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PUCO EXHIBIT FILING

Date of Hearing: 7/8/11

Case No. 08-917-EL-SSO and 08-918-EL-SSO

PUCO Case Caption: Columbus Southern Power and Ohio Power Company

List of exhibits being filed:

Companies' Remand Ex. 6

IEU Remand Ex. 4
Ex. 5
Ex. 6 - pages iv, 3, 13, 22, 25, 31, 35, Annual Reports Title Page, 4, 13, 161
Ex. 7 - pages 123.7, 123.17, 123.38 and 123.39

Reporter's Signature: Maria DiPaolo Jones
Date Submitted: 7/29/11

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BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Assets.	:	Case No. 08-917-EL-SSO
In the Matter of the Application of Ohio Power Company for Approval of its Electric Security Plan; and an Amendment to its Corporate Separation Plan.	:	Case No. 08-918-EL-SSO

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DEPOSITION

of David I. Fein, taken before me, Maria DiPaolo Jones, a Notary Public in and for the State of Ohio, at the offices of American Electric Power, 1 Riverside Drive, Columbus, Ohio, on Wednesday, July 13, 2011, at 10:03 a.m.

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Companies' Remand Ex. 6

The lognormal stock price distribution implies that the variance over any given time period is proportional to its length. Therefore, one method of computing the (constant) future instantaneous variance (σ^2) is to simply rely on past stock return data; that is, to assume that this past variability of the stock's returns is indeed invariant across time.

THE HISTORICAL VARIANCE OF STOCK RETURNS. To compute the historical variance of stock returns, we first need a time series of price data on the stock to compute its continuously compounded rates of return (equal to the logarithms of the stock price relatives). Suppose that we have 16 weekly price observations on stock ABC.

Week #	Price	$\ln(S_t/S_{t-1})$	Week #	Price	$\ln(S_t/S_{t-1})$
1	51.0		9	51.1	0.0157
2	50.5	−0.0098	10	49.3	−0.0358
3	52.0	0.0290	11	49.8	0.0100
4	51.7	−0.0050	12	51.5	0.0034
5	51.2	−0.0097	13	52.1	0.0116
6	50.6	−0.0117	14	52.5	0.0076
7	50.1	−0.0099	15	51.9	−0.0115
8	50.3	0.0040	16	50.3	−0.0310

We can then estimate the mean of the series of continuously compounded rates of return:

$$\hat{\mu} = \frac{1}{n}\sum_{j=1}^{n} R_j \tag{5.3}$$

where

$\hat{\mu}$ = mean of the continuously compounded rates of return in the sample

$R_j = \ln(S_t/S_{t-1})$ = the continuously compounded rate of return over week j, $j = 1, \ldots, n$

n = total number of available continuously compounded rates of return

Hence, in our example, the mean weekly rate of return equals

$$\hat{\mu} = \frac{1}{15}\sum_{j=1}^{15} R_j = -0.00287$$

We can then calculate the variance of the historical weekly returns around their mean given that the unbiased estimator of the variance is equal to[6]

$$\hat{\sigma}^2 = \frac{1}{n-1}\sum_{j=1}^{n}[R_j - \hat{\mu}]^2 \tag{5.4}$$

The unbiased estimator of the variance of the weekly returns in our example is then equal to

$$\hat{\sigma}^2 = \frac{1}{14}\sum_{1}^{15}[R_j - (-0.00287)]^2 = 0.0002934$$

Now, to infer the proper variance parameter σ^2 that enters the Black and Scholes formula, we must remember to annualize the estimated weekly historical variance $\hat{\sigma}^2$, hence

$$\sigma^2 = 52.\hat{\sigma}^2 = 0.01526$$

Finally, the annualized standard deviation σ is equal to

$$\sigma = \sqrt{\sigma^2} = \sqrt{0.01526} = 12.35\%$$

Assuming that the standard deviation (or the variance) of stock ABC's returns will indeed remain constant over time and equal to 12.35% (or 0.01526) per year, we can then use it in conjunction with the Black and Scholes pricing formula to compute the theoretical prices of European options—of any maturity and/or exercise price—written on stock ABC.

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[6] Note that the variance of a sample: $\sigma_S^2 = (1/n)\sum_{j=1}^{n}[R_j - \hat{\mu}]^2$ is biased. This means that its expected value will differ from the true value of the population's variance (σ_0^2):

$$\begin{aligned} E[\sigma_S^2] &= \left[\frac{1}{n}\sum_{j=1}^{n}E[R_j - \hat{\mu}]^2\right] = \frac{1}{n}\sum_{j=1}^{n}E\left[(R_j - \mu)^2 - (\hat{\mu} - \mu)^2\right] \\ &= \frac{1}{n}(n\sigma_0^2 - \sigma_0^2) \\ &= \sigma_0^2\left(1 - \frac{1}{n}\right) \end{aligned}$$

where $\hat{\mu}$ = sample mean, μ = population's true mean and var$[\hat{\mu}] = \sigma_0^2/n$.

Hence, an unbiased estimator of the variance ($\hat{\sigma}^2$) is obtained by multiplying σ_s^2 with the correction factor $n/(n-1)$, so that we obtain

$$\hat{\sigma}^2 = \frac{n}{n-1}\sigma_S^2 = \frac{n}{n-1}\times\frac{1}{n}\sum_{j=1}^{n}[R_j - \hat{\mu}]^2 = \frac{1}{n-1}\sum_{j=1}^{n}[R_j - \hat{\mu}]^2$$

Of course, the number of stock prices (and continuously compounded rates of return) should in practice be greater[7] than 16 (15) to get a reliable estimate of the variance. Generally, one would rely on one year of weekly data (or 52 price observations) to compute the historical variance. However, going so far into the past may be very misleading for some cyclical or growth stocks since their current characteristics (profit level, leverage, management policy, etc.) can vary substantially from what they were twelve months ago. Even for very stable stocks, this procedure can be criticized since a long time span increases the probability of general shifts in the economy and hence of systematically induced changes in the stock's return variability. If we use more closely spaced data—for example, daily stock prices—we can certainly minimize the problem caused by too distant price observations while keeping a sufficient number of observations to estimate the variance accurately.

Using 52 daily price observations would only lead us one month and 22 days into the past and we may expect that such a recently computed historical volatility will be more appropriate to price options. However, we still must assume that the economy changes slowly over time, assuming that this recent but nevertheless historical estimate of stock returns' volatility can adequately approximate the unknown future volatility over the option's remaining time to maturity.

Parkinson's (1980) "extreme values" variance measurement procedure is a second method used to obtain variance estimates based on recent past market data. Assuming that stock prices are lognormally distributed, he suggested estimating the variance with high and low daily prices rather than with closing prices. He defined the following formula to compute the variance from daily high- and low-price relatives[8]

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[7] In this example, we essentially emphasize the technique that should be used to compute the variance of the continuously compounded rates of return. In practice, the choice of the relevant sample size (n) is very delicate since we need a lot of observations (large n) to compute a consistent estimator of the variance while, paradoxically, going too far in the past decreases the extrapolative power of the estimated historical variance. For many highly liquid stocks, this problem can be partially solved by relying on more frequently spaced data and typically on daily stock prices. Note that for currency options, some studies have even relied on intra-daily data to estimate the variance of the exchange rate relative changes [see Wasserfallen and Zimmerman (1986)].

[8] If $p(l, t)$ is defined as the probability that $(X_{\max} - X_{\min}) \leq l$ during a time interval t where X is a variable following a continuous-time random walk, then Parkinson has shown

$$E[l^2] = 4 \ln 2 \sigma^2 t$$

Hence over a unit time interval, we have

$$\sigma^2 = 0.361 E[l^2]$$

Over n unit time intervals we obtain

$$\sigma^2 = \frac{0.361}{n} \sum_{j=1}^{n} l_j^2$$

This corresponds exactly to Eq. (5.5) with

$$l = \ln(S_{Hj}/S_{Lj})$$

$$\sigma_{HL}^2 = \left[\frac{0.361}{n} \sum_{j=1}^{n} \ln(S_{Hj}/S_{Lj})^2 \right] \tag{5.5}$$

where

σ_{HL}^2 = Estimated variance from daily high and low prices

n = Total number of days in the sample

S_{Hj} = Highest quoted price of the stock on day j

S_{Lj} = Lowest quoted price of the stock on day j

This method requires even less data than the daily closing prices based variance since each continuously compounded rate of return now relies on data occurring within the same day and not within two consecutive days. Hence, Parkinson proves that this method is more efficient, providing the same accuracy as the variance estimated from daily closing prices while requiring only a fifth of the data. Instead of using, for example, 60 daily closing prices, we can compute a historical estimate of the variance with the 12 most recent daily high and low prices with the same level of accuracy.

As pointed out by Cox and Rubinstein (1985), this method is very sensitive to errors in data reporting, which can lead us to compute the variance from erroneous high and low daily prices. Since the method does not necessarily rely on a large number of price observations, such reporting errors can severely bias the estimated historical variance. Also, the Parkinson's extreme values method for option pricing cannot be broadly recommended due to the absence of empirical evidence establishing its accuracy of variance estimates and due to the limited number of stock exchanges that report the highest and the lowest daily stock prices.

THE IMPLIED STANDARD DEVIATION METHOD. An even more ambitious attempt toward "refreshing" the variance estimation is provided by the implied standard deviation (ISD) method that estimates the stock returns' variability from the most recent available market data, namely current market prices. The concept is original and appealing since it tries to estimate the variance of stock returns implicitly reflected in current option prices.

Take a careful look at the Black and Scholes European call pricing formula:

$$C = SN(d_1) - Ke^{-r\tau}N(d_2) \tag{4.18}$$

where

$$d_1 = \frac{\ln(S/Ke^{-r\tau})}{\sigma\sqrt{\tau}} + \frac{1}{2}\sigma\sqrt{\tau}$$

$$d_2 = d_1 - \sigma\sqrt{\tau}$$

By observing the current call option's price in conjunction with the stock price, exercise price, time to maturity of the option, and riskless interest rate, we can "invert" the formula to obtain the stock return's standard deviation implied in the observed call price. This method, originally proposed by Latané and Rendleman (1976), estimates the implied standard deviation by an iterative search procedure, which, given a starting value for σ, subsequently attempts to minimize the difference between the observed call option's price and its computed Black and Scholes value.[9]

The major difficulty, however, consists of interpreting the ISD derived from several options[10] written on the same stock since these standard deviations will generally not be equal. Of course, some differences may arise from the non-simultaneity in the various option and stock prices used to compute the implied standard deviations, others arise from the different nature of the options' closing prices (some may be quoted at the bid and others at the ask price). More disturbing is the often perceived pattern in the ISD's according to the options' time to maturity since it suggests that the stock returns' variance is not constant and that it has some degree of time-dependence, which we shall investigate in more detail in the next chapter.

