven Seelye, pages 66-67, wherein he discusses late payments.

a. Following previous base rate cases, have the Companies noticed or identified that late payments tend to increase following increases in base rates?

A-163.

a. The Companies have not identified an increase in late payments following increases in base rates. See attached.


KU Late Payment Charges Assessed by Quarter
Base Rate Increase
January 2013
Base Rate Increase
July 2015
Base Rate Increase
July 2017
Number of Late Payment Charges Assessed
300,000
250,000
200,000
150,000
100,000
50,000
-
1Q-2012
2Q-2012
3Q-2012
4Q-2012
1Q-2013
2Q-2013
3Q-2013
4Q-2013
1Q-2014
2Q-2014
3Q-2014
4Q-2014
1Q-2015
2Q-2015
3Q-2015
4Q-2015
1Q-2016
2Q-2016
3Q-2016
4Q-2016
1Q-2017
2Q-2017
3Q-2017
4Q-2017
1Q-2018
2Q-2018
3Q-2018
Number of Late Payment Charges Assessed
Linear (Number of Late Payment Charges Assessed)

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 164**

**Responding Witness: William Steven Seelye**

Q-164. Refer to the direct testimony of William Steven Seelye, page 74, wherein he states that the LOLP "was supported by several of the intervenors in those proceedings." Further,

a. Identify the intervenors who "supported" the LOLP in the Companies' last base rate proceedings.

A-164.

a. Kentucky League of Cities, Walmart, and Kentucky School Board Association

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 165**

**Responding Witness: Robert M. Conroy**

Q-165. Refer to the direct testimony of Robert M. Conroy, page 7, wherein he cites to the Edison Electric Institutes' Typical Bills and Average Rates Report Winter 2018.

a. Provide a copy of this report.

A-165.

a. See the response to PSC 2-2.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 166**

**Responding Witness: Robert M. Conroy / William S. Seelye**

Q-166. Refer to the direct testimony of Robert M. Conroy, page 9, wherein he states, "I believe an LOLP approach to conducting a cost of service study is appropriate."

a. Explain whether Mr. Seelye approached the Companies about using the LOLP approach or if the Companies initiated the idea and tasked Mr. Seelye with conducting that approach.

b. Is the LOLP approach the only time-differentiated embedded cost of service study approach available?

A-166.

a. Over the past years as the Companies have been filing rate cases, the Companies and The Prime Group have had numerous discussions related to cost of service studies and methodologies. In the last rate case, those discussions included the use of the LOLP methodology. After discussion, the Companies directed Mr. Seelye to present both the historical modified BIP and the LOLP methodology. In the current proceeding, the Companies directed Mr. Seelye to only present the LOLP methodology.

b. No.

**KENTUCKY UTILITIES COMPANY**

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**Case No. 2018-00294**

**Question No. 167**

**Responding Witness: Robert M. Conroy**

Q-167. Refer to the direct testimony of Robert M. Conroy, page 14, wherein he notes that a change to a daily from a monthly Basic Service Charge "avoids any need to prorate service for customers who begin or end service mid-billing period."

a. Provide the amount of savings included in the forecasted period due to the identifiable savings from this efficiency.

A-167.

a. The Companies have not claimed there are savings from going to a daily Basic Service Charge. As such, there is no identifiable savings included in the forecasted period.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 168**

**Responding Witness: Robert M. Conroy**

Q-168. Refer to the direct testimony of Robert M. Conroy, page 14, wherein he discusses "splitting the energy charge into two components for informational purposes on the tariff sheets for rate schedules that do not have demand charges." Further, visit the following link to the Companies' own website: https://lge-ku.com/regulatory/rates-and-tariffs

a. Provide the number of times a month for the year 2017 and 2018 to date that visitors to the site have clicked on/visited the following categories in order to download the PDFs:

i. LG&E Electric Rates

ii. LG&E Gas Rates

iii. KU Electric Rates

All three categories are listed in two separate locations on the website and the response may combine the clicks/visits between the two distinct locations. If discernable, the response should differentiate between unique visits/clicks and subsequent visits/clicks.

A-168.

a. The attached file contains unique visits to lge-ku.cm/regulatory/rates-and-tariffs as well as the unique PDF downloads for each rate schedule. The current analytics tool the Companies use for this data set was not operational in January and February 2017. The previous analytics tool did not track PDF downloads.

The Companies' website provides a copy of their tariffs to provide transparency to the pricing structures of the services provided. The attached table demonstrates the non-employee interest in this information.

**Visits to lge-ku.com/regulatory/rates-and-tariffs**

| | Employees | Non-Employees | All Visitors |
|---|---|---|---|
| Mar-17 | 27 | 429 | 456 |
| Apr-17 | 26 | 489 | 515 |
| May-17 | 26 | 455 | 481 |
| Jun-17 | 35 | 463 | 498 |
| Jul-17 | 26 | 572 | 598 |
| Aug-17 | 34 | 518 | 552 |
| Sep-17 | 37 | 482 | 519 |
| Oct-17 | 18 | 511 | 529 |
| Nov-17 | 26 | 458 | 484 |
| Dec-17 | 24 | 523 | 547 |
| Jan-18 | 40 | 932 | 972 |
| Feb-18 | 34 | 642 | 676 |
| Mar-18 | 41 | 535 | 576 |
| Apr-18 | 29 | 516 | 545 |
| May-18 | 34 | 528 | 562 |
| Jun-18 | 35 | 719 | 754 |
| Jul-18 | 40 | 712 | 752 |
| Aug-18 | 53 | 630 | 683 |
| Sep-18 | 60 | 601 | 661 |
| Oct-18 | 95 | 646 | 741 |
| Nov-18 (partial) | 73 | 372 | 445 |
| | **813** | **11,733** | **12,546** |

**PDF views/downloads**

| | LGE Gas Tariff | LGE Electric Tariff | KU Electric Tariff |
|---|---|---|---|
| Mar-17 | 20 | 64 | 63 |
| Apr-17 | 80 | 236 | 208 |
| May-17 | 96 | 224 | 236 |
| Jun-17 | 78 | 244 | 235 |
| Jul-17 | 74 | 310 | 330 |
| Aug-17 | 87 | 268 | 278 |
| Sep-17 | 43 | 135 | 146 |
| Oct-17 | 20 | 82 | 63 |
| Nov-17 | 71 | 211 | 167 |
| Dec-17 | 85 | 217 | 154 |
| Jan-18 | 123 | 430 | 322 |
| Feb-18 | 77 | 277 | 232 |
| Mar-18 | 83 | 255 | 212 |
| Apr-18 | 68 | 223 | 157 |
| May-18 | 57 | 205 | 151 |
| Jun-18 | 57 | 200 | 144 |
| Jul-18 | 50 | 223 | 209 |
| Aug-18 | 59 | 242 | 190 |
| Sep-18 | 61 | 221 | 177 |
| Oct-18 | 68 | 113 | 188 |
| Nov-18 (partial) | 35 | 119 | 93 |
| | **1,392** | **4,499** | **3,955** |

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 169**

**Responding Witness: Robert M. Conroy**

Q-169. Refer to the direct testimony of Robert M. Conroy, pages 15-16, wherein he answered affirmatively whether "recovering a larger proportion of customer-specific fixed costs through the Basic Service Charge rather than through the energy charge . . . [has] the effect of stabilizing customers' monthly bills[.]"

a. Confirm that recovery of revenues through fixed charges rather than through energy charges has the effect of stabilizing the Companies' monthly revenues.

b. When did the Companies first begin recovering what it considers "customer-specific fixed costs" through residential customers' energy charge?

A-169.

a. All else being equal, recovering fixed costs through fixed charges will tend to stabilize revenues. However, there are other factors that affect the amount of fixed cost recovered from customers.

b. The Basic Service Charge has always been lower than the true cost of service, which has always allowed some fixed costs to be recovered through the Energy Charge.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 170**

**Responding Witness: Robert M. Conroy / David S. Sinclair**

Q-170. Refer to the direct testimony of Robert M. Conroy, page 22, wherein he discusses the "third Green Tariff option" and the proposed Green Tariff.

a. Explain the purpose and need for the eligible customer to "be willing to enter into an obligation for 10 MW or more of new (not already existing) renewable capacity."

b. Do the Companies anticipate that either Company may be the entity that develops the "renewable resource" envisioned under Option #3?

c. Do customers interested in Option #3 get to choose or have input into what type of "renewable resource" it receives electricity for under Option #3, or any input into which "renewable resource" developer is chosen?

d. Are any of the interconnection requests for solar located at the link below requested by either of the Companies?

https://www.oasis.oati.com/woa/docs/LGEE/LGEEdocs/LG&E_and_KU_GI_Queue_Posting_November_05,_2018.pdf

e. Will the projects chosen under Option #3 be pursuant to a formal RFP process?

f. If the response to subpart e., above, is in the affirmative, explain who sets the parameters of the RFP and if the ultimate customer will be consulted during the process.

g. Can customers with multiple locations throughout a service territory aggregate new load in order to participate under Option #3? If not, why not?

h. Have the Companies considered providing a pro-forma mock contract in the tariffs so that interested customers will understand the terms the Companies may consider under Option #3 (e.g., what effect the agreement may have on demand charges, ECR costs, etc.)?

i. If the Companies are unwilling to provide a pro-forma mock contract to provide interested customers additional certainty up-front, why do the Companies believe potential customers would be any more interested with Option #3 than they are now?

A-170.

a. Green Tariff Option #3 is targeted at customers who desire utility scale renewable options (hence 10 MW or more) that will support adding new renewable resources to the grid. The concept of supporting "additionality" (i.e., new renewables) is an important attribute of green tariffs since just purchasing energy from an existing project does nothing to alter the quantity of renewables on the grid.

b. As with all potential generation resources, the Companies may develop a "self-build option" as an alternative for the Green Tariff Option #3 customer to consider. However, the Companies are not proposing that they be required to develop a "self-build option" nor can they force the Green Tariff Option #3 customer to select a proposed "self-build option."

c. Yes.

d. The 10 MW Brown Solar facility is in the list and has been constructed. None of the other requests for solar are by the Companies or related to the Companies in any way.

e. Yes.

f. The Companies will work with the potential Green Tariff Option #3 customer throughout the RFP process.

g. For a customer that has multiple accounts, the renewable energy associated with Option #3 would be proportioned to those specific accounts through the mutually agreed to bilateral contract. The individual accounts will continue to be billed on their associated individual tariff rate. Option #3 is available to any customer addressed in the Availability section of the tariff and not just new loads.

h. No because the terms will be jointly determined in consultation with the potential Green Tariff Option #3 customer and what possible counterparties are willing to propose and accept.

i. The Companies experience in the wholesale marketplace tells us that there is no "certainty up-front" when one issues an RFP for capacity and energy. Any customer interested in pursuing Green Tariff Option #3 must be willing to accept the vagaries and realities of procuring utility-scale renewables in the wholesale electricity markets.

**KENTUCKY UTILITIES COMPANY**

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**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 171**

**Responding Witness: Elizabeth J. McFarland**

Q-171. Refer to the direct testimony of Robert M. Conroy, page 32, wherein he describes the proposed changes to the Economic Development Rider.

a. For the five most-recent customers who have taken service under each Company's Economic Development Rider, provide the demand, by year, for the first 5 years under each contract.

b. As a general matter, would the Companies agree that customers who have taken service under the Economic Development Rider, have increased, rather than decreased their usage over the discount period of the Rider?

A-171.

a. See table of KW/KVA demand below:

Demand While Under Contract by Year for Five Most-Recent EDR Customers*

| Year | Company 1 | Company 2 | Company 3 | Company 4 | Company 5 |
|---|---|---|---|---|---|
| **2014** | 1,928 | | | | |
| **2015** | 2,633 | 3,624 | | | |
| **2016** | 2,162 | 3,733 | | | |
| **2017** | 2,213 | 3,554 | 80,061 | 104,371 | |
| **2018** | 2,895 | 3,582 | 81,357 | 105,541 | 2,156 |

*The values in the table are the average monthly measured base kW or kVA demand for the calendar years shown. The demand value in the first calendar year of an EDR billing arrangement typically does not reflect a full 12 months of measured demand, and the value shown for 2018 are year to date.

b. The data for these customers would not tend to support the question's premise on the whole. For these five customers, demand and energy usage have remained relatively stable over the periods requested (within normal bounds of seasonal or other ordinary fluctuations), though in certain instances demand and energy in the earliest months of an EDR billing arrangement have been slightly lower than in subsequent months. On the whole, the differences are not significant.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 172**

**Responding Witness: Elizabeth J. McFarland**

Q-172. Refer to the direct testimony of Robert M. Conroy, pages 32-33, wherein he describes the minimum load factor of 50% in order to take service under the EDR.

a. Explain how this minimum load factor does not preclude high energy intensity, low load factor customers from expanding in the Companies' territories. Any response should include an explanation as to how many of the new industrial or large commercial customers that have recently located in the Companies' territories satisfy this minimum.

A-172.

a. The load factor requirement to participate in the Economic Development Rider (EDR) tariff does not restrict "high energy intensity, low load factor customers" from locating or expanding within the Company's service territory or taking service under any of the Company's electric tariffs. This requirement is only related to the EDR tariff. The Company is not aware of this requirement precluding a customer from locating within the Company's service territory. This provision incentivizes the attraction of high load factor customers who are more efficient users of the electric system, which provides broad benefits to customers in general.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 173**

**Responding Witness: Christopher M. Garrett**

Q-173. Refer to the direct testimony of Paul W. Thompson, page 2, wherein he discusses the number of customers served by LG&E and KU.

a. Provide a breakout, between LG&E and KU, of the number of unique customers each utility has (e.g., one business with 5 meters on site, or one home with a residential meter at the home and another on a pool house, etc.). The response should not consider businesses with multiple locations located across service territories as one "unique" customer, but rather, the request is seeking information on the number of discrete locations customers are served. If possible, any response should provide the number of unique residential locations, separate from non-residential.

A-173.

a. See the response to PSC 1-27. The information provided reflects the *average* customer count for the periods presented, compared to the *actual* customer count as of December 31, 2017, provided in Mr. Thompson's testimony.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information
Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 174**

**Responding Witness: Kent W. Blake**

Q-174. Refer to the direct testimony of Paul W. Thompson, page 2, wherein he notes that "20 years of common ownership has allowed KU and LG&E to streamline and fully integrate their operations, and jointly plan all aspects of their business, including safety, electric generation, transmission, distribution, customers service, information technology, and all service functions."

a. Confirm that although the Companies plan many of their aspects jointly, the legal separation between LG&E and KU requires the Companies to file separate rate cases for their electric operations and perform separate cost of service studies and revenue requirement models.

A-174.

a. As shown in the Companies' study filed on August 8, 2018 in Case No. 2017-00415[15], the evaluation considered the costs and benefits of a legal merger in every area of the Companies including potential regulatory savings noted above. Ultimately, the study confirmed that the Companies operate as an integrated company in virtually all operational areas and the integrated approach has achieved significant savings for customers. The study concluded by recommending against the legal merger of the two utilities because the savings are not enough to bring all customer rates to the lowest rate offered by each company. The Study in conclusion states:

> The potential legal merger of the two utilities would result in some savings in the accounting, tax, treasury, and regulatory areas, but also result in an increase of ongoing costs in other areas. In addition, the legal merger would require significant one-time costs to achieve the legal merger. Perhaps most importantly, the potential legal merger creates winners and losers among the customers because the savings are not enough to bring all

[15] *In the Matter of: Joint Application of PPL Corporation, PPL Subsidiary Holdings, LLC, PPL Energy Holdings, LLC, LG&E and KU Energy LLC, Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of an Indirect Change of Control of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2017-00415, Order (Ky. PSC Apr., 2018).

> customer rates to the lowest rate offered by each company. KU customers would be adversely impacted in most cases while LG&E customers could benefit from the legal merger. For these reasons, the Companies do not recommend proceeding with the legal merger of LG&E and KU.[16]

The Companies file separate rate cases, perform separate cost of service studies, and calculate separate revenue requirements because separate legal entities they have distinct costs of providing service.

[16] Case No. 2017-00415, LG&E and KU Internal Study of Potential Legal Merger at 21 (Ky. PSC Aug. 8, 2018).

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 175**

**Responding Witness: David S. Sinclair / Robert M. Conroy / William Steven Seelye**

Q-175. Refer to the direct testimony of David S. Sinclair, pages 9-10, wherein he discusses the impact from existing distributed generation, "almost all of it in the form of solar generation."

a. Explain what cost of service impact the 2.4 GWh and 2.6 GWh for KU and LG&E, respectively, have on other customers in the Forecasted Test Year.

b. Explain how much of this 2.4 GWh and 2.6 GWh is due to customers who "net-meter" pursuant to KRS Chapter 278.465 and 278.466.

i. Provide the cost of service impact those "net-metering" customers have on other customers in the Forecasted Test Year.

A-175.

a. The Companies have not performed an analysis of the cost of service impact of the 2.4 GWh and 2.6 GWh of distributed generation.

b. All of the volumes included in this reference are customers who "net-meter."

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 176**

**Responding Witness: Robert M. Conroy**

Q-176. Provide a copy of the most recent KU jurisdictional class cost allocation study and accompanying testimony conducted for Virginia, Tennessee, and FERC.

A-176. Tennessee and FERC do not require KU jurisdictional class cost allocation studies; thus, KU has not conducted a study for either jurisdiction. KU-ODP filed a study in its most recent Virginia base rate case (PUR-2017-00106). See Schedule 40 and the testimony of Douglas A. Leichty, which can be accessed on the Virginia State Corporation Commission website at http://www.scc.virginia.gov/docketsearch#caseDocs/137611.

## KENTUCKY UTILITIES COMPANY

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 177**

**Responding Witness: John K. Wolfe**

Q-177. Refer to the direct testimony of Paul W. Thompson, page 8.

a. Provide a narrative explanation as to how the Companies calculated the avoided customers interruptions and minutes due to the installation of electronic reclosers. Provide all workpapers used in determining these amounts in executable electronic format, preferably in native Excel format, with all formulas intact and cells unprotected and with all columns and rows accessible.

b. Provide the actual and budgeted costs of installing the 350 electronic reclosers, broken out by Capital and O&M.

c. Confirm that due to the magnitude of the referenced July 2018 Storms, impacts arising from them would not be included in the calculation of System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"). If this cannot be confirmed, explain why not.

d. Provide the SAIDI and SAIFI information in Exhibit LEB-5 that is redacted, specifically the redacted information on page 4 of 16 through page 8 of 16.

A-177.

a. For each instance when a DA recloser operates to isolate a fault, the number of customers affected by the outage is compared to the number of customers who would have been affected if the recloser had not been in place. This difference determines the number of Customer Interruptions (CI) saved by the recloser. The outage duration, which is the time required for crews to arrive at the damage location and make repairs, is assumed to be the same in both cases. Thus, Customer Minutes of Interruption (CMI) saved is determined by multiplying the difference in the number of customers affected by the outage duration. See attached.

b. All costs are Capital for the combined Companies.
Actual Cost: $20,838,888
Forecasted Cost: $21,975,977

Original Budgeted Cost: $22,243,937

c. It is confirmed that due to the magnitude of the referenced July 2018 Storms, impacts arising from them would not be in calculations of System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") that exclude major event days (values typically reported).

d. The referenced section of LEB-5 contains the Companies' combined historical SAIDI and SAIFI performance charted against first, second and third quartile performance according to two different industry surveys. The quartile data from these surveys is subject to strict confidentiality obligations imposed by the survey entities. The Companies have sought consent from each survey entity to provide the information responsive to this request. Both entities have refused consent. The Companies are still negotiating for appropriate disclosure of the requested information.

| | | | | | | Totals | 3019 | 4831448.03 |
|---|---|---|---|---|---|---|---|---|
| **Substation** | **Circuit** | **Inc #** | **Outage Date** | **Out Duration** | **Customers Out** | **Customers Would Have Been Out** | **CI Saved by Recloser** | **CMI Saved by Recloser** |
| LANSDOWNE | 106 | 18083741 | 7/20/18 4:12 PM | 1703.5 | 299 | 1332 | 1033 | 1759749.93 |
| IBM | 103 | 18085223 | 7/20/18 4:13 PM | 176.6 | 599 | 1155 | 556 | 98189.6 |
| LANSDOWNE | 118 | 18090355 | 7/20/18 4:14 PM | 3079.9 | 208 | 444 | 236 | 726864.267 |
| LIBERTY ROAD | 42 | 18090252 | 7/20/18 4:27 PM | 2177.9 | 1040 | 1777 | 737 | 1605100.02 |
| BRYANT ROAD | 874 | 18087564 | 7/20/18 10:35 PM | 1403.8 | 1956 | 2413 | 457 | 641544.216 |

## KENTUCKY UTILITIES COMPANY

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 178**

**Responding Witness: Lonnie E. Bellar**

Q-178. Refer to the direct testimony of Lonnie E. Bellar, page 36, wherein he discusses the 2018 transmission SAIDI through July.

a. Provide the Companies' transmission SAIDI for the last 5 calendar years and 2018 to-date as well as each month in 2018 in which the Companies have data. Provide an update to this response as monthly information becomes available.

b. For each year the information is available, provide the annual SAIDI by transmission line voltage (i.e. 69 kV, 115, kV, 230 kV, etc.).

A-178.

a. See tables below.

| Year | SAIDI |
|---|---|
| 2013 | 13.525 |
| 2014 | 12.141 |
| 2015 | 9.467 |
| 2016 | 12.188 |
| 2017 | 5.976 |
| 2018 | 5.377 |

| Year | Month | SAIDI |
|---|---|---|
| 2018 | 1 | 0.057 |
| 2018 | 2 | 0.014 |
| 2018 | 3 | 0.366 |
| 2018 | 4 | 0.729 |
| 2018 | 5 | 0.130 |
| 2018 | 6 | 1.642 |
| 2018 | 7 | 0.029 |
| 2018 | 8 | 1.827 |
| 2018 | 9 | 0.573 |
| 2018 | 10 | 0.008 |

b. See table below.

| | SAIDI By Voltage by Year | | | | |
|---|---|---|---|---|---|
| Year | 69 | 138 | 161 | 345 | 500 |
| 2013 | 13.173 | 0.352 | - | - | - |
| 2014 | 11.050 | 1.091 | - | - | - |
| 2015 | 8.721 | 0.746 | - | - | - |
| 2016 | 10.890 | 1.298 | - | - | - |
| 2017 | 5.541 | 0.435 | - | - | - |
| 2018 | 5.263 | 0.114 | - | - | - |

## KENTUCKY UTILITIES COMPANY

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 179**

**Responding Witness: Lonnie E. Bellar**

Q-179. Refer to the direct testimony of Lonnie E. Bellar, page 36, wherein he discusses the Companies' transmission OHMY.

a. Provide the Companies' transmission OHMY for the last 5 calendar years, and 2018 to-date, as well as each month in 2018 in which the Companies have data. Provide an update to this response as monthly information becomes available.

b. For each year the information is available, provide the annual OHMY by transmission line voltage (i.e. 69 kV, 115, kV, 230 kV, etc.).

