NEW ISSUE - BOOK ENTRY ONLY

In the opinion of Squire Patton Boggs (US) LLP, Bond Counsel, under existing law (i) assuming continuing compliance with certain covenants and the accuracy of certain representations, interest on the Bonds is excluded from gross income for federal income tax purposes, except interest on any Bond for any period during which it is held by a "substantial user" or a "related person," as those terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"), (ii) interest on the Bonds is an item of tax preference under Section 57 of the Code for purposes of the federal alternative minimum tax imposed on individuals and corporations, and (iii) the Bonds, and all interest and income thereon, are exempt from all taxation by the State of West Virginia and any county, municipality, political subdivision or agency thereof, except inheritance taxes. Interest on the Bonds may be subject to certain federal taxes imposed only on certain corporations. See TAX EXEMPTION.

$65,000,000
West Virginia Economic Development Authority
Solid Waste Disposal Facilities Revenue Refunding Bonds
(Kentucky Power Company – Mitchell Project),
Series 2014A

Interest to accrue from date of issuance Due: April 1, 2036

The Series 2014A Bonds (the "Bonds") are limited obligations of the West Virginia Economic Development Authority (the "Issuer"), and do not constitute an indebtedness or a charge against the general credit of the Issuer or the State of West Virginia. The Bonds are payable solely from, and secured by a pledge of, the loan repayments under a note issued under the terms of a Loan Agreement (the "Agreement") between the Issuer and

KENTUCKY POWER COMPANY

(the "Company") and from funds drawn under an irrevocable direct pay letter of credit (the "Letter of Credit") issued by

SUMITOMO MITSUI BANKING CORPORATION

The Letter of Credit will permit the Trustee, The Bank of New York Mellon Trust Company, N.A., to draw up to (a) an amount sufficient to pay (i) the principal of the Bonds when due at maturity or upon redemption or acceleration and (ii) the portion of the purchase price of the Bonds tendered to the Trustee and not remarketed or for which remarketing proceeds have not been timely received by the draw time under the Letter of Credit corresponding to the principal amount of such Bonds, plus (b) an amount equal to 35 days' interest on the Bonds at a maximum rate of 12% per annum to pay (i) interest on the Bonds when due and (ii) the portion of the purchase price of the Bonds tendered to the Trustee and not remarketed or for which remarketing proceeds have not been timely received by the draw time under the Letter of Credit corresponding to the accrued interest on such Bonds. The Letter of Credit will expire on June 26, 2017 or on the earliest occurrence of one or more of the events described herein, unless extended by Sumitomo Mitsui Banking Corporation (the "Letter of Credit Bank") (see *THE LETTER OF CREDIT AND REIMBURSEMENT AGREEMENT-- The Letter of Credit* herein). Unless the Letter of Credit is replaced or extended as described herein, the Bonds will be subject to mandatory purchase prior to its expiration.

The Bonds will initially bear interest at a Weekly Rate determined by the Remarketing Agent (as defined herein) as described under *THE BONDS -- Form and Denomination of Bonds; Payments on the Bonds -- Interest* herein, payable on the first Business Day of each month commencing July 1, 2014. Upon satisfaction of the conditions specified in the Indenture, the Company may from time to time change the interest rate determination method for the Bonds to a Daily Rate, a Weekly Rate or certain other interest rate modes provided for in the Indenture.

The Bonds are subject to mandatory tender and redemption as described under *THE BONDS – Mandatory Tender for Purchase* and *THE BONDS -- Redemption of Bonds* herein. When a Daily Rate or Weekly Rate is in effect for the Bonds, holders of the Bonds will have the option to tender their Bonds for purchase as described under *THE BONDS -- Optional Tender* herein.

While the Bonds bear interest at a Daily Rate or a Weekly Rate they will be issued as fully registered bonds in denominations of $100,000 and any larger denominations constituting an integral multiple of $5,000. The Bonds will be issued pursuant to an Indenture of Trust (the "Indenture"), between the Issuer and The Bank of New York Mellon Trust Company, N.A., as trustee (the "Trustee"). The Bonds will be issued as fully registered bonds and will be registered initially in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company, New York, New York ("DTC"). DTC acts as a securities depository for the Bonds. Except under the limited circumstances described herein, Beneficial Owners of book-entry interests in Bonds will not receive certificates representing their interests. Payments of principal or purchase price of and interest on the Bonds will be made through DTC and disbursements of such payments to Beneficial Owners will be the responsibility of DTC and its Participants. See *THE BONDS – Book-Entry Only System* herein. U.S. Bank Municipal Securities Group, a Division of U.S. Bank National Association, will act as underwriter (the "Underwriter") for the Bonds. U.S. Bancorp Investments, Inc. and U.S. Bank Municipal Securities Group, a Division of U.S. Bank National Association, will act as remarketing agent (the "Remarketing Agent") for the Bonds.

PRICE: 100%

This cover page contains limited information for quick reference only and is not a summary of this Official Statement. Investors should read the entire Official Statement to obtain information essential to the making of an informed investment decision.

The Bonds are offered, subject to prior sale, when, as and if issued and received by the Underwriter, subject to the approval of their validity by Squire Patton Boggs (US) LLP, Bond Counsel, as described herein, and certain other conditions. Certain legal matters, other than the validity of the Bonds and the exclusion from gross income for Federal income tax purposes of interest thereon, will be passed on for the Underwriter by its counsel, Hunton & Williams LLP, New York, New York, for the Letter of Credit Bank by its counsel, Winston & Strawn LLP and for the Company by its internal counsel. Delivery of the Bonds in book-entry-only form is expected on or about June 26, 2014, through the facilities of DTC in New York, New York, against payment therefor.

US Bancorp

Dated: June 19, 2014

CONTENTS OF OFFICIAL STATEMENT

No person has been authorized to give any information or to make any representations other than those contained in this Official Statement in connection with the offer made hereby and, if given or made, such information or representations must not be relied upon as having been authorized by the Issuer, the Company, the Letter of Credit Bank or the Underwriter. Neither the delivery of this Official Statement nor any sale hereunder shall under any circumstances create any implication that there has been no change in the affairs of the Issuer, the Letter of Credit Bank or the Company since the date hereof. This Official Statement does not constitute an offer or solicitation in any jurisdiction in which such offer or solicitation is not authorized, or in which the person making such offer or solicitation is not qualified to do so or to any person to whom it is unlawful to make such offer or solicitation. The Issuer neither has nor assumes any responsibility as to the accuracy or completeness of the information in this Official Statement, all of which has been furnished by others, other than information under *THE ISSUER*.

The Underwriter has provided the following sentence for inclusion in this Official Statement. The Underwriter has reviewed the information in this Official Statement in accordance with, and as a part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriter does not guarantee the accuracy or completeness of such information.

CERTAIN PERSONS PARTICIPATING IN THIS OFFERING MAY ENGAGE IN TRANSACTIONS THAT STABILIZE, MAINTAIN OR OTHERWISE AFFECT THE PRICE

OF THE BONDS, INCLUDING BY ENTERING STABILIZING BIDS. FOR A DESCRIPTION OF THESE ACTIVITIES, SEE *UNDERWRITING* HEREIN.

IN MAKING AN INVESTMENT DECISION, INVESTORS MUST RELY ON THEIR OWN EXAMINATION OF THE ISSUER, THE COMPANY AND THE TERMS OF THE OFFERING, INCLUDING THE MERITS AND RISKS INVOLVED. THESE SECURITIES HAVE NOT BEEN RECOMMENDED BY ANY FEDERAL OR STATE SECURITIES COMMISSION OR REGULATORY AUTHORITY. FURTHERMORE, THE FOREGOING AUTHORITIES HAVE NOT CONFIRMED THE ACCURACY OR DETERMINED THE ADEQUACY OF THIS OFFICIAL STATEMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

$65,000,000
West Virginia Economic Development Authority
Solid Waste Disposal Facilities Revenue Refunding Bonds
(Kentucky Power Company - Mitchell Project),
Series 2014A

INTRODUCTORY STATEMENT

This Official Statement, including the Appendices hereto, is provided to furnish certain information in connection with the issuance by the West Virginia Economic Development Authority, a public corporation and governmental instrumentality of the State of West Virginia ("Issuer") of its Solid Waste Disposal Facilities Revenue Refunding Bonds (Kentucky Power Company - Mitchell Project), Series 2014A, in the aggregate principal amount of $65,000,000 (the "Bonds"). The Issuer neither has nor assumes any responsibility as to the accuracy or completeness of the information in this Official Statement, all of which has been furnished by others, other than the information pertaining to the Issuer under *THE ISSUER*.

The Bonds will be issued under and pursuant to a resolution of the Issuer adopted on March 20, 2014 ("Resolution") and an Indenture of Trust, dated as of June 15, 2014 ("Indenture"), between the Issuer and The Bank of New York Mellon Trust Company, N.A., as trustee (in such capacity, the "Trustee"). Capitalized terms used herein and not otherwise defined shall have the meanings given to them in the Indenture.

Pursuant to a Loan Agreement, dated as of June 15, 2014 ("Agreement"), between the Issuer and Kentucky Power Company ("Company"), the Issuer will loan to the Company the proceeds of the Bonds to be used to provide funds to refund or to pay at redemption the Issuer's Solid Waste Disposal Facilities Revenue Bonds (Ohio Power Company – Mitchell Project) Series 2008A (the "Refunded Bonds"). The Refunded Bonds were issued to redeem bonds that were issued by the Issuer for the purpose of providing a portion of the funds for the acquisition, construction and improvement of solid waste disposal facilities (the "Project"), or portions thereof, designed for the disposal of solid wastes at the Mitchell Generating Station located near Moundsville, West Virginia (the "Plant").

In order to evidence the loan from the Issuer (the "Loan") and to provide for its repayment, the Company will issue a nonnegotiable promissory note (the "Note") pursuant to the Agreement. Payments required under the Note will be sufficient, together with any other funds on deposit in the Bond Fund (hereinafter described) under the Indenture, to pay the principal of and premium, if any, and interest on the Bonds and to make or provide for payments to the paying agent for the Bonds ("Paying Agent"), initially The Bank of New York Mellon Trust Company, N.A., equal to 100% of the principal amount of the Bonds plus accrued interest, if any, upon tender thereof ("Purchase Price"). The Bonds will not otherwise be secured by a mortgage on, or security interest in, any of the Project or any other property of the Company.

The Bonds will initially bear interest at a Weekly Rate until converted to another permitted interest rate mode as described herein. While accruing interest at the Daily or Weekly Rates, the Bonds are subject to optional and mandatory tender, as described herein. Bonds converted to a different interest rate mode will be subject to mandatory tender upon conversion.

When a Daily Rate or Weekly Rate is in effect for the Bonds, holders of the Bonds will have the option to tender their Bonds for purchase as described herein. The Daily Rate or Weekly Rate for an interest period for the Bonds will be determined by the Remarketing Agent as set forth in the Indenture.

While the Bonds bear interest at a Daily Rate or a Weekly Rate they will be issued in denominations of $100,000 and any larger denominations constituting an integral multiple of $5,000. The Bonds will be held by The Depository Trust Company ("DTC"), or its nominee, as securities depository with respect to the Bonds. See *THE BONDS – Book-Entry Only System*.

Concurrently with the issuance of the Bonds, the Company will cause to be delivered to the Trustee an irrevocable direct pay letter of credit (the "Letter of Credit") issued by the Letter of Credit Bank, in the initial aggregate stated amount of $65,747,945. Under the Letter of Credit, the Trustee will be permitted to draw up to (a) an amount sufficient to pay (i) the principal of the Bonds when due at maturity, redemption or acceleration and (ii) the portion of the Purchase Price of the Bonds tendered to the Trustee and not remarketed or for which remarketing proceeds have not been timely received by the draw time under the Letter of Credit corresponding to the principal amount of such Bonds, plus (b) an amount equal to 35 days' interest on the Bonds at a maximum rate of 12% per annum to pay (i) interest on the Bonds when due and (ii) the portion of the Purchase Price of the Bonds tendered to the Trustee and not remarketed or for which remarketing proceeds have not been timely received by the draw time under the Letter of Credit corresponding to the accrued interest on such Bonds. The expiration date of the Letter of Credit is June 26, 2017 unless earlier terminated or extended as described under *The Letter of Credit and Reimbursement Agreement—the Letter of Credit*. The Letter of Credit may be replaced by an Alternate Letter of Credit (as defined herein) prior to its expiration date as described under *The Letter of Credit and Reimbursement Agreement—Replacement of Letter of Credit* herein. If the Letter of Credit expires, is replaced by an Alternate Letter of Credit or is surrendered, the Bonds will be subject to mandatory tender for purchase, as described under *The Bonds — Mandatory Tender for Purchase* herein. The Letter of Credit will be issued pursuant to the Reimbursement Agreement dated as of June 26, 2014 (the "Reimbursement Agreement"), between the Letter of Credit Bank and the Company.

The Bonds are special obligations of the Issuer, and are to be paid solely from, and will be secured by a pledge of, payments to be made to the Issuer under the terms of the Agreement and funds drawn under the Letter of Credit. See *THE BONDS – Security for the Bonds.*

Brief descriptions of the Issuer, the Company, the Letter of Credit Bank and the Project and certain provisions of the Bonds, the Agreement, the Indenture, the Letter of Credit and the Reimbursement Agreement are included in this Official Statement. Certain information with respect to the Company is set forth in Appendix A hereto. Certain information with respect to the Letter of Credit Bank is set forth in Appendix B hereto. Appendix C to this Official Statement sets forth the form of opinion Bond Counsel proposes to deliver relating to the Bonds. The descriptions herein of provisions of the Agreement, the Indenture, the Letter of Credit and the Reimbursement Agreement are qualified in their entirety by reference to such documents, and the description herein of provisions of the Bonds is qualified in its entirety by reference to the form thereof included in the Indenture and the information with respect thereto included in the aforesaid documents. All such descriptions are further qualified in their entirety by reference to laws and principles of equity relating to or affecting generally the enforcement of creditor's rights. Copies of such documents may be obtained from the office of the Company and are available for inspection at the office of the Trustee. Words and terms not defined herein shall have the meanings set forth in the respective documents.

THE ISSUER

The West Virginia Economic Development Authority, empowered and authorized pursuant to Chapter 31, Article 15, Section 1, et. seq. of the Code of West Virginia, 1931, as amended (the "Act"), is a body corporate and politic, constituting a public corporation and government instrumentality of the State of West Virginia, with the power to borrow money and issue its bonds and other debt instruments for any of its purposes, and to finance making loans to finance any project to private corporations or to refund bonds issued for such purposes. Such projects include solid waste disposal facilities. The Issuer has no taxing power.

THE BONDS SHALL NOT CONSTITUTE A DEBT OR A PLEDGE OF THE FAITH AND CREDIT OR TAXING POWER OF THE STATE OF WEST VIRGINIA OR OF ANY COUNTY, MUNICIPALITY OR ANY OTHER POLITICAL SUBDIVISION OF THE STATE OF WEST VIRGINIA, AND THE HOLDERS AND OWNERS THEREOF SHALL HAVE NO RIGHT TO HAVE TAXES LEVIED BY THE LEGISLATURE OF THE STATE OF WEST VIRGINIA OR THE TAXING AUTHORITY OF ANY COUNTY, MUNICIPALITY OR ANY OTHER POLITICAL SUBDIVISION OF THE STATE OF WEST VIRGINIA FOR THE PAYMENT OF THE PRINCIPAL OF, INTEREST ON OR PURCHASE PRICE OF THE BONDS, BUT SHALL BE PAYABLE SOLELY FROM REVENUES AND FUNDS PLEDGED FOR ITS PAYMENT AS AUTHORIZED BY THE ACT.

THE PROJECT

The Project consists of various systems which are designed for the disposal of solid wastes resulting from the operation of the Plant. The solid waste disposal facilities are comprised of the portion of the flue gas desulfurization system (the "FGD System") constructed with respect to the two 800 megawatt units at the Plant that relates to the disposal of solid waste generated as part of the FGD System.

USE OF PROCEEDS

The Issuer will cause the proceeds received upon sale of the Bonds to be deposited into the Refunding Fund created under the Indenture to be used to refund the Refunded Bonds within 90 days of the issuance of the Bonds. See *THE INDENTURE– Refunding Fund*.

THE BONDS

This Official Statement does not provide any information regarding the Bonds after the date, if any, on which the Bonds convert to bear interest, as permitted by the Indenture, at interest rates other than a Daily Rate or Weekly Rate. The Bonds are subject to

mandatory tender in the event of any such conversion. See *THE BONDS -- Mandatory Tender for Purchase* below.

The Bonds are special obligations of the Issuer and will be payable solely from the revenues and receipts arising out of or in connection with the Loan Agreement and funds drawn under the Letter of Credit.

General

The Bonds will be dated as of the date of the initial authentication and delivery thereof and will mature on April 1, 2036. The Bonds initially will bear interest at a Weekly Rate commencing on the date of the issuance of the Bonds, subject to conversion to other interest rate modes as described herein.

Beneficial interests in the Bonds will initially be issued pursuant to a Book-Entry Only System ("Book-Entry Only System") maintained by The Depository Trust Company, New York, New York ("DTC"), as described below under the caption *Book-Entry Only System*. Under the Indenture, the Issuer may appoint a successor securities depository to DTC. (DTC, together with any such successor securities depository, is hereinafter referred to as the "Securities Depository"). The following information is subject in its entirety to the provisions described below under the caption *Book-Entry Only System* while the Bonds are in the Book-Entry Only System.

Upon surrender of the Bonds, principal of and premium, if any, on the Bonds are payable at maturity or upon redemption at the principal office of the Trustee. As long as the Bonds are held by DTC, interest will be paid to DTC on each payment date. If the book-entry system is discontinued, interest on the Bonds will be payable by check or draft mailed by the Trustee to the registered owners.

Form and Denomination of Bonds; Payments on the Bonds

<u>General</u>

While the Bonds bear interest at a Daily Rate or a Weekly Rate they will be issued only as fully registered bonds, without coupons, in denominations of $100,000 and any larger denomination constituting an integral multiple of $5,000 (an "Authorized Denomination"). The Bonds will be registered in the name of Cede & Co., as registered owner and nominee of DTC. DTC acts as securities depository for the Bonds and individual purchases of Bonds may be made in book-entry form only. So long as the Bonds are in book-entry only form, purchasers of Bonds will not receive certificates representing their interest in the Bonds purchased. So long as Cede & Co. is the registered owner of such Bonds, as nominee of DTC, references herein to the Bondholders or registered owners or holder shall mean Cede & Co., and shall not mean the Beneficial Owners (as defined below) of the Bonds.

So long as Cede & Co. is the registered owner of the Bonds, principal of and interest on the Bonds are payable to Cede & Co., as nominee for DTC, which will, in turn, remit such amounts to the DTC Participants (as defined below) for subsequent disbursement to the Beneficial Owners. See – *Book-Entry Only System* below.

The Bank of New York Mellon Trust Company, N.A. has been appointed as Trustee and Paying Agent under the Indenture. The designated office of the Trustee and Paying Agent is located at 6525 W. Campus Oval, 2nd Floor, New Albany, Ohio 43054.

The Trustee will not be required to make any transfer or exchange of any Bond during the ten days prior to the mailing of a notice of Bonds selected for redemption or, with respect to a Bond, after such Bond or any portion thereof has been selected for redemption. Registration of transfers and exchanges shall be made without charge to the Bondholders, except that any required taxes or other governmental charges shall be paid by the Bondholder requesting registration of transfer or exchange.

Interest

Interest on the Bonds will be payable as described below. Interest on the Bonds initially will be payable at a Weekly Rate on the first Business Day of each month, commencing July 1, 2014. The interest rate determination method for the Bonds may be changed by the Company as described under *Change in Interest Rate Determination Method* below. See *Summary* below for a table summarizing certain provisions of the Bonds.

"*Business Day*" means any day other than (i) a Saturday or Sunday, (ii) a day on which commercial banks in New York, New York or the city in which the designated corporate trust office of the Trustee or the principal office of the Remarketing Agent or payment office of the Letter of Credit Bank is located, are required or authorized by law to close, or (iii) a day on which the New York Stock Exchange is closed.

Interest will accrue on the unpaid portion of the principal of the Bonds from the last date to which interest was paid, or if no interest has been paid, from the date of the original issuance of the Bonds until the entire principal amount of the Bonds is paid. When interest is payable at a Daily or Weekly Rate, interest will be computed on the basis of the actual number of days elapsed over a year of 365 days (366 days in leap years).

Daily Rate. When interest on the Bonds is payable at a Daily Rate, the Remarketing Agent will set a Daily Rate on or before 10:00 A.M., New York City time, on each Business Day for that Business Day. Each Daily Rate will be the minimum rate necessary (as determined by the Remarketing Agent based on the examination of tax-exempt obligations comparable to the Bonds known by the Remarketing Agent to have been priced or traded under then-prevailing market conditions) for the Remarketing Agent to sell the Bonds on the day the Daily Rate is set at their principal amount (without regard to accrued interest). The Daily Rate for any non-Business Day will be the rate for the last day for which a rate was set.

Weekly Rate. When interest on the Bonds is payable at a Weekly Rate, the Remarketing Agent will set a Weekly Rate on or before 5:00 P.M., New York City time, on the last Business Day before the commencement of a period during which the Bonds are to bear interest at a Weekly Rate and on each Wednesday thereafter so long as interest on the Bonds is to be payable at a Weekly Rate or, if any Wednesday is not a Business Day, on the next preceding Business Day. Each Weekly Rate will be the minimum rate necessary (as determined by the Remarketing Agent based on the examination of tax-exempt obligations comparable to the Bonds known by the Remarketing Agent to have been priced or traded under then-prevailing market conditions) for the Remarketing Agent to sell the Bonds on the date the Weekly Rate is set at their principal amount (without regard to accrued interest). Each Weekly Rate shall apply to (i) the period beginning on the Thursday after the Weekly Rate is set and ending on the following Wednesday or, if earlier, ending on the day before the effective date of a new method of determining the interest rate on the Bonds or (ii) the period beginning on the effective date of the change to a Weekly Rate and ending on the next Wednesday.

<u>Fallback Interest Period and Rate</u>. If the appropriate Daily or Weekly Rate is not or cannot be determined for any reason, the method of determining interest on the Bonds will be payable at the Alternate Rate.

"Alternate Rate" means, as of any date, the rate equal to The Securities Industry and Financial Markets Association ("SIFMA") Municipal Swap Index of Municipal Market Data most recently available as of the date of determination or, if such index is no longer available, or if the rate is no longer published, a comparable index as described in the Indenture.

<u>Calculation and Notice of Interest</u>. The Remarketing Agent will provide the Trustee and the Company with notice in writing or by other written electronic means or by telephone promptly confirmed by facsimile transmission by 1:00 P.M., New York City time, (i) on the last Business Day of a month in which interest on the Bonds was payable at a Daily Rate, of the Daily Rate for each day in such month, (ii) on each day on which a Weekly Rate becomes effective, of the Weekly Rate and (iii) on any Business Day preceding any redemption or purchase date, any interest rate requested by the Trustee in order to enable it to calculate the accrued interest, if any, due on such redemption or purchase date. Using the rates supplied by such notice, the Trustee will calculate the interest payable on the Bonds. The Remarketing Agent will inform the Trustee and the Company orally at the oral request of either of them of any interest rate so set. The Trustee will confirm the effective interest rate in writing to any Bondholder who requests it.

The setting of the rates by the Remarketing Agent and the calculation of interest payable on the Bonds by the Trustee as provided in the Indenture will be conclusive and binding on the Issuer, the Company, the Trustee and the owners of the Bonds.

<u>Change in Interest Rate Determination Method</u>. The Company may change the method of determining the interest rate on all but not part of the Bonds, from time to time by notifying the Issuer, the Trustee, the Letter of Credit Bank and the Remarketing Agent. The Company's notice will specify (i) the effective date of the proposed change in interest rate determination method, (ii) the proposed interest rate determination method and (iii) a statement as to whether the Letter of Credit shall be terminated in connection with such change. The interest rate payable on the Bonds will be payable at the proposed rate on the effective date specified in the Company's notice, provided that: (i) the Company's notice complies with the provisions of the Indenture and the change to the proposed interest rate determination method complies with

certain limitations set forth in the Indenture; and (ii) a Favorable Opinion of Tax Counsel required under the Indenture has been delivered with the notice (see *Cancellation of Change in Interest Rate Determination Method if Opinion of Tax Counsel is Not Confirmed* below). It is currently anticipated that, should any of the Bonds be converted to bear interest at any rate other than a Daily Rate or a Weekly Rate, a reoffering memorandum or reoffering circular will be distributed describing the Bonds while they bear interest at any such interest rate.

Notice of Change in Interest Rate Determination Method. The Trustee, upon receiving notice from the Company pursuant to the Indenture, is required to give at least 15 days written notice by first-class mail to the Bondholders before the effective date of a change in the interest rate determination method. Each notice will be effective when sent and will state: (i) that the interest rate determination method will change and what the new method will be; (ii) the proposed effective date of the new interest rate; and (iii) that the Bonds will be subject to mandatory tender on the effective date of the change and the information required to be included in a notice of tender pursuant to the Indenture. See *Mandatory Tender for Purchase-Notice of Tender* below.

Cancellation of Change in Interest Rate Determination Method if Opinion of Tax Counsel is Not Confirmed. No change will be made in the interest rate determination method at the direction of the Company as described under *Change in Interest Rate Determination Method* above if the Company shall fail to deliver the Favorable Opinion of Tax Counsel described under *Change in Interest Rate Determination Method* above. If notice of a change in the interest rate determination method has been mailed and, subsequently, a Favorable Opinion of Tax Counsel is rescinded, then the Trustee shall so notify the bondholders and the Bonds shall still be subject to a mandatory tender on the proposed date of change in the interest rate determination method and the Remarketing Agent shall remarket the Bonds pursuant to the terms of the Indenture.

Special Considerations Relating to the Bonds

The Remarketing Agent is Paid by the Company

The Remarketing Agent's responsibilities include determining the interest rate from time to time and remarketing Bonds that are optionally or mandatorily tendered by the owners thereof (subject, in each case, to the terms of the Remarketing Agreement (as defined herein)), all as further described in this Official Statement. The Remarketing Agent is appointed by the Company and is paid by the Company for its services. As a result, the interests of the Remarketing Agent may differ from those of existing holders and potential purchasers of Bonds.

The Remarketing Agent Routinely Purchases Bonds for its Own Account

The Remarketing Agent acts as remarketing agent for a variety of variable rate demand obligations and, in its sole discretion, routinely purchases such obligations for its own account in order to achieve a successful remarketing of the obligations (i.e., because there are otherwise not enough buyers to purchase the obligations) or for other reasons. The Remarketing Agent is permitted, but not obligated, to purchase tendered Bonds for its own account and, if it does so, it may cease doing so at any time without notice. The Remarketing Agent may also make a market in the Bonds by routinely purchasing and selling Bonds other than in connection with an optional or mandatory tender and remarketing. Such purchases and sales may be at or below par. However, the Remarketing Agent is not required to make a market in the Bonds. The Remarketing Agent may also sell any Bonds it has purchased to one or more affiliated investment vehicles for collective ownership or enter into derivative arrangements with affiliates or others in order to reduce its exposure to the Bonds. The purchase of Bonds by the Remarketing Agent may create the appearance that there is greater third party demand for the Bonds in the market than is actually the case. The practices described above also may result in fewer Bonds being tendered in a remarketing.

Bonds may be Offered at Different Prices on Any Date

Pursuant to the Indenture, the Remarketing Agent is required to determine the applicable rate of interest that, in its judgment, is the minimum rate necessary (as determined by the Remarketing Agent based on the examination of tax-exempt obligations comparable to the Bonds known by the Remarketing Agent to have been priced or traded under then-prevailing market conditions) for the Remarketing Agent to sell the Bonds on the day the rate is set at their principal amount (without regard to accrued interest). The interest rate will reflect, among other factors, the level of market demand for the Bonds (including whether the Remarketing Agent is willing to purchase Bonds for its own account). There may or may not be Bonds tendered and remarketed on a day that the rate on the Bonds is set, the Remarketing Agent may or may not be able to remarket any Bonds tendered for purchase on such date at par and the Remarketing Agent may sell Bonds at varying prices to different investors on such date or any other date. The Remarketing Agent is not obligated to advise purchasers in a remarketing if it does not have third party buyers for all of the Bonds at the remarketing price. In the event the Remarketing Agent owns any Bonds for its own account, it may, in its sole discretion in a secondary market transaction outside the tender process, offer such Bonds on any date, including the day that the rate on the Bonds are set, at a discount to par to some investors.

The Ability to Sell the Bonds other than through Tender Process May be Limited

The Remarketing Agent may buy and sell Bonds other than through the tender process. However, it is not obligated to do so and may cease doing so at any time without notice and may require holders that wish to tender their Bonds to do so through the Trustee with appropriate notice. Thus, investors who purchase the Bonds, whether in a remarketing or otherwise, should not assume that they will be able to sell their Bonds other than by tendering the Bonds in accordance with the tender process.