To overcome the problems related to the non-uniqueness of the stock variance estimate, several authors have recommended using a weighting scheme that aggregates the implied standard deviations into a unique estimate for any particular observation date. The simplest weighting scheme consists of taking the arithmetic average of all the implied standard deviations to obtain a unique estimate $\dot{\sigma}$ of the stock's future volatility:

$$\dot{\sigma} = \frac{1}{I}\sum_{i=1}^{I}\sigma_i \tag{5.6}$$

where

σ_i = implied volatility computed from the market price of option i, $i = 1, 2, \ldots, I$

$\dot{\sigma}$ = average implied standard deviation of stock returns.

A more sophisticated approach, suggested by Chiras and Manaster (1978), weights each option's ISD according to its degree of price elasticity with respect

[9] Generally the numerical computation of the implied standard deviation relies on a Newton-Raphson approximation technique.

[10] Note that using the Black and Scholes equation for put prices [see Eq. (4.22)], we can also compute the implied standard deviations from European put prices. The procedure will generally not rely on American put options because they are subject to early exercise even when the underlying stock does not pay dividends.

to the standard deviation. This method is designed to provide more weight to those options whose price is very sensitive to a percentage change in the standard deviation, which results in attributing more weight to out-of-the-money call options.[11] The estimated weighted average implied standard deviation $\dot{\sigma}$ is then computed according to the following formula:

$$\dot{\sigma} = \sum_{i=1}^{I} \omega_i \sigma_i \tag{5.7}$$

where

$$\omega_i = \frac{(\partial C_i/\partial \sigma_i)(\sigma_i/C_i)}{\sum_{i=1}^{I}(\partial C_i/\partial \sigma_i)(\sigma_i/C_i)}$$

represents the weight of the implied standard deviation of call option i

$(\partial C_i/\partial \sigma_i)(\sigma_i/C_i)$ = the elasticity of the price of the ith call option (C_i) with respect to its implied standard deviation (σ_i)[12]

However, as an interesting attempt to reduce the number of computations necessary to obtain a unique implied standard deviation, we mention Beckers' empirical study (1981) of stock returns' future variability estimates. The author suggests that a single ISD computed from the market price of the most at-the-money call option (i.e., the call option with the highest first derivative of its price with respect to σ) will produce a better forecast of stock return's future variability than any other method based on weighted implied standard deviations computed from several options.

This method has the advantage of only requiring a single option's market price to compute the ISD, and we can then use the latter to price all other options according to the Black and Scholes formula. This simultaneous pricing would of course have been biased had it relied on the weighted implied standard deviation method.

The implied standard deviation is currently the most powerful approach for estimating a stock's return future variance from the most recent market data. Empirical studies by Latané and Rendleman (1976) and Beckers (1981) have indeed shown that implied standard deviations are better suited than historical standard deviations to predict a stock's future variability and hence to price stock options.

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[11] These options have indeed the highest price elasticity with respect to a change in the stock returns' standard deviation.

[12] The elasticities are computed by first determining the derivative of the call option's price with respect to its standard deviation from the Black and Scholes formula. We saw in Chapter 4, Section 5 that:

$$\frac{\partial C}{\partial \sigma} = S\sqrt{\tau}N'(d_1) \tag{4.33}$$

Although the ISD method is broadly used among stock and currency option managers, however, there are a variety of "home made" variance estimations used by many banks and financial institutions. They essentially result from the combination of a historically estimated standard deviation with an implicit standard deviation and with each institution's own forecast about the stock's future riskiness.

As a conclusion to this rather delicate task of estimating a stock's future variance from past or current market data, we should remember that the historical variance method and the implied standard deviation method both assume that the stock's variance remains constant over time. Of course, if this assumption is violated, the validity of the variance estimation techniques presented in this section as well as of the Black and Scholes formula become a highly controversial issue.[13]

Now that we have seen how the essential parameters of the Black and Scholes formula are chosen or estimated from available market data, we will present an example to illustrate how this procedure could be practically implemented to compute theoretical prices of European put and call options.

F A Numerical Example

Suppose on February 8, 1988 we want to assess whether the call option with an exercise price of \$52, expiring on March 25, 1988 is a good buy given that the underlying stock ABC is currently selling at \$51.7. We will compute the option's remaining time to maturity expressed as a function of the current calendar year:[14]

$$\tau = 46/366 = 0.125683$$

Looking at the newspaper we then find that the T-Bill with the closest maturity (expiring March 24, 1988) has an annualized yield to maturity of 5.77 percent.

Since the Black and Scholes formula relies on a continuously compounded interest rate, we then need to convert the discrete time annualized yield-to-maturity of the T-Bill into its continuous-time equivalent according to the following formula presented in Chapter 4:

$$r = \ln(1 + i) = \ln(1.0577) = 5.61\%$$

We previously computed the annualized historical standard deviation of stock ABC returns (see section E), which is equal to

$$\sigma = 0.1235$$

[13] We will examine in the next chapter whether it is realistic to assume that the continuously compounded rates of return on the stock follow a normal distribution characterized by a constant mean and a constant variance per unit of time.

[14] Note that we are using the exact number of calendar days in year 1988.

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980 Regulated Operations
20 Discontinuation of Rate-Regulated Accounting
05 Overview and Background

General Note: The Overview and Background Section provides overview and background material for the guidance contained in the Subtopic. It does not provide the historical background or due process. It may contain certain material that users generally consider useful to understand the typical situations addressed by the standards. The Section does not summarize the accounting and reporting requirements.

General

980-20-05-1 This Subtopic addresses the discontinuation of rate-regulated accounting when an entity no longer meets the criteria in paragraph 980-10-15-2.

980-20-05-2 Deregulation of certain industries and changes in the method of regulating others have caused several entities to discontinue application of this Topic for some or all of their operations.

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980 Regulated Operations
20 Discontinuation of Rate-Regulated Accounting
15 Scope and Scope Exceptions

General Note: The Scope and Scope Exceptions Section outlines the items (for example, the entities, transactions, instruments, or events) to which the guidance in the Subtopic does or does not apply. In some cases, the Section may contain definitional or other text to frame the scope.

General

> Overall Guidance

980-20-15-1 This Subtopic follows the same Scope and Scope Exceptions as outlined in the Overall Subtopic, see Section 980-10-15, with specific exceptions as noted below, which provides further guidance on an entity's operations that no longer meet the criteria of regulated operations.

> Entities

980-20-15-2 Failure of an entity's operations to continue to meet the criteria in paragraph 980-10-15-2 can result from different causes. Examples include the following:

a. Deregulation

b. A change in the regulator's approach to setting rates from cost-based rate-making to another form of regulation

c. Increasing competition that limits the entity's ability to sell utility services or products at rates that will recover costs (as used in paragraph 980-10-15-2)

d. Regulatory actions resulting from resistance to rate increases that limit the entity's ability to sell utility services or products at rates that will recover costs if the entity is unable to obtain (or chooses not to seek) relief from prior regulatory actions through appeals to the regulator or the courts.

980-20-15-3 Regardless of the reason for an entity's discontinuation of application of the Regulated Operations Topic, this Subtopic specifies how that discontinuation shall be reported in the entity's general-purpose external financial statements.

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980 Regulated Operations
20 Discontinuation of Rate-Regulated Accounting
20 Glossary

Allowance for Funds Used during Construction

The cost of financing construction as financed partially by borrowings and partially by equity, capitalized as part of the cost of plant and equipment pursuant to requirements of the regulator.

Regulatory Assets and Regulatory Liabilities

Regulatory assets and regulatory liabilities are those assets and liabilities recognized pursuant to the provisions of paragraphs 980-340-25-1 and 980-405-25-1. These assets and liabilities are not recognized by entities in general.

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20 Discontinuation of Rate-Regulated Accounting
35 Subsequent Measurement

General Note: The Subsequent Measurement Section provides guidance on an entity's subsequent measurement and subsequent recognition of an item. Situations that may result in subsequent changes to carrying amount include impairment, fair value adjustments, depreciation and amortization, and so forth.

General

> Discontinuation of Recognition Following Regulator Actions

980-20-35-1 An entity that discontinues application of the Regulated Operations Topic shall no longer recognize the effects of actions of a regulator as assets or liabilities unless the right to receive payment or the obligation to pay exists as a result of past events or transactions and regardless of future transactions.

> Plant, Equipment, and Inventory

980-20-35-2 This Subtopic requires that upon the discontinuation of rate-regulated accounting, the carrying amounts of the plant, equipment, and inventory measured and recorded pursuant to this Topic shall not be adjusted unless those assets are impaired.

980-20-35-3 The carrying amounts of plant, equipment, and inventory for entities applying this Topic differ from those for entities in general only because of the **allowance for funds used during construction**, intra-entity profit, and disallowances of costs of recently completed plants. If any other amounts that would not be includable in the carrying amounts of plant, equipment, or inventory by entities in general are included in or netted against the carrying amounts of plant, equipment, and inventory, those amounts shall be separated from the carrying amounts of plant, equipment, and inventory and accounted for as prescribed in this Subtopic.

980-20-35-4 For example, postconstruction operating costs that were capitalized pursuant to paragraph 980-340-25-1 represent the effects of actions of a regulator regardless of their classification in the financial statements and shall be accounted for as this Subtopic prescribes for the effects of actions of a regulator.

980-20-35-5 Another example of the effect of actions of a regulator that would require adjustment is the cumulative difference, if any, between recorded depreciation and depreciation computed using a generally accepted method of depreciation.

> Regulatory Assets and Liabilities Originating in a Separable Portion of the Entity

980-20-35-6 The **regulatory assets and regulatory liabilities** that originate in a separable portion of an entity to which this Subtopic is applied shall be evaluated on the basis of where (that is, the portion of the business in which) the regulated cash flows to realize and settle them, respectively, will be derived. Regulated cash flows are from rates that are charged to customers and intended by regulators to be for the recovery of the specified regulatory assets and the settlement of regulatory liabilities. They are derived from a levy on rate-regulated goods or services provided by another separable portion of the entity that meets the criteria of paragraph 980-10-15-2 for application of this Topic.

980-20-35-7 There is no elimination of the regulatory assets and regulatory liabilities that originate in the separable portion of the business to which this Subtopic is applied and for which the deregulatory legislation or rate order (whichever is necessary to effect change in the jurisdiction) specifies the collection of regulated cash flows until any of the following occur:

a. They are recovered by (in the case of assets) or settled through (in the case of liabilities) collection of regulated cash flows.

b. They are individually impaired (in the case of assets) or the regulator eliminates the obligation (in the case of liabilities) as specified by the provisions of this Topic.

c. The separable portion of the business from which the regulated cash flows are derived no longer meets the criteria of paragraph 980-10-15-2 for application of this Topic.

980-20-35-8 The source of the cash flow approach adopted in paragraphs 980-20-35-6 through 35-9 shall be used for recoveries of all costs and settlements of all obligations (not just for regulatory assets and regulatory liabilities that are recorded at the date this Subtopic is applied) for which regulated cash flows are specifically provided in the deregulatory legislation or rate order (whichever is necessary to effect change in the jurisdiction).