A-179.

a.

| Year | OHMY | |
|---|---|---|
| 2013 | 9.692 | |
| 2014 | 10.742 | |
| 2015 | 11.166 | |
| 2016 | 10.484 | |
| 2017 | 9.065 | |
| 2018 | 8.512 | through october 31st 2018 |

| Year | Month | OHMY |
|---|---|---|
| 2018 | 1 | 0.571 |
| 2018 | 2 | 0.350 |
| 2018 | 3 | 0.387 |
| 2018 | 4 | 0.645 |
| 2018 | 5 | 1.400 |
| 2018 | 6 | 1.308 |
| 2018 | 7 | 1.198 |
| 2018 | 8 | 1.363 |
| 2018 | 9 | 0.811 |
| 2018 | 10 | 0.479 |

b.

| | OHMY By Year and Voltage | | | | |
|---|---|---|---|---|---|
| **Year** | **69** | **138** | **161** | **345** | **500** |
| 2013 | 7.978 | 0.682 | 0.663 | 0.313 | 0.055 |
| 2014 | 8.586 | 1.087 | 0.571 | 0.479 | 0.018 |
| 2015 | 7.886 | 1.898 | 0.700 | 0.663 | 0.018 |
| 2016 | 8.070 | 1.013 | 0.866 | 0.534 | - |
| 2017 | 7.131 | 0.755 | 0.811 | 0.369 | - |
| 2018 | 6.504 | 0.755 | 0.442 | 0.737 | 0.074 |

2018 is through October 31, 2018.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 180**

**Responding Witness: Lonnie E. Bellar**

Q-180. Refer to the direct testimony of Lonnie E. Bellar, page 44, wherein he discusses the move of LG&E's distribution SCADA to the Distribution Control Center.

a. From what center is KU's distribution SCADA function operated?

b. Provide the savings realized from this move.

A-180.

a. The KU distribution SCADA function is operated from the Lexington Distribution Control Center located in the KU General Office building.

b. LG&E distribution SCADA was moved from the Transmission Control Center (TCC) to the Distribution Control Center (DCC) in order to consolidate all distribution functions and to allow the TCC to focus solely on transmission functions. This move will create consistency between LG&E and KU, prepare for the centralization of the DCC facility in 2nd Quarter 2019, and more closely align to the Distribution strategy of centralized grid operations. The Companies have not quantified the savings resulting from this move, however, the efficiencies achieved have been considered in the forecast test period.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 181**

**Responding Witness: John K. Wolfe**

Q-181. Refer to the direct testimony of Lonnie E. Bellar, page 46.

a. Provide each Companies' SAIDI and SAIFI for the last five (5) complete years, 2018 to-date and each month in 2018, proving each annual number with and without the inclusion of major event days ("MED").

A-181.

a.

| | LG&E | | | |
|---|---|---|---|---|
| | Excluding Major Events | | Including Major Events | |
| | SAIDI | SAIFI | SAIDI | SAIFI |
| 2013 | 78.50 | 0.933 | 147.39 | 1.136 |
| 2014 | 73.75 | 0.897 | 158.62 | 1.156 |
| 2015 | 74.45 | 0.927 | 119.10 | 1.123 |
| 2016 | 73.03 | 0.861 | 89.70 | 0.936 |
| 2017 | 71.93 | 0.835 | 90.81 | 0.912 |
| Jan-18 | 5.70 | 0.062 | 5.70 | 0.062 |
| Feb-18 | 6.09 | 0.055 | 6.09 | 0.055 |
| Mar-18 | 3.94 | 0.040 | 8.34 | 0.054 |
| Apr-18 | 5.02 | 0.052 | 5.02 | 0.052 |
| May-18 | 8.56 | 0.086 | 51.37 | 0.180 |
| Jun-18 | 13.04 | 0.115 | 35.09 | 0.187 |
| Jul-18 | 11.15 | 0.099 | 86.89 | 0.228 |
| Aug-18 | 5.85 | 0.068 | 5.85 | 0.068 |
| Sep-18 | 8.68 | 0.086 | 8.68 | 0.086 |
| Oct-18 | 5.26 | 0.051 | 16.75 | 0.089 |
| YTD Oct 2018 | 73.29 | 0.713 | 229.77 | 1.062 |

| | KU (Kentucky) | | | |
|---|---|---|---|---|
| | Excluding Major Events | | Including Major Events | |
| | SAIDI | SAIFI | SAIDI | SAIFI |
| 2013 | 82.79 | 0.752 | 94.45 | 0.795 |
| 2014 | 79.28 | 0.752 | 156.54 | 1.000 |
| 2015 | 78.10 | 0.773 | 102.13 | 0.893 |
| 2016 | 99.40 | 0.858 | 106.18 | 0.882 |
| 2017 | 66.51 | 0.661 | 92.89 | 0.739 |
| Jan-18 | 7.72 | 0.069 | 7.72 | 0.069 |
| Feb-18 | 5.27 | 0.045 | 5.27 | 0.045 |
| Mar-18 | 6.73 | 0.052 | 6.73 | 0.052 |
| Apr-18 | 5.78 | 0.054 | 10.63 | 0.069 |
| May-18 | 6.50 | 0.066 | 13.15 | 0.099 |
| Jun-18 | 11.77 | 0.099 | 14.78 | 0.125 |
| Jul-18 | 10.56 | 0.068 | 270.58 | 0.252 |
| Aug-18 | 10.08 | 0.082 | 10.08 | 0.082 |
| Sep-18 | 6.32 | 0.051 | 6.32 | 0.051 |
| Oct-18 | 6.77 | 0.063 | 10.64 | 0.082 |
| YTD Oct 2018 | 77.48 | 0.650 | 355.89 | 0.927 |

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
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**Case No. 2018-00294**

**Question No. 182**

**Responding Witness: John K. Wolfe**

Q-182. Refer to the direct testimony of Lonnie E. Bellar, page 54, wherein he discusses the use of and possible expansion of substation monitoring and controls system.

a. Provide the cost savings, including reduction in manual intervention or field service personnel, of the current substation monitoring and controls system.

b. How many substation monitoring and controls systems do the Companies currently have, where are they located, and what criteria did the Companies employ in selecting the current substations?

A-182.

a. The expansion of the substation monitoring and controls system is not applicable to the KU service area.

b. The expansion of the substation monitoring and controls system is not applicable to the KU service area.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 183**

**Responding Witness: Lonnie E. Bellar / David S. Sinclair**

Q-183. Refer to Exhibit LEB-2 to the direct testimony of Lonnie E. Bellar, page 30 of 40, Appendix D, wherein the document discusses the Companies "NERC requirements," including the Companies' ability "to meet the NERC reliability standards contingency reserve requirements."

a. Explain what the Companies' NERC reliability standards contingency reserve requirements is, and if the information is public, where in the public domain it may be accessed.

A-183.

a. As defined by NERC, the Contingency Reserve is a "provision of capacity that may be deployed by the Balancing Authority (BA) to respond to a Balancing Contingency Event and other contingency requirements (such as Energy Emergency Alerts as specified in the associated EOP standard)."

The Companies participate in a Contingency Reserve Sharing Group with TVA to fulfill the BAL-002 Standard Requirements. More details are contained in the SERC Regional Criteria-Contingency Reserve Policy, located at the following link: http://serc1.org/docs/default-source/program-areas/standards-regional-criteria/regional-criteria-and-guidelines/archive/contingency-reserve-policy-(serc-regional-criteria).pdf?sfvrsn=432d34ff_2 beginning on page 8. The TCRSG Deliverability Certificate is located on the Companies' Transmission OATI OASIS website (under Miscellaneous): http://www.oatioasis.com/LGEE/index.html. The current LG&E/KU contingency reserve allocation is equal to the TRM deliverability value contained in this document.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 184**

**Responding Witness: David S. Sinclair**

Q-184. Refer to the direct testimony of David S. Sinclair, page 26, wherein he discusses target summer and winter reserve margin ranges of 17 to 25 and 28 to 38 percent, respectively.

Are the Companies aware of any other utility in the country with such a high season reserve margin as the Companies' winter target reserve margin? If the response is in the affirmative, provide the names of those utilities and the seasonal reserve margin.

A-184. Yes. NERC's 2017/2018 Winter Reliability Assessment showed anticipated winter reserve margins above 30 percent for many assessment areas, including MISO at 45.0 percent and PJM at 39.7 percent. See NERC's report at the following link:

https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_05252018_Final.pdf.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 185**

**Responding Witness: John K. Wolfe**

Q-185. With regard to the Companies' distribution automation program, state whether the Companies will incorporate the IEEE 1547 standard for interconnection and interoperability of distributed energy resources with associated electric power systems interfaces. If they will not, explain why not.

A-185. Yes. The Companies' distribution automation program does incorporate the IEEE 1547 standard for interconnection and interoperability of distributed energy resources.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 186**

**Responding Witness: Lonnie E. Bellar**

Q-186. With regard to the Companies' deployment of smart grid technologies, state how the Companies intend to comply with FERC's recent approval of NERC's Critical Infrastructure Protection Standards (CIP-013-1).

A-186. The Companies assembled a team comprised of Supply Chain, Generation, Transmission, IT, Compliance, and Legal to address the implementation of CIP-013. This team began work during the second quarter of 2018 and has put together a project to address all the requirements of CIP-013. These tasks consist of risk ranking suppliers based on their Cyber profile, contract language added to contracts for suppliers of in scope assets, processes to mitigate issues before the installation of assets and processes to monitor those suppliers and assets for any new cyber issues. The project team is on track to meet the compliance date of the newly approved standard.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 187**

**Responding Witness: John K. Wolfe**

Q-187. With regard to the Companies' deployment of smart grid technologies, state whether they will be deploying additional volt/VAR projects for circuits with high amounts of resistive load.

d. If so, provide copies of all cost/benefit analyses the Companies may have conducted regarding the cost effectiveness of volt/VAR projects.

A-187.

d. The Companies do not have an active volt/VAR program at this time.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 188**

**Responding Witness: John K. Wolfe**

Q-188. With regard to the Companies' deployment of ADMS technology, state whether the Companies have conducted any ADMS Testbed demonstrations in order to model and evaluate ADMS applications. If demonstrations were conducted, provide documents regarding the results of the Testbed demonstrations.

A-188. The Companies have not yet implemented ADMS technology and have not conducted ADMS Testbed demonstrations. However, demonstration of ADMS technology has taken place throughout the industry and has shown solid results.

As stated in Exhibit LEB-5, Section 1.2 of Mr. Bellar's testimony: Demonstrated smart grid technology benefits cited in the Department of Energy's Smart Grid Investment Grant Program Final Report final report include:

- Fewer and shorter outages that result in less inconvenience and lower outage costs for customers.

- Improved grid resilience to extreme weather events by automatically limiting the extent of major outages and improving operator ability to diagnose and repair damaged equipment.

- Faster and more accurate outage location identification for improved repair crew dispatching and service restoration, reducing operating costs, truck rolls, and environmental emissions.

Furthermore, PPL Electric Utilities has reported SAIDI and SAIFI improvements of 21% and 31%, respectively, on circuits where DA, incorporating ADMS, has been deployed.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 189**

**Responding Witness: John K. Wolfe**

Q-189. Identify the value streams the Companies hope to bring about through the deployment of ADMS.

A-189. See demonstrated smart grid technology benefits cited in the Department of Energy's Smart Grid Investment Grant Program Final Report as stated in Exhibit LEB-5, Section 1.2 of Mr. Bellar's testimony and in the response to Question No. 188. See also Exhibit PWT-5, Section 2 of Mr. Thompson's testimony in the 2016 rate case, Case No. 2016-00370.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 190**

**Responding Witness: John K. Wolfe**

Q-190. With regard to the Companies' deployment of smart grid technologies, state to what extent they have examined the use of technologies involving: (i) Geographic Information System (GIS); and (ii) Blockchain, as a potential means of reducing costs associated with the use of both current and planned smart grid technology deployments. Include in your response:

e. whether GIS and/or Blockchain technologies could be used as cost-effective alternatives to such deployments;

f. whether any cost-effective GIS technologies could decrease the need and scope of further planned ADMS and SCADA deployments;

g. whether GIS and/or Blockchain technologies could be used to integrate other IT and operational technologies in such a manner as to reduce costs;

h. whether GIS and/or Blockchain technologies can be utilized to reduce costs associated with reliability, resilience and grid security;

i. in the event the Companies do at some point utilize GIS and/or Blockchain technologies, whether they could adopt existing platforms that would be interoperable with other systems, rather than creating a unique platform specially customized for the Companies' use;

j. copies of any studies/analyses the Companies may have conducted regarding the cost effectiveness, or cost/benefit studies regarding the use of such technologies.

A-190.

e. The Companies currently utilize a Geographic Information System (GIS) to house distribution asset data with spatial representation. This data is automatically exported on a daily basis from the GIS and placed into the connectivity model utilized by both the Oracle Outage Management System (OMS) and the Oracle Distribution Management System (DMS). Blockchain is not utilized by the Companies, but would be evaluated as distributed energy resources became more prevalent within the Commonwealth. Both Information Technology (IT) and Operational Technology (OT) personnel stay abreast on current technologies and best practices across the utility industry.

f. See the response to part a.

g. See the response to part a.

h. See the response to part a.

i. See the response to part a.

j. The Companies have been utilizing a single GIS platform since 2002. Also, see the response to part a.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 191**

**Responding Witness: Lonnie E. Bellar**

Q-191. Reference the Bellar testimony, p. 22, footnote 22, wherein he references the Companies' "Annual TSIP Report" filed under the post-case files in Case Nos. 2016-00370 and 2016-00371. Page 5 of that document states: "The bulk of the additional spending is attributable to the Companies' accelerated replacement of line equipment, in particular, wood poles." Discuss why wood poles have proven to be the primary reason for variances from projected TSIP spending levels.

a. Discuss whether the quality of the wood, its age, and/or the treatment used on the poles' exterior have proven to be problematic.

b. Do the problems have a greater incidence with certain pole vendors?

c. Has unseasoned/green wood proven to be a problem?

d. Identify any criteria utilized when evaluating damaged wood poles as to whether repairs such as further weatherization treatment would suffice, versus outright pole replacement.

e. Identify any criteria utilized when evaluating whether wood poles that need replacing should be replaced with another wood pole, or a metal pole.

f. Provide a table or graph illustrating the total number of wood pole failures over the last fifteen (15) years that have required a replacement, regardless of whether the replacement is wood or metal.

g. Has a survey or study been done of other utilities with similar types of poles and how failure rates have impacted them? If so, provide a copy.

A-191. As described in the "Annual TSIP Report", the Companies pole inspections in 2017 yielded a higher number of defective wood structures in need of replacement than anticipated. As defective structures are a reliability and safety risk, the Companies increased spending to replace more wood structures than originally planned.

a. While the Companies do not have historical records on ages of specific wood poles and structures, they believe the reason for the higher number of defective poles found are due to their age exceeding the expected life of this vintage.

b. The Companies have no data to indicate there is an issue with specific vendors.

c. No, the Companies do not use unseasoned/green wood.

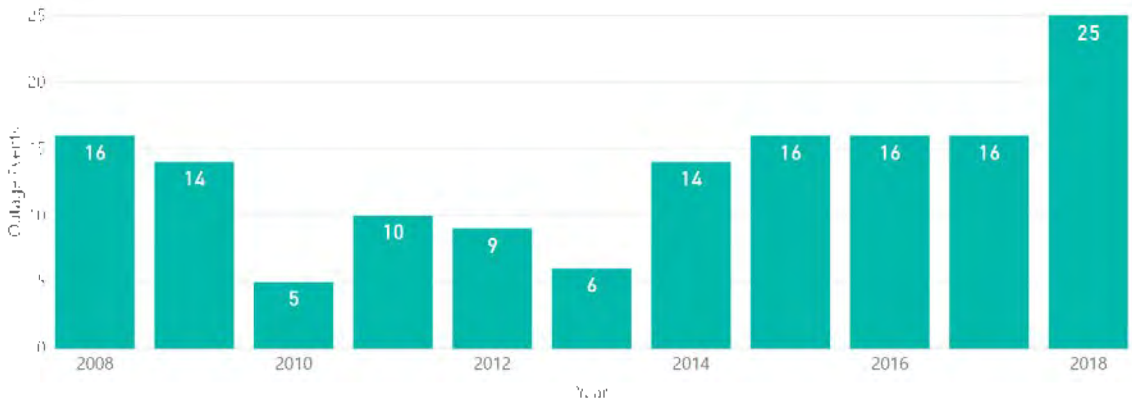
d. As highlighted in the "Annual TSIP Report", the Companies pole inspections include detailed visual observation, sounding, and, when possible, climbing of the poles to observe their condition. These pole inspections are completed by line technicians trained to identify and evaluate wood pole defects and degradation. These technicians do seek opportunities to make repairs, which often include patching of woodpecker holes.

   The Companies also consider component replacement in lieu of outright replacement when feasible. Examples include replacing insulators, replacing crossarms, repairing/replacing guy wires, and repairing/replacing anchors.

e. As the Companies highlighted in the "Annual TSIP Report", "Steel poles have a longer expected life than wood poles, are more resilient to hazards and severe weather events, and do not deteriorate like wood poles. This approach is typical in the industry for transmission structures, particularly in areas where woodpeckers are common."

   Criteria such as pole height, applied loads, material and labor costs, and service conditions are considered when evaluating the use wood or steel poles. See response to AG DR1-Q196 pages 461-465 and pages 587-591 for examples of cost benefit analysis of wood versus steel construction.

f. The chart below shows annual outages caused by a broken poles/structures and broken cross-arms. Some outages could have involved more than a single pole and sometimes poles failed without causing an outage, therefore this summary is not all inclusive, but is the best data available.




g. The Companies are not aware of any such surveys or studies.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 192**

**Responding Witness: John K. Wolfe**

Q-192. Reference the Bellar testimony beginning at p. 45, where he has an extended discussion regarding the Companies' distribution system. State whether the Companies have been experiencing the same types of problems with wood poles used in the distribution system as they have encountered with wood poles used in the transmission system. If so:

a. Discuss whether the quality of the wood, its age, and/or the treatment used on the poles' exterior have proven to be problematic.

b. Do the problems have a greater incidence with certain pole vendors?

c. Has unseasoned/green wood proven to be a problem?

d. Identify any criteria utilized when evaluating damaged wood poles as to whether repairs such as further weatherization treatment would suffice, versus outright pole replacement.

e. Identify any criteria utilized when evaluating whether wood poles that need replacing should be replaced with another wood pole, or a metal pole.

f. Provide a table or graph illustrating the total number of wood pole failures over the last fifteen (15) years that have required a replacement, regardless of whether the replacement is wood or metal.

g. Has a survey or study been done of other utilities with similar types of poles and how failure rates have impacted them? If so, provide a copy.

A-192. The Companies are not experiencing the same levels of problems with wood poles used in the distribution system as they are experiencing with wood poles deployed in the transmission system. The Companies implemented a Distribution Wood Pole Inspection and Treatment Program beginning in 2010. By year end 2018, approximately 497,000 distribution poles will have been inspected. The overall distribution pole replacement rate for the program is 3.8 percent.

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 193**

**Responding Witness: John K. Wolfe**

Q-193. Reference the Bellar testimony generally, the discussion regarding the Distribution Reliability and Resiliency Program ("DRRIP"). Other than enhanced reliability measures, provide copies of any and all cost/benefit analyses the Companies may have conducted indicating the costs of the DRRIP and the monetary savings to ratepayers that the DRRIP is projected to yield.

A-193. The Companies' existing Investment Proposals (i.e., those approved through November 27, 2018) for DRRIP programs included in the base year through the forecasted test period are attached. See also the attachments provided in response to Question No. 43.

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: Breckenridge 1351 Circuit Hardening

Total Expenditures: $850k (Including $77k of contingency)

Project Number(s): 155870

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Chase Mills

**Executive Summary**

LG&E Electric Distribution and LKE Electric Reliability propose to invest $850k on reliability improvements for Breckenridge Circuit 1351 (BR1351). BR1351 circuit hardening project was approved and included in the 2018 Business Plan (BP) under the Circuit Hardening and Reliability Program. The funding for this specific project was approved as a reallocation from the budgeted circuit hardening project during the April RAC process.

This project proposes to reconductor 6,100' of three phase, 13.8 kV distribution circuit along Breckenridge Lane between Brownlee Road and Shelbyville Road. Existing copper conductor is prone to failure. Existing conductor will be replaced with 795 ACSR conductor. This will provide reliability improvements and enhanced contingency capabilities for electric customers in the St. Matthews Mall area.

**Background**

The proposed circuit hardening project will replace 6,100'of three phase, paralleled, copper conductor with three phase, 795 ACSR overhead conductor on Breckenridge Circuit 1351. This conductor is located along Breckenridge Lane between Brownlee Road and Shelbyville Road. Historically, the existing copper conductor is prone to failure, resulting in significant reliability impacts in a highly sensitive area. Furthermore, replacement of the paralleled conductor is required to improve pole spacing and allow for Distribution Automation (DA) investments to be made.

BR1351 experienced 19 interruptions between 2013 and 2017. Five of these interruptions are attributable to the mainline section of BR1351 which will be addressed with this project. Estimated reliability improvements for this circuit as a direct result of this project are 18,162 CMI and 96 CI annually. In addition to numerous commercial customers, BR1351 is the primary feed for a large assisted living facility and Trinity High School. BR1351 is the backup feed for the St. Matthews Mall.

BR1351 shares poles with transmission and 12kV distribution (BR1177). Due to the location along Breckenridge Ln., this project will require continuous flagging of traffic. Costs are also elevated as the line is underbuilt on transmission structures, shares a route with a 12kV circuit, and is parallel overhead construction.

Completion of the proposed investments will enable the company to make future investments through Distribution Automation. Existing construction does not allow for the installation of electronic reclosers. Improved pole spacing as a result of this project will permit the installation of reclosers on both BR1351 and BR1177 along Breckenridge Lane. This project will be completed as part of the Distribution Automation program following the completion of the proposed investments. All other Breckenridge distribution circuits were completed in 2017. Estimated reliability improvements from the implementation of DA on this circuit will be 68,170 CMI and 1,056 CI annually at an estimated cost of 180k. Completing DA on BR1177 and BR1351 is only possible following the completion of the proposed reconductor project. A portion of the benefits from this project were included in the Do Nothing NPVRR calculations.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $1,078
  2. Alternative #1 (Do Nothing): NPVRR: ($000s) $1,289
     The cost of "do nothing" is based on the value gained by reducing average annual circuit outage duration. Using the corporate "cost of unserved energy" ($17.2/kWh), the value of reducing outage duration (CMI) based on average circuit loads is $72k in 2019, escalated annually.

