Accounting for asset retirement obligations: an education & nonprofit perspective*

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PRICEWATERHOUSECOOPERS

Contents

Appendices

I. Introduction

Asbestos poses well-documented health risks.[1] It was commonly used in fireproofing, insulation, and building materials, including in the facilities of colleges, universities and other types of not-for-profit organizations. In the 1970s, the Environmental Protection Agency (EPA) and Occupational Safety and Health Administration (OSHA) began to regulate asbestos in the U.S. When asbestos-containing buildings are renovated, strict regulations now cover the handling and disposal of the hazardous substance.

The accounting for such costs is catching up with the regulations. According to a 2001 pronouncement of the Financial Accounting Standards Board (FASB), institutions should record a liability for legal obligations associated with the retirement of tangible, long-lived assets, such as asbestos-containing facilities, when the amount of the liability can be reasonably estimated. Some argued that it was not possible to reasonably estimate the amount of the future liability. In 2005, the FASB clarified its position, concluding that legal obligations, like the cost of disposing asbestos, must be recorded using the best information that is currently available.

Although the FASB pronouncements pertain to other types of long-lived asset retirement obligations, asbestos is likely to come to mind frequently.[2] Another example would be a not-for-profit organization that leases a facility for a specified period and must, at the end of the period, dispose of leasehold improvements.

Our objectives

We believe that it will take significant effort for institutions to comply with FASB's pronouncements concerning legal obligations associated with the retirement of long-lived assets. Such efforts must begin immediately as the latest pronouncement is effective for fiscal years ending after December 15, 2005, which is fiscal 2006 for most colleges, universities and other types of not-for-profit organizations.

We urge you to begin to understand the issues and prepare for this new challenge as soon as possible. The objective of this paper is to assist you in becoming more informed about the issues that we see colleges, universities and other not-for-profit organizations facing as they begin to implement these new FASB pronouncements.

II. SFAS 143 and FIN 47

SFAS 143

The FASB issued its Statement No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143), in June 2001. It requires entities, including colleges, universities and other types of not-for-profit institutions, to record liabilities for tangible, long-lived assets that must be retired or disposed of (i.e., "settled") in a specified way by law or contract. Such liabilities are known as Asset Retirement Obligations (AROs).

After the issuance of SFAS 143, diversity in practice developed over the timing of liability recognition when the settlement was conditional on a future event. Some entities recorded the ARO at the date of acquisition or construction with uncertainty factored into the calculation of the ARO's fair value. Other entities recognized the ARO only when it was probable that the asset would be retired as of a specified date using a specified method. Some entities recorded the ARO when the asset was actually retired.

FIN 47

Due to this diversity in application of SFAS 143, the FASB issued Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* (FIN 47), in March 2005. In paragraph 3 of FIN 47, a "conditional asset retirement obligation" (CARO) is defined as:

"A legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement."

FIN 47 clarifies that if the fair value of the liability can be reasonably estimated, the entity must recognize a liability for the CARO when it is incurred. The only "conditional" element is the uncertainty related to the timing or method of settlement, which is a measurement issue, not a recognition issue.

PwC observation: FIN 47 does not create a "new" standard for recognition of CAROs. It clarifies the Board's belief that SFAS 143 applies to CAROs.

FIN 47 provides additional guidance for assessing whether an institution has enough information to make a reasonable estimate of the fair value of an ARO. Per FIN 47, the liability is reasonably estimable if one of the following exists:

- It is evident that the fair value of the obligation is embodied in the acquisition price of the purchased asset, or
- An active market exists for the transfer of the obligation, or
- "Sufficient information" exists to apply an expected present value technique.

Regarding the latter, sufficient information exists if either:

- The settlement date and the settlement method have been specified by others by law, regulation or contract, or;
- The following can be reasonably estimated: (1) the settlement date or a range of dates, (2) the method or potential method of settlement, and (3) probabilities associated with the dates and methods of settlement.

FIN 47 concludes that uncertainty about the settlement date and method does not defer the recognition of an ARO because a legal obligation to perform the retirement activities still exists. The likelihood that "we can't estimate" a CARO will be acceptable to your external auditor is remote. The "opt out" provision will not be a common alternative.

FIN 47 is effective for most institutions in the current fiscal year (e.g., the year ending June 30, 2006). The initial recognition for the initial application of FIN 47 will be presented as a cumulative effect of a change in accounting principle in the statement of activities.

We summarize important terms from SFAS 143 and FIN 47 in Table 1.

Table 1

Important terms

The **Conditional Asset Retirement Obligation (CARO)** is a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. However, the obligation to perform the asset retirement activity is unconditional.
An **Asset Retirement Obligation (ARO)** is a legal obligation (i.e., a liability) for the cost of retiring (i.e., "settling") a tangible long-lived asset (e.g., a building containing asbestos) that results from the acquisition, construction, or development and (or) the normal operation of that long-lived asset.
The **Asset Retirement Cost (ARC)** is the capitalized amount that increases the carrying amount of the long-lived asset when a liability for an ARO is recognized. Note that the ARC is the "debit" to offset the "credit" when the ARO is recognized.
The **settlement date** is the estimated date or range of dates that the institution has to meet its legal obligation to dispose of the asbestos, for example.
The **settlement method** concerns how the institution might dispose of the asbestos. For example, will it hire a third party?

III. Implementation

Identifying and estimating potential AROs will require the skills of a multidisciplinary team. We recommend establishing a team that includes representatives from legal, accounting, operations (e.g., facilities and engineering), finance and budget. Major steps in the implementation process include those listed below.

1. Take an inventory.

The first step, and perhaps one of the most time-consuming steps, will be taking an inventory of long-lived assets that have retirement obligations.

2. Determine if there is sufficient information.

The team must determine if the institution has sufficient information to reasonably estimate the value of the ARO using, for most institutions, an expected present value technique. We suggest using the following decision tree.

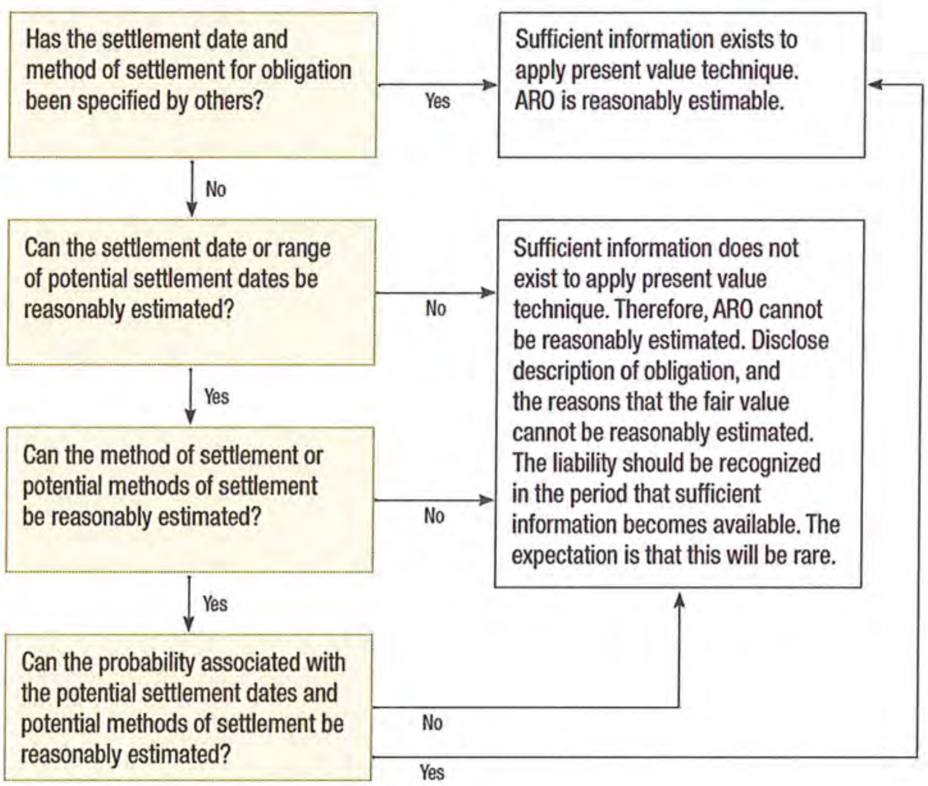
3. Measure the obligation.

An ARO is initially measured at fair value. An institution can use either an observable market price (i.e., current market price for the service required) or a reasonable estimate as a starting point for measurement. Most institutions will use the expected cash flow approach discussed in FASB Concepts Statement 7 (CON 7), *Using Cash Flow Information and Present Value in Accounting Measurements*. SFAS 143 (paragraph 8) states:

"... the expected cash flow approach will usually be the only appropriate technique for an asset retirement obligation."

The expected cash flow approach incorporates multiple cash flow scenarios to reflect a range of possible outcomes, discounted at a credit-adjusted risk-free rate.

Institutions can use past experience to help determine how the ARO would be settled. How has the institution retired long-lived obligations in the past? The answer to this question would probably provide management with a good starting point.



The inflation rate should reflect the increase that management is estimating for the type(s) of service(s) that will be required to remove the legal obligation. Again, for determining the institution's credit-adjusted risk-free rate, past experience, or even current experience, may be a useful guide. This rate may approximate the institution's borrowing rate for a similar amount over a similar period of time.

For a more detailed discussion of each of these elements, see the Q&A in Appendix A of this paper.

4. Develop appropriate policies and documentation.

Institutions will need to develop written policies to codify the accounting for FIN 47/SFAS 143 transactions. In addition, they will need to adequately document their assumptions as well as the estimates that support their financial statement accruals and disclosures. Keep in mind that the auditors will need to audit all significant judgments and estimates.

PwC observation: If an institution concludes that it cannot make a reasonable estimate of the obligation, SFAS 143 requires that it disclose that fact along with the reasons. In these situations, the institution should make sure to adequately document its analysis and the basis for its conclusion. Further, it should develop and implement procedures to periodically reevaluate its conclusion.

5. Develop financial reports and disclosures.

Financial reporting

At initial adoption, institutions should recognize the items in Table 2 in their statements of financial position and statements of activities.

Disclosures

Significant SFAS 143 disclosure requirements include a description of AROs, the fair value of the assets restricted for purposes of settling retirement obligations (if any), and a reconciliation of the beginning and ending carrying amount of the ARO. In addition, in the initial year of adoption, institutions are required to provide pro forma disclosure of the amount of the liability for AROs as if SFAS 143 had been applied for all periods presented. Also, institutions should consider the disclosures required by paragraphs 19(c), 19(d) and 21 of APB Opinion No. 20, *Accounting Changes*.

PwC observation: The transition provisions described above are not impacted by the issuance of SFAS Statement No. 154, *Accounting Changes and Error Corrections*.

Table 2

Recognition of ARO on statement of financial position and statement of activities

	Statement of financial position	Statement of activities
Initial adoption	■ Record ARO equal to the fair value of the legal obligation, adjust for cumulative accretion to date of adoption ■ Capitalize ARO by increasing the carrying value of the asset (the asset retirement cost or ARC), adjust for cumulative depreciation ■ Reverse amounts recognized previously ■ Recognize effects of regulatory treatment by recording or adjusting regulatory assets and liabilities	■ Record net impact as a cumulative effect of a change in accounting principle

IV. Conclusion

We believe that institutions should immediately begin identifying long-lived assets with AROs. The process will take time. For each ARO, institutions will need to determine the settlement date, the settlement method, and the settlement cost using current dollars. They will then need to inflate the cost to the settlement date and discount the future cost using a credit-adjusted risk-free rate and record the ARO. This is for the first year; annually thereafter, the work will need to be updated and adjusted.

The FASB's presumption in SFAS 143 is that, with the exception of land, assets do not last forever, and legal obligations to retire assets in a legally mandated manner must eventually be met. When there is asbestos in a building, for example, the institution will eventually have to replace the HVAC or the walls containing asbestos. The legal obligation to dispose of the asbestos in a certain way exists. It is a question of when (settlement date) the obligation will be incurred and how (method of settlement) the obligation will be fulfilled. The guidance in FIN 47 makes it unlikely that institutions will be able to defer recording liabilities for AROs.

Appendix A

Frequently asked questions

In this Appendix, we explore three categories of implementation issues. The first category is the non-industry-specific issues that entities must consider when implementing FIN 47/SFAS 143. The second category is the implementation issues that are unique to colleges, universities and other types of not-for-profit organizations. The third category is accounting issues that may arise in the years after implementation of this standard.

A. Non-industry-specific implementation issues

How should my organization begin implementing FIN 47/SFAS 143?

Management needs to look at this in two parts. First, does the organization have a legal obligation to take action as a result of owning (or operating) a particular asset. This is a "yes" or "no" question. If the answer is "no," there is no ARC or ARO that needs to be recorded. If the response is "yes," then move to step two.

We strongly recommend that institutions seek advice from counsel on the timing and structure of their legal obligations. See also the question on page 10 about how legislation might impact the CARO.

Once a legal obligation is established, the next step is to address measurement issues. Management needs to determine how and when to address the legal obligation. Then management needs to assign a probability factor to each option. (Note that the sum of the probabilities needs to equal 100%.) After this, apply the inflation rate and discount rate to determine the amount of the ARC and ARO.

Can I set FIN 47 aside and address it during the fiscal year-end close?

No. The impact of FIN 47 can be significant. Identifying a team that includes financial, physical plant, legal, and other officers and staff is essential, and might require start-up time. We highly recommend that efforts to assess FIN 47 be started as soon as possible and that the audit committee (or similar governing body) be kept abreast of the developments.

Can I take the position that I cannot estimate the ARO, and therefore nothing has to be recorded?

Rarely. Example 3 of FIN 47 includes an example of a situation where an organization does not have sufficient information to estimate an ARO. In most cases, we believe sufficient information will be available to estimate the fair value of the ARO. Although an organization may have no plans or expectation of plans to undertake a major renovation that would require removal of the asbestos, organizations should consider the useful life of the long-lived asset, technology changes, operational changes, the entity's past practice or industry practice and other factors that may impact the timing of a major renovation.

If management is unable to arrive at the necessary estimates to perform the calculation, FIN 47 requires that management disclose the reasons why in the footnotes. For example, an organization might disclose what actions management took to obtain settlement cost estimates or to identify legal obligations and why reasonable settlement dates could not be determined. It would be expected that determining discount rates and inflation rates would not be the cause for not recording an ARO.

What if the settlement date is not known?

The exact settlement date will probably not be known. FIN 47 concludes that if a range of possible settlement dates exists, the ARO can be estimated. Organizations will need to work with the range of possible dates, make assumptions and calculate probabilities, which in sum will equal 100%, to establish a liability for the ARO.

PwC observation: The FASB noted that uncertainty regarding timing and method of settlement are factors relevant to the *measurement* of the liability, not the *recognition* of the liability.

Does the timing of retirement have to coincide with the asset's useful life?

No. The asset's depreciable life provides one data point about the potential timing of its retirement. Also, management might need to make a distinction between the physical lives of 100% of the asset's components and the date the retirement obligation will be settled.

PwC observation: Management should ensure that differences in depreciable lives, planned asset retirement dates, and license expiration or extension dates are supportable. In addition, the asset retirement cost capitalized as part of the asset should be depreciated over the depreciable life of the asset, not the planned asset retirement date.

How would I determine future cash flows?

Organizations can use past experience to help determine how the ARO would be settled and they will need to make assumptions about the expected amount of future cash flows (i.e., costs), per SFAS 143, paragraph A20. A third party, for example, would incur overhead, equipment and other charges when handling and disposing of asbestos. An organization would need to consider costs under a variety of scenarios as well as the relative probability of each scenario to determine future cash flows.

How would I determine the credit-adjusted risk-free rate?

As discussed in SFAS 143, paragraph 9, when an organization uses the expected cash flow approach, the estimated cash flows should be discounted using a credit-adjusted risk-free rate. The risk-free interest rate is the interest rate on monetary assets that are essentially risk free (in the U.S., zero coupon U.S. treasury instruments) and that have maturity dates that coincide with the expected timing of the estimated cash flows required to satisfy the ARO. If there is an equal chance that retirement will occur in 2020 or 2030, for example, the organization would apply one rate to the 2020 retirement and another to the 2030 retirement, based on the estimated forward yield curves at the date the obligation is calculated.

CON 7 requires an adjustment to the risk-free interest rate to reflect the entity's credit standing. The credit adjustment should be determined based on the credit standing of the specific organization with the legal liability for asset retirement.

Consistency in the choice of discount rates is important. If different discount rates are being used for similar time periods, management should be prepared to explain why.

What should I use as my inflation rate?

The inflation rate should reflect the increase that management is estimating for the type(s) of service(s) it would be required to obtain in order to fulfil its legal obligation regarding the settlement. This inflation rate may be different than a general inflation factor for the organization's industry or geographic location. Management should ensure that its inflation estimates are comparable to those used in other models, such as the organization's long-term budgeting models.

Should I consider component parts?

Yes. SFAS 143 (paragraph A14) states:

"An asset retirement obligation may exist for component parts of a larger system. In some circumstances, the retirement of the component parts may be required before the retirement of the larger system to which the component parts belong."

If the recognition criteria have been met, SFAS 143 requires organizations to identify the costs of retirement that can be measured and recorded as part of an organization's AROs. Note that buildings with component parts may be an advantage. It might be easier to segregate the disposal costs.

In SFAS 143, the FASB provides an example of an ARO with component parts—a kiln lined with a special type of brick. The bricks become contaminated with hazardous chemicals during use and they wear out after five years. When the bricks are removed, they must be disposed of at a hazardous waste site. The disposal of the bricks would be covered by SFAS 143, but the cost of the replacement bricks and their installation would not be part of the ARO.

Another example would be asbestos that is wrapped around HVAC pipes. An organization would not necessarily have to tear down an entire building to remove its obligation; rather it would need to remove/replace the HVAC pipes that are wrapped in asbestos.

What impact might FIN 47 have on other financial metrics?

Management should evaluate all instances in which financial results or performance metrics are utilized, such as bond covenants, Title IV ratios, benchmarking, third-party rankings and credit ratings. Management should meet with lenders and other affected parties as soon as possible to discuss the impact of FIN 47 and any modifications to existing agreements that may be necessary.

Is there a practice aid that I can use as I begin to assess FIN 47's impact on my organization?

The checklist included in Appendix C of this paper may be helpful in assisting management to begin to assess FIN 47's impact.

B. Q&A for industry-specific implementation issues

What is the impact on the operating results for the year of adoption?

In the year of adoption, the cumulative effect of the AROs would be reported on the institution's statement of activities as a cumulative change of an accounting principle. This impact would be reflected in a separate line directly before the total change in net assets as part of unrestricted net assets.

What is the impact on fund accounting?

For institutions that use fund accounting for internal reporting purposes, the ARC and ARO would be recorded in "Invested in Plant Fund," as would the annual ARC depreciation and ARO accretion.

What is the impact on functional expenses?

In a manner similar to that used to allocate interest expense across functional expense categories, the ARC depreciation and ARO accretion would be reported in a functional expense category. Management will need to review the purpose of the asset for which the ARC and ARO are related. If the annual depreciation/accretion expenses are associated with a piece of research equipment, then those depreciation/accretion expenses should be classified as "research." If the depreciation/accretion expenses are related to a HVAC system in a multi-purpose building, then the depreciation/accretion expenses should probably be allocated among functional expense categories in a manner similar to those used for the annual interest expense on that specific building.

What impact might FIN 47/SFAS 143 have on sponsored research programs?

The impact of FIN 47/SFAS 143 should be discussed with your federal oversight agency as soon as it is reasonably estimated. Your institution may want to negotiate an agreement with the agency to recover the cumulative impact to net assets. The federal agency may not allow a reimbursement all in one fiscal year, but may allow the amount to be recovered over a specified period.

The annual impact of FIN 47/SFAS 143 will be allocated to the affected facilities. Since some of the facilities (and equipment) might be for research, the institution may be able to negotiate an increase in its federal indirect cost rate prior to the expiration of the current agreement. It will be important for institutions to demonstrate that a rigorous analysis was performed to identify the obligations as well as to determine the cost estimates and the allocation methodology.

Even prior to considering the impact on the federal indirect cost recovery rate, institutions that are required to submit a DS-2 should begin to assess the impact of FIN 47/SFAS 143. Again, communication with the applicable federal agency that approves the DS-2 is important in order to inform them that such a change will be submitted.

Does the Clean Air Act or any other legislation impact the CARO?

Legislation (including the three acts described below that set limits on pollutants, hazardous substances, and toxic chemicals) might impact the CARO. Institutions should consult with legal counsel about the timing of legislation and how it might affect the capitalization of the CARO.

1) Clean Air Act

The Clean Air Act, codified as 42 U.S.C. 7401 et seq., is the comprehensive federal law that regulates air emissions from area, stationary, and mobile sources. It sets limits on how much of a pollutant (e.g., asbestos fibers) can be in the air. The U.S. Congress passed the Clean Air Act in 1963, the Clean Air Act Amendment in 1966, the Clean Air Act Extension in 1970, and Clean Air Act Amendments in 1977 and 1990.

2) Pollution Prevention Act (PPA)

The Pollution Prevention Act of 1990, codified as 42 U.S.C. 13101-13109, focuses on reducing the amount of hazardous substances, pollutants or contaminants being released into the environment that may harm the environment or public health.

3) Toxic Substances Control Act (TSCA)

The Toxic Substances Control Act (TSCA, 15 U.S.C. 2601 et seq.) authorizes EPA to screen existing and new chemicals used in manufacturing and commerce to identify potentially dangerous products or uses that should be subject to federal control. As enacted, TSCA also included a provision requiring EPA to take specific measures to control the risks from polychlorinated biphenyls (PCBs) [Section 6(e)]. Subsequently, three titles have been added to address concerns about other specific toxic substances—asbestos in 1986, radon in 1988, and lead in 1992.

C. Subsequent accounting

What if an ARO is identified subsequent to the year of adopting FIN 47?

Management has a responsibility to make a concerted effort to identify the complete population of AROs in the year of adoption. Subsequent "discoveries" of unidentified AROs could call into question the adequacy of management's initial attempt to address these requirements, as well as raise questions as to what other unidentified AROs still exist.

If an ARO is identified subsequent to initial adoption of FIN 47, then management and their auditors need to assess for materiality. If the subsequently discovered ARO is material and should have been recorded in a prior period, then management may be required to restate previously issued financial statements.

This is why it is imperative that a multi-discipline team be assembled in order to identify potential AROs. The team should be comprised of members from finance, physical plant, research, legal, purchasing, technicians, etc. It is also recommended that the team perform an actual walk-through of the facilities in order to ensure the completeness of the list of potential AROs.

What are the changes in the ARO due to the passage of time?

Because the ARO is initially recorded at fair value (i.e., it is discounted from the expected settlement date), SFAS 143 requires that organizations recognize changes in the ARO that result from the passage of time.

Organizations should determine the interest component resulting from the passage of time by applying the interest method of allocation. In applying this method, the organization should use the credit-adjusted risk-free rate(s) applied when the liability (or a portion thereof) was initially measured. Changes resulting from the passage of time should be recognized as an increase in the carrying amount of the liability, with a corresponding period cost classified in the operating section of the income statement. The amount should be separately disclosed to the extent it is material. SFAS 143 allows the use of any descriptor for this item "so long as it conveys the underlying nature of the expense." (Note: Accretion amounts recognized in accordance with SFAS 143 cannot be included as interest costs for purposes of applying SFAS Statement No. 34, *Capitalization of Interest Cost*.)

A change that is due to the passage of time should be incorporated prior to any revisions that are made to the ARO as a result of changes in either the timing or amount of estimated cash flows.

Table 3 below summarizes the financial statement impact of changes due to the passage of time.

Based on current available information, I need to change my ARO estimates. How should I handle this?

As indicated above, management is required to review their estimates on an annual basis (but no changes are to be made to the inflation rate or discount rate). A new method to address the legal obligation may become available or more current cost estimates may be obtained, or there may be changes in the expected timing of settlement. Management will need to recalculate the ARO based on any changes in the underlying estimates and record the changes to the ARO in the current year. If the asset is fully depreciated, subsequent changes to the ARO will be recorded directly in the current year statement of activities. If the asset is not fully depreciated, any subsequent changes to the ARO will also result in an increase or decrease in carrying amount of the related long-lived asset.

What if there are changes in the amount of undiscounted cash flows?

SFAS 143 requires that organizations recognize changes in the ARO that result from revisions made to the amount of future cash flows. Such changes should be recognized in the period of change as an increase or decrease in: a) the carrying amount of the ARO and b) the related asset retirement costs capitalized as part of the carrying amount of the related long-lived asset. Except for fully-depreciated assets, the adjustment initially will not have any income statement impact in the period of change. However, it will impact the future recognition of depreciation and accretion expense.

The change in obligation amount should be measured using the following credit-adjusted risk-free interest rate:

- Increases in the ARO: Consider upward revisions of future cash flows as a new obligation, which should be initially measured using the current credit-adjusted risk-free interest rate.
- Decreases in the ARO: Consider downward revisions in cash flow estimates as an adjustment to the existing ARO. Measure the adjustment at the historical interest rate used to measure the initial ARO to which the downward revision relates.

Organizations will have to document and track the rates used to measure and record the initial ARO and any incremental adjustments.

Table 3

Financial statement impact of ARO over time

	Statement of financial position	Statement of activities
Passage of time	▪ ARO: increase ARO by amount of periodic accretion expense ▪ ARC: allocate to expense through a systematic and rational method over useful life ▪ Recognize effects of regulatory treatment	▪ Record periodic accretion expense as a component of operating expense ▪ Record ARC depreciation ▪ Recognize effects of regulatory treatment

What if there are revisions to the timing of future cash flows?

SFAS 143 also requires that organizations recognize changes in the ARO that result from revisions made to the timing of future cash flows. Under the expected cash flow approach, the credit-adjusted risk-free rate for each scenario will depend on the expected timing of the cash outflows. That is, if an organization has scenarios under which the retirement could occur in 2010, 2025 and 2030, each scenario would be discounted at a different credit-adjusted risk-free interest rate based on the forward yield curves at the date the obligation is calculated. The applicable discount rate is determined based on the year of expected settlement.

How should I consider AROs and ARCs in their asset impairment tests?

Management must test for impairment and recoverability in accordance with FASB Statement No. 144 (SFAS 144), *Accounting for the Impairment of Disposal of Long-Lived Assets*. SFAS 143 (paragraph 12) states:

"In applying the provisions of Statement 144, the carrying amount of the asset being tested for impairment shall include amounts of capitalized asset retirement costs. Estimated future cash flows related to the liability for an asset retirement obligation that has been recognized in the financial statements should be excluded from (a) the undiscounted cash flows used to test the asset for recoverability and (b) the discounted cash flows used to measure the asset's fair value."

If the organization was not previously including the cost of retirement or disposal in the impairment test, the increase in the asset carrying value could result in an impairment that must be recorded at the time of adoption of SFAS 143/FIN 47. Subsequent increases to the asset retirement cost, if significant, should also be considered for potential impairment.

I've completed the settlement of the ARO, now what?

Once the legal obligation is eliminated, then the corresponding ARC (net amount) and ARO must be removed from the organization's financial records. As a result of the removal, the organization may need to recognize a gain or loss on settlement because of the utilization of internal resources (as opposed to the third-party estimates used in the cash flow analysis).

Appendix B

Examples

Fully depreciated assets

Let's consider the case of a college that has determined that it has six buildings with asbestos in the ceilings. Two of the buildings are used for teaching and the other four are dormitories. The two classroom buildings were constructed in 1970 and the dormitories were constructed in 1975. Although the buildings' depreciable lives are 30 years, the original ceilings are still in place. The college's master plan (as well as its shorter-term facilities annual plan) specifies that the ceilings will be replaced within the next 10 years at an estimated disposal cost of $1 million or $2 million, based on third-party estimates and depending on how the replacement will be performed. The institutions' credit-adjusted risk-free rate is 5% and inflation is assumed to be 2%.

The ARO calculation requires two schedules, one for the classrooms (see below) and another for the dormitories (see next page). We are assuming that all other factors are identical within these two groups.

#1 Classrooms

The following entries would have been made in 1975 to record the ARO based on the above scenario:

Dr. Asset retirement cost	$ 340,270 (i - from below)
Cr. ARO	$ 340,270

Since the ceilings are fully depreciated by 2005, there is no entry to record the asset retirement cost (as that would be fully depreciated by 2005 as well). To record the liability at June 30, 2005:

Initial ARO in 1975	$ 340,270 (i - from below)
Accretion in 1976 at 5% (credit-adjusted risk free rate)	$ 17,014 ($340,270 x 0.05)†
ARO in 1976	$ 357,284††
ARO at June 30, 2005 (after 30 years)	$1,470,630††

† Note that the amount is not a fixed amount each year as the interest method is used.

†† In 1976, multiply the $357,284 by 5% (to get $17,864). Add the two together ($357,284 + $17,864 = $375,148). In 1977, multiply the $375,148 by 5% (to get $18,757). Add the two together ($375,148 + $18,757 = $393,906). Continue this process until the year ended June 30, 2006 when the result would be $1,470,630. A similar process would be used in the examples on the following pages.

#1: Classroom buildings

Scenarios	Replacement date (A)	Settlement cost (B)	Probability	Future value (C)	Discounted cost (D)	Probability-weighted ARO (E)
Scenario 1	2011	$ 1,000,000	25%	$1,126,162	$194,440	$ 48,610
Scenario 2	2011	$ 2,000,000	75%	$2,252,325	$388,881	$291,660
						$340,270 (i - to above)

(A) The **replacement date** is based on management's "best estimate" for removal. In our example, we estimated the date based on the institution's master capital plan.