980-20-35-9 A cost or an obligation is recognized as a regulatory asset or a regulatory liability within the separable portion of the entity from which the regulated cash flows for its recovery or settlement, respectively, are derived once it meets both of the following conditions:

a. Expensed or incurred after this Subtopic is applied to the portion of the business where it originated (such as the loss on the sale of an electricity generating plant or the loss on the buy-out of a purchased power contract that is recognized after this Subtopic is applied to the generation portion of the business)

b. Specified for recovery or settlement in the deregulatory legislation or a rate order (whichever is necessary to effect change in the jurisdiction) and is recovered or settled in the same manner (that is, via regulated cash flows) as the regulatory assets and regulatory liabilities described in paragraphs 980-20-35-6 through 35-9.

Those regulatory assets and regulatory liabilities shall be carried in this other separable portion of the business until they are collected or settled, until they are individually impaired (assets) or eliminated (liabilities), or until that separable portion of the business no longer meets the criteria of paragraph 980-10-15-2 for application of this Topic.

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980 Regulated Operations
20 Discontinuation of Rate-Regulated Accounting
40 Derecognition

General Note: The Derecognition Section provides guidance on determining whether and when an entity should remove an item from the financial statements. For example, the entity would derecognize an asset because it no longer has rights to the asset or it would derecognize a liability because it no longer has any obligation.

General

> **Discontinuation of Regulatory Operations Guidance**

980-20-40-1 When an entity determines that its operations in a regulatory jurisdiction no longer meet the criteria of paragraph 980-10-15-2 for application of the Regulated Operations Topic, that entity shall discontinue application of this Topic to its operations in that jurisdiction. If a separable portion of the entity's operations within a regulatory jurisdiction ceases to meet the criteria of that paragraph for application of this Topic, application of this Topic to that separable portion shall be discontinued. That situation creates a presumption that application of this Topic shall be discontinued for all of the entity's operations within that regulatory jurisdiction. That presumption can be overcome by establishing that the entity's other operations within that jurisdiction continue to meet the criteria of paragraph 980-10-15-2 for application of this Topic. The separable portion may be an entity's operations within a regulatory jurisdiction or a smaller portion (such as a *customer class within a regulatory jurisdiction*), *either of which could require the allocation of* system-wide assets and liabilities.

980-20-40-2 When an entity discontinues application of this Topic to all or part of its operations, that entity shall eliminate from its statement of financial position prepared for general-purpose external financial reporting the effects of any actions of regulators that had been recognized as assets and liabilities pursuant to this Topic but would not have been recognized as assets and liabilities by entities in general, and the Impairment or Disposal of Long-Lived Assets Subsections of Subtopic 360-10 shall apply, except for the provisions for income statement reporting in paragraphs 360-10-45-4 and 360-10-50-2. However, the carrying amounts of plant, equipment, and inventory measured and reported pursuant to this Topic shall not be adjusted unless those assets are impaired, in which case the carrying amounts of those assets shall be reduced to reflect that impairment.

980-20-40-3 The carrying amounts of plant, equipment, and inventory for entities applying this Topic differ from those for entities in general only because of the **allowance for funds used during construction**, intra-entity profit, and disallowances of costs of recently completed plants. If any other amounts that would not be includable in the carrying amounts of plant, equipment, or inventory by entities in general (such as postconstruction operating costs capitalized pursuant to paragraph 980-340-25-1) are included in or netted against the carrying amounts of plant, equipment, or inventory, those amounts shall be accounted for as this Subtopic prescribes for the effects of actions of a regulator.

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980-20-40-4 Whether those assets have been impaired shall be judged in the same manner as for entities in general. The net effect of the adjustments required by this Subtopic shall be included in income of the period in which the discontinuation occurs and shall be classified as an extraordinary item.

980-20-40-5 Examples illustrating the discontinuation of regulatory operations guidance include the following:

a. Example 1 (see paragraph 980-20-55-1) illustrates assets recorded based solely on expected future revenue from the regulator.

b. Example 2 (see paragraph 980-20-55-6) illustrates liabilities recorded based solely on actions of the regulator.

c. Example 3 (see paragraph 980-20-55-10) illustrates assets recorded for deferred income taxes not previously recognized for rate-making purposes but expected to be in the future.

> Deregulatory Legislation or Rate Order in a Separable Portion of the Entity

980-20-40-6 When deregulatory legislation is passed or when a rate order (whichever is necessary to effect change in the jurisdiction) that contains sufficient detail for the entity to reasonably determine how the transition plan will affect a separable portion of its business whose pricing is being deregulated is issued, the entity shall stop applying this Topic to that separable portion of its business. It has not been established whether an entity shall stop applying the accounting and reporting for regulatory operations as provided in the other Subtopics of this Topic to that separable portion of its business before the issuance of sufficiently detailed deregulatory legislation or a sufficiently detailed rate order.

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980 Regulated Operations
20 Discontinuation of Rate-Regulated Accounting
45 Other Presentation Matters

General Note: The Other Presentation Matters Section provides guidance on other presentation matters not addressed in the Recognition, Initial Measurement, Subsequent Measurement, and Derecognition Sections. Other presentation matters may include items such as current or long-term balance sheet classification, cash flow presentation, earnings per share matters, and so forth. The FASB Codification also contains Presentation Topics, which provide guidance for general presentation and display items. See those Topics for general guidance.

General

> **Separable Portion Following Discontinuation of Regulatory Operations Guidance**

980-20-45-1 Once the Regulated Operations Topic is no longer applied to a separable portion of an entity's business, the financial statements shall segregate, via financial statement display or footnote disclosure, the amounts contained in the financial statements that relate to that separable portion.

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980 Regulated Operations
20 Discontinuation of Rate-Regulated Accounting
50 Disclosure

General Note: The Disclosure Section provides guidance regarding the disclosure in the notes to financial statements. In some cases, disclosure may relate to disclosure on the face of the financial statements.

General

980-20-50-1 For the period in which an entity reflects the discontinuation of application of the Regulated Operations Topic all or a separable portion of its operations, the entity shall disclose the reasons for the discontinuation and identify the portion of its operations to which the application of this Topic is being discontinued.

980-20-50-2 The disclosure requirements of Subtopic 225-20 for extraordinary items apply to the net adjustment reported in the statement of operations as a result of applying this Subtopic.

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980 Regulated Operations
20 Discontinuation of Rate-Regulated Accounting
55 Implementation Guidance and Illustrations

General Note: The Implementation Guidance and Illustrations Section contains implementation guidance and illustrations that are an integral part of the Subtopic. The implementation guidance and illustrations do not address all possible variations. Users must consider carefully the actual facts and circumstances in relation to the requirements of the Subtopic.

General

> Illustrations

>> Example 1: Assets Recorded Based Solely on Expected Future Revenue from the Regulator

980-20-55-1 This Example illustrates the guidance in paragraphs 980-20-40-1 through 40-4.

980-20-55-2 Utility A operates solely in one regulatory jurisdiction. At December 31, 19X1, Utility A concludes, based on current market conditions, that it no longer meets the criteria of paragraph 980-10-15-2 for the application of the Regulated Operations Topic. Utility A's statement of financial position at December 31, 19X1, includes all of the following items:

a. Deferred purchased power costs (costs of power used for operations in prior periods that were expected to be recovered from customers as a result of an automatic adjustment clause)

b. Deferred costs of abandoned plant (costs for which recovery was being provided through rates)

c. Deferred costs of repairing storm damage.

980-20-55-3 Those items should be reported as follows as of December 31, 19X1.

980-20-55-4 All of those items should be eliminated from the entity's statement of financial position when it ceases to apply this Topic. The resulting charge to income, net of any related tax effects should be reported as an extraordinary item in the period that includes December 31, 19X1. The entity should no longer defer those costs and report them as assets because they could not be reported as assets by entities in general. Entities in general would report a receivable for those items only if a right to receive payment exists as a result of past events or transactions and regardless of future transactions (such as future sales).

980-20-55-5 For example, a contract between a supplier and a customer for the sale of fuel oil may specify that next year's sales price will be adjusted based on the supplier's current-year cost of fuel oil. Even though it is probable that a future economic benefit (the ability to charge a higher price in the future) will result from the supplier's current-year cost of fuel oil, no asset exists at the

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end of the current year because the transactions (sales to the customer) that give the supplier control of the benefit are in the future. However, if the contract provides that the customer is obligated to pay additional amounts related to past purchases and regardless of future purchases, the supplier has an asset and it does not matter whether that payment is made in a single amount or when the customer will pay for next year's purchases.

>> Example 2: Liabilities Recorded Based Solely on Actions of the Regulator

980-20-55-6 This Example illustrates the guidance in paragraphs 980-20-40-1 through 40-4.

980-20-55-7 Utility B operates in two regulatory jurisdictions, State 1 and State 2; 40 percent of Utility B's operations are located in State 1 and 60 percent in State 2; system-wide assets, liabilities, and certain gains and losses are allocated 40 percent to State 1 and 60 percent to State 2. At December 31, 19X2, Utility B concludes, based on current and expected future market conditions in State 1, that it no longer meets the criteria of paragraph 980-10-15-2 for application of this Topic to its operations in State 1. No similar conditions exist in State 2, and actions of State 1's regulators are not expected to influence the decisions of regulators in State 2. Utility B's statement of financial position at December 31, 19X2, includes the following items.

Deferred gain on restructuring debt, being amortized for rate-making purposes on an allocated basis by both states	$ 50,000
Revenues collected subject to refund in prior years in State 1, expected to be refunded through future rates	$ 75,000

980-20-55-8 Those items should be reported as follows as of December 31, 19X2.

980-20-55-9 The portion of the deferred gain allocable to State 1 (determined in this Example to be 40 percent of $50,000, or $20,000), net of any related tax effects, should be eliminated from the entity's statement of financial position when it ceases to apply this Topic to its operations in State 1. No adjustment should be made for the deferred gain applicable to State 2. The regulatory-created accrual for revenues subject to refund in State 1, net of any related tax effects, should be eliminated. Whether any liability related thereto exists should be determined under generally accepted accounting principles (GAAP) for entities in general. For example, amounts that were collected in the current or prior periods for which refunds will be made regardless of future sales should continue to be reported as liabilities after application of this Topic is discontinued. The credit to income resulting from the above adjustments, net of any related tax effects, should be reported as an extraordinary item in the period that includes December 31, 19X2.

>> Example 3: Regulatory-Created Assets Resulting from the Recording of Deferred Income Taxes Not Recognized for Rate-Making

980-20-55-10 This Example illustrates the guidance in paragraphs 980-20-40-1 through 40-4.

980-20-55-11 Utility C operates solely in one regulatory jurisdiction. At June 30, 19X3, Utility C concludes, based on new legislation, that it no longer meets the criteria of paragraph 980-10-15-2 for application of this Topic . Utility C had adopted Subtopic 740-10 in 19X2 and because of applying this Topic had recorded a regulatory-created asset of $650,000 for deferred taxes resulting from temporary differences that had not been recognized in the rate-making process but that were expected to be recovered in the future.