Under Certain Circumstances, the Remarketing Agent May Be Removed, Resign or Cease Remarketing the Bonds, Without a Successor Being Named

Under certain circumstances, the Remarketing Agent may be removed or have the ability to resign or cease its remarketing efforts, without a successor having been named, subject to the terms of the Remarketing Agreement and the Indenture.

Optional Tender

While the Bonds bear interest at a Daily Rate or a Weekly Rate, the holder of any Bond may elect to have its Bond (or any portion of its Bond equal to the lowest authorized denomination or whole multiples thereof) purchased by the Trustee at the Purchase Price.

Daily Rate Tender. When interest on a Bond is payable at a Daily Rate and a book-entry system is in effect, a Beneficial Owner of such Bond (through its Direct Participant (as defined in *Book-Entry Only System* below) in the Securities Depository) may tender its interest in a Bond (or portion of Bond) by delivering an irrevocable written notice by telecopy, facsimile transmission or e-mail transmission to the Trustee and an irrevocable notice to the Remarketing Agent by telephone, telegraph or facsimile transmission, in each case prior to 11:00 A.M., New York City time, on a Business Day, stating the principal amount of the Bond (or portion of Bond) being tendered, payment instructions for the Purchase Price and the Business Day (which may be the date the notice is delivered) the Bond (or portion of Bond) is to be purchased. The Beneficial Owner will effect delivery of such Bond by causing such Direct Participant to transfer its interest in the Bond equal to such Beneficial Owner's interest on the records of the Securities Depository to the participant account of the Trustee with the Securities Depository. Any notice received by the Trustee after 11:00 A.M., New York City time, will be deemed to have been given on the next Business Day.

When interest on a Bond is payable at a Daily Rate and a book-entry system is not in effect, a holder of a Bond may tender the Bond (or portion of Bond) by delivering (i) the notices described above (which must include the certificate number of the Bond) and (ii) the Bond, to the Trustee by 1:00 P.M., New York City time, on the date of purchase.

Weekly Rate Tender. When interest on a Bond is payable at a Weekly Rate and a book-entry system is in effect, a Beneficial Owner of such Bond (through its Direct Participant in the Securities Depository) may tender its interest in a Bond (or portion of Bond) by delivering an irrevocable written notice by telecopy, facsimile transmission or e-mail transmission to the Trustee and an irrevocable notice to the Remarketing Agent by telephone, telegraph or facsimile transmission, in each case prior to 5:00 P.M., New York City time, on a Business Day stating the principal amount of the Bond (or portion of Bond) being tendered, payment instructions for the Purchase Price and the date, which must be a Business Day at least seven days after the notice is delivered, on which the Bond (or portion of Bond) is to be purchased. The Beneficial Owner shall effect delivery of such Bond by causing such Direct Participant to transfer its interest in the Bond equal to such Beneficial Owner's interest on the records of the Securities Depository to the participant account of the Trustee or its agent with the Securities Depository.

When interest on a Bond is payable at a Weekly Rate and a book-entry system is not in effect, a holder of a Bond may tender the Bond (or portion of Bond) by delivering (i) the notices as described above (which must include the certificate number of the Bond) and (ii) the Bond, to the Trustee by 1:00 P.M., New York City time, on the date of purchase.

Payment of Purchase Price. Payment of the Purchase Price of Bonds to be purchased upon optional tender as described above will be made by the Trustee in immediately available funds by 4:00 P.M., New York City time, on the date of purchase. No purchase of Bonds by the

Trustee will be deemed to be a payment or redemption of the Bonds or of any portion thereof and such purchase will not operate to extinguish or discharge the indebtedness evidenced by such Bonds. So long as the Letter of Credit is in effect, all payments of Purchase Price for the Bonds shall be made in accordance with the Indenture. See *Summary* below.

Provisions Applicable to All Tenders. Bonds for which the owners have given notice of tender for purchase but which are not delivered on the tender date shall be deemed tendered. Bonds tendered for purchase on a date after a call for redemption has been given but before the redemption date will be purchased pursuant to the tender.

Notice in respect of tenders and Bonds tendered must be delivered as follows:

Trustee	Remarketing Agent
The Bank of New York Mellon Trust Company, N.A. 6525 W. Campus Oval, 2nd Floor New Albany, Ohio 43054 Attention: Corporate Trust Administration Telephone: (614) 775-5280 Telecopier: (614) 775-5636	U.S. Bancorp Municipal Securities Group 461 Fifth Avenue New York, New York 10017 Attn: Short-Term Trading Telephone: 827-497-0032

Irrevocability

Each notice of tender constitutes an irrevocable tender for purchase of the Bond (or portion thereof) to which the notice relates on the purchase date at a price equal to 100% of the principal amount of such Bond (or portion thereof) plus any interest thereon accrued and unpaid as of the purchase date. The determination of the Trustee as to whether a notice of tender has been properly sent will be conclusive and binding upon the Bondholders.

The Trustee may refuse to accept delivery of any Bond for which a proper instrument of transfer has not been provided. If any owner of a Bond who gave notice of optional tender or which is subject to mandatory tender fails to deliver its Bond to the Trustee at the place and on the applicable date and time specified, or fails to deliver its Bond properly endorsed, and moneys for the payment of such Bond are on deposit with the Trustee, its Bond shall constitute an undelivered Bond and interest shall cease to accrue on its Bonds as of the tender date and such owner shall have no right under the Indenture other than the right to receive payment of the Purchase Price thereof.

Remarketing and Purchase

Except to the extent the Company directs the Remarketing Agent not to remarket Bonds and except as otherwise provided in the Indenture, the Remarketing Agent for the Bonds will offer for sale and use reasonable efforts to sell all Bonds tendered for purchase (as described below) at a price equal to 100% of the principal amount thereof plus accrued interest, if any, to the purchase date. The Trustee will pay the Purchase Price of the Bonds tendered for purchase first from the proceeds of the remarketing of such Bonds to persons other than the Company, the affiliates of the Company and the Issuer and, if such proceeds are insufficient, second from the proceeds of a draw upon the Letter of Credit and, third, from money provided by the Company or otherwise available. See *THE REMARKETING AGREEMENT* below.

Redemption of Bonds

The Bonds are subject to redemption as described below:

Extraordinary Optional Redemption. The Bonds are subject to redemption by the Issuer in whole or in part on any date if the Company, upon the occurrence of any of the following events, exercises its option to direct that redemption from moneys available therefor at a redemption price of 100% of the principal amount redeemed, plus accrued and unpaid interest to the redemption date:

(a) The Project or the Plant (each as defined in the Agreement) shall have been damaged or destroyed to such an extent that the Company deems it not practical or desirable to rebuild, repair or restore the Project or Plant, as the case may be.

(b) Title to, or the temporary use of, all or a significant part of the Project or the Plant shall have been taken under the exercise of the power of eminent domain so as to render the Project unsatisfactory to the Company for its intended purpose.

(c) As a result of any changes in the Constitution of the State of West Virginia, the Constitution of the United States of America or any state or federal laws or as a result of legislative or administrative action (whether state or federal) or by final decree, judgment or order of any court or administrative body (whether state or federal) entered after any contest thereof by the Issuer or the Company in good faith, the Agreement shall have become void or unenforceable or impossible of performance in accordance with the intent and purpose of the parties as described therein.

(d) Unreasonable burdens or excessive liabilities shall have been imposed upon the Issuer or the Company with respect to the Project or the Plant or the operation thereof, including, without limitation, the imposition of federal, state or other ad valorem, property, income or other taxes not being imposed on the date of the Agreement.

(e) Changes in the economic availability of raw materials, operating supplies, energy sources or supplies or facilities (including, but not limited to, facilities in connection with the disposal of industrial wastes) necessary for the operation of the Project or the Plant occur or technological or other changes occur which in the Company's reasonable judgment render the Project or the Plant uneconomic or obsolete.

(f) Any court or administrative body shall enter a judgment, order or decree, or shall take administrative action, requiring the Company to cease all or any substantial part of its operations served by the Project or the Plant to such extent that the Company is or will be prevented from carrying on its normal operations at the Project or the Plant for a period of six consecutive months.

(g) The termination by the Company of operations at the Plant.

Extraordinary Mandatory Redemption. The Bonds are subject to mandatory redemption at any time in whole, or in part if such partial redemption will preserve the exemption from federal income taxation of interest on the remaining outstanding Bonds, at a redemption price equal to the principal amount thereof together with unpaid interest accrued to the date fixed for redemption, and without premium, if (a) a final decree or judgment of any federal court, in which the Company participates to the extent it deems sufficient, or (b) a final action by the Internal Revenue Service, in proceedings in which the Company participates to the extent it deems sufficient, determines that the interest paid or payable on Bonds to a person, other than, as provided in Section 147(a) of the Code, a "substantial user" of the Project or a "related person", is or was includable in the gross income of the owner thereof for federal income tax purposes under the Code, as a result of the failure by the Company to observe or perform any covenant, condition or agreement on its part to be observed or performed under the Agreement or the inaccuracy of any representation by the Company under the Agreement or receipt by the Company of an Opinion of Tax Counsel to such effect obtained by the Company and rendered at the request of the Company; provided, however, that no decree or judgment by any court or action by the Internal Revenue Service shall be considered final unless the Bondholder or Beneficial Owner involved in such proceeding or action (i) gives the Company and the Trustee prompt written notice of the commencement thereof and (ii) if the Company agrees to pay all expenses in connection therewith and to indemnify such Bondholder or Beneficial Owner against all liabilities in connection therewith, offers the Company the opportunity to control the defense thereof. Any such redemption shall be made on a date determined by the Trustee not more than 180 days after the date of such final decree, judgment or action. The Trustee shall give the Issuer and the Company not less than 45 days written notice of such date.

Optional Redemption. When interest on the Bonds is payable at a Daily or Weekly Rate, the Bonds may be redeemed in whole or in part at the option of the Company, on any Business Day.

Notice of Redemption. Whenever Bonds are to be redeemed, the Trustee shall give notice of redemption by mailing such notice to the registered owner of each Bond to be redeemed, at least 30 days prior to the redemption date, as provided in the Indenture.

During the period that DTC or the DTC nominee is the registered holder of the Bonds, the Trustee will not be responsible for mailing notices of redemption, or other notices described herein, to the Beneficial Owners of the Bonds. See - *Book-Entry Only System*.

Mandatory Tender for Purchase

The Bonds are subject to mandatory tender for purchase under certain circumstances. By acceptance of each Bond, the holder agrees to sell and surrender its Bond, properly endorsed, under the conditions described below. All purchases will be made in funds immediately available on the purchase date and will be at the Purchase Price. Bonds tendered for purchase on a date after a call for redemption but before the redemption date will be purchased pursuant to the tender. No purchase of Bonds shall be deemed to be a payment or redemption of the Bonds or of any portion thereof and such purchase will not operate to extinguish or discharge the indebtedness evidenced by such Bonds.

Mandatory Tender Upon a Change in the Method of Determining the Interest Rate on the Bonds. On the effective date of the change in the method of determining the interest rate on the Bonds, the Bonds will be purchased on the effective date of such change at the Purchase Price.

At least 15 days before each mandatory tender occasioned by such change, the Trustee will mail a notice of tender by first-class mail to each Bondholder at the holder's registered address. Each notice of tender will identify the Bonds to be purchased and will state, among other things, (i) the purchase date; (ii) the Purchase Price; (iii) that the Bonds to be tendered must be surrendered to collect the Purchase Price; (iv) the address at which the Bonds must be surrendered; and (v) that interest on the Bonds to be tendered ceases to accrue to such holder on the purchase date.

Mandatory Tender Upon Substitution of Alternate Letter of Credit. The Bonds shall be subject to mandatory tender at the Purchase Price on the date on which an Alternate Letter of Credit is to be substituted for the Letter of Credit (the "Substitution Date"). Bonds purchased pursuant to this provision shall be delivered by the holders at or before 12:00 noon, New York City time, on such Substitution Date, and, subject to the Indenture, payment of the Purchase Price of such Bonds shall be made by wire transfer in immediately available funds by the Trustee on such Substitution Date. The Trustee shall give notice of such mandatory tender by mail to the holders of the Bonds no less than twenty (20) days prior to the Substitution Date. The notice shall state (i) that the Bonds are subject to mandatory tender, (ii) the Substitution Date; (iii) the Purchase Price; (iv) that Bonds must be surrendered to collect the Purchase Price; (v) the address at which the Bonds must be surrendered; and (vi) that interest on Bonds subject to mandatory tender will cease to accrue to such holder from and after the Substitution Date and such holder will be entitled only to the Purchase Price on the Substitution Date. The failure to mail such notice with respect to any Bond shall not affect the validity of the mandatory tender of any other Bond with respect to which notice was so mailed. Any notice mailed will be conclusively presumed to have been given, whether or not actually received by any holder.

"Alternate Letter of Credit" means, with respect to the Bonds, a letter of credit or other security or liquidity device issued in accordance with the requirements of the Indenture which will have a term of not less than one year and will have substantially the same material terms as the Letter of Credit; provided that such letter of credit or other security or liquidity device may (and shall if the Bonds shall provide for redemption premium while it is in effect) provide for coverage of premium payable upon redemption of the Bonds.

Mandatory Tender Due to an Event of Default Under Reimbursement Agreement. Whenever the Letter of Credit is in effect, the Bonds will be subject to mandatory tender if the Trustee receives a written notice from the Letter of Credit Bank that an event of default, as defined in the Reimbursement Agreement, has occurred and is continuing, and the Letter of Credit Bank directs the Trustee to effect such mandatory tender. Such Bonds subject to mandatory tender will be purchased at the Purchase Price on the default tender date specified by the Letter of Credit Bank in such written notice (the "Default Tender Date"). Such Default

Tender Date shall be a Business Day not more than nine (9) nor less than five (5) days after the day such notice is received. The Trustee shall immediately notify the paying agent of receipt of such notice and of the Default Tender Date. Bonds purchased pursuant to this provision will be delivered by the holders (with all necessary endorsements) to the designated corporate trust office of the Trustee, at or before 12:00 noon, New York City time, on the Default Tender Date, and, subject to the Indenture, payment of the Purchase Price shall be made by wire transfer in immediately available funds by the Trustee on the Default Tender Date; provided, however, that payment of the Purchase Price shall be made pursuant to this provision only if the Bond is so delivered to the Trustee.

The Trustee will give notice to the Issuer, the Remarketing Agent, the Company and the Letter of Credit Bank (the "Notice Parties") and all holders prior to the close of business on the Business Day after receipt of the notice described in the preceding paragraph stating (i) that the Bonds are subject to mandatory tender; (ii) the Default Tender Date; (iii) the Purchase Price; (iv) that Bonds must be surrendered to collect the Purchase Price; (v) the address at which the Bonds must be surrendered; (vi) that interest on such Bonds will cease to accrue to such holder from and after the Default Tender Date and such holder will be entitled only to the Purchase Price on the Default Tender Date; and (vii) if the Bonds are then rated by Moody's Investor Service, Inc. ("Moody's"), Standard & Poor's, a division of The McGraw-Hill Companies ("Standard & Poor's") or Fitch, Inc. ("Fitch"), that such rating or ratings will terminate on the Default Tender Date. The failure to mail such notice with respect to any Bond will not affect the validity of the mandatory tender of any other Bond with respect to which notice was so mailed. Any notice mailed will be conclusively presumed to have been given, whether or not actually received by a holder.

Mandatory Tender Upon Expiration or Termination of Letter of Credit. If (i) the Letter of Credit is scheduled to expire on the Expiration Date (as defined below) and by the Renewal Date (as defined below) no extension of such Letter of Credit or Alternate Letter of Credit has been delivered to the Trustee or (ii) on or before the Renewal Date, the Company has delivered notice in accordance with the Reimbursement Agreement, stating that the Letter of Credit will be terminated with respect to all the Bonds on the Expiration Date, then the Bonds shall be subject to mandatory tender on the date five Business Days prior to the Expiration Date (the "Expiration Tender Date") at the Purchase Price. Bonds purchased pursuant to this provision will be delivered by the holders at or before 12:00 noon, New York City time, on the Expiration Tender Date, and subject to the Indenture, payment of the Purchase Price shall be made by wire transfer in immediately available funds by the Trustee on such Expiration Tender Date; provided, however, that payment of the Purchase Price will be made pursuant to this provision only if the Bond is so delivered to the Trustee.

The Trustee will give notice to all holders and the Notice Parties no less than twenty (20) days prior to the Expiration Tender Date. The notice will state (i) that the Bonds are subject to mandatory tender; (ii) the Expiration Tender Date; (iii) the Purchase Price; (iv) that Bonds must be surrendered to collect the Purchase Price; (v) the address at which the Bonds must be surrendered; (vi) that the Letter of Credit will terminate on the date specified in such notice; (vii) that interest on such Bonds will cease to accrue to such holder from and after the Expiration Tender Date and such holder will be entitled only to the Purchase Price on the Expiration Tender

Date; and (viii) if the Bonds are then rated by Moody's, Standard & Poor's or Fitch, that such rating or ratings will terminate on the Expiration Tender Date. The failure to mail such notice with respect to any Bond shall not affect the validity of the mandatory tender of any other Bond with respect to which notice was so mailed. Any notice mailed will be conclusively presumed to have been given, whether or not actually received by a holder.

"Expiration Date" means the stated expiration date of the Letter of Credit, or such stated expiration date as it may be extended from time to time as provided in the Letter of Credit, or any earlier date on which the Letter of Credit shall expire or be terminated or cancelled.

"Renewal Date" means the thirty-fifth (35th) day prior to the Expiration Date.

Notice of Tender. Failure to give any required notice of tender as to any particular Bonds or any defect therein will not affect the validity of the tender of any Bonds in respect of which no such failure or defect occurs. Any notice mailed as described above shall be effective when sent and will be conclusively presumed to have been given whether or not actually received by the addressee.

Effect of Notice of Tender. When notice is required and given, and when Bonds are to be tendered without notice, Bonds tendered become due and payable on the purchase date; in such case when funds are deposited with the Trustee sufficient for purchase, interest on the Bonds to be purchased ceases to accrue as of the date of purchase.

Summary

Certain provisions of the Bonds and the Indenture (other than when the Bonds bear interest at a rate other than a Daily Rate or Weekly Rate) are summarized in the following table:

	DAILY RATE	WEEKLY RATE
OPTIONAL TENDER; NOTICE	On any Business Day; notice no later than 11:00 A.M., New York City time, same Business Day	On any Business Day; notice no later than 5:00 P.M., New York City time, seven days in advance
INTEREST PERIODS	Each day	Thursday through Wednesday
INTEREST RATE DETERMINED	Each Business Day by 10:00 A.M., New York City time	Each Wednesday (or next preceding Business Day)
INTEREST ACCRUAL PERIOD	Interest Payment Date to Interest Payment Date	Interest Payment Date to Interest Payment Date
INTEREST PAYMENT DATE	First Business Day of next month	First Business Day of next month

	DAILY RATE	WEEKLY RATE
RECORD DATE	Business Day before Interest Payment Date	Business Day before Interest Payment Date
OPTIONAL REDEMPTION BY COMPANY	On any Business Day	On any Business Day
MANDATORY TENDER	(i) On effective date of change in interest rate determination method, (ii) substitution of Alternate Letter of Credit, (iii) event of default under Reimbursement Agreement, and (iv) expiration or termination of Letter of Credit	(i) On effective date of change in interest rate determination method, (ii) substitution of Alternate Letter of Credit, (iii) event of default under Reimbursement Agreement, and (iv) expiration or termination of Letter of Credit

Book-Entry Only System

DTC, New York, New York will act as securities depository for the Bonds. The Bonds will be issued as fully-registered bonds registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered Bond certificate will be issued for the Bonds, representing in the aggregate the total principal amount of the Bonds, and will be deposited with the Trustee on behalf of DTC.

DTC is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934, as amended (the "1934 Act"). DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues and money market instruments (from over 100 countries) that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly (the "Indirect Participants"). The DTC rules applicable to its Participants are on file with the Securities and Exchange Commission ("SEC"). More information about DTC can be found at www.dtcc.com (it being understood that information available at this website is not incorporated herein by reference).

Purchases of Bonds under the DTC system must be made by or through Direct Participants, who will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser of each Bond (the "Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase, but Beneficial Owners are expected to receive written confirmation providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in Bonds, except in the event that use of the book-entry-only system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Beneficial Owners of Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the Bonds, such as redemptions, tenders, defaults and proposed amendments to the Bond documents. For example, Beneficial Owners of the Bonds may wish to ascertain that the nominee holding the Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners. In the alternative, Beneficial Owners may wish to provide their names and addresses to the registrar and request that copies of notices be provided directly to them.

Redemption notices shall be sent to DTC. If less than all of the Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such Bond to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Issuer as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds and principal and interest payments on the Bonds will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detailed information from the Company or the Trustee, on each payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC, the Company, the Trustee or the Issuer, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds and principal and interest payments to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

A Beneficial Owner shall give notice to elect to have its Bonds purchased or tendered, through its Participant, to the Trustee and Remarketing Agent, and shall effect delivery of such Bonds by causing the Direct Participant to transfer the Participant's interest in the Bonds, on DTC's records, to the Remarketing Agent. The requirement for physical delivery of the Bonds in connection with an optional tender or a mandatory tender for purchase will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on DTC's records and followed by a book-entry credit of tendered Bonds to the Remarketing Agent's DTC account.

DTC may discontinue providing its services as depository with respect to the Bonds at any time by giving reasonable notice to the Issuer or the Trustee. Under such circumstances, in the event that a successor depository is not obtained, certificates for the Bonds are required to be printed and delivered. The Issuer may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor Securities Depository) with respect to the Bonds. In that event, certificates for the Bonds will be printed and delivered and thereafter, transfer, exchange, and replacement of Bonds would be governed by the applicable terms of the Indenture.

The information in this section concerning DTC and DTC's book-entry-only system has been obtained from sources that the Issuer, the Company and the Trustee believe to be reliable, but none of the Issuer, the Company or the Trustee takes any responsibility for the accuracy of such statements. None of the Issuer, the Company or the Trustee has any responsibility for the performance by DTC or its Participants of their respective obligations as described herein or under the rules and procedures governing their respective operations.

None of the Issuer, the Underwriter, the Company, the Letter of Credit Bank, the Trustee or any agent for payment on or registration of transfer or exchange of any Bond will have any responsibility or obligation to Direct Participants, Indirect Participants or

the persons for whom they act as nominees with respect to the accuracy of the records of DTC, its nominee or any Direct Participant with respect to any ownership interest in the Bonds, or payments to, or the providing of notice for, Direct Participants, Indirect Participants, or beneficial owners or other action taken by DTC, or its nominee, Cede & Co., as the sole owners of the Bonds.

Security for the Bonds

The Bonds will be special obligations of the Issuer, the principal of and premium, if any, and interest on which will be payable solely from (i) the payments to be made by the Company under the Agreement and the Note, which are pledged to the Trustee and (ii) the funds drawn under the Letter of Credit. The pledge does not extend to funds to which the Trustee is entitled in its own right as fees, reimbursement, indemnity or otherwise. The Bonds will not be secured by a mortgage or security interest in the Project or any other property of the Company. The Agreement provides that Loan Payments will be paid to the Trustee by the Company for the account of the Issuer.

THE LETTER OF CREDIT AND REIMBURSEMENT AGREEMENT

In addition to the descriptions of certain provisions of the Letter of Credit and the Reimbursement Agreement contained elsewhere herein, the following is a summary of certain provisions of the Letter of Credit and the Reimbursement Agreement and does not purport to be comprehensive or definitive. All references herein to the Letter of Credit or the Reimbursement Agreement are qualified in their entirety by reference to the Letter of Credit or the Reimbursement Agreement, as applicable, for the detailed provisions thereof. Any future credit agreement or reimbursement agreement pursuant to which an Alternate Letter of Credit is issued may have terms substantially different from those described below.

The Letter of Credit

Concurrently with the issuance of the Bonds, the Company will cause to be delivered to the Trustee the Letter of Credit issued by the Letter of Credit Bank, in the initial aggregate stated amount of $65,747,945. Under the Letter of Credit, the Trustee will be permitted to draw up to (a) an amount sufficient to pay (i) the principal of the Bonds when due at maturity, redemption or acceleration and (ii) the portion of the Purchase Price of the Bonds tendered to the Trustee and not remarketed or for which remarketing proceeds have not been timely received by the draw time under the Letter of Credit corresponding to the principal amount of such Bonds, plus (b) an amount equal to 35 days' interest on the Bonds at a maximum rate of 12% per annum to pay (i) interest on the Bonds when due and (ii) the portion of the Purchase Price of the Bonds tendered to the Trustee and not remarketed or for which remarketing proceeds have not been timely received by the draw time under the Letter of Credit corresponding to the accrued interest on such Bonds. The Letter of Credit will expire on June 26, 2017 or on the earliest occurrence of one or more events described below. The Letter of Credit may be extended from time to time by the Letter of Credit Bank in its discretion, unless terminated earlier pursuant to its terms.

The Letter of Credit is subject to termination on (a) the Letter of Credit Bank's close of business on June 26, 2017 (unless extended from time to time), (b) the earlier of (1) the fifteenth calendar day following conversion of all of the Bonds to a rate other than a Daily Rate or Weekly Rate and (2) the date on which the Letter of Credit Bank honors a drawing under the Letter of Credit on or after the conversion of all of the Bonds to a rate other than a Daily Rate or Weekly Rate, (c) the fifteenth calendar day following the Letter of Credit Bank's receipt of a notice of termination from the Trustee, (d) the date on which an Acceleration Drawing (as defined in the Letter of Credit) is honored by the Letter of Credit Bank, (e) the fifteenth calendar day after receipt by the Trustee of a written notice from the Letter of Credit Bank stating that there is an event of default (as defined in the Reimbursement Agreement) under the Reimbursement Agreement and directing the Trustee either to accelerate the Bonds or to effect a mandatory tender of the Bonds, and (f) the date on which the Letter of Credit Bank honors a Stated Maturity Drawing (as defined in the Letter of Credit).

The stated amount of the Letter of Credit (originally $65,747,945) is subject to adjustment for payments made by the Letter of Credit Bank to the Trustee pursuant to drawings under the Letter of Credit. Payments made (i) pursuant to drawings on the Letter of Credit to make scheduled principal payments on the Bonds, (ii) to pay the unpaid principal and accrued interest on the Bonds on redemption, and (iii) to pay the unpaid principal and accrued interest on the Bonds upon acceleration, permanently reduce the principal component of the stated amount of the Letter of Credit by an amount equal to such payments. Payments made pursuant to drawings on the Letter of Credit to pay interest on the Bonds and to pay the Purchase Price of Bonds tendered to the Trustee in accordance with the Indenture will reduce the stated amount by an amount equal to such payments; provided that (i) such amounts reduced with respect to the payment of accrued and unpaid interest only are reinstated automatically upon payment of such interest drawings by the Letter of Credit Bank and (ii) such amounts reduced with respect to drawings to pay the Purchase Price of tendered Bonds are reinstated upon notice from the Trustee when such Bonds are remarketed and the Letter of Credit Bank is reimbursed for such drawing.

Replacement of Letter of Credit

The Company may surrender the Letter of Credit or replace the Letter of Credit with an Alternate Letter of Credit or other facility meeting the requirements of the Indenture. The Bonds will be subject to mandatory tender for purchase (i) on the date five Business Days prior to the date of the surrender of the Letter of Credit without the delivery of an Alternate Letter of Credit or (ii) on the date of the replacement of the Letter of Credit with an Alternate Letter of Credit.

The Reimbursement Agreement

In addition to the description of certain provisions of the Reimbursement Agreement contained elsewhere herein, the following is a brief summary of certain provisions of the Reimbursement Agreement and does not purport to be comprehensive or definitive. All references herein to the Reimbursement Agreement are qualified in their entirety by reference to the Reimbursement Agreement for the detailed provisions thereof.

The Letter of Credit will be issued pursuant to a Reimbursement Agreement between the Company and the Letter of Credit Bank.