(B) The **settlement cost** ($1 million and $2 million) is stated in current (2005) dollars. We are assuming that a cost study was conducted on one building and that the conditions are the same for the second building.

(C) The **future value** is the settlement cost adjusted for 2% inflation from 2005 until the replacement date.

(D) This is the **discounted cost** of the future value, discounted back to when the legal obligation was created. For this example, we are assuming legislation became effective in 1975. Therefore, the discount is calculated back to 1975. (Institutions should seek legal advice on the timing of their obligations.)

(E) The **probability-weighted ARO** is the discounted cost weighted for the probability of each scenario.

#2: Dormitories

Scenarios	Replacement date (F)	Settlement cost (G)	Probability	Future value (H)	Discounted cost (I)	Probability-weighted ARO (J)
Scenario 1	2010	$ 1,000,000	10%	$1,104,081	$200,189	$ 20,016
Scenario 2	2010	$ 2,000,000	50%	$2,208,162	$400,318	$200,159
Scenario 3	2015	$ 1,000,000	10%	$1,218,994	$173,153	$ 17,315
Scenario 4	2015	$ 2,000,000	30%	$2,437,989	$346,306	$103,892
						$341,382 (ii -to below)

(F) The **replacement date** is based on the institution's master plan for replacement of the ceilings. In 2015, the institution plans to renovate the entire group of dormitory buildings.

(G) The **settlement cost** ($1 million and $2 million) is stated in current (2005) dollars. We are assuming that a cost study was conducted on one building and that the conditions are the same for the three other buildings.

(H) The **future value** is the settlement cost adjusted for 2% inflation from 2005 until the replacement date.

(I) This is the **discounted cost** of the future value, discounted back to the date of construction. We are assuming that the date of construction and the date when the legal obligation began are the same.

(J) The **probability-weighted ARO** is the discounted cost weighted for the probability of each scenario.

#1 Classrooms, continued

For the year ended on June 30, 2006, the cumulative catch-up adjustment would be as follows:

Dr. Cumulative change in accounting principle	$1,470,630
Dr. Current interest expense	$ 73,531 ($1,470,630 x 0.05)
Cr. ARO	$1,544,161

Each year, the accretion at 5% would continue to be recorded until the settlement date. The calculation would be updated for changes in settlement date or cost of settlement (with no change to the credit-adjusted risk-free rate or inflation for the initial ARO, once they are established in the initial calculation). These changes would be recognized as normal period costs through the statement of activities.

#2: Dormitories

The following entries would have been made in 1975 to record the ARO:

Dr. Asset retirement cost	$ 341,382 (ii - from above)
Cr. ARO	$ 341,382

Since the ceilings are fully depreciated by 2005, there is no entry to record the asset retirement cost (as that would be fully depreciated by 2005 as well).

#2: Dormitories (continued)

To record the liability at June 30, 2005:

Initial ARO in 1970	$ 341,382
Accretion at 5% (credit-adjusted risk-free rate)	$ 17,069 ($341,382 x 0.05)
ARO at June 30, 2005 (after 35 years)	$1,475,434

For the fiscal year ended June 30, 2006, the cumulative catch-up adjustment and current year expense would be as follows:

Dr. Cumulative change in accounting principle	$1,475,434
Dr. Current year expense	$ 73,772 ($1,470,630 x 0.05)
Cr. ARO	$1,549,206

Similar to the classroom example, the accretion at 5% would continue to be recorded until the settlement date and the calculation would be updated for changes in settlement date or cost of settlement (there would be no change to credit-adjusted risk-free rate or inflation, once they are established in the initial calculation). These changes would be recognized as normal period costs through the statement of activities.

#3: Classroom buildings

Scenarios	Replacement date (K)	Settlement cost (L)	Probability	Future value (M)	Discounted cost (N)	Probability-weighted ARO (O)
Scenario 1	2011	$ 1,000,000	25%	$1,126,162	$404.227	$101,057
Scenario 2	2011	$ 2,000,000	75%	$2,252,325	$808,455	$606,341
						$707,398 (iii - to below)

(K) The **replacement date** is based on management's "best estimate" for removal. In our example, we estimated the date based on the institution's master capital plan.

(L) The **settlement cost** ($1 million and $2 million) is stated in current (2005) dollars. We are assuming that a cost study was conducted on one building and that the conditions are the same for the second building; therefore, the settlement cost is the same.

(M) The **future value** is the settlement cost adjusted for 2% inflation from 2005 until the replacement date.

(N) This is the **discounted cost** of the future value, discounted back to the date of construction. We are assuming that the date of construction and the date when the legal obligation began are the same.

(O) The **probability-weighted ARO** is the discounted cost weighted for the probability of each scenario.

#3: Classroom buildings (assets not fully depreciated)

For this example, assume the same facts as above, but the classroom buildings were acquired in 1990, have a remaining useful life of 20 years, and are not yet fully depreciated.

The following entries would have been made in 1990 to record the ARO:

Dr. Asset retirement cost	$ 707,398 (iii - from above)
Cr. ARO	$ 707,398

Since the ceilings are not fully depreciated by 2005, there is an entry to record the accumulated depreciation on the asset through June 30, 2005 and the 2006 depreciation expense:

Dr. Cumulative change in accounting principle	$ 530,549
Dr. Current year depreciation	$ 35,370 ($707,398 x 0.05)
Cr. Accumulated Depreciation	$ 565,919

To calculate the ARO balance in 2005:

Initial ARO in 1990	$ 707,398
Accretion in 1991 at 5% (credit-adjusted risk free rate)	$ 35,370 ($707,398 x 0.05)
ARO at June 30, 2005 (after 15 years)	$1,470,630
Accretion in 2006	$ 73,531 ($1,470,630 x 0.05)
ARO at June 30, 2006	$1,544,161

At June 30, 2005, the cumulative catch-up adjustment would be as follows:

Dr. Cumulative change in accounting principle	$ 763,232†††
Cr. ARO	$ 763,232†††

The net impact of the two entries in fiscal year 2006 is:

Dr. Asset retirement cost	$ 707,398 (iii - from above)
Dr. Current year depreciation expense	$ 35,370 ($707,398 x 0.05)
Dr. Cumulative change in accounting principle	$1,293,781
Dr. Current ARO accretion	$ 73,531 ($1,470,630 x 0.05)
Cr. Accumulated depreciation	$ 565,919
Cr. ARO	$1,544,161

As in the above examples, each year, the accretion at 5% would continue to be recorded until the settlement date. The calculation would be updated for changes in settlement date or cost of settlement (with no change to the credit-adjusted risk-free rate or inflation for the initial ARO, once they are established in the initial calculation). These changes would be recognized as normal period costs through the statement of activities.

Interested readers can find other examples in Appendix C and D of SFAS 143.

††† $1,470,630 - $707,398

Appendix C

Implementation checklist

1. Develop a policy to consider asset retirement obligations during property acquisition, when purchasing certain fixed assets or when entering into long-term agreements. The policy should include a provision to depreciate the Asset Retirement Cost (ARC), to accrete interest on the Asset Retirement Obligation (ARO), and to evaluate the retirement obligation based on new facts and circumstances that may cause a change to the original ARO. Additionally, the policy should prescribe financial statement reporting and disclosure, how the inflation factor will be derived and how the institution will determine its credit-adjusted risk-free rate.

2. Assess existing AROs for the current fiscal year. NOTE: the requirement for conditional asset retirement obligations is for fiscal years ending after December 15, 2005. Consider what assets may be affected by taking the following actions:

   a) Obtain a list of property, plant and equipment.

   b) Inquire with facilities management regarding possible asset requirement obligations that may be relevant for buildings and property.

   c) Inquire with program officers, equipment technicians or other persons knowledgeable about specialized equipment or assets that may trigger possible AROs.

   d) Obtain lease and other purchase agreements and review for possible AROs.

   e) Inquire with counsel or other personnel who are familiar with federal, state or local laws that may trigger possible AROs.

3. For each possible ARO, identify the legal obligation to perform an asset retirement activity. Quantify the obligation and the related asset by taking the following actions:

   a) Estimate the cost or cost scenarios for the AROs and substantiate your estimates with supportable assumptions. Use techniques similar to cash flow modelling.

      i. Labor costs based on prevailing wages.

      ii. Overhead charges for labor based on current applicable rates.

      iii. Estimated costs to assume risk or surcharges for hazardous materials (i.e., "hazmat").

   b) Estimate the probability of the different cost scenarios.

   c) Estimate the timeliness and related probability of satisfying the ARO.

   d) Apply inflation adjustment based on estimated settlement.

   e) Apply present value based on credit-adjusted risk-free rate of return.

4. For the first year-end after December 15, 2005, evaluate and recognize the applicable cumulative depreciation for the ARC and the cumulative interest accretion of the ARO.

5. Because this is recognized as a change in accounting principle, compute the change on a pro forma basis and disclose the adjustment in the footnotes for the beginning of the earliest year presented and at the end of all years presented as if FIN 47 had been applied during all periods affected. NOTE: Most not-for-profit organizations present single year or comparative financial information only. As applicable, assess effect on bond covenants and other financial statement measures.

6. For subsequent years, depreciate the ARC and continue to accrete interest on the ARO, as well as re-evaluate the estimates used in the calculation for appropriateness.

7. Prepare a disclosure template for financial reporting.

About the authors

John A. Mattie is PricewaterhouseCoopers' National Education & Nonprofit Practice Leader. He has over 25 years of diversified audit and consulting experience with particular expertise serving public and private research universities as well as independent schools and other types of not-for-profit organizations.

Christina Dutch is a senior audit manager at PricewaterhouseCoopers. For the past 18 months, she has been serving in PwC's National Risk & Quality (R&Q) as one of the technical consultants on FIN 47 as well as on other technical matters related to not-for-profit organizations.

Claire Esten is a senior audit manager in the Boston office of PricewaterhouseCoopers. She serves colleges, universities, independent schools, and other types of not-for-profit organizations in the Northeast region.

Lee Ann Leahy is a PricewaterhouseCoopers' audit partner with more than 20 years of experience serving education, academic medical centers, and other types of not-for-profit organizations. Lee has served in our National office as a consultant on not-for-profit industry issues, including financial reporting standards for not-for-profit entities.

Sean Riley is a PricewaterhouseCoopers' audit partner. He has been a frequent presenter on accounting and financial reporting issues, including FIN 47, at various higher education forums. He serves on the audits of colleges, universities, independent schools, and other not-for-profit organizations in the Northeast region.

Rick Wentzel is a PricewaterhouseCoopers' audit partner who is based in our Los Angeles office. He specializes in serving colleges, universities and other not-for-profit organizations on the west coast. Rick was formerly a controller at a college in the Los Angeles area.

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Endnotes

1 A helpful website for asbestos-related information is: http://www.epa.gov/region4/air/asbestos/inform.htm

2 Other examples would include research universities that have laboratories and instruments with mercury, lead, radioactive materials or chemicals that might be subject to unique disposal regulations. Underground storage tanks for fuel or kilns also might be examples of asset retirement obligations that are within the scope of the FASB's pronouncement.

www.pwc.com/education

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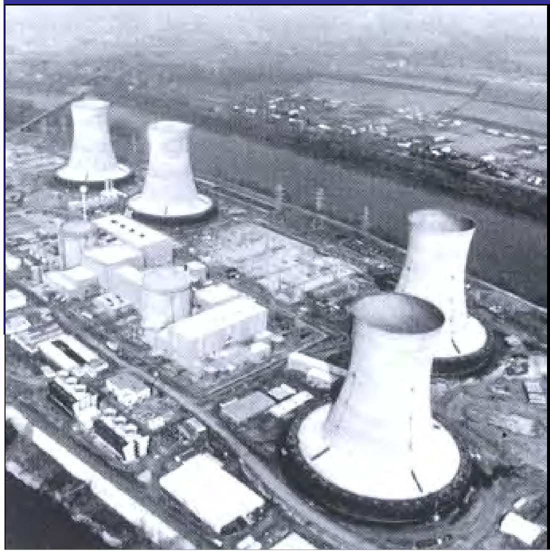
EDISON ELECTRIC INSTITUTE

American Gas Association

Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations

Asset Retirement Obligations Implementation Issues



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Lisa Perkett	Xcel Energy
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Paul Stetz	PSEG Energy Technologies
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Table of Contents

Statement of Financial Accounting Standards No. 143 Accounting For Asset Retirement Obligations

Overview[1]

In June 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations" (ARO's). SFAS No. 143 changes the way companies recognize and measure legal retirement obligations that result from the acquisition, construction and normal operation of tangible long-lived assets. In general, companies will be required to recognize much sooner any legal liability associated with the future retirement of tangible long-lived assets.

SFAS No. 143 is effective for fiscal years beginning after June 15, 2002 (January 1, 2003 for calendar year companies). Asset retirement obligations must be recognized as a liability and measured at fair value. The cost associated with the recognition of the asset retirement obligation is capitalized as part of the related asset's book cost and is depreciated over the expected life of the asset.

The asset retirement obligation is initially recorded at fair value, so the increase in that liability causes accretion expense (similar to interest) to be recognized each period as an operating expense in the income statement.

SFAS No. 143 does not grandfather any current accounting for existing obligations. Companies will convert to the new standard and recognize the cumulative effect of initially applying the statement as a change in accounting principle. The amount to be reported as a cumulative effect adjustment in the statement of operations is the difference between the amounts, if any, recognized in the statement of financial position prior to the application of SFAS No. 143 and the net amount that is recognized in the financial statements by applying the new Standard. Any asset retirement obligations that are currently reported as part of accumulated depreciation will be reversed as part of the cumulative effect adjustment.

Scope

The scope of SFAS No. 143 is set forth in paragraph 2 of the Statement: "This Statement applies to **legal obligations** associated with the retirement of a tangible

[1] The methods, processes, and procedures contained in this paper are intended to illustrate and provide examples for one or more analytical models by which certain Asset Retirement Obligations (ARO's) could be evaluated. This material is intended neither to exclude the validity of other models, nor to be an exhaustive and comprehensive presentation of all valid models. The models described in this paper may not be applicable to particular situations and are not necessarily recommended for the reader's specific application. It is the conclusion of the authors that each entity assessing ARO's should consult with its auditor, accountants, and legal counsel.

long-lived asset" (emphasis added). The obligations included within the scope of the standard are those associated with the retirement of a long-lived asset that result from the acquisition, construction, or the normal operation of a long-lived tangible asset. An ARO liability should be recognized if it meets the definition of a liability in FASB Concepts Statement No. 6, "Elements of Financial Statements." In assessing whether an ARO meets this definition, an entity should determine if:

a) It has a present duty or responsibility to one or more other entities that entails settlement by probable future transfer or use of assets,

b) It has little or no discretion to avoid a future transfer of use of assets, and

c) An obligating event has already happened.

What does this mean and how does a company determine if a long-lived asset is within this scope definition? Only assets that are defined as tangible and long-lived are included. There has been much discussion concerning what constitutes a tangible long-lived asset. While there is no clear definition given, examples of tangible long-lived assets include items such as generation plants, mines, gas mains and compressor stations, substations, transformers, buildings, capacitors, lines, poles, streetlights and fee property. Examples of assets that are not tangible long-lived assets include software, organization costs, and goodwill. A company must then determine if any legal obligations exist that are associated with the retirement of these long-lived assets. Retirement is defined as other-than-temporary removal of a long-lived asset from service. It includes sale, abandonment, recycling, or disposal in some other manner. However, it does not include the temporary idling of a long-lived asset.

Identifying ARO's and measuring the liability is the most critical part in the adoption of SFAS No. 143. It is recommended that utilities form working teams and include representatives from legal, accounting, financial, operations and other business units as deemed necessary. These teams will need to define very specifically what the scope of SFAS No. 143 is for their company and how the review of what is within the scope will take place. This entire process should be well documented.

Basically the determination of whether assets are within the scope of SFAS No. 143 is a review of legal obligations past and present that relate to the purchase, construction, development, or normal operation of the asset. Utilities have substantial tangible long-lived assets, many of which were constructed over several decades. As a result, a significant amount of work may be required to identify the legal obligations associated with utility assets. Also an obligation may result from only a portion of an asset (e.g., disposal of PCBs from a transformer) and only that portion must be recognized under the Standard. For purposes of SFAS No. 143, a legally enforceable obligation can result from:

a) A government action, such as law, statute, or ordinance,

b) An agreement between entities, such as a written or oral contract,

c) Conduct, which would obligate the promisor to perform under the doctrine of promissory estoppel.

To identify ARO's, the legal department may perform a review of codes, statues, regulations, ordinances and typical obligating documents including contracts, permits, certificates of need, etc. It is important to establish ground rules to prevent the review from becoming impossible in size. Start with a definition of tangible long-lived assets and a list of those assets that meet the definition. It is important to give this definition to the legal team and any area assisting on this project because the areas outside of accounting may not be cognizant of useful lives. For areas where there is a large magnitude of similar documents, use of a sampling technique may be employed. However, it should be noted that if the result of the sampling does not produce evidence of a legal obligation, one might want to include an ARO disclosure if there could be an obligation, albeit remote, in the contracts not sampled. An example of such a document is the easement associated with distribution property.

By assessing plant assets and reviewing documents including contracts, licenses, leases, etc., the team can develop potential ARO's. Although the chance of determining that a legal obligation has accrued under a doctrine of promissory estoppel is small, the team should consider potential areas where such liability might arise. The review of promissory estoppel is difficult, and varies state by state. The recommendation is to identify relationships or other documentation that employees know about or have in their possession. Companies may query their corporate communications archives, and staff, company counsel, and field personnel, where necessary, to identify conduct that may involve the doctrine of promissory estoppel. An inventory questionnaire may be used to assist with the field review. The discovery of a promise alone is not enough to create a retirement obligation through promissory estoppel. A determination must be made that a third party relied upon such a promise to its detriment and that a court is likely to order equitable relief.

Many utilities have included removal costs in depreciation rates or some other rate recovery mechanism. For ratemaking purposes, the collection of depreciation expense, including the salvage, and gross removal cost should remain intact. If customers have been paying for the cost of removal through rates, they may have a reasonable expectation that the utility will expend the costs to remove the asset at the end of its useful life. The inclusion of a cost of removal component in depreciation rates, in and of itself, does not constitute a legal obligation to remove or dispose of the asset under the doctrine of promissory estoppel. However, promises made by utilities in rate case proceedings or the specific orders issued by regulatory bodies in rate cases could be evaluated as a potential legal obligation. This determination is a legal question that should be evaluated with the assistance of legal counsel. Barring any legal obligations, the inclusion of removal costs in depreciation rates does not constitute an ARO.

Prior to adoption of SFAS No. 143, Generally Accepted Accounting Principles (GAAP) as applied by utilities included an accrual of many estimated removal costs over the life of the asset and to classify the accrued removal cost liability as a part of the provision for accumulated depreciation. If all or a portion of asset retirements are not included in the scope of SFAS No. 143, GAAP continues to allow the accrual of the removal cost liability over the life of the asset. GAAP generally does not address where regulatory assets or liabilities should be recorded. Accordingly, the removal cost liability related to these types of assets that is recorded in accordance with rate recovery need not be reclassified as a regulatory liability. If an asset does fall under the scope of SFAS No. 143 and a company is subject to SFAS No. 71, “Accounting for the Effects of Certain Types of Regulation,” any removal cost related to that asset currently classified as a part of the provision for accumulated depreciation should be removed and replaced with an ARO liability in accordance with SFAS No. 143. Additionally, for SFAS 71 companies, any cumulative effect adjustments and/or any ongoing differences between the application of removal costs in a regulated environment and SFAS 143 should be recorded as a regulatory liability or asset.

To summarize, the scope of the final statement includes only liabilities for legal obligations that compel the owner to remove or dispose of the asset or of some component at retirement. If the “company has a legal obligation to perform decontamination activities when the plant ceases operations” (A12), then there is an ARO related to that plant. A conceptual framework for the ARO includes:

a) A legal requirement to remove an asset or component part must exist first before any ARO is recognized for removal costs. However, if there is no legal obligation to remove a component, then no ARO is required. For example, if an exhaust stack is retired in place at a production facility and there are no legal requirements to remove the stack, there is no ARO. Conversely, if there is a state requirement to remove any structure over 25 feet upon cessation of service, then there likely is an ARO.

b) A legal obligation may exist to dispose of a component part of an asset: “Any legal obligations that require disposal of the replaced part are within the scope of this Statement” (A9). For example, there may not be a legal requirement to remove a component part, but the component part may wear out or be removed for other reasons. In this case, the removal cost of the asset would not constitute an ARO. However, there may be legal requirements to dispose of the component part once it has been removed. The legal requirement to dispose of the component would constitute an ARO (A15).

c) All ARO liabilities must meet the liability criteria in FAS Concepts Statement Number 6, “Elements of Financial Statements.” Only present (current) obligations meet these criteria.

The Standard identifies examples of potential ARO’s including landfill closure and nuclear decommissioning, however, there are probably more in existence. The following are examples of types of assets that may be within the scope of SFAS No. 143 and circumstances that may or may not create an ARO:

1. Nuclear Production

a) *Final Nuclear Decommissioning* – a company has a legal obligation to perform decontamination activities when the plant ceases operations. Contamination results from the normal operation of the plant and a liability should be recorded. A company needs to review contracts, licenses, operating agreements, leases, etc. to assess their extent of liability. In addition to obligations surrounding contamination, there may be legal requirements to return the plant to a "greenfields" state. These costs are usually identified in required decommissioning studies. If the legal obligation is determined to include only the contaminated portions of the plant, then adjustments to the entire decommissioning study will need to be made to reflect only those portions as an ARO.

b) *Nuclear Fuel Storage Facilities* – a company needs to review associated documents, which surround this asset. It is generally assumed that the federal government will bear the responsibility for spent nuclear fuel when it is finally removed from the plant site. The removal of the storage facilities for spent nuclear fuel (*i.e*., Independent Spent Fuel Storage Installations) after the spent fuel has been removed will be the obligation of the company. This obligation would create an ARO and may be included already in final decommissioning. If no storage facilities currently exist but they will be required when the spent fuel pool reaches capacity, the removal obligation of such facilities would need to be considered when assessing an entity's obligation when the obligating event has occurred.

c) *Interim Retirements* - an asset retirement obligation may exist for component parts of the larger system. The retirement of this component part may happen prior to retirement of the entire system and may constitute an obligation separate from the final retirement or decommissioning. An example is a steam generator that needs replacement prior to the end of the life of the unit. An obligation associated with the disposal of a second steam generator will occur at the time of replacement of the generator (resulting in the irradiation of a second generator). The cash flow of the removal obligation to dispose of the second steam generator may be linked with the final decommissioning of the plant (*e.g*. if the replaced steam generator is left on site and factored into the decommissioning study) or can be reflected in a new ARO. Since it will probably be included in future plant decommissioning estimates, recording as a change in the existing ARO cash flow will simplify future accounting. Not all interim retirements will create an ARO. The recommendation is that a company will need to assess interim retirements individually as to frequency and materiality to determine when an ARO should be recognized and also what costs should be captured as an ARO.

An example of this follows: Entity A has a highly contaminated nuclear asset with a cost of removal of approximately $2 million. $.8 million is for labor and supplies needed to remove the asset and $1.2 million is for the "special" disposition costs for disposing of the contaminated asset. Because this is an interim retirement, the recommendation is that only the $1.2 million of disposition costs be accounted for in the ARO. For interim retirements such as these, it is generally assumed that there is no legal obligation to remove the asset, only a legal obligation to dispose of the asset. In contrast, when the plant is closed and the replaced asset is being removed, it is generally assumed that the entire $2 million of costs be included in the ARO due to the legal obligations associated with closing the plant. In a similar example, suppose the labor and supplies to remove the asset are $1.98 million and the disposition costs are only $.02 million. In this example a company may choose not to record any ARO based on immateriality. Each company will need to address its own specific materiality thresholds.

2. Steam Production

a) *General* – after reviewing legal documents, which include easements, licenses, leases, etc., a company may discover they have no legal obligations associated with asset retirement. Alternatively, a company may discover legal obligations associated with assets such as intake structures, ash ponds, underground storage tanks, coal piles, tanks used to accumulate hazardous waste, or coal mines. In some instances, there is no legal obligation to remove an asset or restore the land. In another instance, an existing law or a lease on the land may require decommissioning of the plant or components of the plant.

b) *Environmental Obligations* – a company may have certain environmental obligations. If these environmental obligations result from environmental law, contract, or other agreement or license that require the remediation of an obligation at a specific point (*e.g.*, a specific time after ceasing operations or at retirement), then they are legal obligations. An ARO results only from environmental remediation liabilities arising from the normal operation of the power plants. A company may have some liability associated with the retirement and removal of a segment of the power plant such as ash ponds or intake structures. Asbestos to be removed as part of an asset retirement is subject to the requirements of SFAS No. 143 and the cost of removal should be included in determining the obligation. If asbestos clean-up is performed prior to the asset retirement then it should be accounted for in accordance with the guidance of the American Institute of Certified Public Accountants (AICPA) Statement of Position (SOP) 96-1, “Environmental Remediation Liabilities.”

c) *Shared Assets* – some generating facilities are co-owned or have many joint owners. Co-owners should cooperate to the extent possible regarding consistent treatment of SFAS 143. For example, a situation may arise here one party defines an ARO and the other owners do not. In this situation, it would be helpful for the company to review the circumstances behind why the one of the companies chose to recognize an ARO. There could be instances where one company has made commitments and the other company will need to have their legal staffs decide whether or not this promise could be construed as their obligation, as well. However, legitimate differences may occur between joint owners. Differences in the amount of the estimated ARO may occur, but different judgments about whether an ARO exists should be rare.

3. Hydro Production

a) *Federal Government* – many hydro dams are operated under governmental water rights or flowage rights licenses issued by the Federal Energy Regulatory Commission (FERC). These licenses may not have explicit terms stating that a company is responsible for removal or closure costs related to the ultimate retirement of the dams. These dams have an extremely long useful life if operated and maintained properly and it is often presumed that the asset will be operated into perpetuity. Since removal of the dam property is not required under current operations, there is no ARO arising from the FERC licenses. But that may not always be the case. If the plant will be decommissioned, an application to FERC would be made and if a FERC order is issued, and the utility starts the surrender application process, then an ARO would be created. Also, if a dam is structurally impaired and legally, it must be removed, an ARO is created.

b) *State Government* – although the dams and spillways are controlled by Federal licenses, there may be additional requirements placed on the facility by the state or local agencies. A review of such requirements may produce an ARO even though the review of the Federal license did not.

4. Electric Transmission And Distribution

a) *Transmission and Distribution Lines* – a company may have transmission or distribution lines that operate under property easement agreements. Most utilities hold perpetual easements. Whether or not the easement is perpetual, a company, in general, operates the transmission and distribution lines as if the assets will be operated in perpetuity. If a perpetual easement were to be released, a company may have a legal obligation to remove the lines, or in some instances, a state may require removal if the entire line is retired. A legal obligation may exist if the contract for the easement requires removal of the lines at a given point. In both instances, legal counsel should be consulted to determine whether a legal obligation exists. The issue of whether these types of obligation can be measured is dealt with in the next section.

b) *Interim Retirements* - there are interim retirements of transmission and distribution (T&D) plant that are components of the system occurring annually that may have retirement obligations associated with them. These may be due to environmental or other contractual agreements. Examples of these would be wood poles and electrical equipment containing PCB's, such as transformers and capacitors. However, where a utility intends to remove PCB's and return the unit to service, the PCB removal might constitute maintenance cost rather than an ARO since it is not related to the retirement of an asset. The disposal of treated wood poles may be regulated under state law and may require special handling and disposal. These retirements need to be addressed for frequency and materiality to determine when the interim retirement would fall within the scope of SFAS No. 143.

5. Gas Transmission and Distribution

a) *Gas Transmission and Distribution Mains and Services* – a company may have a gas transmission or distribution system that operates under property easement agreements. The company would usually hold perpetual easements. If an easement were to be released, the company may not have an obligation to remove the system but would allow a retirement in place. In this case, no ARO is required. Gas pipelines containing PCBs must meet certain requirements prior to abandonment or when removed for disposal. These requirements may trigger an ARO. In some instances, a state may require removal if the entire line is retired. In this case the line would have an ARO. Generally, a company operates the gas transmission and distribution system as if the assets will be operated in perpetuity. A legal obligation may be construed to exist due to the easement requiring removal of the lines or, if material, a requirement to cut and cap the line at retirement. The issue of whether these types of obligation can be measured is dealt with in the next section.

b) *Interim Retirements* - there are interim retirements of components of gas transmission and distribution assets occurring annually. Some of these may have retirement obligations due to environmental or other contractual reasons. Generally, replacing sections of pipe or other interim replacement of gas assets will not create an ARO as long as the replacement will satisfy any material legal removal requirements (e.g., cutting and capping pipe). Environmental-related disposal requirements, if any, should be addressed based on materiality and timing.

6. Other Long-Lived Assets

a) *Underground tanks* could be considered as a retirement obligation. In some instances, state requirements create an obligation when the tanks are initially installed. In other cases, there are no legal obligations surrounding the disposal of the tanks until the entity does something with the land the tanks are on. (*i.e*., sells the property). In this latter case, a legal obligation would exist, but the ARO may not be reasonably determinable. There still may be no obligation if the clean-up is performed under SOP 96-1.

b) *Coal mines* could possibly be considered an ARO with regard to potential closure and/or site reclamation requirements. If the assumption is made that the mines are the assets and they are reclaimed in 12-18 months, there may not be an ARO as the mines would not be considered long-lived assets. If the mines were open for longer periods and there are legal reclamation requirements, then the reclamation at these mines may constitute an ARO.