980-20-55-12 The following reporting is required for that regulatory-created asset.

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980-20-55-13 Utility C should eliminate that regulatory-created asset from its statement of financial position when the entity ceases to apply this Topic. The charge to income, net of any related tax effects, should be reported as an extraordinary item in the period that includes June 30, 19X3.

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980 Regulated Operations
20 Discontinuation of Rate-Regulated Accounting
75 XBRL Elements

Allowance for Funds Used During Construction, Capitalized Interest

Element Name: *PublicUtilitiesAllowanceForFundsUsedDuringConstructionCapitalizedInterest*
2011-06-15

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- Allowance for Funds Used during Construction

This XBRL element references the following paragraph(s)/term(s) in other Subtopic(s):

- 980 Regulated Operations > 835 Interest > 45 Other Presentation > General, 45-1

Capitalized Interest Costs, Including Allowance for Funds Used During Construction

Element Name: *InterestCostsIncurredCapitalized*
2011-06-15

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- Allowance for Funds Used during Construction

This XBRL element references the following paragraph(s)/term(s) in other Subtopic(s):

- 980 Regulated Operations > 835 Interest > 45 Other Presentation > General, 45-1

Competitive Transition Charge, Noncurrent

Element Name: *CompetitiveTransitionChargeNoncurrent*

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 35 Subsequent Measurement > General, 35-1
- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 35 Subsequent Measurement > General, 35-6
- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 45 Other Presentation > General, 45-1

This XBRL element references the following paragraph(s)/term(s) in other Subtopic(s):

- Incurred Cost

Discontinuance of Certain Regulatory Reporting Practices

Element Name: *DiscontinuanceOfCertainRegulatoryReportingPractices*

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 50

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Disclosure > General, 50-1

This XBRL element references the following paragraph(s)/term(s) in other Subtopic(s):

- 235 Notes to Financial Statements > 10 Overall > 50 Disclosure > General, 50-3

Discontinued Application of Specialized Accounting for Regulated Operations

Element Name: *DiscontinuedApplicationOfSpecializedAccountingForRegulatedOperations*

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 50 Disclosure > General, 50-1
- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 50 Disclosure > General, 50-2

Interest Costs, Capitalized During Period

Element Name: *InterestCostsCapitalized*
2011-06-15

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- Allowance for Funds Used during Construction

This XBRL element references the following paragraph(s)/term(s) in other Subtopic(s):

- 835 Interest > 20 Capitalization of Interest > 50 Disclosure > General, 50-1(b)

Public Utilities, Deregulation Activities

Element Name: *PublicUtilitiesDeregulationActivities*

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 50 Disclosure > General, 50-1

This XBRL element references the following paragraph(s)/term(s) in other Subtopic(s):

- 860 Transfers and Servicing > 10 Overall > 55 Implementation > General, 55-7

Public Utilities, Deregulation of Electricity Pricing Activities

Element Name: *PublicUtilitiesDeregulationOfElectricityPricingActivities*

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 45 Other Presentation > General, 45-1
- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 50 Disclosure > General, 50-1
- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 50 Disclosure > General, 50-2

This XBRL element references the following paragraph(s)/term(s) in other Subtopic(s):

- 860 Transfers and Servicing > 10 Overall > 55 Implementation > General, 55-7

Public Utilities, Disclosure of Regulatory Matters Pending

Element Name: *PublicUtilitiesDisclosureOfRegulatoryMattersPending*

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 40 Derecognition > General, 40-6

This XBRL element references the following paragraph(s)/term(s) in other Subtopic(s):

- 450 Contingencies > 20 Loss Contingencies > 50 Disclosure > General, 50-1
- 450 Contingencies > 20 Loss Contingencies > 50 Disclosure > General, 50-3
- 450 Contingencies > 20 Loss Contingencies > 50 Disclosure > General, 50-4
- 450 Contingencies > 20 Loss Contingencies > 50 Disclosure > General, 50-5
- 980 Regulated Operations > 360 Property, Plant, and Equipment > 55 Implementation > General, 55-16
- 980 Regulated Operations > 360 Property, Plant, and Equipment > 55 Implementation > General, 55-17
- 980 Regulated Operations > 360 Property, Plant, and Equipment > 55 Implementation > General, 55-20
- 980 Regulated Operations > 360 Property, Plant, and Equipment > 55 Implementation > General, 55-21
- 980 Regulated Operations > 360 Property, Plant, and Equipment > 55 Implementation > General, 55-22
- 980 Regulated Operations > 360 Property, Plant, and Equipment > 55 Implementation > General, 55-23
- 980 Regulated Operations > 360 Property, Plant, and Equipment > 55 Implementation > General, 55-24
- 980 Regulated Operations > 360 Property, Plant, and Equipment > 55 Implementation > General, 55-25
- 980 Regulated Operations > 360 Property, Plant, and Equipment > 55 Implementation > General, 55-27
- 980 Regulated Operations > 360 Property, Plant, and Equipment > 55 Implementation > General, 55-28
- 980 Regulated Operations > 360 Property, Plant, and Equipment > 55 Implementation > General, 55-29

Public Utilities, Impact of Deregulation Activities

Element Name: *PublicUtilitiesImpactOfDeregulationActivities*

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 45 Other Presentation > General, 45-1
- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 50 Disclosure > General, 50-1
- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 50 Disclosure > General, 50-2

Public Utility Regulated or Unregulated Status [Axis]

Element Name: *PublicUtilityRegulatedOrUnregulatedStatusAxis*

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 45 Other Presentation > General, 45-1

Public Utility, Property, Plant and Equipment [Table]

Element Name: *PublicUtilityPropertyPlantAndEquipmentTable*

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 45 Other Presentation > General, 45-1

This XBRL element references the following paragraph(s)/term(s) in other Subtopic(s):

- 210 Balance Sheet > 10 Overall > S99 SEC Materials > General, S99-1(SX 210.5-02.13(b))

Regulated and Unregulated Operation [Domain]

Element Name: *RegulatedAndUnregulatedOperationDomain*

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 45 Other Presentation > General, 45-1

Schedule of Public Utility Property, Plant, and Equipment [Table Text Block]

Element Name: *ScheduleOfPublicUtilityPropertyPlantAndEquipmentTextBlock*

This XBRL element references the following paragraph(s)/term(s) in this Subtopic:

- 980 Regulated Operations > 20 Discontinuation of Rate-Regulated Accounting > 45 Other Presentation > General, 45-1

This XBRL element references the following paragraph(s)/term(s) in other Subtopic(s):

- 210 Balance Sheet > 10 Overall > S99 SEC Materials > General, S99-1(SX 210.5-02.13(b))

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980 Regulated Operations
10 Overall
15 Scope and Scope Exceptions

General Note: The Scope and Scope Exceptions Section outlines the items (for example, the entities, transactions, instruments, or events) to which the guidance in the Subtopic does or does not apply. In some cases, the Section may contain definitional or other text to frame the scope.

General Note for Financial Instruments: Some of the items subject to the guidance in this Subtopic are **financial instruments**. For guidance on matters related broadly to all financial instruments, (including the fair value option, accounting for registration payment arrangements, and broad financial instrument disclosure requirements), see Topic 825. See Section 825-10-15 for guidance on the scope of the Financial Instruments Topic.

General

> Overall Guidance

980-10-15-1 The Subtopics within the Regulated Operations Topic only provide incremental industry-specific guidance for the entities defined in this Scope Section, or as further defined in the Scope Sections of the individual Regulated Operations Subtopics. Entities within the scope of this Topic shall also comply with the applicable guidance not included in this Topic.

> Entities

980-10-15-2 The guidance in the Regulated Operations Topic applies to general-purpose external financial statements of an entity that has regulated operations that meet all of the following criteria:

a. The entity's rates for regulated services or products provided to its customers are established by or are subject to approval by an independent, third-party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers.

b. The regulated rates are designed to recover the specific entity's costs of providing the regulated services or products. This criterion is intended to be applied to the substance of the regulation, rather than its form. If an entity's regulated rates are based on the costs of a group of entities and the entity is so large in relation to the group of entities that its costs are, in essence, the group's costs, the regulation would meet this criterion for that entity.

c. In view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the entity's costs can be charged to and collected from customers. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs. This last criterion is not intended as a requirement that the entity earn a fair return on shareholders' investment under all conditions; an entity can earn less than a fair return for many reasons unrelated to the ability to bill and collect rates that will recover **allowable costs**. For example, mild weather might reduce demand for energy utility services. In that case, rates that were expected to recover an entity's allowable costs might not do so. The resulting decreased earnings do not demonstrate an inability to charge and collect rates that would recover the entity's costs; rather, they demonstrate the uncertainty inherent in estimating weather conditions. This requirement must also be evaluated in light of the circumstances. For example, if the entity has an exclusive franchise to provide regulated services or products in an area and competition from other services or products is minimal, there is usually a reasonable expectation that it will continue to meet the other criteria. Exclusive franchises can be revoked, but they seldom are. If the entity has no exclusive franchise but has made the very large capital investment required to provide either the regulated services or products or an acceptable substitute, future competition also may be unlikely.

980-10-15-3 In some cases, the rates set by state regulatory agencies are accepted for Medicare and Medicaid reimbursement purposes. There is some disagreement about the extent to which such rates are based on a provider's costs. If regulatory agencies in those states base rates on the provider's costs and adopt a permanent system of regulation, health care providers in those jurisdictions could be subject to the provisions of this Topic. However, the criterion in (c) in the preceding paragraph also would have to be considered to determine whether this Topic applies to the entity.

980-10-15-4 If some of an entity's operations are regulated and meet the criteria of paragraph 980-10-15-2, this Topic shall be applied to only that portion of the entity's operations.

980-10-15-5 Guidance in other Codification Topics that applies to entities in general also applies to regulated entities. However, entities subject to this Topic shall apply it instead of any conflicting provisions of other parts of the Codification. For example, a regulator might authorize a regulated entity to incur a major research and development cost because the cost is expected to benefit future customers. The regulator might also direct that cost to be capitalized and amortized as an allowable cost over the period of expected benefit. If the criteria of paragraph 980-340-25-1 are met, the entity shall **capitalize** that cost even though Subtopic 730-10 requires such costs to be charged to income currently. That Subtopic shall still apply to accounting for other research and development costs of the regulated entity, as shall the disclosure requirements of that Subtopic.

980-10-15-6 Section 915-205-45 and paragraphs 915-215-45-1 through 45-3 and 915-235-50-1, which require disclosure of additional information, apply to development stage entities, which are also regulated entities in all cases.