The Reimbursement Agreement contains, among other matters, representations, warranties and covenants on the part of the Company, the breach of which or material inaccuracy of which entitles the Letter of Credit Bank to notify the Trustee of an "event of default" (as defined in the Reimbursement Agreement) under the Reimbursement Agreement and directing the Trustee either to accelerate the Bonds or to effect a mandatory tender of the Bonds. The following events constitute "events of default" under the Reimbursement Agreement:

(a) The Company shall default in (i) the payment of any amount payable to the Letter of Credit Bank in reimbursement of any drawing under a Letter of Credit within three days after the same becomes due and payable; or (ii) the failure to make any other payment of fees or other amounts payable under the Reimbursement Agreement when the same becomes due and payable and such default shall continue unremedied for five or more calendar days; or

(b) Any representation or warranty made by the Company in the Reimbursement Agreement or by the Company (or any of its officers) in connection with the Reimbursement Agreement or in any certificate, financial or other statement furnished by the Company pursuant to the Reimbursement Agreement or any document related thereto shall prove to have been incorrect in any material respect when made; or

(c) (i) The Company shall fail to perform or observe certain specified terms, covenants or agreements contained in the Reimbursement Agreement (e.g., maintenance of existence, failure to give notice within five days after obtaining knowledge of a default, restriction on mergers and consolidations, restriction on disposition of any of the Company's equity in its subsidiaries, subjecting Bonds purchased with the Letter of Credit proceeds to be registered in the name of the Letter of Credit Bank, causing or providing notice of an optional redemption or purchase or change in interest rate determination method (other than to or from a Daily Rate or a Weekly Rate) resulting in a mandatory redemption or purchase unless sufficient funds are deposited on or prior to the date of such redemption or purchase or unless such notice is conditional upon receipt of such funds, agreeing to certain amendments to the Indenture, making or amending references to the Letter of Credit Bank in this Official Statement, use of Letter of Credit proceeds for a purpose other than payment of principal of, interest on, redemption price of and Purchase Price of the Bonds, a disposition by the Company or any of its subsidiaries of certain assets, creation by the Company and its subsidiaries of certain liens and encumbrances, restriction on entering into certain restrictive agreements, or (ii) the Company shall fail to perform or observe any other term, covenant or agreement contained in the Reimbursement Agreement or any other Loan Document (as defined in the Reimbursement Agreement) if such failure shall remain unremedied for 30 days after written notice thereof shall have been given to the Company; or

(d) Any event shall occur or condition shall exist under any agreement or instrument relating to debt of the Company (but excluding debt outstanding under the Reimbursement Agreement) or any subsidiary outstanding in a principal or notional amount of at least $50,000,000 in the aggregate if the effect of such event or condition is to accelerate or require early termination of the maturity or tenor of such debt, or any such debt shall be declared to be due and payable, or required to be prepaid or redeemed (other than by a regularly scheduled required prepayment or redemption), terminated, purchased or defeased, or an offer to prepay, redeem, purchase or defease such debt shall be required to be made, in each case prior to the stated maturity or the original tenor thereof; or

(e) The Company or any subsidiary shall generally not pay its debts as such debts become due, or shall admit in writing its inability to pay its debts generally, or shall make a general assignment for the benefit of creditors; or any proceeding shall be instituted by or against the Company or any subsidiary seeking to adjudicate it a bankrupt or insolvent, or seeking liquidation, winding up, reorganization, arrangement, adjustment, protection, relief, or composition of it or its debts under any law relating to bankruptcy, insolvency or reorganization or relief of debtors, or seeking the entry of an order for relief or the appointment of a receiver, trustee, custodian or other similar official for it or for any substantial part of its property and, in the case of any such proceeding instituted against it (but not instituted by it), either such proceeding shall remain undismissed or unstayed for a period of 60 days, or any of the actions sought in such proceeding (including, without limitation, the entry of an order for relief against, or the appointment of a receiver, trustee, custodian or other similar official for, it or for any substantial part of its property) shall occur; or the Company or any subsidiary shall take any corporate action to authorize any of the actions set forth above in this subsection (e); or

(f) Any judgment or order for the payment of money in excess of $50,000,000 in the case of the Company or any subsidiary to the extent not paid or covered by insurance shall be rendered against the Company or any subsidiary and either (i) enforcement proceedings shall have been commenced by any creditor upon such judgment or order or (ii) there shall be any period of 30 consecutive days during which a stay of enforcement of such judgment or order, by reason of a pending appeal or otherwise, shall not be in effect; or

(g) Certain events related to employee benefit matters shall have occurred and the liability of the Company and certain of its affiliates related to such employee benefit related event exceeds $50,000,000; or

(h) An "Event of Default" under and as defined in the Indenture shall have occurred and be continuing; or

(i) There shall be no Remarketing Agreement in effect at a time when support for the payment of principal and purchase price of and interest on any Bonds is required to be provided by the Company pursuant to the Indenture.

THE LOAN AGREEMENT

Loan of Proceeds

The Issuer will loan the proceeds of the sale of the Bonds to the Company, in accordance with the Loan Agreement and the Indenture.

Term of Loan Agreement

The term of the Loan Agreement will continue until such time as all of the outstanding Bonds are fully paid (or provision has been made for such payment) pursuant to the Indenture and all other money payable by the Company under the Loan Agreement shall have been paid.

Payments

The Company will make payments on the Loan Agreement which will be sufficient to pay, when due, the principal of, and premium, if any, interest on, and Purchase Price of, the Bonds. To evidence the obligations of the Company to make the Loan Payments and repay the Loan, the Company will, concurrently with the issuance of the Bonds, execute and deliver the Note to the Trustee, as assignee of the Issuer under the Indenture, in an aggregate principal amount equal to the aggregate principal amount of the Bonds. The Company will receive as a credit against its obligations to make payments under the Agreement with respect to the Bonds all payments made by the Letter of Credit Bank under the Letter of Credit.

Obligations Unconditional

The obligations of the Company to make Loan Payments and other payments required to be made pursuant to the Loan Agreement are absolute and unconditional, and the Company will make such payments without abatement, diminution or deduction regardless of any cause or circumstances whatsoever including, without limitation, any defense, set-off, recoupment or counterclaim which the Company may have or assert against the Issuer, the Trustee, the Remarketing Agent, the Letter of Credit Bank or any other Person.

Maintenance and Modification

During the term of the Loan Agreement, the Company will use its best efforts to keep and maintain, or cause to be kept and maintained, the Project, including all appurtenances thereto and any personal property therein or thereon, in satisfactory operating order, repair, condition and appearance, subject to reasonable wear and tear, so that the Project will continue to constitute a facility that can be financed by the Issuer under the Act for the purpose for which it was designed. Subject to certain conditions, the Company has the right, from time to time, to remodel the Project or make additions, modifications and improvements thereto, the cost of which must be paid by the Company. The Company also has the right, subject to certain conditions, to substitute or remove any portion of the Project.

Tax Exemption

The Company will covenant and represent in the Loan Agreement that it has taken and caused or required to be taken and will take and cause or require to be taken all actions that may be required of it for the interest on the Bonds to be and remain excluded from the gross income of the owners thereof for federal income tax purposes, and that it has not taken or permitted to be taken on its behalf, and it will not take or permit to be taken on its behalf, any action which, if taken, would adversely affect that exclusion under the provisions of the Code.

Assignment of the Loan Agreement

The Loan Agreement may be assigned in whole or in part by the Company only with the consent of the Issuer, subject to the following conditions: (a) no assignment will relieve the Company from primary liability for any of its obligations under the Loan Agreement; (b) any assignment by the Company must retain for the Company such rights and interests to permit it to perform its remaining obligations under the Loan Agreement, and any assignee from the Company shall assume the obligations of the Company hereunder to the extent of the interest assigned; (c) the Company will, within 30 days after the execution thereof, furnish or cause to be furnished to the Issuer, the Letter of Credit Bank and the Trustee a true and complete copy of each assignment together with any instrument of assumption; and (d) any assignment from the Company will not materially impair fulfillment of the purposes of the Project to be accomplished by operation of the Project as provided in the Loan Agreement.

Events of Default and Remedies

The Loan Agreement provides that the occurrence of one or more of the following events will constitute an "Event of Default:"

(a) The failure to pay any Loan Payment or any payment required to be made to pay the Purchase Price when due;

(b) The occurrence of an event of default described in paragraphs (a), (b) or (c) under *THE INDENTURE—Events of Defaults and Remedies*;

(c) Failure by the Company to observe and perform any other agreement, term or condition under the Loan Agreement, other than such failure which will result in an event of default described in (a) or (b) above, which continues for a period of 90 days after notice to the Company by the Issuer or the Trustee or such longer period as the Issuer and the Trustee may agree to in writing; *provided* that the failure shall not constitute an Event of Default if the Company institutes curative action within the applicable period and diligently pursues that action to completion;

(d) Any representation or warranty under the Loan Agreement shall not have been true in all material respects when made; and

(e) Certain events relating to bankruptcy, insolvency or reorganization of the Company.

A failure by the Company described in subparagraph (c) above is not a default under that subparagraph if it occurs by reason of certain courses, circumstances and events of force majeure specified in the Loan Agreement that are not reasonably within the control of the Company.

Whenever any Event of Default under a Loan Agreement has happened and is subsisting, the Issuer or the Trustee may take either or both of the following remedial steps:

(a) Inspect, examine and make copies of the books, records, accounts and financial data of the Company, only, however, insofar as they pertain to the Project; and

(b) Pursue all remedies to recover all amounts then due and thereafter to become due under the Loan Agreement and the Note, or to enforce the performance and observance of any other obligation or agreement of the Company under those instruments.

So long as the Letter of Credit is in full force and effect and the Letter of Credit Bank has not wrongfully dishonored a drawing under the Letter of Credit or wrongfully repudiated the Letter of Credit, the exercise of remedies under the Loan Agreement with respect to Events of Default (other than with respect to defaults resulting from failures of the Company relating to certain rights of the Issuer not assigned under the Indenture), and any waivers of Events of Default shall be at the direction or with the written consent of the Letter of Credit Bank.

Any amounts collected pursuant to action taken upon the happening of an Event of Default will be paid into the Bond Fund and applied in accordance with the provisions of the Indenture or, if the outstanding Bonds have been paid and discharged in accordance with the provisions of the Indenture, will be paid as provided in the Indenture for transfers of remaining amounts in the Bond Fund.

Amendments to the Loan Agreement

The Indenture provides that the Loan Agreement may be amended without the consent of or notice to the owners of the Bonds only as may be required or permitted (i) by the provisions of the Loan Agreement or the Indenture or for the purposes for which the Indenture may be amended or supplemented without the consent of the owners, (ii) for the purpose of curing any ambiguity or formal defect or omission in the Loan Agreement or (iii) in connection with any other change therein which, in the judgment of the Trustee, is not to the prejudice of the Trustee or the owners of the Bonds. Any other amendments to the Loan Agreement may be made only with the written approval or consent of (i) the owners of not less than a majority in aggregate principal amount of the Bonds outstanding and (ii) the Letter of Credit Bank, so long as the Letter of Credit is in effect and the Letter of Credit Bank has not wrongfully dishonored a drawing thereunder or wrongfully repudiated the Letter of Credit. An opinion of Bond Counsel to the effect that such action is permitted under the Act and the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes (a "Favorable Opinion of Tax Counsel") is required for any amendment to the Loan Agreement.

THE INDENTURE

Additional information summarizing certain provisions of the Indenture is contained under the heading *THE BONDS*. So long as DTC or its nominee is the registered owner of the Bonds, all references to owners or holders shall mean DTC. See *THE BONDS - Book-Entry Only System* herein.

Pledge and Security

Pursuant to the Indenture, the payments to be made by the Company under the Loan Agreement and the Note will be assigned by the Issuer to the Trustee to secure the payment, when due, of the principal of, and premium, if any, and interest on, the Bonds. The Issuer will also absolutely and irrevocably assign to the Trustee all right, title and interest in and to the Letter of Credit Account in the Bond Fund and all moneys therein, and will mortgage, pledge and grant a security interest to the Trustee in all right, title and interest of the Issuer in and to (i) the Revenues (other than the Letter of Credit Account in the Bond Fund, and the moneys therein, assigned above), including without limitation, all Loan Payments and all other amounts receivable by the Issuer under the Loan Agreement in respect of repayment of the loan and (ii) the Note and the Loan Agreement (except certain rights to the payment of its costs and expenses, to indemnification and to enforce certain covenants of the Company); provided, that the Trustee, in case of an acceleration of the Bonds, will have a prior claim on the Bond Fund, other than money in the Letter of Credit Account, for the payment of its compensation and expenses.

Purchase Fund

The Trustee will apply money contained in the accounts described below maintained within the Purchase Fund as follows:

Remarketing Proceeds Account. Upon receipt of the proceeds of a remarketing of Bonds on a purchase date, the Trustee will directly deposit such proceeds, and will deposit only such proceeds, in the Remarketing Proceeds Account for application to the Purchase Price of the Bonds; provided that, at any time when the Letter of Credit is in effect, proceeds of any remarketing of Bonds to the Issuer, the Company or any affiliate of either of them and proceeds of the remarketing of any other Company-Held Bonds and any Bank-Owned Bonds which have been remarketed will be held and maintained in a subaccount for the benefit of the Letter of Credit Bank, separated and segregated from all other money in the Remarketing Proceeds Account. Upon instruction from the Letter of Credit Bank, any amount held by the Trustee in the subaccount described in the preceding sentence will be paid to the Letter of Credit Bank. Neither the Issuer nor the Company will have any interest in the Remarketing Proceeds Account.

Letter of Credit Purchase Account. Upon receipt of the immediately available funds provided to the Trustee under the Letter of Credit pursuant to the Indenture, the Trustee will directly deposit such money, and will deposit only such money, in the Letter of Credit Purchase Account for application to the Purchase Price of the Bonds. Any amounts deposited in the Letter of Credit Purchase Account and determined by the Trustee to be not needed with respect to any purchase date for the payment of the Purchase Price for any Bonds will be promptly returned following such determination to the Letter of Credit Bank with written notice to the Company. Neither the Issuer nor the Company will have any interest in the Letter of Credit Purchase Account.

Company Purchase Account. Upon receipt of immediately available funds provided to the Trustee by the Company pursuant to the Indenture, the Trustee shall directly deposit such money, and shall deposit only such money, in the Company Purchase Account for application to the Purchase Price of the Bonds. Any amounts deposited in the Company Purchase Account and determined by the Trustee to be not needed with respect to any purchase date for the payment of the Purchase Price for any Bonds shall be promptly returned following such determination to the Company.

Bond Fund

Payments made by the Company under the Agreement with respect to the Bonds and certain other amounts specified in the Indenture will be deposited in the Bond Fund. The Trustee will apply money contained in the accounts described below maintained within the Bond Fund as follows:

(a) Interest Account. The Trustee, on each Interest Payment Date, will withdraw and apply from moneys on deposit in the Interest Account an amount sufficient to pay interest on the outstanding Bonds on such Interest Payment Date; *provided, however*, when the Letter of Credit or an Alternate Letter of Credit is in effect, the Trustee, on each Interest Payment Date, shall withdraw and apply moneys in the Interest Account, if any, to reimburse the Letter of Credit Bank for draws on the Letter of Credit or the Alternate Letter of Credit pursuant to the Indenture.

(b) Principal Account. The Trustee, on each Principal Payment Date (as defined in the Indenture), will withdraw and apply from moneys on deposit in the Principal Account, an amount equal to the principal becoming due on the Bonds on such Principal Payment Date (other than a redemption date). Money in such Principal Account will be used and withdrawn by the Trustee on each Principal Payment Date solely for the payment of the principal of outstanding Bonds; *provided, however*, when the Letter of Credit or an Alternate Letter of Credit is in effect, the Trustee will apply such amounts, if any, to reimburse the Letter of Credit Bank for draws on the Letter of Credit or the Alternate Letter of Credit pursuant to the Indenture.

(c) Redemption Account. The Trustee, on or before each redemption date, will withdraw and apply from moneys on deposit in the Redemption Account amounts required to pay the principal of and premium, if any, and accrued interest on Bonds to be redeemed prior to their stated maturity. Money in such Redemption Account will be used and withdrawn by the Trustee on each redemption date solely for the payment of the principal of and premium, if any, and accrued interest on outstanding Bonds upon the redemption thereof prior to their stated maturity; *provided, however*, when the Letter of Credit or an Alternate Letter of Credit is in effect, the Trustee shall apply such amounts, if any, to reimburse the Letter of Credit Bank for draws on the Letter of Credit or the Alternate Letter of Credit pursuant to the Indenture.

(d) Letter of Credit Account. The Trustee will directly deposit, or cause to be directly deposited, the proceeds of draws on the Letter of Credit or an Alternate Letter of Credit to pay interest on and principal of the Bonds in such Letter of Credit Account, and shall deposit only those proceeds therein. Money in such Letter of Credit Account will be used and withdrawn by the Trustee on each Interest Payment Date and each Principal Payment Date first, before any other source of funds, to pay the principal of and interest on the Bonds; *provided, however*, that in no event shall moneys in such Letter of Credit Account be used to pay interest and premium on or principal of Bonds that are Bank-Owned Bonds or Company-Held Bonds (each as defined in the Indenture) if the Letter of Credit or Alternate Letter of Credit does not permit drawings thereunder with respect to Bank-Owned Bonds or Company-Held Bonds. Amounts in the Letter of Credit Account shall be held uninvested. Neither the Issuer nor the Company shall have any interest in the Letter of Credit Account.

(e) Payments by Company. If during any period that a Letter of Credit is in effect there is not sufficient money in the Letter of Credit Account to make the payments on an Interest Payment Date or Principal Payment Date, the Trustee will make such payments from money provided by the Company and deposited into the other accounts of the Bond Fund.

Refunding Fund

The proceeds received from the sale of the Bonds (other than any accrued interest) will be deposited in the Refunding Fund. Moneys on deposit in the Refunding Fund shall be transferred to the Refunded Bonds Trustee on the date specified in the Indenture for deposit into the purchase fund created in the Refunded Bonds Indenture and used, together with other moneys provided by the Company, to purchase the Refunded Bonds. After such purchase of the Refunded Bonds, the Refunded Bonds Trustee will thereupon retire, cancel and extinguish the Refunded Bonds so that the same are no longer outstanding under the Refunded Bonds Indenture.

Investment of Moneys Held by the Trustee

Moneys deposited in the Refunding Fund and in the accounts maintained within the Bond Fund (except the Letter of Credit Account) will be invested at the direction of the Company in Permitted Investments (as defined in the Indenture). Moneys held in the Purchase Fund will be held uninvested.

The Loan Agreement provides that the Company and the Issuer shall take no action, nor shall the Company approve the Trustee taking any action, or making any investment or use of the proceeds of the Bonds, which would cause the Bonds to be "arbitrage bonds" within the meaning of Section 148 of the Code.

Events of Default and Remedies

The following events are Events of Default under the Indenture:

(a) Default in the payment when due of any interest on any Bond;

(b) Default in the due and punctual payment of the principal of, or premium, if any, on any Bond, whether at the stated maturity thereof, or upon unconditional proceedings for redemption thereof;

(c) Default in the due and punctual payment of the Purchase Price of any Bond required to be purchased in accordance with its terms;

(d) Default in the performance or observance of any other of the covenants, agreements or conditions on the part of the Issuer in the Indenture or in the Bonds, continuing 30 days after delivery of notice thereof;

(e) The occurrence and continuance of an event of default under the Loan Agreement as described under *THE LOAN AGREEMENT – Events of Default and Remedies*; or

(f) Receipt by the Trustee of a written notice from the Letter of Credit Bank stating that an event of default has occurred under the Reimbursement Agreement and directing the Trustee to declare the principal of the outstanding Bonds immediately due and payable.

Upon the occurrence and continuance of an Event of Default under (a), (b) or (c) above the Trustee may, and upon the written request of the owners of at least 25% in aggregate principal amount of the Bonds then outstanding shall, declare the principal of and accrued interest on the outstanding Bonds to be due and payable immediately. If an Event of Default under paragraph (d) or (e) above occurs and is continuing, the Trustee may, and upon the request of the owners of at least 25% in aggregate principal amount of the Bonds then outstanding, shall, declare the principal of and accrued interest on the outstanding Bonds to be due and payable immediately, *provided, however,* when the Letter of Credit is in effect and so long as the Letter of Credit Bank has not wrongfully dishonored a drawing under the Letter of Credit (or otherwise repudiated the Letter of Credit), the Trustee will make such a declaration only with the written consent of the Letter of Credit Bank. If an Event of Default under paragraph (f) above occurs and is continuing, the Trustee shall declare the principal of and accrued interest on the outstanding Bonds to be due and payable immediately.

Upon any such declaration, the principal of and accrued interest on the outstanding Bonds shall be due and payable immediately. Notwithstanding anything else herein to the contrary, interest on the outstanding Bonds will cease to accrue immediately upon a declaration of acceleration for an Event of Default under (f) above. When the Letter of Credit is in effect, the Trustee shall, immediately upon a declaration of acceleration, draw upon the Letter of Credit to pay the principal of and interest on the outstanding Bonds; *provided*, that in no event shall a drawing be made with respect to Bank-Owned Bonds or Company-Held Bonds, if the Letter of Credit by its terms does not permit such a drawing. In the event the Letter of Credit Bank fails to honor a draw on the Letter of Credit (or otherwise repudiates the Letter of Credit) in accordance with the immediately preceding sentence, the Trustee shall immediately notify the Company of such failure and shall request that the Company transfer sufficient amounts to pay the principal of and interest on the Bonds.

The Trustee may rescind an acceleration of the Bonds and its consequences if (1) all payment defaults with respect to the Bonds have been cured and all reasonable fees and charges of the Trustee, including reasonable attorneys' fees, have been paid, and (2) the Bondholders have not been notified of the acceleration, and (3) while the Letter of Credit is in effect, the Letter of Credit Bank has notified the Trustee in writing (i) that the amount available to be drawn under the Letter of Credit has been reinstated so as to be available in any amount equal to the principal amount of the Bonds outstanding less the principal amount of any Bank-Owned Bonds, plus the applicable Letter of Credit Interest Amount (as defined in the Indenture) and any required premium coverage and (ii) that the Letter of Credit Bank has rescinded in writing any event of default under the Reimbursement Agreement. Except as provided in this section, the Trustee will not declare the Bonds to be due and payable.

If an Event of Default occurs and is continuing, the Trustee may pursue any available remedy by proceeding at law or in equity to collect the principal of and premium, if any, or interest on the Bonds or to enforce the performance of any provision of the Bonds or the Indenture. So long as the Letter of Credit is in effect and the Letter of Credit Bank has not wrongfully dishonored a drawing thereunder or wrongfully repudiated the Letter of Credit, the Trustee will pursue any remedy only at the direction of or with the consent of the Letter of Credit Bank.

A majority in aggregate principal amount of the outstanding Bonds by notice to the Trustee may waive an existing Event of Default and its consequences; *provided, however*, that, when the Letter of Credit is in effect and so long as the Letter of Credit Bank has not wrongfully dishonored a drawing under such Letter of Credit or wrongfully repudiated the Letter of Credit, no such waiver shall be effective with respect to the Bonds unless and until the Letter of Credit Bank has notified the Trustee in writing (i) that the amount available to be drawn under the Letter of Credit has been reinstated so as to be available in an amount equal to the principal amount of the Bonds outstanding less the principal amount of any Bank-Owned Bonds, plus the applicable Letter of Credit Interest Amount and any required premium coverage, (ii) that the Letter of Credit Bank has rescinded in writing the notice of default, and (iii) that the Letter of Credit Bank has waived in writing any event of default under the Reimbursement Agreement. When an Event of Default is waived, it is cured and stops continuing, but no such waiver will extend to any subsequent or other Event of Default or impair any right consequent to it.

When there is a Letter of Credit in effect and so long as the Letter of Credit Bank has not wrongfully dishonored a drawing under such Letter of Credit or wrongfully repudiated the Letter of Credit, the Letter of Credit Bank may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or of exercising any trust or power conferred on it with respect to the Bonds. When there is no Letter of Credit in effect or when the Letter of Credit Bank has wrongfully dishonored a drawing under the Letter of Credit or wrongfully repudiated the Letter of Credit, the holders of a majority in aggregate principal amount of Bonds outstanding may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or of exercising any trust or power conferred on it.

An owner of a Bond may not pursue any remedy with respect to the Indenture or the Bonds unless (a) the owner gives the Trustee notice stating that an Event of Default is continuing, (b) the owners of at least 25% in aggregate principal amount of the outstanding Bonds make a written request to the Trustee to pursue the remedy, (c) such owner or owners offer to the Trustee indemnity satisfactory to the Trustee against any loss, liability or expense, (d) the Trustee does not comply with the request within 60 days after receipt of the request and the offer of indemnity, and (e) with respect to the Bonds, the Letter of Credit is either not in effect or the Letter of Credit Bank has wrongfully dishonored a drawing under the Letter of Credit or wrongfully repudiated the Letter of Credit.

Except as described below, funds drawn under the Letter of Credit will be used only for the payment of principal of and interest on, premium, if any (to the extent that the Letter of Credit covers premium) and the Purchase Price of, the Bonds, as provided in the Letter of Credit. If the Trustee collects any money pursuant to the Indenture or if any moneys shall be on deposit in the Bond Fund at the time of acceleration of the Bonds or shall be deposited into the Bond Fund as a result of such an acceleration, it will pay out such monies in the following order: first to the Trustee for amounts to which it is entitled under such Indenture (*provided*, that if such money constitutes proceeds of a draw under the Letter of Credit, the Trustee shall only use such proceeds to pay the owners of the Bonds); second to owners for amounts due and unpaid on the Bonds for principal, premium and interest, ratably, without preference or priority of any kind, according to the amounts due and payable on the Bonds for principal, premium and interest, respectively, third to the Letter of Credit Bank to the extent it certifies that the Company is indebted to it on account of draws Letter of Credit or otherwise under the Reimbursement Agreement; and fourth to the Company (*provided*, that if such money constitutes proceeds of a draw under the Letter of Credit, the Trustee shall pay the Letter of Credit Bank rather than the Company). Any lien of the Trustee provided for in the Indenture will in no event apply to any funds drawn under the Letter of Credit or to other funds held for the benefit of the Bondholders. The Trustee may fix a payment date for any payment to the Bondholders.

Supplemental Indentures

The Issuer and the Trustee may, without the consent of, or notice to, any of the Bondholders, enter into such indenture or indentures supplemental to the Indenture as shall not be inconsistent with the terms and provisions thereof:

(a) to cure any ambiguity, defect or omission in the Indenture, or otherwise amend the Indenture, in such manner as shall not in the opinion of the Trustee impair the security under the Indenture;

(b) to grant to or confer upon the Trustee for the benefit of the Bondholders any additional rights, remedies, powers or authorities that may lawfully be granted to or conferred upon the Bondholders or the Trustee;

(c) to evidence any succession to the Issuer and the assumption by its successor of the covenants, agreements and obligations of the Issuer under the Indenture, the Agreement and the Bonds, to add additional covenants of the Issuer or surrender any right or power therein conferred upon the Issuer;

(d) to subject to the pledge of the Indenture additional revenues, properties or collateral, which may be accomplished by, among other things, entering into instruments with the Company and/or other persons providing for further security, covenants, limitations or restrictions for the benefit of the Bonds;

(e) to modify the Indenture to permit qualification under the Trust Indenture Act of 1939, as amended, or any similar statute at the time in effect;

(f) to amend any provision pertaining to matters under federal income tax laws, including Section 148(f) of the Code;

(g) to authorize different Authorized Denominations of the Bonds and to make correlative amendments and modifications to the Indenture regarding exchangeability of Bonds of different Authorized Denominations, redemptions of portions of Bonds of particular Authorized Denominations and similar amendments and modifications of a technical nature;

(h) to increase or decrease the number of days specified for the giving of notices of mandatory tender and to make corresponding changes to the period for notice of redemption of the Bonds; *provided*, that no decreases in any such number of days will become effective except while the Bonds bear interest at a Daily Rate or a Weekly Rate and until 30 days after the Trustee has given notice to the owners of the Bonds;

(i) to provide for an uncertificated system of registering the Bonds or to provide for the change to or from a Book-Entry System for the Bonds;

(j) to evidence the succession of a new trustee or the appointment by the Trustee or the Issuer of a co-trustee;

(k) to make any change related to the Bonds that does not materially adversely affect the rights of any Bondholder; and

(l) to make any other changes to the Indenture that take effect as to any or all remarketed Bonds following a mandatory tender.

The Indenture also provides that the owners of not less than a majority in aggregate principal amount of the Bonds outstanding shall have the right, from time to time, to consent to and approve the execution by the Issuer and the Trustee of such other indenture or supplemental indentures as shall be deemed necessary and desirable by the Issuer and the Trustee for the purpose of modifying, altering, amending, adding to or rescinding, in any particular, any of the terms or provisions contained in the Indenture or in any supplemental indenture; *provided, however,* that nothing shall permit, without certain additional consents, (a) an extension of the maturity date of the principal of or the interest on any Bond; (b) a reduction in the principal amount of any Bond, the rate of interest thereon or any redemption premium; or (c) a reduction in the aggregate principal amount of the Bonds required for consent to such supplemental indenture or for actions related to amendments to the Loan Agreement. A Favorable Opinion of Bond Counsel is required for any supplement to the Indenture.

When the Letter of Credit is in effect and so long as the Letter of Credit Bank has not wrongfully dishonored a drawing under the Letter of Credit or wrongfully repudiated the Letter of Credit, no waiver of or amendment or supplement to the Indenture other than certain of those enumerated in the Indenture shall be made without the prior written consent of the Letter of Credit Bank to such amendment or supplement.

Discharge of the Indenture

If the whole amount of principal and interest due and payable on the Bonds has been paid and if, at the time of such payment, the Issuer shall have kept, performed and observed all the covenants and promises in such Bonds and in the Indenture required or contemplated to be kept, performed and observed by the Issuer or on its part on or prior to that time, then the Indenture shall be considered to have been discharged in respect of such Bonds and such Bonds shall cease to be entitled to the lien of the Indenture and such lien and all covenants, agreements and other obligations of the Issuer hereunder shall cease, terminate, become void and be completely discharged as to such Bonds.