7. Lease Obligations

a) SFAS No. 143 applies to companies that incur retirement obligations including companies that lease assets to others. There may be costs associated with a lease that should be recorded as an asset retirement obligation.

b) An obligation to remove leasehold improvements at the end of the lease may be an ARO under the Standard if the landlord can contractually require the lessee to remove the leasehold improvements at the end of the lease. The timing of the recognition of the ARO is when the obligating event occurs (*i.e*., when the improvements are made that may later be required to be removed).

c) Obligations of a lessee imposed by a lease agreement or by a party other than the lessor that meet the definition of either minimum lease payments or contingent rentals in paragraph 5 of FASB Statement No. 13, “Accounting for Leases” are not within the scope of SFAS No. 143.

8. Remediation Responsibilities

a) SFAS No. 143 does not apply to obligations resulting from improper operation of an asset or a system. Environmental damage that requires immediate clean-up resulting from improper operations (*e.g.,* an oil spill) would probably be liable under SOP 96-1 and not subject to the Standard.

b) If the clean-up is delayed and can be completed with the system retirement, it is determined as due to proper operations and is an obligation under SFAS No. 143.

Measurement

Once it is determined that an asset retirement obligation falls within the scope of SFAS No. 143 - the next step is measurement of the liability. The amount of the liability would initially be measured at fair value. An entity shall recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be determined. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of fair value can be made. In subsequent periods, an entity would recognize any changes in the amount resulting from the passage of time and revisions to either the timing or amount of estimated cash flows.

The initial measurement of the liability will be at fair value (*i.e.* the amount that an entity would be required to pay in an active market to settle the asset retirement obligation). The guidelines require a fair value measurement even though some entities may perform the retirement activities using internal resources. If quoted market prices are not available, an estimate of fair value can be calculated using valuation techniques such as the expected present value method. SFAS No. 143 states “a present value technique is often the best available technique with which to estimate the fair value of a liability.” If a present value technique is used to estimate fair value, estimates of future cash flows used in that technique must be consistent with the objective of measuring fair value. FASB Concepts Statement No. 7, “Using Cash Flow Information and Present Value in Accounting Measurements,” discusses two present value techniques: a traditional approach, in which a single set of estimated cash flows and a single interest rate (a rate commensurate with the risk) are used to estimate fair value and an expected cash flow approach, in which multiple cash flow scenarios that reflect the range of possible outcomes and a credit-adjusted risk-free rate are used to estimate fair value. The expected cash flow approach will usually be the only appropriate technique for an ARO. In estimating the probability of estimated cash flows, if the probability is evenly distributed around the estimate, no further probability assessment is required.

For periods subsequent to the initial measurement, entities are required to recognize changes in the liability resulting from the passage of time and from revisions in the timing or amount of estimated cash flows. Changes resulting from the passage of time will increase the carrying amount of the liability over time and will be recognized as an operating cost rather than as interest expense in the financial statements. Entities will use the effective interest method and the credit-adjusted risk-free rate for interest allocation to the liability. The objective of the method is to recognize a level effective interest rate that is equivalent to the entity’s risk-free rate (rate of zero coupon US Treasury bonds) adjusted for the entity’s credit standing. The credit-adjusted risk-free rate may be adjusted as a result of the amount of funding that has been provided to an external nuclear decommissioning trust based on its relationship to the related ARO.

Revisions in the timing or amount of estimated cash flows are to be recognized as changes in the carrying amount of the liability and the related capitalized asset and are to be measured using the current credit-adjusted risk-free rate for upward revisions, or using the credit-adjusted risk-free rate applied in the initial measurement for downward revisions. Such increments to retirement assets and liabilities will have to be tracked and accounted for separately. The tracking of layers would be similar to the multiple years cash flows demonstrated in Appendix A – “Multiple Year Cash Flows”.

The statement requires a company to recognize the present value of its total estimated cash flows as a liability with a corresponding increase to the related long-lived asset. Use of cost- accumulation-based estimated engineering studies or removal cost studies might be discounted at the company’s credit-adjusted risk-free interest rate to record the initial value of the liability, plus cumulative unrecognized interest accretion if the liability occurred in the past. The cumulative effect adjustment for unrecognized depreciation and accretion expense may be recoverable/refundable in rates and, therefore, a company may recognize an additional regulatory asset/liability rather than a cumulative adjustment to the income statement.

In developing expected retirement cash flows, most entities will use the expected present value method due to the non-existence of an active market for settling ARO’s. Removal costs should be based on gross removal costs instead of net. The estimated salvage value is included in determining the depreciation base of the asset. Therefore, the estimated salvage should be excluded from the cash flows used to estimate the ARO. When an entity uses the expected present value method, the entity would need to incorporate assumptions into its cash flows that would reflect the assumptions that third parties would be required to consider in order to take on the settlement of the obligation. Such third party or market assumptions include the following:

a) The costs that a third party would incur in performing the tasks necessary to retire the asset,

b) Other amounts that a third party would normally include such as inflation, overhead, equipment charges, profit margin, and advances in technology,

c) The extent that a third party's costs or timing would differ due to different future scenarios and relative probability,

d) The market risk premium that a third party would demand for them to take on the risks (similar to a contingency factor).

An example would be two entities using nuclear decommissioning studies to determine an ARO for their nuclear power plants. In one case, Entity A intends to decommission their plant using internal resources. Entity B had planned to have their decommissioning performed by a third party. Both entities reflected their intentions in their decommissioning studies. In developing their ARO, Entity A would add assumptions about profit margins, overheads and other third party costs to their ARO estimate, similar to Entity B. Failure to include certain third party costs would be inconsistent with SFAS No. 143.

Some general guidelines for determining whether to recognize an ARO and corresponding examples are described below:

a) When it has been established that a liability exists, a cash flow can be determined and there is a high or medium probability of the settlement date - as is the case for nuclear decommissioning costs - a liability must be recorded. Cash flows are estimated by cost-accumulation-based engineering studies and the settlement date is provided by the license date.

b) When it has been established that a liability exists - a cash flow can be determined but there is a low probability of the settlement date - the measurement will reflect the low probability in the expected cash flows. An example would be the removal of an asset when the retirement is indefinite. Removal costs and a corresponding estimate of cash flows could be obtained. However, since retirement is indefinite, no reasonable estimate of the timing can be made. If a reasonable estimate can be made of the timing, that probability estimate should be used in the expected cash flow analysis to determine the ARO to be recorded.

c) When it has been established that a liability exists - a cash flow cannot be determined and there is not a reasonable estimate of the settlement date - no liability is recorded but disclosure of the ARO is required. In subsequent periods, the ARO must be re-evaluated until sufficient information exists to determine a reasonable estimate of fair value. Generally, mass assets such as transmission and distribution assets have indeterminate estimated cash flows and settlement dates.

An entity shall disclose the following information about its asset retirement obligations:

a) A general description of the asset retirement obligations and the associated long-lived assets,

b) The fair value of assets that are legally restricted for purposes of settling asset retirement obligations,

c) A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations showing separately the changes attributable to (1) liabilities incurred in the current period, (2) liabilities settled in the current period, (3) accretion expense, and (4) revisions in estimated cash flows, whenever there is a significant change in one or more of those four components during the reporting period.

If the fair value of an asset retirement obligation cannot be reasonably estimated, that fact and the reasons why must be disclosed. For the year of adoption, pro forma disclosure is required for the amount of the liability for asset retirement obligations as if SFAS No. 143 had been applied for all periods affected.

Calculation Process Overview

This section is intended to provide some general guidelines for the calculation and measurement of ARO liabilities. The calculation of estimated cash flows and present values, accretion, and depreciation with corresponding amounts needed for journal entries will be illustrated. Examples for subsequent cash flow increases and decreases will also be shown. An example footnote disclosure for interim retirements for regulated companies is illustrated and the assumptions used for the multiple cash flows found in Appendix A are summarized. Some general guidelines for the calculation and measurement of ARO liabilities are as follows:

a) Estimates must be based on current active market pricing or prices for similar valuation, not at a cost using internal labor resources.
b) If removal will take longer than one year, estimated cash flows should be determined for each year.
c) The accretion schedule and present value depreciation schedules should be prepared individually for each cash flow, rather than as a sum total.
d) If variable removal options exist, probability analysis should be done to determine the appropriate cash flows. Also, if there is a potential license extension, inflation factors should be applied to cash flows for the time periods added.

e) Re-evaluation of estimated cash flow: for increases in estimates, current risk-free rates should be used; for decreases, the risk free rate in effect when the original liability was calculated would be used.

f) If more than one generating unit is at a facility, depending on timing, each unit may carry its own ARO. Additionally common-area removal costs are presumed to be included with the final unit being removed. This could result in a layering effect on the books.

g) Exclude salvage value from cash flow estimates.

h) New asset calculations would still apply except there would be no accumulated depreciation or accretion to date when placed in service.

1. Calculating Expected Cash Flows

Assumptions – for this example, the expected cash flows are based on the components of the cost of removal including labor, overheads, contractor's mark-up, and market risk-premium. The overhead rate is 80% of labor, a profit margin based on contactor's mark-up of 20%, and a market risk premium of 5%. The asset was placed in service on January 1, 1995 and has an estimated useful life of 20 years; the implementation date is January 1, 2003. Inflation from the time the asset was installed until the date of retirement is 4%. Removal expenditures will take place in the year 2014. The credit-adjusted risk-free rate of 6.5% is used to compute the expected present value. The cost of removal liability accrued to date for a non-regulated company or the cost embedded in accumulated depreciation for a regulated company is assumed to be $500,000.

Labor	$200,000
OH & Equipment: (80% x 200,000)	160,000
Contractor's Mark-up: (20% x (200,000 + 160,000))	72,000

Expected Cash Flows Before Inflation	$432,000

Inflation Rate	4%
Inflated Cash Flows: 432,000 x (1 + 4%) ^ 20	946,565
Market Risk Premium (5% x 946,565)	47,328

Total Expected Cash Flows	**$993,893**
	=======

Inflated Cash Flows: Cash Flows x (1 + rate) ^ #years

2. Calculate the Present Value of the Estimated Cash Flows

Using a credit-adjusted risk-free rate, the future expected cash flows are present valued to the point where the liability was incurred. In this example the asset life is assumed to be 20 years.

Expected Cash Flow	$993,893
Credit-Adjusted Risk-Free Rate	6.5%
Present Value	**282,064**
	======

Present Value (Cash Flow / (1 + rate) ^ #years)

3. Calculate Accretion Schedule using the same risk-free rate

The present value is accreted over the life of the asset at the specific rate so at the end of the term the total equals the future expected cash flows.

	Present Value	Annual Accretion	Liability Balance
1995	**282,064**	18,334	300,398
1996	300,398	19,526	319,924
1997	319,924	20,795	340,719
1998	340,719	22,147	362,866
1999	362,866	23,586	386,452
2000	386,452	25,119	411,572
2001	411,572	26,752	438,324
2002	438,324	28,491	466,815
2003	466,815	30,343	497,158
2004	497,158	32,315	529,473
2005	529,473	34,416	563,889
2006	563,889	36,653	600,541
2007	600,541	39,035	639,577
2008	639,577	41,572	681,149
2009	681,149	44,275	725,424
2010	725,424	47,153	772,576
2011	772,576	50,217	822,794
2012	822,794	53,482	876,275
2013	876,275	56,958	933,233
2014	933,233	60,660	**993,893**

Annual Accretion = Present Value x Credit-Adjusted Risk-Free Rate
Liability Balance = Present Value + Annual Accretion

4. Calculate Depreciation Expense Schedule

Present Value of the asset retirement cost is depreciated over the life of the asset.
The total at end of the asset's life must equal the Present Value.

Year	Depreciation Expense
1995	14,103
1996	14,103
1997	14,103
1998	14,103
1999	14,103
2000	14,103
2001	14,103
2002	14,103
2003	14,103
2004	14,103
2005	14,103
2006	14,103
2007	14,103
2008	14,103
2009	14,103
2010	14,103
2011	14,103
2012	14,103
2013	14,103
2014	14,103
Total	**282,064**

Depreciation Expense = Present Value of **$282,064** / 20 years (estimated useful life)

5. Create Expense Worksheet (combine above schedules)

Annual accretion and annual depreciation of the Present Value are added together to get the total new expenses. A total line can be inserted into the worksheet to accumulate totals to date for use in the journal entry at implementation.

	Annual Accretion Expense	Annual Depreciation Expense	Total Expenses
1995	18,334	14,103	32,437
1996	19,526	14,103	33,629
1997	20,795	14,103	34,898

	Annual Accretion Expense	**Annual Depreciation Expense**	**Total Expenses**
1998	22,147	14,103	36,250
1999	23,586	14,103	37,689
2000	25,119	14,103	39,223
2001	26,752	14,103	40,855
2002	28,491	14,103	42,594
Totals to Date	**184,751**	**112,826**	297,577
2003	30,343	14,103	44,446
2004	32,315	14,103	46,418
2005	34,416	14,103	48,519
2006	36,653	14,103	50,756
2007	39,035	14,103	53,138
2008	41,572	14,103	55,676
2009	44,275	14,103	58,378
2010	47,153	14,103	61,256
2011	50,217	14,103	64,321
2012	53,482	14,103	67,585
2013	56,958	14,103	71,061
2014	60,660	14,103	74,763
Total	711,831	282,062	993,893

Annual Accretion Expense + Annual Depreciation Expense = Total Expenses

6. Summary of Journal data

Sample journal entries are shown in Appendix B. Information needed for journal entry consideration is shown below:

	Amount
Asset Retirement Liability (ARO) = PV element	282,064
Asset Retirement Liability (ARO) = Accretion to date element	184,751
Additional Accumulated depreciation = PV depreciated thru 2002	112,826
2003 Depreciation Expense = PV depreciation per schedule	14,103
2003 Accretion expense = per schedule	30,343

7. Subsequent Cash Flow Increases

Increases in cash flows must use the current risk free rate.

Original Cash Flow Estimate	993,893	Year 2002
Original Risk- Free Rate used	6.50%	Year 2002
Subsequent Revised Cash Flow	1,493,893	Year 2003
DELTA Increase in Cash Flow	500,000	Year 2003
Current Risk Free Rate	**7.50%**	Year 2003

New Layer of ARO

Incremental Increase	500,000
Present Value (500,000.00 / (1+7.5%) ^12)	209,927

PV Calculation = incremental cash flow / (1+rate)^# Remaining years
(1995 + 20 years = 2015, 2015 - CY 2003 = 12 yr. Remaining)

New Layer of Accretion/Depreciation

Accretion Expense

Accretion expense is calculated using the new credit-adjusted risk-free rate in effect at the time of the change in estimate (2003). The rate in effect in 2003 is 7.50%.

Year	Present Value	Annual Accretion Expense	Liability Balance
2003	**209,927**	15,745	225,672
2004	225,672	16,925	242,597
2005	242,597	18,195	260,792
2006	260,792	19,559	280,351
2007	280,351	21,026	301,377
2008	301,377	22,603	323,981
2009	323,981	24,299	348,279
2010	348,279	26,121	374,400
2011	374,400	28,080	402,480

Year	Present Value	Annual Accretion Expense	Liability Balance
2012	402,480	30,186	432,666
2013	432,666	32,450	465,116
2014	465,116	34,884	**500,000**

Annual Accretion = Present Value x New Credit-Adjusted Risk-Free Rate

(209,927 x 7.5%)

Depreciation Expense

Depreciation expense is calculated over the remaining life of the asset (12 years).

Year	Depreciation Expense
2003	17,494
2004	17,494
2005	17,494
2006	17,494
2007	17,494
2008	17,494
2009	17,494
2010	17,494
2011	17,494
2012	17,494
2013	17,494
2014	17,494
Total	**209,927**

Annual Depreciation Expense = Present Value / Remaining Life of Asset ($209,927 / 12)

8. Subsequent Cash Flow Decreases

Decreases in cash flow estimates must use the rate applied to the asset at the time the original ARO was calculated.

Original Cash Flow Estimate	993,893	Year 2002
Original Risk- Free Rate used	6.50%	Year 2002
Subsequent Revised Cash Flow	793,893	Year 2010
DELTA Decrease in Cash	(200,000)	Year 2010

Flow		
Original Risk-Free Rate Used	**6.50%**	Year 2002

New Layer of ARO

Incremental Decrease	(200,000)
Present Value (-200,000.00 / (1+6.5%) ^5)	(145,976)

PV Calculation = incremental cash flow / (1+rate)^# Remaining years (1995 + 20 years = 2015, 2015 - CY 2010 = 5 yr. Remaining)

New Layer of Accretion/Depreciation

Accretion Expense

Accretion expense is calculated using the original credit-adjusted risk-free rate in effect at the time of implementation. The rate in effect in 2002 is 6.50%.

Year	Present Value	Annual Accretion Expense	Liability Balance
2010	**(145,976)**	(9,488)	(155,465)
2011	(155,465)	(10,105)	(165,570)
2012	(165,570)	(10,762)	(176,332)
2013	(176,332)	(11,462)	(187,793)
2014	(187,793)	(12,207)	**(200,000)**

Annual Accretion = Present Value x Original Credit-Adjusted Risk-Free Rate
(145,976 x 6.5%)

Depreciation Expense

Depreciation expense is calculated over the remaining life of the asset (5 years).

Year	Depreciation Expense
2010	(29,195)
2011	(29,195)
2012	(29,195)
2013	(29,195)
2014	(29,195)
Total	(145,976)

Annual Depreciation Expense = Present Value / Remaining Life of Asset
(145,976 / 5)

Calculating Multiple Year Cash Flows – (See Appendix A)

Assumptions used for the calculation of multiple year cash flows in Appendix A are shown below:

Nuclear Plant Dismantlement Schedule

- Assumptions
  - 40 Year Life
  - 4 years of estimated cash flows
  - Placed in Service 1990
  - Discount/Accretion Rate is 5%
- Estimated Annual Cash Flows
- Accretion Schedules
- PV Depreciation Schedules

Summary of Data for Journal Entry Consideration

Journal Entry Accounting for Regulated and Unregulated Operations

The purpose of this section is to provide accounting guidance on journal entry preparation for both regulated and unregulated operations resulting from the implementation of SFAS No. 143 including implementation, monthly journal entries subsequent to implementation, settlement of the obligation, and the retirement of the initial asset.

The impact on regulated entities resulting from SFAS No. 143 (implementation to settlement) will be income neutral and will be reflected as a regulatory asset/liability on the balance sheet as long as the recovery/refunding of the regulatory asset/liability is probable under SFAS No. 71. To the extent such recovery/refunding is not probable, there will be an impact on the income statement.

Journal entries from the example in Appendix B are shown for illustrative purposes. See Appendix B for “Unregulated and Regulated Operations – ARO Journal Entry Assumptions.”

Unregulated Operations

1) *Journal Entries Required at Implementation:* there are a number of journal entries required at implementation to properly reflect the effect of SFAS No. 143. These journal entries are:

- To record the initial fair value of the ARO asset and ARO liability,
- To record the effect of depreciation on the ARO asset from the time the ARO liability was incurred to implementation (offset is cumulative effect),
- To record the effect of accretion on the ARO liability from the time the ARO liability was incurred to implementation (offset is cumulative effect),

- To record the reversal of gross cost of removal liability accrued to date (offset is cumulative effect), if any
- To record taxes on the net cumulative effect on income (offset is cumulative effect).

Consolidated Entry at Implementation

DESCRIPTION	DEBIT	CREDIT
Long Lived Assets - ARO - *(New Account)*	**282,064**	
COR Liability Accrued to Date	**500,000**	
Cumulative Effect Adjustments		**111,333**
Accumulated Depreciation of ARO Asset - *(New Account)*		**112,826**
ARO Liability - *(New Account)*		**466,815**
Taxes Payable		**91,090**
To record the Implementation of FAS 143		

Individual Entries

To record the initial fair value of the ARO asset and ARO liability

Upon implementation of SFAS No. 143, the ARO liability (in current dollars) must be future valued at the anticipated inflation rate to when the projected cash outflows will occur and adjusted for a market risk premium as required by the Statement. The ARO liability must then be present valued back to when the liability was first incurred using the company's credit-adjusted risk-free rate. This present value of the future cash flows at the time the liability was first incurred is the ARO asset, which is to be depreciated using a systematic and rational allocation method. This amount is also the initial ARO liability before any accretion on the ARO liability to date of implementation and beyond.

DESCRIPTION	DEBIT	CREDIT
Long Lived Assets - ARO - *(New Account)*	**282,064**	
ARO Liability - *(New Account)*		**282,064**
To record the initial present value of ARO liability		
The ARO asset is valued at the present value of the liability at the time the liability is incurred.		
The offset ARO Asset is the ARO Liability at implementation		

To record the effect of depreciation on the ARO asset from the time the ARO liability was incurred to implementation

The ARO asset must be depreciated using a systematic and rational allocation method. This adjustment to the cumulative effect is for the accumulated depreciation that would have been recorded if the asset had been established at the time the ARO liability was incurred to date of implementation of SFAS No. 143.

DESCRIPTION	DEBIT	CREDIT
Cumulative Effect Adjustment	**112,826**	
Accumulated Depreciation of ARO Asset - *(New Account)*		**112,826**
To record cumulative effect of ARO depreciation		
Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.		
The total depreciation that would have been incurred if the asset was established at the time the liability was incurred and depreciated to date is reflected as a Cumulative Effect of an Accounting Change.		

To record the effect of accretion on the ARO liability from the time the liability was incurred to implementation

The ARO liability must be accreted to the final future value of the ARO liability at the company's credit-adjusted risk-free rate. This adjustment to the cumulative effect is for the total life to date accretion that would have occurred if the ARO liability was established and accreted from the time the ARO liability was incurred to date of implementation of SFAS No. 143.

DESCRIPTION	DEBIT	CREDIT
Cumulative Effect Adjustment	**184,751**	
ARO Liability - *(New Account)*		**184,751**
To record cumulative effect of accretion expense		
The ARO liability must be accreted to the anticipated cash outlay		
The total accretion expense that would have been incurred if the liability was accreted from the time the liability was incurred to date is reflected as a Cumulative Effect of an Accounting Change.		

To record the reversal of gross cost of removal liability accrued to date

Any gross cost of removal liability accrued to date must be reversed from the balance sheet and offset against the cumulative effect.

DESCRIPTION	DEBIT	CREDIT
COR Liability Accrued to Date	**500,000**	
Cumulative Effect Adjustment		**500,000**
To record the reversal of COR liability accrued to date		
The COR liability currently reflected on the Balance Sheet must be fully reversed.		
The offset will be a Cumulative Effect of an Accounting Change.		

To record taxes payable or receivable on the net cumulative effect

The tax effect (based on the company's effective tax rate) of the cumulative effect must be reflected. *Note:* the deferred tax effect (based on the combined statutory tax rate) of the associated cumulative book versus tax timing difference must be reflected but is not illustrated here. Deferred taxes need to be reflected at the combined statutory tax rate equal to the cumulative book and tax timing recognition on an ongoing basis.

DESCRIPTION	DEBIT	CREDIT
Cumulative Effect Adjustment (tax effect of total adjustments)	91,090	
Taxes Payable		91,090
~~To record taxes payable on cumulative effect~~		

2) *Monthly Journal Entries Subsequent to Implementation:* there are a number of journal entries that are required each month to properly reflect the effect of SFAS No. 143 on operations. These journal entries are:

- To record annual depreciation expense,
- To record annual accretion expense.

To record annual depreciation expense

Depreciation expense on the present value of the future cash flows at the time the liability was first incurred (ARO asset) must be recorded using a systematic and rational allocation method.

DESCRIPTION	DEBIT	CREDIT
Depreciation Expense	**14,103**	
Accumulated Depreciation of ARO Asset - *(New Account)*		**14,103**
To record annual depreciation expense for 2003		
Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.		

DESCRIPTION	DEBIT	CREDIT
Depreciation Expense	**250,000**	
Accumulated Depreciation		**250,000**
To record annual depreciation expense on $5,000,000 asset for which ARO is attached		
The $5,000,000 asset for which the ARO is attached is already in the G/L systems and is shown for illustrative purposes.		

To record annual accretion expense

The ARO liability must be accreted at the company's credit-adjusted risk-free rate.

DESCRIPTION	DEBIT	CREDIT
Accretion Expense (New Account)	**30,343**	
ARO Liability - *(New Account)*		**30,343**
To record annual accretion expense for 2003		
The liability at implementation must be accreted to the anticipated cash outlay.		

3) *Settlement of the obligation and the retirement of the initial asset:* there are a number of journal entries that are required at the time the asset for which the ARO is attached is retired and the settlement of the ARO obligation is made to properly reflect the effect of SFAS No. 143 on operations. These journal entries are:

- To record retirement on asset for which the ARO is attached,
- To record retirement of ARO asset,
- To record gain or loss on settlement of ARO liability when liability is extinguished.

To record retirement on the asset for which the ARO is attached

The asset for which the ARO is attached is retired. Any gain or loss is to be reflected on the company's income statement. No gain or loss was assumed for this example.

DESCRIPTION	DEBIT	CREDIT
Accumulated depreciation	5,000,000	
Fixed Asset		5,000,000
To record retirement of asset for which ARO is attached		
The original asset for which the ARO is attached must be retired and any gain / loss reflected.		

To record retirement of an ARO Asset

When the ARO asset is retired the difference between any cash inflow (none for ARO assets) and the net book value of the ARO asset is to be reflected as a gain or loss on the company's income statement.

DESCRIPTION	DEBIT	CREDIT
Accumulated Depreciation of ARO Asset - *(New Account)*	282,064	
Long Lived Assets - ARO - *(New Account)*		282,064
To record the retirement of ARO asset		
The ARO Asset must be retired from the G/L Systems and any gain or loss reflected.		

To record gain or loss on settlement of an ARO liability

When the ARO liability is settled, any gain or loss resulting from the difference between the ARO liability currently reflected on the balance sheet and the total actual cash outflow to settle the liability must be reflected in operations. Any gain or loss should be reflected when the last cash payment is made and the gain or loss can be accurately calculated.

DESCRIPTION	DEBIT	CREDIT
ARO Liability - *(New Account)*	993,893	
Cash/Accounts payable		900,000
Gain / Loss on ARO Settlement - (New Account)		93,893
To record the gain on settlement of ARO liability		
A new account must be established to record any gain or loss from settlement of ARO Liability.		
The gain / loss is calculated by the difference between what is accreted on the liability and the cash outlay.		

Regulated Operations

The impact on regulated entities resulting from SFAS No. 143 (implementation to settlement) will be profit and loss neutral and will be reflected as a regulatory asset/liability on the balance sheet as long as the recovery of the regulatory asset/liability is probable under SFAS No. 71. Overall, the journal entries required at implementation, subsequent to implementation and settlement are primarily the same except that during implementation any cumulative effect that would have occurred in an unregulated environment would be reflected generally as a regulatory asset/liability in a regulatory environment to the extent the differences in ARO expense for SFAS No. 143 and ARO expense for ratemaking purposes will be reflected in rates. Any effect on earnings going forward from implementation that would have been realized in an unregulated environment would be reflected as a regulatory asset/liability in a regulated environment.

1) *Journal Entries Required at Implementation:* there are a number of journal entries required at implementation to properly reflect the effect of SFAS No. 143. These journal entries are:

- To record the initial fair value of the ARO asset and ARO liability,
- To record accumulated depreciation on the ARO asset from the time the ARO liability was incurred to implementation (offset is regulatory asset/liability),
- To record accumulated accretion on the ARO liability from the time the ARO liability was incurred to implementation (offset is regulatory asset/liability),
- To record the reversal of gross cost of removal liability accrued to date (offset is regulatory asset/liability).

Consolidated Entry at Implementation

DESCRIPTION	DEBIT	CREDIT
Long Lived Assets - ARO - *(New Account)*	**282,064**	
COR Liability Accrued to Date	**500,000**	
Regulatory Asset / Liability (New Account)		**202,423**
Accumulated Depreciation of ARO Asset - *(New Account)*		**112,826**
ARO Liability - *(New Account)*		**466,815**
To record the Implementation of SFAS 143		

Individual Entries

To record the initial fair value of the ARO asset and ARO liability

The journal entry to record the initial present value of the ARO asset and the ARO liability at implementation is the same for both regulated and unregulated entities.

Upon implementation of SFAS No. 143, the ARO liability (in current dollars) must be future valued at the anticipated inflation rate to when the projected cash outflows will occur and adjusted for a market risk premium as required by the Statement. The ARO liability must then be present valued back to when the liability was first incurred using the company's credit-adjusted risk-free rate. This present value of the future cash flows at the time the liability was first incurred is the ARO asset to be depreciated using a systematic and rational allocation method. This amount is also the initial ARO liability before any accretion on the ARO liability to date of implementation and beyond.

DESCRIPTION	DEBIT	CREDIT
Long Lived Assets - ARO - *(New Account)*	**282,064**	
ARO Liability - *(New Account)*		**282,064**
To record the initial present value of ARO liability		
The ARO asset is valued at the present value of the liability at the time the liability is incurred.		
The offset ARO Asset is the ARO Liability at implementation		

To record the effect of depreciation on the ARO asset from the time the ARO liability was incurred to implementation

As with unregulated entities, the ARO asset must be depreciated using a systematic and rational allocation method. The total accumulated depreciation that would have been recorded if the asset were established at the time the ARO liability was incurred to date of implementation of SFAS No. 143 is reflected as a regulatory asset/liability on the regulated entity's balance sheet rather than as a component of the cumulative effect.