> Transactions

980-10-15-7 The guidance in the Regulated Operations Topic does not apply to any of the following transactions:

a. Accounting for price controls that are imposed by governmental action in times of emergency, high inflation, or other unusual conditions, or accounting for contracts in general. However, if the terms of a contract between an entity and its customer are subject to regulation and the criteria of paragraph 980-10-15-2 are met with respect to that contract, the guidance in this Topic shall apply.

b. An entity's regulatory accounting. Regulators may require regulated entities to maintain their accounts in a form that permits the regulator to obtain the information needed for regulatory purposes. This Topic neither limits a regulator's actions nor endorses them. Regulators' actions are based on many considerations. Accounting addresses the effects of those actions. This Topic merely specifies how the effects of different types of rate actions are reported in general-purpose financial statements.

c. The criterion in paragraph 980-10-15-2(a) is intended to exclude contractual arrangements in which the government, or another party that could be viewed as a regulator, is a party to a contract and is the entity's principal customer.

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980 Regulated Operations
340 Other Assets and Deferred Costs
25 Recognition

General Note: The Recognition Section provides guidance on the required criteria, timing, and location (within the financial statements) for recording a particular item in the financial statements. Disclosure is not recognition.

General

> **Effects of Regulation**

> > **Recognition of Regulatory Assets**

980-340-25-1 Rate actions of a regulator can provide reasonable assurance of the existence of an asset. An entity shall **capitalize** all or part of an **incurred cost** that would otherwise be charged to expense if both of the following criteria are met:

a. It is probable (as defined in Topic 450) that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in **allowable costs** for rate-making purposes.

b. Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. If the revenue will be provided through an automatic rate-adjustment clause, this criterion requires that the regulator's intent clearly be to permit recovery of the previously incurred cost.

A cost that does not meet these asset recognition criteria at the date the cost is incurred shall be recognized as a regulatory asset when it does meet those criteria at a later date.

> > **Phase-In Plans**

980-340-25-2 If a **phase-in plan** is ordered by a regulator in connection with a plant on which no substantial physical construction had been performed before January 1, 1988, none of the allowable costs that are deferred for future recovery by the regulator under the plan for rate-making purposes shall be capitalized for general-purpose financial reporting purposes (hereinafter referred to as financial reporting). Allowable costs that are deferred for future recovery by the regulator under the plan consist of all allowable costs deferred for rate-making purposes under the plan beyond the period in which those allowable costs would be charged to expense under generally accepted accounting principles (GAAP) applicable to entities in general.

980-340-25-3 If a phase-in plan is ordered by a regulator in connection with a plant completed before January 1, 1988, or a plant on which substantial physical construction had been performed before January 1, 1988, the following criteria shall be applied to that plan. If the phase-in plan meets all of those criteria, all allowable costs that are deferred for future recovery by the regulator

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under the plan shall be capitalized for financial reporting as a separate asset (a deferred charge). If any one of those criteria is not met, none of the allowable costs that are deferred for future recovery by the regulator under the plan shall be capitalized for financial reporting. The criteria to determine whether capitalization is appropriate are:

a. The allowable costs in question are deferred pursuant to a formal plan that has been agreed to by the regulator.

b. The plan specifies the timing of recovery of all allowable costs that will be deferred under the plan.

c. All allowable costs deferred under the plan are scheduled for recovery within 10 years of the date when deferrals begin.

d. The percentage increase in rates scheduled under the plan for each future year is no greater than the percentage increase in rates scheduled under the plan for each immediately preceding year. That is, the scheduled percentage increase in Year 2 is no greater than the percentage increase granted in Year 1, the scheduled percentage increase in Year 3 is no greater than the scheduled percentage increase in Year 2, and so forth.

980-340-25-4 The following Examples illustrate various circumstances that may or may not constitute phase-in plans:

a. Example 1 (see paragraph 980-340-55-9) illustrates a sale with leaseback as a capital lease.

b. Example 2 (see paragraph 980-340-55-12) illustrates a sale with leaseback as an operating lease.

c. Example 3 (see paragraph 980-340-55-15) illustrates a sale with leaseback with profit recognition accelerated.

d. Example 4 (see paragraph 980-340-55-18) illustrates the modified depreciation method.

e. Example 5 (see paragraph 980-340-55-21) illustrates deferred costs before a rate order is issued.

f. Example 7 (see paragraph 980-340-55-39) illustrates a phase-in plan for two plants completed at different times that share common facilities.

> > Allowance for Earnings on Shareholder Investments Capitalized for Rate-Making Purposes

980-340-25-5 If specified criteria are met, paragraph 980-340-25-1 requires capitalization of an incurred cost that would otherwise be charged to expense. An allowance for earnings on shareholders' investment is not an incurred cost that would otherwise be charged to expense. Accordingly, such an allowance shall not be capitalized pursuant to that paragraph. The phrase *an allowance for earnings on shareholders' investment*, as used in this Subtopic, is intended to have the same meaning as the phrase *a designated cost of equity funds*, used in paragraph 980-835-30-1 , which, in specified circumstances, requires capitalization of an allowance for earnings on shareholders' investment (a designated cost of equity funds) during construction.

980-340-25-6 Paragraphs 980-340-25-2 through 25-3 require capitalization of an allowance for earnings on shareholders' investment for qualifying phase-in plans. If an allowance for earnings on shareholders' investment is capitalized for rate-making purposes other than during construction or as part of a phase-in plan, the amount capitalized for rate-making purposes shall not be capitalized for financial reporting. For the requirement to accrue a carrying charge related to the expected recovery of the investment in abandoned assets, see paragraph 980-360-35-7.

July 26, 2011

450 Contingencies
20 Loss Contingencies
20 Glossary

Contingency

An existing condition, situation, or set of circumstances involving uncertainty as to possible gain (gain contingency) or loss (loss contingency) to an entity that will ultimately be resolved when one or more future events occur or fail to occur.

Gain Contingency

An existing condition, situation, or set of circumstances involving uncertainty as to possible gain to an entity that will ultimately be resolved when one or more future events occur or fail to occur.

Loss Contingency

An existing condition, situation, or set of circumstances involving uncertainty as to possible loss to an entity that will ultimately be resolved when one or more future events occur or fail to occur. The term loss is used for convenience to include many charges against income that are commonly referred to as expenses and others that are commonly referred to as losses.

Probable

The future event or events are likely to occur.

Reasonably Possible

The chance of the future event or events occurring is more than remote but less than likely.

Remote

The chance of the future event or events occurring is slight.

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980 Regulated Operations
405 Liabilities
25 Recognition

General Note: The Recognition Section provides guidance on the required criteria, timing, and location (within the financial statements) for recording a particular item in the financial statements. Disclosure is not recognition.

General Note for Fair Value Option: Some of the items subject to the guidance in this Subtopic may qualify for application of the Fair Value Option Subsections of Subtopic 825-10. Those Subsections (see paragraph 825-10-05-5) address circumstances in which entities may choose, at specified election dates, to measure eligible items at fair value (the fair value option). See Section 825-10-15 for guidance on the scope of the Fair Value Option Subsections of the Financial Instruments Topic.

General

> **Regulator-Imposed Liabilities**

980-405-25-1 Rate actions of a regulator can impose a liability on a regulated entity. Such liabilities are usually obligations to the entity's customers. The following are the usual ways in which liabilities can be imposed and the resulting accounting:

a. A regulator may require refunds to customers. Refunds can be paid to the customers who paid the amounts being refunded; however, they are usually provided to current customers by reducing current charges. Refunds that meet the criteria of accrual of loss contingencies (see paragraph 450-20-25-2) shall be recorded as liabilities and as reductions of revenue or as expenses of the regulated entity.

b. A regulator can provide current rates intended to recover costs that are expected to be incurred in the future with the understanding that if those costs are not incurred future rates will be reduced by corresponding amounts. If current rates are intended to recover such costs and the regulator requires the entity to remain accountable for any amounts charged pursuant to such rates and not yet expended for the intended purpose, the entity shall not recognize as revenues amounts charged pursuant to such rates. The usual mechanism used by regulators for this purpose is to require the regulated entity to record the anticipated cost as a liability in its regulatory accounting records. Those amounts shall be recognized as liabilities and taken to income only when the associated costs are incurred. (For related implementation guidance, see paragraph 980-405-55-1).

c. A regulator can require that a gain or other reduction of net **allowable costs** be given to customers over future periods. That would be accomplished, for rate-making purposes, by amortizing the gain or other reduction of net allowable costs over those future periods and reducing rates to reduce revenues in approximately the amount of the amortization. If a gain or other reduction of net allowable costs is to be amortized over future periods for rate-making

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purposes, the regulated entity shall not recognize that gain or other reduction of net allowable costs in income of the current period. Instead, it shall record it as a liability for future reductions of charges to customers that are expected to result.

July 26, 2011

980 Regulated Operations
605 Revenue Recognition
25 Recognition

General Note: The Recognition Section provides guidance on the required criteria, timing, and location (within the financial statements) for recording a particular item in the financial statements. Disclosure is not recognition.

General Note for Fair Value Option: Some of the items subject to the guidance in this Subtopic may qualify for application of the Fair Value Option Subsections of Subtopic 825-10. Those Subsections (see paragraph 825-10-05-5) address circumstances in which entities may choose, at specified election dates, to measure eligible items at fair value (the fair value option). See Section 825-10-15 for guidance on the scope of the Fair Value Option Subsections of the Financial Instruments Topic.

General

> **Alternative Revenue Programs**

980-605-25-1 Traditionally, regulated utilities whose rates are determined based on cost of service invoice their customers by applying approved base rates (designed to recover the utility's **allowable costs** including a return on shareholders' investment) to usage. Some regulators of utilities have also authorized the use of additional, alternative revenue programs. The major alternative revenue programs currently used can generally be segregated into two categories, Type A and Type B.

980-605-25-2 Type A programs adjust billings for the effects of weather abnormalities or broad external factors or to compensate the utility for demand-side management initiatives (for example, no-growth plans and similar conservation efforts). Type B programs provide for additional billings (incentive awards) if the utility achieves certain objectives, such as reducing costs, reaching specified milestones, or demonstratively improving customer service.

980-605-25-3 Both types of programs enable the utility to adjust rates in the future (usually as a surcharge applied to future billings) in response to past activities or completed events.

980-605-25-4 Once the specific events permitting billing of the additional revenues under Type A and Type B programs have been completed, the regulated utility shall recognize the additional revenues if all of the following conditions are met:

a. The program is established by an order from the utility's regulatory commission that allows for automatic adjustment of future rates. Verification of the adjustment to future rates by the regulator would not preclude the adjustment from being considered automatic.

b. The amount of additional revenues for the period is objectively determinable and is probable of recovery.

c. The additional revenues will be collected within 24 months following the end of the annual period in which they are recognized.

> **Long-Term Power Sales Contracts**

980-605-25-5 In general, **nonutility generators** are not regulated and do not meet the criteria of an entity with regulated operations as provided in paragraph 980-10-15-2. However, since nonutility generators provide many of the same services as entities with regulated operations, the guidance for nonutility generators is included in paragraphs 980-605-25-5 through 25-18. That portion of this Subsection assumes the seller of power under the long-term contract does not meet the criteria for application of this Topic.

980-605-25-6 Nonutility generators provide a significant percentage of new electric generating capacity in the United States. Some of these generating plants are built by users primarily for their own energy needs while others are built specifically to sell power, usually to rate-regulated utilities, under long-term power sales contracts. Those contracts price the power sold under a wide variety of terms and arrangements.