No Personal Liability of Issuer's Officials

No covenant, stipulation, obligation or agreement of the Issuer contained in the Indenture will be or be deemed to be a covenant, stipulation, obligation or agreement of any present or future member, officer, agent or employee of the Issuer in other than his or her official capacity. No member of the Issuer or official executing the Bonds, the Indenture, the Loan Agreement or any amendment or supplement to the Indenture or the Loan Agreement will be liable personally on the Bonds or be subject to any personal liability or accountability by reason of the issuance or execution thereof.

Removal of Trustee

The Trustee may be removed by the owners of not less than a majority in principal amount of Bonds at the time outstanding or by the Issuer and the Company. The Trustee shall continue to serve as such until a successor Trustee shall be appointed under the Indenture and such successor Trustee has accepted such appointment.

THE REMARKETING AGREEMENT

U.S. Bancorp Investments, Inc. and U.S. Bank Municipal Securities Group, a Division of U.S. Bank National Association, have been appointed as the Remarketing Agent for the Bonds. If and to the extent the Company directs the Remarketing Agent to remarket the Bonds delivered for purchase pursuant to the Indenture, the Remarketing Agent, pursuant to and subject to the provisions of a remarketing agreement with the Company (the "Remarketing Agreement"), will offer for sale and use reasonable efforts to sell such Bonds at a price equal to 100% of the principal amount thereof plus accrued interest, if any, to the purchase date. The Remarketing Agent may resign by giving notice to the Issuer, the Company and the Trustee (such resignation will be effective upon the appointment of a successor remarketing agent or 30 days after such notice has been sent) and may suspend remarketing upon the occurrence of certain events. The Company may remove the Remarketing Agent at any time upon 30 days' notice and appoint a successor by notifying the Remarketing Agent, the Issuer and the Trustee.

THE TRUSTEE

The Bank of New York Mellon Trust Company, N.A. serves as trustee under other indentures providing for certain tax-exempt bonds for the benefit of the Company. The Company and certain of its affiliates maintain banking relationships with affiliates of The Bank of New York Mellon, N.A. and borrow from such affiliates from time to time. The Bank of New York Mellon Trust Company, N.A., and its affiliates, serve as trustee under other indentures with, or for the benefit of, affiliates of the Company.

UNDERWRITING

Subject to the terms and conditions set forth in a Bond Purchase Agreement ("Purchase Agreement") to be entered into between the Issuer and the Underwriter, the Underwriter has agreed to purchase the Bonds at a purchase price of 100% of the principal amount thereof. Under the terms and conditions of the Purchase Agreement, the Underwriter is committed to take and pay for all of the Bonds if any are taken. The Company has agreed to pay the Underwriter $97,500 as compensation and to reimburse the Underwriter for its reasonable expenses.

The Issuer has been advised by the Underwriter that the Bonds may be offered and sold to certain dealers (including dealers depositing Bonds into investment trusts) and others at prices lower than the public offering price set forth on the cover page of this Official Statement. After the Bonds are released for sale to the public, the public offering price and other selling terms may from time to time be varied by the Underwriter.

In connection with this offering and in compliance with applicable law and industry practice, the Underwriter may overallot or effect transactions which stabilize, maintain or otherwise affect the market price of the Bonds at levels above those which might otherwise prevail in the open market, including by entering into stabilizing bids. A stabilizing bid means the placing of a bid, or the effecting of any purchase, for the purpose of pegging, fixing or maintaining the price of a security. In general, purchases of a security for the purpose of stabilization could cause the price of the security to be higher than it might be in the absence of such purchases.

Neither the Issuer, the Company nor the Underwriter makes any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the Bonds. In addition, neither the Issuer, the Company nor the Underwriter makes any representation that the Underwriter will engage in such transactions or that such transactions, once commenced, will not be discontinued without notice.

Pursuant to an Inducement Letter, the Company has agreed to indemnify the Underwriter and the Issuer against certain civil liabilities, including liabilities under the federal securities laws, or contribute to payments that the Underwriter or the Issuer may be required to make in respect thereof.

In the ordinary course of its business, the Underwriter and certain of its affiliates have in the past and may in the future engage in investment banking, commercial banking or other transactions of a financial nature with the Company and its affiliates, for which it has received, or may receive, customary compensation.

"US Bancorp" is the marketing name of U.S. Bancorp and its subsidiaries, including U.S. Bank Municipal Securities Group, a Division of U.S. Bank National Association ("USB MSG"), which is serving as the Underwriter of the Bonds, and U.S. Bancorp Investments, Inc., which, along with USB MSG, is serving as Remarketing Agent for the Bonds.

CONTINUING DISCLOSURE AGREEMENT

The Company has agreed to deliver certain continuing disclosure information satisfying the requirements of Rule 15c2-12 ("Rule") under the 1934 Act. The Company will undertake in a written agreement for the benefit of the holders and beneficial owners of the Bonds (the "Continuing Disclosure Undertaking") to provide the Municipal Securities Rulemaking Board ("MSRB") as the sole nationally recognized securities repository through the MSRB's Electronic Municipal Market Access ("EMMA") certain financial and operating data concerning the Company. In addition, the Company will undertake, for the benefit of the holders and beneficial owners of the Bonds, to provide to the MSRB through EMMA, in a timely manner (not in excess of ten (10) business days after the occurrence of such event), notices of any of the events enumerated in the Rule. Notices of the aforesaid events and any filing to be made under the Continuing Disclosure Undertaking may be made solely by transmitting such filing to the MSRB through EMMA as provided at http://emma.msrb.org. The contents of such website do not constitute a part of this Official Statement.

The sole and exclusive remedy for breach or default under the Continuing Disclosure Undertaking is an action to compel specific performance of the undertakings of the Company and no person, including a holder of the Bonds, may recover monetary damages thereunder under any circumstances. A breach or default under the Continuing Disclosure Undertaking shall not constitute an event of default under the Indenture or the Agreement. In addition, if all or any part of the Rule ceases to be in effect for any reason, then, subject to the terms of the Continuing Disclosure Undertaking, the information required to be provided under the Continuing Disclosure Undertaking, insofar as the provision of the Rule no longer in effect required the provision of such information, shall no longer be required to be provided.

TAX EXEMPTION

In the opinion of Squire Patton Boggs (US) LLP, Bond Counsel, under existing law: (i) interest on the Bonds is excluded from gross income for federal income tax purposes under Section 103(a) of the Code, except for interest on any Bond for any period during which it is held by a "substantial user" or a "related person" as those terms are used in Section 147(a) of the Code; (ii) interest on the Bonds is an item of tax preference under Section 57 of the Code for purposes of the federal alternative minimum tax imposed on individuals and corporations; and (iii) the Bonds, and all interest and income thereon, are exempt from all taxation by the State of West Virginia and any county, municipality, political subdivision or agency thereof, except inheritance taxes. Bond Counsel expresses no opinion as to any other tax consequences regarding the Bonds.

The opinion on tax matters will be based on and will assume the accuracy of certain representations and certifications, and continuing compliance with certain covenants, of the Issuer and the Company contained in the transcript of proceedings and that are intended to evidence and assure the foregoing, including that the Bonds are and will remain obligations the interest on which is excluded from gross income for federal income tax purposes. Bond Counsel will not independently verify the accuracy of the Issuer's and the Company's certifications and representations or the continuing compliance with the Issuer's and the Company's covenants.

The opinion of Bond Counsel is based on current legal authority and covers certain matters not directly addressed by such authority. It represents Bond Counsel's legal judgment as to exclusion of interest on the Bonds from gross income for federal income tax purposes but is not a guaranty of that conclusion. The opinion is not binding on the Internal Revenue Service (the "IRS") or any court. Bond Counsel expresses no opinion about (i) the effect of future changes in the Code and the applicable regulations under the Code or (ii) the interpretation and the enforcement of the Code or those regulations by the IRS.

The Code prescribes a number of qualifications and conditions for the interest on state and local government obligations to be and to remain excluded from gross income for federal income tax purposes, some of which require future or continued compliance after issuance of the obligations. Noncompliance with these requirements by the Issuer or the Company may cause loss of such status and result in the interest on the Bonds being included in gross income for federal income tax purposes retroactively to the date of issuance of the Bonds. The Company and the Issuer have each covenanted to take the actions required of it for the interest on the Bonds to be and to remain excluded from gross income for federal income tax purposes, and not to take any actions that would adversely affect that exclusion. After the date of issuance of the Bonds, Bond Counsel will not undertake to determine (or to so inform any person) whether any actions taken or not taken, or any events occurring or not occurring, or any other matters coming to Bond Counsel's attention, may adversely affect the exclusion from gross income for federal income tax purposes of interest on the Bonds or the market value of the Bonds.

A portion of the interest on the Bonds earned by certain corporations may be subject to a federal corporate alternative minimum tax. In addition, interest on the Bonds may be subject to a federal branch profits tax imposed on certain foreign corporations doing business in the United States and to a federal tax imposed on excess net passive income of certain S corporations.

Under the Code, the exclusion of interest from gross income for federal income tax purposes may have certain adverse federal income tax consequences on items of income, deduction or credit for certain taxpayers, including financial institutions, certain insurance companies, recipients of Social Security and Railroad Retirement benefits, those that are deemed to incur or continue indebtedness to acquire or carry tax-exempt obligations, and individuals otherwise eligible for the earned income tax credit. The applicability and extent of these and other tax consequences will depend upon the particular tax status or other tax items of the owner of the Bonds. Bond Counsel will express no opinion regarding those consequences.

Payments of interest on tax-exempt obligations, including the Bonds, are generally subject to IRS Form 1099-INT information reporting requirements. If a Bond owner is subject to backup withholding under those requirements, then payments of interest will also be subject to backup withholding. Those requirements do not affect the excludability of such interest from gross income for federal income tax purposes.

Bond Counsel's engagement with respect to the Bonds ends with the issuance of the Bonds, and, unless separately engaged, Bond Counsel is not obligated to defend the Issuer, the Company or the owners of the Bonds regarding the tax status of interest on the Bonds in the event of an audit examination by the IRS. The IRS has a program to audit tax-exempt obligations to determine whether the interest thereon is includible in gross income for federal income tax purposes. If the IRS does audit the Bonds, under current IRS procedures, the IRS will treat the Issuer as the taxpayer and the beneficial owners of the Bonds will have only limited rights, if any, to obtain and participate in judicial review of such audit. Any action of the IRS, including but not limited to selection of the Bonds for audit, or the course or result of such audit, or an audit of other obligations presenting similar tax issues, may affect the market value for the Bonds.

Prospective purchasers of the Bonds upon their original issuance at prices other than the respective prices indicated on the cover of this Official Statement, and prospective purchasers of the Bonds at other than their original issuance, should consult their own tax advisers regarding other tax considerations such as the consequences of market discount, as to all of which Bond Counsel expresses no opinion.

Risk of Future Legislative Changes and/or Court Decisions

Legislation affecting tax-exempt obligations is regularly considered by the United States Congress and may also be considered by the State legislature. Court proceedings may also be filed, the outcome of which could modify the tax treatment of obligations such as the Bonds. There can be no assurance that legislation enacted or proposed, or actions by a court, after the date of issuance of the Bonds will not have an adverse effect on the tax status of interest on the Bonds or the market value or marketability of the Bonds. These adverse effects could result, for example, from changes to federal or state income tax rates, changes in the structure of federal or state income taxes (including replacement with another type of tax), or repeal (or reduction in the benefit) of the exclusion of interest on the Bonds from gross income for federal or state income tax purposes for all or certain taxpayers.

For example, recent presidential and legislative proposals would eliminate, reduce or otherwise alter the tax benefits currently provided to certain owners of state and local government bonds, including proposals that would result in additional federal income tax on taxpayers that own tax-exempt obligations if their incomes exceed certain thresholds. Investors in the Bonds should be aware that any such future legislative actions (including federal income tax reform) may retroactively change the treatment of all or a portion of the interest on the Bonds for federal income tax purposes for all or certain taxpayers. In such event, the market value of the Bonds may be adversely affected and the ability of holders to sell their Bonds in the secondary market may be reduced. The interest rates on the Bonds are not subject to adjustment in the event of any such change.

Investors should consult their own financial and tax advisers to analyze the importance of these risks.

LEGAL MATTERS

Certain legal matters relating to the authorization and validity of the Bonds will be subject to the approving opinion of Squire Patton Boggs (US) LLP, Bond Counsel, which will be furnished at the expense of the Company upon delivery of the Bonds, in substantially the form set forth as Appendix C (the "Bond Opinion"). The Bond Opinion will be limited to matters relating to authorization and validity of the Bonds and to the tax-exempt status of interest thereon as described in the section *TAX EXEMPTION.* Bond Counsel has not been engaged to investigate the financial resources of the Company or its ability to provide for payment of the Bonds, and the Bond Opinion will make no statement as to such matters or as to the accuracy or completeness of this Official Statement or any other information that may have been relied on by anyone in making the decision to purchase Bonds.

Certain legal matters will be passed upon by Jeffrey D. Cross or Thomas G. Berkemeyer, each as counsel for the Company. Jeffrey D. Cross is Deputy General Counsel of American Electric Power Service Corporation, an affiliate of the Company. Thomas G. Berkemeyer is Associate General Counsel of American Electric Power Service Corporation. Certain legal matters, other than the validity of the Bonds and the exclusion from gross income of interest thereon, will be passed upon by Hunton & Williams LLP, New York, New York, counsel for the Underwriter. Certain legal matters will be passed upon for the Letter of Credit Bank by its counsel, Winston & Strawn LLP. Squire Patton Boggs (US) LLP and Hunton & Williams LLP each act as counsel to certain affiliates of the Company for some matters.

The various legal opinions to be delivered concurrently with the delivery of the Bonds express the professional judgment of the attorneys rendering the opinions as to the legal issues explicitly addressed therein. In rendering a legal opinion, the attorney does not become an insurer or guarantor of the expression of professional judgment, of the transaction opined upon, or of the future performance of the parties to the transaction, nor does the rendering of an opinion guarantee the outcome of any legal dispute that may arise out of the transaction.

MISCELLANEOUS

The attached Appendices are an integral part of the Official Statement and must be read together with all of the balance of this Official Statement.

The Issuer does not assume any responsibility for the matters contained in this Official Statement other than information under *THE ISSUER*. All findings and determinations by the Issuer relating to the issuance and sale of the Bonds are, and have been, made by the Issuer for its own internal uses and purposes in performing its duties under West Virginia law.

APPENDIX A

KENTUCKY POWER COMPANY

Kentucky Power Company (the "Company") is engaged in the generation, transmission and distribution of electric power to approximately 172,000 retail customers in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. The Company owns 1,858 MW of generating capacity, including 780 MW which acquired it from Ohio Power Company in a year-end transaction. The Company uses its generation to serve its retail and other customers. As of December 31, 2013, the Company had 642 employees. The principal industries served by the Company include petroleum refining, coal mining and chemical production. The Company's principal executive offices are located at 1 Riverside Plaza, Columbus, Ohio, and the telephone number is (614) 716-1000.

AVAILABLE INFORMATION

On July 31, 2007, the Company filed a Form 15 under the Securities Exchange Act of 1934 (the "1934 Act"), which suspended its duty to file reports under Section 13 and 15(d) under the 1934 Act. Accordingly, the Company no longer files reports and other information with the Securities and Exchange Commission (the "SEC").

FINANCIAL STATEMENTS

Annex 1 to this Appendix A contains the balance sheets of the Company as of December 31, 2013 and 2012 and the statements of income, comprehensive income (loss), changes in common shareholder's equity and cash flows for each of the three years in the period ended December 31, 2013 and the related notes thereto. Annex 2 to this Appendix A contains the unaudited condensed balance sheets of the Company as of March 31, 2014 and December 31, 2013 and the unaudited condensed statements of income, comprehensive income (loss), changes in common shareholder's equity and statements of cash flows of the Company for the three months in the periods ended March 31, 2014 and 2013 and the related notes thereto.

RISK FACTORS

Investing in the Bonds involves risk. Please see the risk factors described below. Before making an investment decision, you should carefully consider these risks. The risks and uncertainties described are those presently known to us. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our business operations, our financial results and the value of the Bonds.

GENERAL RISKS OF OUR REGULATED OPERATIONS

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions.

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits, construction of additional transmission facilities, modernizing existing infrastructure as well as other initiatives. We provide service at rates approved by the Kentucky Public Service Commission (the "KPSC"). If the KPSC does not approve adjustments to the rates we charge, we would not be able to recover the costs associated with our planned extensive investment. This would cause our financial results to be diminished.

We may not recover costs incurred to begin construction on projects that are canceled.

Our business plan for the construction of new projects involves a number of risks, including construction delays, nonperformance by equipment and other third party suppliers, and increases in equipment and labor costs. To limit the risks of these construction projects, we enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects is canceled for any reason, including our failure to receive necessary regulatory approvals and/or siting or environmental permits, we could incur significant cancellation penalties under the equipment purchase orders and construction contracts. In addition, if we have recorded any construction work or investments as an asset, we may need to impair that asset in the event the project is canceled.

Rate regulation may delay or deny full recovery of capital improvements, additions, storm damage operations and maintenance expense repairs and other costs.

We provide service at rates approved by the KPSC. These rates are generally regulated based on an analysis of our expenses incurred in a test year. Thus, KPSC-approved rates may or may not match our expenses at any given time. There may also be a delay between the timing of when these costs are incurred and when these costs are recovered. We often finance the operations and maintenance expense to repair facilities damaged by storms or other severe weather events until the operations and maintenance storm costs, including any deferred regulatory assets, are recovered in rates. We have also traditionally financed capital investments and improvements until the new asset was placed in service. Provided the asset was found to be a prudent investment, the asset was then added to rate base and entitled to a return through rate recovery. Similarly, long lead times in construction and scheduled repairs, the high costs of plant and equipment and volatile capital markets have heightened the risks involved in our capital investments, repairs and improvements. While we are actively pursuing strategies to accelerate rate recognition of investments and cash flow, including pre-approvals, a return on construction work in progress, rider/trackers, formula rates and the inclusion of future test-year projections into rates, there can be no assurance that these will be adopted, that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will be done in a timely manner.

Certain of our revenues and results of operations are subject to risks that are beyond our control.

Our operations are structured to comply with all applicable federal and state laws and regulations and we take measures to minimize the risk of significant disruptions. Material disruptions at one or more of our operational facilities, however, could negatively impact our revenues, operating and capital expenditures and results of operations. Such events may also create additional risks related to the supply and/or cost of equipment and materials. We could experience unexpected but significant interruption due to several events, including, but not limited to:

- Major facility or equipment failure.
- An environmental event such as a serious spill or release.
- Fires, floods, droughts, earthquakes, hurricanes, tornados or other natural disasters.
- Wars, terrorist acts (including cyber-terrorism) or threats and other catastrophic events.
- Significant health impairments or disease events.
- Other serious operational problems.

PJM has changing market and transmission structures, which could affect our performance.

Our results are likely to be affected by differences in the market and transmission structures in PJM. The rules governing PJM may also change from time to time which could affect our costs or revenues. Because the manner in which PJM will evolve remains unclear, we are unable to assess fully the impact that changes in these power markets may have on our business.

We could be subject to higher costs and/or penalties related to mandatory reliability standards.

As a result of EPACT, owners and operators of the bulk power transmission system are subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation and enforced by the Federal Energy Regulatory Commission (the "FERC"). The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with new reliability standards may subject us to higher operating costs and/or increased capital expenditures. While we expect to recover costs and expenditures from customers through regulated rates, there can be no assurance that the applicable commissions will approve full recovery in a timely manner. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable from customers through regulated rates.

RISKS RELATED TO MARKET, ECONOMIC OR FINANCIAL VOLATILITY AND OTHER RISKS

Our financial performance may be adversely affected if we are unable to successfully operate our facilities or perform certain corporate functions.

Our performance is highly dependent on the successful operation of our generation, transmission and distribution facilities. Operating these facilities involves many risks, including:

- Operator error and breakdown or failure of equipment or processes.

- Operating limitations that may be imposed by environmental or other regulatory requirements.
- Labor disputes.
- Compliance with mandatory reliability standards, including mandatory cyber security standards.
- Information technology failure that impairs our information technology infrastructure or disrupts normal business operations.
- Information technology failure that affects our ability to access customer information or causes us to lose confidential or proprietary data that materially and adversely affects our reputation or exposes us to legal claims.
- Fuel or water supply interruptions caused by transportation constraints, adverse weather such as drought, non-performance by our suppliers and other factors.
- Catastrophic events such as fires, earthquakes, explosions, hurricanes, tornados, ice storms, terrorism (including cyber-terrorism), floods or other similar occurrences.

Hostile cyber intrusions could severely impair our operations, lead to the disclosure of confidential information and damage our reputation.

We own assets deemed as critical infrastructure, the operation of which is dependent on information technology systems. Further, the computer systems that run our facilities are not completely isolated from external networks. Parties that wish to disrupt the U.S. bulk power system or our operations could view our computer systems, software or networks as targets for cyber attack. In addition, our business requires that we collect and maintain sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss.

A successful cyber attack on the systems that control our generation, transmission, distribution or other assets could severely disrupt business operations, preventing us from serving customers or collecting revenues. The breach of certain business systems could affect our ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. We maintain property and casualty insurance that may cover certain physical damage or third-party injuries caused by potential cyber security incidents. However, other damage and claims arising from such incidents may not be covered or may exceed the amount of any insurance available. For these reasons, a significant cyber incident could reduce future net income and cash flows and impact financial condition.

In an effort to reduce the likelihood and severity of cyber intrusions, we have a comprehensive cyber security program designed to protect and preserve the confidentiality, integrity and availability of data and systems. In addition, we are subject to mandatory cyber security regulatory requirements. However, cyber threats continue to evolve and adapt, and, as a result, there is a risk that we could experience a successful cyber attack despite our current security posture and regulatory compliance efforts.

If we are unable to access capital markets on reasonable terms, it could reduce future net income and cash flows and impact financial condition.

We rely on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. Volatility and reduced liquidity in the financial markets could affect our ability to raise capital and fund our capital needs, including construction costs and refinancing maturing indebtedness. In addition, if capital is available only on less than reasonable terms or to borrowers whose creditworthiness is better than ours, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could reduce future net income and cash flows and impact financial condition.

Downgrades in our credit ratings could negatively affect our ability to access capital and/or to operate our power trading businesses.

The credit ratings agencies periodically review our capital structure and the quality and stability of our earnings. Any negative ratings actions could constrain the capital available to us and could limit our access to funding for our operations. Our business is capital intensive, and we are dependent upon our ability to access capital at rates and on terms we determine to be attractive. In periods of market turmoil, access to capital is difficult for all borrowers. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and could reduce future net income and cash flows and impact financial condition.

Our power trading business relies on our investment grade ratings. Most of our counterparties require the creditworthiness of an investment grade entity to stand behind transactions. If our ratings were to decline below investment grade, our ability to operate our power trading business profitably would be diminished because we would likely have to deposit cash or cash-related instruments which would reduce our profits.

Our operating results may fluctuate on a seasonal or quarterly basis and with general economic and weather conditions.

Electric power generation is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. The pattern of this fluctuation may change depending on the terms of power sale contracts that we enter into. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish our results of operations and harm our financial condition. Conversely, unusually extreme weather conditions could increase our results of operations in a manner that would not likely be sustainable.

Further, deteriorating economic conditions generally result in reduced consumption by our customers, particularly industrial customers who may curtail operations or cease production entirely, while an expanding economic environment generally results in increased revenues. As a result, our overall operating results in the future may fluctuate on the basis of prevailing economic conditions.

Failure to attract and retain an appropriately qualified workforce could harm our results of operations.

Certain events, such as an aging workforce without appropriate replacements, mismatch of skillset or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be negatively affected.

Parties we have engaged to provide construction materials or services may fail to perform their obligations, which could harm our results of operations.

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades, construction of additional generation units and transmission facilities as well as other initiatives. We are exposed to the risk of substantial price increases in the costs of materials used in construction. We have engaged numerous contractors and entered into a large number of agreements to acquire the necessary materials and/or obtain the required construction related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and almost certainly cause delays in that and related projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. This would cause our financial results to be diminished, and we might incur losses or delays in completing construction.

Changes in commodity prices and the costs of transport may increase our cost of producing power or decrease the amount we receive from selling power, harming our financial performance.

We are exposed to changes in the price and availability of coal and the price and availability to transport coal. We have existing contracts of varying durations for the supply of coal, but as these contracts end or otherwise are not honored, we may not be able to purchase coal on terms as favorable as the current contracts. Similarly, we are exposed to changes in the price and availability of emission allowances. We use emission allowances based on the amount of coal we use as fuel and the reductions achieved through emission controls and other measures. As long as current environmental programs remain in effect, we have sufficient emission allowances to cover the majority of our projected needs for the next two years and beyond. If the United States Environmental Protection Agency (the "Federal EPA") is able to create a replacement rule to reduce interstate transport, and it is acceptable by the courts, additional costs may be incurred either to acquire additional allowances or to achieve further reductions in emissions. If we need to obtain allowances under a replacement rule, those purchases may not be on as favorable terms as those under the current environmental programs. Our risks relative to the price and availability to transport coal include the volatility of the price of diesel which is the primary fuel used in transporting coal by barge.

We also have plans to convert a generating unit from coal to natural gas-fired facilities. This would expose us to market prices of natural gas. Historically, natural gas prices have tended to be more volatile than prices for other fuel sources. Recently however, the availability of natural gas from shale production has lessened price volatility. Our ability to make off-system sales at a profit is highly dependent on the price of natural gas. As the price of natural gas falls, other market participants that utilize natural gas-fired generation will be able to offer electricity at increasingly competitive prices relative to our off-system sales prices, so the margins we realize from sales will be lower and, on occasion, we may need to curtail operation of marginal plants. We expect the availability of shale natural gas and issues related to its accessibility will have a long-term material effect on the price and volatility of natural gas.

Prices for coal, natural gas and emission allowances have shown material upward and downward swings in the past. Changes in the cost of coal, emission allowances or natural gas and changes in the relationship between such costs and the market prices of power will affect our financial results.

In addition, actual power prices and fuel costs will differ from those assumed in financial projections used to value our trading and marketing transactions, and those differences may be material. As a result, our financial results may be diminished in the future as those transactions are marked to market.

We are subject to physical and financial risks associated with climate change.

There is a growing consensus on the evidence of global climate change. Climate change creates physical and financial risk. Physical risks from climate change include an increase in sea level and changes in weather conditions, such as changes in precipitation and extreme weather events. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes.

Increased energy use due to weather changes may require us to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of our service territory could also have an impact on our revenues. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand on our own and/or other systems may raise electricity prices as we buy short-term energy to serve our own system, which would increase the cost of energy we provide to our customers.

Severe weather impacts our service territories, primarily when thunderstorms, tornadoes, hurricanes and snow or ice storms occur. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations, principally our fossil generating units. A negative impact to water supplies due to long-term drought conditions could adversely impact our ability to provide electricity to customers, as well as increase the price they pay for energy. We may not recover all costs related to mitigating these physical and financial risks.

To the extent climate change impacts a region's economic health, it may also impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods and services, has an impact on the economic health of our communities.

We cannot predict the outcome of the legal proceedings relating to our business activities.

We are involved in legal proceedings, claims and litigation arising out of our business operations. Adverse outcomes in these proceedings could require significant expenditures that could have a material adverse effect on our results of operations.

RISKS RELATED TO OWNING AND OPERATING GENERATION ASSETS AND SELLING POWER

Our costs of compliance with existing environmental laws are significant.

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. The electricity we generate is produced by the combustion of fossil fuels. Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generation plants are subject to increased regulations, controls and mitigation expenses. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities and could cause us to retire generating capacity prior to the end of its estimated useful life. These expenditures have been significant in the past and we expect that they will continue to be significant in order to comply with the current and proposed regulations. Costs of compliance with environmental regulations could reduce future net income and impact financial condition, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed and additional substances become regulated. If we retire generation plants prior to the end of their estimated useful life, there can be no assurance that we will recover the remaining costs associated with such plants. We typically recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates in regulated jurisdictions. Failure to recover these costs could reduce our future net income and cash flows and possibly harm our financial condition.

Regulation of CO_2 emissions, either through legislation or by the Federal EPA, could materially increase costs to us and our customers or cause some of our electric generating units to be uneconomical to operate or maintain.

In June 2014, Federal EPA issued standards for modified and reconstructed units, and a guideline for the development of state implementation plans that would reduce carbon emissions from existing utility units. Federal EPA is to finalize those standards by June 2015, and to require states to submit implementation plans no later than June 2016.

If CO_2 and other emission standards are imposed, the standards could require significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. We typically recover costs of complying with new requirements such as the potential CO_2 and other greenhouse gases emission standards from customers through regulated rates in regulated jurisdictions. For our sales of energy based on market rate authority, however, there is no such recovery mechanism. Failure to recover these costs, should they arise, could reduce our future net income and cash flows and possibly harm our financial condition.

Courts adjudicating nuisance and other similar claims against us may order us to pay damages or to limit or reduce our CO_2 emissions.