DESCRIPTION	DEBIT	CREDIT
Regulatory Asset/Liability - *(New Account)*	**112,826**	
Accumulated Depreciation of ARO Asset - *(New Account)*		**112,826**
To record accumulated depreciation on ARO assets		
Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.		
The total depreciation that would have been incurred if the asset was established at the time the liability was incurred and depreciated to date is reflected as a Regulatory Asset.		

To record the effect of accretion on the ARO liability from the time the liability was incurred to implementation

As with unregulated entities, the ARO liability must be accreted to the final future value of the ARO liability at the company's credit-adjusted risk-free rate. The accumulated accretion that would have occurred if the ARO liability was established and accreted from the time the ARO liability was incurred to date of implementation of SFAS No. 143 is reflected as a regulatory asset/liability on the regulated entity's balance sheet rather than to the cumulative effect.

DESCRIPTION	DEBIT	CREDIT
Regulatory Asset/Liability - *(New Account)*	**184,751**	
ARO Liability - *(New Account)*		**184,751**
To record accumulated accretion on ARO liability		
The ARO liability must be accreted to the anticipated cash outlay		
The total accretion expense that would have been incurred if the liability was accreted from the time the liability was incurred to date is reflected as a Regulatory Asset.		

To record the reversal of gross cost of removal liability accrued to date

The gross cost of removal liability accrued to date must be reversed from the balance sheet (accumulated depreciation) and offset against the regulatory asset/liability.

DESCRIPTION	DEBIT	CREDIT
Accumulated Deprecation	**500,000**	
Regulatory Asset/Liability - *(New Account)*		**500,000**
To reclassify existing Cost of Removal to regulatory asset/liability		
The COR liability currently reflected on the Balance Sheet must be fully reversed from the reserve.		
The offset will be a Regulatory Liability.		

2) *Monthly Journal Entries Subsequent to Implementation:* there are a number of journal entries that are required each month to properly reflect the effect of SFAS No. 143 on operations. However, no depreciation on the ARO asset or accretion on the ARO liability is reflected on the regulated entity's income statement, but rather these adjustments are recorded to the regulatory asset/liability on the balance sheet as the effect of SFAS No. 143 is income neutral as long as recovery is probable under SFAS No. 71. The entries to reflect both depreciation and accretion expense are originally made to the appropriate expense category. However, the monthly amounts are then adjusted from the expense category to a regulatory asset/liability. These journal entries are:

- To record annual depreciation expense,
- To record annual accretion expense.

To record annual depreciation expense

The present value of the future cash flows at the time the liability was first incurred (ARO asset) must be depreciated using a systematic and rational allocation method. The difference between the depreciation being recovered in rates and the depreciation for the ARO will be recorded as a regulatory asset/liability on the balance sheet.

DESCRIPTION	DEBIT	CREDIT
Depreciation Expense	**14,103**	
Accumulated Depreciation of ARO Asset - *(New Account)*		**14,103**
To record annual depreciation expense		
Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.		

DESCRIPTION	DEBIT	CREDIT
Regulatory Asset/Liability - *(New Account)*	**14,103**	
Depreciation Expense		**14,103**
To reverse annual depreciation to regulatory asset/liability (Utility is I/S Neutral)		
The monthly depreciation expense must be reflected against a Regulatory Asset so that all effects of FAS 143 are Income Statement neutral.		

DESCRIPTION	DEBIT	CREDIT
Depreciation Expense	**250,000**	
Accumulated Depreciation		**250,000**
To record annual depreciation expense on $5,00,000 asset for which ARO is attached		
The $5,000,000 asset for which the ARO is attached is already in the G/L systems and is shown for illustrative purpose		

To record monthly accretion expense

Every month, the ARO liability must be accreted to the final future value of the ARO liability at the company's credit-adjusted risk-free rate. The amount accreted is to be reclassified to a regulatory asset/liability on the balance sheet.

DESCRIPTION	DEBIT	CREDIT
Accretion Expense (New Account)	**30,343**	
ARO Liability - *(New Account)*		**30,343**
To record annual accretion expense on ARO liability		
The liability at implementation must be accreted to the anticipated cash outlay.		

DESCRIPTION	DEBIT	CREDIT
Regulatory Asset/Liability - *(New Account)*	**30,343**	
Accretion Expense		**30,343**
To reverse annual accretion expense to regulatory asset/liability (Utility is I/S neutral)		
The monthly depreciation expense must be reflected against a Regulatory Asset so that all effects of FAS 143 are Income Statement neutral.		

3) *Settlement of the obligation and the retirement of the initial asset*: there are a number of journal entries that are required at the time the asset for which the ARO is attached is retired and the settlement of the ARO obligation is made to properly reflect the effect of SFAS No. 143 on operations. However, no gain or loss on the settlement of either the ARO asset or the ARO liability is reflected on the regulated entity's income statement, but rather these adjustments are recorded to the regulatory asset/liability on the balance sheet as the effect of SFAS No. 143 is profit and loss neutral as long as recovery of the regulatory asset/liability is probable under SFAS No. 71. These journal entries are:

- To record retirement on the asset for which the ARO is attached,
- To record retirement of ARO asset,

- To record settlement of ARO liability.

To record retirement of ARO Asset

When the ARO asset is retired the difference between any cash inflow (none for ARO assets) and the net book value of the ARO asset is to be recorded to a regulatory asset on the company's balance sheet.

DESCRIPTION	DEBIT	CREDIT
Accumulated Depreciation of ARO Asset - *(New Account)*	**282,064**	
Long Lived Assets - ARO - *(New Account)*		**282,064**
<u>To record the retirement of ARO asset</u>		
The ARO Asset must be retired from the G/L Systems and any gain or loss reflected.		
The gain / loss is recorded to a Regulation Asset / Liability.		

To record retirement on the asset for which the ARO is attached

When the asset for which the ARO is attached is retired any gain or loss is to be reflected as a regulatory asset/liability or in the provision for accumulated depreciation, or income statement depending on the asset and the regulatory accounting related to that asset.

DESCRIPTION	DEBIT	CREDIT
Accumulated depreciation	**5,000,000**	
Fixed Asset		**5,000,000**
<u>To record retirement of asset for which ARO related</u>		
The original asset for which the ARO is attached must be retired and any gain / loss reflected.		

To record settlement of the ARO liability

In a regulated environment, when the ARO liability is settled, the difference between the ARO liability currently reflected on the balance sheet and the total actual cash outflow to settle that liability must be recorded to a regulatory asset/liability on the balance sheet. This adjustment should be made when the last cash payment is made and the difference between the ARO liability on the balance sheet and total cash outflows can be accurately calculated.

DESCRIPTION	DEBIT	CREDIT
ARO Liability - *(New Account)*	**993,893**	
Cash/Accounts payable		**900,000**
Regulatory Asset/Liability - *(New Account)*		**93,893**
<u>To record the gain on settlement of ARO liability</u>		
The gain / loss is calculated by the difference between what is accreted on the liability and the cash outlay.		
The gain / loss is recorded to a Regulation Asset / Liability.		

Other Considerations (Unregulated and Regulated Operations)

- The original asset for which the ARO is attached, the ARO asset and the ARO liability must be linked within the General Ledger Systems.
- The original asset for with the ARO is attached, the ARO asset and the ARO liability must be retired at the same time and any gain or loss recognized upon settlement (unregulated).
- Corporate systems should be programmed to record monthly depreciation and accretion expense so that manual entries are not required.
- Accretion on the ARO liability and depreciation on the ARO asset will stop upon settlement.

(See Appendix B for Unregulated and Regulated Operations – ARO Journal Entry Assumptions)

Financial Statement Disclosure

Requirements of the Standard

The final stage of implementing SFAS No. 143 is the complying with disclosure requirements. The statement contains two disclosure requirements found in paragraph 22 which are:

> An entity shall disclose the following information about its asset retirement obligations:
>
> (a) A general description of the asset retirement obligations and the associated long-lived assets,
> (b) The fair value of assets that are legally restricted for purposes of settling asset retirement obligations,
> (c) A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations showing separately the changes attributable to (1) liabilities incurred in the current period, (2) liabilities settled in the current period, (3) accretion expense, and (4) revisions in estimated cash flows, whenever there is a significant change in one of more of those four components during the reporting period.
>
> If the fair value of an asset retirement obligation cannot be reasonably estimated, that fact and the reasons therefore shall be disclosed.

The second disclosure requirements involves a transition disclosure requirement found in paragraph 27:

> An entity shall compute on a pro forma basis and disclose in the footnotes to the financial statements for the beginning of the earliest year presented and at the end of all years presented the

amount of the liability for asset retirement obligations as if this Statement had been applied during all periods affected.

The pro forma amounts shall be computed using information current at the time of adoption, current assumptions and current interest rates. It appears that this transition disclosure is a one-time measurement since the ongoing disclosure would replace this information going forward.

Appendix B of SFAS No. 143, titled "Background Information and Basis for Conclusions," provides some background information but does not provide any additional guidance on disclosure. If an entity does not have assets that fall within the scope of this Standard, there is no disclosure requirement.

For those entities with assets that fall within the scope of the Standard, the source of information will obviously be available from the measurement, calculation process, and journal entry process described previously. Without specific guidance, the content and format of the disclosure will likely evolve over time. For many, the disclosure may take the form of a separate footnote. The content and style of disclosure will likely vary depending on such individual circumstances as the number or types of assets or the related obligations, differences in measurement approaches, consolidations of companies and business segments, and the materiality of the details. Other circumstances affecting this disclosure for the gas and electric utility industry will be related to application of SFAS No. 71, and the final conclusions by FERC in Docket RM02-7 that may involve changes in the Uniform System of Accounts to accommodate SFAS No. 143.

Other transitional disclosure requirements

Until the Statement is implemented, there is a disclosure requirement for adoption of new accounting pronouncements (SAB 74). Basically, an entity is to provide qualitative or quantitative information, when available, about the expected impact of implementation, updated quarterly.

Other related disclosure impacts

Disclosure

Additional disclosure issues exist beyond the requirements of the Statement such as other notes to the financial statements involving property, depreciation, or estimates. Current and proposed disclosure rules of the Securities and Exchange Commission (SEC) should also be reviewed for additional SFAS No. 143 related disclosures.

Impairments

SFAS No. 143 will result in an increase in the carrying amount of an asset equal to the calculated asset cost. As a result, a test of impairment and recoverability should be performed in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets."

Record Keeping Issues

The Edison Electric Institute (EEI) and The American Gas Association (AGA) do not support specific regulations related to record keeping requirements for ARO's. As companies develop strategies and methods for the implementation and on-going reviews required for the Standard, various methods may evolve over time on how ARO's will be determined and measured. Because of this, EEI and AGA believe that companies should be allowed flexibility for maintaining the associated records. Basic accounting guidelines require that companies maintain sufficient, detailed records in order to support information provided in financial statements.

EEI and AGA have developed some suggested record keeping guidelines that may help companies develop their own policies. They are as follows:

1) Documentation of communications with Business Units/Functions. The initial documentation of these discussions should be very detailed and thorough. Each year, a review of this documentation should be done to determine any changes, new issues, etc.

2) Documentation of the due diligence analysis provided by the legal department as to what is considered a legal obligation and why. This should also include discussions surrounding issues that were ultimately not determined to be legal obligations and why. The legal department should then perform an annual review for any changes, new issues, etc. This should also include a review of the Business Units/Functions documentation referred to in item 1) above.

3) Support for all items associated with the calculation of the ARO including, but not limited to, the following:
   - Third-party written estimates and related assumptions, or
   - Internal cost estimates including assumptions for profits or mark-up, overheads, market risk premium, etc.,
   - Timing of cash outflows,
   - Inflation rate,
   - Risk-free credit rate,
   - Estimated retirement dates,
   - Amortization schedules for interest accretion expense,
   - Depreciation schedules.

4) Support for ARO transactions and balances included in the regulatory asset and liability accounts.

5) Periodic Audits - Companies should conduct regular audits for ARO's subject to SFAS No. 143. Companies should prepare written audit instructions that ensure the following:

   - A methodical review of company assets, plus the authorities that might impose ARO's,

- A procedure for sampling voluminous, repetitive records (*e.g.*, form contracts, easements),
- A record of the audit itself, including:
  - personnel and records reviewed,
  - assets reviewed,
  - authorities reviewed with respect to each asset,
  - legal determination made as to each authority ,
  - basis of any cost calculations.

Appendix A – Multiple Year Cash Flows

Nuclear Plant Dismantlement Schedule
40 Year Life
Placed in Service 1990

		Present Value at 5%		
2030	400,000,000.00	56,818,272.92	40 years	
2031	500,000,000.00	67,640,801.10	41 years	40 Years
2032	600,000,000.00	77,303,772.68	42 years	
2033	200,000,000.00	24,540,880.22	43 years	
	1,700,000,000.00	**226,303,726.91**		

Year	Liability Bal 1/1	Accretion 5.0%	Liab Bal 12/31	Year-End Unit 1	Accretion Exp Original PV	Deprec. Exp 56,818,272.92	Total Expense
1990	56,818,272.92	2,840,913.65	59,659,186.57	1990	2,840,913.65	1,420,456.82	4,261,370.47
1991	59,659,186.57	2,982,959.33	62,642,145.89	1991	2,982,959.33	1,420,456.82	4,403,416.15
1992	62,642,145.89	3,132,107.29	65,774,253.19	1992	3,132,107.29	1,420,456.82	4,552,564.12
1993	65,774,253.19	3,288,712.66	69,062,965.85	1993	3,288,712.66	1,420,456.82	4,709,169.48
1994	69,062,965.85	3,453,148.29	72,516,114.14	1994	3,453,148.29	1,420,456.82	4,873,605.12
1995	72,516,114.14	3,625,805.71	76,141,919.85	1995	3,625,805.71	1,420,456.82	5,046,262.53
1996	76,141,919.85	3,807,095.99	79,949,015.84	1996	3,807,095.99	1,420,456.82	5,227,552.82
1997	79,949,015.84	3,997,450.79	83,946,466.63	1997	3,997,450.79	1,420,456.82	5,417,907.62
1998	83,946,466.63	4,197,323.33	88,143,789.96	1998	4,197,323.33	1,420,456.82	5,617,780.15
1999	88,143,789.96	4,407,189.50	92,550,979.46	1999	4,407,189.50	1,420,456.82	5,827,646.32
2000	92,550,979.46	4,627,548.97	97,178,528.44	2000	4,627,548.97	1,420,456.82	6,048,005.80
2001	97,178,528.44	4,858,926.42	102,037,454.86	2001	4,858,926.42	1,420,456.82	6,279,383.24
2002	102,037,454.86	5,101,872.74	107,139,327.60	2002	5,101,872.74	1,420,456.82	6,522,329.57
		-		**TTLS to Date**	**50,321,054.68**	**18,465,938.70**	
2003	107,139,327.60	5,356,966.38	112,496,293.98	2003	5,356,966.38	1,420,456.82	6,777,423.20
2004	112,496,293.98	5,624,814.70	118,121,108.68	2004	5,624,814.70	1,420,456.82	7,045,271.52
2005	118,121,108.68	5,906,055.43	124,027,164.11	2005	5,906,055.43	1,420,456.82	7,326,512.26
2006	124,027,164.11	6,201,358.21	130,228,522.32	2006	6,201,358.21	1,420,456.82	7,621,815.03
2007	130,228,522.32	6,511,426.12	136,739,948.43	2007	6,511,426.12	1,420,456.82	7,931,882.94
2008	136,739,948.43	6,836,997.42	143,576,945.86	2008	6,836,997.42	1,420,456.82	8,257,454.24
2009	143,576,945.86	7,178,847.29	150,755,793.15	2009	7,178,847.29	1,420,456.82	8,599,304.12
2010	150,755,793.15	7,537,789.66	158,293,582.81	2010	7,537,789.66	1,420,456.82	8,958,246.48
2011	158,293,582.81	7,914,679.14	166,208,261.95	2011	7,914,679.14	1,420,456.82	9,335,135.96
2012	166,208,261.95	8,310,413.10	174,518,675.04	2012	8,310,413.10	1,420,456.82	9,730,869.92
2013	174,518,675.04	8,725,933.75	183,244,608.80	2013	8,725,933.75	1,420,456.82	10,146,390.58
2014	183,244,608.80	9,162,230.44	192,406,839.24	2014	9,162,230.44	1,420,456.82	10,582,687.26
2015	192,406,839.24	9,620,341.96	202,027,181.20	2015	9,620,341.96	1,420,456.82	11,040,798.78
2016	202,027,181.20	10,101,359.06	212,128,540.26	2016	10,101,359.06	1,420,456.82	11,521,815.88
2017	212,128,540.26	10,606,427.01	222,734,967.27	2017	10,606,427.01	1,420,456.82	12,026,883.84
2018	222,734,967.27	11,136,748.36	233,871,715.63	2018	11,136,748.36	1,420,456.82	12,557,205.19
2019	233,871,715.63	11,693,585.78	245,565,301.42	2019	11,693,585.78	1,420,456.82	13,114,042.60
2020	245,565,301.42	12,278,265.07	257,843,566.49	2020	12,278,265.07	1,420,456.82	13,698,721.89
2021	257,843,566.49	12,892,178.32	270,735,744.81	2021	12,892,178.32	1,420,456.82	14,312,635.15
2022	270,735,744.81	13,536,787.24	284,272,532.05	2022	13,536,787.24	1,420,456.82	14,957,244.06
2023	284,272,532.05	14,213,626.60	298,486,158.65	2023	14,213,626.60	1,420,456.82	15,634,083.43
2024	298,486,158.65	14,924,307.93	313,410,466.59	2024	14,924,307.93	1,420,456.82	16,344,764.76
2025	313,410,466.59	15,670,523.33	329,080,989.92	2025	15,670,523.33	1,420,456.82	17,090,980.15
2026	329,080,989.92	16,454,049.50	345,535,039.41	2026	16,454,049.50	1,420,456.82	17,874,506.32
2027	345,535,039.41	17,276,751.97	362,811,791.38	2027	17,276,751.97	1,420,456.82	18,697,208.79
2028	362,811,791.38	18,140,589.57	380,952,380.95	2028	18,140,589.57	1,420,456.82	19,561,046.39
2029	380,952,380.95	19,047,619.05	400,000,000.00	2029	19,047,619.05	1,420,456.82	20,468,075.87
2030	400,000,000.00						

Appendix A – Multiple Year Cash Flows

41 Years

Year	Liability Bal 1/1	Accretion	Liab Bal 12/31	Year-End	Accretion Exp	Deprec. Exp	Total Expense
		5.0%		Unit 1	Original PV	67,640,801.10	
1990	67,640,801.10	3,382,040.05	71,022,841.15	1990	3,382,040.05	1,649,775.64	5,031,815.69
1991	71,022,841.15	3,551,142.06	74,573,983.21	1991	3,551,142.06	1,649,775.64	5,200,917.69
1992	74,573,983.21	3,728,699.16	78,302,682.37	1992	3,728,699.16	1,649,775.64	5,378,474.80
1993	78,302,682.37	3,915,134.12	82,217,816.49	1993	3,915,134.12	1,649,775.64	5,564,909.75
1994	82,217,816.49	4,110,890.82	86,328,707.31	1994	4,110,890.82	1,649,775.64	5,760,666.46
1995	86,328,707.31	4,316,435.37	90,645,142.68	1995	4,316,435.37	1,649,775.64	5,966,211.00
1996	90,645,142.68	4,532,257.13	95,177,399.81	1996	4,532,257.13	1,649,775.64	6,182,032.77
1997	95,177,399.81	4,758,869.99	99,936,269.80	1997	4,758,869.99	1,649,775.64	6,408,645.63
1998	99,936,269.80	4,996,813.49	104,933,083.29	1998	4,996,813.49	1,649,775.64	6,646,589.13
1999	104,933,083.29	5,246,654.16	110,179,737.46	1999	5,246,654.16	1,649,775.64	6,896,429.80
2000	110,179,737.46	5,508,986.87	115,688,724.33	2000	5,508,986.87	1,649,775.64	7,158,762.51
2001	115,688,724.33	5,784,436.22	121,473,160.54	2001	5,784,436.22	1,649,775.64	7,434,211.85
2002	121,473,160.54	6,073,658.03	127,546,818.57	2002	6,073,658.03	1,649,775.64	7,723,433.66
				TTLS to Date	**59,906,017.48**	**21,447,083.27**	
2003	127,546,818.57	6,377,340.93	133,924,159.50	2003	6,377,340.93	1,649,775.64	8,027,116.57
2004	133,924,159.50	6,696,207.98	140,620,367.48	2004	6,696,207.98	1,649,775.64	8,345,983.61
2005	140,620,367.48	7,031,018.37	147,651,385.85	2005	7,031,018.37	1,649,775.64	8,680,794.01
2006	147,651,385.85	7,382,569.29	155,033,955.14	2006	7,382,569.29	1,649,775.64	9,032,344.93
2007	155,033,955.14	7,751,697.76	162,785,652.90	2007	7,751,697.76	1,649,775.64	9,401,473.39
2008	162,785,652.90	8,139,282.64	170,924,935.54	2008	8,139,282.64	1,649,775.64	9,789,058.28
2009	170,924,935.54	8,546,246.78	179,471,182.32	2009	8,546,246.78	1,649,775.64	10,196,022.41
2010	179,471,182.32	8,973,559.12	188,444,741.44	2010	8,973,559.12	1,649,775.64	10,623,334.75
2011	188,444,741.44	9,422,237.07	197,866,978.51	2011	9,422,237.07	1,649,775.64	11,072,012.71
2012	197,866,978.51	9,893,348.93	207,760,327.43	2012	9,893,348.93	1,649,775.64	11,543,124.56
2013	207,760,327.43	10,388,016.37	218,148,343.81	2013	10,388,016.37	1,649,775.64	12,037,792.01
2014	218,148,343.81	10,907,417.19	229,055,761.00	2014	10,907,417.19	1,649,775.64	12,557,192.83
2015	229,055,761.00	11,452,788.05	240,508,549.05	2015	11,452,788.05	1,649,775.64	13,102,563.69
2016	240,508,549.05	12,025,427.45	252,533,976.50	2016	12,025,427.45	1,649,775.64	13,675,203.09
2017	252,533,976.50	12,626,698.82	265,160,675.32	2017	12,626,698.82	1,649,775.64	14,276,474.46
2018	265,160,675.32	13,258,033.77	278,418,709.09	2018	13,258,033.77	1,649,775.64	14,907,809.40
2019	278,418,709.09	13,920,935.45	292,339,644.54	2019	13,920,935.45	1,649,775.64	15,570,711.09
2020	292,339,644.54	14,616,982.23	306,956,626.77	2020	14,616,982.23	1,649,775.64	16,266,757.86
2021	306,956,626.77	15,347,831.34	322,304,458.11	2021	15,347,831.34	1,649,775.64	16,997,606.97
2022	322,304,458.11	16,115,222.91	338,419,681.01	2022	16,115,222.91	1,649,775.64	17,764,998.54
2023	338,419,681.01	16,920,984.05	355,340,665.07	2023	16,920,984.05	1,649,775.64	18,570,759.69
2024	355,340,665.07	17,767,033.25	373,107,698.32	2024	17,767,033.25	1,649,775.64	19,416,808.89
2025	373,107,698.32	18,655,384.92	391,763,083.23	2025	18,655,384.92	1,649,775.64	20,305,160.55
2026	391,763,083.23	19,588,154.16	411,351,237.40	2026	19,588,154.16	1,649,775.64	21,237,929.80
2027	411,351,237.40	20,567,561.87	431,918,799.27	2027	20,567,561.87	1,649,775.64	22,217,337.51
2028	431,918,799.27	21,595,939.96	453,514,739.23	2028	21,595,939.96	1,649,775.64	23,245,715.60
2029	453,514,739.23	22,675,736.96	476,190,476.19	2029	22,675,736.96	1,649,775.64	24,325,512.60
2030	476,190,476.19	23,809,523.81	500,000,000.00	2030	23,809,523.81	1,649,775.64	25,459,299.45
2031	500,000,000.00			2031			

Appendix A – Multiple Year Cash Flows

42 Years

Year	Liability Bal 1/1	Accretion	Liab Bal 12/31
		5.0%	
1990	77,303,772.68	3,865,188.63	81,168,961.31
1991	81,168,961.31	4,058,448.07	85,227,409.38
1992	85,227,409.38	4,261,370.47	89,488,779.85
1993	89,488,779.85	4,474,438.99	93,963,218.84
1994	93,963,218.84	4,698,160.94	98,661,379.78
1995	98,661,379.78	4,933,068.99	103,594,448.77
1996	103,594,448.77	5,179,722.44	108,774,171.21
1997	108,774,171.21	5,438,708.56	114,212,879.77
1998	114,212,879.77	5,710,643.99	119,923,523.76
1999	119,923,523.76	5,996,176.19	125,919,699.95
2000	125,919,699.95	6,295,985.00	132,215,684.95
2001	132,215,684.95	6,610,784.25	138,826,469.19
2002	138,826,469.19	6,941,323.46	145,767,792.65
		-	
2003	145,767,792.65	7,288,389.63	153,056,182.29
2004	153,056,182.29	7,652,809.11	160,708,991.40
2005	160,708,991.40	8,035,449.57	168,744,440.97
2006	168,744,440.97	8,437,222.05	177,181,663.02
2007	177,181,663.02	8,859,083.15	186,040,746.17
2008	186,040,746.17	9,302,037.31	195,342,783.48
2009	195,342,783.48	9,767,139.17	205,109,922.65
2010	205,109,922.65	10,255,496.13	215,365,418.78
2011	215,365,418.78	10,768,270.94	226,133,689.72
2012	226,133,689.72	11,306,684.49	237,440,374.21
2013	237,440,374.21	11,872,018.71	249,312,392.92
2014	249,312,392.92	12,465,619.65	261,778,012.57
2015	261,778,012.57	13,088,900.63	274,866,913.19
2016	274,866,913.19	13,743,345.66	288,610,258.85
2017	288,610,258.85	14,430,512.94	303,040,771.80
2018	303,040,771.80	15,152,038.59	318,192,810.39
2019	318,192,810.39	15,909,640.52	334,102,450.91
2020	334,102,450.91	16,705,122.55	350,807,573.45
2021	350,807,573.45	17,540,378.67	368,347,952.12
2022	368,347,952.12	18,417,397.61	386,765,349.73
2023	386,765,349.73	19,338,267.49	406,103,617.22
2024	406,103,617.22	20,305,180.86	426,408,798.08
2025	426,408,798.08	21,320,439.90	447,729,237.98
2026	447,729,237.98	22,386,461.90	470,115,699.88
2027	470,115,699.88	23,505,784.99	493,621,484.88
2028	493,621,484.88	24,681,074.24	518,302,559.12
2029	518,302,559.12	25,915,127.96	544,217,687.07
2030	544,217,687.07	27,210,884.35	571,428,571.43
2031	571,428,571.43	28,571,428.57	600,000,000.00
2032	600,000,000.00		

Year-End	Accretion Exp	Deprec. Exp	Total Expense
Unit 1	Original PV	77,303,772.68	
1990	3,865,188.63	1,840,566.02	5,705,754.65
1991	4,058,448.07	1,840,566.02	5,899,014.08
1992	4,261,370.47	1,840,566.02	6,101,936.49
1993	4,474,438.99	1,840,566.02	6,315,005.01
1994	4,698,160.94	1,840,566.02	6,538,726.96
1995	4,933,068.99	1,840,566.02	6,773,635.01
1996	5,179,722.44	1,840,566.02	7,020,288.45
1997	5,438,708.56	1,840,566.02	7,279,274.58
1998	5,710,643.99	1,840,566.02	7,551,210.00
1999	5,996,176.19	1,840,566.02	7,836,742.20
2000	6,295,985.00	1,840,566.02	8,136,551.01
2001	6,610,784.25	1,840,566.02	8,451,350.26
2002	6,941,323.46	1,840,566.02	8,781,889.48
TTLS to Date	**68,464,019.97**	**23,927,358.21**	
2003	7,288,389.63	1,840,566.02	9,128,955.65
2004	7,652,809.11	1,840,566.02	9,493,375.13
2005	8,035,449.57	1,840,566.02	9,876,015.59
2006	8,437,222.05	1,840,566.02	10,277,788.06
2007	8,859,083.15	1,840,566.02	10,699,649.17
2008	9,302,037.31	1,840,566.02	11,142,603.32
2009	9,767,139.17	1,840,566.02	11,607,705.19
2010	10,255,496.13	1,840,566.02	12,096,062.15
2011	10,768,270.94	1,840,566.02	12,608,836.96
2012	11,306,684.49	1,840,566.02	13,147,250.50
2013	11,872,018.71	1,840,566.02	13,712,584.73
2014	12,465,619.65	1,840,566.02	14,306,185.66
2015	13,088,900.63	1,840,566.02	14,929,466.64
2016	13,743,345.66	1,840,566.02	15,583,911.68
2017	14,430,512.94	1,840,566.02	16,271,078.96
2018	15,152,038.59	1,840,566.02	16,992,604.61
2019	15,909,640.52	1,840,566.02	17,750,206.54
2020	16,705,122.55	1,840,566.02	18,545,688.56
2021	17,540,378.67	1,840,566.02	19,380,944.69
2022	18,417,397.61	1,840,566.02	20,257,963.62
2023	19,338,267.49	1,840,566.02	21,178,833.50
2024	20,305,180.86	1,840,566.02	22,145,746.88
2025	21,320,439.90	1,840,566.02	23,161,005.92
2026	22,386,461.90	1,840,566.02	24,227,027.92
2027	23,505,784.99	1,840,566.02	25,346,351.01
2028	24,681,074.24	1,840,566.02	26,521,640.26
2029	25,915,127.96	1,840,566.02	27,755,693.97
2030	27,210,884.35	1,840,566.02	29,051,450.37
2031	28,571,428.57	1,840,566.02	30,411,994.59
2032			