980-605-25-7 The long-term power sales contracts may provide for any of the following:

a. Stated prices per kilowatt hour that increase, decrease, or remain level over the term of the contract

b. Formula-based prices per kilowatt hour

c. Billings that are a combination of stated prices and formula-based prices per kilowatt hour.

980-605-25-8 One example of a combination is a contract that provides for billings pursuant to a stated price schedule but also provides for a payment to be made or received by the nonutility generator at the end of the contract so that total revenue recognized and payments made over the contract term equal the amount computed pursuant to the formula-based pricing arrangement. The differences between payments made and the amount computed under the formula-based pricing arrangement are recorded in an interest-bearing tracker account. In other cases, the cumulative balance in the tracker account at a defined point in the contract life may be amortized to zero through adjustments to subsequent billings. Another example of such a combination is a contract that provides for billings pursuant to a stated price schedule but that provides for a payment to be made by the nonutility generator, if necessary, at the end of the contract so that the total revenue recognized and total amounts received by the nonutility generator over the contract term are limited to the lesser of the amount computed pursuant to the stated price schedule or the formula-based pricing arrangement.

980-605-25-9 Long-term power supply contracts that would qualify for lease accounting pursuant to Topic 840 are outside the scope of this Subtopic.

980-605-25-10 For a discussion of the considerations required to determine whether a long-term power sales contract arrangement contains a lease, see Subtopic 840-10.

>> **Contracts Containing Scheduled Price Changes**

980-605-25-11 For a power sales contract that contains scheduled price changes a nonutility generator shall recognize as revenue the lesser of the following:

a. The amount billable under the contract

b. An amount determined by the kilowatt hours made available during the period multiplied by the estimated average revenue per kilowatt hour over the term of the contract.

980-605-25-12 The determination of the lesser amount shall be made annually based on the cumulative amounts that would have been recognized had each method been consistently applied from the beginning of the contract term.

> > Contracts Providing for Revenue Determination or Limitation Under Formula-Based Pricing Arrangements

980-605-25-13 A nonutility generator shall recognize revenue in each period determined under the separate, formula-based pricing arrangement if it determines or limits total revenues billed under the contract (see the preceding two paragraphs). The separate, formula-based pricing arrangement shall not be used to recognize revenue if its only purpose is to establish liquidating damages. The nonutility generator shall recognize a receivable only if the contract requires a payment to the nonutility generator at the end of the contract term and such payment is probable of recovery. A receivable arises when amounts billed are less than the amount computed pursuant to the formula-based pricing arrangement.

> > Contracts Meeting Definition of Derivative

980-605-25-14 If a long-term power sales contract meets the definition of a derivative under Topic 815, then it would be marked to fair value through earnings, unless designated as a hedging instrument in certain types of hedging relationships. Otherwise, the guidance in this Section would apply. Some long-term power sales contracts that meet the definition of a derivative may qualify for the normal purchases and normal sales scope exception contained in paragraph 815-10-15-17 (b), in which case the long-term power sales contract would be accounted for under this Section .

980-605-25-15 Long-term power sales contracts that are accounted for as derivatives may possibly qualify as hedging instruments in **all-in-one hedges**. The guidance in Section 815-10-55 may be relevant.

980-605-25-16 For a discussion of issues involved in accounting for derivative contracts held for trading purposes and contracts involved in energy trading and risk management activities, see paragraph 815-10-45-9.

> > Contracts Containing Both Fixed and Variable Pricing Terms

980-605-25-17 The following addresses a power sales contract that has both fixed and variable-based pricing (based on market prices, actual avoided costs, or formula-based pricing arrangements) terms, where the variable-based pricing does not determine or limit the total billings under the contract. It is limited to variable price arrangements in which the rate is at least equal to expected costs. The guidance only addresses the revenue recognition associated with the energy component of these long-term power sales contracts.

980-605-25-18 Long-term power sales contracts that have both fixed and variable pricing terms shall be bifurcated and accounted for as follows:

a. The revenue associated with the fixed or scheduled price period of the contract shall be recognized in accordance with paragraphs 980-605-25-11 through 25-12 (that is, the lesser of the amount billable under the contract or an amount determined by the kilowatt hours made available during the period multiplied by the estimated average revenue per kilowatt hour over the term of the contract).

b. The revenue associated with the variable price period of the contract shall be recognized as billed, in accordance with the provisions of the contract for that period.

If the contractual terms during the separate fixed and variable portions of the contract are not representative of the expected market rates at the inception of the contract, the revenue associated with the entire contract shall be recognized in accordance with paragraphs 980-605-25-11 through 25-12.

IEU Remand Ex. 6

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2010

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _________ to_________

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-2680	COLUMBUS SOUTHERN POWER COMPANY (An Ohio Corporation)	31-4154203
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215	
	Telephone (614) 716-1000	

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Name of each exchange on which registered
American Electric Power Company, Inc.	Common Stock, $6.50 par value	New York Stock Exchange
Appalachian Power Company	None	
Columbus Southern Power Company	None	
Indiana Michigan Power Company	None	
Ohio Power Company	None	
Public Service Company of Oklahoma	6% Senior Notes, Series B, Due 2032	New York Stock Exchange
Southwestern Electric Power Company	None	

Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of each class
American Electric Power Company, Inc.	None
Appalachian Power Company	4.50% Cumulative Preferred Stock, Voting, no par value
Columbus Southern Power Company	None
Indiana Michigan Power Company	None
Ohio Power Company	4.50% Cumulative Preferred Stock, Voting, $100 par value
Public Service Company of Oklahoma	None
Southwestern Electric Power Company	4.28% Cumulative Preferred Stock, Voting, $100 par value
	4.65% Cumulative Preferred Stock, Voting, $100 par value
	5.00% Cumulative Preferred Stock, Voting, $100 par value

FORWARD-LOOKING INFORMATION

This report made by the registrants contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7—Management's Financial Discussion and Analysis," but there are others throughout this document, which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue," and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties such as those below and as further described in our Risk Factors that could cause actual results to differ materially from those projected. Forward-looking statements in this document speak only as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition, particularly in Ohio.
- Weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity, including the Turk Plant, and transmission line facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including oversight of energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions (including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance).
- Resolution of litigation.
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of debt.
- Volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities.
- Changes in utility regulation, including the implementation of ESPs and related regulation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.

SWEPCO also owns and operates a lignite coal mining operation. In addition to its AEP System interconnections, SWEPCo is interconnected with Cleco Corp., Empire District Electric Co., Entergy Corp. and Oklahoma Gas & Electric Co. SWEPCo is a member of SPP.

TCC (organized in Texas in 1945) is engaged in the transmission and distribution of electric power to approximately 775,000 retail customers through REPs in southern Texas. TCC has sold all of its generation assets. At December 31, 2010, TCC had 1,006 employees. Among the principal industries served by TCC are chemical and petroleum refining, chemicals and allied products, oil and gas extraction, food processing, metal refining, plastics, and machinery equipment. In addition to its AEP System interconnections, TCC is a member of ERCOT.

TNC (organized in Texas in 1927) is engaged in the transmission and distribution of electric power to approximately 186,000 retail customers through REPs in west and central Texas. TNC's generating capacity has been transferred to an affiliate at TNC's cost pursuant to an agreement effective through 2027. At December 31, 2010, TNC had 319 employees. Among the principal industries served by TNC are petroleum refining, agriculture and the manufacturing or processing of cotton seed products, oil products, precision and consumer metal products, meat products and gypsum products. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

WPCo (organized in West Virginia in 1883 and reincorporated in 1911) provides electric service to approximately 41,000 retail customers in northern West Virginia. WPCo does not own any generating facilities. WPCo is a member of PJM. It purchases electric power from OPCo for distribution to its customers. At December 31, 2010, WPCo had 52 employees.

AEGCo (organized in Ohio in 1982) is an electric generating company. AEGCo sells power at wholesale to I&M, CSPCo and KPCo. AEGCo has no employees.

SERVICE COMPANY SUBSIDIARY

AEP also owns a service company subsidiary, AEPSC. **AEPSC provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to the AEP affiliated companies. The executive officers of AEP and certain of its public utility subsidiaries are employees of AEPSC. At December 31, 2010, AEPSC had 5,132 employees.**

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any public utility subsidiary is primarily sold to customers by such public utility subsidiary at rates approved by the public utility commission in the jurisdiction of sale. See *Regulation — Rates* under *Item 1, Utility Operations.*

Under both the Interconnection Agreement and CSW Operating Agreement, power that is not needed to serve the native load of our public utility subsidiaries is sold in the wholesale market by AEPSC on behalf of those subsidiaries. See *Risk Management and Trading*, below, for a discussion of the trading and marketing of such power.

AEP's System Integration Agreement provides for the integration and coordination of AEP's East companies, PSO and SWEPCo. 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). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits for activities within each zone.

Risk Management and Trading

As agent for AEP's public utility subsidiaries, AEPSC sells excess power into the market and engages in power, natural gas, coal and emissions allowances risk management and trading activities focused in regions in which AEP traditionally operates and in adjacent regions. These activities primarily involve the purchase and sale of electricity (and to a lesser extent, natural gas, coal and emissions allowances) under physical forward contracts at fixed and variable prices. These contracts include physical transactions, over-the-counter swaps and exchange-traded futures and options. The majority of physical forward contracts are typically settled by netting into offsetting contracts. These transactions are executed with numerous counterparties or on exchanges. Counterparties and exchanges may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2010, counterparties have posted approximately $28 million in cash, cash equivalents or letters of credit with AEPSC for the benefit of AEP's public utility subsidiaries (while, as of that date, AEP's public utility subsidiaries had posted approximately $172 million with counterparties and exchanges). Since open trading contracts are valued based on market prices of various commodities, exposures change daily. See *Management's Financial Discussion and Analysis*, included in the 2010 Annual Reports, under the heading entitled *Quantitative and Qualitative Disclosures About Risk Management Activities* for additional information.

Fuel Supply

The following table shows the sources of fuel used by the AEP System:

	2008	**2009**	**2010**
Coal and Lignite	86%	88%	82%
Natural Gas	6%	6%	8%
Nuclear	8%	5%	9%
Hydroelectric and other	<1%	1%	<1%

Price increases in one or more fuel sources relative to other fuels may result in increased use of other fuels. Variations in the generation of nuclear power are primarily related to a 2008 forced outage caused by a low pressure turbine blade failure event. The unit returned to service in December 2009.

Coal and Lignite: AEP's public utility subsidiaries procure coal and lignite under a combination of purchasing arrangements including long-term contracts, affiliate operations and spot agreements with various producers and coal trading firms. Electric demand experienced a slight increase in 2010 which resulted in a slight increase in coal and lignite tons consumed. In response to continued lower consumption rates at certain locations during 2010, AEP continued to work with coal suppliers to better match deliveries with consumption and minimize the impact on fuel inventory costs, carrying costs and cash. System wide, inventory levels were reduced by 11 days in 2010.