In the past, there have been several cases seeking damages based on allegations of federal and state common law nuisance in which we or our affiliates, among others, were defendants. In general, the actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance due to impacts of global warming and climate change. The plaintiffs in these actions generally seek recovery of damages and other relief. If the pending or other future actions are resolved against us, substantial modifications of our existing coal-fired power plants could be required and we might be required to limit or reduce CO_2 emissions. Such remedies could require us to purchase power from third parties to fulfill our commitments to supply power to our customers. This could have a material impact on our costs. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay damages or penalties and/or halt operations. While management believes such costs should be recoverable from customers as costs of doing business in our jurisdictions where generation rates are set on a cost of service basis, without such recovery those costs could reduce our future net income and cash flows and harm our financial condition. Moreover, our results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Changes in technology and regulatory policies may cause our generating facilities to be less competitive.

We primarily generate electricity at large central facilities. This method results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in technologies or changes in regulatory policies will reduce costs of new technology to levels that are equal to or below that of most central station electricity production, which could have a material adverse effect on our results of operations.

Our profitability is impacted by our continued authorization to sell power at market-based rates.

FERC has granted us authority to sell electricity at market-based rates. FERC reserves the right to revoke or revise this market-based rate authority if it subsequently determines that we or our affiliates can exercise market power in transmission or generation, create barriers to entry or engage in abusive affiliate transactions. We must file a market power update every three years to show that we continue to meet FERC's standards with respect to generation market power and other criteria used to evaluate whether entities qualify for market-based rates. The loss of market-based rate authority by any of these entities could have a material adverse effect on our results of operations.

Our revenues and results of operations from selling power are subject to market risks that are beyond our control.

We sell power from our generation facilities into the spot market and other competitive power markets on a contractual basis. We also enter into contracts to purchase and sell electricity, natural gas, emission allowances and coal as part of our power marketing and energy trading operations. With respect to such transactions, the rate of return on our capital investments is not determined through mandated rates, and our revenues and results of operations are likely to depend, in large part, upon prevailing market prices for power in our regional markets and other competitive markets. These market prices can fluctuate substantially over relatively short periods of time. Trading margins may erode as markets mature and there may be diminished opportunities for gain should volatility decline. In addition, the FERC, which has jurisdiction over wholesale power rates, as well as RTOs that oversee some of these markets, may impose price limitations, bidding rules and other mechanisms to address some of the volatility in these markets. Power supply and other similar agreements entered into during extreme market conditions may subsequently be held to be unenforceable by a reviewing court or the FERC. Fuel and emissions prices may also be volatile, and the price we can obtain for power sales may not change at the same rate as changes in fuel and/or emissions costs. These factors could reduce our margins and therefore diminish our revenues and results of operations. Volatility in market prices for fuel and power may result from:

- Weather conditions, including storms.
- Economic conditions.
- Outages of major generation or transmission facilities.
- Seasonality.
- Power usage.
- Illiquid markets.
- Transmission or transportation constraints or inefficiencies.
- Availability of competitively priced alternative energy sources.
- Demand for energy commodities.
- Natural gas, crude oil and refined products and coal production levels.
- Natural disasters, wars, embargoes and other catastrophic events.
- Federal, state and foreign energy and environmental regulation and legislation and/or incentives.

Commodity trading and marketing activities are subject to inherent risks which can be reduced and controlled but not eliminated.

We attempt to manage the exposure of our power trading activities by establishing and enforcing risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate the risks associated with these activities. As a result, we cannot predict the impact that our energy trading and risk management decisions may have on our business, operating results or financial position.

We routinely have open trading positions in the market, within guidelines we set, resulting from the management of our trading portfolio. To the extent open trading positions exist, fluctuating commodity prices can improve or diminish our financial results and financial position.

Our power trading risk management activities, including our power sales agreements with counterparties, rely on projections that depend heavily on judgments and assumptions by management of factors such as the future market prices and demand for power and other energy-related commodities. These factors become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. Even when our policies and procedures are followed and decisions are made based on these estimates, results of operations may be diminished if the judgments and assumptions underlying those calculations prove to be inaccurate.

We may not successfully manage the uncertainty involved with our power trading (including coal, natural gas and emission allowances trading and power marketing).

Our power trading activities also expose us to risks of commodity price movements. To the extent that our power trading does not hedge the price risk associated with the generation it owns, or controls, through long-term power purchase agreements, we would be exposed to the risk of rising and falling spot market prices.

For example, the use of new technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing further downward pressure on natural gas prices and has reduced the need for our coal-fired generation. Further, in the event that alternative generation resources, such as wind and solar, are mandated or otherwise subsidized or encouraged through climate legislation or regulation and added to the available generation supply, such resources could displace a higher marginal cost fossil plant, which could reduce the price at which market participants sell their electricity. This occurrence could then reduce the market price at which all generators in that region would be able to sell their output. These events could adversely affect our financial condition, results of operations and cash flows, and could also result in an impairment of certain long-lived assets.

In connection with these trading activities, we routinely enter into financial contracts, including futures and options, over-the counter options, financially-settled swaps and other derivative contracts. These activities expose us to risks from price movements. If the values of the financial contracts change in a manner we do not anticipate, it could harm our financial position or reduce the financial contribution of our trading operations.

Parties with whom we have contracts may fail to perform their obligations, which could harm our results of operations.

We are exposed to the risk that counterparties that owe us money or power could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices that may exceed our contractual prices, which would cause our financial results to be diminished and we might incur losses. Although our estimates take into account the expected probability of default by a counterparty, our actual exposure to a default by a counterparty may be greater than the estimates predict.

We rely on electric transmission facilities that we do not own or control. If these facilities do not provide us with adequate transmission capacity, we may not be able to deliver our wholesale electric power to the purchasers of our power.

We depend on transmission facilities owned and operated by other nonaffiliated power companies to deliver the power we sell at wholesale. This dependence exposes us to a variety of risks. If transmission is disrupted, or transmission capacity is inadequate, we may not be able to sell and deliver our wholesale power. If a region's power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

The FERC has issued electric transmission initiatives that require electric transmission services to be offered unbundled from commodity sales. Although these initiatives are designed to encourage wholesale market transactions, access to transmission systems may in fact not be available if transmission capacity is insufficient because of physical constraints or because it is contractually unavailable. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

Financial derivatives reforms could increase the liquidity needs and costs of our commercial trading operations.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was signed into law (the "Dodd-Frank Act"). The federal legislation was enacted to reform financial markets and significantly alter how over-the-counter ("OTC") derivatives are regulated. The law increased regulatory oversight of OTC energy derivatives, including: (a) imposing pervasive regulation by the Commodity Futures Trading Commission (the "CFTC") on dealers and traders who hold significant positions in swaps, (b) requiring certain standardized OTC derivatives to be traded on registered exchanges as directed by CFTC, (c) imposing new and potentially higher capital and margin requirements on swap dealers and traders who hold significant positions in swaps and (d) increasing the monitoring and compliance obligations of parties who engage in swaps, including new recordkeeping and reporting requirements with governmental entities. The CFTC has issued regulations exempting certain end users of energy commodities from being required to clear OTC derivatives, provided that they (a) are using the swaps to hedge or mitigate commercial risk and (b) satisfy certain other requirements. To the extent we meet such requirements, the end user exemption could reduce the effect of the law's clearing requirements on our hedging activity. Pursuant to authority granted under the Dodd-Frank Act, the CFTC has also issued rules that, among other things, further define the OTC derivative products and entities subject to additional regulatory oversight, which recently became effective. These requirements could subject us to additional regulatory oversight related to our OTC derivative transactions, cause our OTC derivative transactions to be more costly and have an impact on financial condition due to additional capital requirements. In addition, as these reforms aim to standardize OTC products it could limit the effectiveness of our hedging programs because we would have less ability to tailor OTC derivatives to match the precise risk we are seeking to manage.

RATIO OF EARNINGS TO FIXED CHARGES

The Ratio of Earnings to Fixed Charges for each of the periods indicated is as follows:

Twelve Months Period Ended	Ratio
December 31, 2011	2.61
December 31, 2012	2.46
December 31, 2013	1.33
March 31, 2014	2.00

The Ratio of Earning to Fixed Charges for the three months ended March 31, 2014 was 6.09. For the purposes of calculating the Ratio of Earnings to Fixed Charges, “earnings” represents income before income taxes, extraordinary items, and cumulative effect of accounting changes, plus fixed charges. “Fixed charges” consist of interest expense, amortization of debt issuance costs, and the portion of operating rental expense which management believes is representative of the interest within rental expense.

INDEPENDENT AUDITORS

The financial statements of Kentucky Power Company as of December 31, 2013 and 2012, and for each of the three years in the period ended December 31, 2013, included in this Official Statement have been audited by Deloitte & Touche LLP, independent auditors, as stated in their report appearing herein.

Annex 1 to Appendix A

Kentucky Power Company

2013 Annual Report

Audited Financial Statements

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West Companies	PSO, SWEPCo, TCC and TNC.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary that acquired the generation assets and liabilities of OPCo.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
CO_2	Carbon dioxide and other greenhouse gases.
CWIP	Construction Work in Progress.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
FAC	Fuel Adjustment Clause.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IAA	AEP System Interim Allowance Agreement.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo which defined the sharing of costs and benefits associated with their respective generating plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_x	Nitrogen oxide.

Term	Meaning
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PCA	Power Coordination Agreement.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utility Commission of Ohio.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholder of
Kentucky Power Company:

We have audited the accompanying financial statements of Kentucky Power Company (the "Company"), which comprise the balance sheets as of December 31, 2013 and 2012, and the related statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2013, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013 in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

The financial statements give retroactive effect to the transfer of a fifty percent interest in Units 1 and 2 of the Mitchell Plant to the Company on December 31, 2013, which has been accounted for at historical cost as a transfer between entities under common control as described in Note 1 to the financial statements. Our opinion is not modified with respect to this matter.

Deloitte & Touche LLP

Columbus, Ohio
February 25, 2014

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2013, 2012 and 2011
(in thousands)

	Years Ended December 31, 2013	2012	2011
REVENUES			
Electric Generation, Transmission and Distribution	$ 721,840	$ 753,095	$ 847,867
Sales to AEP Affiliates	103,731	70,776	104,682
Other Revenues	684	546	494
TOTAL REVENUES	826,255	824,417	953,043
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	200,139	219,328	336,164
Purchased Electricity for Resale	11,003	11,319	23,924
Purchased Electricity from AEP Affiliates	269,088	223,649	210,299
Other Operation	75,038	75,410	77,804
Maintenance	66,977	63,125	67,094
Asset Impairments and Other Related Charges	32,847	-	-
Depreciation and Amortization	91,692	87,995	86,498
Taxes Other Than Income Taxes	20,272	19,659	18,567
TOTAL EXPENSES	767,056	700,485	820,350
OPERATING INCOME	59,199	123,932	132,693
Other Income (Expense):			
Interest Income	231	351	2,324
Allowance for Equity Funds Used During Construction	1,367	1,574	1,229
Interest Expense	(44,509)	(49,375)	(51,101)
INCOME BEFORE INCOME TAX EXPENSE	16,288	76,482	85,145
Income Tax Expense	7,382	23,507	31,169
NET INCOME	$ 8,906	$ 52,975	$ 53,976

The common stock of KPCo is wholly-owned by AEP.

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2013, 2012 and 2011
(in thousands)

	Years Ended December 31,		
	2013	2012	2011
Net Income	$ 8,906	$ 52,975	$ 53,976
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $113, $117 and $94 in 2013, 2012 and 2011, Respectively	210	216	(174)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $755, $687 and $540 in 2013, 2012 and 2011, Respectively	1,402	1,275	1,002
Pension and OPEB Funded Status, Net of Tax of $4,168, $1,801 and $400 in 2013, 2012 and 2011, Respectively	7,741	3,345	(743)
TOTAL OTHER COMPREHENSIVE INCOME	9,353	4,836	85
TOTAL COMPREHENSIVE INCOME	$ 18,259	$ 57,811	$ 54,061

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2013, 2012 and 2011
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2010	$ 50,450	$ 478,022	$ 157,467	$ (24,915)	$ 661,024
Capital Contribution from Parent		41,972			41,972
Common Stock Dividends			(39,602)		(39,602)
Net Income			53,976		53,976
Other Comprehensive Income				85	85
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2011	50,450	519,994	171,841	(24,830)	717,455
Capital Contribution from Parent		11,542			11,542
Common Stock Dividends			(33,997)		(33,997)
Net Income			52,975		52,975
Other Comprehensive Income				4,836	4,836
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2012	50,450	531,536	190,819	(19,994)	752,811
Capital Contribution from Parent		83,112			83,112
Common Stock Dividends			(20,034)		(20,034)
Net Income			8,906		8,906
Other Comprehensive Income				9,353	9,353
Pension and OPEB Adjustment Related to Mitchell Plant				5,221	5,221
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$ 50,450	$ 614,648	$ 179,691	$ (5,420)	$ 839,369

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2013 and 2012
(in thousands)

	December 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 743	$ 1,482
Accounts Receivable:		
Customers	17,889	25,826
Affiliated Companies	9,781	53,285
Accrued Unbilled Revenues	857	4,472
Miscellaneous	75	249
Allowance for Uncollectible Accounts	(78)	(164)
Total Accounts Receivable	28,524	83,668
Fuel	92,313	98,717
Materials and Supplies	43,940	38,306
Risk Management Assets	4,356	6,175
Accrued Tax Benefits	5,249	5,186
Prepayments and Other Current Assets	3,284	6,791
TOTAL CURRENT ASSETS	178,409	240,325
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,052,757	1,438,999
Transmission	507,844	495,981
Distribution	693,481	652,615
Other Property, Plant and Equipment (Including Plant to be Retired)	480,759	65,150
Construction Work in Progress	128,599	87,924
Total Property, Plant and Equipment	2,863,440	2,740,669
Accumulated Depreciation and Amortization	943,889	884,016
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,919,551	1,856,653
OTHER NONCURRENT ASSETS		
Regulatory Assets	216,360	213,734
Long-term Risk Management Assets	3,484	6,882
Employee Benefits and Pension Assets	11,446	-
Deferred Charges and Other Noncurrent Assets	20,207	54,986
TOTAL OTHER NONCURRENT ASSETS	251,497	275,602
TOTAL ASSETS	$ 2,349,457	$ 2,372,580

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2013 and 2012

	December 31, 2013	December 31, 2012
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 8,564	$ 13,359
Accounts Payable:		
General	21,619	75,444
Affiliated Companies	39,171	56,256
Long-term Debt Due Within One Year – Nonaffiliated	-	250,000
Risk Management Liabilities	1,828	3,320
Customer Deposits	25,211	23,485
Deferred Income Taxes	6,486	2,376
Accrued Taxes	20,801	16,650
Accrued Interest	6,678	12,002
Regulatory Liability for Over-Recovered Fuel Costs	2,851	7,928
Other Current Liabilities	19,411	29,480
TOTAL CURRENT LIABILITIES	152,620	490,300
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	729,389	529,195
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	2,105	3,700
Deferred Income Taxes	549,672	503,147
Regulatory Liabilities and Deferred Investment Tax Credits	22,926	26,159
Employee Benefits and Pension Obligations	6,041	32,387
Deferred Credits and Other Noncurrent Liabilities	27,335	14,881
TOTAL NONCURRENT LIABILITIES	1,357,468	1,129,469
TOTAL LIABILITIES	1,510,088	1,619,769
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	614,648	531,536
Retained Earnings	179,691	190,819
Accumulated Other Comprehensive Income (Loss)	(5,420)	(19,994)
TOTAL COMMON SHAREHOLDER'S EQUITY	839,369	752,811
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,349,457	$ 2,372,580

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2013, 2012 and 2011
(in thousands)

	Years Ended December 31, 2013	2012	2011
OPERATING ACTIVITIES			
Net Income	$ 8,906	$ 52,975	$ 53,976
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	91,692	87,995	86,498
Deferred Income Taxes	12,440	10,168	33,153
Asset Impairments and Other Related Charges	32,847	-	-
Allowance for Equity Funds Used During Construction	(1,367)	(1,574)	(1,229)
Mark-to-Market of Risk Management Contracts	2,357	2,510	(220)
Pension Contributions to Qualified Plan Trust	-	(5,547)	(18,239)
Fuel Over/Under-Recovery, Net	(5,078)	4,790	2,274
Change in Other Noncurrent Assets	7,334	(13,338)	(10,711)
Change in Other Noncurrent Liabilities	(2,953)	697	2,927
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	55,144	(7,523)	14,707
Fuel, Materials and Supplies	3,130	(55,120)	(3,618)
Accounts Payable	(68,480)	3,429	(9,748)
Accrued Taxes, Net	4,013	(11,400)	(2,152)
Accrued Interest	(5,324)	(545)	131
Other Current Assets	3,817	607	730
Other Current Liabilities	(9,186)	2,974	4,363
Net Cash Flows from Operating Activities	129,292	71,098	152,842
INVESTING ACTIVITIES			
Construction Expenditures	(141,832)	(130,964)	(83,902)
Change in Advances to Affiliates, Net	-	70,332	(3,272)
Acquisitions of Assets	(563)	(419)	(1,289)
Proceeds from Sales of Assets	5,566	1,032	439
Net Cash Flows Used for Investing Activities	(136,829)	(60,019)	(88,024)
FINANCING ACTIVITIES			
Capital Contribution from Parent	83,112	11,542	41,972
Issuance of Long-term Debt – Nonaffiliated	199,700	-	-
Change in Advances from Affiliates, Net	(4,795)	13,359	-
Retirement of Long-term Debt – Nonaffiliated	(250,000)	-	(65,000)
Principal Payments for Capital Lease Obligations	(1,440)	(1,503)	(1,742)
Dividends Paid on Common Stock	(20,034)	(33,997)	(39,602)
Other Financing Activities	255	224	51
Net Cash Flows from (Used for) Financing Activities	6,798	(10,375)	(64,321)
Net Increase (Decrease) in Cash and Cash Equivalents	(739)	704	497
Cash and Cash Equivalents at Beginning of Period	1,482	778	281
Cash and Cash Equivalents at End of Period	$ 743	$ 1,482	$ 778
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 48,602	$ 48,740	$ 50,429
Net Cash Paid for Income Taxes	6,100	23,089	7,785
Noncash Acquisitions Under Capital Leases	3,448	2,136	621
Construction Expenditures Included in Current Liabilities as of December 31,	7,253	28,565	13,735

See Notes to Financial Statements beginning on page 10.

INDEX OF NOTES TO FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 172,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

In accordance with management's December 2010 announcement and an October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

Effective January 1, 2014, the FERC approved a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo, I&M and KPCo will be individually responsible for planning their respective capacity obligations and there will be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies.

Effective January 1, 2014, AEPSC conducts power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M and KPCo. Power and natural gas risk management activities are allocated based on the three member companies' respective equity positions and the SIA. KPCo shared in coal risk management activities based on its proportion of fossil fuels burned by the AEP System. Risk management activities primarily involve the purchase and sale of electricity under physical forward contracts at fixed and variable prices and, to a lesser extent, natural gas and coal. The power, natural gas and coal contracts include physical transactions, OTC options and financially-settled swaps and exchange-traded futures and options. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts. For contracts entered and settled prior to January 1, 2014, power and natural gas risk management activities were allocated based on the Interconnection Agreement and the SIA. For contracts entered prior to January 1, 2014 and settled after January 1, 2014, power and natural gas risk management activities are allocated based on frozen MLR ratios as of December 31, 2013. KPCo shared in the revenues and expenses associated with these risk management activities with the other AEP East Companies, PSO and SWEPCo.

Under a unit power agreement with AEGCo, an affiliated company that was not a member of the Interconnection Agreement, KPCo purchases 30% of AEGCo's 50% share of the total output of the 2,600 MW Rockport Plant capacity. Therefore, KPCo purchases 390 MWs of Rockport Plant capacity. The unit power agreement expires in December 2022. KPCo pays a demand charge for the right to receive the power, which is payable even if the power is not taken.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East Companies and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East Companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months.

Prior to January 1, 2014, the Interconnection Agreement permitted the AEP East Companies to pool their generation assets on a cost basis. It established an allocation method for generating capacity among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. Members of the Interconnection Agreement were compensated for their costs of energy delivered and charged for energy received. The capacity reserve relationship of the Interconnection Agreement members changed as generating assets were added, retired or sold and relative peak demand changed. The Interconnection Agreement calculated each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation was the MLR, which determined each member's percentage share of revenues and costs.

To minimize the credit requirements and operating constraints when operating within PJM, the AEP East Companies, as well as KGPCo and WPCo, agreed to a netting of all payment obligations incurred by any of the AEP East Companies against all balances due to the AEP East Companies and to hold PJM harmless from actions that any one or more AEP East Companies may take with respect to PJM.

Corporate Separation

Background

On December 31, 2013, based on FERC and PUCO orders which approved the corporate separation of OPCo's generation assets and generation liabilities, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. Also on December 31, 2013, AGR subsequently transferred at net book value a one-half interest (780 MW) in the Mitchell Plant to KPCo. The transfer of these generation assets and associated liabilities was approved by the FERC and the KPSC.

Significant Accounting Issues

AGR's transfer of a one-half ownership in the Mitchell Plant to KPCo at net book value qualifies as an acquisition of a business under common control. Pursuant to "Business Combinations" accounting guidance, KPCo retrospectively adjusted its financial statements as if the transfer had occurred at the beginning of the earliest period presented.

None of the OPCo regulatory assets and regulatory liabilities were transferred to KPCo. As previously approved by the PUCO, these regulatory assets and liabilities will be recovered/refunded primarily through OPCo non-bypassable riders.

Substantially all of the current income tax receivables and payables related to OPCo's generation activities prior to December 31, 2013 will remain on OPCo's balance sheet. These current income tax receivables and payables are the responsibility of OPCo. Deferred tax assets and liabilities related to KPCo's acquired share of the Mitchell Plant were transferred to KPCo based upon the Mitchell Plant's related asset and liability values. Following these transfers, KPCo adjusted its deferred tax balances and related regulatory assets to reflect its respective deferred state tax rates.

Long-term Debt

On December 31, 2013, KPCo was assigned $200 million of Long-term Debt – Nonaffiliated from AGR related to a term credit facility.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

KPCo's rates are regulated by the FERC and the KPSC. The FERC also regulates KPCo's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires a nonregulated affiliate to bill an affiliated public utility company at no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The KPSC also regulates certain intercompany transactions under its affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets, wholesale power transactions and wholesale transmission operations and rates. KPCo's wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when KPCo negotiates and files a cost-based contract with the FERC or the FERC determines that KPCo has "market power" in the region where the transaction occurs. KPCo has entered into wholesale power supply contracts with various municipalities that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

The KPSC regulates all of the distribution operations and rates and retail transmission rates on a cost basis. The KPSC also regulates the retail generation/power supply operations and rates.

In addition, the FERC regulates the SIA, the System Transmission Integration Agreement and the Transmission Agreement, all of which are still active and allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement. In accordance with management's December 2010 announcement and October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated. In December 2013, the FERC issued orders approving the creation of a Power Coordination Agreement (PCA), effective January 1, 2014. Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent.

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated electric public utility company, KPCo's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," KPCo records regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America (GAAP) requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Inventory

Fossil fuel inventories and materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, KPCo accrues and recognizes, as Accrued Unbilled Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, for KPCo. See “Sale of Receivables – AEP Credit” section of Note 13 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense related to receivables purchased from KPCo under a sale of receivables agreement. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Concentrations of Credit Risk and Significant Customers

KPCo does not have any significant customers that comprise 10% or more of its operating revenues as of December 31, 2013.

Management monitors credit levels and the financial condition of KPCo’s customers on a continuing basis to minimize credit risk. The KPSC allows recovery in rates for a reasonable level of bad debt costs. Management believes adequate provision for credit loss has been made in the accompanying financial statements.

Emission Allowances

KPCo records emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. KPCo follows the inventory model for these allowances. Allowances expected to be consumed within one year are reported in Materials and Supplies. Allowances with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost. The purchases and sales of allowances are reported in the Operating Activities section of the statements of cash flows. The net margin on sales of emission allowances is included in Electric Generation, Transmission and Distribution Revenues for nonaffiliated transactions and in Sales to AEP Affiliates Revenues for affiliated transactions because of its integral nature to the production process of energy and KPCo’s revenue optimization strategy for operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets.

Property, Plant and Equipment

Electric utility property, plant and equipment are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain the plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held-for-sale criteria under the accounting guidance for "Impairment or Disposal of Long-lived Assets." When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

The fair value of an asset or investment is the amount at which that asset or investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. KPCo records the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances to/from Affiliates, Accounts Receivable and Accounts Payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. The AEP System's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A significant portion of the Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the benefits trusts are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities and cash equivalents funds. Fixed income securities do not trade on an exchange and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are primarily real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current regulatory assets. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended. These deferrals are amortized when refunded or when billed to customers in later months with the KPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the KPSC. On a routine basis, the KPSC reviews and/or audits KPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a FAC under-recovery is no longer probable of recovery, KPCo adjusts its FAC deferrals and records a provision for estimated refunds to recognize these probable outcomes. Changes in fuel costs, including purchased power, are reflected in rates in a timely manner through the FAC. A portion of profits from off-system sales are given to customers through the FAC.

Revenue Recognition

Regulatory Accounting

KPCo's financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, KPCo records them as assets on its balance sheets. KPCo tests for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, KPCo writes off that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

KPCo recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues on the statements of income upon delivery of the energy to the customer and includes unbilled as well as billed amounts.

Most of the power produced at the generation plants of the AEP East Companies is sold to PJM. The AEP East Companies purchase power from PJM to supply power to their customers. Generally, these power sales and purchases are reported on a net basis in revenues on the statements of income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the statements of income. Other RTOs in which KPCo participates do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's economic substance. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, KPCo records expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting. KPCo defers the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

AEPSC, on behalf of the AEP East Companies, engages in wholesale power, coal and natural gas marketing and risk management activities focused on wholesale markets where the AEP System owns assets and adjacent markets. These activities include the purchase and sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

KPCo recognizes revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. KPCo uses MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. The realized gains and losses on wholesale marketing and risk management transactions are included in Revenues on the statements of income on a net basis. The unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). KPCo initially records the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, KPCo subsequently reclassifies the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on the statements of income. KPCo defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 9.

Maintenance

Maintenance costs are expensed as incurred. If it becomes probable that KPCo will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues.

Income Taxes and Investment Tax Credits

KPCo uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits are accounted for under the flow-through method except where regulatory commissions have reflected investment tax credits in the rate-making process on a deferral basis. Investment tax credits that have been deferred are amortized over the life of the plant investment.

KPCo accounts for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." KPCo classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Other Operation expense.

Excise Taxes

As an agent for some state and local governments, KPCo collects from customers certain excise taxes levied by those state or local governments on customers. KPCo does not recognize these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt is refinanced, the reacquisition costs are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. The net amortization expense is included in Interest Expense.

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the interest rate sensitivity of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The investment policy for the pension fund allocates assets based on the funded status of the pension plan. The objective of the asset allocation policy is to reduce the investment volatility of the plan over time. Generally, more of the investment mix will be allocated to fixed income investments as the plan becomes better funded. Assets will be transferred away from equity investments into fixed income investments based on the market value of plan assets compared to the plan's projected benefit obligation. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	30.0 %
Fixed Income	55.0 %
Other Investments	15.0 %

OPEB Plans Assets	Target
Equity	66.0 %
Fixed Income	33.0 %
Cash	1.0 %

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. Each investment manager's portfolio is compared to a diversified benchmark index.

For equity investments, the limits are as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, the concentration limits must not exceed:

- 3% in any single issuer
- 5% for private placements
- 5% for convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers, the following limitations apply:

- AAA rated debt: a single issuer should account for no more than 5% of the portfolio.
- AA+, AA, AA- rated debt: a single issuer should account for no more than 3% of the portfolio.
- Debt rated A+ or lower: a single issuer should account for no more than 2% of the portfolio.
- No more than 10% of the portfolio may be invested in high yield and emerging market debt combined at any time.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and development risk classifications and some investments in Real Estate Investment Trusts, which are publicly traded real estate securities.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investment instruments. Commingled private equity funds are used to enhance the holdings' diversity.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for cash collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the cash collateral is invested. The difference between the rebate owed to the borrower and the cash collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is providing modest incremental income with a limited increase in risk.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Earnings Per Share (EPS)

KPCo is a wholly-owned subsidiary of AEP. Therefore, KPCo is not required to report EPS.

Subsequent Events

Management reviewed subsequent events through February 25, 2014, the date that KPCo's 2013 annual report was issued.

2. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following table provides the components of changes in AOCI for the year ended December 31, 2013. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2013

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate and Foreign Currency	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in thousands)		
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ 1,275	$ (20,860)	$ (19,994)
Change in Fair Value Recognized in AOCI	152	-	-	7,741	7,893
Amounts Reclassified from AOCI	(2)	60	1,402	-	1,460
Net Current Period Other Comprehensive Income	150	60	1,402	7,741	9,353
Pension and OPEB Adjustment Related to Mitchell Plant	-	-	-	5,221	5,221
Balance in AOCI as of December 31, 2013	$ 23	$ (222)	$ 2,677	$ (7,898)	$ (5,420)

Reclassifications from Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the year ended December 31, 2013.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Year Ended December 31, 2013

Gains and Losses on Cash Flow Hedges	Amount of (Gain) Loss Reclassified from AOCI (in thousands)
Commodity:	
Electric Generation, Transmission and Distribution Revenues	$ (64)
Purchased Electricity for Resale	84
Other Operation Expense	(8)
Maintenance Expense	(5)
Property, Plant and Equipment	(11)
Subtotal - Commodity	(4)
Interest Rate and Foreign Currency:	
Interest Expense	93
Subtotal - Interest Rate and Foreign Currency	93
Reclassifications from AOCI, before Income Tax (Expense) Credit	89
Income Tax (Expense) Credit	31
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	58
Pension and OPEB	
Amortization of Prior Service Cost (Credit)	(364)
Amortization of Actuarial (Gains)/Losses	2,521
Change in Funded Status	-
Reclassifications from AOCI, before Income Tax (Expense) Credit	2,157
Income Tax (Expense) Credit	755
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1,402
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 1,460

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2012 and 2011. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2012

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2011	$ (283)	$ (342)	$ (625)
Changes in Fair Value Recognized in AOCI	(246)	-	(246)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	(16)	-	(16)
Purchased Electricity for Resale	427	-	427
Other Operation Expense	(5)	-	(5)
Maintenance Expense	-	-	-
Interest Expense	-	60	60
Property, Plant and Equipment	(4)	-	(4)
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ (409)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2011

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2010	$ (48)	$ (403)	$ (451)
Changes in Fair Value Recognized in AOCI	(431)	-	(431)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	205	-	205
Purchased Electricity for Resale	51	-	51
Other Operation Expense	(32)	-	(32)
Maintenance Expense	(37)	-	(37)
Interest Expense	-	61	61
Property, Plant and Equipment	(47)	-	(47)
Regulatory Assets (a)	56	-	56
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2011	$ (283)	$ (342)	$ (625)

(a) Represents realized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

3. RATE MATTERS

KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. Rate matters can have a material impact on net income, cash flows and possibly financial condition. KPCo's recent significant rate orders and pending rate filings are addressed in this note.

Plant Transfer

In October 2012, the AEP East Companies submitted several filings with the FERC. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, KPCo filed a request with the KPSC for approval to transfer at net book value to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of December 31, 2013, the net book value of Big Sandy Plant, Unit 2 was $249 million, before cost of removal, including materials and supplies inventory and CWIP. In March 2013, KPCo issued a Request for Proposal (RFP) to purchase up to 250 MW of long-term capacity and energy to replace a portion of the capacity from Big Sandy Plant, Unit 1. In June 2013, KPCo filed the results of its RFP with the KPSC.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. The settlement also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo's request to defer FGD project costs for Big Sandy Plant, Unit 2. As a result of this order, in 2013, KPCo recorded a pretax regulatory disallowance of $33 million in Asset Impairments and Other Related Charges on the statement of income. In November 2013, the KPSC denied the Attorney General's petition for rehearing. In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In December 2013, KPCo filed motions with the Franklin County Circuit Court to dismiss the appeal. A hearing on the motions to dismiss was held in January 2014. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed.

2013 Kentucky Base Rate Case

In June 2013, KPCo filed a request with the KPSC for an annual increase in base rates of $114 million based upon a return on common equity of 10.65% to be effective January 2014. The proposed revenue increase included cost recovery of the proposed transfer of the one-half interest in the Mitchell Plant (780 MW). In October 2013, the KPSC issued an order in the plant transfer case which modified and approved a settlement agreement that included the approval of the proposed transfer of the one-half interest in the Mitchell Plant to KPCo. The modified and approved settlement agreement also included KPCo's agreement to withdraw this base rate case request and file a base case proceeding no later than December 2014 with its current base rates to remain in effect until at least May 2015. In November 2013, KPCo withdrew this base rate request and the withdrawal was approved by the KPSC.

FERC Rate Matters

Corporate Separation and Termination of Interconnection Agreement

In October 2012, the AEP East Companies submitted several filings with the FERC seeking approval to fully separate OPCo's generation assets from its distribution and transmission operations and to transfer at net book value AGR's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each), to be effective December 31, 2013. In April 2013, the FERC issued orders approving the transfer of OPCo's generation assets to AGR, and the

Mitchell Plant assets to APCo and KPCo. In January 2014, the FERC dismissed an Industry Energy Users-Ohio petition for rehearing of its order granting OPCo authority to implement corporate separation by transferring its generation assets to AGR. In December 2013, the transfer of the Mitchell Plant to KPCo was completed. See the "Plant Transfer" section of Rate Matters.

In accordance with management's December 2010 announcement and October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

In December 2013, the FERC issued orders approving the creation of a Power Coordination Agreement (PCA), effective January 1, 2014, conditioned upon certain compliance filings which were filed with the FERC in January 2014. The PCA was established among APCo, I&M and KPCo with AEPSC as the agent to coordinate their respective power supply resources. Under the PCA, KPCo would be individually responsible for planning its respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies through May 31, 2015.

In October 2013, the AEP East Companies submitted additional filings with the FERC updating the October 2012 filings to reflect changes necessitated by orders from the Virginia SCC and the KPSC related to the proposed asset transfers and to position the company for the final stages of corporate separation. In December 2013, the FERC issued an order approving these additional filings. See the "Plant Transfers" section of Rate Matters.

If KPCo experiences decreases in revenues or increases in expenses as a result of changes to its relationship with affiliates and is unable to recover the change in revenues and costs through rates, prices or additional sales, it could reduce future net income and cash flows.

4. EFFECTS OF REGULATION

Regulated Generating Unit to be Retired Before or During 2016

The following regulated generating unit is probable of abandonment. Accordingly, CWIP and Plant in Service has been reclassified as Other Property, Plant and Equipment on the balance sheet as of December 31, 2013. The following table summarizes the plant investment and cost of removal, currently being recovered, for the generating unit as of December 31, 2013.

Plant Name and Unit	Gross Investment	Accumulated Depreciation	Net Investment	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
			(in thousands)			
Big Sandy Plant, Unit 2	$ 423,687	$ 180,192	$ 243,495	$ 47,181	2015	27 years
Total	$ 423,687	$ 180,192	$ 243,495	$ 47,181		

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	**December 31, 2013**	**December 31, 2012**	**Remaining Recovery Period**
	(in thousands)		
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	$ 12,146	$ 12,146	
Mountaineer Carbon Capture and Storage Commercial Scale Facility	-	873	
Total Regulatory Assets Not Yet Being Recovered	12,146	13,019	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Other Regulatory Assets Being Recovered	1,422	1,668	various
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	154,603	127,489	22 years
Pension and OPEB Funded Status	32,458	52,048	11 years
Storm Related Costs	7,048	11,746	2 years
Postemployment Benefits	4,530	5,230	5 years
Medicare Subsidy	2,383	-	11 years
Peak Demand Reduction/Energy Efficiency	914	1,589	1 year
Other Regulatory Assets Being Recovered	856	945	various
Total Regulatory Assets Being Recovered	204,214	200,715	
Total Noncurrent Regulatory Assets	$ 216,360	$ 213,734	

Regulatory Liabilities:	**December 31, 2013**	**December 31, 2012**	**Remaining Refund Period**
	(in thousands)		
Current Regulatory Liability			
Over-recovered Fuel Costs - does not pay a return	$ 2,851	$ 7,928	1 year
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 19,231	$ 21,066	(a)
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	3,259	4,288	4 years
Deferred Investment Tax Credits	126	356	7 years
Other Regulatory Liabilities Being Paid	310	449	various
Total Regulatory Liabilities Being Paid	22,926	26,159	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 22,926	$ 26,159	

(a) Relieved as removal costs are incurred.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

COMMITMENTS

Construction and Commitments

KPCo has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, KPCo contractually commits to third-party construction vendors for certain material purchases and other construction services. KPCo also purchases fuel, materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes KPCo's actual contractual commitments as of December 31, 2013:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 198,192	$ 246,401	$ 232,240	$ 348,360	$ 1,025,193
Energy and Capacity Purchase Contracts	35,144	70,156	69,993	139,846	315,139
Construction Contracts for Capital Assets (b)	1,786	-	-	-	1,786
Total	$ 235,122	$ 316,557	$ 302,233	$ 488,206	$ 1,342,118

(a) Represents contractual commitments to purchase coal and other consumables as fuel for electric generation along with related transportation of the fuel.
(b) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2013, there were no material liabilities recorded for any indemnifications.

KPCo is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East Companies related to power purchase and sale activity pursuant to the SIA.

Lease Obligations

KPCo leases certain equipment under master lease agreements. See "Master Lease Agreements" section of Note 12 for disclosure of lease residual value guarantees.

CONTINGENCIES

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an electric utility, subject to various deductibles. Insurance coverage includes all risks of physical loss or damage to assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of KPCo's retentions. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

Carbon Dioxide Public Nuisance Claims

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011. Plaintiffs refiled their complaint in federal district court. The court ordered all defendants to respond to the refiled complaints in October 2011. In March 2012, the court granted the defendants' motion for dismissal on several grounds, including the doctrine of collateral estoppel and the applicable statute of limitations. In May 2013, the U.S. Court of Appeals for the Fifth Circuit affirmed the district court's dismissal of the complaint. The plaintiffs did not appeal to the U.S. Supreme Court.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. In September 2012, the Ninth Circuit Court of Appeals affirmed the trial court's decision, holding that the CAA displaced Kivalina's claims for damages. Plaintiffs filed seeking further review in the U.S. Supreme Court. In May 2013, the U.S. Supreme Court denied the plaintiffs' request for review.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag and sludge. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. KPCo currently incurs costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. As of December 31, 2013, there is one site for which KPCo has received an information request which could lead to a Potentially Responsible Party designation. In the instance where KPCo has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named for each site and several of the parties are financially sound enterprises. At present, management's estimates do not anticipate material cleanup costs for identified sites.

6. IMPAIRMENT

2013

Big Sandy Plant, Unit 2 FGD Project

In the third quarter of 2013, KPCo recorded a pretax write-off of $33 million in Asset Impairments and Other Related Charges on the statement of income primarily related to the Big Sandy Plant, Unit 2 FGD project. See the "Plant Transfer" section of Note 3.

7. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1.

KPCo participates in an AEP sponsored qualified pension plan and an unfunded nonqualified pension plan. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and nonqualified pension plans. KPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

KPCo recognizes its funded status associated with defined benefit pension and OPEB plans in its balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. KPCo recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status and recognizes, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. KPCo records a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31 of each year used in the measurement of KPCo's benefit obligations are shown in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	2013	2012	2013	2012
Discount Rate	4.70 %	3.95 %	4.70 %	3.95 %
Rate of Compensation Increase	4.50 % (a)	4.50 % (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

NA Not applicable.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2013, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.5%.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1 of each year used in the measurement of KPCo's benefit costs are shown in the following table:

	Pension Plans			Other Postretirement Benefit Plans		
	2013	**2012**	**2011**	**2013**	**2012**	**2011**
Discount Rate	3.95 %	4.55 %	5.05 %	3.95 %	4.75 %	5.25 %
Expected Return on Plan Assets	6.50 %	7.25 %	7.75 %	7.00 %	7.25 %	7.50 %
Rate of Compensation Increase	4.50 %	4.50 %	4.50 %	NA	NA	NA

NA Not applicable.

The expected return on plan assets for 2013 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth.

The health care trend rate assumptions as of January 1 of each year used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	**2013**	**2012**
Initial	6.75 %	7.00 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	2020

Assumed health care cost trend rates have a significant effect on the amounts reported for the OPEB health care plans. A 1% change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(in thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 164	$ (108)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	2,101	(1,710)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. The plans are monitored to control security diversification and ensure compliance with the investment policy. As of December 31, 2013, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2013 and 2012

The following tables provide a reconciliation of the changes in the plans' benefit obligations, fair value of plan assets and funded status as of December 31. The benefit obligation for the defined benefit pension and OPEB plans are the projected benefit obligation and the accumulated benefit obligation, respectively.

	Pension Plans		Other Postretirement Benefit Plans	
	2013	2012	2013	2012
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1,	$ 183,994	$ 170,910	$ 66,513	$ 83,480
Service Cost	1,763	2,231	750	1,636
Interest Cost	7,074	7,762	2,491	3,821
Actuarial (Gain) Loss	(13,578)	15,617	(15,950)	437
Plan Amendment Prior Service Credit	-	-	-	(19,043)
Benefit Payments	(9,821)	(12,526)	(4,423)	(5,319)
Participant Contributions	-	-	1,198	1,194
Medicare Subsidy	-	-	227	307
Benefit Obligation as of December 31,	$ 169,432	$ 183,994	$ 50,806	$ 66,513
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 165,534	$ 151,450	$ 60,402	$ 55,418
Actual Gain on Plan Assets	13,865	21,063	5,748	5,752
Company Contributions	-	5,547	-	3,357
Participant Contributions	-	-	1,198	1,194
Benefit Payments	(9,821)	(12,526)	(4,423)	(5,319)
Fair Value of Plan Assets as of December 31,	$ 169,578	$ 165,534	$ 62,925	$ 60,402
Funded (Underfunded) Status as of December 31,	$ 146	$ (18,460)	$ 12,119	$ (6,111)

Amounts Recognized on the Balance Sheets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	2012	2013	2012
	(in thousands)			
Employee Benefits and Pension Assets - Prepaid Benefit Costs	$ 146	$ -	$ 11,300	$ -
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	-	(18,460)	819	(6,111)
Funded (Underfunded) Status	$ 146	$ (18,460)	$ 12,119	$ (6,111)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	2012	2013	2012
Components	(in thousands)			
Net Actuarial Loss	$ 51,587	$ 75,591	$ 12,769	$ 32,797
Prior Service Cost (Credit)	203	259	(24,069)	(26,468)
Recorded as				
Regulatory Assets	$ 42,089	$ 47,519	$ (9,631)	$ 4,529
Deferred Income Taxes	3,395	9,916	(584)	630
Net of Tax AOCI	6,306	18,415	(1,085)	1,170

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2013 and 2012 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2013	2012	2013	2012
Components	(in thousands)			
Actuarial (Gain) Loss During the Year	$ (17,611)	$ 5,845	$ (17,745)	$ (1,467)
Prior Service Credit	-	-	-	(19,043)
Amortization of Actuarial Loss	(6,393)	(5,225)	(2,283)	(2,117)
Amortization of Prior Service Credit (Cost)	(56)	(120)	2,399	676
Change for the Year	$ (24,060)	$ 500	$ (17,629)	$ (21,951)

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 39,294	$ -	$ -	$ -	$ 39,294	23.2 %
International	18,522	-	-	-	18,522	10.9 %
Real Estate Investment Trusts	2,084	-	-	-	2,084	1.2 %
Common Collective Trust - International	-	352	-	-	352	0.2 %
Subtotal - Equities	59,900	352	-	-	60,252	35.5 %
Fixed Income:						
Common Collective Trust - Debt	-	933	-	-	933	0.5 %
United States Government and Agency Securities	-	13,922	-	-	13,922	8.2 %
Corporate Debt	-	57,592	-	-	57,592	34.0 %
Foreign Debt	-	12,372	-	-	12,372	7.3 %
State and Local Government	-	1,007	-	-	1,007	0.6 %
Other - Asset Backed	-	1,198	-	-	1,198	0.7 %
Subtotal - Fixed Income	-	87,024	-	-	87,024	51.3 %
Real Estate	-	-	8,575	-	8,575	5.0 %
Alternative Investments	-	-	11,865	-	11,865	7.0 %
Securities Lending	-	1,266	-	-	1,266	0.8 %
Securities Lending Collateral (a)	-	-	-	(1,627)	(1,627)	(0.9)%
Cash and Cash Equivalents	-	1,749	-	-	1,749	1.0 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	474	474	0.3 %
Total	$ 59,900	$ 90,391	$ 20,440	$ (1,153)	$ 169,578	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2013	$ 7,740	$ 6,894	$ 14,634
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	1,197	532	1,729
Relating to Assets Sold During the Period	-	537	537
Purchases and Sales	(362)	3,902	3,540
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2013	$ 8,575	$ 11,865	$ 20,440

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 17,535	$ -	$ -	$ -	$ 17,535	27.9 %
International	22,796	-	-	-	22,796	36.2 %
Common Collective Trust - Global	-	544	-	-	544	0.9 %
Subtotal - Equities	40,331	544	-	-	40,875	65.0 %
Fixed Income:						
Common Collective Trust - Debt	-	3,255	-	-	3,255	5.2 %
United States Government and Agency Securities	-	2,093	-	-	2,093	3.3 %
Corporate Debt	-	4,078	-	-	4,078	6.5 %
Foreign Debt	-	796	-	-	796	1.2 %
State and Local Government	-	171	-	-	171	0.3 %
Other - Asset Backed	-	301	-	-	301	0.5 %
Subtotal - Fixed Income	-	10,694	-	-	10,694	17.0 %
Trust Owned Life Insurance:						
International Equities	-	490	-	-	490	0.8 %
United States Bonds	-	7,836	-	-	7,836	12.4 %
Cash and Cash Equivalents	2,527	325	-	-	2,852	4.5 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	178	178	0.3 %
Total	$ 42,858	$ 19,889	$ -	$ 178	$ 62,925	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table presents the classification of pension plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 46,114	$ -	$ -	$ -	$ 46,114	27.9 %
International	17,512	-	-	-	17,512	10.5 %
Real Estate Investment Trusts	3,192	-	-	-	3,192	1.9 %
Common Collective Trust - International	-	153	-	-	153	0.1 %
Subtotal - Equities	66,818	153	-	-	66,971	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	1,118	-	-	1,118	0.7 %
United States Government and Agency Securities	-	25,215	-	-	25,215	15.2 %
Corporate Debt	-	43,539	-	-	43,539	26.3 %
Foreign Debt	-	7,002	-	-	7,002	4.2 %
State and Local Government	-	1,550	-	-	1,550	0.9 %
Other - Asset Backed	-	1,255	-	-	1,255	0.8 %
Subtotal - Fixed Income	-	79,679	-	-	79,679	48.1 %
Real Estate	-	-	7,740	-	7,740	4.7 %
Alternative Investments	-	-	6,894	-	6,894	4.2 %
Securities Lending	-	2,832	-	-	2,832	1.7 %
Securities Lending Collateral (a)	-	-	-	(3,203)	(3,203)	(1.9)%
Cash and Cash Equivalents	-	4,433	-	-	4,433	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	188	188	0.1 %
Total	$ 66,818	$ 87,097	$ 14,634	$ (3,015)	$ 165,534	100.0 %

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

The following table sets forth a reconciliation of changes in the fair value of assets classified as Level 3 in the fair value hierarchy for the pension assets:

	Corporate Debt	Real Estate	Alternative Investments	Total Level 3
		(in thousands)		
Balance as of January 1, 2012	$ 224	$ 5,757	$ 5,652	$ 11,633
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	1,049	355	1,404
Relating to Assets Sold During the Period	(79)	-	172	93
Purchases and Sales	(145)	934	715	1,504
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 7,740	$ 6,894	$ 14,634

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 16,255	$ -	$ -	$ -	$ 16,255	26.9 %
International	19,436	-	-	-	19,436	32.2 %
Subtotal - Equities	35,691	-	-	-	35,691	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	2,795	-	-	2,795	4.6 %
United States Government and Agency Securities	-	3,166	-	-	3,166	5.2 %
Corporate Debt	-	5,964	-	-	5,964	9.9 %
Foreign Debt	-	1,008	-	-	1,008	1.7 %
State and Local Government	-	280	-	-	280	0.5 %
Other - Asset Backed	-	379	-	-	379	0.6 %
Subtotal - Fixed Income	-	13,592	-	-	13,592	22.5 %
Trust Owned Life Insurance:						
International Equities	-	1,985	-	-	1,985	3.3 %
United States Bonds	-	6,263	-	-	6,263	10.3 %
Cash and Cash Equivalents	2,391	439	-	-	2,830	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	41	41	0.1 %
Total	$ 38,082	$ 22,279	$ -	$ 41	$ 60,402	100.0 %

(a) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

The accumulated benefit obligation for the pension plan is as follows:

Accumulated Benefit Obligation	December 31, 2013	December 31, 2012
	(in thousands)	
Qualified Pension Plan	$ 166,951	$ 180,892
Total	$ 166,951	$ 180,892

For the underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans as of December 31, 2012 were as follows:

	Underfunded Pension Plans 2012 (in thousands)
Projected Benefit Obligation	$ 183,994
Accumulated Benefit Obligation	$ 180,892
Fair Value of Plan Assets	165,534
Underfunded Accumulated Benefit Obligation	$ (15,358)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the pension plans of $2.7 million during 2014. The estimated contributions to the pension trust are at least the minimum amount required by the Employee Retirement Income Security Act and additional discretionary contributions may also be made to maintain the funded status of the plan.

The table below reflects the total benefits expected to be paid from the plan or from KPCo's assets. The payments include the participants' contributions to the plan for their share of the cost. In November 2012, changes to the retiree medical coverage were announced. Effective for retirements after December 2012, contributions to retiree medical coverage were capped reducing exposure to future medical cost inflation. Effective for employees hired after December 2013, retiree medical coverage will not be provided. The impact of the changes is reflected in the Benefit Plan Obligation table as plan amendments. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Estimated Payments	
	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
2014	$ 10,760	$ 4,508
2015	11,334	4,820
2016	11,489	5,126
2017	11,946	5,385
2018	12,674	5,538
Years 2019 to 2023, in Total	64,896	30,389

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost (credit) for the years ended December 31, 2013, 2012 and 2011:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2013	2012	2011	2013	2012	2011
	(in thousands)					
Service Cost	$ 1,763	$ 2,231	$ 2,188	$ 750	$ 1,636	$ 1,513
Interest Cost	7,074	7,762	8,105	2,491	3,821	4,082
Expected Return on Plan Assets	(9,832)	(11,290)	(10,847)	(3,999)	(3,931)	(4,255)
Amortization of Prior Service Cost (Credit)	56	120	194	(2,399)	(676)	(46)
Amortization of Net Actuarial Loss	6,393	5,225	4,155	2,283	2,117	1,055
Net Periodic Benefit Cost (Credit)	5,454	4,048	3,795	(874)	2,967	2,349
Capitalized Portion	(2,372)	(1,388)	(1,139)	380	(1,018)	(705)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3,082	$ 2,660	$ 2,656	$ (494)	$ 1,949	$ 1,644

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2014 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 4,335	$ 734
Prior Service Cost (Credit)	55	(2,443)
Total Estimated 2014 Amortization	$ 4,390	$ (1,709)
Expected to be Recorded as		
Regulatory Asset	$ 3,731	$ (1,595)
Deferred Income Taxes	231	(40)
Net of Tax AOCI	428	(74)
Total	$ 4,390	$ (1,709)

American Electric Power System Retirement Savings Plan

KPCo participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled $2.3 million in 2013, $2.3 million in 2012 and $2.2 million in 2011.

8. BUSINESS SEGMENTS

KPCo has one reportable segment, an integrated electricity generation, transmission and distribution business. KPCo’s other activities are insignificant.

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and marketer of wholesale electricity, natural gas, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact KPCo due to changes in the underlying market prices or rates. AEPSC, on behalf of KPCo, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of KPCo. To accomplish these objectives, AEPSC, on behalf of KPCo, primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for “Derivatives and Hedging.” Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

AEPSC, on behalf of KPCo, enters into power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo’s commodity portfolio. For disclosure purposes, such risks are grouped as “Commodity,” as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with the established risk management policies as approved by the Finance Committee of AEP’s Board of Directors.

The following table represents the gross notional volume of KPCo’s outstanding derivative contracts as of December 31, 2013 and 2012:

Notional Volume of Derivative Instruments

	Volume		
	December 31,		Unit of
Primary Risk Exposure	**2013**	**2012**	**Measure**
	(in thousands)		
Commodity:			
Power	10,071	18,838	MWhs
Coal	2	247	Tons
Natural Gas	509	2,018	MMBtus
Heating Oil and Gasoline	261	269	Gallons
Interest Rate	$ 2,615	$ 4,836	USD

Fair Value Hedging Strategies

AEPSC, on behalf of KPCo, enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify KPCo’s exposure to interest rate risk by converting a portion of KPCo’s fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

AEPSC, on behalf of KPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. KPCo does not hedge all commodity price risk.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities as "Commodity." KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of KPCo, also enters into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The forecasted fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. KPCo does not hedge all interest rate exposure.

At times, KPCo is exposed to foreign currency exchange rate risks primarily when KPCo purchases certain fixed assets from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of KPCo, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. KPCo does not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCo's FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of KPCo's risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2013 and 2012 balance sheets, KPCo netted $0 and $253 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $1 million and $2.2 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of KPCo's derivative activity on the balance sheets as of December 31, 2013 and 2012:

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 9,520	$ 85	$ -	$ 9,605	$ (5,249)	$ 4,356
Long-term Risk Management Assets	4,306	-	-	4,306	(822)	3,484
Total Assets	13,826	85	-	13,911	(6,071)	7,840
Current Risk Management Liabilities	7,583	65	-	7,648	(5,820)	1,828
Long-term Risk Management Liabilities	2,970	-	-	2,970	(865)	2,105
Total Liabilities	10,553	65	-	10,618	(6,685)	3,933
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,273	$ 20	$ -	$ 3,293	$ 614	$ 3,907

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 25,448	$ 72	$ -	$ 25,520	$ (19,345)	$ 6,175
Long-term Risk Management Assets	12,117	43	-	12,160	(5,278)	6,882
Total Assets	37,565	115	-	37,680	(24,623)	13,057
Current Risk Management Liabilities	23,806	239	-	24,045	(20,725)	3,320
Long-term Risk Management Liabilities	9,469	85	-	9,554	(5,854)	3,700
Total Liabilities	33,275	324	-	33,599	(26,579)	7,020
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,290	$ (209)	$ -	$ 4,081	$ 1,956	$ 6,037

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents KPCo's activity of derivative risk management contracts for the years ended December 31, 2013, 2012 and 2011:

Amount of Gain (Loss) Recognized on
Risk Management Contracts

	Years Ended December 31,		
Location of Gain (Loss)	**2013**	**2012**	**2011**
		(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 1,483	$ (1,597)	$ 2,248
Sales to AEP Affiliates	-	-	31
Fuel and Other Consumables Used for Electric Generation	-	-	(3)
Regulatory Assets (a)	-	-	93
Regulatory Liabilities (a)	(1,029)	1,047	(1,158)
Total Gain (Loss) on Risk Management Contracts	$ 454	$ (550)	$ 1,211

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the balance sheets.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

KPCo's accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's statements of income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk affects Net Income during the period of change.

KPCo records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on KPCo's statements of income. During 2013, 2012 and 2011, KPCo did not designate any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's balance sheets, depending on the specific nature of the risk being hedged. During 2013, 2012 and 2011, KPCo designated power, coal and natural gas derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the statements of income. During 2013, 2012 and 2011, KPCo designated heating oil and gasoline derivatives as cash flow hedges.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its balance sheets into Interest Expense on its statements of income in those periods in which hedged interest payments occur. During 2013, 2012 and 2011, KPCo did not designate any interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2013, 2012 and 2011, KPCo did not designate any foreign currency derivatives as cash flow hedges.

During 2013, 2012 and 2011, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets and the reasons for changes in cash flow hedges, see Note 2.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets as of December 31, 2013 and 2012 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2013

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 79	$ -	$ 79
Hedging Liabilities (a)	59	-	59
AOCI Loss Net of Tax	23	(222)	(199)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	23	(60)	(37)

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2012

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 63	$ -	$ 63
Hedging Liabilities (a)	272	-	272
AOCI Loss Net of Tax	(127)	(282)	(409)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(100)	(60)	(160)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's balance sheets.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of December 31, 2013, the maximum length of time that KPCo is hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions was 12 months.