**Project Description**

- **Project Scope and Timeline**

The LGE EDO Electric Distribution Design group has completed the engineering design. Existing contractor resources will be assigned following the approval of the project and existing EDO construction blanket contracts and resources will be used. Project will be scheduled following project approval.

- **Project Cost**

Total project costs are $850k which includes a 10% contingency.
Project will be funded from 2018 LGE System Hardening Reliability Project (153006), which was approved by the April 2018 Corporate RAC.

**Economic Analysis and Risks**

- **Bid Summary**

Field construction work will be completed under existing contracts with overhead distribution line business partners. All required materials will be procured using established materials contracts.

- **Budget Comparison and Financial Summary**

| Financial Detail by Year - Capital ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 758 | | | | 758 |
| 2. Cost of Removal Proposed | 92 | | | | 92 |
| 3. Total Capital and Removal Proposed (1+2) | 850 | - | - | - | 850 |
| 4. Capital Investment 2018 BP | - | | | | - |
| 5. Cost of Removal 2018 BP | - | | | | - |
| 6. Total Capital and Removal 2018 BP (4+5) | - | - | - | - | - |
| 7. Capital Investment variance to BP (4-1) | (758) | - | - | - | (758) |
| 8. Cost of Removal variance to BP (5-2) | (92) | - | - | - | (92) |
| 9. Total Capital and Removal variance to BP (6-3) | (850) | - | - | - | (850) |

| Financial Detail by Year - O&M ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | | | | | - |
| 2. Project O&M 2018 BP | | | | | - |
| 3. Total Project O&M variance to BP (2-1) | - | - | - | - | - |

The EDO 2018 BP includes a Circuit Hardening and Reliability program budget, which the funding for this project was reallocated from during the April RAC process.

**Financial Summary ($000s):**

| | |
|---|---|
| Discount Rate: | 6.58% |
| Capital Breakdown: | |
| Labor: | $ 0 |
| Contract Labor: | $ 637 |
| Materials: | $ 63 |
| Local Engineering: | $ 56 |
| Burdens: | $ 17 |
| Contingency: | $ 77 |
| Reimbursements: | ($ 0) |
| Net Capital Expenditure: | $ 850 |

- **Assumptions**
  The CEM model used the cost of unserved energy for the “Do Nothing” alternative NPVRR. Useful life of the project is 30 years.

- **Environmental**
  There are no environmental issues associated with this project.

- **Risks**
  Delaying this investment will result in further deterioration of the copper conductor and will result in more frequent conductor failures and electrical service interruptions resulting in decreased customer satisfaction and increased customer complaints.

**Conclusions and Recommendation**

It is recommended that BR1351 Circuit Hardening Project be approved the Breckenridge for $850k. The hardening of this circuit will resolve ongoing reliability and restoration issues.

**Investment Proposal Project 134198 Canal-Del Park Conductor Replacement**

Investment Proposal for Investment Committee Meeting on: July 31, 2018

Project Name: Canal-Del Park Conductor Replacement

Total Expenditures: $8,089k
Total Contingency: $737k (10%)

Project Number(s): Transmission Lines - 134198
Distribution Operations – 157697

Business Unit/Line of Business: Transmission Lines/Distribution Operations

Prepared/Presented By: John Doll/Adam Smith

**Executive Summary**

The proposed project is to replace 2.84 miles of overhead transmission line conductor that is over 60 years old and beyond its expected useful life. Performance of this line has diminished, with the most recent wire failure occurring in 2011 from a failed static. Over 3,700 customers with a peak load over 11 MVA are served by the facilities being replaced, with the largest customer being Reynolds Foil, Inc. This project will improve reliability, maintain system integrity, and reduce the risk of failures and unplanned transmission interruptions to the Del Park, Falls City, Shawnee, and Vermont areas of Louisville, Kentucky.

A Transmission System Improvement Plan was submitted as support in the 2016 Rate Case, outlining programs and projects aimed at reducing the risk of failure, avoiding extended sustained outages, and limiting costly emergency repairs. The programs submitted with the plan were selected to ensure long-term system integrity and modernize the transmission system to avoid degradation of performance over time due to aging infrastructure. Replacement of overhead wires beyond or approaching their expected useful lives were included as part of the Transmission System Improvement Plan to replace aging infrastructure.

Transmission Lines plans to replace the 2.84 mile 69kV line between the Canal and Del Park substations with aluminum conductor steel-reinforced (ACSR) conductor and the deteriorating 3/8" HS static wire will be replaced with optical ground wire (OPGW). In addition, sixty-seven (67) wood structures will be replaced with new steel structures, two (2) lattice towers will be replaced with new steel structures, and seven (7) existing steel structures will remain. Distribution Operations will transfer distribution equipment along this route from the existing to new transmission structures.

The total project cost is $8,089k ($6,805k Transmission Lines, $1,284k Distribution Operations). This project was included in the 2018 Business Plan (BP) for $3,500k, with estimated spend of $200k in 2018, $2,663k in 2019, and $637k in 2020. This was a preliminary estimate based on "per mile" costs for similar past projects. This estimate did not include the installation of eight drilled shaft foundations or the replacement of a double circuit lattice tower within the constrained space near the Canal substation. The need for this work was determined only after a detailed engineering analysis. Additionally, multiple adjustments in the alignment were made to facilitate construction and improve the configuration of this circuit for future accessibility and maintenance, including minimizing the footprint of the circuit within railroad right of way.

The current total project cost is $8,089k, with estimated spend of $662k in 2018, $6,808k in 2019, and $619k in 2020. The 2018 spend was approved by the RAC in the 6+6 forecast. The 2019-2020 spend is consistent with the proposed 2019 BP.

**Background**

The existing 2.84 mile section of 69kV line between Canal and Del Park contains aging 4/0 copper conductor which dates back to 1955 and has experienced diminishing performance in recent years. Similar copper conductors with 60+ years of service life often have sections with broken conductor strands and significant corrosion at the clamps where the conductor attaches to the structure. Furthermore, multiple static and cross arm failures have occurred in recent years, causing significant damage to the already brittle and aged wire. The most recent event occurred in 2018 due to a cross arm failure.

Due to the condition of this line, there is risk for additional failures that will expose the transmission network to further unscheduled outages. The following pictures are representative of the 4/0 conductor, static, and cross arm conditions on sections of this line.

The first picture shows conductor damaged by a static failure, there are multiple instances of this along this circuit. The second picutre depicts a fractured crossarm and is representative of most structures along this route.

The aging conductor will be replaced with aluminum conductor steel-reinforced (ACSR) conductor and the deteriorating 3/8" HS static wire will be replaced with OPGW (optical ground wire). In addition, new steel structures will be installed in place of existing wood structures. A Comprehensive Visual Inspection was completed on this line in 2016. From this inspection, two

(2) structures were found to be in need of replacement. The two (2) structures found during inspection will be addressed as part of this project.

In January of 2018, the transmission project was opened for detailed design. The detailed engineering identified underground utilities at strategic locations along the route to facilitate structure placement and foundation design. Soil borings were also taken to provide geotechnical reports to support design of the drilled shaft foundations. In addition, plats were provided for the properties adjacent to the railroad to assist with easement acquisition and permitting. The transmission line design was provided to all departments involved for comment and review.

Additional easements are required along the southernmost section of this circuit, namely the three spans closest to the Del Park substation. The existing structures are double circuited wood poles. This configuration will be replaced with steel poles on davit arms which allow for necessary energized working clearances in the future, and proper separation between conductors. Additional separation from the existing wood pole structures is required to allow the existing circuits to remain energized while this work is performed. In order to achieve this, the new alignment must be shifted to the north, beyond the existing easement. The Real Estate and Right of Way department indicates the easement acquisition is feasible and likely.

Furthermore, easements will be acquired for seven spans paralleling 32$^{nd}$ street between Alford Avenue and Rowan Street. Accessing this section of the circuit is difficult due to the proximity to the railroad right of way to the east and housing to the west. Homeowners have fenced in several properties in this section and have severely limited access to both transmission and distribution facilities as well as third party attachments. Easements at this location would grant LG&E improved access and allow construction and maintenance activities to be performed without requiring permission from the railroad.

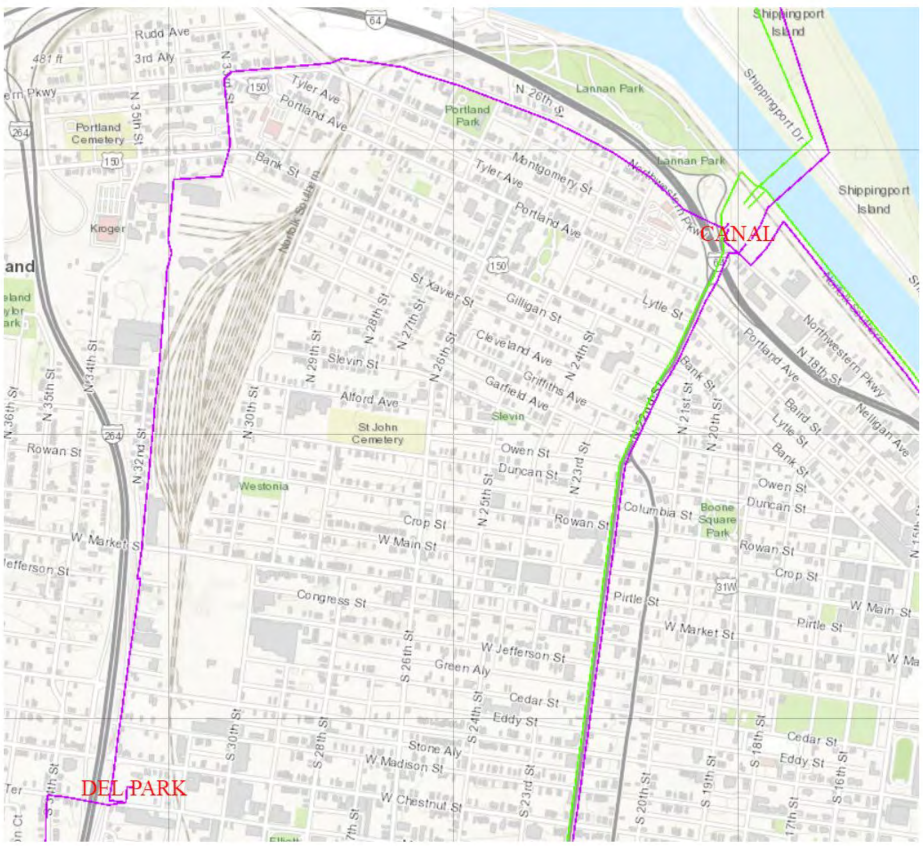
This project also includes a supporting project from Distribution Operations. Distribution Operations plans to transfer distribution equipment from the existing to new transmission structures.

- **Alternatives Considered**
    1. Recommendation: NPVRR: ($000s) $9,575
       The recommendation is to replace 2.84 miles containing 4/0 copper with new ACSR conductor, and the existing 3/8” static wire with new OPGW. In addition, 67 wood structures will be replaced with new steel structures, two lattice towers will be replaced with new steel structures, and seven existing steel structures will remain.

    2. Alternative #1: Do Nothing NPVRR: ($000s) N/A
       This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan that was filed as support in the 2016 Rate Case and assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

3. Alternative #2 – Construct Alternate Route: NPVRR: ($000s) $9,740
   The next best alternative would be to construct a new 2.5 mile transmission line which would provide an alternate route beginning at structure 1 and would parallel the line along different roadways for 2.5 miles. Constructing a new route would require the purchase of 2.5 miles of new right of way that customers may not be willing to sell. Selecting a new route for this alternative would likely cause project delays and result in community concerns and opposition over the new route.

**Project Description**
Recommendation – Canal-Del Park Conductor Replacement Facility Map




- **Project Scope and Timeline**
  **Transmission Lines Project Description – Project 134198**
  The Transmission Lines project involves the upgrade of 2.84 miles of existing conductor with ACSR and existing static wire with OPGW between the Canal and Del Park 69kV line. This project also involves the replacement of 67 existing wood structures with new steel structures, and the replacement of two lattice towers.

Transmission Lines Project Scope and Timeline

| | |
|---|---|
| Design Start | January 2018 |
| Design Complete | June 2018 |
| Space reserved for steel pole production with manufacturer | July 2018 |
| Materials Delivered | January 2019 |
| Construction Start | April 2019 |
| Facility In-Service | July 2019 |
| Permit Close Out / Project Completion | February 2020 |

**Distribution Operations Project Description – Project 157697**
Distribution Operations plans to transfer distribution equipment to the new transmission structures. In addition, Distribution Operations plans to replace existing cross-arms, LB switches, transformers and capacitor banks.

Distribution Operations Project Scope and Timeline

| | |
|---|---|
| Design Start | February 2018 |
| Design Complete | January 2019 |
| Materials Ordered | 1st Quarter 2019 |
| Materials Delivered | 1st Quarter 2019 |
| Construction Start | 1st Quarter 2019 |
| Construction Finish | December 2019 |

- **Project Cost**

| | Transmission Lines | Distribution Operations | Total |
|---|---|---|---|
| Total 2018 | $662k | $0k | $662k |
| Total 2019 | $5,524k | $1,284k | $6,808k |
| Total 2020 | $619k | $0k | $619k |
| Contingency | 10% | 10% | |

**Economic Analysis and Risks**

- **Bid Summary**
  **Transmission Lines**

Based on detailed engineering, Transmission Lines has estimated the material package for this project to be $868k. The project will utilize conductor, OPGW, custom steel structures, standard steel structures, and material. The OPGW will be purchased through AFL. The conductor will be competitively bid through normal Supply Chain processes. The line construction will be based on continuing contracts with our line contractors. B&B Electric, Davis H. Elliot, William E. Groves and Pike Electric are the four contractors awarded the Transmission Overhead Construction and Maintenance contract from the October 2011 Investment Committee (IC) meeting. The contract extension was re-approved by the IC in April of 2017.

**Distribution Operations:**

Distribution Operations line relocation will be performed by company labor (no bids required).

- **Budget Comparison and Financial Summary**

| Financial Detail by Year - Capital ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 662 | 5,352 | 619 | - | 6,632 |
| 2. Cost of Removal Proposed | - | 1,457 | - | - | 1,457 |
| 3. Total Capital and Removal Proposed (1+2) | 662 | 6,808 | 619 | - | 8,089 |
| 4. Capital Investment 2018 BP | 200 | 2,047 | 637 | | 2,885 |
| 5. Cost of Removal 2018 BP | | 616 | - | | 616 |
| 6. Total Capital and Removal 2018 BP (4+5) | 200 | 2,663 | 637 | - | 3,500 |
| 7. Capital Investment variance to BP (4-1) | (462) | (3,304) | 18 | - | (3,747) |
| 8. Cost of Removal variance to BP (5-2) | - | (841) | - | - | (841) |
| 9. Total Capital and Removal variance to BP (6-3) | (462) | (4,145) | 18 | - | (4,589) |

| Financial Detail by Year - O&M ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | - | - | - | - | - |
| 2. Project O&M 2018 BP | - | - | - | - | - |
| 3. Total Project O&M variance to BP (2-1) | - | - | - | - | - |

Discount Rate: 6.59%
Capital Breakdown:

| | 148857 Trans Lines | 157697 Dist Ops | Total |
|---|---|---|---|
| Labor | $341k | $0k | $341k |
| Contract Labor | $3,680k | $910k | $4,590k |
| Materials | $868k | $144k | $1,012k |
| Local Engineering | $904k | $84k | $988k |
| Burdens | $391k | $28k | $419k |
| Contingency | $619k | $118k | $737k |
| Other | $2k | $0 | $2k |
| Reimbursements | $0 | $0 | $0 |
| Net Capital Expenditure | $6,805k | $1,284k | $8,089k |

- **Assumptions**
  Recommendation - This assumes that the 2.84 miles of existing conductor will be replaced with ACSR and the existing static wire will be replaced with OPGW. An outage must be obtained to complete the project and is scheduled for 2019. This also assumes that all highway and railroad crossing permits will be granted by the Kentucky Transportation Cabinet (KYTC), and associated railroads. It is anticipated that no customers will be out of service for the duration of this work.

  Alternative #1 – Do Nothing - This option is not advisable as this line is nearing the end of its useful life and puts Transmission at risk of not being able to accomplish the objectives established as part of the Transmission System Improvement Plan, that was filed as support in the 2016 Rate Case, which assumed the completion of this project. These objectives include reducing the risk of failure, avoiding an extended sustained outage, and costly emergency repairs.

  Alternative #2 – Next Best Alternative – This alternative assumes that a new 2.5 mile transmission line would be constructed. This option would require additional funding due to the need to purchase 2.5 miles of new right of way, in which the property owners may not be willing to sell. The impacts associated with this option would be more disruptive and have a larger negative impact on the community during construction.

- **Environmental**
  There are no known environmental issues regarding air, water, lead, asbestos, etc., associated with this project.

- **Customer Experience**
  A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses along the route.

- **Risks**
  - Without the proposed replacement of the existing wire in the Canal-Del Park 69kV line, the company risks increased exposure to line outages. The wire along the 2.84 miles has deteriorated over time, and is beyond its expected useful life. There have been notable failures in the conductor's 60 year service life. Unplanned outages are often time-consuming and costly when it comes to repairs.
  - The Louisville Metro Department of Public Works requires permits for lane closures and flagging. The permit application will be submitted prior to construction. Lane closure permits are typically obtained in a timely manner from this agency to support our projects.
  - This project requires an easement acquisition from Bethel United Ministries, Inc. This easement has been informally agreed upon and is currently being processed for formal execution.
  - A Norfolk Southern railroad permit is required for a line segment being constructed over an existing crossing. The permit application was submitted in June 2018.

- The local community may react negatively to the work and potential inconvenience of the project. A communication plan is being developed in coordination with the project proponents, corporate communications, and external affairs. This plan will be executed to limit the impacts to the community and businesses.

**Conclusions and Recommendation**

It is recommended that the Investment Committee approve the Canal-Del Park Conductor Replacement project for $8,089k to improve the reliability of the electric transmission system.

**Approval Confirmation for Capital Projects Greater Than $2 million:**

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

| | | | |
|---|---|---|---|
| Kent W. Blake | Date | Paul W. Thompson | Date |
| Chief Financial Officer | | Chairman, CEO and President | |

Investment Proposal for Investment Committee Meeting on: October 25, 2017

Project Name: Distribution Automation (DA) and Distribution Management System (DMS)

Total Approved Expenditures: $ 14,122k (Approved on 12/19/2016)

Total Revised Expenditures: $ 112,170k

Project Number(s): DA – 154092, 154093; DMS – 154094, 154095, 154096

Business Unit/Line of Business: Electric Distribution Operations (EDO)

Prepared/Presented By: Steve Woodworth, Denise Simon

**Reason for Revision**

Electric Distribution Operations (EDO) Distribution Automation (DA) and Distribution Management System (DMS) Investment Proposal was approved by the Investment Committee on December 19, 2016 (see Appendix A). Through the Investment Proposal, EDO requested agreement with the overall $112,357k DA plan as well as specific capital funding authority of $14,122k from the Investment Committee, to enable execution of initial DA phases:

- $80k for communications preliminary engineering and design in 2016
- $800k for communications infrastructure in 2017
- $7,120k for recloser installations in 2017
- $6,122k for DMS in 2017 – 2019 ($2,500k in 2017, $2,922k in 2018, and $700k in 2019)

As part of the 2017 Rate Case, the Kentucky Public Service Commission (KPSC) approved a Certificate of Public Convenience and Necessity (CPCN) for EDO's DA Program. Based on this approval, EDO is now requesting full capital funding authority of $112,170k to enable full execution of the DA Program, through 2022. Funding authority for the entire program will provide needed flexibility to the project team as they manage the complex nature of field work that can be directly impacted by resource availability, local weather events, customer requests, and mutual assistance activities.

Movement of capital funds between years is a natural by-product of multi-year capital programs that are as complex as DA. The project team will continue to utilize the Project Steering Committee to review and approve funding deviations between years, and will work with the EDO and Corporate RAC to address “puts and takes” that will occur throughout the six-year program.

The requested $112,170k is slightly less than the $112,357k in the original proposal. The tables below provide details of changes in annual spend.

| | 2016/2017 | | 2018 | | 2019 | | 2020 | | 2021 | | 2022 | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| All $ in 000's | Original | Revised | Original | Revised | Original | Revised | Original | Revised | Original | Revised | Original | Revised | Original | Revised |
| Reclosers and Communications | $8,000 | $7,394 | $22,328 | $22,393 | $21,300 | $22,476 | $18,203 | $20,203 | $18,203 | $20,202 | $18,201 | $12,201 | $106,235 | $104,869 |
| DMS / DSCADA | $2,500 | $2,920 | $2,922 | $2,857 | $700 | $1,524 | - | - | - | - | - | - | $6,122 | $7,301 |
| Total | $10,500 | $10,314 | $25,250 | $25,250 | $22,000 | $24,000 | $18,203 | $20,203 | $18,203 | $20,202 | $18,201 | $12,201 | $112,357 | $112,170 |
| Distribution SAIFI Reduction | 1.0% | 1.6% | 1.9% | 2.2% | 10.7% | 6.9% | 2.2% | 6.7% | 1.4% | 0.8% | 1.4% | 0.5% | 18.6% | 18.7% |
| Distribution SAIDI Reduction | 0.4% | 0.9% | 1.2% | 1.3% | 6.7% | 4.2% | 1.5% | 4.4% | 1.1% | 0.7% | 1.0% | 0.4% | 11.9% | 11.9% |

| All $ in 000's | Original | Revised | Variance | Reason for Change |
|---|---|---|---|---|
| **Reclosers and Communications** | $ 106,235 | $ 104,869 | $ (1,366) | 1) Reclosers are now being delivered with communications equipment pre-installed by the manufacturer resulting in all communications costs being embedded in the total cost of the reclosers. 2) Reduction in contingency by $1,179k to provide additional funding for DMS/DSCADA. This reduction will not impact the number of recloser installations identified in the original IP. With this reduction, recloser contingency is $9,500k. 3) Change in burden rate lowered 2017 costs ($187k). |
| **DMS / DSCADA** | $ 6,122 | $ 7,301 | $ 1,179 | 1) Change in scope for integration to the Transmission Energy Management System (EMS). The solution requires additional hardware ($406k), software ($267k), vendor services ($98k), and internal labor ($300k). 2) Additional cost for testing ($108k). |
| **Total** | **$ 112,357** | **$ 112,170** | $ (187) | 1) Change in burden rate lowered 2017 costs ($187k). |

## Financial Summary

| **Financial Summary ($000s):** | **Approved** | **Revised** |
|---|---|---|
| Discount Rate: | 6.5% | 6.32% |
| Capital Breakdown: | | |
| Labor: | $2,000 | $11,373 |
| Contract Labor: | $3,676 | $34,541 |
| Materials: | $3,812 | $36,452 |
| Local Engineering: | $1,281 | $7,881 |
| Burdens | $1,605 | $12,424 |
| Contingency: | $1,748 | $9,499 |
| Reimbursements: | ($0) | ($0) |
| Net Capital Expenditure: | $14,122 | $112,170 |
| NPVRR: | $122,722 | $131,429 |

The capital breakdown originally approved was for 2017-2019 for DMS and 2016-2017 for DA; however the NPVRR calculation reflected the full DA program costs and benefits. The capital for the full program in the original document was $112,357k.

| Financial Detail by Year - Capital ($000s) | 2017 | 2018 | 2019 | Post 2019 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 10,314 | 25,250 | 24,000 | 52,606 | 112,170 |
| 2. Cost of Removal Proposed | - | - | - | - | - |
| 3. Total Capital and Removal Proposed (1+2) | 10,314 | 25,250 | 24,000 | 52,606 | 112,170 |
| 4. Capital Investment 2018 BP | 10,314 | 25,250 | 24,000 | 52,606 | 112,170 |
| 5. Cost of Removal 2018 BP | - | - | - | - | - |
| 6. Total Capital and Removal 2018 BP (4+5) | 10,314 | 25,250 | 24,000 | 52,606 | 112,170 |
| 7. Capital Investment variance to BP (4-1) | - | - | - | - | - |
| 8. Cost of Removal variance to BP (5-2) | - | - | - | - | - |
| 9. Total Capital and Removal variance to BP (6-3) | - | - | - | - | - |

| Financial Detail by Year - O&M ($000s) | 2017 | 2018 | 2019 | Post 2019 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | 213 | 1,096 | 1,234 | 2,655 | 5,198 |
| 2. Project O&M 2018BP | 212 | 1,086 | 1,213 | 2,549 | 5,060 |
| 3. Total Project O&M Variance to BP (2-1) | (1) | (10) | (21) | (106) | (138) |

The incremental O&M is associated with telecommunications costs that were not included in the 2018 BP; however, they will be covered through the EDO RAC process.