FERC

Under the FPA, the FERC regulates rates for interstate power sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require AEP to provide open access transmission service at FERC-approved rates. The FERC also regulates unbundled transmission service to retail customers. The FERC also regulates the sale of power for resale in interstate commerce by (i) approving contracts for wholesale sales to municipal and cooperative utilities and (ii) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. Except for wholesale power that AEP delivers within its control area of the SPP, AEP has market-rate authority from the FERC, under which much of its wholesale marketing activity takes place. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The FERC also requires all transmitting utilities, directly or through an RTO, to establish an OASIS, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities' transmission employees from providing non-public transmission information to the utility's marketing employees.

The FERC oversees RTOs, entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals. The AEP East Companies are members of PJM. SWEPCo and PSO are members of SPP.

The FERC has jurisdiction over the issuances of securities of most of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both the FERC and state regulators are permitted to review the books and records of any company within a holding company system. EPACT gives the FERC limited "backstop" transmission siting authority as well as increased utility merger oversight.

COMPETITION

Under current Ohio legislation, electric generation is sold in a competitive market in Ohio, and our native load customers in Ohio have the ability to switch to alternative suppliers for their electric generation service. Competitive power suppliers are targeting retail customers by offering alternative generation service. A growing number of CSPCo's commercial retail customers have switched to alternative generation providers while additional Ohio customers have provided notice of their intent to switch. In 2010, CSPCo lost about 3% of its total load due to customer switching. These evolving market conditions will continue to impact CSPCo's results of operations. To date, OPCo's customer losses have been insignificant. In February 2010, the PUCO granted a retail supply subsidiary of AEP a certificate to operate as a competitive retail electric service provider in Ohio.

The public utility subsidiaries of AEP, like the electric industry generally, face competition in the sale of available power on a wholesale basis, primarily to other public utilities and power marketers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market by creating a generation market with fewer barriers to entry and mandating that all generators have equal access to transmission services. As a result, there are more generators able to participate in this market. The principal factors in competing for wholesale sales are price (including fuel costs), availability of capacity and power and reliability of service.

AEP's public utility subsidiaries also compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize sources of energy other than electric power. With respect to competing generators and self-generation, the public utility subsidiaries of AEP believe that they generally maintain a favorable competitive position. With respect to alternative sources of energy, the public utility subsidiaries of AEP believe that the reliability of their service and the limited ability of customers to substitute other cost-effective sources for electric power place them in a favorable competitive position, even though their prices may be higher than the costs of some other sources of energy.

Our request for rate recovery in Ohio for distribution service may not be approved in its entirety. *(Applies to AEP, CSPCo and OPCo)*

In January 2011, CSPCo and OPCo filed a notice of intent with the PUCO to file for an annual increase in distribution rates of $34 million and $59 million, respectively, either as individual companies, or, if their proposed merger is approved, as a single merged entity. The increase is based upon an 11.15% return on common equity to be effective January 2012. If the PUCO denies all or part of the requested rate recovery, it could reduce future net income and cash flows.

Our request for rate recovery in Ohio for generation service may not be approved in its entirety. *(Applies to AEP, CSPCo and OPCo)*

In January 2011, CSPCo and OPCo filed an application with the PUCO to approve the new ESP that includes a standard service offer pricing for generation effective with the first billing cycle of January 2012 through the last billing cycle of May 2014. The requested increase in 2012 is $54 million and in 2013 is $106 million. If the PUCO denies all or part of the requested rate recovery, it could reduce future net income and cash flows.

Ohio may require us to refund revenue that we have collected. *(Applies to AEP, CSPCo and OPCo)*

Ohio law requires that the PUCO determine on an annual basis if rate adjustments included in prior orders resulted in significantly excessive earnings. If the rate adjustments result in significantly excessive earnings, the excess amount could be returned to customers. In September 2010, CSPCo and OPCo filed their 2009 significantly excessive earnings filings with the PUCO. In January 2011, the PUCO ruled that CSPCo generated approximately $43 million in significantly excessive earnings during 2009. The ruling is subject to rehearing by the PUCO and could be appealed in the courts. If rehearing or a final appeal, if any, results in findings of additional significantly excessive earnings, then further amounts will be returned to customers. CSPCo and OPCo must file their 2010 significantly excessive earnings filings with the PUCO. If the PUCO determines that CSPCo's and/or OPCo's 2010 earnings were significantly excessive, CSPCo and/or OPCo may be required to return a portion of their revenues to customers.

Ohio may require us to refund fuel costs that we have collected. *(Applies to OPCo)*

The PUCO selected an outside consultant to conduct an audit of recovery under the fuel adjustment clause for the period of January 2009 through December 2009. The audit report included a recommendation that the PUCO should review whether any proceeds from a 2008 coal contract settlement agreement which totaled $72 million should reduce OPCo's under-recovery balance. Of the total proceeds, approximately $58 million was recognized as a reduction to fuel expense prior to 2009 and $14 million reduced fuel expense in 2009 and 2010. If the PUCO orders any portion of the $58 million or other future adjustments be used to reduce the current year fuel adjustment clause deferral, it would reduce future net income and cash flows and impact financial condition.

Ohio may require us to refund rider revenue that we have collected. *(Applies to CSPCo and OPCo)*

The PUCO approved recovery of an Economic Development Rider (EDR) by CSPCo and OPCo. An intervenor in that proceeding has filed a notice of appeal of that award with the Supreme Court of Ohio. As of December 31, 2010, CSPCo and OPCo have incurred $38 million and $30 million, respectively, in EDR costs including carrying costs. If CSPCo and OPCo are not ultimately permitted to recover their deferrals it would reduce future net income and cash flows and impact financial condition.

We also own natural gas-fired facilities, which increases our exposure to market prices of natural gas. Natural gas prices tend to be more volatile than prices for other fuel sources. 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.

Prices for coal, natural gas and emission allowances have shown material upward and downward swings in the recent 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. Since the prices we obtain for power may not change at the same rate as the change in coal, emission allowances or natural gas costs, we may be unable to pass on the changes in costs to our customers.

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.

Risks Relating to State Restructuring

Our customers have recently begun to select alternative electric generation service providers, as allowed by Ohio legislation. *(Applies to AEP and CSPCo)*

Under current Ohio legislation, electric generation is sold in a competitive market in Ohio, and our native load customers in Ohio have the ability to switch to alternative suppliers for their electric generation service. Competitive power suppliers are targeting retail customers by offering alternative generation service. A growing number of CSPCo's commercial retail customers have switched to alternative generation providers while additional Ohio customers have provided notice of their intent to switch. In 2010, CSPCo lost about 3% of its total load due to customer switching. To date, OPCo's losses have not been significant. These evolving market conditions will continue to impact CSPCo's results of operations.

There is uncertainty as to our recovery of stranded costs resulting from industry restructuring in Texas. *(Applies to AEP.)*

Restructuring legislation in Texas required utilities with stranded costs to use market-based methods to value certain generating assets for determining stranded costs. We elected to use the sale of assets method to determine the market value of TCC's generation assets for stranded cost purposes. In general terms, the amount of stranded costs under this market valuation methodology is the amount by which the book value of generating assets, including regulatory assets and liabilities that were not securitized, exceeds the market value of the generation assets, as measured by the net proceeds from the sale of the assets. In May 2005, TCC filed its stranded cost quantification application with the PUCT seeking recovery of $2.4 billion of net stranded generation costs and other recoverable true-up items. A final order was issued in April 2006. In the final order, the PUCT determined TCC's net stranded generation costs and other recoverable true-up items to be approximately $1.475 billion. We have appealed the PUCT's final order seeking additional recovery consistent with the Texas Restructuring Legislation and related rules, other parties have appealed the PUCT's final order as unwarranted or too large. Management cannot predict the ultimate outcome of any future court appeals or any future remanded PUCT proceeding.

Collection of our revenues in Texas is concentrated in a limited number of REPs. *(Applies to AEP.)*

Our revenues from the distribution of electricity in the ERCOT area of Texas are collected from REPs that supply the electricity we distribute to their customers. Currently, we do business with approximately one hundred REPs. In 2010, TCC's largest customer accounted for 25% of its operating revenue and its second largest customer accounted for 13% of its operating revenue; TNC's largest customer (a non-utility affiliate) accounted for 29% of its operating revenues and its second largest customer accounted for 16% of its operating revenues. Adverse economic conditions, structural problems in the Texas market or financial difficulties of one or more REPs could impair the ability of these REPs to pay for our services or could cause them to delay such payments. We depend on these REPs for timely remittance of payments. Any delay or default in payment could adversely affect the timing and receipt of our cash flows and thereby have an adverse effect on our liquidity.

Parties with whom we have contracts may fail to perform their obligations, which could harm our results of operations. *(Applies to each registrant.)*

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. *(Applies to each registrant.)*

We depend on transmission facilities owned and operated by other unaffiliated 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 for electricity and gas, 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.

We do not fully hedge against price changes in commodities. *(Applies to each registrant.)*

We routinely enter into contracts to purchase and sell electricity, natural gas, coal and emission allowances as part of our power marketing and energy and emission allowances trading operations. 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.

We manage our exposure by establishing risk limits and entering into contracts to offset some of our positions (i.e., to hedge our exposure to demand, market effects of weather and other changes in commodity prices). However, we do not always hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position may be improved or diminished based upon our success in the market.

Financial derivatives reforms could increase the liquidity needs and costs of our commercial trading operations. *(Applies to each registrant.)*

In July 2010, federal legislation was enacted to reform financial markets that significantly alter how over-the-counter (OTC) derivatives are regulated. The law increased regulatory oversight of OTC energy derivatives, including (1) requiring standardized OTC derivatives to be traded on registered exchanges regulated by the Commodity Futures Trading Commission (CFTC), (2) imposing new and potentially higher capital and margin requirements and (3) authorizing the establishment of overall volume and position limits. The law gives the CFTC authority to exempt end users of energy commodities which could reduce, but not eliminate, the applicability of these measures to us and other end users. These requirements could cause our OTC transactions to be more costly and have an adverse effect on our liquidity 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.

2010 Annual Reports

American Electric Power Company, Inc. and Subsidiary Companies

Appalachian Power Company and Subsidiaries

Columbus Southern Power Company and Subsidiaries

Indiana Michigan Power Company and Subsidiaries

Ohio Power Company Consolidated

Public Service Company of Oklahoma

Southwestern Electric Power Company Consolidated

Audited Financial Statements and
Management's Financial Discussion and Analysis

AEP AMERICAN ELECTRIC POWER

AEP: America's Energy Partner®

Settlement with Bank of America

In February 2011, we reached a settlement with BOA and paid $425 million in full settlement of all claims against us. We also received title to 55 BCF of cushion gas in the Bammel storage facility as part of the settlement. The effect of the settlement had no impact on our financial statements for the year ended December 31, 2010. We do not expect the effect of the settlement to have a material impact on our 2011 consolidated net income.