Credit Risk

AEPSC, on behalf of KPCo, limits credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. AEPSC, on behalf of KPCo, uses Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

When AEPSC, on behalf of KPCo, uses standardized master agreements, these agreements may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents: (a) KPCo's fair value of such derivative contracts, (b) the amount of collateral KPCo would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2013 and 2012:

	December 31,	
	2013	**2012**
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 118	$ 432
Amount of Collateral KPCo Would Have Been Required to Post	565	741
Amount Attributable to RTO and ISO Activities	522	703

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of December 31, 2013 and 2012:

	December 31,	
	2013	**2012**
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 4,039	$ 9,907
Amount of Cash Collateral Posted	-	365
Additional Settlement Liability if Cross Default Provision is Triggered	3,817	6,041

10. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt as of December 31, 2013 and 2012 are summarized in the following table:

	December 31,			
	2013		2012	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 749,389	$ 841,594	$ 799,195	$ 967,366

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2013 and 2012. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 170	$ 11,168	$ 2,487	$ (6,064)	$ 7,761
Cash Flow Hedges:					
Commodity Hedges (a)	-	85	-	(6)	79
Total Risk Management Assets	$ 170	$ 11,253	$ 2,487	$ (6,070)	$ 7,840
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 144	$ 10,092	$ 316	$ (6,678)	$ 3,874
Cash Flow Hedges:					
Commodity Hedges (a)	-	65	-	(6)	59
Total Risk Management Liabilities	$ 144	$ 10,157	$ 316	$ (6,684)	$ 3,933

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 833	$ 33,315	$ 3,417	$ (24,571)	$ 12,994
Cash Flow Hedges:					
Commodity Hedges (a)	-	103	-	(40)	63
Total Risk Management Assets	$ 833	$ 33,418	$ 3,417	$ (24,611)	$ 13,057
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 392	$ 31,665	$ 1,218	$ (26,527)	$ 6,748
Cash Flow Hedges:					
Commodity Hedges (a)	-	312	-	(40)	272
Total Risk Management Liabilities	$ 392	$ 31,977	$ 1,218	$ (26,567)	$ 7,020

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2013, 2012 and 2011.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2013	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2012	$ 2,199
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(732)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	101
Transfers into Level 3 (d) (e)	273
Transfers out of Level 3 (e) (f)	(187)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	517
Balance as of December 31, 2013	$ 2,171

Year Ended December 31, 2012	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2011	$ 416
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(1,071)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	5
Purchases, Issuances and Settlements (c)	2,282
Transfers into Level 3 (d) (e)	309
Transfers out of Level 3 (e) (f)	(434)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	692
Balance as of December 31, 2012	$ 2,199

Year Ended December 31, 2011	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2010	$ 1,073
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(454)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(16)
Purchases, Issuances and Settlements (c)	336
Transfers into Level 3 (d) (e)	524
Transfers out of Level 3 (e) (f)	(635)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(412)
Balance as of December 31, 2011	$ 416

(a) Included in revenues on KPCo's statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's statements of income. These net gains (losses) are recorded as regulatory assets/liabilities.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of December 31, 2013 and 2012:

Significant Unobservable Inputs
December 31, 2013

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	Forward Price Range High
	(in thousands)					
Energy Contracts	$ 1,924	$ 198	Discounted Cash Flow	Forward Market Price	$ 13.04	$ 80.50
FTRs	563	118	Discounted Cash Flow	Forward Market Price	(5.10)	10.44
Total	$ 2,487	$ 316				

Significant Unobservable Inputs
December 31, 2012

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	Forward Price Range High
	(in thousands)					
Energy Contracts	$ 3,067	$ 786	Discounted Cash Flow	Forward Market Price	$ 9.40	$ 68.80
FTRs	350	432	Discounted Cash Flow	Forward Market Price	(3.21)	14.79
Total	$ 3,417	$ 1,218				

(a) Represents market prices in dollars per MWh.

11. INCOME TAXES

The details of KPCo's income taxes as reported are as follows:

	Years Ended December 31, 2013	2012	2011
		(in thousands)	
Income Tax Expense (Credit):			
Current	$ (4,828)	$ 13,617	$ (1,625)
Deferred	12,440	10,168	33,153
Deferred Investment Tax Credits	(230)	(278)	(359)
Income Tax Expense	$ 7,382	$ 23,507	$ 31,169

The following is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory tax rate and the amount of income taxes reported:

	Years Ended December 31, 2013	2012	2011
		(in thousands)	
Net Income	$ 8,906	$ 52,975	$ 53,976
Income Tax Expense	7,382	23,507	31,169
Pretax Income	$ 16,288	$ 76,482	$ 85,145
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 5,701	$ 26,769	$ 29,801
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	2,648	2,382	2,563
AFUDC	(749)	(894)	(818)
Removal Costs	(2,475)	(3,885)	(2,010)
Investment Tax Credits, Net	(230)	(278)	(359)
State and Local Income Taxes, Net	1,581	1,535	2,261
Tax Adjustments	1,097	(1,076)	751
Other	(191)	(1,046)	(1,020)
Income Tax Expense	$ 7,382	$ 23,507	$ 31,169
Effective Income Tax Rate	45.3 %	30.7 %	36.6 %

The following table shows elements of KPCo's net deferred tax liability and significant temporary differences:

	December 31, 2013	December 31, 2012
	(in thousands)	
Deferred Tax Assets	$ 56,347	$ 42,212
Deferred Tax Liabilities	(612,505)	(547,735)
Net Deferred Tax Liabilities	$ (556,158)	$ (505,523)
Property Related Temporary Differences	$ (436,812)	$ (410,100)
Amounts Due from Customers for Future Federal Income Taxes	(29,842)	(29,800)
Deferred State Income Taxes	(80,357)	(54,658)
Deferred Income Taxes on Other Comprehensive Loss	2,918	10,760
Regulatory Assets	(17,063)	(20,604)
All Other, Net	4,998	(1,121)
Net Deferred Tax Liabilities	$ (556,158)	$ (505,523)

AEP System Tax Allocation Agreement

KPCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. KPCo and other AEP subsidiaries completed the examination of the years 2007 and 2008 in April 2011 and settled all outstanding issues on appeal for the years 2001 through 2006 in October 2011. The settlements did not have a material impact on KPCo and other AEP subsidiaries' net income, cash flows or financial condition. The IRS examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2009.

Tax Credit Carryforward

A federal income tax operating loss sustained in 2009 along with lower federal taxable income in 2012, 2011 and 2010 resulted in unused federal income tax credits of $232 thousand, not all of which have an expiration date. As of December 31, 2013, KPCo had federal general business tax credit carryforwards of $218 thousand. If these credits are not utilized, the federal general business tax credits will expire in the years 2029 through 2032.

KPCo anticipates future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused.

Uncertain Tax Positions

KPCo recognizes interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation expense in accordance with the accounting guidance for "Income Taxes."

The following table shows amounts reported for interest expense, interest income and reversal of prior period interest expense:

	Years Ended December 31, 2013	2012	2011
		(in thousands)	
Interest Expense	$ -	$ 23	$ 193
Interest Income	99	-	1,849
Reversal of Prior Period Interest Expense	-	-	284

The following table shows balances for amounts accrued for the receipt of interest and the payment of interest and penalties:

	December 31, 2013	2012
	(in thousands)	
Accrual for Receipt of Interest	$ 1	$ 1
Accrual for Payment of Interest and Penalties	98	92

The reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2013	2012	2011
		(in thousands)	
Balance as of January 1,	$ 1,333	$ 1,608	$ 2,711
Increase - Tax Positions Taken During a Prior Period	-	-	1,604
Decrease - Tax Positions Taken During a Prior Period	(725)	(93)	(1,586)
Increase - Tax Positions Taken During the Current Year	-	-	-
Decrease - Tax Positions Taken During the Current Year	-	-	-
Decrease - Settlements with Taxing Authorities	-	(182)	(99)
Decrease - Lapse of the Applicable Statute of Limitations	-	-	(1,022)
Balance as of December 31,	$ 608	$ 1,333	$ 1,608

The total amount of unrecognized tax benefits (costs) that, if recognized, would affect the effective tax rate is $0 thousand for 2013 and 2012 and $(4) thousand for 2011. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

The American Taxpayer Relief Act of 2012 (the 2012 Act) was enacted in January 2013. Included in the 2012 Act was a one-year extension of the 50% bonus depreciation. The 2012 Act also retroactively extended the life of research and development, employment and several energy tax credits, which expired at the end of 2011. The enacted provisions will not materially impact KPCo's net income or financial condition but did have a favorable impact on cash flows in 2013.

Federal Tax Regulations

In 2013, the U.S. Treasury Department issued final and re-proposed regulations regarding the deduction and capitalization of expenditures related to tangible property, effective for the tax years beginning in 2014. In addition, the IRS issued Revenue Procedures under the Industry Issue Resolutions program that provides specific guidance for the implementation of the regulations for the electric utility industry. The impact of these final regulations is not material to net income, cash flows or financial condition.

State Tax Legislation

In May 2011, Michigan repealed its Business Tax regime and replaced it with a traditional corporate net income tax rate of 6%, effective January 1, 2012.

During the third quarter of 2013, it was determined that the state of West Virginia had achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate will be reduced from 7.0% to 6.5% in 2014. The enacted provisions will not materially impact KPCo's net income, cash flows or financial condition.

12. LEASES

Leases of property, plant and equipment are for remaining periods up to 10 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. For capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. The components of rental costs are as follows:

	Years Ended December 31,		
Lease Rental Costs	**2013**	**2012**	**2011**
		(in thousands)	
Net Lease Expense on Operating Leases	$ 1,387	$ 1,141	$ 835
Amortization of Capital Leases	1,743	1,710	1,897
Interest on Capital Leases	311	311	344
Total Lease Rental Costs	$ 3,441	$ 3,162	$ 3,076

The following table shows the property, plant and equipment under capital leases and related obligations recorded on KPCo's balance sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on KPCo's balance sheets.

	December 31,	
	2013	**2012**
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Generation	$ 2,854	$ 2,776
Other Property, Plant and Equipment	3,425	4,618
Total Property, Plant and Equipment Under Capital Leases	6,279	7,394
Accumulated Amortization	1,869	2,576
Net Property, Plant and Equipment Under Capital Leases	$ 4,410	$ 4,818
Obligations Under Capital Leases		
Noncurrent Liability	$ 3,420	$ 3,128
Liability Due Within One Year	990	1,729
Total Obligations Under Capital Leases	$ 4,410	$ 4,857

Future minimum lease payments consisted of the following as of December 31, 2013:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2014	$ 1,147	$ 1,324
2015	1,025	1,153
2016	812	1,091
2017	672	923
2018	471	629
Later Years	851	1,493
Total Future Minimum Lease Payments	4,978	$ 6,613
Less Estimated Interest Element	568	
Estimated Present Value of Future Minimum Lease Payments	$ 4,410	

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of December 31, 2013, the maximum potential loss for these lease agreements was approximately $1.1 million assuming the fair value of the equipment is zero at the end of the lease term.

13. FINANCING ACTIVITIES

Long-term Debt

There are certain limitations on establishing liens against KPCo's assets under its indentures. None of the long-term debt obligations of KPCo have been guaranteed or secured by AEP or any of its affiliates.

The following details long-term debt outstanding as of December 31, 2013 and 2012:

Type of Debt	Maturity	Weighted Average Interest rate as of December 31, 2013	Interest Rate Ranges as of December 31, 2013	2012	Outstanding as of December 31, 2013	2012
					(in thousands)	
Senior Unsecured Notes	2017-2039	6.40%	5.625%-8.13%	5.625%-8.13%	$ 530,000	$ 780,000
Notes Payable - Affiliated	2015	5.25%	5.25%	5.25%	20,000	20,000
Other Long-term Debt (a)	2015	1.188%	1.188%		200,000	-
Unamortized Discount, Net					(611)	(805)
Total Long-term Debt Outstanding					749,389	799,195
Long-term Debt Due Within One Year					-	250,000
Long-term Debt					$ 749,389	$ 549,195

(a) In July 2013, AGR, APCo, KPCo and OPCo entered into a $1 billion term credit facility due in May 2015 to provide liquidity during the corporate separation process. In 2013, OPCo borrowed $1 billion under the credit facility and retired other certain debt. On December 31, 2013, OPCo assigned the $1 billion in credit facility borrowings to AGR upon the transfer of OPCo's generation assets to AGR. Also on December 31, 2013, AGR subsequently assigned a portion of the borrowings to KPCo in the amount of $200 million upon AGR's transfer of certain of those generation assets.

Long-term debt outstanding as of December 31, 2013 is payable as follows:

	2014	2015	2016	2017	2018	After 2018	Total
				(in thousands)			
Principal Amount	$ -	$ 220,000	$ -	$ 325,000	$ -	$ 205,000	$ 750,000
Unamortized Discount, Net							(611)
Total Long-term Debt Outstanding							$ 749,389

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits KPCo from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the book value of the common stock. This restriction does not limit the ability of KPCo to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, KPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. As of December 31, 2013, none of KPCo's retained earnings have restrictions related to the payment of dividends to Parent.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2013 and 2012 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2013 and 2012 are described in the following table:

Year	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2013	$ 32,649	$ 31,421	$ 10,911	$ 14,584	$ 8,564	$ 250,000
2012	13,359	80,205	9,200	46,187	13,359	250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the years ended December 31, 2013, 2012 and 2011 are summarized in the following table:

Year Ended December 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2013	0.43 %	0.29 %	0.41 %	0.24 %	0.37 %	0.32 %
2012	0.42 %	0.42 %	0.56 %	0.39 %	0.42 %	0.48 %
2011	- %	- %	0.56 %	0.06 %	- %	0.35 %

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, on KPCo's statements of income. For amounts borrowed from and advanced to the Utility Money Pool, KPCo incurred the following amounts of interest expense and earned the following amounts of interest income, respectively, for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	2012	2011
		(in thousands)	
Interest Expense	$ 12	$ 1	$ -
Interest Income	36	222	318

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's statements of income. KPCo manages and services its accounts receivable sold.

In June 2013, AEP Credit amended its receivables securitization agreement to extend through June 2014. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. AEP Credit amended a commitment of $385 million to now expire in June 2014. The remaining commitment of $315 million expires in June 2015. AEP Credit intends to extend or replace the agreement expiring in June 2014 on or before its maturity.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $43 million and $46 million as of December 31, 2013 and 2012, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $2 million for each of the years ended December 31, 2013, 2012 and 2011.

KPCo's proceeds on the sale of receivables to AEP Credit were $522 million, $517 million and $579 million for the years ended December 31, 2013, 2012 and 2011, respectively.

14. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 11 in addition to "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 13.

Interconnection Agreement

In accordance with management's December 2010 announcement and October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated.

APCo, I&M, KPCo, OPCo and AEPSC were parties to the Interconnection Agreement which defined the sharing of costs and benefits associated with the respective generating plants. This sharing was based upon each AEP utility subsidiary's MLR and was calculated monthly on the basis of each AEP utility subsidiary's maximum peak demand in relation to the sum of the maximum peak demands of all four AEP utility subsidiaries during the preceding 12 months.

Effective January 1, 2014, the FERC approved the creation of the Power Coordination Agreement among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Also effective January 1, 2014, the FERC approved the Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent to address open commitments related to the termination of the Interconnection Agreement and responsibilities to PJM. See "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters in Note 3.

Prior to January 1, 2014, power, natural gas and risk management activities were conducted by AEPSC and profits and losses were allocated under the SIA to members of the Interconnection Agreement, PSO and SWEPCo. Risk management activities involved the purchase and sale of power and natural gas under physical forward contracts at fixed and variable prices. In addition, the risk management of power, and to a lesser extent natural gas contracts, included exchange traded futures and options and OTC options and swaps. The majority of these transactions represented physical forward contracts in the AEP System's traditional marketing area and were typically settled by entering into offsetting contracts. In addition, AEPSC entered into transactions for the purchase and sale of power and natural gas options, futures and swaps, and for the forward purchase and sale of power outside of the AEP System's traditional marketing area.

Operating Agreement

PSO, SWEPCo and AEPSC are parties to the Operating Agreement which was approved by the FERC. The Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. Parties are compensated for energy delivered to recipients based upon the deliverer's incremental cost plus a portion of the recipient's savings realized by the purchaser that avoids more costly alternatives. Revenues and costs arising from third party sales are generally shared based on the amount of energy PSO or SWEPCo contributes that is sold to third parties.

System Integration Agreement (SIA)

The SIA provides for the integration and coordination of AEP East Companies' and AEP West Companies' zones. This includes joint dispatch of generation within the AEP System and the distribution, between the two zones, of costs and benefits associated with the transfers of power between the two zones (including sales to third parties and risk management and trading activities). The SIA is designed to function as an umbrella agreement in addition to the Interconnection Agreement (prior to January 1, 2014) and the Operating Agreement, each of which controls the distribution of costs and benefits within a zone.

Power generated, allocated or provided under the Interconnection Agreement or the Operating Agreement is primarily sold to customers at rates approved by the public utility commission in the jurisdiction of sale.

Under both the Interconnection Agreement and the Operating Agreement, power generated that is not needed to serve the AEP System's native load is sold in the wholesale market by AEPSC on behalf of the generating subsidiary.

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales under the Interconnection Agreement, direct sales to affiliates, net transmission agreement sales, natural gas contracts with AEPES and other revenues for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
Related Party Revenues	**2013**	**2012**	**2011**
		(in thousands)	
Sales under Interconnection Agreement	$ 79,909	$ 60,198	$ 99,593
Direct Sales to West Affiliates	119	64	314
Transmission Agreement Sales	862	3,022	4,480
Natural Gas Contracts with AEPES	-	-	32
Other Revenues	22,841	7,492	263
Total Affiliated Revenues	$ 103,731	$ 70,776	$ 104,682

The following table shows the purchased power expenses incurred for purchases under the Interconnection Agreement and from affiliates for the years ended December 31, 2013, 2012 and 2011:

Related Party Purchases	2013	2012	2011
		Years Ended December 31, (in thousands)	
Purchases under Interconnection Agreement	$ 161,293	$ 121,267	$ 112,217
Direct Purchases from West Affiliates	1	11	51
Purchases from AEGCo	107,794	102,371	98,031
Total Affiliated Purchases	$ 269,088	$ 223,649	$ 210,299

The above summarized related party revenues and expenses are reported in Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on KPCo's statements of income.

System Transmission Integration Agreement

AEP's System Transmission Integration Agreement provides for the integration and coordination of the planning, operation and maintenance of the transmission facilities of AEP East Companies' and AEP West Companies' zones. Similar to the SIA, the System Transmission Integration Agreement functions as an umbrella agreement in addition to the Transmission Agreement (TA) and the Transmission Coordination Agreement (TCA). The System Transmission Integration Agreement contains two service schedules that govern:

- The allocation of transmission costs and revenues.
- The allocation of third-party transmission costs and revenues and AEP System dispatch costs.

The System Transmission Integration Agreement anticipates that additional service schedules may be added as circumstances warrant.

APCo, I&M, KGPCo, KPCo, OPCo and WPCo are parties to the TA, effective November 2010, which defines how transmission costs through PJM OATT are allocated among the AEP East Companies, KGPCo and WPCo on a 12-month average coincident peak basis.

KPCo's net charges recorded as a result of the TA for the years ended December 31, 2013, 2012 and 2011 were $3 million, $1.1 million and $410 thousand, respectively, and were recorded in Other Operation expenses on KPCo's statements of income.

PSO, SWEPCo and AEPSC are parties to the TCA, dated January 1, 1997, revised 1999 and 2011, as restated and amended, by and among PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two AEP utility subsidiaries. The TCA has been approved by the FERC and establishes a coordinating committee, which is charged with overseeing the coordinated planning of the transmission facilities of the parties to the agreement.

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc. (NPC) have an agreement whereby OPCo operates a 500 MW natural gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with OPCo and NPC to manage and procure fuel for the Mone Plant. The natural gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East Companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2014. KPCo's related purchases of natural gas managed by AEPES were $124 thousand, $173 thousand and $183 thousand for the years ended December 31, 2013, 2012 and 2011, respectively. These purchases are reflected in Purchased Electricity for Resale on KPCo's statements of income.

Unit Power Agreements (UPA)

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. Subsequently, I&M assigns 30% of the power to KPCo. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo and a UPA between KPCo and AEGCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. The KPCo UPA ends in December 2022.

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. KPCo recorded expenses of $4 million, $1.6 million and $2.2 million in 2013, 2012 and 2011, respectively, for urea transloading provided by I&M. These expenses were recorded as fuel expenses or other operation expenses.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet, then transfers the cost to the affiliate for reimbursement. KPCo recorded its assigned portion of these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were $1.1 million, $647 thousand and $672 thousand for the years ended December 31, 2013, 2012 and 2011, respectively.

Affiliate Railcar Agreement

KPCo has an agreement providing for the use of its affiliates' leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. KPCo recorded these costs in Fuel on the balance sheets and such costs are recoverable from customers. The following table shows the net effect of the railcar agreement on KPCo's balance sheets:

Billing Company	December 31, 2013	December 31, 2012
	(in thousands)	
AGR	$ (20)	$ 381
APCo	26	436

Purchases from OVEC under the Interconnection Agreement

In 2011, the parties to the Interconnection Agreement purchased power from OVEC to serve off-system sales and retail sales. These purchases are reported in Purchased Electricity for Resale on KPCo's statement of income. KPCo recorded $4.5 million in expense for the year ended December 31, 2011.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The following table shows the sales and purchases, recorded at net book value, for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31, 2013	2012	2011
		(in thousands)	
Sales	$ 951	$ 1,032	$ 404
Purchases	1,702	1,078	2,188

The amounts above are recorded in Property, Plant and Equipment on the balance sheets.

Global Borrowing Notes

As of December 31, 2013 and 2012, AEP has an intercompany note in place with KPCo. The debt is reflected in Long-term Debt – Affiliated on KPCo's balance sheets. KPCo accrues interest for its share of the global borrowing and remits the interest to AEP. The accrued interest is reflected in Accrued Interest on KPCo's balance sheets.

Intercompany Billings

KPCo performs certain utility services for other AEP subsidiaries when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

15. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. KPCo is not the primary beneficiary of any VIE and has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the years ended December 31, 2013, 2012 and 2011 were $38 million, $40 million and $35 million, respectively. The carrying amount of liabilities associated with AEPSC as of December 31, 2013 and 2012 was $4 million and $6 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the years ended December 31, 2013, 2012 and 2011 were $108 million, $102 million and $98 million, respectively. The carrying amount of liabilities associated with AEGCo as of December 31, 2013 and 2012 was $11 million and $10 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

16. PROPERTY, PLANT AND EQUIPMENT

Depreciation

KPCo provides for depreciation of Property, Plant and Equipment on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide KPCo's annual property information:

2013	Regulated (a)				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 1,052,757	$ 365,645	3.7%	40-60	$ -	$ -	NA	NA
Transmission	507,844	172,604	1.8%	25-75	-	-	NA	NA
Distribution	693,481	216,771	3.4%	11-75	-	-	NA	NA
CWIP	128,599	(8,320)	NM	NM	-	-	NA	NA
Other	475,229	196,977	4.3%	20-75	5,530	212	NM	NM
Total	$ 2,857,910	$ 943,677			$ 5,530	$ 212		

2012	Regulated				Nonregulated (a)			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 558,935	$ 221,976	3.8%	40-50	$ 880,064	$ 277,074	3.8%	60
Transmission	490,152	162,774	1.6%	25-75	5,829	3,082	2.3%	NM
Distribution	652,615	200,340	3.4%	11-75	-	-	NA	NA
CWIP	44,281	(6,327)	NM	NM	43,643	380	NM	NM
Other	57,451	24,409	7.2%	20-75	7,699	308	NM	NM
Total	$ 1,803,434	$ 603,172			$ 937,235	$ 280,844		

2011	Regulated		Nonregulated (a)	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	3.8%	40-50	3.8%	60
Transmission	1.7%	25-75	2.4%	NA
Distribution	3.5%	11-75	NA	NA
CWIP	NM	NM	NM	NM
Other	8.2%	NM	3.4%	NM

(a) For 2013, KPCo's ownership in the Mitchell Plant is included in the Regulated amounts listed above. For 2012 and 2011, KPCo's ownership in the Mitchell Plant is included in the Nonregulated amounts listed above.

NA Not applicable.

NM Not meaningful.

The composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability.

Asset Retirement Obligations (ARO)

KPCo records ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for the retirement of asbestos removal. KPCo has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since KPCo plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when KPCo abandons or ceases the use of specific easements, which is not expected.

The following is a reconciliation of the 2013 and 2012 aggregate carrying amounts of ARO for KPCo:

Year	ARO as of January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of December 31,
			(in thousands)			
2013	$ 8,759	$ 742	$ -	$ (255)	$ 11,280	$ 20,526
2012	8,488	709	-	(438)	-	8,759

Allowance for Funds Used During Construction (AFUDC)

KPCo's amounts of allowance for borrowed and equity funds used during construction are summarized in the following table:

	Years Ended December 31, 2013	2012	2011
		(in thousands)	
Allowance for Equity Funds Used During Construction	$ 1,367	$ 1,574	$ 1,229
Allowance for Borrowed Funds Used During Construction	3,047	2,275	996

Jointly-owned Electric Facilities

KPCo has a 50.0% ownership share of Units 1 and 2 at the Mitchell Generating Station. In addition to KPCo, the Mitchell Generating Station is jointly-owned by AGR. Using its own financing, each participating company is obligated to pay its share of the costs in the same proportion as its ownership interest. KPCo's proportionate share of the operating costs associated with this facility is included in its statements of income and the investment and accumulated depreciation are reflected in its balance sheets under Property, Plant and Equipment as follows:

	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
KPCo's Share as of December 31, 2013					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 907,304	$ 75,253	$ 305,170
KPCo's Share as of December 31, 2012					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 878,036	$ 43,106	$ 276,658

(a) Operated by KPCo.

17. SUSTAINABLE COST REDUCTIONS

In April 2012, management initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. Management selected a consulting firm to facilitate an organizational and process evaluation and a second firm to evaluate current employee benefit programs. The process resulted in involuntary severances and was completed by the end of the first quarter of 2013. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

KPCo recorded a charge of $2 million to Other Operation expense in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative. In addition, the sustainable cost reduction activity for the year ended December 31, 2013 is described in the following table:

Balance as of December 31, 2012	Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance as of December 31, 2013
		(in thousands)			
$ 497	$ 180	$ -	$ (276)	$ (401)	$ -

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the statements of income. Management does not expect additional costs to be incurred related to this initiative.

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. KPCo's unaudited quarterly financial information is as follows:

	2013 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in thousands)			
Total Revenues	$ 230,644	$ 181,549	$ 211,536	$ 202,526
Operating Income (Loss)	32,607	18,214	(14,044)(a)	22,422
Net Income (Loss)	14,403	4,985	(16,513)(a)	6,031

	2012 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in thousands)			
Total Revenues	$ 210,365	$ 185,183	$ 213,995	$ 214,874
Operating Income	29,309	33,392	34,990	26,241
Net Income	12,154	15,345	15,754	9,722

(a) Includes a regulatory disallowance for Big Sandy Plant, Unit 2 (see Note 3 and Note 6).

Annex 2 to Appendix A

Kentucky Power Company

2014 First Quarter Report

Financial Statements

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GLOSSARY OF TERMS

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standards Update.
CWIP	Construction Work in Progress.
FASB	Financial Accounting Standards Board.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
WVPSC	Public Service Commission of West Virginia.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	2013
REVENUES		
Electric Generation, Transmission and Distribution	$ 227,631	$ 201,315
Sales to AEP Affiliates	5,415	29,197
Other Revenues	84	132
TOTAL REVENUES	233,130	230,644
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	72,362	74,680
Purchased Electricity for Resale	3,113	3,370
Purchased Electricity from AEP Affiliates	31,422	56,490
Other Operation	19,865	18,333
Maintenance	18,642	17,083
Depreciation and Amortization	23,522	23,109
Taxes Other Than Income Taxes	5,303	4,972
TOTAL EXPENSES	174,229	198,037
OPERATING INCOME	58,901	32,607
Other Income (Expense):		
Interest Income	33	27
Allowance for Equity Funds Used During Construction	1,456	261
Interest Expense	(9,101)	(11,572)
INCOME BEFORE INCOME TAX EXPENSE	51,289	21,323
Income Tax Expense	18,741	6,920
NET INCOME	$ 32,548	$ 14,403

The common stock of KPCo is wholly-owned by AEP.