**Conclusions and Recommendation**

EDO recommends Investment Committee approval of the Distribution Automation and Distribution Management System project for $112,170k. The funding requested in this revised proposal will provide for installation of electronic SCADA connected reclosers and deployment of the DMS and DSCADA systems. The overall DA program is projected to improve SAIDI by 11.9%, and SAIFI by 18.7%.

**Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:**

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

| | |
|---|---|
| Kent W. Blake<br>Chief Financial Officer | Paul W. Thompson<br>President and Chief Operating Officer |

Victor A. Staffieri
Chairman and Chief Executive Officer

## Template for Revised Capital Investment Proposal

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: LG&E Downtown Network Vault Structural Repairs Project 2018

Total Approved Expenditures: $1,231k (Approved on 1/22/2018)

Total Revised Expenditures: $1,731k

Project Number(s): 148898

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jason Tipton

### Reason for Revision

Electric Distribution Operations (EDO) is authorized to invest $1,231k during 2018 towards continuation of its Downtown Network Vault Structural Repairs Program. The program was initiated in 2017 to address aged, defective, and deteriorating network vault structural assets that have been identified through PSC mandated inspections.

A structural engineering firm has been engaged to evaluate and prioritize repairs across the roughly 200 vault structures in the downtown network area in Louisville. Through this prioritization process, three network vaults had been initially identified for significant structural repairs in 2018 due to deficiencies that were found. These vaults are: Greater Louisville Vault, Brown Office Bldg Vault, and Kentucky Towers Vault. Since the 2018 project was approved, two more vaults (Lincoln Bank Vault and Galleria Towers Vault) have needed emergency repairs. Both vaults were already on the vault repair prioritization list but needed to be escalated due to accelerated deterioration of the vault tops.

While crews were performing a PSC inspection of Lincoln Bank Vault, it was observed that the condition of the roofing structure had significantly worsened since the initial evaluation, and a street plate was placed on the damaged top for public safety until repairs were completed. During PILC project work in the Galleria Towers Vault, it was discovered that two transformers in the vault had damaged high side compartments resulting in replacement of both transformers. Unfortunately, the vault slabs were rusted in such a manner that the slab could not be removed without cutting the vault top to replace these transformers. The additional $500k requested will cover the cost of the additional two vault top replacements that were not in the original scope of work.

**Financial Summary**

| Financial Summary ($000s): | Approved | Revised | Explanation |
|---|---|---|---|
| Discount Rate: | 6.58% | 6.59% | |
| Capital Breakdown: | | | |
| Labor: | $ 69 | $ 85 | |
| Contract Labor: | $ 626 | $ 900 | Additional vault tops needing replacement, not included in original scope of work |
| Materials: | $ 345 | $ 485 | Additional vault tops needing replacement, not included in original scope of work |
| Local Engineering: | $ 94 | $ 140 | |
| Burdens: | $ 97 | $ 121 | |
| Contingency: | $ 0 | $ 0 | |
| Reimbursements: | ($ 0) | ($ 0) | |
| Net Capital Expenditure: | $1,231 | $1,731 | See above. |
| NPVRR: | $1,568 | $2,195 | |

| Financial Detail by Year - Capital ($000s) | Pre-2018 | 2018 | 2019 | Post 2019 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | - | 1,731 | - | - | 1,731 |
| 2. Cost of Removal Proposed | - | - | - | - | - |
| 3. Total Capital and Removal Proposed (1+2) | - | 1,731 | - | - | 1,731 |
| 4. Capital Investment 2018 BP | - | 1,231 | - | - | 1,231 |
| 5. Cost of Removal 2018 BP | - | - | - | - | - |
| 6. Total Capital and Removal 2018 BP (4+5) | - | 1,231 | - | - | 1,231 |
| 7. Capital Investment variance to BP (4-1) | - | (500) | - | - | (500) |
| 8. Cost of Removal variance to BP (5-2) | - | - | - | - | - |
| 9. Total Capital and Removal variance to BP (6-3) | - | (500) | - | - | (500) |

| Financial Detail by Year - O&M ($000s) | Pre-2018 | 2018 | 2019 | Post 2019 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | - | - | - | - | - |
| 2. Project O&M 2018 BP | - | - | - | - | - |
| 3. Total Project O&M Variance to BP (2-1) | - | - | - | - | - |

The incremental funding was approved through the August EDO RAC process.

**Conclusions and Recommendation**
EDO recommends approval of the LG&E Downtown Network Vault Structural Repairs Project for $1.731M in 2018 in order to ensure the ongoing operating reliability and safety of the Downtown Louisville Network.

Investment Proposal for Investment Committee Meeting on: October 25, 2017

Project Name: KU SCADA Expansion Project

Total Expenditures: $16,989k (including contingency of $1,544k)

Project Number(s): 155975

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Tony Durbin/Ray Connolly/Dan Hawk

**Executive Summary**

Electric Distribution Operations (EDO) seeks funding authority of $16,989k over the next four years to expand Supervisory Control and Data Acquisition (SCADA) capability in the Kentucky Utilities and Old Dominion Power service territories through upgrading, retrofitting and replacing distribution substation assets. Benefits of this program include:

- Expected System Average Interruption Duration Index (SAIDI) improvement of 3.43 minutes.
- Increased functionality and situational awareness for Distribution Control Center (DCC).
- Leveraging DMS fault locating capability resulting in faster response times and improved utilization of Company resources.
- Immediate system operator response to 911, public safety, fire and police emergencies.
- Enhanced safety functionality for Company and contract personnel performing live line maintenance.
- Real-time capabilities for data collection of substation loading to be used in real-time operations and long-term system planning.
- Up to an estimated $50k/yr. avoided annual costs.

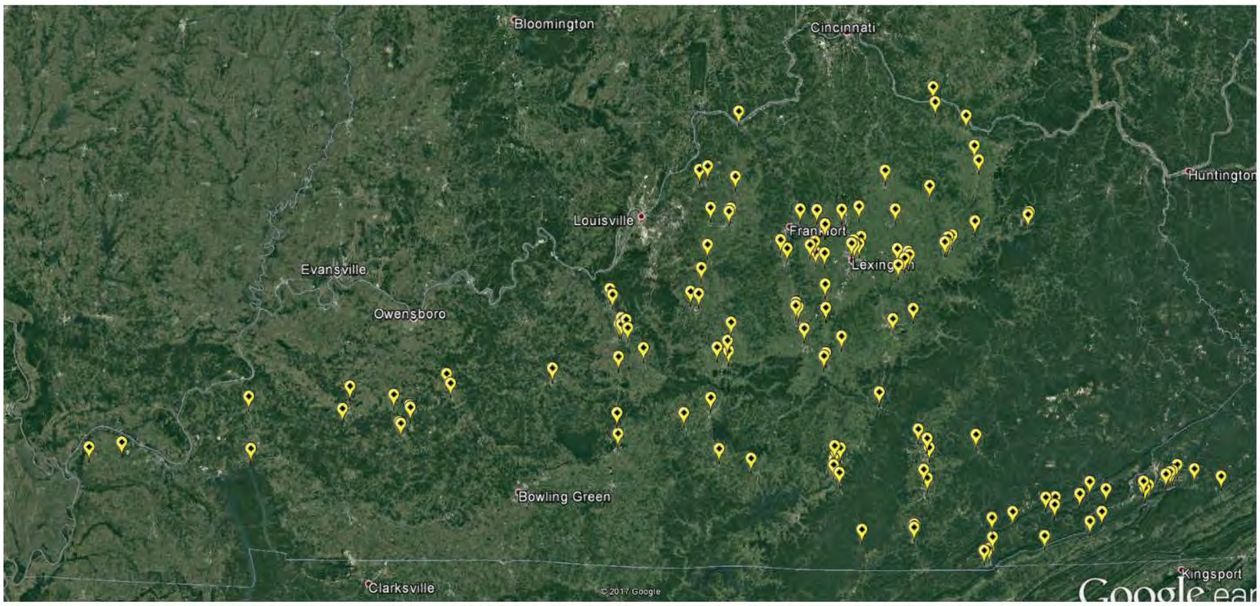
This project's main focus is to bring SCADA capabilities to distribution substations. This will be accomplished primarily through the replacement of 170 power circuit breakers and 160 electromechanical relay packages and the retrofit of 100 circuits with communications equipment. Legacy electromechanical relays lack features enabling alarming, fault data, diagnostics, supervisory control, and as a mechanical device, require routine periodic on-going maintenance. The relay upgrade will include a pre-configured "Relay in a Box" solution which will reduce periodic maintenance requirements, enable system operations with SCADA, and provide the necessary fault data to achieve pinpointed and timely service restoration.

It is considered "good utility practice" for electrical system operators to deploy SCADA technology to manage the electrical infrastructure, protect the public, and to minimize customer exposure to outages. The KU service territory is significantly lacking such operational capabilities.

The proposed 2018 Business Plan (BP) includes $17,063k for this project.

**Background**

For comparison, LG&E has a total of 538 feeders, with 454 having SCADA capability while KU and ODP have a total of 1,108 feeders, with 215 having SCADA capability. These KU and ODP circuits, spread across 73 substations, currently account for approximately 175,000 customers or 30% of the customer base. This program aims to add SCADA capabilities to 129 additional substations, resulting in 260,000 additional customers. At the end of this program, 75% of KU and ODP customers are expected to be connected to the Distribution Management System (DMS) via substation SCADA. Criteria was developed to rank and prioritize stations based on customers connected and loading of the station. Since the intent of the project is to reach as many customers as possible, stations with <500 customers were removed from the scope of this project. A map of the proposed locations is shown below.




SCADA functionality and visibility brings an array of operational, reliability, and safety capabilities. This includes better situational awareness by the Distribution Control Center (DCC) operators, more efficient use of company resources in day-to-day operations, and increased reliability through quicker fault locating and restoration time. This project will involve many departments and organizations, as well as deliver many benefits across the Company. Benefits include:

- *Efficient Operations:* Expanded SCADA functionality in KU substations provides DCC and field resources with the ability to know the status of station breakers quickly during an emergency, after an interruption, and during normal operations. The microprocessor relays that will be installed in substations will allow control center operators to identify possible fault locations through the use of the Distribution Management System (DMS). Field personnel will then be directly dispatched to the trouble area identified, leading to faster restoration times and more efficient use of field resources. These efficiencies are estimated to reduce entire circuit outages by 30 minutes on average. DCC operators will also be able to control breakers and components like reclosers from the control center, reducing the need for crews to visit the substation before and after performing live line work. Additionally, the feature rich microprocessor relaying will provide alarming and diagnostics data to system operations. Of significance is battery monitoring and alarming, which today is unavailable and places stations at significant risk for breaker failure operation and total loss of a station.

- *Emergency Response:* With the ability to remotely control substation assets, system operators will be able to quickly respond in times of emergency (e.g. 911 calls) and coordination during the restoration of a Transmission outage – providing for better public safety and equipment protection. This is a very valuable benefit, as today's response to such events is time consuming and requires dispatching a person physically to the substation(s) to de-energize equipment.

- *Enhanced Safety:* The upgraded relays also bring a unique feature that enhances the safety for Company and contract crews performing live line maintenance. These advanced relays offer a "Hot Line Tag" (HLT) feature that goes above and beyond our current practices for protecting line crews at the circuit breaker. The HLT option, when enabled, makes the device more sensitive to faults such that clearing times are faster to potentially reduce impacts of arc flash situations.

- *System Data:* Capturing data will enhance Distribution's and Transmission's abilities to analyze real-time situations and have the best information to make decisions. For Distribution, circuit loading data will provide the operator information to know if an overload is occurring and/or other circuit's conditions in the area if action is required. Transmission Operations will benefit from additional system data to further improve State Estimator and Power Flow results – two analyses that drive operator action on the transmission system. System data will also be extremely beneficial for Distribution Planning to compare and optimize planning models with the real circuit data, aiding in capital project prioritization.

In addition to the benefits listed above, the advancement of SCADA capabilities into the KU and ODP service territories is a major step to advancing the distribution system in terms of technology and preparing for future changes. Many utilities all across the country are facing challenges with distributed resources and grid modernization efforts. While these challenges are not impacting Kentucky today, SCADA expansion will better prepare the companies to handle these issues as they arise.

The proposed program will have a monthly telecommunications cost. The project is expected to cost $22k per year once fully implemented. This cost is the data usage for the devices to communicate information with the DSCADA system. Alternatives were considered to aggregate information at the substation and bring back fewer communications channels, however, current technology options eliminated this option and increased security risks through local wireless connections.

The majority of the circuits that will be retrofitted for SCADA capability currently utilize legacy electromechanical relays and breakers. These assets cannot provide the desired capabilities and require additional maintenance compared to newer relays and breakers. EDO has evaluated assets associated with the targeted circuits for SCADA expansion. This evaluation drove a three tier approach to the program implementation:

1. For an identified circuit that is protected by a circuit breaker that was manufactured prior to 1980, it was determined any capital improvement of this device was unjustified. These assets are near end of life and would be better suited for complete replacement with upgraded relays. Replacing these breakers is also estimated to avoid periodic maintenance costs of $75k over the next ten years. 170 circuits were identified as part of the program that meet this criteria.
2. A key driver to this program is to implement microprocessor relays in order to obtain full SCADA capabilities. Replacing electromechanical relays, along with breaker upgrades, will avoid overall relay maintenance expenses by an estimated $37k per year once the program is fully implemented. In 2006, the Distribution Substation specification for substation circuit breakers was revised to standardize on microprocessor relays. Due to this change, circuits with breakers that were manufactured between 1980 and 2006 are determined to still have substantial useful life and a relay upgrade would be all that is needed to implement SCADA. The “Relay in a Box” solution was determined to be the least cost solution. 160 circuits were identified as part of the program that meet this criteria.
3. Lastly, breakers installed after 2006 contain the desired microprocessor relays to meet the objectives and deliver the benefits of this program. These breakers will be retrofitted with Calamp radios to deliver SCADA capabilities. 100 circuits were identified as part of the program that meet this criteria.

**Alternatives Considered**

1. Recommended option: NPVRR ($000s): $19,000
   Implement the KU SCADA Expansion program.

2. Alternative #1: Current Replacement Plan NPVRR ($000s): $24,412
   The choice to not implement the recommended KU SCADA program results in a continued capital spend requirement of $10M+ over the next 20 years under current proactive replacement strategies. KU and ODP have over 250 breakers in service today that are between 40 and 70 years old and nearing end of life. Under the current replacement strategies, these breakers will be prioritized and replaced over the next 20 years. The Company cannot expect significant improvement in outage restoration times on non-SCADA equipped stations without these expanded capabilities, resulting in an expected decline in customer satisfaction and an estimated cost of unserved energy of $1.2M/yr once fully implemented (escalated each year). On-going relay and breaker maintenance costs will also be required to address aged assets until they are replaced in later years under current programs. This alternative does not align with EDO’s strategy to address aged assets, nor promote reliability improvements through advanced grid intelligence and system controls.

**Project Description**

- **Project Scope and Timeline**

| | |
|---|---|
| 2017/18 | Preliminary engineering and detailed scope development. |
| 2018 | Select EPCM contractor and secure material contracts. |
| 2018 | Complete SCADA installations at 6 substations |
| 2019 | Complete SCADA installations at 26 substations |
| 2020 | Complete SCADA installations at 47 substations |
| 2021 | Complete SCADA installations at 50 substations |

- **Project Cost**
  The total estimated cost of the program is $16,989k. The costs used in the estimates are consistent with actual average costs for proactive breaker replacement in 2017 as well as PPL's actual costs to implement the "Relay in a Box" solution with adjustments to account for construction differences. A 10% contingency is incorporated into the project cost estimates.

**Economic Analysis and Risks**

- **Bid Summary**
  - For material, a new Sole Source Agreement with Schweitzer Engineering Laboratories (SEL) is being submitted for Investment Committee approval for the "Relay in a Box" solution. Other material will be purchased utilizing existing purchase agreements that will be amended to account for this program.
  - For installation labor, the plan is to utilize the existing Substation Construction Contracts (recently rebid and approved by the IC in August 2017 for $28M over 5 years). The contracts in this award include: Davis H. Elliot, G&G Utility, and Chu-Con, William E. Groves, CE Power, R&K Contracting, Doss and Horky, Bray Electric, and M. Bowling. After the first year, we may take a look at rebidding the work to the most productive contractors based on a unit cost pricing model.
  - For engineering, the plan is to utilize the existing EPCM (Engineering, Procurement, and Construction Management) contracts for distribution (awarded in February 2017 for $9.4M over 5 years) which include the following: B&M, S&L, Mesa, UCS, and Primera. We may also look at utilizing some other regional Engineering firms on a limited basis to minimize travel/site surveying costs.

**Budget Comparison and Financial Summary**

The 2018 BP contains funding to meet the level of this project. The $46k variance from the BP in 2018 will be reallocated from the 2018 Danville Legacy Breaker project that is within EDO's BP. The incremental telecommunications costs in O&M were not included in the 2018 BP and will be covered through the EDO RAC process.

| Financial Detail by Year ($000s) | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 893 | 3,325 | 5,031 | 5,100 | 14,349 |
| 2. Cost of Removal Proposed | 168 | 616 | 928 | 928 | 2,640 |
| 3. Total Capital and Removal Proposed (1+2) | 1,061 | 3,941 | 5,959 | 6,028 | 16,989 |
| 4. Capital Investment 2018 BP | 1,015 | 4,045 | 6,003 | 6,000 | 17,063 |
| 5. Cost of Removal 2018 BP | - | - | - | - | - |
| 6. Total Capital and Removal 2018 BP (4+5) | 1,015 | 4,045 | 6,003 | 6,000 | 17,063 |
| 7. Capital Investment variance to BP (4-1) | 122 | 720 | 972 | 900 | 2,714 |
| 8. Cost of Removal variance to BP (5-2) | (168) | (616) | (928) | (928) | (2,640) |
| 9. Total Capital and Removal variance to BP (6-3) | (46) | 104 | 44 | (28) | 74 |

| Financial Detail by Year - O&M ($000s) | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | 1 | 4 | 9 | 17 | 31 |
| 2. Project O&M 2018 BP | - | - | - | - | - |
| 3. Total Project O&M variance to BP (2-1) | (1) | (4) | (9) | (17) | (31) |

**Financial Summary ($000s):**

| | |
|---|---|
| Discount Rate: | 6.32% |
| Capital Breakdown: | |
| Labor: | $ 704 |
| Contract Labor: | $ 5,629 |
| Materials: | $ 6,272 |
| Transportation: | $ 8 |
| Local Engineering: | $ 1,514 |
| Burdens: | $ 1,318 |
| Contingency: | $ 1,544 |
| Reimbursements: | ($ 0) |
| Net Capital Expenditure: | $16,989 |

- **Assumptions**
  - Estimates are based on bids received from EPCM contractors in 2017.
  - EPCM contractors will be utilized to complete the entire project scope.
  - EPCM will coordinate design and build, requiring minimal company resources.

- **Environmental**
  This project will include replacement of select oil filled circuit breakers, reducing future environmental risk related to spills and contamination. It is likely these oil filled circuit breakers contain PCB levels above acceptable levels and will require special disposal.

**Risks**

- The estimates are based on engineering and installation averages of breaker replacement projects during 2017, PPL's actual costs to implement the "Relay in a Box" solution, and good engineering judgement. There is a cost risk since each substation is unique to some degree, driving construction and engineering costs to vary from site to site. This risk will be mitigated by detailed and accurate scope documents and continued review and revision (as needed) of the program cost expenditures.
- There is a potential risk in the wireless communication costs associated with each breaker. This project assumes a $4/month charge per circuit. An increase in this price will drive annual operating costs to increase. This risk can be mitigated through a reduction in data usage from each device. While not optimal, reducing polling frequencies and data transmitted can reduce costs while maintaining most functionality.
- This project modifies existing circuits, and there is always a risk of inadvertent outages for the customers served. This risk can be mitigated using good engineering and commissioning practices, detailed functional testing, and good project management.
- There is a possible schedule risk due to the number of circuits that need to be modified, installed, and tested. Depending on loading, the DCC could stagger the outages in such a way that seamless transition between substations will not occur. This risk can be mitigated by securing outages early in the year and involving the DCC earlier in the scheduling.

**Conclusions and Recommendation**

EDO recommends that the Investment Committee approve the KU SCADA Expansion program for $16,989k in order to improve efficiency and productivity, and continue to provide safe and reliable electric service to our distribution customers.

**Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:**

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

| | |
|---|---|
| Kent W. Blake<br>Chief Financial Officer | Paul W. Thompson<br>President and Chief Operating Officer |

Investment Proposal for Investment Committee Meeting on: February 28, 2018

Project Name: SCM Enhanced Substation Wildlife Protection

Total Expenditures: $5,180k

Project Number(s): 156330 (budget on 155293)

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jude Beyerle

**Executive Summary**

Electric Distribution Operations (EDO) proposes to secure capital funding for enhanced wildlife protection at 40 KU substations. From 2012-2017, wildlife was the single largest contributor to distribution substation level outages at KU, representing 38% of all SAIDI (System Average Interruption Duration Interval) at KU substations.