Appendix A – Multiple Year Cash Flows

Year	Liability Bal 1/1	Accretion	Liab Bal 12/31
		5.0%	
1990	24,540,880.22	1,227,044.01	25,767,924.23
1991	25,767,924.23	1,288,396.21	27,056,320.44
1992	27,056,320.44	1,352,816.02	28,409,136.46
1993	28,409,136.46	1,420,456.82	29,829,593.28
1994	29,829,593.28	1,491,479.66	31,321,072.95
1995	31,321,072.95	1,566,053.65	32,887,126.59
1996	32,887,126.59	1,644,356.33	34,531,482.92
1997	34,531,482.92	1,726,574.15	36,258,057.07
1998	36,258,057.07	1,812,902.85	38,070,959.92
1999	38,070,959.92	1,903,548.00	39,974,507.92
2000	39,974,507.92	1,998,725.40	41,973,233.32
2001	41,973,233.32	2,098,661.67	44,071,894.98
2002	44,071,894.98	2,203,594.75	46,275,489.73
		-	
2003	46,275,489.73	2,313,774.49	48,589,264.22
2004	48,589,264.22	2,429,463.21	51,018,727.43
2005	51,018,727.43	2,550,936.37	53,569,663.80
2006	53,569,663.80	2,678,483.19	56,248,146.99
2007	56,248,146.99	2,812,407.35	59,060,554.34
2008	59,060,554.34	2,953,027.72	62,013,582.06
2009	62,013,582.06	3,100,679.10	65,114,261.16
2010	65,114,261.16	3,255,713.06	68,369,974.22
2011	68,369,974.22	3,418,498.71	71,788,472.93
2012	71,788,472.93	3,589,423.65	75,377,896.57
2013	75,377,896.57	3,768,894.83	79,146,791.40
2014	79,146,791.40	3,957,339.57	83,104,130.97
2015	83,104,130.97	4,155,206.55	87,259,337.52
2016	87,259,337.52	4,362,966.88	91,622,304.40
2017	91,622,304.40	4,581,115.22	96,203,419.62
2018	96,203,419.62	4,810,170.98	101,013,590.60
2019	101,013,590.60	5,050,679.53	106,064,270.13
2020	106,064,270.13	5,303,213.51	111,367,483.64
2021	111,367,483.64	5,568,374.18	116,935,857.82
2022	116,935,857.82	5,846,792.89	122,782,650.71
2023	122,782,650.71	6,139,132.54	128,921,783.24
2024	128,921,783.24	6,446,089.16	135,367,872.41
2025	135,367,872.41	6,768,393.62	142,136,266.03
2026	142,136,266.03	7,106,813.30	149,243,079.33
2027	149,243,079.33	7,462,153.97	156,705,233.29
2028	156,705,233.29	7,835,261.66	164,540,494.96
2029	164,540,494.96	8,227,024.75	172,767,519.71
2030	172,767,519.71	8,638,375.99	181,405,895.69
2031	181,405,895.69	9,070,294.78	190,476,190.48
2032	190,476,190.48	9,523,809.52	200,000,000.00
2033	200,000,000.00		

43 Years

Year-End	Accretion Exp	Deprec. Exp	Total Expense
Unit 1	Original PV	24,540,880.22	
1990	1,227,044.01	570,718.14	1,797,762.16
1991	1,288,396.21	570,718.14	1,859,114.36
1992	1,352,816.02	570,718.14	1,923,534.17
1993	1,420,456.82	570,718.14	1,991,174.97
1994	1,491,479.66	570,718.14	2,062,197.81
1995	1,566,053.65	570,718.14	2,136,771.79
1996	1,644,356.33	570,718.14	2,215,074.47
1997	1,726,574.15	570,718.14	2,297,292.29
1998	1,812,902.85	570,718.14	2,383,621.00
1999	1,903,548.00	570,718.14	2,474,266.14
2000	1,998,725.40	570,718.14	2,569,443.54
2001	2,098,661.67	570,718.14	2,669,379.81
2002	2,203,594.75	570,718.14	2,774,312.89
TTLS to Date	**21,734,609.52**	**7,419,335.88**	
2003	2,313,774.49	570,718.14	2,884,492.63
2004	2,429,463.21	570,718.14	3,000,181.36
2005	2,550,936.37	570,718.14	3,121,654.52
2006	2,678,483.19	570,718.14	3,249,201.33
2007	2,812,407.35	570,718.14	3,383,125.49
2008	2,953,027.72	570,718.14	3,523,745.86
2009	3,100,679.10	570,718.14	3,671,397.25
2010	3,255,713.06	570,718.14	3,826,431.20
2011	3,418,498.71	570,718.14	3,989,216.86
2012	3,589,423.65	570,718.14	4,160,141.79
2013	3,768,894.83	570,718.14	4,339,612.97
2014	3,957,339.57	570,718.14	4,528,057.71
2015	4,155,206.55	570,718.14	4,725,924.69
2016	4,362,966.88	570,718.14	4,933,685.02
2017	4,581,115.22	570,718.14	5,151,833.36
2018	4,810,170.98	570,718.14	5,380,889.13
2019	5,050,679.53	570,718.14	5,621,397.67
2020	5,303,213.51	570,718.14	5,873,931.65
2021	5,568,374.18	570,718.14	6,139,092.33
2022	5,846,792.89	570,718.14	6,417,511.04
2023	6,139,132.54	570,718.14	6,709,850.68
2024	6,446,089.16	570,718.14	7,016,807.31
2025	6,768,393.62	570,718.14	7,339,111.76
2026	7,106,813.30	570,718.14	7,677,531.45
2027	7,462,153.97	570,718.14	8,032,872.11
2028	7,835,261.66	570,718.14	8,405,979.81
2029	8,227,024.75	570,718.14	8,797,742.89
2030	8,638,375.99	570,718.14	9,209,094.13
2031	9,070,294.78	570,718.14	9,641,012.93
2032	9,523,809.52	570,718.14	10,094,527.67
2033			

Appendix A – Multiple Year Cash Flows

Summary of Data for Journal Entry Consideration

January 1, 2003	Debit	Credit	
Long-lived asset increase (asset retirement cost)	226,303,726.91		Present Value
Accumulated Depreciation on the Books (To date Decommission Fund + Fund Earnings Ttls)	-		Calculated YE 2002
Cumulative-effect adjustment DR = UNDERFUNDED CR = OVERFUNDED	271,685,417.71		
Accumulated Depreciation		71,259,716.06	PV Depreciated through 2002
ARO liability		426,729,428.56	Accretion to Date PLUS PV
Total	497,989,144.62	497,989,144.62	
December 31, 2003			
Depreciation exp annual 2003	5,481,516.62		Per schedule summed 2003 from each schedule
Accumulated dep annual 2003		5,481,516.62	
Accretion exp annual 2003	21,336,471.43		Per schedule summed 2003 from each schedule
ARO liability 2003		21,336,471.43	
Total	26,817,988.05	26,817,988.05	

Appendix B – Unregulated and Regulated Operations ARO Journal Entry Assumptions

Implementation Date:	01/01/03
Date Asset was placed in service;	01/01/95
Asset Useful Life:	20
Retirement Date:	12/31/14
Future Value (Inflation) Rate:	4%
Discount Rate (Credit-adjusted risk-free rate):	6.5%
Contractor's Mark-up:	20%
Market Risk Premium	5%
COR Liability Accrued to Date or Cost embedded in Accumulated Depreciation:	$500,000
Cash Payment to settle ARO on 12/31/14:	$900,000
Depreciation is calculated based on:	20
Accretion is calculated by using the credit-adjusted risk-free rate	6.5%
Original Asset Value (for which ARO is attached)	$5,000,000
Corporate tax rate:	45.0%

Initial Measurement of the ARO liability at 01/01/03

Labor	$200,000
Overheads & Equipment (80% X $200.000)	$160,000
Contractor's Mark-up (20% X ($200,000 + $160,000)	$72,000
Expected Cash Flows Before Inflation	$432,000
Expected Cash Flows Adjusted for Inflation	
Inflation Factor assuming 4% for 20 years ($432,000 X (1 + 4%) ^ 20) From 01/01/95 to 12/31/14	$946,565
Market Risk Premium ($946,565 X 5%)	$47,328
Total Expected Cash Flows (1)	$993,893
Present Value using the credit-adjusted risk-free rate ($993,893 / (1 + 6.5%) ^ 20) (2)	$282,064

NOTE:
(1) The amount represents the future value of the ARO (i.e., the anticipated liability amount (expected cash flow) when the asset is removed. This is the amount that the current liability ($282,064+$184,751 = $466,815) would accrete to every month from implementation date (assuming 01/01/03 in this example) to 12/31/14 at a rate of 6.5%. G/L Systems should be programmed to calculate the monthly accretion from the original liability ($466,815) to the expected cash flows at 12/31/14). Total final liability is $993,893.

(2) The initial ARO liability as of 01/01/03 and the capitalized asset cost is to be provided. No GL calculation will be required.

ADDITIONAL CONFIGURATION REQUIREMENTS:
1. There must be a way to link the original asset ($500,000) and ARO asset ($282,064) and the liability ($466,815 to $993,893)
2. The original asset, ARO asset and ARO liability must be retired at the same time. The accretion on the ARO liability stops upon settlement.

EDISON ELECTRIC INSTITUTE
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696

AGA
American Gas Association

LG&E Energy LLC

Supporting Papers
FIN 47 Implementation

December 31, 2005

Executive Summary

In June 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (SFAS No. 143). LG&E Energy LLC and associated Companies (the Company) adopted SFAS No. 143 as of January 1, 2003.

SFAS No. 143 resulted in a significant accounting change for the Company and its regulated utilities. The standard changed the way companies recognize and measure legal retirement obligations that result from the acquisition, construction and normal operation of tangible long-lived assets. A legal obligation is an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or contract. **Please refer to the Appendix A for the "SFAS No. 143 Supporting Papers" document for details (executive summary, journal entries, etc) of the implementation of SFAS No. 143. A binder is also kept in Property Accounting Department which contains this same document as well as detailed attachments.**

In March 2005, the FASB issued Financial Accounting Standards Board Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* (FIN 47). FIN 47 clarifies that the term "conditional asset retirement obligation" as used in SFAS No. 143 refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. An entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Stated otherwise: While the initial implementation of SFAS No. 143 required the accrual of an asset retirement obligation (ARO) liability for legally required removal costs, AROs were not recorded for legally required disposal costs related to assets which themselves were never legally required to be retired. Therefore, even though a legal requirement may have existed to dispose of items such as asbestos once the building was leveled, there was no legal requirement to level the building (it could be abandoned in place), and so no ARO was recorded under SFAS 143. FIN 47 has provided interpretative guidance around this issue which will result in the establishment of AROs for these "conditional" obligations based on the premise that, barring intervening circumstances, the building containing the asbestos will be removed from service as a result of its eventual deterioration. The ability of an entity to indefinitely defer settlement of an ARO does not relieve the entity of the obligation. Implicit in this conclusion is the belief that no tangible asset will last forever (except land).

As a result of the issuance of FIN 47, the Company has established additional AROs. The accounting treatment for the establishment of these additional AROs under FIN 47 remains the same as AROs set up under SFAS No. 143. LG&E and KU evaluated the impact of this pronouncement and have identified a list of possible AROs including:

asbestos, PCBs and other contaminants, hydro generation, treated poles, manholes, tires, water pump structures and various gas storage and distribution assets.

FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005 for the Company). The cumulative effect of initially applying FIN 47 will be recognized as a change in accounting principle. Pro forma disclosures are required in the footnotes to the financial statements for the beginning of the earliest year presented and at the end of all years presented for the amount of the liability for AROs as if FIN 47 had been applied during all periods affected.

Analysis

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Analysis of FIN 47, which began in second quarter 2005, was a coordinated effort of accounting, legal, environmental, operations and senior management personnel. Much of the preliminary work required to identify possible assets which might fall within the scope of FIN 47 had been completed during the original implementation of SFAS No. 143. Various documents from the SFAS No. 143 implementation were reviewed including the legal review memo prepared by the Legal Department and the SFAS No. 143 Executive Summary prepared by Property Accounting. A list of assets was compiled based on the review of these documents and included assets specifically (asbestos, treated poles) mentioned in FIN 47.

A general overview of assets identified by functional group follows.

Overview

KU and LG&E have certain electrical equipment containing PCBs, such as transformers and capacitors, which require special disposal. Although, both companies undertook a program in the 1980s to replace this PCB impaired equipment, plant and distribution personnel were utilized to determine if additional ARO liabilities existed, in accordance with FIN 47. The review found that distribution transformers, containing PCB oil, were remediated prior to the enactment of FASB 143 and that necessary AROs for PCB contaminated oil related to GSUs (Generator Step-Up Transformer's) and oil storage tanks were established under FASB 143. No additional AROs are needed, under FIN 47, related to PCB oil.

Batteries are used in substation areas to power equipment when electricity is shut down at generating facilities. Steve Legler, Fred Jackson, Bryan Baker, Russell Baker and Sam Carr provided the estimates of disposal, in accordance with FIN 47. The implementation ARO liability for 14 locations averages $1,019 each. The total estimated costs, from all sources, associated with the disposal of the batteries are considered immaterial for purposes of FIN 47 and thus no ARO liability is being established.

Remediation of lead paint is an environmental issue. Steve Legler offered guidance in this area. Steve indicated that there are several ways to remediate the lead paint. The cost of the remediation varies greatly with the method selected. As p~~Since there are no~~

~~plans to demolishing any structure containing lead paint, the method of remediation or the cost involved is not known.~~ aint is an Operation and Maintenance expense item, any cost of remediation would be expensed as incurred. A ~~It is not reasonable to estimate a remediation cost with so many unknown variables.~~scenario does not currently exists that would require an ARO liability for lead paint. Therefore, no ARO liability for lead paint ~~will be set up~~is being established.

Generation

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Neither LG&E nor KU identified a legal obligation to demolish steam generating plants or restore the land to "green field condition" when a power plant is decommissioned. The utilities' past practice has been to secure retired generating sites in a safe manner and abandon the plant in place. Although no legal obligation exists for the generating units as a whole, a potential ARO was identified for the removal and disposal of asbestos contained in the generating plants. All of the Company's steam generation plants, with the exception of Trimble County, were constructed before 1980. Asbestos is commonly found in assets constructed prior to 1980. Some asbestos abatement has been performed in the past years, but based on discussion with representatives from the various plants, it was determined that much asbestos remained to be abated. Several meetings were held with plant personnel to determine the best method of quantifying asbestos removal and disposal costs associated with generation assets. Ultimately, the group determined that a reasonable estimate could be made based on quotes received from NEC, a reputable company experienced in asbestos abatement. Accordingly, an ARO was established for asbestos at the applicable generating plants.

Inquires were also made of generation personnel to determine if any legal liabilities exist with regard to coal docks and bridges and tunnels. No additional legal liabilities were identified by the Legal Department. Accordingly, no ARO will be established for these items.

Hydro Generation

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LG&E operates its Ohio Falls plant under a 30-year licensing agreement with the U.S. Army Corps of Engineers. This agreement requires the dam to be restored to the Corps' specifications upon abandonment of the plant. The Company has renewed the licensing agreement with the Corps of Engineers continually since the plant's construction and expects to renew the agreement continually at each expiration date. ~~T~~The Corps has not indicated the specifications required upon abandonment of the plant. As no specifications have been made the current ARO liability estimate for this item would be $0~~'s requirements upon abandonment cannot be reasonably quantified~~ and as such no ARO liability is being established.

KU owned the Lock 7 and Dix Dam hydro facilities during 2005. Lock 7 was sold as of December 29, 2005 thus negating the need of an ARO liability. A legal review of the hydro license for Dix Dam found no specific legal obligation upon the final decommissioning of the plant. It should be noted, however, that permitting authorities, particularly FERC, have significant inherent discretion in setting conditions to permit a surrender of a permit. These conditions are based upon the specific facts, issues and concerns at the time of decommissioning. FERCs requirements upon abandonment cannot be reasonably quantified and as such no ARO liability is being established.

An ARO will be established for Ohio Falls asbestos abatement. Documentation from Dan Kremer, Manager Commercial Operations, regarding Asbestos abatement at Ohio Falls is based on actual removal cost of Unit 7 in 2005 plus additional costs associated specifically with Ohio Falls.

An ARO will be established for Dix Dam asbestos abatement. Documentation from Sam Carr, Manager Commercial Operations, regarding Asbestos abatement at Dix Dam is based on analysis provided by Dave Beck.

General Facilities

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Per discussions with Jerry Grant, Manager-Office Services, and Karan Kapp, Senior Budget & Cost Analyst, Facilities, many office buildings, service centers and business offices owned by KU and LG&E contain asbestos. Jerry and Karan were able to identify which facilities contained asbestos based on a comprehensive facility survey which had been undertaken earlier in 2005. Based on this information, an estimate for asbestos removal and disposal was calculated using estimates from reputable vendors and industry standards. The Excel model constructed by Karan Kapp to calculate this estimate was also provided to Transmission, Distribution and Gas in order to facilitate estimates for asbestos in those areas. An ARO for facility asbestos will be established.

Electric Transmission and Distribution

A review of the electric transmission substations was completed by Transmission personnel for asbestos. It was estimated that 10 LG&E transmission substations and 69 KU transmission substations contain asbestos in the roofs, floor tiles or insulation. An estimate was prepared based the asbestos model developed by Karan Kapp. An ARO will be established for the removal and disposal of asbestos.

A review of electric distribution substations was completed by Distribution personnel for asbestos. A detailed review was undertaken for LG&E substations and it was estimated that approximately 66 substations contained asbestos in the roofs, floor tiles or insulation. For KU, it was estimated that 10% or 47 substations contained asbestos. The asbestos exposure for KU's substation is limited primarily to wiring as the buildings themselves are constructed of metal. Estimates were prepared based on the asbestos model developed by Karan Kapp. AROs will be established for the removal and disposal of asbestos.

LG&E and KU own transmission and distribution lines that operate under perpetual property easement agreements. These easements do not generally require restoration of the right of way or removal of the property. Therefore, no legal liability exists to remove poles and attached cross arms. However, there are environmental regulations which require the proper disposal of treated poles and cross arms into a different section of the landfill. Upon investigation it was determined that treated poles are disposed of at the same costs as disposal of untreated utility poles in the main section of the landfill. No incremental costs of disposal exist, and accordingly an ARO is not required under FIN 47.

Gas

LG&E owns a gas transmission and distribution system that operates under perpetual property easement agreements. If an easement were to be released, the Company does not have an obligation to remove the system but retires it in place. However, the Company does have a legal obligation to purge the gas and cut and cap the pipes upon abandonment. Peter Clyde, Group Leader Engineering & Planning used a completed large scale 2004 main replacement project from 2004 for the basis of his estimate to calculate an ARO for cutting, capping and purging of gas pipes. An ARO has been established based on Peter's estimate.

LG&E operates wells in its gas storage system that must be plugged if abandoned, per Kentucky mines & minerals law/regulations. The estimated cost of plugging the 593 wells is $10.9 million in total. Because LG&E intends to operate the wells perpetually and the retirement date is indeterminate, no ARO was established under SFAS 143. With the additional guidance from FIN 47 regarding the assumption that no asset will last forever, an ARO will now be established as part of the FIN 47 implementation.

LG&E also operates 4 above ground gas compressor stations under perpetual lease agreements. The ground leases for the Muldraugh KY, Cedar Fields IN, and Brandenburg KY (Riggs and Doe Run sites) were reviewed for contractual obligations. A 1946 letter of agreement to the Brandenburg KY (Riggs site) lease requires LG&E to "return it to lessor on the expiration of this lease in approximately the same condition as found at the present time." The estimated cost to dismantle and remove the Brandenburg station is $65,000.

Beyond the above, the leases did not contain any required actions upon abandonment except an obligation to pay $1 to terminate the lease itself. (Additionally, under the Muldraugh lease, LG&E is permitted, but not required to remove equipment. Facilities left after termination become government property.)

Based on the review of the agreements an ARO will be established for the Brandenburg KY (Riggs site) compressor station only.

A review of the compressor stations, gas regulator stations and city gate facilities revealed various amounts of asbestos. Estimates for removal and disposal were formulated by personnel in the Gas Storage and Gas Control Departments. These estimates were based on the asbestos model developed by Karan Kapp and modified as necessary. An ARO will be established for these costs consistent with asbestos amounts identified in other lines of business.

LG&E Energy Corp.

Supporting Papers
SFAS 143 Implementation

December 30, 2002

Executive Summary

In June 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. LG&E Energy Corp. and associated Companies (the Company) intend to adopt Statement 143 as of January 1, 2003.

Statement 143 results in significant accounting change for the Company and its regulated utilities. The standard changes the way companies recognize and measure legal retirement obligations that result from the acquisition, construction and normal operation of tangible long-lived assets. A legal obligation is an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or contract.

Prior to Statement 143, the Company's regulated utilities accrued retirement and removal costs as a component of depreciation expense. SFAS 143 prohibits this approach for assets within its scope. Asset retirement obligations (AROs) must now be recognized as a liability and measured at fair value. The cost associated with the recognition of the asset retirement obligation is capitalized as part of the related asset's book cost and is depreciated over the expected life of the asset.

The asset retirement obligation is initially recorded at fair value. In each subsequent period, the liability is increased through the recognition of accretion expense. Much as depreciation expense allocates the cost of installing an asset over its useful life, accretion expense allocates the cost of removing an asset over its useful life. Accretion expense appears as an operating expense in the income statement.

At adoption the Company must recognize the cumulative effect of applying the statement as a change in accounting principle. The amount reported as a cumulative effect adjustment in the statement of operations is the difference between the amounts recognized in the statement of financial position prior to the application of Statement 143 and the net amount that is recognized in the financial statements by applying the standard. Asset retirement obligations that are currently recorded by the regulated utilities as part of accumulated depreciation will be reversed as part of the cumulative effect adjustment.

The Company expects to book significant ARO assets and liabilities related to its regulated utilities. However the Company expects the standard to be revenue neutral for its utility operations through the application of SFAS 71, Accounting for the affects of Certain Types of Regulation. (See Appendix H, pg. 21)

Planning

The Company began planning for SFAS 143 in the 4th quarter of 2001. A four-stage implementation timeline was developed consisting of analysis, planning, implementation and adoption stages.

The planning stage involved developing the proper approach, reactions and strategies. It also involved communication with regulators, outside auditors and industry members and associations to evaluate consistency with the industry.

During 2001 and 2002 the Company participated in numerous industry and regulatory forums to gain an understanding of the standard and to ensure consistency with the industry. These forums included:

EEI Asset Retirement Obligations Seminar – October 2001

EEI Roundtable Discussion on Accounting for AROs – March 2002

EEI – FERC Accounting Liaison meeting April 2002

FERC Technical Conference – May 2002

AGA/EEI ARO Seminar – July 2002

EEI – FERC Accounting Liaison meeting October 2002

Through its participation in these forums the Company has developed an understanding of the standards' technical requirements consistent with the industry. The Company advocated this understanding before the Federal Energy Regulatory Commission at the EEI – FERC Accounting Liaison meetings in April and October 2002. On April 9, 2003 the FERC issued Final Order No.631 'Accounting Reporting and Rate Filing Requirements for Asset Retirement Obligations" in Docket No. RMO2-7-000. The Final rule was consistent in all material respects with the company's understanding of SFAS 143.

The Final Rule in effect revises the FERC chart of accounts to accommodate FAS 143 accounting. Specifically it establishes new balance sheet accounts for the ARO assets and liabilities. It also establishes new income statement accounts for accretion and depreciation expense. In addition, the NOPR grants utilities the authority to transfer removal costs previously accrued under regulatory accounting practices to the new liability accounts. Thus, all ARO assets within the scope of SFAS 143 will be subject to the new FERC accounting procedures. Current regulatory depreciation practices remain in place for all non-ARO assets. Because the Final Rule provides for the establishment of regulatory assets and liabilities when companies meet the requirements of SFAS 71, the Company expects SFAS 143 to be revenue neutral for its regulated entities.

Analysis

The analysis stage, which also began in first quarter 2002, was a coordinated effort of accounting, legal, environmental, operations and senior management personnel. The determination of whether assets are within the scope of Statement 143 is essentially a review of legal documents past and present that relate to the purchase, construction, development, or normal operation of the asset. The Company has numerous tangible long-lived assets that were constructed over many decades. Thus, significant effort and resources were required to identify the legal obligations associated with plant assets.

The Company addressed the analysis stage from both a legal and operations perspective. First, a working group was assembled representing legal, accounting, environmental and operating personnel. This group was trained on the standard, including what qualified as an ARO and how to identify qualifying AROs, prior to the identification process

The legal department was then asked to perform a review of legal documents including laws, statutes, contracts, permits, certificates of need and right of way agreements. Operations personnel were asked to identify and quantify known retirement and removal activities undertaken within their group for review as a potential ARO. The environmental group was asked to identify any environmental regulation that obligated the company upon disposal of an asset.

Through this process, a preliminary inventory of ARO assets was quantified for each functional group and the relevant legal requirement was documented. Preliminary results by functional group are as follows.

Generation

Neither LG&E nor KU identified a legal obligation to demolish steam generating plants or restore the land to “green field condition” when a power plant is decommissioned. The utilities’ past practice has been to secure retired generating sites in a safe manner and abandon the plant in place. Although no legal obligation exists for the generating units as a whole, both utilities identified AROs associated with component assets when a generating plant is decommissioned. These AROs primarily arise from environmental regulation.

The preliminary inventory of steam generation obligations were identified, in part, based on the Company’s recent experience with the retirement of its Pineville generating unit. The Pineville generating unit failed in early 2002 and was retired from the Company’s’ books. Because the failure and retirement occurred prior to the implementation of SFAS 143 it was not within the scope of the statement. However, based on that experience, operating personnel developed an inventory of potential AROs and actual third party decommissioning costs related to steam generating assets. Potential AROs identified included:

Holding pond remediation

Coal and limestone storage pile remediation

Boiler water remediation

Oil storage tank remediation

Removal and disposal of underground storage tanks

Empty and remediate all above ground hazardous material storage

Remove and remediate all mercury sources

Drain generation step up transformers and wrap in nitrogen blanket

Ground water monitoring

In addition to the potential AROs suggested by the Pineville experience, the evaluation included a search for potential AROs that were not pertinent to Pineville, but might relate to another facility. Each power plant manager was asked to evaluate the retirement activities necessary at their location to identify potential AROs specific to that location.

Once generation personnel developed the inventory of potential AROs, the Environmental Department was asked to document the regulatory requirement giving rise to the obligation, When no environmental obligation was found the legal department was asked to review the potential ARO to determine if any legal obligation existed. Through this process, the Company was able to establish a definitive legal/regulatory obligation for each ARO included in the final inventory.

The Company's findings based on actual experience at Pineville and the input of power plant managers are consistent with the industry white paper published by the Edison Electric Institute (EEI) in August 2002.

Hydro Generation

LG&E operates its Ohio Falls plant under a 30-year licensing agreement with the U.S. Army Corps of Engineers. This agreement requires the dam to be restored to the Corps' specifications upon abandonment of the plant. The cost of this restoration is estimated at $8 million. The Company has renewed the licensing agreement with the Corps of Engineers continually since the plants' construction and expects to renew the agreement continually at each expiration date. Therefore, because the hydro plant has an indeterminate retirement date no ARO liability is being established at this time.

KU owns two hydro facilities, Dix Dam and Lock 7. Estimated decommissioning costs for these plants are $1.3 million and $3.4 million respectively. However, a legal review the hydro licenses found no specific legal obligation upon the final decommissioning of these plants. It should be noted, however, that permitting authorities, particularly FERC, have significant inherent discretion in setting conditions to permit a surrender of a permit. These conditions are based upon the specific facts, issues and concerns at the time of decommissioning. In the case of Lock 7, a study determined that it was likely that surrender of the FERC permit would involve both removal of generation equipment and demolition of station down to water line. Because no specific legal liability was identified and the retirement date is indeterminate no ARO liability is being established at this time.

Electric Transmission and Distribution Plant

In general, the Company and the industry operate its transmission and distribution (T&D) lines as if the assets will be operated into perpetuity. Even if the utility were to cease business, it is more likely than not that another energy company would simply takeover the lines.

LG&E and KU own transmission and distribution lines that operate under perpetual property easement agreements. These easements do not generally require restoration of the right of way or removal of the property. If an easement were to be released, the company would retire the equipment in place and maintain it in a safe manner.

However, there are components of T&D that have retirement obligations associated with them due to environmental or other contractual agreements. KU and LG&E have certain electrical equipment containing PCBs, such as transformers and capacitors, which require special disposal. Both companies undertook a program in the 1980's to replace this PCB impaired equipment. Thus the companies have few if any obligations related to PCB contamination. The retirements related to these assets were addressed for frequency and materiality to determine if the interim retirement would fall within the scope of SFAS 143 as described below.