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	2013
Net Income	$ 32,548	$ 14,403
OTHER COMPREHENSIVE INCOME, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $5 and $118 in 2014 and 2013, Respectively	10	218
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $63 and $134 in 2014 and 2013, Respectively	117	248
TOTAL OTHER COMPREHENSIVE INCOME	127	466
TOTAL COMPREHENSIVE INCOME	$ 32,675	$ 14,869

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 50,450	$ 531,536	$ 190,819	$ (19,994)	$ 752,811
Capital Contribution from Parent		231			231
Common Stock Dividends			(3,892)		(3,892)
Net Income			14,403		14,403
Other Comprehensive Income				466	466
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2013	$ 50,450	$ 531,767	$ 201,330	$ (19,528)	$ 764,019
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2013	$ 50,450	$ 614,648	$ 179,691	$ (5,420)	$ 839,369
Capital Contribution Returned to Parent		(100,000)			(100,000)
Common Stock Dividends			(15,000)		(15,000)
Other Changes in Common Shareholder's Equity		2,812			2,812
Net Income			32,548		32,548
Other Comprehensive Income				127	127
Pension and OPEB Adjustment Related to Kammer Plant				(1,308)	(1,308)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2014	$ 50,450	$ 517,460	$ 197,239	$ (6,601)	$ 758,548

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	March 31, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,244	$ 743
Accounts Receivable:		
Customers	11,974	17,889
Affiliated Companies	28,281	9,781
Accrued Unbilled Revenues	12	857
Miscellaneous	106	75
Allowance for Uncollectible Accounts	(63)	(78)
Total Accounts Receivable	40,310	28,524
Fuel	45,433	92,313
Materials and Supplies	41,141	43,940
Risk Management Assets	4,277	4,356
Accrued Tax Benefits	35	5,249
Regulatory Asset for Under-Recovered Fuel Costs	10,594	-
Prepayments and Other Current Assets	5,595	3,284
TOTAL CURRENT ASSETS	148,629	178,409
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,063,586	1,052,757
Transmission	510,963	507,844
Distribution	698,685	693,481
Other Property, Plant and Equipment (Including Plant to be Retired)	477,716	480,759
Construction Work in Progress	139,321	128,599
Total Property, Plant and Equipment	2,890,271	2,863,440
Accumulated Depreciation and Amortization	962,785	943,889
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,927,486	1,919,551
OTHER NONCURRENT ASSETS		
Regulatory Assets	214,765	216,360
Long-term Risk Management Assets	2,880	3,484
Employee Benefits and Pension Assets	13,804	11,446
Deferred Charges and Other Noncurrent Assets	14,618	20,207
TOTAL OTHER NONCURRENT ASSETS	246,067	251,497
TOTAL ASSETS	$ 2,322,182	$ 2,349,457

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2014 and December 31, 2013
(Unaudited)

	March 31, 2014	December 31, 2013
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 49,404	$ 8,564
Accounts Payable:		
General	42,993	21,619
Affiliated Companies	25,648	39,171
Risk Management Liabilities	905	1,828
Customer Deposits	25,289	25,211
Deferred Income Taxes	10,055	6,486
Accrued Taxes	26,216	20,801
Accrued Interest	5,640	6,678
Regulatory Liability for Over-Recovered Fuel Costs	-	2,851
Other Current Liabilities	20,681	19,411
TOTAL CURRENT LIABILITIES	206,831	152,620
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	729,430	729,389
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	1,630	2,105
Deferred Income Taxes	546,344	549,672
Regulatory Liabilities and Deferred Investment Tax Credits	24,490	22,926
Employee Benefits and Pension Obligations	7,754	6,041
Deferred Credits and Other Noncurrent Liabilities	27,155	27,335
TOTAL NONCURRENT LIABILITIES	1,356,803	1,357,468
TOTAL LIABILITIES	1,563,634	1,510,088
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	517,460	614,648
Retained Earnings	197,239	179,691
Accumulated Other Comprehensive Income (Loss)	(6,601)	(5,420)
TOTAL COMMON SHAREHOLDER’S EQUITY	758,548	839,369
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,322,182	$ 2,349,457

See Condensed Notes to Condensed Financial Statements beginning on page 8.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	2013
OPERATING ACTIVITIES		
Net Income	$ 32,548	$ 14,403
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	23,522	23,109
Deferred Income Taxes	2,118	7,924
Allowance for Equity Funds Used During Construction	(1,456)	(261)
Mark-to-Market of Risk Management Contracts	(707)	1,798
Property Taxes	3,784	3,603
Fuel Over/Under-Recovery, Net	(13,445)	(7,945)
Change in Other Noncurrent Assets	626	373
Change in Other Noncurrent Liabilities	717	1,017
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(11,786)	15,743
Fuel, Materials and Supplies	49,679	25,257
Accounts Payable	(505)	(35,052)
Accrued Taxes, Net	10,629	(76)
Accrued Interest	(1,038)	(5,229)
Other Current Assets	(1,530)	904
Other Current Liabilities	1,481	(6,083)
Net Cash Flows from Operating Activities	94,637	39,485
INVESTING ACTIVITIES		
Construction Expenditures	(20,979)	(35,241)
Acquisitions of Assets	(1,036)	(18)
Proceeds from Sales of Assets	85	1,255
Other Investing Activities	98	-
Net Cash Flows Used for Investing Activities	(21,832)	(34,004)
FINANCING ACTIVITIES		
Capital Contribution from (Returned to) Parent	(100,000)	231
Change in Advances from Affiliates, Net	40,840	(2,320)
Principal Payments for Capital Lease Obligations	(1,208)	(317)
Dividends Paid on Common Stock	(15,000)	(3,892)
Other Financing Activities	3,064	197
Net Cash Flows Used for Financing Activities	(72,304)	(6,101)
Net Increase (Decrease) in Cash and Cash Equivalents	501	(620)
Cash and Cash Equivalents at Beginning of Period	743	1,482
Cash and Cash Equivalents at End of Period	$ 1,244	$ 862
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 9,888	$ 16,596
Net Cash Paid for Income Taxes	-	111
Noncash Acquisitions Under Capital Leases	596	721
Construction Expenditures Included in Current Liabilities as of March 31,	15,540	19,185

See Condensed Notes to Condensed Financial Statements beginning on page 8.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

The unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three months ended March 31, 2014 is not necessarily indicative of results that may be expected for the year ending December 31, 2014. The condensed financial statements are unaudited and should be read in conjunction with the audited 2013 financial statements and notes thereto, which are included in KPCo's 2013 Annual Report.

Management reviewed subsequent events through April 25, 2014, the date that the first quarter 2014 report was issued.

Revenue Recognition

Electricity Supply and Delivery Activities – Transactions with PJM

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts.

KPCo sells power produced at its generation plants to PJM and purchase power from PJM to supply its retail load. These power sales and purchases for retail load are netted hourly for financial reporting purposes. On an hourly net basis, KPCo records sales of power to PJM in excess of purchases of power as revenues. Also, on an hourly net basis, KPCo records purchases of power from PJM to serve retail load in excess of sales of power to PJM as Purchased Electricity for Resale. Upon termination of the Interconnection Agreement, KPCo manages and accounts for its purchases and sales with PJM individually based on market prices.

2. NEW ACCOUNTING PRONOUNCEMENT

Upon issuance of final pronouncements, management reviews the new accounting literature to determine its relevance, if any, to KPCo's business. The following summary of a final pronouncement will impact the financial statements.

ASU 2014-08 "Presentation of Financial Statements and Property, Plant and Equipment" (ASU 2014-08)

In April 2014, the FASB issued ASU 2014-08 changing the presentation of discontinued operations on the statements of income and other requirements for reporting discontinued operations. Under the new standard, a disposal of a component or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results when the component meets the criteria to be classified as held for sale or is disposed. The amendments in this update also require additional disclosures about discontinued operations and disposal of an individually significant component of an entity that does not qualify for discontinued operations. This standard must be prospectively applied to all reporting periods presented in financial reports issued after the effective date. Early adoption is permitted for disposals that have not been reported in financial statements previously issued or available for issuance.

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. If applicable, this standard will change the presentation of financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. Management plans to adopt ASU 2014-08 effective January 1, 2015.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three months ended March 31, 2014 and 2013. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2014

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of December 31, 2013	$ 23	$ (222)	$ (5,221)	$ (5,420)
Change in Fair Value Recognized in AOCI	326	-		326
Amounts Reclassified from AOCI	(332)	16	117	(199)
Net Current Period Other Comprehensive Income	(6)	16	117	127
Pension and OPEB Adjustment Related to Kammer Plant	-	-	(1,308)	(1,308)
Balance in AOCI as of March 31, 2014	$ 17	$ (206)	$ (6,412)	$ (6,601)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ (19,585)	$ (19,994)
Change in Fair Value Recognized in AOCI	161	-	-	161
Amounts Reclassified from AOCI	42	15	248	305
Net Current Period Other Comprehensive Income	203	15	248	466
Balance in AOCI as of March 31, 2013	$ 76	$ (267)	$ (19,337)	$ (19,528)

Reclassifications Out of Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the three months ended March 31, 2014 and 2013.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended March 31, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI	
	Three Months Ended March 31,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Electric Generation, Transmission and Distribution Revenues	$ -	$ 19
Purchased Electricity for Resale	(452)	54
Other Operation Expense	(3)	(3)
Maintenance Expense	(5)	(2)
Property, Plant and Equipment	(6)	(4)
Regulatory Assets/(Liabilities), Net (a)	(43)	-
Subtotal - Commodity	(509)	64
Interest Rate and Foreign Currency:		
Interest Expense	23	23
Subtotal - Interest Rate and Foreign Currency	23	23
Reclassifications from AOCI, before Income Tax (Expense) Credit	(486)	87
Income Tax (Expense) Credit	(170)	30
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(316)	57
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(54)	(91)
Amortization of Actuarial (Gains)/Losses	234	472
Reclassifications from AOCI, before Income Tax (Expense) Credit	180	381
Income Tax (Expense) Credit	63	133
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	117	248
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ (199)	$ 305

(a) Represents realized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the condensed balance sheets.

4. RATE MATTERS

As discussed in KPCo's 2013 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2013 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2014 and updates KPCo's 2013 Annual Report.

Regulatory Assets Not Yet Being Recovered

	March 31, 2014	December 31, 2013
Noncurrent Regulatory Assets	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings:		
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ 12,146	$ 12,146
Total Regulatory Assets Not Yet Being Recovered	$ 12,146	$ 12,146

If these costs are ultimately determined not to be recoverable, it could reduce future net income and cash flows and impact financial condition.

Plant Transfer

In October 2012, the AEP East Companies submitted several filings with the FERC. In December 2012, KPCo filed a request with the KPSC for approval to transfer at net book value to KPCo a one-half interest in the Mitchell Plant, comprising 780 MW of average annual generating capacity. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of March 31, 2014, the net book value of Big Sandy Plant, Unit 2 was $247 million, before cost of removal, including materials and supplies inventory and CWIP.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. The settlement also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo’s request to defer FGD project costs for Big Sandy Plant, Unit 2. As a result of this order, in 2013, KPCo recorded a pretax regulatory disallowance of $33 million in Asset Impairments and Other Related Charges on the statement of income. In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In December 2013, KPCo filed motions with the Franklin County Circuit Court to dismiss the appeal. A hearing on the motions to dismiss was held in January 2014. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed. If any part of the KPSC order is overturned, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo’s business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo’s 2013 Annual Report should be read in conjunction with this report.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for “Guarantees.” There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of March 31, 2014, there were no material liabilities recorded for any indemnifications.

KPCo is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East Companies related to power purchase and sale activity conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of March 31, 2014, the maximum potential loss for these lease agreements was approximately $1.2 million assuming the fair value of the equipment is zero at the end of the lease term.

6. BENEFIT PLANS

KPCo participates in an AEP sponsored qualified pension plan and an unfunded nonqualified pension plan. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and nonqualified pension plans. KPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

Components of Net Periodic Benefit Cost

The following table provides the components of KPCo's net periodic benefit cost (credit) for the plans for the three months ended March 31, 2014 and 2013:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$ 575	$ 470	$ 118	$ 208
Interest Cost	2,010	1,827	601	643
Expected Return on Plan Assets	(2,418)	(2,564)	(1,060)	(1,030)
Amortization of Prior Service Cost (Credit)	14	14	(606)	(611)
Amortization of Net Actuarial Loss	1,117	1,651	187	588
Net Periodic Benefit Cost (Credit)	$ 1,298	$ 1,398	$ (760)	$ (202)

7. BUSINESS SEGMENTS

KPCo has one reportable segment, an integrated electricity generation, transmission and distribution business. KPCo's other activities are insignificant.

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and marketer of wholesale electricity, natural gas, coal and emission allowances. These risks include commodity price risk, interest rate risk, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact KPCo due to changes in the underlying market prices or rates. AEPSC, on behalf of KPCo, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes, focusing on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of KPCo. To accomplish these objectives, AEPSC, on behalf of KPCo, primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

AEPSC, on behalf of KPCo, enters into power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo's commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with the established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following table represents the gross notional volume of the KPCo's outstanding derivative contracts as of March 31, 2014 and December 31, 2013:

Notional Volume of Derivative Instruments

	Volume		
	March 31, 2014	**December 31, 2013**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	5,900	10,071	MWhs
Coal	447	2	Tons
Natural Gas	398	509	MMBtus
Heating Oil and Gasoline	190	261	Gallons
Interest Rate	$ 2,236	$ 2,615	USD

Fair Value Hedging Strategies

AEPSC, on behalf of KPCo, enters into interest rate derivative transactions as part of an overall strategy to manage the mix of fixed-rate and floating-rate debt. Certain interest rate derivative transactions effectively modify KPCo's exposure to interest rate risk by converting a portion of KPCo's fixed-rate debt to a floating rate. Provided specific criteria are met, these interest rate derivatives are designated as fair value hedges.

Cash Flow Hedging Strategies

AEPSC, on behalf of KPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of power and natural gas ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. KPCo does not hedge all commodity price risk.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial heating oil and gasoline derivative contracts in order to mitigate price risk of future fuel purchases. Cash flow hedge accounting for these derivative contracts was discontinued effective March 31, 2014. For disclosure purposes, these contracts were included with other hedging activities as "Commodity" as of December 31, 2013. As of March 31, 2014, these contracts will be grouped as "Commodity" with other risk management activities. KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of KPCo, also enters into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. The forecasted fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. KPCo does not hedge all interest rate exposure.

At times, KPCo is exposed to foreign currency exchange rate risks primarily when KPCo purchases certain fixed assets from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of KPCo, may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency's appreciation against the dollar. KPCo does not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCo's FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the condensed balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of KPCo's risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2014 and December 31, 2013 condensed balance sheets, KPCo netted $7 thousand and $0 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $280 thousand and $1 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of KPCo's derivative activity on the condensed balance sheets as of March 31, 2014 and December 31, 2013:

Fair Value of Derivative Instruments
March 31, 2014

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 8,291	$ 46	$ -	$ 8,337	$ (4,060)	$ 4,277
Long-term Risk Management Assets	3,557	-	-	3,557	(677)	2,880
Total Assets	11,848	46	-	11,894	(4,737)	7,157
Current Risk Management Liabilities	5,151	18	-	5,169	(4,264)	905
Long-term Risk Management Liabilities	2,376	-	-	2,376	(746)	1,630
Total Liabilities	7,527	18	-	7,545	(5,010)	2,535
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,321	$ 28	$ -	$ 4,349	$ 273	$ 4,622

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 9,520	$ 85	$ -	$ 9,605	$ (5,249)	$ 4,356
Long-term Risk Management Assets	4,306	-	-	4,306	(822)	3,484
Total Assets	13,826	85	-	13,911	(6,071)	7,840
Current Risk Management Liabilities	7,583	65	-	7,648	(5,820)	1,828
Long-term Risk Management Liabilities	2,970	-	-	2,970	(865)	2,105
Total Liabilities	10,553	65	-	10,618	(6,685)	3,933
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,273	$ 20	$ -	$ 3,293	$ 614	$ 3,907

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented on the condensed balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."
(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."
(c) There are no derivative contracts subject to a master netting arrangement or similar agreement which are not offset in the statement of financial position.

The table below presents KPCo's activity of derivative risk management contracts for the three months ended March 31, 2014 and 2013:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2014 and 2013

Location of Gain (Loss)	2014	2013
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 6,940	$ 596
Fuel and Other Consumables Used for Electric Generation	1	-
Regulatory Assets (a)	-	-
Regulatory Liabilities (a)	1,120	(467)
Total Gain on Risk Management Contracts	$ 8,061	$ 129

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment recorded as either current or noncurrent on the condensed balance sheets.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the condensed statements of income on an accrual basis.

KPCo's accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's condensed statements of income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains), in accordance with the accounting guidance for "Regulated Operations."

Accounting for Fair Value Hedging Strategies

For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof attributable to a particular risk), the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item associated with the hedged risk affects Net Income during the period of change.

KPCo records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on KPCo's condensed statements of income. During the three months ended March 31, 2014 and 2013, KPCo did not designate any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets until the period the hedged item affects Net Income. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's condensed balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2014 and 2013, KPCo designated power, coal and natural gas derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. During the three months ended March 31, 2013, KPCo designated heating oil and gasoline derivatives as cash flow hedges. KPCo discontinued cash flow hedge accounting for these derivative contracts effective March 31, 2014.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Interest Expense on its condensed statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2014 and 2013, KPCo did not designate any interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets into Depreciation and Amortization expense on the condensed statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three months ended March 31, 2014 and 2013, KPCo did not designate any foreign currency derivatives as cash flow hedges.

During the three months ended March 31, 2014 and 2013, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2014 and 2013, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets as of March 31, 2014 and December 31, 2013 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
March 31, 2014

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 43	$ -	$ 43
Hedging Liabilities (a)	15	-	15
AOCI Gain (Loss) Net of Tax	17	(206)	(189)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	17	(60)	(43)

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2013

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 79	$ -	$ 79
Hedging Liabilities (a)	59	-	59
AOCI Gain (Loss) Net of Tax	23	(222)	(199)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	23	(60)	(37)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's condensed balance sheets.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of March 31, 2014, the maximum length of time that KPCo is hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions was 2 months.

Credit Risk

AEPSC, on behalf of KPCo, limits credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. AEPSC, on behalf of KPCo, uses Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

When AEPSC, on behalf of KPCo, uses standardized master agreements, these agreements may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, collateral agreements allow for termination and liquidation of all positions in the event of a failure or inability to post collateral.

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents: (a) KPCo's fair value of such derivative contracts, (b) the amount of collateral KPCo would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of March 31, 2014 and December 31, 2013:

	March 31, 2014	December 31, 2013
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 57	$ 118
Amount of Collateral KPCo Would Have Been Required to Post	1,079	565
Amount Attributable to RTO and ISO Activities	981	522

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of March 31, 2014 and December 31, 2013:

	March 31, 2014	December 31, 2013
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 3,366	$ 4,039
Amount of Cash Collateral Posted	-	-
Additional Settlement Liability if Cross Default Provision is Triggered	2,644	3,817

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. The AEP System's market risk oversight staff independently monitors the risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of the contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A significant portion of the Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt as of March 31, 2014 and December 31, 2013 are summarized in the following table:

	March 31, 2014		December 31, 2013	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 749,430	$ 860,557	$ 749,389	$ 841,594

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2014 and December 31, 2013. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 81	$ 9,058	$ 2,087	$ (4,112)	$ 7,114
Cash Flow Hedges:					
Commodity Hedges (a)	-	46	-	(3)	43
Total Risk Management Assets	$ 81	$ 9,104	$ 2,087	$ (4,115)	$ 7,157
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 63	$ 6,205	$ 637	$ (4,385)	$ 2,520
Cash Flow Hedges:					
Commodity Hedges (a)	-	18	-	(3)	15
Total Risk Management Liabilities	$ 63	$ 6,223	$ 637	$ (4,388)	$ 2,535

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 170	$ 11,168	$ 2,487	$ (6,064)	$ 7,761
Cash Flow Hedges:					
Commodity Hedges (a)	-	85	-	(6)	79
Total Risk Management Assets	$ 170	$ 11,253	$ 2,487	$ (6,070)	$ 7,840
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 144	$ 10,092	$ 316	$ (6,678)	$ 3,874
Cash Flow Hedges:					
Commodity Hedges (a)	-	65	-	(6)	59
Total Risk Management Liabilities	$ 144	$ 10,157	$ 316	$ (6,684)	$ 3,933

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts.

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2014 and 2013.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives and other investments classified as Level 3 in the fair value hierarchy:

Three Months Ended March 31, 2014	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2013	$ 2,171
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	5,374
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(5,913)
Transfers into Level 3 (d) (e)	(786)
Transfers out of Level 3 (e) (f)	(1)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	605
Balance as of March 31, 2014	$ 1,450

Three Months Ended March 31, 2013	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2012	$ 2,199
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(297)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	55
Transfers into Level 3 (d) (e)	126
Transfers out of Level 3 (e) (f)	(107)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(172)
Balance as of March 31, 2013	$ 1,804

(a) Included in revenues on KPCo's condensed statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents the settlement of risk management commodity contracts for the reporting period.
(d) Represents existing assets or liabilities that were previously categorized as Level 2.
(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.
(f) Represents existing assets or liabilities that were previously categorized as Level 3.
(g) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's condensed statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of March 31, 2014 and December 31, 2013:

Significant Unobservable Inputs
March 31, 2014

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	Forward Price Range High
	(in thousands)					
Energy Contracts	$ 1,327	$ 580	Discounted Cash Flow	Forward Market Price	$ 13.34	$ 59.60
FTRs	760	57	Discounted Cash Flow	Forward Market Price	(5.05)	9.17
Total	$ 2,087	$ 637				

Significant Unobservable Inputs
December 31, 2013

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	Forward Price Range High
	(in thousands)					
Energy Contracts	$ 1,924	$ 198	Discounted Cash Flow	Forward Market Price	$ 13.04	$ 80.50
FTRs	563	118	Discounted Cash Flow	Forward Market Price	(5.10)	10.44
Total	$ 2,487	$ 316				

(a) Represents market prices in dollars per MWh.

10. INCOME TAXES

AEP System Tax Allocation Agreement

KPCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the loss of the Parent, the method of allocation reflects a separate return result for each company in the consolidated group.

Federal and State Income Tax Audit Status

The IRS examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. The IRS examination of years 2011 and 2012 started in April 2014. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2009.

11. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first three months of 2014.

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.

Federal Power Act

The Federal Power Act prohibits KPCo from participating "in the making or paying of any dividends of such public utility from any funds properly included in capital account." The term "capital account" is not defined in the Federal Power Act or its regulations. Management understands "capital account" to mean the book value of the common stock. This restriction does not limit the ability of KPCo to pay dividends out of retained earnings.

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, KPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of March 31, 2014 and December 31, 2013 are included in Advances from Affiliates on KPCo's condensed balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the three months ended March 31, 2014 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of March 31, 2014	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 50,366	$ 50,332	$ 20,343	$ 34,026	$ 49,404	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the three months ended March 31, 2014 and 2013 are summarized in the following table:

Three Months Ended March 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2014	0.33 %	0.28 %	0.33 %	0.28 %	0.31 %	0.32 %
2013	0.43 %	0.35 %	0.36 %	0.36 %	0.38 %	0.36 %

Sale of Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued unbilled revenue balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's condensed statements of income. KPCo manages and services its accounts receivable sold.

AEP Credit's receivables securitization agreement provides a commitment of $700 million from bank conduits to purchase receivables. A commitment of $385 million expires in June 2014. The remaining commitment of $315 million expires in June 2015. AEP Credit intends to extend or replace the agreement expiring in June 2014 on or before its maturity.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $60 million and $43 million as of March 31, 2014 and December 31, 2013, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended March 31, 2014 and 2013 were $763 thousand and $520 thousand, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended March 31, 2014 and 2013 were $179 million and $140 million, respectively.

12. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. Management believes that significant assumptions and judgments were applied consistently. KPCo is not the primary beneficiary of any VIE and has not provided financial or other support to any VIE that was not previously contractually required.

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended March 31, 2014 and 2013 were $13 million and $7 million, respectively. The carrying amount of liabilities associated with AEPSC as of March 31, 2014 and December 31, 2013 was $5 million and $4 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended March 31, 2014 and 2013 were $30 million and $25 million, respectively. The carrying amount of liabilities associated with AEGCo as of March 31, 2014 and December 31, 2013 was $11 million and $11 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

APPENDIX B

DESCRIPTION OF SUMITOMO MITSUI BANKING CORPORATION

The information included in this Appendix B has been obtained from the Bank. None of the Issuer, the Company or the Underwriter makes any representation as to the accuracy or completeness of such information.

The delivery of the Official Statement shall not create any implication that there has been no change in the affairs of Sumitomo Mitsui Banking Corporation since the date hereof, or that the information contained or referred to in this Appendix B is correct as of any time subsequent to its date.

SUMITOMO MITSUI BANKING CORPORATION

Sumitomo Mitsui Banking Corporation (*Kabushiki Kaisha Mitsui Sumitomo Ginko*) ("SMBC") is a joint stock corporation with limited liability (*Kabushiki Kaisha*) under the laws of Japan. The registered head office of SMBC is located at 1-2, Marunouchi 1-chome, Chiyoda-ku, Tokyo 100-0005, Japan.

SMBC was established in April 2001 through the merger of two leading banks, The Sakura Bank, Limited and The Sumitomo Bank, Limited. In December 2002, Sumitomo Mitsui Financial Group, Inc. ("SMFG") was established through a stock transfer as a holding company under which SMBC became a wholly owned subsidiary. **SMFG reported ¥ 161,534,387 million (USD 1,564,702 million) in consolidated total assets as of March 31, 2014.**

SMBC is one of the world's leading commercial banks and provides an extensive range of banking services to its customers in Japan and overseas. In Japan, SMBC accepts deposits, makes loans and extends guarantees to corporations, individuals, governments and governmental entities. It also offers financing solutions such as syndicated lending, structured finance and project finance. SMBC also underwrites and deals in bonds issued by or under the guarantee of the Japanese government and local government authorities, and acts in various administrative and advisory capacities for certain types of corporate and government bonds. Internationally, SMBC operates through a network of branches, representative offices, subsidiaries and affiliates to provide many financing products including syndicated lending and project finance.

The New York Branch of SMBC is licensed by the State of New York Banking Department to conduct branch banking business at 277 Park Avenue, New York, New York, and is subject to examination by the State of New York Banking Department and the Federal Reserve Bank of New York.

Financial and Other Information

Audited consolidated financial statements for SMFG and its consolidated subsidiaries for the fiscal years ended March 31, 2013, as well as other corporate data, financial information and analyses are available in English on the website of the Parent at www.smfg.co.jp/english.

The information herein has been obtained from SMBC, which is solely responsible for its content. The delivery of the Official Statement shall not create any implication that there has been no change in the affairs of SMBC since the date hereof, or that the information contained or referred herein is correct as of any time subsequent to its date.

APPENDIX C

PROPOSED FORM OF OPINION OF BOND COUNSEL

We have examined the transcript of proceedings relating to the issuance by the West Virginia Economic Development Authority (the "Issuer") of $65,000,000 principal amount of Solid Waste Disposal Facilities Revenue Refunding Bonds (Kentucky Power Company – Mitchell Project), Series 2014A (the "Bonds"). The Bonds are being issued pursuant to Chapter 31, Article 15, Section 1, et seq., of the Code of West Virginia, 1931 (the "Act"), for the purpose of making a loan to assist Kentucky Power Company (the "Company") in the refunding of $65,000,000 Solid Waste Disposal Facilities Revenue Refunding Bonds (Ohio Power Company – Mitchell Project), Series 2008A, previously issued by the Issuer to assist a certain affiliate of the Company in refinancing of a portion of the costs of acquiring, constructing and installing certain solid waste disposal facilities qualified for financing under the Act, as more particularly described in the Indenture of Trust dated as of June 15, 2014 (the "Indenture") between the Issuer and The Bank of New York Mellon Trust Company, N.A., as trustee (the "Trustee"), and in the Loan Agreement dated as of June 15, 2014 (the "Agreement") between the Issuer and the Company. We have also examined executed counterparts of the Indenture and the Agreement and a conformed copy of an executed Bond.

Based on such examination and subject to the limitations stated below, we are of the opinion that, under existing law:

1. The Bonds, the Indenture and the Agreement are valid and binding obligations of the Issuer, enforceable in accordance with their respective terms.

2. The Bonds constitute special obligations of the Issuer, and the principal of and interest on the Bonds and the purchase price of the Bonds (collectively, "debt charges") are payable solely from the revenues and other moneys assigned by the Indenture to secure those payments. Those revenues and other moneys include the payments required to be made by the Company under its promissory note delivered to the Issuer, and irrevocably assigned by the Issuer to the Trustee, all pursuant to the Agreement. The payment of debt service on the Bonds is not secured by an obligation or pledge of any money raised by taxation, and the Bonds do not represent or constitute a general obligation or a pledge of the faith and credit of the Issuer, the State of West Virginia or any of its political subdivisions.

3. Interest on the Bonds is excluded from gross income for federal income tax purposes under Section 103(a) of the Internal Revenue Code of 1986, as amended (the "Code"), except interest on any Bond for any period during which it is held by a "substantial user" or a "related person" as those terms are used in Section 147(a) of the Code, and is an item of tax preference for purposes of the federal alternative minimum tax imposed on individuals and corporations. The Bonds, and all interest and income thereon, are exempt from all taxation by the State of West Virginia and any county, municipality, political subdivision or agency thereof, except inheritance taxes. We express no opinion as to any other tax consequences regarding the Bonds.

The opinions stated above are based on an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. In rendering all such opinions, we assume, without independent verification, and rely upon (i) the accuracy of the factual matters represented, warranted or certified in the proceedings and documents we have examined, (ii) the due and legal authorization, execution and delivery of those documents by, and the valid, binding and enforceable nature of those documents upon, any parties other than the Issuer and (iii) the correctness of the legal conclusions contained in the legal opinion letter of counsel to the Company and in the legal opinion letter of counsel to the Issuer delivered in connection with this matter.

In rendering those opinions with respect to the treatment of the interest on the Bonds under the federal tax laws, we further assume and rely upon compliance with the covenants in the proceedings and documents we have examined, including those of the Issuer and the Company. Failure to comply with certain of those covenants subsequent to issuance of the Bonds may cause interest on the Bonds to be included in gross income for federal income tax purposes retroactively to their date of issuance.

The rights of the owners of the Bonds and the enforceability of the Bonds, the Indenture and the Agreement are subject to bankruptcy, insolvency, arrangement, fraudulent conveyance or transfer, reorganization, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion, and to limitations on legal remedies against public entities.

We express no opinion with respect to any indemnification, contribution, penalty, choice of law, choice of forum, choice of venue, waiver or severability provisions contained in the Bonds, the Indenture or the Agreement.

The opinions rendered in this letter are stated only as of this date, and no other opinion shall be implied or inferred as a result of anything contained in or omitted from this letter. Our engagement as bond counsel with respect to the Bonds has concluded on this date.

Respectfully submitted,