Wildlife protection is included in the design and construction of new and expanded distribution substations. However, EDO's current design practice was only formalized as of 2012, and numerous previously constructed KU distribution substations continue to utilize legacy standards that are sometimes less than adequate in providing the highest level of station protection. Primary wildlife threats to these stations include raccoons, squirrels, birds and snakes.

There are 471 KU substations with distribution facilities. Of these, 329 have some degree of wildlife protection and 142 have no wildlife protection. As previously noted, even those substations that have some level of existing wildlife protection are not secured at a standard necessary to provide enough protection to substantially impact the number and duration of interruptions.

Priorities for a substation’s inclusion in this project will include: history of past interruptions or repetitive interruptions, amount of load served, and SAIDI impact. Substations with some or no level of wildlife protection will be targeted by the project.

The 2018 Business Plan (BP) includes $510k in 2018, $1,250k in 2019, $1,700k in 2020 and $1,720k in 2021 for this project.

**Background**

From the period January 2012 to December 2017, KU experienced a total 17.06 minutes of SAIDI, or an average of 2.9 minutes per year of SAIDI impact from wildlife outages in distribution substations. This leading outage cause was the single largest contributor to KU distribution substation SAIDI by a factor of four above any other cause, and was higher than the next six causes combined.

For reference, the 20 most impactful wildlife outages from 2012 – 2017 were as follows:

| Date | Substation | Customer Count | Outage Minutes | SAIDI Minutes | Load (kW, estimated) | Animal |
|---|---|---|---|---|---|---|
| 5/6/2012 | Dawson Springs | 966 | 273 | 0.48 | 1900 | Bird |
| 10/7/2012 | Parker Seal | 2194 | 83 | 0.33 | 9700 | Raccoon |
| 3/23/2013 | Rockwell | 3122 | 70 | 0.40 | 17300 | Squirrel |
| 6/30/2013 | Stonewall | 5470 | 80 | 0.80 | 26600 | Squirrel |
| 8/13/2013 | Hamblin | 1499 | 128 | 0.35 | 5600 | Raccoon |
| 9/29/2014 | Sonora | 1854 | 169 | 0.57 | 4700 | Squirrel |
| 9/24/2014 | Reynolds | 3186 | 36 | 0.21 | 26600 | Squirrel |
| 1/9/2015 | London | 2632 | 102 | 0.49 | 10500 | Squirrel |
| 5/28/2015 | Wilson Downing | 5312 | 70 | 0.68 | 14000 | Squirrel |
| 6/19/2015 | Shavers Chapel | 2464 | 188 | 0.84 | 8000 | Snake |
| 6/30/2015 | Greenville | 1875 | 129 | 0.44 | 6300 | Bird |
| 9/21/2015 | Stonewall | 5492 | 67 | 0.67 | 28600 | Squirrel |
| 10/24/2015 | London | 2637 | 83 | 0.40 | 9700 | Squirrel |
| 8/16/2016 | Buena Vista | 1890 | 125 | 0.43 | 7100 | Squirrel |
| 8/28/2016 | Lansdowne | 6643 | 64 | 0.77 | 24700 | Squirrel |
| 9/27/2016 | IBM | 4082 | 54 | 0.40 | 18600 | Raccoon |
| 11/23/2016 | Stonewall | 5570 | 47 | 0.48 | 21800 | Squirrel |
| 12/24/2016 | East Bernstadt | 1224 | 261 | 0.58 | 9400 | Squirrel |
| 3/16/2017 | Bryant Road | 2785 | 55 | 0.28 | 15500 | Bird |
| 7/4/2017 | Alexander | 5442 | 74 | 0.73 | 15400 | Bird |

EDO formalized its internal wildlife protection design and construction standards in 2012. All distribution substations constructed or expanded since 2012 have been equipped with wildlife protection in accordance with these standards. This proposed investment will provide for the upgrade or installation of wildlife protection at KU distribution substations which were constructed prior to EDO's establishment of the new design and construction standards. The enhanced protection will address wildlife threats such as raccoons, squirrels, birds and snakes. Each species has unique motives and methods for intruding electrical substations, and optimizing protection against all threats may require overlapping protective schemes. The planned protection schemes will utilize solutions from leading suppliers including Midsun, Green Jacket, TE Connectivity and Vanquish.

Some of the largest substations in the Lexington area are of particular concern. These stations, including Stonewall, Wilson Downing, Alexander and Lansdowne have high customer counts (> 5,000) and, despite the addition of a level of wildlife protection at these locations in the mid 2000's, they continue to experience outages at an unacceptable rate.

The proposed project scope includes installation of enhanced substation protection at an estimated 40 substations where wildlife outages have had or can be expected to have the most substantial SAIDI impact in the future. The 40 substation locations have accounted for 15.5 minutes of SAIDI impact, or 91% of all distribution substation wildlife outages from 2012 to date. Substations were selected for the program based on their history of past interruptions or repetitive interruptions, amount of load served, and SAIDI impact.

LG&E substations are not a part of this initiative. LG&E substations largely use metalclad switchgear construction with underground exit cables for distribution. This provides a very effective wildlife barrier (see example construction photos). At LG&E, wildlife outages represent only 5% of SAIDI impact.


*Figure 1Metalclad Switchgear Indoor 12kV Bus Construction*


*Figure 2 KU Outdoor 12kV Bus Construction*

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing, 3 –Next Best Alt)**

1. Recommendation: NPVRR: ($000s) $29,192k

Install enhanced wildlife protection at approximately 40 KU distribution substations. The estimated total cost of this option is $5,180k.

With a focus on larger KU distribution substations with a history of wildlife outages, there is an estimated 50% reduction in wildlife related incidents at project completion, with a smaller, proportional benefit as the project progresses.

An analysis of 2012 – Dec 2017 wildlife outages for the 40 substations expected to be addressed by this initiative provides the following averages:

- 8 outages per year
- 112 minutes (1.87 hours)/per outage
- 10,200 kW interrupted load/per outage

A review of recent MxOrders and associated charges indicates a cost per outage for actual repair and clean-up is $8k, or $64k/per year for 8 wildlife outages per year.

With reference to the project scope and timeline; the calculation of the cost of unserved energy and repairs yield a total assumed cost of $57,713k:

- (8 outages) x (10,200 kW) x (1.87 Hours) x ($17.20/kW-Hr) + $64k = $2,689k per year, for 2018.

- (8 Failures) x (.95{10% project benefit}) x (10,200 kW) x (1.87 Hours) x ($17.20/kW-Hr) + (.95{10% project benefit}) x $64k = $2,554k per year, for 2019.

- (8 Failures) x (.84{32% project benefit}) x (10,200 kW) x (1.87 Hours) x ($17.20/kW-Hr) + (.84{32% project benefit}) x $64k = $2,258k per year, for 2020.

- (8 Failures) x (.68{63% project benefit}) x (10,200 kW) x (1.87 Hours) x ($17.20/kW-Hr) + (.68{63% project benefit}) x $64k = $1,828k per year, for 2021.

- (8 Failures) x (.5{100% project benefit}) x (10,200 kW) x (1.87 Hours) x ($17.20/kW-Hr) + (.5{100% project benefit}) x $64k = $1,344k per year, for 2022 and forward.

2. Do Nothing (alternative #1) NPVRR: ($000s) $40,156k

   Electing not to fund this project will result in future wildlife outages continuing at levels consistent with 2012-2017 averages. The cost of unserved energy and repairs will continue as per the 2018 calculation in the recommended option for a total assumed cost of $107,560k:

   The calculation of the cost of unserved energy and repairs yields:
   - (8 outages) x (10200 kW) x (1.87 Hours) x ($17.20/kW-Hr) + $64k = $2,689k per year

3. Next Best Alternative(s): NPVRR: ($000s) N/A

   No other alternative is seen as viable or a cost effective use of capital funding. LG&E has very few wildlife outages due to the historical use of metalclad switchgear. To complete upgrades to metalclad switchgear at the equivalent number of KU substations as this project entails is estimated at $2M per substation, or $80M total.

**Project Description**

- **Project Scope and Timeline**

| | |
|---|---|
| 1st half 2018 | Finalize design and scope of work and substation list, place PO with EPCM as required, order materials |
| 2nd half 2018 | Complete wildlife protection installations at 3-5 substations |
| 2019 | Complete wildlife protection installations at 8-10 substations |
| 2020 | Complete wildlife protection installations at 12-15 substations |
| 2021 | Complete wildlife protection installations at 12-15 substations |

- **Project Cost**
  The estimated project cost is $510k in 2018, $1,250k in 2019, $1,700k in 2020 and $1,720k in 2021.

  This project is estimated with no contingency. Multiple locations will be targeted, and project funding will be managed and optimized to adequately complete as many stations as possible within the funding allocation.

**Economic Analysis and Risks**

- **Bid Summary**
  Competitive bids will be solicited from qualified material suppliers. Distribution Substations has established existing CPAs with a number of qualified construction contractors and EPCM firms.

- **Budget Comparison and Financial Summary**

This funding for this project has been approved as a part of the 2018 BP.

| Financial Detail by Year - Capital ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 510 | 1,250 | 1,700 | 1,720 | 5,180 |
| 2. Cost of Removal Proposed | - | - | - | - | - |
| 3. Total Capital and Removal Proposed (1+2) | 510 | 1,250 | 1,700 | 1,720 | 5,180 |
| 4. Capital Investment 2018 BP | 510 | 1,250 | 1,700 | 1,720 | 5,180 |
| 5. Cost of Removal 2018 BP | | - | - | - | - |
| 6. Total Capital and Removal 2018 BP (4+5) | 510 | 1,250 | 1,700 | 1,720 | 5,180 |
| 7. Capital Investment variance to BP (4-1) | - | - | - | - | - |
| 8. Cost of Removal variance to BP (5-2) | - | - | - | - | - |
| 9. Total Capital and Removal variance to BP (6-3) | - | - | - | - | - |

| Financial Detail by Year - O&M ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | - | - | - | - | - |
| 2. Project O&M 2018 BP | - | - | - | - | - |
| 3. Total Project O&M variance to BP (2-1) | - | - | - | - | - |

This project has been approved as a part of the 2018 BP.

**Financial Summary ($000s):**

| | |
|---|---|
| Discount Rate: | 6.58% |
| Capital Breakdown: | |
| Labor: | $ 85 |
| Contract Labor: | $2,280 |
| Materials: | $2,205 |
| Transportation: | $ 10 |
| Local Engineering: | $ 350 |
| Burdens: | $ 250 |
| Contingency: | $ 0 |
| Reimbursements: | ($ 0) |
| Net Capital Expenditure: | $5,180 |

## Assumptions

- Project costs are based upon previous wildlife protection projects and vendor estimates for enhanced installations. The project estimates 40 stations will be completed, but the final count will vary based upon actual pricing and the exact stations chosen.
- EPCM contractors will be utilized as needed to complete the project scope.
- EPCM contractors will be utilized as needed to coordinate installations, requiring minimal company resources.

## Environmental

- No environmental issues are known at this time.

## Risks

- Installations in isolated substations may require a portable substation or work procedures using hot line techniques.
- There is a cost risk since each substation is unique to some degree; driving design, material and installation costs to vary from site to site. This risk will be mitigated by advanced planning and review of each location in the early phases of the project.
- There is a possible schedule risk due to the number of stations to be protected and coordination with numerous other capital upgrade initiatives. This risk can be mitigated by coordinating with other projects and scheduled outages, securing outages early in the year and involving the DCC earlier in the scheduling.

**Conclusions and Recommendation**
It is recommended that the Investment Committee approve the SCM Enhanced Substation Wildlife Protection project for $5,180k to increase reliability on the KU system, enhance customer service and reduce operating and capital costs associated with wildlife outages.

**Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:**

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

| | | | |
|---|---|---|---|
| Kent W. Blake | Date | Paul W. Thompson | Date |
| Chief Financial Officer | | President and Chief Operating Officer | |

Investment Proposal for Investment Committee Meeting on: November 28, 2018

Project Name: LG&E Downtown Network Vault Structural Repairs Project 2019

Total Expenditures: $1.7M (includes no contingency)

Project Number(s): 151485

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jason Tipton

**Executive Summary**

LG&E Electric Distribution Operations (EDO) seeks funding authority to invest $1.7M on secondary network vault reconstruction and repair during 2019. LG&E's electric distribution secondary network in downtown Louisville, located between the Ohio River, 9th Street, York Street, and Floyd Street, is comprised of 200 electrical vaults, some of which were originally constructed as far back as the early 1930's. These vaults house critical electrical equipment needed to serve customers in Louisville's primary downtown business district and hospital zone. The vaults are primarily constructed of concrete or brick walls and floors, and their ceilings are supported with beams or columns to support the weight of pedestrians and vehicles. The majority of these vaults are under public sidewalks.

LG&E Electric Distribution Operations (EDO) inspects its secondary network vaults every six months, in accordance with 807 KAR 5:006. Through these inspections, LG&E has noted considerable and accelerating deterioration of some vaults to the point substantial replacement or repairs are needed. During 2018, EDO continued prioritizing vaults identified with structural deficiencies and consulted with a third party structural engineering firm to develop a strategic plan for future reconstruction and repair. Through this initiative, four network vaults are targeted for remedial action during 2019.

The total estimated cost is included in the 2019 Business Plan. Future year vault reconstruction and repair investment targets will be established annually, as vaults are identified and prioritized for remedial action based on EDO's semi-annual inspections and ongoing external structural engineering evaluation and counsel.

**Background**

*General*
The LG&E EDO Downtown Network was originally constructed in the 1930's, and contains five separate secondary network systems with 27 circuits within the core downtown Louisville business and medical districts. The network area is roughly bounded by the Ohio River (north), Floyd Street (east), York Street (south) and 8th Street (west). Louisville's downtown network is roughly one square mile, and contains 200 network vaults within its borders.

*Justification for Improvements*
There are four main drivers for making structural improvements to the Downtown Network vault system.

1. Structural Issues - Some vaults have brick walls with mortar missing and walls threatening to cave in, concrete walls with cracks and spalling concrete, or beam supports with severe cracks that are rusted and damaged. The concrete ceilings have deteriorated over time and display damage from decades of deicing salts. The metal framework on some removable concreate slabs have rusted, complicating worker efforts to handle the slabs and gain access to associated vaults.

2. Outdated Construction Standards - Concrete encased steel beams used to be a common building practice that has been utilized in many of the LG&E EDO network vaults. However, it is now known that this is a poor choice of construction in an exterior environment. The concrete encasements are cracked or crumbling due to steel beam corrosion, and chunks of concrete are falling off in many locations, leading to potential damage to equipment and safety concerns for workers.

3. Public and Company Safety - The metal framework rusts and causes the vault top panels to buckle, creating tripping hazards for pedestrians. The concrete pieces falling from the ceiling beams pose a risk to workers in the vaults, both from direct hits and from the potential to fall on energized equipment in the vault while they are present. Also, in the unlikely event that a vault top becomes compromised, it could lead to portions of the sidewalk caving in.

4. Regulatory Requirements - In accordance with PSC regulation 807 KAR 5:006, LG&E is required to inspect vaults and document deficiencies with vault structures every 6 months. Upon finding a potentially hazardous condition with a facility, LG&E is required to make repairs and document our actions for future PSC review.

<u>*3rd Party Evaluation*</u>
In 2016, LG&E hired a structural engineering firm to evaluate several of the LG&E EDO network vaults to assist in starting the first year of this program. Since the initial assessment, more vaults have been evaluated and prioritized by the engineering firm to be addressed in future years of this project. For 2019, it was determined that four vaults need significant structural repairs due to deficiencies that were noted.

Three of the vaults have similar insufficiencies: 224 S. 4th Street, Standard Gravure at 627 S. 6th Street, and South Bell 480V at 521 W. Chestnut Street. These vaults all exhibit extensive damage to the vault top removable panels due to deicing agents over the years, and concrete encased beams that are significantly deteriorated. The vault walls have substantial spalling to the point that rebar is exposed in several locations. The steel columns are rusted beyond repair in most cases, to the extent of visible holes through the column in some areas near the base.

The fourth vault is 518 S. 4th Street, which is unique in that half of the vault top is a driving lane for cars entering an alley near the Seelbach Hotel, which goes to the rear of the hotel for deliveries along with access to the parking garage. This vault top has support beams that are rusted significantly and need to be replaced with an updated design reflecting the most recent standards and codes for a traffic rated driveway.

**Alternatives Considered**

1. <u>Recommendation:</u> NPVRR: ($000s) $2,156
   It is recommended that the LG&E Downtown Network Vault Structural Repairs Project be approved for $1.7M for 2019 in order to ensure the ongoing operating reliability of the Downtown Louisville Network distribution system by addressing aged, defective, and deteriorating network vault structural assets.

2. <u>Do Nothing:</u> NPVRR: ($000s) N/A
   The do nothing approach is not a viable option. Failure to proceed with the LG&E Downtown Network Vault Structural Repairs Project introduces a growing probability that vault structural failures caused by increasingly aging infrastructure will occur. While the total loss of one of the three grid networks in downtown Louisville is a very low probability event, it would likely occur if a vault were to collapse upon itself and damage multiple primary circuits inside the vault. Along with the primary circuits being damaged, the vault top could be compromised, leading to the collapse of the sidewalk into the vault. A lengthy network outage would severely impact downtown central business district customers, comprised of metro and federal government agencies (police, security, traffic, etc.), judicial and legal systems, hospitals and medical offices, banking and investment institutions as well as other commercial businesses, including entertainment and tourism.

## Project Description

- **Project Scope and Timeline**
  The total estimated cost will provide for reconstruction and repair of four vaults identified and prioritized through internal inspection and 3rd party evaluation:
    - 224 S. 4th Street
    - Standard Gravure at 627 S. 6th Street
    - South Bell 480V at 521 W. Chestnut Street
    - 518 S. 4th Street

- **Project Cost**
  The total estimated cost is $1.7M. This total will provide for reconstruction and repair of the prioritized vaults, and includes funding for structural engineering analysis of future year candidates for corrective actions.

## Economic Analysis and Risks

- **Bid Summary**
  Each vault reconstruction and repair project will be competitively bid using standard Supply Chain procedures.

- **Budget Comparison and Financial Summary**

| Financial Detail by Year - Capital ($000s) | 2019 | 2020 | 2021 | Post 2021 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 1,700 | - | - | - | 1,700 |
| 2. Cost of Removal Proposed | - | - | - | - | - |
| 3. Total Capital and Removal Proposed (1+2) | 1,700 | - | - | - | 1,700 |
| 4. Capital Investment 2019 BP | 1,699 | - | - | - | 1,699 |
| 5. Cost of Removal 2019 BP | - | - | - | - | - |
| 6. Total Capital and Removal 2019 BP (4+5) | 1,699 | - | - | - | 1,699 |
| 7. Capital Investment variance to BP (4-1) | (1) | - | - | - | (1) |
| 8. Cost of Removal variance to BP (5-2) | - | - | - | - | - |
| 9. Total Capital and Removal variance to BP (6-3) | (1) | - | - | - | (1) |

| Financial Detail by Year - O&M ($000s) | 2019 | 2020 | 2021 | Post 2021 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | - | - | - | - | - |
| 2. Project O&M 2019 BP | - | - | - | - | - |
| 3. Total Project O&M variance to BP (2-1) | - | - | - | - | - |

**Financial Summary ($000s):**

| | |
|---|---|
| Discount Rate: | 6.59% |
| Capital Breakdown: | |
| Labor: | $ 82 |
| Contract Labor: | $ 936 |
| Materials: | $ 429 |
| Local Engineering: | $ 117 |
| Burdens: | $ 113 |
| Transportation | $ 23 |
| Contingency: | $ 0 |
| Reimbursements: | ($ 0) |
| Net Capital Expenditure: | $ 1,700 |

- **Assumptions**
  Cost estimates are based on current vault conditions and planned remedial actions.

- **Environmental**
  No environmental issues are anticipated at this time.

- **Risks**
  Network system reliability, worker and public safety, and Company image could be negatively impacted in the future if the prioritized vaults are not addressed as proposed.

**Conclusions and Recommendation**

EDO recommends that Management approve the LG&E Downtown Network Vault Structural Repairs Project for $1.7M for 2019 in order to ensure the ongoing operating reliability and safety of the Downtown Louisville Network.

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: LG&E Downtown Network Vault Structural Repairs Project 2018

Total Expenditures: $1.231M (includes no contingency)

Project Number(s): 148898

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jason Tipton

**Executive Summary**

LG&E Electric Distribution Operations (EDO) seeks funding authority to invest $1.231M on secondary network vault reconstruction and repair during 2018. LG&E's electric distribution secondary network in downtown Louisville, located between the Ohio River, 9th Street, York Street, and Floyd Street, is comprised of 200 electrical vaults, some of which were originally constructed as far back as the early 1930's. These vaults house critical electrical equipment needed to serve customers in Louisville's primary downtown business district and hospital zone. The vaults are primarily constructed of concrete or brick walls and floors, and their ceilings are supported with beams or columns to support the weight of pedestrians and vehicles. The majority of these vaults are under public sidewalks.

LG&E Electric Distribution Operations (EDO) inspects its secondary network vaults every six months, in accordance with 807 KAR 5:006. Through these inspections, LG&E has noted considerable and accelerating deterioration of some vaults to the point substantial replacement or repairs are needed. During 2017, EDO prioritized vaults identified with structural deficiencies and consulted with a third party structural engineering firm to develop a strategic plan for future reconstruction and repair. Through this initiative, three network vaults were targeted for remedial action during 2018.

The total estimated cost is included in the 2018 Business Plan. Future year vault reconstruction and repair investment targets will be established annually, as vaults are identified and prioritized for remedial action based on EDO's semi-annual inspections and ongoing external structural engineering evaluation and counsel.

## Background

*General*

The LG&E EDO Downtown Network was originally constructed in the 1930's, and contains five separate secondary network systems with 27 circuits within the core downtown Louisville business and medical districts. The network area is roughly bounded by the Ohio River (north), Floyd Street (east), York Street (south) and 8th Street (west). Louisville's downtown network is roughly one square mile, and contains 200 network vaults within its borders.

*Justification for Improvements*

There are four main drivers for making structural improvements to the Downtown Network vault system.

1. Structural Issues - Some vaults have brick walls with mortar missing and walls threatening to cave in, concrete walls with cracks and spalling concrete, or beam supports with severe cracks that are rusted and damaged. The concrete ceilings have deteriorated over time and display damage from decades of deicing salts. The metal framework on some removable concreate slabs have rusted, complicating worker efforts to handle the slabs and gain access to associated vaults.

2. Outdated Construction Standards - Concrete encased steel beams used to be a common building practice that has been utilized in many of the LG&E EDO network vaults. However, it is now known that this is a poor choice of construction in an exterior environment. The concrete encasements are cracked or crumbling due to steel beam corrosion, and chunks of concrete are falling off in many locations, leading to potential damage to equipment and safety concerns for workers.