Per Mike Toll Manager Transmission Planning and Substations, there are no legal or environmental requirements for disposal of station transformers. Other substation equipment such as bushings may have some obligation related to PCB contaminants. If so, this equipment must be disposed of per EPA regulation. However the cost, less than $20K per year, is immaterial. In 2002, the Company disposed of four assets at a cost of $17K. The 2002 activity was higher than normal according to Mike Toll. In addition, specific assets impacted are not identifiable until failure or replacement.

Per Andre Johnson, Team Leader Environmental and Transformer Services, PCB contaminated line transformers must be disposed of per environmental regulation. The company disposes of PCB contaminated line transformers through a third party vendor. LG&E costs were approximately $10K in 2002. KU costs were approximately $42K in 2002. Based on 2002 disposals the cost of this activity on an annual basis is immaterial. In addition, specific assets impacted are not identifiable until failure or replacement.

Both utilities determined that the retirement of T&D generation step up transformers are within the scope of SFAS 143 since a final retirement date and decommissioning costs could be reasonably estimated. These transformers are located at the generating stations and subject to certain environmental requirements upon final retirement of the generating units. No other AROs were identified related to interim T&D retirements.

In summary, LG&E and KU have identified certain T&D obligations related to the final retirement of generating units. No other material retirement obligations were identified for Electric Transmission and Distribution. In addition, the Company's T&D system as a whole is being operated as a perpetual asset. Therefore, the retirement date is indeterminate and no ARO can be calculated. This position is consistent with both the EEI white paper and industry practice.

Gas Transmission and Distribution Plant

LG&E owns a gas transmission and distribution system that operates under perpetual property easement agreements. If an easement were to be released, the Company does not have an obligation to remove the system but retires it in place. The Company operates the gas transmission and distribution system as if the assets will be operated into perpetuity. Even if the utility were to cease business, it is more likely than not that another energy company would takeover the lines.

However, LG&E operates wells in its gas storage system that must be plugged if abandoned, per Kentucky mines & minerals law/regulations. Because LG&E intends to operate the wells perpetually and the retirement date is indeterminate, no ARO has been established. The estimated cost of plugging the 546 wells is $17 thousand per well or $9.2 million in total.

LG&E also operates 4 above ground gas compressor stations under perpetual lease agreements. The ground leases for the Muldraugh KY, Cedar Fields IN, and Brandenburg KY (Riggs and Doe Run sites) were reviewed for contractual obligations. A 1946 letter of agreement to the Brandenburg KY (Riggs site) lease requires LG&E to "return it to lessor on the expiration of the this lease in approximately the same condition as found at the present time." The estimated cost to dismantle and remove the Brandenburg station is $48 thousand.

Beyond the above, the leases did not contain any required actions upon abandonment except an obligation to pay $1 to terminate the lease itself. (Additionally, under the Muldraugh lease, LG&E is permitted, but not required to remove equipment. Facilities left after termination become government property.)

Because the review of the agreements revealed no legal obligations, other than for the Brandenburg/Riggs site, no AROs are being established. In addition because the Brandenburg/Riggs site is operated as a perpetual asset with an indeterminate retirement date no ARO is being established for that site. However the estimated costs of the Brandenburg/Riggs contractual obligation is being disclosed in the footnotes to the financial statements.

In summary, LG&E has identified certain immaterial obligations related to the abandonment of its gas storage wells and the Brandenburg compressor station. No other AROs have been identified for Gas Transmission and Distribution. Because the system is being operated as a perpetual asset and the retirement date is indeterminate no AROs are being established. The amount of the potential obligation at the Brandenburg site is being disclosed in the footnotes to the financial statements. This position is consistent with both the EEI white paper and industry practice.

Cash Flow Modeling

Concurrent with the identification of potential AROs, the company has developed a cash flow model to calculate and comply with the various recognition and measurement provisions of the standard. (See Appendix A) The model calculates:

1. The amount of the ARO asset and liability to be established as of the original in service date
2. Annual accretion expense from the original in service date
3. The cumulative ARO liability at the transition date
4. Depreciation expense on ARO asset from the original in service date
5. Cumulative depreciation on ARO asset at the transition date
6. Depreciation and Removal cost related to underlying asset from the original in service date
7. Regulatory asset/liability due to the difference between regulatory and GAAP accounting methods

Inputs to the model are as follows:

1. Asset original cost – Original installation costs per company fixed asset records. This is the basis for determining removal costs previously accrued through regulatory depreciation.
2. Regulatory depreciation rate- Depreciation rate established in Company's most recent depreciation study.
3. Salvage rate- Calculated rate based on net salvage data from Company's most recent depreciation study. This represents the removal cost component of regulatory depreciation rates.
4. GAAP depreciation rate- the regulatory depreciation rate less the salvage rate. This represents depreciation allowable under SFAS 143. This rate is applied to the ARO asset and the underlying tangible asset going forward.
5. In service date- Original asset in service date per company fixed asset records.
6. Retirement date- Estimated retirement date based on Company's most recent depreciation study.
7. Discount rate-Current corporate utility bond index rate for A rated issuers as reported by Bloomberg. 6.61 % as of December 2002.
8. Inflation rate- 30-year Treasury bond rate less 30-year inflation adjusted bond rate as reported by Bloomberg. 2.1% as of November 2002.

9. ARO in Current $- Estimated fair market cost to settle obligation today

Accounting Systems

Based on the guidance issued in the FERC Final Order, the Company believes that significant software modifications are not necessary to implement SFAS 143. Because the number of AROs is limited, the company expects to track AROs with its current accounting system and spreadsheet applications. The Company's chart of accounts and accounting systems were modified to reflect the new income statement and balance sheet accounts established in the FERC NOPR.

Accounting Procedures

The FERC Final Order on SFAS 143 requires that the Company keep subsidiary records and supporting documentation for each asset retirement obligation. The Company must record the identity and nature of the legal obligation, the year incurred, the underlying asset giving rise to the obligation and supporting computations related to the measurement of the obligation. The Company has revised its accounting procedures to comply with the FERC requirements as follows.

Initial ARO Establishment-

1. <u>ARO Asset</u>-Upon establishment of an ARO, an asset equivalent to the present value of the retirement obligation is established in the appropriate FERC plant account of the ORACLE fixed asset module. The fixed asset records shall include a description of the ARO asset including the underlying tangible asset #, the amount of the asset, the FERC plant account, the location code, the original in service date and the estimated retirement date
2. <u>Underlying Tangible Asset</u>-The ARO asset is linked to the underlying tangible asset in existing records by referencing the asset number of the underlying asset in the description field of the ARO asset.
3. <u>ARO Liability</u>-An offsetting liability is established in account 230 by creating a distinct and separate project for each ARO liability in the ORACLE project accounting module. The project accounting records shall include a description of the ARO liability, the related ARO asset #, the underlying tangible asset #, the amount of the original liability, the location code, the ARO inception date and the expected settlement date

Depreciation

1. ARO Asset - Depreciation expense related to the intangible ARO asset is charged to account 403.1, "Depreciation for Asset Retirement Costs". A corresponding credit is charged to Account 108.1 "Accumulated Reserve for Depreciation of ARO Assets"
2. Underlying Tangible Asset - Depreciation expense related to the underlying tangible asset is charged to account 403 "Depreciation Expense." A corresponding credit is charged to Account 108 "Accumulated Provision for Depreciation of Electric Utility Plant".

3. Depreciation rates – The depreciation rate approved by the Public Service Commission for regulatory accounting purposes is applied to the underlying asset. However, because SFAS No. 143 does not allow the accrual of removal costs through depreciation for assets within its scope and because the Company qualifies for SFAS 71 treatment, a regulatory asset or liability will be established to record the difference between depreciation allowed by regulators and that allowed by GAAP.

   The depreciation rate allowed by GAAP is applied to the ARO asset going forward. The GAAP rate is the rate approved in the Company's most recent depreciation study less the net salvage component.

Accretion

1. Accretion expense – Accretion expense is charged to account 411.10, "Accretion Expense". A corresponding credit is charged to Account 230 "Asset Retirement Obligations"

Cumulative Effect adjustment

1. The cumulative effect adjustment is established by a debit to account 435 "Extraordinary Deductions". Offsetting credits are charged to account 230, "Asset Retirement Obligations" for the accumulated accretion and to Account 108.1, "Accumulated Reserve for Depreciation of ARO Assets" for accumulated depreciation. (The cumulative effect adjust is equivalent to the total accumulated accretion and depreciation expense that would have been accrued if the liability had been established at the time the liability was originally incurred, less any removal costs accrued through regulatory depreciation)

Regulatory Assets and Liabilities

1. Regulatory Assets –Pursuant to SFAS 71, depreciation and accretion expense related to the ARO asset and liability is offset with a regulatory asset. The regulatory asset is established by a debit to account 182.3, "Regulatory Assets". A corresponding regulatory credit is established in account 407.4 "Other Regulatory Credits". (See Appendix I)
2. Regulatory Liabilities – Pursuant to SFAS 71 previously accrued removal costs in excess of that allowed under SFAS 143 is offset with a regulatory liability. The regulatory liability is established by a credit to account 254, "Regulatory Liabilities". A corresponding debit is established in account 407.3 "Other Regulatory Debits"

Settlement

1. Gain on Settlement – Gains resulting from the settlement of an asset retirement obligation are charged to account 411.6, "Gains from Disposition of Utility Plant"
2. Loss on Settlement - Losses resulting from the settlement of an asset retirement obligation are charged to account 411.7, "Losses from Disposition of Utility Plant"(see Appendix H)

Identifying Removal Costs Currently Recorded

The Company estimated the amount of removal costs related to AROs recorded in its accumulated reserve. The estimate is based on data from the Company's most recent depreciation study. Based on that study the Company determined the removal cost component inherent in each depreciate rate. That removal cost component is applied to the original cost and in-service date of the underlying asset to estimate the removal cost accrued for the specific asset. The estimated removal costs related to ARO assets was removed from the accumulated reserve pursuant to the FERC Final Order No.631 'Accounting Reporting and Rate Filing Requirements for Asset Retirement Obligations".

Subsequent to the Company's implementation of SFAS 143 the FERC issued its Final Order No. 631. The order required Companies to estimate the cost of removal embedded in the accumulated reserve for non-ARO assets and to segregate those cost within Account 108 for reporting purposes.

Pursuant to that Order, the Company contracted for an independent analysis of non-ARO removal costs to be performed in conjunction with its 2003 depreciation study. That analysis was completed and in December 2003 a journal entry was prepared segregating those removal costs within FERC Account 108 "Accumulated Provision for Depreciation of Electric Utility Plant".

Implementation

In the implementation stage which began in the 3rd quarter 2002, t the company;

1. Identified removal cost previously accrued
2. Determined ARO asset write-ups
3. Quantified regulatory assets/liabilities
4. Modified accounting Systems
5. Revised Accounting Policies
6. Communicated with Regulatory Agencies
7. Discussed implications with the Tax Department
8. Drafted required financial footnotes and disclosures
9. Obtained final management approval
10. Obtained final verification that all regulatory requirements have been identified
11. Verified consistent application across all assets
12. Verified that all obligations identified are included in the calculations
13. Verified that obligations exist for all assets included
14. Ensured compliance with the final FERC order
15. Reviewed final product with PriceWaterhouseCoopers

Adoption

The company adopted SFAS 143 effective January 1, 2003.

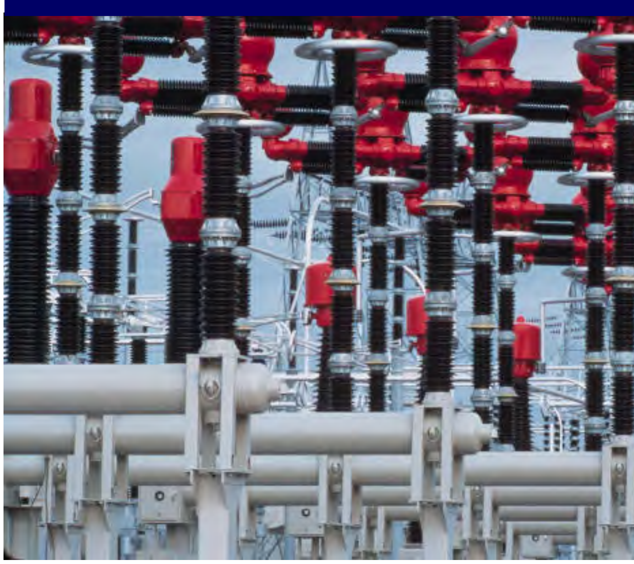
EDISON ELECTRIC INSTITUTE

American Gas Association

FASB Interpretation No. 47

Accounting for Conditional Asset Retirement Obligations

An Industry White Paper



July 2005

EDISON ELECTRIC INSTITUTE

AGA American Gas Association

FASB Interpretation No. 47
Accounting for Conditional Asset Retirement Obligations
An Industry White Paper

Introduction

"This Interpretation clarifies that the term *conditional asset retirement* obligation as used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform the asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event."

This white paper has been written with an eye toward the Electric and Gas utility business. It is intended to assist one in doing the investigation and review necessary to properly recognize and disclose any new asset retirement obligations resulting from the adoption of this Interpretation. Each company will need to work through their particular issues and review all assumptions with their legal staff to assure proper representation of this topic. At first glance, this Interpretation can appear overwhelming. But one needs to approach this in a thoughtful and reasonable manner that represents the intent and purpose of the Interpretation without getting so lost in the details that the accounting becomes impossible to maintain within a cost effective manner. Without careful thought to the intent and the process to achieve it, the accounting for this Interpretation may not be manageable as the issue moves throughout time.

FASB Statement No. 143, *Accounting for Asset Retirement Obligations* provides a complex process for determining recognition criteria, measurement procedures, and accounting and disclosure requirements for the financial implications of an obligation related to the future retirement of existing property. Because FIN 47 represents clarification of a limited, but important, concept within the broad scope of accounting for asset retirement obligations, this document is limited to discussing compliance within this new interpretation. It is beyond the scope of this document to attempt to provide a comprehensive discussion of all the provisions of FASB Statement No. 143.

Another white paper was prepared by EEI and AGA shortly after SFAS 143 was issued. This white paper is supplemental to that earlier one. The following terms and acronyms are used throughout this document.

Term or Acronym	Description
ARC	Asset Retirement Cost (Plant Asset)
ARO	Asset Retirement Obligations
FERC Order 631	Accounting, Financial Reporting, and Rate Filing Docket No. RM02-7-000, *Requirements for Asset Retirement Obligations*
FERC Order 552	Revision to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2-A
FIN 47 or Interpretation	FASB Interpretation No. 47, *Accounting for*

Term or Acronym	Description
	Conditional Asset Retirement Obligations
FSP	FASB Statement of Position
SAB 99	SEC Staff Accounting Bulletin No. 99, *Materiality*
SFAS 71	FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation*
SFAS 143	FASB Statement No. 143, *Accounting for Asset Retirement Obligations*

Reasons for an Interpretation

Diverse accounting practices have been developed with respect to the timing of liability recognition for legal obligations associated with the retirement of a tangible long-lived asset when the timing and (or) method of settlement of the obligation are conditional on a future event. For example, some entities have recognized the fair value of the obligation prior to the retirement of the asset with the uncertainty about the timing and (or) method of settlement incorporated into the liability's fair value. Other entities, however, have recognized the fair value of the obligation only when it is probable the asset will be retired as of a specified date using a specified method or when the asset is actually retired.

The Interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO when incurred if the liability's fair value can be reasonably estimated. The Interpretation clarifies when an entity would have sufficient information to reasonably estimate the fair value of the ARO. This clarification should improve the relevance, reliability, and comparability of the amounts recognized in the financial statements.

The FASB believes application of the Interpretation will result in a more consistent recognition of liabilities relating to AROs, in more information about expected future cash outflows associated with those obligations, and in more information about investments in long-lived assets because additional asset retirement costs will be recognized as part of the carrying amounts of the assets. At the January 26, 2005 meeting, the FASB addressed a request to reconsider the entire concept of recording AROs (see FASB Board minutes at *www.fasb.org/board_meeting_minutes/board_meeting_minutes.shtml*). This discussion provides significant insight to the FASB's expectations and considerable support for the role of management's judgment and reasonableness in the recognition of AROs. In summary, the FASB essentially establishes what disclosure is expected whenever there is an ARO while also narrowing the circumstances in which the measurement could be avoided.

Sufficient Information

In SFAS 143, the term *retirement* is defined as the other-than-temporary removal of a long-lived asset from service. The term *retirement* encompasses sale, abandonment, recycling, or disposal in some other manner. The term does not encompass the temporary idling of a long-lived asset.

- "If an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation, it must recognize a liability at the time the liability is incurred. An asset retirement obligation would be reasonably estimable if (a) it is evident that the fair value of the obligation is embodied in the acquisition price of the asset, (b) an active market exists for the transfer of the obligation, or (c) sufficient information exists to apply an expected present value technique." This is from paragraph 4 of the Interpretation.

- The Interpretation states that when the method of settlement and settlement date have been specified by others such as in a law, regulation or contract, the entity has sufficient information to apply an expected present value technique. Therefore the ARO would be reasonably estimable and a liability must be recorded. The only uncertainty in these situations is whether performance will be required.

  From paragraph 5a, "uncertainty about whether performance will be required does not defer the recognition of an asset retirement obligation because a legal obligation to stand ready to perform the retirement activities still exists", and that uncertainty does not prevent the determination of a reasonable estimate of fair value. There are two possible outcomes in situations in which the only uncertainty is whether performance will be required—the entity will be required to perform or the entity will not be required to perform.

  If there is no information about which outcome is more probable, paragraph A23 of SFAS 143 requires 50 percent likelihood for each outcome to be used until additional information is available. In certain cases, determining the settlement date for the obligation that has been specified by others is a matter of judgment that depends on the relevant facts and circumstances.

- In situations where the date and method of settlement are not specified by others, if information is available to reasonably estimate (1) the settlement date or the range of potential settlement dates, (2) the method of settlement or potential methods of settlement **and** (3) the probabilities associated with the potential settlement dates and potential methods of settlement, the FASB believes sufficient information is present to apply an expected present value technique. Therefore, the ARO would be reasonably estimable and a liability must be recorded.

Information that is derived from an entity's past practice, industry practice, and management's intent can provide a basis for estimating the potential methods of settlement. Entities must take into account only the methods of settling the obligation that are currently available to the entity.

The ability of an entity to indefinitely defer settlement of an ARO does not relieve the entity of the obligation. Implicit in this conclusion is the belief that no tangible asset will last forever (except land) and, accordingly, the asset retirement activities will eventually be performed. Furthermore, the ability of an entity to sell the asset prior to its disposal does not relieve the entity of its present duty or responsibility to settle the obligation. The sale would cause the buyer to assume the obligation, in turn affecting the sales price.

Change in the Way Disposal is Viewed

The FASB believes that if a current law, regulation, or contract requires an entity to perform an asset retirement activity; there is an unambiguous requirement to perform the retirement activity even if that activity can be indefinitely deferred. As noted above, no tangible asset will last forever (except land) and, accordingly, the asset retirement activities will eventually be performed. Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement.

- A law or entity's promise may create a duty or responsibility, but that law or promise in and of itself may not be the obligating event that results in an entity having little or no discretion to avoid a future transfer or use of assets.
- SFAS 143 states that the obligating event is the acquisition, construction, or development and (or) the normal operation of the long-lived asset when a law or promise exists that creates a duty or responsibility relating to the retirement of the asset. At this point, the obligation cannot be realistically avoided if the asset is operated for its intended use.

All companies are subject to federal and state solid waste disposal requirements for non-hazardous materials and refuse[1]. These laws require such materials to be disposed in a licensed public landfill with other household garbage. Although there is no legal obligation to retire assets under these solid waste laws, these retired and dismantled assets must be transported to licensed public landfills. Companies regularly incur monthly expenses for use of these public landfills for disposal of non-hazardous materials and refuse (i.e. garbage) which in most cases would cover disposal of non-hazardous retired assets.

The scope of SFAS 143 and FIN 47 focuses on "special" requirements for disposal of retired assets that would add incremental costs to the retirement of those assets above what a company expenses monthly for non-hazardous material and refuse disposal. This is evidenced by the reference to "special" requirements in the examples to FIN 47 and the proposed FSP on SFAS 143 relating to the European Union (EU) Directive on Waste Electrical and Electronic Equipment that requires EU members to adopt legislation for environmentally sound disposal of electrical and electronic waste equipment.

This white paper assumes that even though some legal obligation may exist to dispose of non-hazardous materials and refuse resulting from retirements of fixed assets, the disposal costs for non-hazardous materials and refuse may be inconsequential for many assets and may not add significant incremental costs to the asset retirement activities. A company may decide that there is not a legal obligation for removal whereby an asset is disposed within the cost boundaries of the standard garbage fees and only incremental charges above this standard may constitute a removal obligation. Moreover, the incremental charge associated with additional service may be considered part of the standard costs. To illustrate this analysis with an example, consider the following removal activities typical for a treated and a non-treated pole:

[1] These rules federal and state regulations are governed under Subtitle D of the Resource Conservation and Recovery Act. Subtitle D regulates garbage, refuse, sludge from waste treatment plants, non-hazardous industrial waste and other discard materials including solid, semi-solid and liquid materials resulting form commercial and industrial activities (e.g. demolition debris, mining waste, oil & gas waste).

Pole Removal Example

		Non-treated	Treated
1.	Labor to removal the pole and haul it to the yard	$75	$75
2.	Grinding the pole into small pieces (not required by regular landfill)	0	10
3.	Transporting the pole to the landfill	15	15
4.	Landfill Fees	10	40

The costs to remove and transport the pole, for both types of pole, would not be considered an ARO in this example. The landfill fees for the treated pole would be considered an ARO, but one would need to determine if the incremental cost would be the ARO basis or would one use the total cost. If the landfill accepting the treated pole is different than the one accepting the non-treated pole, the total cost would be used and if the same facility then the incremental would be applicable. Lastly, the cost to grind the pole would be considered part of the ARO, as this cost is not incurred for non-treated poles.

As always, a full review of the company position on this issue is paramount to defining the magnitude of potential AROs. Each company needs to decide if these laws constitute a legal obligation in respect to the SFAS 143 and the Interpretation. In instances where the legal requirement relates only to the disposal of the asset subject to the ARO, the cost to remove the asset is not included in the ARO. However, if there were a legal requirement to remove the asset, the cost of removal would be included.

Date of Obligating Event

There has been some discussion around when the obligating event occurs. Quickly, most would point to the in-service date of the asset if a law, regulation, or contract creating the obligation was in place before the in-service date. Similarly, one would choose the date the law, regulation, or contract created the obligation if it came to be after the in-service date. However, SFAS 143 refers to obligations that "result from the acquisition, construction, or development and (or) the normal operation of the long-lived asset". One could question if this infers the purchase of material during the construction process or to inventory. Whereby, the company may have incurred a legal obligation before the in-service date of the asset. Timing of the recognition of the ARO, as discussed in paragraphs 3-10 and B32-B41 of SFAS 143, is when all the following criteria are met:

- The obligation meets the definition of a liability in paragraph 35 of Concepts Statement 6.
- A future transfer of assets associated with the obligation is probable.
- The amount of the liability can be reasonably estimated.

During construction of long-lived assets, such as a steam generating plant, legal obligations to eventually retire the plant may be incurred and measurement of those obligations may be prudent during the construction phase. It is important to remember that the obligating event has to have already happened to create a liability. In the case of a nuclear power facility, the obligation to remove the facility may not exist until the facility is operated and contamination occurs. Thus, the contamination constitutes the obligating event. Along with these two instances provided, work performed on leased property also may create a legal obligation during the construction phase. Furthermore, the amount of the liability may grow in subsequent periods as the construction of the asset continues. These changes, in the amount of the original estimate, may need to be recognized as an increase in the carrying amount of the liability.

Another example may be a treated pole purchased to inventory. One could argue that the obligating event has occurred at the purchase of the pole even though it is held for a time in the inventory account before moving through construction work in progress to plant in-service. The assumption presupposes that the manufacturer treated the pole before the company purchased it. The scenario would change if the company treats its poles itself. This component can add more complexity to an already multifarious process.

The definition for the obligating date needs to be fully thought out and clear as to the materiality of and the ability to recognize the obligation before the in-service date. One may likely conclude that the obligation will be flagged during construction or when in inventory only for those exceptionally large items. Otherwise, the in-service date will prevail. For any decision, either for this section or for others throughout this document, one needs to assure that it is legally reviewed and representative of management's judgment as to the correct application of the Interpretation and SFAS 143.

Indefinite Life

FIN 47 does not eliminate the recognition of an indefinite life, but rather distinguishes uncertainty from indefinite. The first sentence in paragraph B22 of the Interpretation provides specific guidance in three clauses where FASB considers an ARO is reasonably estimable, "if information is available":

1. "To estimate the settlement date or the range of potential settlement dates,"
2. "The method of settlement or potential methods of settlement," **and** (*emphasis added).*
3. "The probabilities associated with potential settlement dates and methods of settlement."

The third clause would seem to imply that the **probable** service lives and estimated net salvage developed from utility depreciation studies could lead to the conclusion that an ARO is reasonably estimable. Paragraph B19 through B27 also provided more specific language than originally addressed in SFAS 143, which substantially narrowed the circumstance that would lead to a conclusion that an ARO is not estimable.

The current utility industry position, prior to the release of this Interpretation, is that a company cannot calculate an ARO for the ultimate retirement of its distribution and transmission **systems** because each system has an indefinite life. A depreciation study develops probabilities of life and net salvage for a large group of similar assets, and that many cycles of replacements occur to the group or system. An example of the distinction between a "group of similar assets" versus a "system"; a power line or gas line between two points will probably have multiple retirements and replacement additions (items in a group), particularly if a portion of the line is moved for any reason, but the line itself generally continues long afterwards (as a system). In addition, it is part of a larger group of assets when life analysis is done; all similar power lines or gas lines are considered together. In other words, the probable lives in a depreciation study are on the interim retirements and additions to the line, and not representative of the probable life of the line (or the system). Further, it has been suggested that retirement of the **system** would invoke other accounting pronouncement governing status as an ongoing entity, impairment of an asset, or accounting for discontinued operations.

Accordingly, sufficient information may not be available to reasonably estimate the ARO liability on the ultimate retirement of transmission or distribution property. The industry also does not believe that an ARO should be calculated for such interim retirements when there is not an obligation for that specific interim retirement or when a company cannot reasonable estimate when a specific interim retirement with an obligation would take place. The third characteristic of a liability is that the transaction or other event obligating the entity has already happened. One does not know what portion of a distribution or transmission system will be retired until an event such as a gas leak, storm damage, or a road widening requires work on the asset, making it difficult to estimate the costs and timing. This generally is corrected or recorded in the same accounting period so no liability would be accrued.

However, FIN 47 provides further interpretation of FAS 143 that may require a reassessment of the indefinite life concept. Example 1 specifically addresses this mass asset system versus individual asset contrast and clearly attempts to close the loophole that a system has an infinite life, therefore no ARO can be measured. FIN 47 requires that the fair value of an ARO be recognized when it can be reasonably estimated. It also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. For some utilities, data derived from their most current depreciation study possibly could be a potential source to provide information to calculate an estimated ARO for distribution and transmission assets that constitute an entire system. This data is used to recover property costs (including removal cost) for regulatory purposes and also may serve as a platform for calculating the expected ARO liability. Depreciation study data is used in the Snapshot example within the Mass Assets, Electric and Gas section of this paper.

An argument also can be made that depreciation study data does not provide sufficient information to estimate a reasonable ARO liability. Depreciation data is utilized to provide for matching of existing property cost with the customer benefiting from that property cost. It is not designed, in concept, to provide an estimated liability for the permanent removal of the entire distribution and transmission system. The assumption is the entity will continue to be a going concern. As such, depreciation study data may need to be used cautiously as it may not be an appropriate mechanism to use when calculating all ARO liabilities. Discarding the depreciation study data, no data may be available to reasonably estimate the ARO liability.

Given this quandary, the indefinite life concept currently used by most utilities may continue in effect for the ultimate retirement of the system, but the individual assets comprising the system may not have indefinite life. Again, it was very clear that a "do nothing" scenario might not be a defendable position and that material obligations should be recognized or disclosed if a legal retirement obligation applies to the interim retirement of a system and the timing and method of settlement can be reasonably estimated. Any conclusion needs to be supported with full documentation and justification for the indefinite life choice and should be disclosed.

Materiality

FIN 47 clearly states, "The provisions of this Interpretation need not be applied to immaterial items." However, many immaterial items may constitute, in aggregate, a material item. Determination of materiality is company specific and often an issue-specific routine. It should be defined and documented for each segment of the business. Along with the materiality threshold, a company should define the way in which assets will be summed to test materiality. It is assumed that the test will be for balance sheet materiality, as most utilities will offset any income statement effect with regulatory accounting. When the ARO does impact the income statement, an income statement materiality test may be used. For example, one must decide if distribution assets will be combined with nuclear assets in determining materiality. Perhaps a company will sum all asset obligations relative to a segment of the utility business keeping the nuclear AROs separate from the distribution calculation. Defining the materiality test to a lower level than function should be a decision based on propriety and not with the intent of avoiding this Interpretation. Additional guidance on materiality can be found in the Securities and Exchange Commission's SAB No. 99.