Ohio Customer Choice

In our Ohio service territory, various competitive retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. As of December 31, 2010, approximately 5,000 Ohio retail customers (primarily CSPCo customers) have switched to alternative CRES providers. As a result, in comparison to 2009, we lost approximately $16 million of generation related gross margin in 2010 and currently forecast incremental lost margins of approximately $54 million for 2011. We anticipate recovery of a portion of this lost margin through off-system sales and our newly created CRES provider. Our CRES provider will target retail customers in Ohio, both within and outside of our retail service territory.

Termination of AEP Power Pool

Originally approved by the FERC in 1951 and subsequently amended in 1951, 1962, 1975 1979 (twice) and 1980, the Interconnection Agreement establishes the AEP Power Pool which permits the AEP East companies to pool their generation assets on a cost basis. In December 2010, each member gave notice to AEPSC and the other AEP Power Pool members of its decision to terminate the Interconnection Agreement effective January 1, 2014 or such other date approved by the FERC, subject to state regulatory input. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently. The decision to terminate is subject to management's ongoing evaluation. The AEP Power Pool members may revoke their notices of termination. If members of the current AEP Power Pool experience decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and are unable to recover the change in revenues and costs through rates, prices or additional sales, it could have an adverse impact on future net income and cash flows.

Transmission Agreement

The AEP East companies are parties to a Transmission Agreement defining how they share the costs associated with their relative ownership of transmission assets. This sharing was based upon each company's MLR until the FERC approved a new Transmission Agreement effective November 1, 2010. The new Transmission Agreement will be phased-in for retail rates over periods of up to four years, adds KGPCo and WPCo as parties to the agreement and changes the allocation method. Our recovery mechanism for transmission costs is through our base rates. State regulatory phase-in of the new agreement may limit our ability to fully recover our transmission costs.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $395 million. Management believes that I&M should recover a significant portion of repair and replacement costs through the turbine vendor's warranty, insurance and the regulatory process. I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011. If the ultimate costs of the incident are not covered by warranty, insurance or through the related regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 6.

2010 Compared to 2009

Reconciliation of Year Ended December 31, 2009 to Year Ended December 31, 2010
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Year Ended December 31, 2009	$	1,329
Changes in Gross Margin:		
Retail Margins		601
Off-system Sales		53
Transmission Revenues		15
Other Revenues		(257)
Total Change in Gross Margin		412
Total Expenses and Other:		
Other Operation and Maintenance		(351)
Depreciation and Amortization		(37)
Taxes Other Than Income Taxes		(60)
Interest and Investment Income		5
Carrying Costs Income		23
Allowance for Equity Funds Used During Construction		(5)
Interest Expense		(26)
Equity Earnings of Unconsolidated Subsidiaries		8
Total Expenses and Other		(443)
Income Tax Expense		(97)
Year Ended December 31, 2010	$	1,201

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- **Retail Margins** increased $601 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $138 million increase in the recovery of E&R costs in Virginia, costs related to the Transmission Rate Adjustment Clause in Virginia and construction financing costs in West Virginia.
    - A $49 million increase in the recovery of advanced metering costs in Texas.
    - A $43 million net rate increase for KPCo.
    - A $42 million net rate increase for SWEPCo.
    - A $39 million net rate increase for I&M.
    - A $37 million net rate increase for PSO.
    - A $14 million net rate increase in our other jurisdictions.
    - For the increases described above, $183 million of these increases relate to riders/trackers which have corresponding increases in other expense items.
  - A $229 million increase in weather-related usage primarily due to a 60% increase in cooling degree days in our eastern service territory and 7% and 15% increases in heating degree days in our eastern and western service territories, respectively.
  - A $78 million increase due to higher fuel and purchased power costs recorded in 2009 related to the Cook Plant Unit 1 (Unit 1) shutdown. This increase was offset by a corresponding decrease in Other Revenues as discussed below.

  These increases were partially offset by:
  - A $43 million decrease due to a refund provision for the 2009 Significantly Excessive Earnings Test (SEET).
  - A $38 million decrease due to the termination of an I&M unit power agreement.

AEPSC conducts power, gas, coal and emission allowance risk management activities on CSPCo's behalf. CSPCo shares in the revenues and expenses associated with these risk management activities, as described in the preceding paragraph, with the other AEP East companies, PSO and SWEPCo. Power and gas risk management activities are allocated based on the existing power pool agreement and the SIA. CSPCo shares in coal and emission allowance 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 gas, coal and emission allowances. The electricity, gas, coal and emission allowance 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.

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.

CSPCo is jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to purchase power and sale activity pursuant to the SIA.

Ohio Customer Choice

In CSPCo's service territory, various competitive retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. As of December 31, 2010, approximately 5,000 CSPCo retail customers have switched from CSPCo to alternative CRES providers. As a result, in comparison to 2009, CSPCo lost approximately $16 million of generation related gross margin in 2010. Management currently forecasts incremental lost margins of approximately $53 million for 2011. Management anticipates recovery of a portion of this lost margin through off-system sales.

Regulatory Activity

2009 – 2011 ESP

During 2009, the PUCO issued an order that modified and approved CSPCo's ESP which established rates through 2011. The order also limited annual rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011. The order provided a FAC for the three-year period of the ESP. Several notices of appeal are outstanding at the Supreme Court of Ohio relating to significant issues in the determination of the approved ESP rates. In January 2011, the PUCO issued an order that determined that relevant CSPCo 2009 earnings were significantly excessive. As a result, the PUCO ordered CSPCo to refund $43 million of its earnings to customers, which was recorded as a revenue provision on CSPCo's December 2010 books. See "Ohio Electric Security Plan Filings" section of Note 4.

Proposed January 2012 – May 2014 ESP

In January 2011, CSPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing for generation effective with the first billing cycle of January 2012 through the last billing cycle of May 2014. The SSO presents redesigned generation rates by customer class. Customer class rates individually vary, but on average, customers will experience net base generation increases of 1.4% in 2012 and 2.7% for the period January 2013 through May 2014. See "Ohio Electric Security Plan Filings" section of Note 4.

Litigation and Environmental Issues

In the ordinary course of business, CSPCo is involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, management cannot state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. Management assesses the probability of loss for each contingency and accrues a liability for cases which have a probable likelihood of loss if the loss can be estimated. For details on regulatory proceedings and pending litigation, see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect net income, financial condition and cash flows.

IEU Remand Ex. 7

THIS FILING IS

Item 1: [X] An Initial (Original) Submission OR [ ] Resubmission No. ___

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Ohio Power Company	End of 2009/Q4

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated electric public utility company, OPCo'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," OPCo records regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the passage of legislation requiring restructuring and a transition to customer choice and market-based rates, OPCo discontinued the application of "Regulated Operations" accounting treatment for the generation portion of its business.

Use of Estimates

The preparation of these financial statements 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, 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 on the Statement of Cash Flows include Cash, Working Fund and Temporary Cash Investments on the Comparative Balance Sheet with original maturities of three months or less.

Supplementary Information

	2009	2008
For the Year Ended December 31,	**(in thousands)**	
Cash Was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	$ 121,937	$ 115,330
Income Taxes (Net of Refunds)	(62,704)	100,430
Noncash Acquisitions Under Capital Leases	2,383	3,910
Noncash Acquisitions of Coal Land Rights	-	41,600
At December 31,		
Noncash Construction Expenditures Included in Accounts Payable	29,929	33,177
Revenue Refund Included in Accounts Payable	-	62,045

Special Deposits

Special Deposits include funds held by trustees primarily for margin deposits for risk management activities and environmental construction expenditures.

2. RATE MATTERS

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

Ohio Electric Security Plan Filings

The PUCO issued an order in March 2009 that modified and approved OPCo's ESP that established rates at the start of the April 2009 billing cycle. The ESP is in effect through 2011. The order also limits rate increases for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. Some rate components and increases are exempt from these limitations. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009.

The order provides a FAC for the three-year period of the ESP. The FAC increase will be phased in to avoid having the resultant rate increases exceed the ordered annual caps described above. The FAC increase is subject to quarterly true-ups, annual accounting audits and prudence reviews. The order allows OPCo to defer any unrecovered FAC costs resulting from the annual caps and to accrue associated carrying charges at OPCo's weighted average cost of capital. The deferred FAC regulatory asset balance at the end of the three-year ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018.

Discussed below are the outstanding uncertainties related to the ESP order:

The Ohio Consumers' Counsel filed a notice of appeal with the Supreme Court of Ohio raising several issues including the alleged retroactive rates, recovery of carrying charges on certain environmental investments, Provider of Last Resort (POLR) charges and the decision not to offset rates by off-system sales margins.

The Industrial Energy Users-Ohio group filed a notice of appeal with the Supreme Court of Ohio challenging other components of the ESP order including the POLR charge, the distribution riders for gridSMART[SM] and enhanced reliability, the PUCO's conclusion and supporting evaluation that the modified ESPs are more favorable than the expected results of a market rate offer, the unbundling of the fuel and non-fuel generation rate components, the scope and design of the fuel adjustment clause and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is still pending.

OPCo's cost for contributions to the retirement savings plans was $7.6 million and $7.2 million for the years ended December 31, 2009 and 2008, respectively.

UMWA Benefits

OPCo provides UMWA pension, health and welfare benefits for certain unionized mining employees, retirees and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by OPCo. Benefits are paid from OPCo's general assets. Contributions and benefits paid were not material in 2009 and 2008.

6. BUSINESS SEGMENTS

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

7. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

OPCo is exposed to certain market risks as a major power producer and marketer of wholesale electricity, 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 OPCo due to changes in the underlying market prices or rates. These risks are managed using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value based on open trading positions by utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of OPCo, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. 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 OPCo, enters into electricity, coal, natural gas, interest rate and to a lesser degree heating oil, gasoline, emission allowance and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of OPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with long-term commodity derivative positions. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. From time to time, AEPSC, on behalf of OPCo, 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. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." 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 following table represents the gross notional volume of outstanding derivative contracts as of December 31, 2009:

Primary Risk Exposure	Unit of Measure	Volume
Commodity:		(in thousands)
Power	MWHs	112,745
Coal	Tons	23,631
Natural Gas	MMBtus	10,539
Heating Oil and Gasoline	Gallons	838
Interest Rate	USD	$ 13,487

Cash Flow Hedging Strategies

AEPSC, on behalf of OPCo, enters into and designates as cash flow hedges certain derivative transactions for the purchase and sale of electricity, coal, heating oil and natural gas ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management closely 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. OPCo does not hedge all commodity price risk.

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

AEPSC, on behalf of OPCo, 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 OPCo, also enters into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated 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. OPCo does not hedge all interest rate exposure.

At times, OPCo is exposed to foreign currency exchange rate risks primarily because some fixed assets are purchased from foreign suppliers. In accordance with AEP's risk management policy, AEPSC, on behalf of OPCo, 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. OPCo does not hedge all foreign currency exposure.