3. Public and Company Safety - The metal framework rusts and causes the vault top panels to buckle, creating tripping hazards for pedestrians. The concrete pieces falling from the ceiling beams pose a risk to workers in the vaults, both from direct hits and from the potential to fall on energized equipment in the vault while they are present. Also, in the unlikely event that a vault top becomes compromised, it could lead to portions of the sidewalk caving in.

4. Regulatory Requirements - In accordance with PSC regulation 807 KAR 5:006, LG&E is required to inspect vaults and document deficiencies with vault structures every 6 months. Upon finding a potentially hazardous condition with a facility, LG&E is required to make repairs and document our actions for future PSC review.

*3rd Party Evaluation*

In 2016, LG&E hired a structural engineering firm to evaluate several of the LG&E EDO network vaults to assist in starting the first year of this program. Since the initial assessment, more vaults continue to be evaluated and prioritized by the engineering firm to help drive future years of this project. For 2018, it was determined that three vaults needed significant structural repairs due to deficiencies that were noted. Greater Louisville Vault at 130 S 4th Street has extensive damage to the vault top removable panels due to deicing agents over the years and concrete encased beams that are significantly deteriorated. For general public safety, this vault currently has a street plate over the slab opening. Brown Office Bldg. Vault at 321 W Broadway has a duct bank routing through this vault, which is no longer allowed in today's construction practices. This has led to telecommunications and primary cable splices inside of the vault. The duct bank is in very poor condition and is supported by the roof system which has been compromised over the years due to deicing agents and outdated construction designs. Kentucky Towers at 509 S. 5th Street has rusted beams that are beyond repair, the wall adjacent to street contains spalling concrete, and the interior walls are formed from inadequate brick structure. Kentucky Towers was initially listed for structural repair in 2017. This vault was reassigned to the 2018 project scope due to EDO addressing recently discovered structural concerns in other vaults that were reprioritized by the structural engineer on the project.

**Alternatives Considered**

1. Recommendation: NPVRR: ($000s) $1,568
   It is recommended that the LG&E Downtown Network Vault Structural Repairs Project be approved for $1.231M for 2018 in order to ensure the ongoing operating reliability of the Downtown Louisville Network distribution system by addressing aged, defective, and deteriorating network vault structural assets.

2. Do Nothing: NPVRR: ($000s) N/A
   The do nothing approach is not a viable option. Failure to proceed with the LG&E Downtown Network Vault Structural Repairs Project introduces a growing probability that vault structural failures caused by increasingly aging infrastructure will occur. While the total loss of one of the three grid networks in downtown Louisville is a very low probability event, it would likely occur if a vault were to collapse upon itself and damage multiple primary circuits inside the vault. Along with the primary circuits being damaged, the vault top could be compromised, leading to the collapse of the sidewalk into the vault. A lengthy network outage would severely impact downtown central business district customers, comprised of metro and federal government agencies (police, security, traffic, etc.), judicial and legal systems, hospitals and medical offices, banking and investment institutions as well as other commercial businesses, including entertainment and tourism.

**Project Description**

- **Project Scope and Timeline**
  The total estimated cost will provide for reconstruction and repair of three vaults identified and prioritized through internal inspection and 3rd party evaluation:
  - Greater Louisville Vault at 130 S 4th Street.
  - Brown Office Bldg. Vault at 321 W Broadway.
  - Kentucky Towers at 509 S. 5th Street.
- **Project Cost**
  The total estimated cost is $1.231M. This total will provide for reconstruction and repair of the prioritized vaults, and includes funding for structural engineering analysis of future year candidates for corrective actions.

**Economic Analysis and Risks**

- **Bid Summary**
  Each vault reconstruction and repair project will be competitively bid using standard Supply Chain procedures.

- **Budget Comparison and Financial Summary**

| Financial Detail by Year - Capital ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 1,231 | - | - | - | 1,231 |
| 2. Cost of Removal Proposed | - | - | - | - | - |
| 3. Total Capital and Removal Proposed (1+2) | 1,231 | - | - | - | 1,231 |
| 4. Capital Investment 2018 BP | 1,231 | - | - | - | 1,231 |
| 5. Cost of Removal 2018 BP | - | - | - | - | - |
| 6. Total Capital and Removal 2018 BP (4+5) | 1,231 | - | - | - | 1,231 |
| 7. Capital Investment variance to BP (4-1) | - | - | - | - | - |
| 8. Cost of Removal variance to BP (5-2) | - | - | - | - | - |
| 9. Total Capital and Removal variance to BP (6-3) | - | - | - | - | - |

| Financial Detail by Year - O&M ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | - | - | - | - | - |
| 2. Project O&M 2018 BP | - | - | - | - | - |
| 3. Total Project O&M variance to BP (2-1) | - | - | - | - | - |

**Financial Summary ($000s):**
Discount Rate: 6.58%
Capital Breakdown:
Labor: $ 69
Contract Labor: $ 626
Materials: $ 345

| | |
|---|---|
| Local Engineering: | $ 94 |
| Burdens: | $ 97 |
| Contingency: | $ 0 |
| Reimbursements: | ($ 0) |
| Net Capital Expenditure: | $1,231 |

- **Assumptions**
  - Cost estimates are based on current vault conditions and planned remedial actions.

- **Environmental**
  No environmental issues are anticipated at this time.

- **Risks**
  Network system reliability, worker and public safety, and Company image could be negatively impacted in the future if the prioritized vaults are not addressed as proposed.

**Conclusions and Recommendation**
EDO recommends that Management approve the LG&E Downtown Network Vault Structural Repairs Project for $1.231M for 2018 in order to ensure the ongoing operating reliability and safety of the Downtown Louisville Network.

Investment Proposal for Investment Committee Meeting on: August 29, 2018

Project Name: LGE PILC UG Network Cable Replacement Program-2018

Total Approved Expenditures: $8.758M (Approved on 10/25/17)

Total Revised Expenditures: $11.333M

Project Number(s): 148899

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jason Tipton / Shawn Stickler

**Reason for Revision**

Electric Distribution Operations (EDO) is authorized to invest $8.758M during 2018 towards continuation of its Paper Insulated Lead Covered (PILC) Cable Replacement Program. The program was initiated early in 2013, and originally scheduled to be completed by the end of 2023. During the 2018 business planning period, EDO decided to compress the schedule of the PILC cable replacement program by two years, to take advantage of ongoing work efficiencies and projected program benefits.

Current year inspections of program duct routes continue to reveal substantially deteriorated subsurface conditions, necessitating complete replacement of duct sections. To assure annual cable replacement targets can be met with the compressed schedule, EDO proposes to increment its 2018 capital allocation by $2.6M to increase focus on duct replacement during the remainder of 2018. The proposed funding will be pulled from EDO's 2021 PILC Cable Replacement Program allocation.

The Total Revised Expenditures of $11.333M includes 2018 burden reductions of $25k.

**Financial Summary**

| **Financial Summary ($000s):** | **Approved** | **Revised** | **Explanation** |
|---|---|---|---|
| Discount Rate: | 6.32% | 6.59% | |
| Capital Breakdown: | | | |
| Labor: | $ 95 | $ 95 | |
| Contract Labor: | $ 7,187 | $ 9,417 | See explanation below. |
| Materials: | $ 455 | $ 555 | |
| Local Engineering: | $ 699 | $ 947 | Increase in Contract Labor & Materials. |
| Burdens: | $ 297 | $ 293 | |
| Transportation: | $ 25 | $ 25 | |
| Contingency: | $ 0 | $ 0 | |
| Reimbursements: | ($ 0) | ($ 0) | |
| Net Capital Expenditure: | $ 8,758 | $11,333 | |
| NPVRR: | $ 11,394 | $14,371 | |

To ensure increased yearly cable target objectives can be achieved, EDO proposes to focus on duct infrastructure replacement throughout the remainder of 2018.

| **Financial Detail by Year - Capital ($000s)** | **2018** | **2019** | **Post 2019** | **Total** |
|---|---|---|---|---|
| 1. Capital Investment Proposed | 11,333 | - | - | 11,333 |
| 2. Cost of Removal Proposed | - | - | - | - |
| 3. Total Capital and Removal Proposed (1+2) | 11,333 | - | - | 11,333 |
| 4. Capital Investment 2018 BP | 8,758 | - | - | 8,758 |
| 5. Cost of Removal 2018 BP | - | - | - | - |
| 6. Total Capital and Removal 2018 BP (4+5) | 8,758 | - | - | 8,758 |
| 7. Capital Investment variance to BP (4-1) | (2,575) | - | - | (2,575) |
| 8. Cost of Removal variance to BP (5-2) | - | - | - | - |
| 9. Total Capital and Removal variance to BP (6-3) | (2,575) | - | - | (2,575) |

| **Financial Detail by Year - O&M ($000s)** | **2018** | **2019** | **Post 2019** | **Total** |
|---|---|---|---|---|
| 1. Project O&M Proposed | | | | - |
| 2. Project O&M 2018 BP | | | | - |
| 3. Total Project O&M Variance to BP (2-1) | - | - | - | - |

The incremental funding was approved through the July Corporate RAC process.

**Conclusions and Recommendation**

It is recommended that the Investment Committee approve the revised authority requested for the 2018 PILC Replacement Project for $11.333M. This will enable EDO to meet its compressed PILC Cable Replacement Program schedule, and provide for continued safe and reliable operation of the Downtown Louisville Network.

**Approval Confirmation for Capital Projects Greater Than $2 million:**

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

| | | | |
|---|---|---|---|
| Kent W. Blake | Date | Paul W. Thompson | Date |
| Chief Financial Officer | | Chairman, CEO and President | |

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: Rogers Gap 0451 Circuit Hardening

Total Expenditures: $1,800k (Including $300k of contingency)

Project Number(s): 156250

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Jeffrey Poston

**Executive Summary**

KU Electric Distribution and LKE Electric Reliability propose to invest $1,800k on reliability improvements for the Rogers Gap 0451 circuit. The 0451 Circuit Hardening project was approved during the 2017 AIS process and included in the 2018 Business Plan under the Circuit Hardening Reliability Program. Additional funding for 2018 and 2019 is required to address all necessary improvements. This project is currently approved for $553k (June 2018) and was originally expected to be completed in 2018. Additions to the scope of work are expected to be completed in 2019.

This project proposes to reconductor 13 miles of 3-phase #4 copper while also replacing defective poles and equipment along U.S. Highway 25 from Georgetown to Corinth. Portions of the 13 miles will be relocated to the highway as the existing route travels through rough terrain, making restoration efforts increasingly difficult. The existing copper conductor is prone to failure and will be replaced with 2/0 ACSR conductor. Electric customers will experience fewer interruptions and shortened outage durations upon completion of this project.

The incremental funding needed in 2018 was approved through the October Corporate RAC process. The 2019 funding will be covered through the Circuit Hardening Reliability Program.

## Background

Rogers Gap 0451 is located in the Lexington Operations Center area and serves over 1,100 customers from Georgetown to Sadieville and on to Corinth. Circuit 0451 is one of the longest in the LKE Distribution System with over 60 miles of overhead conductor. Thirteen miles of defective, 3-phase mainline #4 copper on the circuit has proven to be unreliable and needs to be replaced. Portions of the mainline were constructed off the highway through rough terrain. The project will relocate several portions to locations along the highway Right-of-Way (R-O-W). Additionally, the small conductor size has limited the available fault current at the end of the line making successful fault coordination exceptionally challenging. This project will replace the remaining 13 miles of defective copper along with defective poles and equipment. The project has been designed and estimated at $1,800k (including $300k of contingency).

Due to the location of the project along U.S. Highway 25, continuous flagging is required. Vegetation management is also required along new and existing R-O-W. Design and Engineering have been completed collectively by UCS and the Electric Reliability group. Acquisition of R-O-W has been contracted to O.R. Colan and will be managed by the Real Estate & Right-of-Way group.

By hardening the circuit as proposed, the number of outages, outage response times, and coordination for sectionalizing devices will be improved. It is expected that 1,020 customer interruptions and 168,945 customer minutes will be saved annually after completion of the project and nine "Critical" customers will experience reliability improvements including local fire and water departments, railroad, and communications. Recent PSC complaints will be also addressed.

- **Alternatives Considered**
  1. Recommendation: NPVRR: ($000s) $2,038
  2. Alternative #1: (Do Nothing) NPVRR: ($000s) $3,151
     The cost of "do nothing" is based on the value gained by reducing average annual circuit outage duration through completion of the Recommendation. Using the corporate "cost of unserved energy" ($17.2/kWh), the value of reducing outage duration (CMI) based on average circuit loads is $170k annually.

## Project Description

- **Project Scope and Timeline**
  The engineering and design have been collectively completed by UCS and the Electric Reliability group. Acquisition of R-O-W, where needed, has been contracted to O.R. Colan. Existing contractor resources will be assigned following the approval of the project and existing EDO construction blanket contracts and resources will be used. The first sections should be completed by the end of 2018, and the remainder of the work will be finished in 2019.

- **Project Cost**
  Total project costs are $1,800k including 20% contingency. The project will be funded from the 2018 and 2019 KU System Hardening Reliability Project (152999).

**Economic Analysis and Risks**

- **Bid Summary**
  Field construction work will be completed under existing contracts with overhead distribution line business partners. All required materials will be procured using established materials contracts.

- **Budget Comparison and Financial Summary**

| Financial Detail by Year - Capital ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 680 | 990 | | | 1,670 |
| 2. Cost of Removal Proposed | 50 | 80 | | | 130 |
| 3. Total Capital and Removal Proposed (1+2) | 730 | 1,070 | - | - | 1,800 |
| 4. Capital Investment 2019 BP | - | - | | | - |
| 5. Cost of Removal 2019 BP | - | - | | | - |
| 6. Total Capital and Removal 2019 BP (4+5) | - | - | - | - | - |
| 7. Capital Investment variance to BP (4-1) | (680) | (990) | - | - | (1,670) |
| 8. Cost of Removal variance to BP (5-2) | (50) | (80) | - | - | (130) |
| 9. Total Capital and Removal variance to BP (6-3) | (730) | (1,070) | - | - | (1,800) |

| Financial Detail by Year - O&M ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | | | | | - |
| 2. Project O&M 2019 BP | | | | | - |
| 3. Total Project O&M variance to BP (2-1) | - | - | - | - | - |

This is funded from the System Hardening Reliability program.

**Financial Summary ($000s):**

| | |
|---|---|
| Discount Rate: | 6.59% |
| Capital Breakdown: | |
| Labor: | $ 88 |
| Contract Labor: | $1,066 |
| Materials: | $ 104 |
| Local Engineering: | $ 151 |
| Burdens: | $ 91 |
| Contingency: | $ 300 |
| Reimbursements: | ($ ) |
| Net Capital Expenditure: | $1,800 |

- **Assumptions**
  The CEM model used the cost of unserved energy for the "Do Nothing" alternative NPVRR. Useful life of the project is 30 years.

- **Environmental**
  None

- **Risks**
  Delaying this investment will result in further deterioration of the copper conductor. Conductor failures and associated electrical service interruptions will become more prevalent. Customer satisfaction will decline as customer complaints continue to rise.

**Conclusions and Recommendation**

It is recommended that Management approve the revised Rogers Gap 0451 Circuit Hardening project for $1,800k to resolve ongoing reliability, restoration, and coordination issues.

Investment Proposal for Investment Committee Meeting on: April 26, 2017

Project Name: LG&E Substation Monitoring and Control (SMAC) Program

Total Expenditures: $5,076k (including contingency of $461k)

Project Number(s):148727

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Robin Chacko/Tony Durbin

**Executive Summary**

Electric Distribution Operations (EDO) - Substation Construction and Maintenance (SC&M) seeks funding authority to expand the use of Substation Monitoring and Control (SMAC) at fourteen (14) LG&E distribution substations. Currently, LG&E Substation Operations expends a considerable amount of time and resources traveling to the fourteen substations to manually remove circuit reclosing, ground relaying, and automatic transformer tap changing from service per the direction of the Distribution Control Center (DCC). SC&M's proposed four-year project will add the necessary control circuitry within the targeted substations to enable DCC Restoration Coordinators to complete these routine tasks remotely through Substation Control and Data Acquisition (SCADA) and eliminate the requirement of LG&E Substation operators to travel to the fourteen substations to perform the tasks manually.

The majority of LG&E existing substations already include SMAC functionality, and SMAC is standard on all new or expanded substations. SC&M's proposed four year program will start in 2017 and equip remaining unequipped LG&E substations with this functionality. The addition of SCADA control for circuit reclosing, ground relaying, and automatic transformer tap changer control will also speed up restoration efforts, increase LG&E Substation Operation's productivity and reduce wait times of other Distribution Operations groups who cannot begin work until these routine substation tasks are completed.

EDO's 2017 Business Plan (BP) allocated $3,377k for the proposed SMAC project. This investment proposal includes an incremental $1,699k for the project in 2020, based on bids received for the 14 substations since the 2017 BP was finalized. The 2017 BP allocation was based on unit pricing experienced in 2016 on LG&E's Fern Valley Substation SMAC Project.

The additional $1,699k for 2020 will be addressed in the 2018 BP. Once this project is complete, all LG&E 12kV and 14kV substations will be equipped with SMAC technology.

**Background**

The LG&E SMAC program is driven by the need to automate substation processes which will improve operational efficiency, and in turn, reduce truck rolls by LG&E Substation Operations to manually remove circuit reclosing, ground relaying, and automatic transformer tap changing from service, per the direction of the DCC for routine operations. Eliminating these manual tasks will reduce the annual workload of LG&E Substation Operations by approximately 2,400 hours annually, eliminate the need to hire two additional employees in the workgroup, and eliminate standby time of electric distribution crews as they cannot begin work on circuits served from the aforementioned 14 substations until these routine substation tasks are completed.

This proposed project will add the necessary SCADA control technology on the remaining 14 LG&E substations that do not have SMAC functionality, enabling the DCC to remotely control reclosing, ground relaying (14kV only), and automatic transformer tap changing

Where SCADA control of the reclosing function is not installed, a considerable amount of LG&E Substation Operations’ duties are devoted to manual control of reclosing and the application of associated “caution cards”. Caution, or Hot Line Clearance, is the assurance that automatic reclosing features of a circuit have been made inoperative. A caution card is applied as a safety feature to protect the distribution crews while working on circuits by preventing automatic reclosing or manual closing of the circuit if it trips out. Manual application of caution cards requires rolling a truck to the substation, manual control of the reclosing relay within the substation control house, and hanging (or removing) a physical caution card on the control panel door. Today, these caution visits are almost exclusively concentrated at the 14 distribution substations in the LG&E territory that are SCADA capable and without automatic reclosing SMAC capability. Specifically, 14 out of a total of 93 SCADA capable distribution substations in the LG&E system do not have SMAC capability. From 2013 to 2016, LG&E Substation Operations spent an average of 1,918 hours per year to complete caution applications at distribution substations.

Another area where SCADA control can be improved is at the LG&E 14kV distribution substations. Although not requested as frequently as reclosing control, ground relay control is requested when 14kV distribution circuits are switched out for load swaps. This feature prevents the misoperation of the ground relay when single phase switching takes place on the 14kV impedance-grounded distribution circuits. From 2014 to 2016, LG&E Substation Operations spent an average of 514 hours per year to complete load swap applications at distribution substations.

Additionally, when switching takes place between distribution circuits, the load tap changers on the substation transformers associated with these distribution circuits are locked to prevent the substation transformer taps from changing due to changes in the distribution load, which can cause substantial and potentially dangerous voltage differences across opened circuit ties. This is accomplished by the taps’ control feature on the substation transformers.

This project was recently reviewed to determine if there were any synergies to be gained with upcoming DMS work associated with the Distribution Automation project. It was determined that the SMAC functionality would be implemented on sixteen (16) feeders by upgrading the existing electromechanical relays to modern, digital relays. This will provide better integration with future DMS requirements.

**Alternatives Considered**

1. Recommended option: NPVRR ($000s): $6,522
   Complete the LG&E Substation Monitoring and Control (SMAC) program.

   Between 2017 and 2020, LG&E Substation Operations should invest $5,067k towards the acquisition, engineering and installation of SCADA control technology at fourteen LG&E substations, to enable remote circuit reclosing, ground relaying, and automatic transformer tap changing by DCC System Operators. This option will eliminate approximately 1,216 O&M labor hours annually, associated with drive times, and manual operation of fourteen substations by LG&E Substation Operators. An additional 4,863 labor hours (O&M and capital) associated with distribution crew (tree trimmers, line technicians, and network technicians) standby time will also be eliminated.

2. Do nothing option: NPVRR ($000s): $8,144

   Substation Operations' do nothing option assumes continuation of current operating practices, including utilization of Substation Operators to manually perform caution and load swap applications at the fourteen (14) remaining LG&E substations without SCADA control.

   The Do Nothing option is not recommended because it would necessitate the hiring of two incremental employees due to the overall workload demands and scheduling limitations of the work group. Additional operational efficiencies would also not be realized, including improved customer restoration times and implementation of Distribution Automation strategies.

   The average annual labor expenses associated with the manual tasks for the fourteen substations is $57k (1,216 hours). The estimated average annual labor expenses associated with distribution crew standby time is $116k (2,857 hours). The estimate average annual labor capital cost associated with distribution crew standby time is $134k (2,006 hours).

**Project Description**

- **Project Scope and Timeline**
  2017 Preliminary engineering and detailed scope development.
  2017 Bid work at all fourteen (14) distribution substations and award Contract Purchase Agreement (CPA) to successful Engineering, Procurement, and Construction Management (EPCM) firms.
  2017 Complete SCADA modifications at Breckenridge and Shively substations.
  2018 Complete SCADA modifications at Del Park, Floyd, Grady, and Madison substations.
  2019 Complete SCADA modifications at Algonquin, Magazine, and Seminole substations.
  2020 Complete SCADA modifications at Canal, Clay, Clifton, Highland, and Hillcrest substations.

- **Project Cost**
  The total estimated cost of the program is $5,076k. The costs used in the estimates are consistent with bids received from Engineering Procurement & Construction Management (EPCM) contractors in 2017. A 10 % contingency is incorporated into the project cost estimates. There is no distribution work associated with this project.

**Economic Analysis and Risks**

- **Bid Summary**
  - Bids for the substation material, services, and labor have been received and are being evaluated for the SMAC program.