For those companies that have more than one legal entity, the materiality should be done at the individual legal entity and not at the consolidated level. Now, one legal entity may have an ARO and another may not for the same class of assets because of the variety in the rules and regulation as well as the difference in size of the companies. This white paper does not advocate a consolidated materiality review of AROs where multiple legal entities exist within the corporation. The obligation is clearly the responsibility of the originating legal entity and it should be maintained at that level. However, the disclosures may be more detailed on the utility reports and summarized at the parent level.

Decision Tree

In general, a more substantive review of regulations, laws, and contract obligations will be required to assure that conditional AROs are properly recognized. Each company will need to assess its particular facts and circumstances as the same general situation may play out differently depending on the legal documents and company policies that surround it. To help facilitate this review, a decision tree for analyzing each situation is provided below.

<u>Decision Tree Notes</u>

1. Paragraph 3 of FIN 47 advises to include all legal obligations to perform an asset retirement activity, even those in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement.

   Paragraph B7 of the Interpretation states, "As used in Statement 143, a legal obligation is an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel."

2. Paragraph 4 of the Interpretation references paragraph 17 of FASB Concepts Statement No. 7, *Using Cash Flow Information and Present Value in Accounting Measurements,* which states, "If a price for an asset or liability or an essentially similar asset or liability can be observed in the

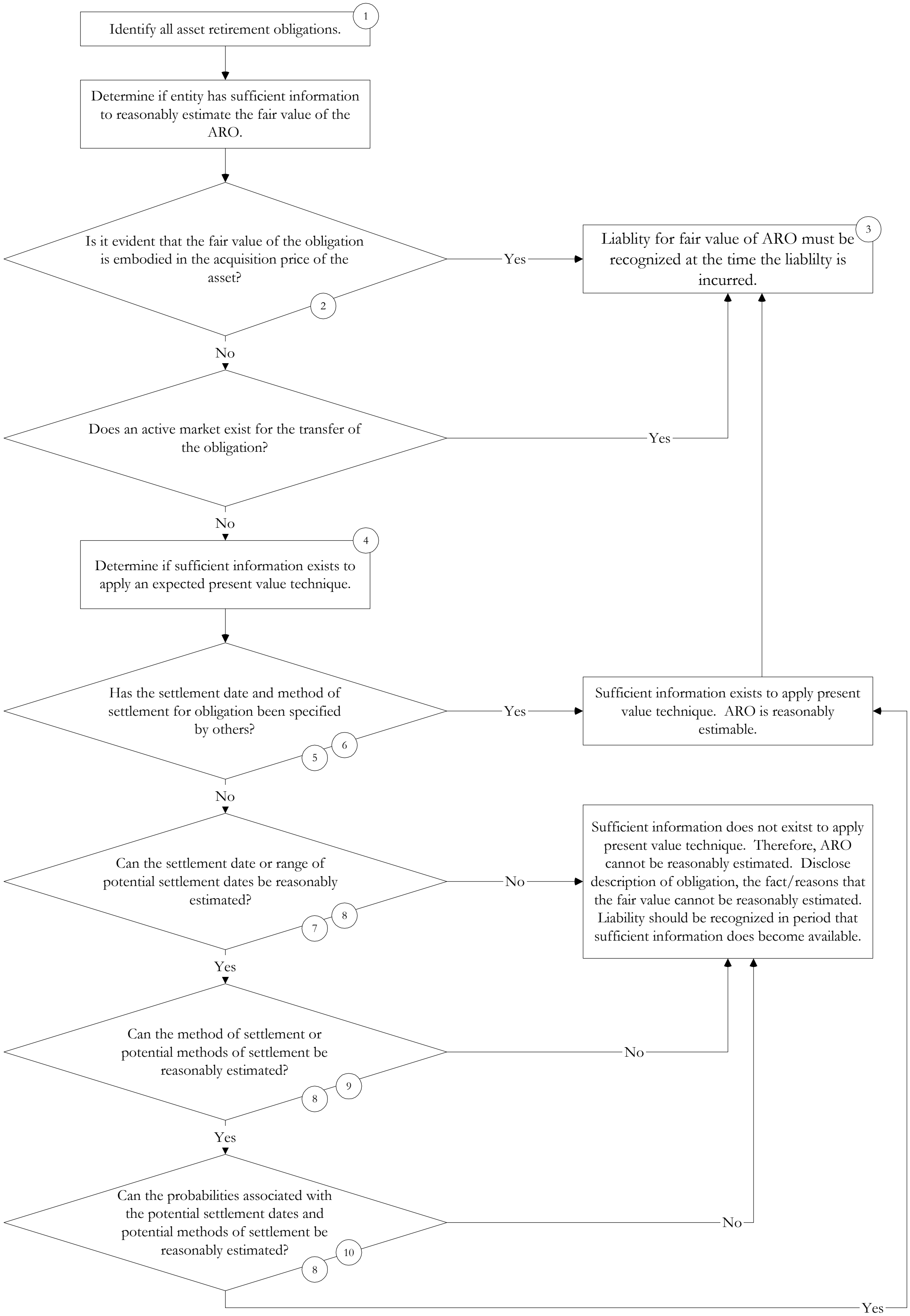
marketplace, there is no need to use present value measurements. The marketplace assessment of present value is already embodied in such prices."

3. Paragraph 3 of the Interpretation reiterates the SFAS 143 requirement that the fair value of an asset retirement obligation be recognized when the obligation is incurred—generally upon acquisition, construction, or development and (or) through the normal operation of the asset.

4. Present value techniques are discussed in paragraphs 39–54 and 75–88 of Concepts Statement 7. These techniques, which incorporate uncertainty about the timing and method of settlement into the fair value measurement, should be used when the fair value of the liability cannot be estimated based on the acquisition price or on an observable market price.

5. For example, specified in a law, regulation or contract (Paragraph 5a of the Interpretation).

Decision Tree



Decision Tree Notes Continued:

6. Paragraph 5a of the Interpretation states that uncertainty about whether performance will be required does **not** defer the recognition of an asset retirement obligation because a legal obligation to stand ready to perform the retirement activities still exists, and it does not prevent the determination of a reasonable estimate of fair value because the only uncertainty is whether performance will be required.

   There are two possible outcomes in situations in which the only uncertainty is whether performance will be required—the entity will be required to perform or the entity will not be required to perform. If there is no information about which outcome is more probable, paragraph A23 of Statement 143 requires 50 percent likelihood for each outcome to be used until additional information is available.

   In certain cases, determining the settlement date for the obligation that has been specified by others is a matter of judgment that depends on the relevant facts and circumstances. For example, a contract that provides the entity with an ability to extend its term through renewal should be evaluated to determine whether the settlement date should take into consideration renewal periods.

7. Paragraph 5b of the Interpretation states that the estimated economic life of the asset might indicate a potential settlement date for the asset retirement obligation. However, the original estimated economic life of the asset might not establish, in and of itself, that date because the entity may intend to make improvements to the asset that could extend the life of the asset or the entity could defer settlement of the obligation beyond the economic life of the asset. In those situations, the entity would look beyond the economic life of the asset in determining the settlement date or range of potential settlement dates to use when estimating the fair value of the asset retirement obligation.

8. Paragraph 5b gives examples of information that is expected to provide a basis for estimating the potential settlement dates, potential methods of settlement, and the associated probabilities. Examples include, but are not limited to, information that is derived from an entity's past practice, industry practice, management's intent, or the asset's estimated economic life.

9. Paragraph 5b of the Interpretation limits "potential methods of settlement" to those methods that are currently available to the entity. Therefore, uncertainty about future methods yet to be developed would not prevent the entity from estimating the fair value of the asset retirement obligation.

10. Paragraph 5b of the Interpretation states that the entity should have a reasonable basis for assigning probabilities to the potential settlement dates and potential methods of settlement to reasonably estimate the fair value of the asset retirement obligation. If the entity does not have a reasonable basis of assigning probabilities, it is expected that the entity would still be able to reasonably estimate fair value when the range of time over which the entity may settle the obligation is so narrow and (or) the cash flows associated with each potential method of settlement are so similar that assigning probabilities without having a reasonable basis for doing so would not have a material impact on the fair value of the asset retirement obligation.

Specific Property Considerations

Four examples were included in FIN 47. This white paper discusses those examples in the context of the Electric and Gas utility business. The examples are as follows:

1. Telecommunication poles
2. Bricks in a kiln
3. Factory with asbestos and regulations go into effect after purchase
4. Factory with asbestos and regulations are in place at acquisition

Basically, the premise put forward by the FASB in this Interpretation was that no tangible asset, except land, would last forever and accordingly, asset retirement activities will eventually be performed. In completing the retirement work, if a company is required to dispose of the asset in a specific manner or could be required to perform any one of a number of different methods of settlement, to be chosen at some later date, the company will need to evaluate the asset's retirement obligations. The four examples provided were meant to cover various situations a company may face. To bring the examples into the context of the energy industry, the list has been tailored to the potential issues for the Electric and Gas business. The following are the asset issues discussed in the remaining document:

1. Mass assets, electric and gas ***(Telecommunication poles)***
2. Minor Items ***(Bricks in a kiln)***
3. Asbestos, PCBs, and other contaminants ***(Factory with asbestos and regulations go into effect after purchase or in place at acquisition)***
4. Rights-of-Way and franchises
5. General equipment
6. Hydro generation

Mass Assets, Electric and Gas

Example 1 of Appendix A, Illustrative Examples, provides specific discussion on wood pole treated with certain chemicals. However, the circumstances may be comparable to other utility property generally described as mass asset property. The following summarizes Example 1, followed by a discussion of comparability and applicability to other mass assets, and finally a discussion of various issues for utilities to consider in their implementation of FIN 47.

<u>Summary of Example 1 of Appendix A</u>
Example 1 discusses a situation in which a utility is using treated wood poles and where there is existing legislation that requires special disposal procedures in the state in which the utility operates. The example recognizes that the poles may be removed from the ground for a variety of operational reasons other than disposal, and further recognizes that the disposal obligation is not triggered by removal of the pole. Once a pole is removed from the ground, it may be disposed of, sold, or reused as part of other activities. In

this example, the disposal obligation is not triggered by removal of the pole. Based on that premise, Example 1 includes specific guidance that requires an assessment of AROs related to treated wood poles. That guidance suggests assessing the ARO and related accounting based on the following:

1. The **recognition point begins with the purchase** of the pole, rather than when the pole was placed into service (in-service date is when the pole first became a long-lived fixed asset). See obligating event and materiality above.
2. That **reuse does not change the obligation**, only defers it (common industry practice is to retire the pole at time of removal, not track it while in inventory, and considered a new addition when reused and placed in the ground again).
3. The **utility already has the information necessary to estimate** a range of settlement dates, methods of settlement, and the related probabilities **based on entity-specific practices, industry practices, management's intent, or the asset's estimated economic life.** (It is important to note that only in the example did the entity have sufficient information to estimate the fair value of the liability for the ARO. Each entity will have to make their own determination as to whether they have sufficient information.)
4. The utility is **not relieved of the obligation by selling** the pole to another party through the assertion that the exchange price reflects the estimated fair value of the obligation.

<u>Impact On Asset Retirement Obligations Accounting</u>
Example 1 of FIN 47 represents a utility that has a legal requirement to follow special procedures for disposal of treated wood poles. In this example, the utility is presumed to have all the information necessary to calculate an asset retirement obligation and is expected to make appropriate disclosure. Therefore, the asset retirement obligation should be recognized when the entity purchases the pole. This may result in a significant change from the requirements under FAS 143, where previous estimates and disclosures were not made because: 1) most disposal activities were performed by third parties so there were no future direct costs to be expended by the utility, 2) it was not reasonable to track the obligation (and settlement) due to reuse and different options for disposal, or 3) that the obligation was conditional due to circumstances known only at the time of removing the pole from the ground. There were no future costs because most utilities could give the poles away to third parties at no cost to the utility, but under FIN 47 even the ultimate disposal cost to a third party is to be considered (that net zero would be bifurcated into the avoided future disposal removal cost and the salvage – remember salvage is not recognizable for ARO purposes.)

Example 1 could apply to other mass asset property where a portion of the asset may be subject to special disposal procedures. Some examples might be property containing PCBs, mercury, lead, or any chemical considered hazardous. In the case of natural gas pipelines, specific activities are legally mandated for abandonment or removal and disposal. The ARO may include the cost of testing, removal, disposal or decontamination of pipeline segments and liquids. In other words, FIN 47 requires that if a utility has a special procedure requirement at ultimate disposal, then the utility either would have a measurable ARO with all the related accounting requirements, which should be recognized if the entity has sufficient information to estimate the fair value of the obligation. If the entity does not have sufficient information to reasonably estimate the obligation, the entity only has a disclosure requirement until sufficient information becomes available.

Concerns and Issues

This raises several concerns and issues for both the individual utility and for the industry:

1. Initial determination of legal obligation – The language seems to indicate that if there is a special disposal procedure, that there will be a cost of performing that disposal activity and therefore, an asset retirement obligation. The legal obligation review may need to be expanded to other assets containing materials, which are considered hazardous with special disposal procedures required by some legal mandate.

2. Record keeping and reporting changes – Many if not most utilities track poles as assets from the date put in the ground until the next time it is removed rather than from purchase to disposal. Time in inventory (initially and upon salvage for reuse) is often not tracked – much less details on how many were treated and what happened to the treated portion at disposal. An individual utility may have to develop such tracking details.

3. Third party disposal – Example 1 states that the "ability to sell the poles prior to disposal does not relieve the entity of its …obligation", and states that "the assumption of the obligation affects the exchange price". This could be a significant issue in compliance for some utilities. It implies that the utility is not relieved of the obligation; and, therefore, should attempt to measure the ARO.

   The use of the pole would affect disposal requirements, as Example 1 clearly requires a company to identify future disposal costs. Therefore, unless there is a market price available, the company would need to apply present value techniques, estimating the life of the pole before disposal. Such information about that future transaction may be particularly hard to estimate when the utility purchases the pole and needs to record the obligation.

4. SEC transfer of other provisions for accrued cost of removal – Any change because of reassessing the ARO for treated wood poles also would affect any recognition of the SEC interpretation on depreciation accruals for future removal costs.

   Background: SFAS 143 does not allow a provision for future removal costs to be included in depreciation reserves. FERC Order 631 provides that utilities that qualify to apply SFAS 71 and if the requirements for Order 552 are met, any provisions for future removal cost would be transferred to a regulatory liability. However, FERC Order 631 continues to allow provision for future removal costs for assets that do not have an existing legal retirement obligation. A conflict may exist because many utilities also have adopted the unofficial SEC interpretation that SFAS 143 does not allow for any accrual of future removal costs, and all provisions for future removal costs should be excluded from accumulated reserves (or transferred to a regulatory liability if eligible for SFAS 71). There is inherent contradiction for many utility assets whereby it needs to be recognized in two different ways for reporting the same activity to the two different entities.

   FERC Order 631 requires that only for accounts where an ARO is recognized, then previous provisions for future removal costs should be transferred from the accumulated reserve (and carried as a regulatory obligation under SFAS 71, if the requirements for Order 552 are met). Many utilities have also adopted the unofficial SEC interpretation that SFAS 143 does not allow for any accrual of future removal costs, and all provisions for future removal costs should be excluded from accumulated reserves (or transferred to a regulatory liability if eligible for SFAS 71).

The cumulative effect adjustment for SEC reporting will be the difference between the amount previously recognized prior to FIN 47 and the amount recognized following the advice in FIN 47 (as mentioned under Transition Accounting below). FERC reporting will be governed by any new advice that FERC may issue prior to adoption of FIN 47.

Recommendation

Since ARO compliance for this category of plant type, mass assets, may be quite onerous, a recommendation is offered for consideration to achieve the intent of the Interpretation without excess burden to the company and the accounting personnel. Each company will need to decide if the recommendation is feasible for their books and records. SFAS 143 (paragraph A22) permits the use of estimates and computational shortcuts that are consistent with the fair value measurement objective when computing an aggregate asset retirement obligation for assets that are components of a larger group of assets. This is appropriate for large transmission and distribution utilities that use group accounting. Therefore, the recommendation is to approximate the literal compliance with FIN 47 with an approximation that uses a statistical based method in order to achieve the **intent** of the statements without incurring undue burden on the accounting personnel.

1. Statistical Method – There are varying levels of information available to the individual utility from their depreciation studies from Simulated Plant Record to Equal Life Group study methods applied property data from individual accounts/sub accounts to functional categories like distribution plant. Even availability of details (such as separating net salvage into removal cost or into removal cost just for treated poles) will vary for different utilities. The following are general descriptions of possible approximation procedures that might be used:

   a. <u>Modified group property/modified depreciation study</u>. Using the latest available depreciation study, the utility could develop the percentage adjustments to indicated life and negative salvage estimates to approximate the timing and the amount of the future removal cash flow. Many utilities have property records that provide the age of existing property and combined with average age, a future cash flow estimate could be prepared for each vintage of property (average age less current age result in the time to expected removal). There may be a standard length of time between removal from service until actual disposal and that could be added to remaining life.

      It may be necessary to analyze the property in the pole account as not all the units may be part of the retirement obligation and to identify a percentage adjustment to approximate the proportion of obligating poles that are treated to all others and adjust the future cash flows to represent only the legally required disposal.

      If dispersion curves were used in the study, the related retirement curves also could be used to approximate the period of disposal. When time estimates and future cash flows are estimated, then one can compute the various ARO elements (ARC, depreciation and accretion tables, and associated regulatory assets). For the first year, monthly entries are made based on that estimate only. In subsequent years and if vintaged retirements are available, it would be possible to go through the individual settlement calculations for each ARO vintage group plus recognize any layers if disposal cost estimates change or a new study is performed. If vintage retirement data is not available, do exactly the same calculation, but true up the components (which would eliminate all the subsequent measurements and layering).

b. Fin 47 requires the use of current assumptions. It may be necessary to perform a new depreciation study to obtain current information on expected lives and removal costs for existing property. Negative salvage estimates that have been taken from depreciation studies reflect previous assumptions. In other words, the study reflects removal costs that have already happened and may not even reflect costs or methods of disposal under a new or recent legal requirement (or only partially reflect it). To the extent that previous assumptions are the same as current assumptions, the depreciation study may be used.

The gross removal portion of the negative net salvage amount also may contain a removal component that may or may not be part of the retirement obligation. Use of the approved rate to determine the obligation under this Interpretation could result in an inflated obligation. In either case, it should be updated to reflect current assumptions, based on management's intent, the asset's estimated economic life as well as entity and industry practices. Be sure to exclude gross salvage value from estimated removal costs and to split the removal costs into its components in order to identify only those pieces that represent the retirement obligation.

c. Snapshot. If immaterial or one is unable to modify or perform annual studies, work with what is available at the end of each year. Then compute the ARO by taking a snapshot each year and true up for differences.

2. Detail Method – If detailed records exist or it is feasible to create detailed records and reporting just for treated wood poles (or like mass assets), and then it would be possible to fully comply with SFAS 143 and FIN 47.

3. For either method, one may want to:

a. Re-examine the legal obligation to determine if there is a specific obligation due to the type of treatment on the poles along with other mass assets **and** that complying will result in a cost. For some locations, there are no "special" disposal tracking or fees. Examine the disposal fee for poles to determine if it is related to special facilities or just additional cost for garbage service. No cost means no accruals need to be booked.

b. Determine if the future fee could qualify as immaterial. For example, a $5 fee or a 50-cent information sheet to buyers could be immaterial on the surface. However, balance sheet materiality would apply and it is the fair value of the ARO items as grouped that may determine materiality.

c. Review the additional reporting and record keeping requirements of the full application to determine if the cost of keeping records is unreasonable for the effort and that an alternative method may yield a reasonable estimate. For example, if one can match disposal to vintaged purchases, then one should be able to comply using the Detailed Method instead of developing a statistical approximation.

d. Similar to above, review whether the depreciation studies are reasonably compatible. Remember FIN 47 "example 1" is concerned with "purchase to disposal" total life versus studies based upon "site life" and in-service time (does not recognize reuse.) Similarly, then, approximation methods might be reasonable. Paragraph 2 of SFAS 143 states that this "applies to legal obligations associated with the *retirement*[2] of a tangible long-lived asset that results from **the acquisition, construction or development…**" This sentence has two interpretations - the first half indicates it only applies to plant in-service, while the second half adds the purchase or construction to the point of application. This review may want to include making a determination on the reasonableness and materiality of the difference between in-service date versus the date of construction or purchase.

e. Alternative approaches also may be justified if one qualifies as a regulated utility. As a regulated utility, the entire ARO compliance effort may result only in balance sheet adjustments with no earning impacts. The most reasonable application of managerial judgment might involve only a high-level, rough estimate of the current obligation without all the various kinds of offsetting regulatory assets and regulatory liabilities. It may be that all those offsetting line items and calculations provides only confusion and a good description of the circumstances is the most appropriate disclosure, especially if preliminary efforts indicate that full compliance results in an immaterial impact.

An example of a possible "snapshot" follows. Utilities with recent, extensive, and detailed studies may have such particulars and resources to develop a very close approximation of full ARO accounting. Many utilities will have very limited information available from latest depreciation studies and property records. This example is intended to show how to approximate an ARO calculation with the bare minimum of information.

Assuming that the utility depreciation study only provides an average service life and net salvage (no basis for a split for removal costs), has a count or estimate of treated poles in service, and vintage or estimate of age of those poles:

For Year 1 (2005) the following applies:

- Surviving plant is equal to 100,000 poles,
- Average service life is estimated to be 50 years,
- Average age of existing poles is 30 years (assume the average remaining life is 20 years even though it most likely would be closer to 25 years using Iowa Curves)
- Disposal cost is $15 per pole fee set by law in 2000 at a local waste management facility.
- Future removal cost in 20 years would be $1.5 million ($15 times 100,000). Note, apply an inflation factor as well if disposal fee can increase due to inflation,
- Apply a current discount rate (credit adjusted risk free rate) back to the year that the obligation began (in this example it is the year 2000) to determine ARC,
- Set up schedules to determine ARC depreciation, accumulated reserve, accretion table, and current value of ARO in year 2005 (also determine regulatory accounting to offset any expenses or income if eligible for SFAS 71 treatment – FERC Accounts 182.3 and 407.4 for regulatory assets, FERC Accounts 254 and 407.3 for regulatory liabilities).

For Year 2 (it is now 2006) the following occurs:

- Surviving plant has been reduced to 95,000 poles (additions and retirement led to a net reduction,
- Average service life is still estimated to be 50 years,

- Average age of existing poles has changed due to the additions and retirements – and is now 29.5 years (average remaining life is now 21.5 years)
- Disposal cost is still $15 per pole fee set by law at a local waste management facility back in year 2000 (watch for whether this should be inflated),
- Future removal cost in 21.5 years would be $1.425 million (15 times 95,000),
- Apply a current discount rate (credit adjusted risk-free rate) back to year 2000 to determine ARC (FERC account 359.1 or 374),
- Set up schedules to determine ARC depreciation, accumulated reserve, accretion table, and current value of ARO now in year **2006** (also determine regulatory accounting to offset any expenses or income if eligible for SFAS 71 treatment – FERC Accounts 182.3 and 407.4 for regulatory assets, FERC Accounts 254 and 407.3 for regulatory liabilities).
- Compare the Year 2 (2006) results to Year 1 (2005) results:
    1. Adjust both the ARC asset, ARC accumulated reserve, and the ARO liability to the new numbers.
    2. The remaining differences (accretion, depreciation, and affect of the change upon the current) will be recognized as a gain or loss or deferred under regulatory accounting (adjust previously recorded amount – difference may change the amount from an asset to a liability which should be a reversal of the prior year entry and a new entry in order to keep the connection between 407.3 and 254 or 407.4 and 182.3 as appropriate).
    3. Layering is being ignored for both because this is only an approximation and this does recognize that the forecast future date of cash flows has changed for all assets and in the long run will achieve a more appropriate obligation at the time of disposal.

In the situation where more information is available (such as vintage data), and the effort reasonable, then the above "snapshot" approach could be applied to each vintage. If service life is estimated using dispersion curves such as Iowa Curves, another enhancement would be to use the "retirement rate" percentages from those curves to develop the estimated time for future retirements. Such an enhancement may be unreasonable (especially if being computed manually) because it would be many times more complicated with the number of vintages involved and it may result in an immaterial difference to the results. These are issues subject to that managerial judgment discussed at the beginning of this document.

Questions for Review: Mass Assets, Electric and Gas

1. Which mass assets are subject to this section?
2. What actuarial assumptions has the company been using with those assets identified as falling within FIN 47?
3. Are the state laws or federal ones defining the disposal restrictions related to any of these minor items?
4. Can one determine a reasonable estimate the current disposal costs and does that apply to all or most in the mass asset group?
5. Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

6. Is the ARO associated with this mass assets material enough to spur recognition in the books and records or should its presence just be disclosed?

Minor Items

SFAS 143 applies to legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, development, or normal operations of the asset itself. In the utility business, property accountants break the huge investment in fixed assets into retirement units, whereby anything less than a retirement unit is not significant enough to be a unit of property. These items that are less than a retirement unit are often called minor items. When construction ensues to install one or more retirement units, minor items directly associated with the retirement units are often part of the construction cost. However, a minor item is not replaced with future construction dollars just because its original cost was part of fixed assets. These items are replaced using maintenance dollars or the replacement is expensed at that time. Minor items to the utility business are basically our "bricks in a kiln".

So it can easily be seen that these minor items can be a quandary when determining a conditional ARO. In some respects, these minor items can consist of the contaminants discussed below. Replacing these in the course of normal operations may be construed as impossible to determine as not enough facts are available to measure the conditional ARO. One would need to know when in the course of operations these minor items will be replaced. However, a more routine maintenance replacement may not be as difficult to predict than an item that perchance could fail. For example, if oil is replaced after every certain number of hours of operation, then one may be able to estimate the disposal obligation. The bricks example infers that the disposal of these bricks, because it is known and routine, may constitute an ARO. A company needs to decide if any of the minor items, those that are part of the asset on installation, but are replaced on maintenance throughout the life of the asset, qualify for conditional ARO treatment. Minimally, the proper removal of oil may be a legal obligation upon retirement of the asset.

However, one keeps coming back to the idea that these items are not fixed assets in exclusion of the retirement unit. Oil sitting on the shelf (i.e. inventory not specifically a property unit) does not fall within the scope of SFAS 143. If the installation of the oil is expensed at the time it is added to the fixed asset, one could conclude that it is not part of the fixed asset cost and perhaps the only retirement obligation is the one associated with the retirement of the asset either interim or final. Assuming this conclusion, the replacement of a minor item during operation in exclusion of the retirement unit would be considered normal maintenance and not subject to ARO accounting. Whereas, the retirement of the asset including the minor item could constitute an ARO, conditional or otherwise, if the minor item causes the asset retirement to meet the rules of SFAS 143 or FIN 47.

Recommendation

Before minor items are recognized as an ARO, make sure that the component is not part of an ARO established for the asset to which the minor item relates. For example, the bricks in the kiln were replaced many times over the life of the kiln's useful life. If an ARO exists for the final disposal of the kiln in its entirety, one would not want to set up an ARO for the disposal of the final set of bricks. Clearly define the minor items that should be included and test early on in this process for materiality. One may have bricks, but the bricks represent such a small component of one's balance sheet and income statement that the inclusion of such in the ARO process may be immaterial at all times, especially if the asset (the kiln) has no ARO. Keep track of the asset to which these minor items relate in order to determine if a future ARO will be warranted by association. Lastly, document the minor items with possible AROs that are routinely replaced versus those where replacement cannot be predicted.

Some Questions for Review: Minor Items

1. Can the minor items be identified that could cause an ARO situation to occur when it is removed with the asset retirement?
2. Does the company have a definitive list of minor units of property?
3. Are the state laws or federal ones defining the disposal restrictions related to any of these minor items?
4. Can a one make a reasonable estimate of when the asset will be retired and whether the minor item will exist as part of the asset at that retirement date?
5. Does any of the guidance from AICPA Statement of Position (SOP) 96-1, "Environmental Remediation Liabilities" supersede the application of SFAS 143 or FIN 47?
6. Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?
7. Is the ARO associated with this minor item material enough to spur recognition in the books and records?

Asbestos, PCBs, and Other Contaminants

Asbestos

Assets constructed before 1980 may have used asbestos as insulation or fire retardant. Typical removal of this substance involves extensive effort to protect workers and the environment from harm along with very specific disposal rules. For that matter, any asset with asbestos may have an ARO associated with it. The determination of whether the removal is performed as a part of normal ongoing maintenance during the life of the asset or is present at the time of retirement may need to be factored into the fair value analysis.

For non-real property, the ability to determine the amount of contamination may be an issue and a costly one at that. The engineering staff generally can determine if the asset being worked on contains asbestos, but determining the amount of contamination may not be feasible. This may make the process more difficult in applying FIN 47, but it may not preclude recognition in the financial statements. At the minimum, disclosure may be necessary for specific assets that are contaminated. For instance, the amount of existing asbestos in a generating facility may not be known and the timing of the removal of it during normal maintenance may be difficult to forecast. The obligation, in this circumstance may be measurable only after the work has been defined. If the ARO is known, measurable, and satisfied all during the same accounting period, then perhaps only a disclosure is necessary for these instances.

Real estate may be easier to estimate if one knows the extent of the contamination. It may be that when the building was first constructed asbestos was throughout every floor. Many years later, some of the asbestos may have been removed in past maintenance on various sections of the building. The engineers familiar with the building should know the relative extent of the contamination. If the building has been through a recent assessment, it may be possible to estimate the loss in market value of the building because of the asbestos. However, asbestos abatement may not be comparable to the loss in market value, and this loss should be weighed with the potential for undertaking the removal oneself.