**Budget Comparison and Financial Summary**

| Financial Detail by Year ($000s) | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 748 | 1,163 | 1,370 | 1,642 | 4,923 |
| 2. Cost of Removal Proposed | 22 | 34 | 40 | 57 | 153 |
| 3. Total Capital and Removal Proposed (1+2) | 770 | 1,197 | 1,410 | 1,699 | 5,076 |
| 4. Capital Investment 2017 BP | 736 | 1,184 | 1,343 | | 3,263 |
| 5. Cost of Removal 2017 BP | 34 | 13 | 67 | | 114 |
| 6. Total Capital and Removal 2017 BP (4+5) | 770 | 1,197 | 1,410 | - | 3,377 |
| 7. Capital Investment variance to BP (4-1) | (12) | 21 | (27) | (1,642) | (1,660) |
| 8. Cost of Removal variance to BP (5-2) | 12 | (21) | 27 | (57) | (39) |
| 9. Total Capital and Removal variance to BP (6-3) | - | - | - | (1,699) | (1,699) |

| Financial Detail by Year - O&M ($000s) | 2017 | 2018 | 2019 | 2020 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | - | - | - | - | - |
| 2. Project O&M 2017 BP | - | - | - | - | |
| 3. Total Project O&M variance to BP (2-1) | - | - | - | | - |

The 2017 BP has these projects in separate project numbers for each year but once approved, the work will all be completed under one project number. The project estimates are higher than the 2017 BP in total, so the increases needed in 2020 will be addressed through the 2018 BP process.

**Financial Summary ($000s):**
Discount Rate: 6.5%
Capital Breakdown:
Labor: $ 888
Contract Labor: $ 1,469
Materials: $ 1,056
Transportation: $ 52
Local Engineering: $377
Burdens: $773
Contingency: $461
Reimbursements:
Net Capital Expenditure: $5,076

- **Assumptions**
    - Estimates are based on bids received from EPCM contractors in 2017.
    - Two EPCM contractors will be utilized to complete the entire project scope.

- **Environmental**
  There are no known environmental issues at this time.

- **Risks**
    - The estimates are based on engineering and installation unit pricing for reclosing control panel modifications, ground relay control panel modifications, and transformer tap changer control panel modifications. Unit prices were also estimated for conduit installation, cable installation, trench installation, and functional testing. There is a cost risk since the conduit and cable installation will vary from site to site. This risk will be mitigated by detailed and accurate scope documents.
    - This project modifies existing circuits, and there is always a risk of inadvertent outages for the customers served. This risk can be mitigated using good engineering and commissioning practices, detailed functional testing, and good project management.
    - There is a possible schedule risk due to the number of circuits that need to be modified, installed, and tested. Depending on loading, the DCC could stagger the outages in such a way that seamless transition between substations will not occur. This risk can be mitigated by securing outages early in the year and involving the DCC earlier in the scheduling.

**Conclusions and Recommendation**

EDO-SC&M recommends that the Investment Committee approve the LG&E Substation Monitoring and Control (SMAC) program for $5,076k in order to improve efficiency and productivity, and continue to provide safe and reliable electric service to our distribution customers.

**Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:**

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

| | |
|---|---|
| Kent W. Blake<br>Chief Financial Officer | Paul W. Thompson<br>President and Chief Operating Officer |

Investment Proposal for Investment Committee Meeting on: May 30, 2018

Project Name: LG&E Southern Substation Exit Circuit Replacement

Total Expenditures: $2,114k (includes 15% contingency)

Project Number(s): 156526 (Duct Replacement) and 156527 (Cable Replacement)

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Rob Wolf / Shawn Stickler

**Executive Summary**

Electric Distribution Operations (EDO) seeks approval to invest $2,114k on the proactive changeout of the exit circuit cables and duct banks at the Southern Substation. This funding will cover the costs to replace the existing Paper Insulated, Lead Covered (PILC) cable technology and duct system between the exit circuit cable poles and the substation switchgear.

Due to the deteriorated condition and small size of the existing duct, a failure in an existing circuit would require an extended exit circuit outage in order to install new duct and cable. The existing duct is too small to accommodate modern cable sizes, and LG&E stopped installing new PILC in the early 1980s. The existing PILC cables have been in service for approximately 70 years, and are well past their expected service life.

The total project cost of $2,114k was not included in the 2018 Business Plan. EDO is requesting incremental funding of $903k in 2018 for replacement of the duct banks, which was approved by the Corporate RAC in April. Funding for 2019 of $1,211k for replacement of the cable will be requested in the 2019 Business Plan. The new duct bank and cable at Southern Substation is expected to be placed in service during the fourth quarter of 2019.

**Background**

Southern Substation is a 4kV substation located behind 1475 South 3rd St. in Old Louisville. The bus arrangement consists of nine (9) circuits serving just over 4,000 customers and businesses. The exit cables for these circuits are PILC construction that were installed in the 1940's. These circuits were routed in 3.5" duct from the substation switchgear to cable poles throughout the area, but arranged predominantly along South 3rd St. between West Lee St. and West Kentucky St.

This exit circuit replacement project will provide for the replacement of approximately 8,000 feet of underground duct bank and approximately 20,000 feet of cable.

Alternatives to the proposed replacement include reactive replacement of failed cables on a run-to-failure basis. This run to failure alternative is more costly and is not recommended due to the known impacts that cable failures have on system reliability and the customer experience.

- **Alternatives Considered (1 –Recommendation, 2 –Do nothing)**

  1. Recommendation: NPVRR: ($000s) $2,603
     The recommended option is to proactively replace the Southern Substation exit circuits and underground duct for $903k in 2018 and $1,211k in 2019 in order to prevent extended outages due to failure on the aged PILC cable systems and duct systems presently operating beyond designed life expectancy.

  2. Do Nothing: NPVRR: ($000s) N/A
     This is not considered a viable option as LG&E has an obligation to serve and would not be able to serve the customers' anticipated load. If no action is taken, the aging infrastructure will put reliability at risk for over 4,000 customers. The existing PILC cables will be allowed to run to failure prior to replacement, which will lead to extended outage times for the circuit. In most cases, the circuit can be switched out to feed from another station temporarily, but the circuit will be left in this contingency situation for months until new duct and cable can be installed. The cables have been in service for approximately 70 years. This exceeds the normal life expectancy of medium voltage power cables by almost double. The failed cables cannot be replaced without new duct being installed due to the existing duct being in poor condition and undersized for modern cable sizes.

**Project Description**

- **Project Scope and Timeline**
  The LG&E Southern Substation underground duct will be replaced in 2018, while the exit circuit cables will be replaced in 2019.

- **Project Cost**
  The proposed estimate for this work is $903k in 2018 and $1,211k in 2019. Project costs include the ancillary costs associated with terminations and splices. There is a 15% contingency of $276k included for this project.

**Economic Analysis and Risks**

- **Bid Summary**
  Contract labor for the duct and cable replacement will be handled by LG&E resident contract crews under their existing approved contracts.

- **Budget Comparison and Financial Summary**

| Financial Detail by Year - Capital ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 903 | 1,079 | - | - | 1,982 |
| 2. Cost of Removal Proposed | - | 132 | - | - | 132 |
| 3. Total Capital and Removal Proposed (1+2) | 903 | 1,211 | - | - | 2,114 |
| 4. Capital Investment 2018 BP | - | - | - | - | - |
| 5. Cost of Removal 2018 BP | - | - | - | - | - |
| 6. Total Capital and Removal 2018 BP (4+5) | - | - | - | - | - |
| 7. Capital Investment variance to BP (4-1) | (903) | (1,079) | - | - | (1,982) |
| 8. Cost of Removal variance to BP (5-2) | - | (132) | - | - | (132) |
| 9. Total Capital and Removal variance to BP (6-3) | (903) | (1,211) | - | - | (2,114) |

| Financial Detail by Year - O&M ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | | | | | - |
| 2. Project O&M 2018 BP | | | | | - |
| 3. Total Project O&M variance to BP (2-1) | - | - | - | - | - |

**Financial Summary ($000s):**
Discount Rate: 6.59%
Capital Breakdown:
Labor: $ 0
Contract Labor: $ 883
Materials: $ 750
Local Engineering: $ 130
Burdens: $ 75
Contingency: $ 276
Reimbursements: ($ 0)
Net Capital Expenditure: $2,114

- **Assumptions**
Successful completion of this project assumes availability of qualified contractors to complete the work on time.

- **Environmental**
The existing PILC will be removed and disposed of appropriately.

- **Risks**
The higher density of utilities in the ground downtown, getting timely and accurate locates, metro permitting, and crew availability are all risks for completing the project on time and on budget.

**Conclusions and Recommendation**
It is recommended that the Investment Committee approve the LG&E Southern Substation Exit Circuit Replacement Project for $2,114k to ensure the ongoing operating reliability of the Southern Substation feeders.

**<u>Approval Confirmation for Capital Projects Greater Than $2 million</u>:**

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

| | | | |
|---|---|---|---|
| Kent W. Blake | Date | Paul W. Thompson | Date |
| Chief Financial Officer | | Chairman, CEO and President | |

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: UPS GL1335 Cable Replacement

Total Expenditures: $1,150k (includes 10% contingency)

Project Number(s): 155235

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Shawn Stickler/Steve Woodworth

**Executive Summary**

LG&E Electric Distribution Operations (EDO) seeks funding authority to invest $1,150k for replacement of both sets of cable on the first half of the GL1335 (Grade Lane) circuit feeding UPS Worldport. The replaced portion of the circuit (3.7 miles of cable) will originate at the Grade Lane Substation and terminate at the new mid-point switchgear yard across from Midfield Access Rd. LG&E supplies power to UPS Worldport with four parallel 13.8KV circuits from both Grade Lane Substation (2.86 mile primary feed) and Seminole Substation (2.39 mile backup feed). Both of these feeder paths are submerged in water the majority of the time.

UPS Worldport has had four (4) cable failures since 2006. All four failures have occurred at cable splices, and all of the splice failures occurred on GL1335 in the first half of the circuit. After analyzing the splices following these failures, each one exhibited evidence of water ingress into the splice under the copper tape shield, and demonstrated observable corrosion and evidence of heating. Using a modern designed concentric neutral cable and splicing techniques with this cable replacement will allow GL1335 to better withstand the wet environment. It is also believed that significant amounts of cable thumping used to locate previous failures have caused damage to the first half of GL1335. Because the Grade Lane circuits are close to 3 miles long, extensive thumping was required in order to find faults on the unusually long feeder.

The technique of finding faults is to ‘thump’ the cable. When a high voltage is applied to a faulted cable, the resulting high-current arc from the failed cable to a ground source makes a noise audible above ground. Cable thumping requires a current on the order of tens of thousands of amps at voltages as high as 25kV to make an underground noise loud enough to hear above ground. The heating from this high current often causes some degradation of the cable insulation. This is a necessary outcome and accepted throughout the industry because if cable thumping time is minimal, so is the cable insulation damage. There is no existing technology (or combination of technologies) that can entirely replace cable thumping. In conjunction with this project, LG&E is taking steps in 2017 to install mid-point switches to sectionalize all 8 UPS feeders in order to reduce thumping time and locate faults quicker to minimize any potential future damage from fault finding activities.

The total project cost of $1,150k will be reallocated from the general reliability Circuits Identified For Improvement (CIFI) project through defined RAC processes and was not specified in the 2017 or 2018 Business Plans (BP). The 2017 spending was approved in the July Corporate RAC meeting. The GL1335 cable replacement will be completed by the third quarter of 2018.

**Background**

Worldport is the worldwide air hub for UPS (United Parcel Service) located at the Louisville International Airport. The facility is currently 5.2 million square feet (90 football fields). With over 20,000 employees, UPS is one of the largest employers in Louisville, and in the Commonwealth of Kentucky. Worldport is the largest fully automated package handling facility in the world. UPS has invested more than $1 billion at the Worldport location.

LG&E supplies power to UPS Worldport with four parallel 13.8KV circuits from both Grade Lane Substation (2.86 mile primary feed) and Seminole Substation (2.39 mile backup feed). Both of these feeder paths are submerged in water the majority of the time due to the area geology. Worldport and the surrounding areas are in ‘Wet Woods’, which means there is a hardened impervious layer of clay below the soil that impairs drainage. There have been 4 cable/splice failures on the first half of GL1335 circuit since 2006.

**Alternative Considered**

1. <u>Recommendation:</u> NPVRR: $1,453K

   Move forward with the LEO UPS GL1335 Cable Replacement Project in order to ensure the ongoing operating reliability of the feeders supplying the UPS Worldport campus.

2. <u>Do Nothing:</u> NPVRR: N/A

   The do nothing approach is not a viable option. Failure to proceed with the LG&E UPS Cable Replacement Project introduces a growing probability that we will continue to see faults on the GL1335 feeder serving the UPS Worldport facility. Further failures on the circuit would severely impact the operations of a major customer, and cause harm to LG&E’s reputation as a reliable energy supplier.

## Project Description

- **Project Scope and Timeline**
  The total estimated cost will provide for the replacement of 19,600 circuit feet (3.7 miles) of cable, and will include both set 1 and set 2 of GL1335 cable originating at the Grade Lane Substation and terminating at the new mid-point switchgear yard across from Midfield Access Rd. This project will be completed by the third quarter of 2018.

- **Project Cost**
  The total estimated cost for the project is $1,150k, which includes a 10% contingency. In 2017, $500k will be spent to purchase materials for the project and complete prep work for the replacement. The remaining $650k will be spent in 2018 to perform the replacement work.

## Economic Analysis and Risks

- **Bid Summary**
  This project will use existing material and labor contracts and will follow established Supply Chain procedures.

- **Budget Comparison and Financial Summary**

| Financial Detail by Year - Capital ($000s) | 2017 | 2018 | 2019 | Post 2019 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 500 | 650 | - | - | 1,150 |
| 2. Cost of Removal Proposed | - | - | - | - | - |
| 3. Total Capital and Removal Proposed (1+2) | 500 | 650 | - | - | 1,150 |
| 4. Capital Investment 2017 BP | - | - | - | - | - |
| 5. Cost of Removal 2017 BP | - | - | - | - | - |
| 6. Total Capital and Removal 2017 BP (4+5) | - | - | - | - | - |
| 7. Capital Investment variance to BP (4-1) | (500) | (650) | - | - | (1,150) |
| 8. Cost of Removal variance to BP (5-2) | - | - | - | - | - |
| 9. Total Capital and Removal variance to BP (6-3) | (500) | (650) | - | - | (1,150) |

| Financial Detail by Year - O&M ($000s) | 2017 | 2018 | 2019 | Post 2019 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | - | - | - | - | - |
| 2. Project O&M 2017 BP | - | - | - | - | - |
| 3. Total Project O&M variance to BP (2-1) | - | - | - | - | - |

The project is not individually included in the 2017 BP, but will be covered by a reallocation from the budgeted reliability CIFI project through the Corporate RAC.

**Financial Summary ($000s):**

| | |
|---|---|
| Discount Rate: | 6.32% |
| Capital Breakdown: | |
| Labor: | $ 0 |
| Contract Labor: | $ 503 |
| Materials: | $ 417 |
| Local Engineering: | $ 97 |
| Burdens: | $ 28 |
| Contingency: | $ 105 |
| Reimbursements: | ($ 0) |
| Net Capital Expenditure: | $1,150 |

- **Assumptions**
  Successful completion of this project on time assumes availability of qualified contractors to complete the work and the cooperation of UPS to allow access to specified areas to complete the project on time.

- **Environmental**
  No environmental issues are anticipated at this time.

- **Risks**
  - System reliability and Company image could be negatively impacted in the future if the feeder is not replaced as proposed.
  - UPS will need to allow LG&E to transfer the UPS facilities to their backup circuits from Seminole substation. Additionally, UPS will have to run their sorts without an immediate backup circuit present since all Grade Lane feeders will need to be deenergized in order for LG&E crews to complete the work safely. In the event of a failure on a Seminole circuit during this work, UPS will sustain a 30-60 minute outage while LG&E personnel vacate the manholes and manually roll UPS over to the other Grade Lane circuits.

**Conclusions and Recommendation**
It is recommended that Management approve the LG&E UPS GL1335 Cable Replacement Project for $1,150k in order to ensure the ongoing operating reliability of the UPS Worldport feeders.

Investment Proposal for Investment Committee Meeting on: N/A

Project Name: LG&E URD Cable Replacement/Rejuvenation Program-2019

Total Expenditures: $1.701M

Project Number(s): 151553

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Rob Wolf / Steve Woodworth

**Executive Summary**

Electric Distribution Operations (EDO) seeks approval to invest $1.701M on proactive and reactive cable rejuvenation and replacement during 2019. This proposed program will target LG&E Underground Residential Development (URD) direct buried cables installed between the mid-1960s and mid-1980s.

Cable rejuvenation is a cable life extension technology where a dielectric fluid is injected into conductor strands of in-service medium voltage cable to restore its dielectric characteristics to near-new cable levels. The technology provides a cost effective alternative to traditional cable replacement when used in a proactive cable infrastructure renewal program.

EDO's proposed funding level will provide for proactive rejuvenation of targeted LG&E URD cable sections prioritized based on cable age, failure and repair history, customer impact, and overall circuit performance. Additionally, the funding level will provide for replacement of any prioritized cable sections that cannot be rejuvenated with the life extension technology. The 2019 Business Plan (BP) includes $1.701M. These funds will continue the proactive program EDO has traditionally used, and will also allow for a small number of reactive cable injections. Reactive rejuvenation will enable EDO to rejuvenate a cable immediately after a repair following a cable failure.

Alternatives to the proposed rejuvenation program include proactive replacement of cables and/or reactive repair or replacement of failed cables on a run-to-failure basis. These alternatives are more costly, and the run to failure alternative is not recommended due to the known impacts that cable failures have on system reliability and customer experience.

EDO included $1.701M in its proposed 2019 Business Plan for cable rejuvenation or replacement.

**Background**

Over the last five years, LG&E has averaged 156 URD primary cable failures per year, with a maximum single year failure rate of 166 in 2016. Over 95% of failures occurred on 1st and 2nd generation solid dielectric cables installed in underground residential subdivisions between the mid-1960's and mid-1980's. Failure rates on these 30-year design life systems have been steadily increasing over the past 35 years.

During 2010, LG&E successfully initiated a URD cable rejuvenation pilot project to evaluate the feasibility of utilizing an insulation rejuvenation technology in aged, direct buried, underground cables that were exhibiting increasing failure rates. The technology provides a cost effective alternative to traditional cable replacement when used in a proactive cable infrastructure renewal program and is warranted to add 20 or more years of extended cable life at approximately one-half the cost of traditional replacement alternatives.

EDO's proposed funding will enable LG&E to continue with the program initiated in 2010, allow for proactive rejuvenation or replacement (where rejuvenation is not viable) of LG&E's oldest and poorest performing URD direct buried cable, and allow for limited reactive rejuvenation of failed URD cable. This will help increase system reliability, minimize customer disruptions, and reduce the likelihood of accelerated reactive URD cable replacement costs in future years. The program prioritizes selected assets by age, failure history, customer impact, and URD circuits identified for improvement (CIFI).

The URD cable rejuvenation process includes the following activities:

- Capacity and condition assessment of the cable neutral;
- Flow test through phase conductor strands to verify injectability;
- Replacement of existing terminating equipment with injection capable devices;
- Injection of proprietary dielectric fluid into the cable stranding;
- Migration of dielectric fluid throughout cable insulation wall to restore dielectric strength; and,
- Tracking and tagging of rejuvenated segments for warranty and asset records.

Benefits of the process are:

- Significantly reduces the probability of in-service failures on rejuvenated circuit segments. To date, there have been (23) in-service failures of the rejuvenated cables segments in the LG&E service territory, which is less than 1% of the more than 2,600 rejuvenated segments. This also equates to one failure for every 32,075 circuit feet (or 6.1 circuit miles) of rejuvenated cables.
- Increases the remaining life of cables by 20 years or more at approximately half the cost of traditional physical replacement.
- Avoids future repair costs of rejuvenated cable segments, otherwise allowed to run-to-failure.

- **Alternatives Considered**

1. Recommendation: NPVRR: ($000s) $2,157k
The recommended option is the LG&E URD Cable Rejuvenation/Replacement project for $1.701M for 2019 in order to reduce in-service failure rates on aged, medium voltage direct buried cable systems presently operating beyond designed lives. The average blended cost to replace or rejuvenate (when viable) is $13.60/ft.

2. Do Nothing: NPVRR: ($000s) $4,534k
If no action is taken, the aged and failing population of direct buried residential (URD) cables will be allowed to run-to-failure prior to replacement. The existing LG&E run-to-failure program permits each cable segment on a URD circuit to fail up to three times prior to scheduled replacement. The average residential underground customer on a system with an average of 7 segments per URD circuit will experience up to 21 outage events of 4 hour durations (and additional short term interruptions following subsequent repair) before a URD circuit is replaced in its entirety. It is expected that all untreated original pre-1980 cable will require replacement during the next 8 years. A do-nothing alternative will subject underground residential customers to significantly greater outages caused by cable failure. The do-nothing alternative provides a total annualized cost of $577k, which is comprised of two parts. The first is the cost of unscheduled outages, which can be avoided by proactively and reactively replacing cable ($264k). The second cost is from the unserved energy during these unscheduled outages ($313k). This contributes an estimated 1.38 SAIDI minutes at the LG&E system level.

3. Alternative #2: NPVRR: ($000s) $3,965k
There are no favorable economic alternatives to a balanced rejuvenation/replacement program for addressing aged and deteriorating URD primary cable systems.
A <u>proactive replacement only</u> program requires the complete physical replacement of the aged cables prior to reaching unacceptable failure rates and reliability levels. A proactive replacement only program can address less than half of the number of segments for the same level of funding as the rejuvenation and replacement program recommended, and thus would be a more costly program. The cost to replace the injectable cable in recommendation #1 is on average $25/ft, or $3.127M for the same 125,000 ft of cable.

## Project Description

- **Project Scope and Timeline**
The LG&E subdivisions determined to be the worst performing URD circuits composed of direct buried, pre-mid-1980's assets, are planned for the 2019 rejuvenation and replacement work. Additionally, a number of failed cables will be evaluated for reactive repair and rejuvenation.

- **Project Cost**
  The 2019 proposed estimate for this work is $1.701M for both rejuvenation and replacement (where rejuvenation is not viable). Project costs include the ancillary costs associated with replacing terminations and splices. There is no contingency in this project.

  Based on past rejuvenation experience, the program provides a 24% replacement and 76% rejuvenation split. The $1.701M proposed in 2019 is estimated to address approximately 125,000 feet of cable at a blended cost of approximately $13.60/ft.

**Economic Analysis and Risks**

- **Bid Summary**
  Contract labor for the proposed rejuvenation program will be provided by Novinium Inc. under an existing cable rejuvenation contract, which took effect on January 1, 2017. Novinium purchased UtilX, who was their only competitor in this space.

  Replacement contract labor will be provided by LG&E resident contract crews under their existing approved contracts.

- **Budget Comparison and Financial Summary**

| Financial Detail by Year - Capital ($000s) | 2019 | 2020 | 2021 | Post 2021 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 1,701 | - | - | - | 1,701 |
| 2. Cost of Removal Proposed | - | - | - | - | - |
| 3. Total Capital and Removal Proposed (1+2) | 1,701 | - | - | - | 1,701 |
| 4. Capital Investment 2019 BP | 1,701 | - | - | - | 1,701 |
| 5. Cost of Removal 2019 BP | - | - | - | - | - |
| 6. Total Capital and Removal 2019 BP (4+5) | 1,701 | - | - | - | 1,701 |
| 7. Capital Investment variance to BP (4-1) | - | - | - | - | - |
| 8. Cost of Removal variance to BP (5-2) | - | - | - | - | - |
| 9. Total Capital and Removal variance to BP (6-3) | - | - | - | - | - |

| Financial Detail by Year - O&M ($000s) | 2019 | 2020 | 2021 | Post 2021 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | - | - | - | - | - |
| 2. Project O&M 2019 BP | - | - | - | - | - |
| 3. Total Project O&M variance to BP (2-1) | - | - | - | - | - |

**Financial Summary ($000s):**

| | |
|---|---|
| Discount Rate: | 6.59% |
| Capital Breakdown: | |
| Labor: | $ 3 |
| Contract Labor: | $ 1,536 |
| Materials: | $ 12 |
| Transportation: | $ 1 |
| Local Engineering: | $ 124 |
| Burdens: | $ 25 |
| Contingency: | $ 0 |
| Reimbursements: | ($ 0) |
| Net Capital Expenditure: | $ 1,701 |

- **Assumptions**
  Labor resource availability, weather conditions and work volumes will enable the proposed scope of work to be completed before December 2019.

- **Environmental**
  There is no environmental impact with this project.

- **Risks**
  There is minimal technical risk with this project as cable rejuvenation methods have a long history within the industry and are proven to extend cable system life. Prior to the pilot project in 2010, references from Duke Power, Dayton Power and Seattle Power & Light were contacted to discuss their cable rejuvenation experiences. The companies gave positive feedback on their cable rejuvenation processes and continue to use cable rejuvenation services.

  Rejuvenation services are warrantied against cable insulation failure by natural, age related causes for at least 20 years. In the event of a failure on a rejuvenated segment, Novinium will reimburse the original rejuvenation injection fee any time in the 20 year warranty period. An average of 2.6 segments per year have failed after having been injected, which yields a less than 1% failure rate.

**Conclusions and Recommendation**

EDO recommends that Management approve the LG&E URD Cable Replacement/Rejuvenation Program for 2019 spending of $1.701M as a program to rejuvenate or replace aging URD direct buried cables, helping to improve system reliability and customer satisfaction.

Investment Proposal for Investment Committee Meeting on: November 28, 2017

Project Name: LG&E URD Cable Replacement/Rejuvenation Program-2018

Total Expenditures: $2.162M

Project Number(s): 148920

Business Unit/Line of Business: Electric Distribution Operations

Prepared/Presented By: Rob Wolf / Steve Woodworth

**Executive Summary**

Electric Distribution Operations (EDO) seeks approval to invest $2.162M on proactive and reactive cable rejuvenation and replacement during 2018. This proposed program will target LG&E Underground Residential Development (URD) direct buried cables installed between the mid-1960s and mid-1980s.

Cable rejuvenation is a cable life extension technology where a dielectric fluid is injected into conductor strands of in-service medium voltage cable to restore its dielectric characteristics to near-new cable levels. The technology provides a cost effective alternative to traditional cable replacement when used in a proactive cable infrastructure renewal program.

EDO's proposed funding level will provide for proactive rejuvenation of targeted LG&E URD cable sections prioritized based on cable age, failure and repair history, customer impact, and overall circuit performance. Additionally, the funding level will provide for replacement of any prioritized cable sections that cannot be rejuvenated with the life extension technology. The 2018 Business Plan (BP) includes $2.162M. These funds will continue the proactive program EDO has traditionally used, and will also allow for a small number of reactive cable injections. Reactive rejuvenation will enable EDO to rejuvenate a cable immediately after a repair following a cable failure.

Alternatives to the proposed rejuvenation program include proactive replacement of cables and/or reactive repair or replacement of failed cables on a run-to-failure basis. These alternatives are more costly, and the run to failure alternative is not recommended due to the known impacts that cable failures have on system reliability and customer experience.

EDO included $2.162M in its proposed 2018 Business Plan for 2018 cable rejuvenation or replacement.

## Background

Over the last five years, LG&E has averaged 156 URD primary cable failures per year, with a maximum single year failure rate of 166 in 2016. Over 95% of failures occurred on 1st and 2nd generation solid dielectric cables installed in underground residential subdivisions between the mid-1960's and mid-1980's. Failure rates on these 30-year design life systems have been steadily increasing over the past 35 years.

During 2010, LG&E successfully initiated a URD cable rejuvenation pilot project to evaluate the feasibility of utilizing an insulation rejuvenation technology in aged, direct buried, underground cables that were exhibiting increasing failure rates. The technology provides a cost effective alternative to traditional cable replacement when used in a proactive cable infrastructure renewal program and is warranted to add 20 or more years of extended cable life at approximately one-half the cost of traditional replacement alternatives.

EDO's proposed funding will enable LG&E to continue with the program initiated in 2010, allow for proactive rejuvenation or replacement (where rejuvenation is not viable) of LG&E's oldest and poorest performing URD direct buried cable, and allow for limited reactive rejuvenation of failed URD cable. This will help increase system reliability, minimize customer disruptions, and reduce the likelihood of accelerated reactive URD cable replacement costs in future years. The program prioritizes selected assets by age, failure history, customer impact, and URD circuits identified for improvement (CIFI).

The URD cable rejuvenation process includes the following activities:

- Capacity and condition assessment of the cable neutral;
- Flow test through phase conductor strands to verify injectability;
- Replacement of existing terminating equipment with injection capable devices;
- Injection of proprietary dielectric fluid into the cable stranding;
- Migration of dielectric fluid throughout cable insulation wall to restore dielectric strength; and,
- Tracking and tagging of rejuvenated segments for warranty and asset records.

Benefits of the process are:

- Significantly reduces the probability of in-service failures on rejuvenated circuit segments. To date, there have been (17) in-service failures of the rejuvenated cables segments in the LG&E service territory, which is less than 1% of the more than 2,100 rejuvenated segments. This also equates to one failure for every 35,700 circuit feet (or 6.8 circuit miles) of rejuvenated cables.
- Increases the remaining life of cables by 20 years or more at approximately half the cost of traditional physical replacement.
- Avoids future repair costs of rejuvenated cable segments, otherwise allowed to run-to-failure.

- **Alternatives Considered**

1. Recommendation: NPVRR: ($000s) $2,813k
   The recommended option is the LG&E URD Cable Rejuvenation/Replacement project for $2.162M for 2018 in order to reduce in-service failure rates on aged, medium voltage direct buried cable systems presently operating beyond designed lives. The average blended cost to replace or rejuvenate (when viable) is $13.75/ft.

2. Do Nothing: NPVRR: ($000s) $6,773k
   If no action is taken, the aged and failing population of direct buried residential (URD) cables will be allowed to run-to-failure prior to replacement. The existing LG&E run-to-failure program permits each cable segment on a URD circuit to fail up to three times prior to scheduled replacement. The average residential underground customer on a system with an average of 7 segments per URD circuit will experience up to 21 outage events of 4 hour durations (and additional short term interruptions following subsequent repair) before a URD circuit is replaced in its entirety. It is expected that all untreated original pre-1980 cable will require replacement during the next 9 years. A do-nothing alternative will subject underground residential customers to significantly greater outages caused by cable failure. The do-nothing alternative provides a total annualized cost of $725k, which is comprised of two parts. The first is the cost of unscheduled outages, which can be avoided by proactively and reactively replacing cable ($393k). The second cost is from the unserved energy during these unscheduled outages ($332k). This contributes an estimated 1.43 SAIDI minutes at the LG&E system level.

3. Alternative #2: NPVRR: ($000s) $5,106k
   There are no favorable economic alternatives to a balanced rejuvenation/replacement program for addressing aged and deteriorating URD primary cable systems.
   A proactive replacement only program requires the complete physical replacement of the aged cables prior to reaching unacceptable failure rates and reliability levels. A proactive replacement only program can address less than half of the number of segments for the same level of funding as the rejuvenation and replacement program recommended, and thus would be a more costly program. The cost to replace the injectable cable in recommendation #1 is on average $25/ft, or $3.925M for the same 157,000 ft of cable.

**Project Description**

- **Project Scope and Timeline**
  The LG&E subdivisions determined to be the worst performing URD circuits composed of direct buried, pre-mid-1980's assets, are planned for the 2018 rejuvenation and replacement work. Additionally, a number of failed cables will be evaluated for reactive repair and rejuvenation.

- **Project Cost**
  The 2018 proposed estimate for this work is $2.162M for both rejuvenation and replacement (where rejuvenation is not viable). Project costs include the ancillary costs associated with replacing terminations and splices. There is no contingency in this project.

  Based on past rejuvenation experience, the program provides a 25% replacement and 75% rejuvenation split. The $2.162M proposed in 2018 is estimated to address approximately 157,000 feet of cable at a blended cost of approximately $13.75/ft.

**Economic Analysis and Risks**

- **Bid Summary**
  Contract labor for the proposed rejuvenation program will be provided by Novinium Inc. under an existing cable rejuvenation contract, which took effect on January 1, 2017. Novinium purchased UtilX, who was their only competitor in this space.

  Replacement contract labor will be provided by LG&E resident contract crews under their existing approved contracts.

- **Budget Comparison and Financial Summary**

| Financial Detail by Year - Capital ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 2,162 | - | - | - | 2,162 |
| 2. Cost of Removal Proposed | - | - | - | - | - |
| 3. Total Capital and Removal Proposed (1+2) | 2,162 | - | - | - | 2,162 |
| 4. Capital Investment 2018 BP | 2,162 | - | - | - | 2,162 |
| 5. Cost of Removal 2018 BP | - | - | - | - | - |
| 6. Total Capital and Removal 2018 BP (4+5) | 2,162 | - | - | - | 2,162 |
| 7. Capital Investment variance to BP (4-1) | - | - | - | - | - |
| 8. Cost of Removal variance to BP (5-2) | - | - | - | - | - |
| 9. Total Capital and Removal variance to BP (6-3) | - | - | - | - | - |

| Financial Detail by Year - O&M ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | - | - | - | - | - |
| 2. Project O&M 2018 BP | - | - | - | - | - |
| 3. Total Project O&M variance to BP (2-1) | - | - | - | - | - |

**Financial Summary ($000s):**

| | |
|---|---|
| Discount Rate: | 6.32% |
| Capital Breakdown: | |
| Labor: | $ 0 |
| Contract Labor: | $ 1,623 |
| Materials: | $ 299 |
| Local Engineering: | $ 173 |
| Burdens: | $ 67 |
| Contingency: | $ 0 |
| Reimbursements: | ($ 0) |
| Net Capital Expenditure: | $ 2,162 |

- **Assumptions**
  Labor resource availability, weather conditions and work volumes will enable the proposed scope of work to be completed before December 2018.

- **Environmental**
  There is no environmental impact with this project.

- **Risks**
  There is minimal technical risk with this project as cable rejuvenation methods have a long history within the industry and are proven to extend cable system life. Prior to the pilot project in 2010, references from Duke Power, Dayton Power and Seattle Power & Light were contacted to discuss their cable rejuvenation experiences. The companies gave positive feedback on their cable rejuvenation processes and continue to use cable rejuvenation services.

  Rejuvenation services are warrantied against cable insulation failure by natural, age related causes for at least 20 years. In the event of a failure on a rejuvenated segment, Novinium will reimburse the original rejuvenation injection fee any time in the 20 year warranty period.. An average of 2.1 segments per year have failed after having been injected, which yields a less than 1% failure rate.

**Conclusions and Recommendation**
EDO recommends that the Investment Committee approve the LG&E URD Cable Replacement/Rejuvenation Program for 2018 spending of $2.162M as a program to rejuvenate or replace aging URD direct buried cables, helping to improve system reliability and customer satisfaction.

**Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:**

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

| | |
|---|---|
| Kent W. Blake<br>Chief Financial Officer | Paul W. Thompson<br>President and Chief Operating Officer |

Investment Proposal for Investment Committee Meeting on: December 20, 2017

Project Name: Distribution Wood Pole Inspection and Maintenance Program - 2018

Total Expenditures: $11,920k (Including $238k of contingency)

Project Number(s): LGE: 18PITP340, KU: 18PITP216, 18PITP156, 18PITP246, 18PITP315, 18PITP766, 18PITP416, 18PITP366, 18PITP236 and 18PITP426

Business Unit/Line of Business: Electric Distribution Operations / Distribution

Prepared/Presented By: John Ashton / Denise Simon

## Executive Summary

The Investment Committee approved the Electric Distribution Operations' Distribution Wood Pole Inspection and Maintenance Program on February 24, 2010, with the provision that future year investments in the program be presented and approved annually. The purpose of this Investment Proposal is to obtain 2018 program funding authority from the Investment Committee. The 2018 program scope is focused on providing a detailed pole inspection, preservative re-treatment and load analysis of approximately 65,000 poles and the reinforcement or replacement of structures found to be defective. The program projections for 2018 include replacement of 2,300 defective poles and reinforcement of 200 poles.

The other option considered is to inspect only on the 2-year KPSC required inspection cycle. This type of inspection is not rigorous enough to adequately identify at-risk poles, does not inspect for ground line rot and does not include pole loading calculations. Foregoing a pole inspection and treatment program and depending only on the regulatory cycle inspections will result in decreased life of the assets and will increase pole failures and associated outages.

The 2018 Business Plan (BP) includes $11,920k for this program in 2018.

## Background

The Distribution Wood Pole Inspection and Maintenance Program was implemented in 2010. By year end 2017, approximately 432,000 poles will have been inspected, and 138,000 poles will have been treated, 16,800 poles will have been replaced and 1,500 poles will have been reinforced by splinting. Cumulative spend from 2010-2016 is $68 million with the 2017 forecasted spend at $10.4 million.

EDO has more than 516,000 distribution wood poles in the asset base with an estimated average age of 30 years. An additional 156,000 foreign-owned poles have LG&E and KU attachments.

Wood poles are initially treated with a preservative during processing to extend the life of the pole. The effectiveness of the initial preservative treatment declines with age. Wood poles become more susceptible to deterioration from fungal decay and insect damage. In most cases, the decay is difficult to detect because it occurs out of sight just below the ground-line where conditions of moisture, temperature and air are most favorable for growth of fungi. Ground-line is also the point of maximum loading stress for a pole.

In addition to the wood pole inspection program, distribution poles receive an inspection every two years in accordance with KPSC requirements. During these inspections, only a small percentage of poles are inspected near ground-line or tested to detect internal decay. No poles are excavated to inspect below ground-line which is critical for detecting decay. Continuing the wood pole inspection program as proposed will enhance the ability to detect decay and extend the life of the treated and reinforced poles.

A survey of utilities confirms that the industry typical program generally involves inspecting and applying a supplemental treatment to the ground-line area on every pole. The supplemental treatment arrests any decay present and can significantly increase the useful life of the pole at a very small cost relative to the cost to replace a pole. One industry study indicates the predicted pole life with no remedial treatment is 32.5 years compared to a predicted pole life of greater than 50 years for poles with remedial treatment.

By associating historical pole failure outage data with previously completed PITP circuits, there is an annual SAIDI and SAIFI benefit of 0.52 minutes and 0.002 interruptions per customer, respectively, through the Pole Inspection and Treatment Program.

EDO's program is "condition based," such that the level of inspection and re-treatment is dependent on each pole's actual condition. The use of a "condition based" approach provides a cost effective strategy to inspect and re-treat poles. Inspection will include above and below grade evaluations. Re-treating and load analysis will only be performed on the poles that indicate a need. The program entails a progressive level of inspection for each pole and re-treatment only when necessary. In conjunction with the pole inspection, pole loading will be assessed. Any pole found to be loaded beyond acceptable limits will be reinforced or replaced. Joint-use poles not owned by LGE and KU will only receive a loading analysis.

The estimated 2018-2022 capital costs included in the 2018BP are shown below. This proposal only requests funding for 2018.

| | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| Amount in 000s | $11,920 | $12,278 | $12,646 | $13,025 | $13,416 |

- **Alternatives Considered**

  1. Recommendation: NPVRR: ($000s) $16,060

  2. Alternative #1: NPVRR: ($000s) $48,643
     Electing not to continue the PITP program would result in an increase in pole failures and outages. The NPVRR shown is the combination of the investment to replace poles as they fail rather than proactively (capital costs of $10,358k), and the resulting cost of unserved energy from these failures (costs of $37,193k). Projections indicate approximately 2,300 poles will be replaced as part of the PITP program during 2018. Without remedial actions, these 2,300 poles are projected to fail within 2 years. The cost of unserved energy was calculated using the projected number of pole failures over the next two years along with the 5-year average outage duration of preventable, pole-related failures. During a pole-failure outage, the time required to restore the outage is nearly 2.5 times longer than that of an outage taken for planned pole replacement work.

## Project Description

- **Project Scope and Timeline**
  - The 2018 pole inspection and treatment program will begin in January of 2018. Inspection crews will plan to complete work in 9 months. Pole replacement crews will begin work in January and work through December of 2018. This program covers distribution poles only. Transmission poles are covered under a separate inspection program.

- **Project Cost**
  - The total estimated capital project cost for 2018 is $11,920k and $63,285k over the BP period of 2018-2022.

  - A capital contingency of 2% for the program is included to cover any variables that may deviate from the business plan projections (i.e. higher pole reject rates and miscellaneous costs such as ground-wire repairs).

## Economic Analysis and Risks

- **Bid Summary**
  - The inspection and treatment work is completed by Lost Time Control West (DBA GeoForce Utility Technologies). The contract was approved at the November 2014 Investment Committee and will expire December 31, 2019.

  - Pole replacements will be performed by contract labor under currently approved contracts and unit prices. The wood poles used will be purchased under an existing contract for wood poles.

- **Budget Comparison and Financial Summary**

| Financial Detail by Year - Capital ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Capital Investment Proposed | 10,598 | - | - | - | 10,598 |
| 2. Cost of Removal Proposed | 1,322 | - | - | - | 1,322 |
| 3. Total Capital and Removal Proposed (1+2) | 11,920 | - | - | - | 11,920 |
| 4. Capital Investment 2018 BP | 10,598 | - | - | - | 10,598 |
| 5. Cost of Removal 2018 BP | 1,322 | - | - | - | 1,322 |
| 6. Total Capital and Removal 2018 BP (4+5) | 11,920 | - | - | - | 11,920 |
| 7. Capital Investment variance to BP (4-1) | - | - | - | - | - |
| 8. Cost of Removal variance to BP (5-2) | - | - | - | - | - |
| 9. Total Capital and Removal variance to BP (6-3) | - | - | - | - | - |

| Financial Detail by Year - O&M ($000s) | 2018 | 2019 | 2020 | Post 2020 | Total |
|---|---|---|---|---|---|
| 1. Project O&M Proposed | 490 | - | - | - | 490 |
| 2. Project O&M 2018 BP | 490 | - | - | - | 490 |
| 3. Total Project O&M variance to BP (2-1) | - | - | - | - | - |

The 2018 Business Plan includes this funding in projects 123136 and 123137 in the Reliability department. The projects listed on page 1 are the specific projects (in the applicable operations centers' departments) for which approval is requested. Funds will be moved from the budgeted projects to the specific operations center projects through the Corporate RAC process.

**Financial Summary ($000s):**

| | |
|---|---|
| Discount Rate: | 6.32% |
| Capital Breakdown: | |
| Labor: | $0 |
| Contract Labor: | $8,875 |
| Materials: | $1,320 |
| Local Engineering: | $1,125 |
| Burdens: | $362 |
| Contingency: | $238 |
| Reimbursements: | ($0) |
| Net Capital Expenditure: | $11,920 |

- **Assumptions**
  - Estimates are based on field experience from EDO inspections during the first eight years of the pole inspection and treatment program.
  - A minimal number of poles associated with structure loading will be replaced and the associated cost can be managed within existing funding.

- **Environmental**
  - There are no environmental issues. Chemicals used for the re-treatment of wood poles are EPA approved and will be applied by qualified contractors licensed for their application.

- **Risks**
  - Actual rejection rates could be greater than those experienced in previous years of the program resulting in the need for additional funding or an extended cycle to complete the program.
  - Average cost to replace a pole could increase significantly if the majority of rejects are located in metro areas.

**Conclusions and Recommendation**
EDO recommends the Investment Committee approve continuation of the Distribution Wood Pole Inspection and Maintenance Program, and authorize 2018 investments of $11,920k for the project. The program continues to enhance the life of EDO wood pole assets and contribute to improved reliability performance for customers.

**Approval Confirmation for Capital Projects Greater Than or Equal to $2 million:**

The Capital project spending included in this Investment Proposal has been approved by the members of the LKE Investment Committee. Pursuant to the LKE Authority Limit Matrix, the signatures below are also required for approval of this Capital project spending request.

| | | | |
|---|---|---|---|
| Kent W. Blake | Date | Paul W. Thompson | Date |
| Chief Financial Officer | | President and Chief Operating Officer | |

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 194**

**Responding Witness: Robert M. Conroy / John K. Wolfe**

Q-194. Reference the Bellar testimony at p. 50, wherein he states the Companies are considering an expansion of the Distribution Automation ("DA") program. LEB-6

a. If the Companies decide to expand the program as Mr. Bellar discusses, will they file a new CPCN with the Commission? If not, why not?

b. Regarding any potential expansion of the DA program, provide any and all cost benefit analyses the Companies may have conducted as to the proposed expansion, separate and distinct from the DA program as it currently exists.

A-194.

a. See the response to Question No. 42(a).

b. See the response to Question No. 42(b).

**KENTUCKY UTILITIES COMPANY**

**Response to Attorney General's Initial Data Requests for Information**
**Dated November 13, 2018**

**Case No. 2018-00294**

**Question No. 195**

**Responding Witness: Lonnie E. Bellar**

Q-195. Reference the Bellar testimony, p. 44, where he states: "The Transmission Reliability Outage Database System ("TRODS"), first implemented in 2014, has been continuously refined to simplify engineer access to disparate data to more readily determine the source of outages and prevent future outages."

a. Provide examples of the types of "disparate data" that the TRODS system provides to engineers.

b. Explain how the TRODS system has provided savings to ratepayers, and provide any and all quantifications of those savings, if applicable.

A-195.

a. TRODS combines data from the following data sources:

1. TOA (Transmission Outage Application – Operational process tool)
2. Cascade (substation asset management)
3. LOAD (facility ratings tool)
4. Power Plan (financial information)
5. Lightning database
6. AP SADE (vegetation)
7. Geospatial information for facility locations and outage locations
8. Customer outage information
9. InSITE (GIS and work management system for transmission lines)

b. As stated in testimony, TRODS simplifies the access to information which allows engineers to spend less time gathering data and make better decisions. However, no quantification of savings has been developed for TRODS.