Estimation of retirement, as with all assets falling within the scope of this Interpretation, can be quite difficult as some of the assets contaminated also are the longest living assets. Even with the loss in value due to selling the building with the contamination, one still may have a difficult time determining retirement parameters. Non-real property may be easier to estimate, as there often exists a manufacturing life on most retirement units.

Polychlorinated Biphenyls (PCBs)

PCBs are man-made chemical compounds previously used in the manufacture of products to make them flexible and heat resistant. Because of these fire retardant qualities, manufacturers sometimes used it in the insulating oil of capacitors, transformers and other electrical equipment. PCBs also can be found in hydraulic fluids, lubricants, paints, sealants, carbonless paper, ink, caulking compounds, and plastics.

PCBs are very stable and do not readily break down in the environment and therefore require special care during handling and disposal. The use of PCBs is regulated under the Federal Toxic Substances Control Act (TSCA). The Environmental Protection Agency (EPA) has set strict regulations regarding the manufacture, use, storage, transportation and disposal of specific levels of PCBs. PCB concentrations below specified levels are not regulated under TSCA.

The existence of regulations related to disposal of PCBs creates a duty to dispose of PCBs in a prescribed manner. The obligation to perform this asset retirement activity is unconditional even though uncertainty may exist about the timing and (or) method of settlement.

The Interpretation states an entity shall recognize a liability for the fair value of the conditional Asset Retirement Obligation (ARO) if the fair value of the liability can be reasonably estimated. If one has assets that contain PCBs and one has sufficient information to reasonably estimate the fair value of the ARO, then the PCB ARO must be recorded. Sufficient information needed to reasonably estimate the fair value includes:

- Settlement date, or information to estimate a range of potential settlement dates
- Method of settlement or potential method of settlement, and
- The probability associated with the potential settlement dates and method of settlement.

The ability to defer settlement, such as storing PCB containing equipment, does not relieve the entity of the obligation. The PCB will eventually need to be disposed of following EPA prescribed procedures. The obligation to perform the asset retirement activity is unconditional even though uncertainty may exist about the timing or method of settlement. The PCB ARO is the cost to dispose of the PCBs as required by the EPA.

Example 1 included in Appendix A of the Interpretation indicates that the ability to sell the PCB containing equipment or facility prior to disposal does not relieve the entity of its present duty to settle the obligation. The sale of the equipment or facility transfers the obligation to another entity. The assumption of the obligation by the buyer affects the sale price. Therefore, an ARO should be recorded once known; when the asset is sold, the ARO liability is debited and the sale price is adjusted to reflect the transfer of the ARO obligation. It is assumed that the utility has factored into the calculation of the ARO, the probability that not all of the assets may be contaminated upon sale.

An entity does not have sufficient information to estimate the fair value of the ARO if:

- The settlement date is indeterminate (the range of time over which the entity may settle the obligation is unknown or cannot be estimated),
- Method of settlement is unknown, and
- Sufficient information is not available to apply an expected present value technique

In this case, an entity will record an ARO when sufficient information exists. It currently qualifies as an ARO, albeit not measurable, and it would be subject to certain accounting and disclosure requirements related to reserves and provisions for cost of future removal. Example 3 included in Appendix A of the Interpretation illustrates this point. However, paragraph 22 of Statement 143 requires that if the liability's fair value cannot be reasonably estimated, that fact and the reasons shall be disclosed.

Electrical equipment damaged by a car, lightning or other incident, which result in a spill of insulating oil containing PCBs will be out-of-scope of this Interpretation since the spill is not considered normal operations. Paragraph 2 of the Interpretations states that "Statement 143 applies to legal obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, except as explained in paragraph 17 of that Statement for certain obligations of lessees."

Other Contaminants

As part of the normal operations for a utility, other contaminants may exist in fixed assets that would require "special" disposal procedures under federal and state regulations. Below are examples of these assets that may contain other contaminants:

Generation

- Groundwater contamination in ***ash ponds*** from metals such as nickel, chromium and arsenic
- Groundwater and soil contamination from unlined ***chemical cleaning basins*** (i.e. boiler cleaning waste basins)
- Soil and ground water contamination associated with ***above and below ground storage tanks*** (i.e. petroleum or other contamination)
- ***Solid waste landfills*** that require installation of a final cover system, grading the final cover, and establish vegetation on the final cover
- ***Septic tanks*** that must be drained and filled with sand prior to closure
- ***Wastewater and sewage treatment facilities*** that may contain hazardous wastewater treatment sludge or sewage

Transmission & distribution

- Soil contamination from arsenic at ***substations***
- Soil contamination from mineral oil at ***substations*** from ***non-PCB transformers***

Other

- ***Equipment*** containing sulfur hexafluoride (SF_6) gas

This is not an exhaustive list of potential contaminates resulting from normal operations of utilities. Each company should consult with environmental experts and legal counsel to properly assess these and other contaminants for potential AROs. Care should be given to ensure that contaminants at these facilities do not fall under the scope of SOP 96-1, *Environmental Remediation Liabilities*, and that these contaminants resulted from normal operations.

Recommendation

EEI and AGA issued a White Paper entitled *Asset Retirement Obligation Implementation White Paper* late 2002, which recommended a team approach to identifying and estimating AROs. That approach can be used for the implementation of FIN 47. Listed below are some of the main points included in the White Paper:

- Use a team approach, ARO team members should include representatives from various company operating departments,
- Develop an inventory of potential AROs,
- Accounting and Legal departments must review and discuss these potential AROs to determine if a legal obligation exists,
- Once it is determined that the obligation falls within the scope of SFAS 143 and FIN 47, the next step is measurement of the ARO liability. The amount of the ARO liability is to be measured at fair value.

Refer to the 2002 EEI and AGA White paper section entitled "Calculation Process Overview" for suggested ARO calculation guidelines and examples. The White Paper also includes journal entry examples and record keeping suggestions.

Questions for Review: Asbestos, PCBs, and Other Contaminants

1. Can all the assets be identified that contain asbestos, PCBs, or other contaminants and can the amount of asbestos that is contained in the asset be determined?
2. Does the company treat these contaminants as a major or minor unit of property?
3. Are the state laws more onerous than the federal ones?
4. Can a market value of the asset be determined with and without the contaminant?
5. Does any of the guidance from AICPA Statement of Position (SOP) 96-1, "Environmental Remediation Liabilities" supersede the application of SFAS 143, Accounting for Retirement Obligations or FIN 47?
6. Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

Rights-of-Way and Franchises

Land, although not specifically excluded from scope of SFAS 143 and FIN 47, is perhaps the one asset that can live forever. Rights of way and easements are land related intangible assets that also are excluded from the scope of SFAS 143 and FIN 47. However, consideration should be given to whether there is a conditional obligation that can be associated to specific, existing, long-lived assets within rights-of-way and franchise areas. It should be noted that there is no asset retirement obligation associated with the franchise (or right-of-way) itself. If it is determined that there is an ARO, it only will be with the assets located within that franchise (or right-of-way). Similar situations may exist with leased land or leasehold improvements, however this section is dealing with the intangible asset created by the right-of-way or franchise agreement. An ARO associated with a lease may be more determinable due to the language of the legal agreement.

Typically, utilities are granted franchises by each local jurisdiction in which they have distribution and transmission assets. Typically, the local jurisdiction retains the right to require the removal of the utility's assets, at the discretion of the local jurisdiction. Consequently, the wording in the franchise imposes certain requirements due to revocation of ordinances and road relocations. Just as typically, however, the intent of the utility and the local jurisdiction is for the utility to continue to provide service on a permanent basis in the service area, and the utility is required to remove its assets only when necessary to allow the local jurisdiction to perform some public work.

Generally, the wording in such franchises indicates that there is a possibility that any individual asset could be required to be moved at any time, but the wording neither identifies specific assets to be removed nor sets a specific time that the removal is required. Furthermore, the franchise wording typically indicates that the franchise is either perpetual or renewable.

Paragraph 3 of FASB Interpretation No. 47 states:

> "The term *conditional asset retirement obligation* as used in paragraph A23 of Statement 143 refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exist about the timing and (or) method of settlement."

This definition identifies three variables: "If", "When" and "How/How Much".

- The "If" is satisfied if it has been determined that an asset will have to be retired at some future date', i.e. the obligating event has occurred.
- The "When" is the date or range of dates when the retirement will/must occur.
- The "How" is the method (and by extension, the cost) associated with the retirement.

In the case of franchises, the obligating event would be the determination by the local jurisdiction that an asset or group of assets must be removed. In granting a franchise, however, the presumption by both the utility and the local jurisdiction is that this event will never occur. The fact that this event does occur on occasion (road widening, for example) is not sufficient to negate this presumption.

In a franchise situation, a conditional ARO does not exist, because the obligating event has not yet occurred. The possibility exists that the obligating event will occur, but the possibility alone is not itself an obligating event. The questions of "when" and "how/how much" do not even come into play, because it has not been established that any asset or group of assets will have to be removed. It is impossible to calculate an asset retirement amount, so journal entries are not required. Furthermore, the possibility that an ARO could come into existence need not be disclosed in a footnote.

It should be noted that franchise language typically requires a utility to remove its assets from a given location, not retire those assets. Theoretically, the utility could satisfy the requirements of the franchise by simply moving those assets. In the case of a road widening, for example, the utility could just pick up all of its poles and wires and move them. In reality, new poles and wire are installed and the old poles and wire are removed. But, the decision to install the new and then remove the old is a management decision, to allow for continuous service while the assets are being "relocated". And in some cases, those assets being removed could be re-used elsewhere (poles, for example). There is no asset retirement obligation, because there is no obligation to retire assets.

This situation can change for major projects, however. If a jurisdiction notifies a utility that it must remove specific assets, for any reason, and assuming the utility will retire those assets, the obligating event for those specific assets will have occurred, and an ARO would exist at that point. If the timing and method of removal can be reasonably estimated (and it probably could be), then the utility would be required to calculate and record an ARO. For example, if the utility is notified that a given section of a subway system is to be extended in five years, and that the utility will have to relocate its poles, wires, buried cable or gas mains along the route of the subway extension, all of the requirements of an ARO will have been met. At this point the utility would be required to record an asset retirement obligation for these assets.

It is not uncommon for local jurisdictions to reimburse the utility some or all of the cost of removal when that local jurisdiction requires that assets be relocated. Such reimbursements are not salvage; they are, in fact, a reduction of the cost of removal. Since the cost of removal is the basis for calculating the amount of the asset retirement obligation, any such reimbursement must be reflected (as a reduction) in the ARO calculation. This could substantially reduce the amount of the ARO (or in the case of a 100% reimbursement, totally eliminate it).

Rights-of-Way are similar to franchises, but on a smaller scale. Rights-of-Way typically are granted by individual citizens or companies, cover smaller areas of land, and may be for shorter periods than franchises. The logic in applying the criteria for establishing an ARO is the same, however. If and when an obligating event occurs, an ARO would have to be recognized if sufficient information exists to estimate the fair value of the obligation or disclosed (if sufficient information does not exist). The determination that a Right-of-Way will not be renewed would be an obligating event. Until that time, no calculations or disclosure by the utility would be required.

If it is determined that an asset retirement obligation does exist, it is important that companies do not double-count or double-record the ARO amount. For example, companies may have a program to identify and track asset retirement obligations for the disposal of treated poles. If a treated pole is in a franchise area or right-of-way and must be removed, and it is deemed that an ARO does exist, the cost of disposing of the treated pole should not be counted twice – once under the program to identify costs of disposing of treated poles, and then again as part of the cost of removing an asset from a franchise area or right-of-way. Property accounting personnel should take care to coordinate the ARO identification and measurement efforts to ensure that all ARO costs are recorded, but that those costs are recorded only once.

Recommendation

The costs of franchises and rights-of-way do not themselves incur an asset retirement obligation. Generally, the assets within the franchise area or right-of-way do not incur an asset liability solely because those assets are subject to the franchise or right-of-way. Under certain circumstances, however, those assets could incur an asset retirement obligation. If it is deemed that an asset retirement obligation does exist for certain assets in a franchise area or right-of-way, care should be taken not to include costs that have been included under another ARO identification program within the company.

Questions for Review: Rights-of-Way and Franchises

1. Who maintains the file of all franchises and rights-of-way agreements?
2. What is the exact wording in the franchises and rights-of-way agreements? (Specifically, what do it require the company to do?)
3. Can one identify al of the assets in the franchise and rights-of way areas?
4. Are the assets in the franchise and rights-of way areas covered under some other ARO identification program within the company?
5. Do the company have procedures in place to make sure that one is not double-counting the ARO?
6. Can one reasonably estimate the amount of reimbursements the company will receive for any required cost of removal?

General Property

The possible changes in ARO accounting as indicated in the guidance and examples provided in FIN 47 also may apply to utility property classified under the General Plant function. Recently, the lead and mercury content in personal computers have been drawing attention of lawmakers, environmental agencies, and disposal sites. There are other potential issues like the mercury in fluorescent light bulbs and chemicals in common batteries. Individual utilities may want to assess ARO requirements as modified by FIN 47.

It may be possible that each of the four examples could apply depending upon the circumstances of the legal obligation and property accounting issues such as whether the obligation relates to a retirement unit, a minor item, or a smaller portion of an asset. For example the coatings or trace elements in a personal computer might be comparable to the chemicals in the treated wood poles in Example 1 in Appendix A of FIN 47. If the obligation relates to specific components of the computer, Examples 3 and 4 may be more applicable.

There may be an additional complication in applying FIN 47 to General Plant property. Many utilities have adopted amortization accounting (such as allowed under Federal Energy Regulatory Commission Accounting Release No. 15, "Vintage Year Accounting For General Plant Accounts"). A main objective of adopting amortization accounting was often to eliminate the relatively unreasonable cost of tracking the status of large volumes of low cost property. Under amortization accounting, the cost of the long-lived asset is given an assumed life and reporting of movement or disposition of the property ceases.

While there may be insufficient information in the property records, there may be alternative sources of information. In the personal computer circumstance, a utility may already have a policy of storing the PC prior to disposal – possibly to be in compliance or anticipation of compliance with disposal obligation. The assessment of application of FIN 47 might include evaluation of the existing availability of such alternative information or of possibly creating such information to facilitate compliance with both the legal obligation and the accounting requirements.

Recommendation

1. Review the circumstances for each account – identify the legal obligation, availability of the information to determine the estimated future removal cost, and the property accounting method (item property, group property, or amortization accounting).
2. Amortization accounting would represent a unique situation, because it was probably adopted because of a determination that it was unreasonable to maintain detailed record keeping under group or item property. There may still be a basis for recording an ARO, if alternative information is available and the effort reasonable or not considered immaterial.
    a. For example, company using amortization accounting with a policy that requires that unused PCs be returned to a central location for disposal with a known disposal cost. If quantities are kept with the unamortized period, then it is possible to estimate a total liability (quantity unamortized plus quantity waiting for disposal multiplied by the disposal fee). All that is necessary is to estimate the timing of the disposals.
    b. Some utilities may keep other records on such items outside of the accounting, which may provide sufficient information to calculate the exposure quantity and approximate timing of disposal.
    c. This accounting method is designed to alleviate the record keeping burden on small value, high volume assets and one should attempt to maintain this simplicity in the ARO analysis and calculation.
3. The possible situations are numerous, but if information is available and cost is large enough, then one of the methods described above (such as used for mass assets) may be applicable for making the calculation.

Questions for Review: General Property

1. Can one define the legal requirements for removal for the general assets?
2. Does the company use AR-15, amortization of general property?
3. Can one estimate potential future retirements?
4. Are the obligations for this category material?
5. If immaterial, is it appropriate to group these AROs with others to determine materiality?
6. Can you estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

Hydro Generation

Hydro dams and facilities fall into conditional obligations primarily due to three factors:

1. An exceptionally long life of the total facility,
2. The large magnitude of costs and complications associated with removal, and
3. The uneven probabilities involved.

In some circumstances, however, the obligation may already provide the information to support recording an estimate. In other circumstances, there may be legitimacy in asserting that too much uncertainty exists to make a reasonable estimate.

Hydro facilities (generation equipment, dam, reservoir, and other plant) typically have an extremely long life. That life may also involve multiple steps, in that the dam may continue to provide service long after generation ceases, and may be rebuilt or repaired multiple times in order to maintain the reservoir for conservation or flood control purposes. That combined total facility life may be so long that "there are no boundaries of time or an extremely lengthy period of time, that bears on a person's ability to make a reasonable estimate of the timing and the amount of the cash flows" [1] (Minutes of January 26, 2005 Board Meeting, wwwfasb.org). Estimating life may be further complicated by whether the obligation is identified (individually or overlapping) by multiple jurisdictions (a FERC license, a Corp of Engineers building permit, an act of Congress, state law, or even promissory estoppel).

The exceptionally long life expectancy will typically represent the greatest obstacle to developing a reasonable estimate of ARO. Many reservoirs can be traced to the early history of the United States, so it is reasonable for a total life of a hydro facility to be measured in hundreds of years. Another complication may be multiple legal jurisdictions involved in the obligation over different phases of that total life. Further, economics may support a truly indefinite life since the magnitude of a repair/rebuild may be the clear option of choice compared to the magnitude of the cost of removal of the facility - at any point in time when a removal consideration is being faced.

The long-life combined with the economics favoring indefinite repair over removal creates a time frame in which acts of gods (unprecedented floods, earthquake, etc.) would have to be included in setting probabilities of life. Statistical models may not be applicable when a long life would also involve such random factors – not only for the life, but also the wide range of possible methods of removal complicated by varying relationships to the cause of removal.

Recommendation

Understanding the nature and timing of the current legal obligation is a critical first step, but one that may be particularly difficult to determine. With Hydro licenses, the requirement to remove the dam and flowage structure, albeit purportedly required by the FERC, may not occur if the environment has adapted and become accustom to the dam. One may have to rely more on local data that is in relation to a legal obligation to define the possible course of action.

A conditional ARO is a judgment-based process and if it results in no ARO recognition, then documentation of such conclusion must be done. If a life or range of lives can be identified, the next step is to review the extent of possible methods for meeting the obligation. If life and method of settlement can be identified, the next step would be to identify the availability of other critical elements in estimating an ARO.

Questions for Review: Hydro Generation

1. What is the nature of the legal obligation(s) involved – does it apply to only a portion of the hydro or to the full facility?
2. Can a life or a range of lives be reasonably identified with any degree of statistical validity?
3. Can the methods of settlement be identified with reasonable estimates of probability?
4. Can a market value of the asset be determined with and without asbestos?
5. If all of the above exists, can costs and cash flows be reasonably estimable with any degree of statistical validity?
6. And, can inflation be reliably predicted from present to the time of removal?
7. Does a risk-free interest rate exist for such a period and will credit adjustments be applicable to determine the rate necessary to convert the ARO into the capitalized asset retirement cost and accretion models necessary under SFAS 143?
8. Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

Overall Recommendation

There will be no single way to estimate the conditional ARO on the property that was excluded in the earlier review. Several recommendations have been provided within this white paper, but as always, each company will need to decide the appropriate conditional ARO. This review includes the determination of the potential liability, the costing and probability of occurrence, the method for calculating the liability and asset, the materiality of the ARO, forward processing, and the appropriate disclosure. The basic concept throughout was to define the property and to encourage one to find a way to provide for the intent of the accounting without creating unbearable duress in doing the calculation. Also, the calculation for the first recognition at the end of this year should be one consideration, but the process used should define the ongoing revision of the conditional liability and the eventual settlement.

The whole process used should be defined and documented to support audit review and to satisfy any Sarbanes/Oxley provisions within the company. Even if one chooses to disclose and not to account, the documentation for the first and subsequent measurements must be such that it will completely support that decision. Overall, proper management and design of the process keeping a keen site on the form and intent should enable one to fully represent the conditional ARO without creating a nightmare of a process.

Effective Date

Effective Date
Paragraph 8 of the Interpretation specifies the effective date and states:

> The Interpretation shall be effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year enterprises). Retrospective application of interim financial information is permitted but is not required. Early adoption of the Interpretation is encouraged.

Transition Accounting:
Paragraphs 9 and 10 of the Interpretation provide requirements for transitional accounting and state:

> "For amounts recognized upon the initial application of the Interpretation, an entity shall recognize the following items in its statement of financial position: (a) a liability for any existing AROs adjusted for cumulative accretion to the date of adoption of the Interpretation, (b) an asset retirement cost capitalized as an increase to the carrying amount of the associated long-lived asset(s), and (c) accumulated depreciation on that capitalized cost."

> "Amounts resulting from initial application of the Interpretation shall be measured using current (that is, as of the date of adoption of the Interpretation) information, current assumptions, and current interest rates. The amount recognized as an asset retirement cost shall be measured as of the date the asset retirement obligation was incurred. Cumulative accretion and accumulated depreciation shall be recorded for the time period from the date the liability would have been recognized had the provisions of the Interpretation been in effect when the liability was incurred to the date of adoption of the Interpretation."

> "An entity shall recognize the cumulative effect of initially applying the Interpretation as a change in accounting principle. The amount to be reported as a cumulative-effect adjustment in the statement of operations is the difference between the amounts, if any, recognized in the statement of financial position prior to the application of the Interpretation and the net amount that is recognized in the statement of financial position pursuant to paragraph 9 of the Interpretation."

Thus, the recognition of new AROs due to adopting this Interpretation is similar to the first recognition done for SFAS 143. Once the full accounting is established for an ARO, the change in estimate routine from SFAS 143 is used for all subsequent layers. For mass assets and other AROs recognized in aggregate, the change in the obligation acknowledged in the second and successive years may be defined as a new layer. This would have to be discussed and agreed upon by management and your auditors as an appropriate treatment.

Subsequent Accounting for Indeterminate AROs:
As has occurred throughout this issue, a quandary seems to exist relating to subsequent recognition if a previously indeterminate ARO becomes measurable and material such that one must invoke the full accounting treatment, not just the disclosure part. The question that has been difficult to get a consensus on is as follows:

Should transition accounting be used in future years to record the initial measurement of an ARO, which was previously treated as indeterminate or would the measurement of this ARO constitute a change in estimate and thus the accounting for a subsequent layer be applicable?

There does not seem to be agreement on this point and it may be a common occurrence. A survey of 18 EEI companies (by Constellation) showed responses that were split down the middle as to whether transition accounting would apply when asset retirement costs were first being measured (previously immeasurable) in years after adoption of FIN 47.

It would seem that transition accounting would not be used in years following adoption of FIN 47. Both FAS 143's paragraph 25 and FIN 47's paragraph 9 on transitional accounting specifically refer to measuring an asset retirement cost (as of the date the obligation was incurred) and provide for accumulated depreciation "to the date of adoption of this Statement" or "Interpretation". Neither FAS 143's paragraph B19 nor Fin 47's paragraph B27 specifically provide a method for asset retirement costs when it states that obligations should be measured at the point where information becomes available.

FIN 47 paragraph 9 ends by stating: "Cumulative accretion and accumulated depreciation shall be recorded for the time period from the date the liability would have been recognized had the provisions of this Interpretation been in effect when the liability was incurred to the date of <u>adoption</u> of this <u>Interpretation</u>." (Emphasis added.) Since the date of subsequent measurement of a specific ARO is not the date of adoption of the pronouncement, it would seem that transition accounting would not be applicable. To rely on this premise, it is assumed that the following is true:

1. An asset was defined as either having an ARO or not based on the legal review at time of adoption
2. Of those assets with an ARO, the ones that were measurable and material were accounted for and disclosed in the financial statements
3. The remaining assets with an ARO were immeasurable, immaterial, or indeterminate in nature, such that only a disclosure was presented in the financial statements
4. A new legal obligation created in the current period for an asset would start the ARO accounting in the current period and no transitional or layer would apply
5. An asset with an ARO would use the cumulative-effect accounting upon adoption of FIN 47 or did use this accounting upon adoption of SFAS 143
6. Any change in estimate, a new layer is created. With an asset where only a disclosure existed, the new layer is done based on a zero layer from adoption.

FIN 47 seems to constitute new rules regarding the determination of when an ARO exists, and how (or what information can be used) to measure that ARO. When booking entries, which adopt these new rules, it explicitly directs one to discount the asset retirement cost back to the origination of the obligation. However, neither SFAS 143 nor FIN 47 requires this when new facts result in a change in the measurement of an existing ARO. In future years, if an immeasurable ARO becomes measurable, this is due to a change in facts rather than a change in the rules. Therefore, it seems more closely aligned with the prospective treatment given to a new layer. It seems likely that if the FASB wanted transition accounting for this situation, it would have explicitly required it in SFAS 143 paragraph B19 and FIN 47 paragraphs B19 and 27. This elucidation has not been tested through any audit and each company will need to decide if this accounting is appropriate for their financial statements.

Transition Disclosures:

Paragraph 11 of the Interpretation provides requirements for transitional disclosures and states:

> In addition to disclosures required by paragraphs 19(c), 19(d), and 21 of APB Opinion No. 20, *Accounting Changes,* an entity shall compute on a pro forma basis and disclose in the footnotes to the financial statements for the beginning of the earliest year presented and at the end of all years presented the amount of the liability for AROs as if the Interpretation had been applied during all periods affected. The pro forma amounts of that liability shall be measured using the information, assumptions, and interest rates used to measure the obligation recognized upon adoption of the Interpretation.

Until the Interpretation is implemented, there is a disclosure requirement for adoption of new accounting pronouncements (SAB 74). Basically, an entity is to provide qualitative or quantitative information, when available, about the expected impact of implementation, updated quarterly.

EDISON ELECTRIC INSTITUTE
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
202-508-5000
www.eei.org

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Part II

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Federal Energy Regulatory Commission

18 CFR Parts 35, et al.

Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations; Final Rule

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 35, 101, 154, 201, 346, and 352

[Docket No. RM02–7–000, Order No. 631]

Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations

Issued April 9, 2003.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Final rule.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is amending its regulations to update the accounting and financial reporting requirements for asset retirement obligations under its Uniform Systems of Accounts for public utilities and licensees, natural gas and oil pipeline companies.

The Commission is establishing uniform accounting and financial reporting for the recognition and measurement of liabilities arising from retirement and decommissioning obligations of tangible long-lived assets, and related costs. More specifically, the Commission is adding new balance sheet accounts to record the liability and the related asset, new income statement accounts to record the accretion of the liability and the depreciation of the related asset, adding and revising as necessary the definitions, general and plant instructions contained in the Uniform Systems of Accounts. The Commission is also revising the following Annual Reports: FERC Form Nos. 1, 1–F, 2, 2–A, and 6 to include the new accounts contained in the Final Rule. Finally, the Commission is revising its rate filing requirements to address the above-mentioned changes.

An important objective of the rule is to provide sound and uniform accounting and financial reporting for the above types of transactions and events. The new accounts and changes to the FERC Forms will add visibility, completeness and consistency of the accounting and reporting of liabilities for asset retirement obligations and the related asset retirement costs, the accretion expense on the liability and the depreciation expense on the capitalized asset retirement costs.

EFFECTIVE DATE: The rule will become effective May 21, 2003.

FOR FURTHER INFORMATION CONTACT:
Mark Klose (Project Manager), Office of the Executive Director, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8283.
Raymond Reid (Technical Information), Office of the Executive Director, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6125.
Robert T. Catlin (Technical Information), Office of Markets, Tariffs, and Rates, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8754.
Julia A. Lake (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8370.

SUPPLEMENTARY INFORMATION:

I. Introduction

1. The Federal Energy Regulatory Commission (Commission) is revising its regulations to update the accounting, reporting and rate filing requirements. In a Notice of Proposed Rulemaking (NOPR) issued on October 30, 2002,[1] the Commission proposed to revise its Uniform Systems of Accounts [2] for public utilities and licensees,[3] natural gas companies [4] and oil pipeline companies [5] by establishing uniform accounting requirements for the recognition of liabilities for legal obligations associated with the retirement of tangible long-lived assets and the associated capitalization of these amounts as part of the cost of the asset giving rise to the obligation.

2. An asset retirement obligation is a liability resulting from a legal obligation to retire or decommission a plant asset. The types of work activities typically include removing or dismantling the asset. For example, public utilities have a legal liability to decommission nuclear plants under certain Nuclear Regulatory Commission (NRC) regulations. The type of activities may include the dismantlement and removal of the reactor vessel and the related contaminated facilities.

3. After carefully considering the comments received, the Commission has determined that a Final Rule revising its accounting regulations, Annual Report Forms (FERC Form Nos. 1, 1–F, 2, 2–A and 6), and rate filing requirements for asset retirement obligations should be issued.

4. The purpose of this Final Rule is to improve the usefulness and transparency of financial information provided to the Commission and other users of the FERC Forms by establishing uniform accounting and reporting requirements for legal obligations associated with the retirement of tangible long-lived assets. The Commission is of the view that such

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[1] 67 FR 69816 (Nov. 19, 2002) and 67 FR 70890 (Nov. 27, 2002), IV FERC Stats. & Regs. ¶ 32,565 (Oct. 30, 2002).

[2] Section 301(a) of the Federal Power Act (FPA), 16 U.S.C. 825(a), section 8 of the Natural Gas Act (NGA), 15 U.S.C. 717g and section 20 of the Interstate Commerce Act (ICA) 49 App.U.S.C. 20 (1988), authorize the Commission to prescribe rules and regulations concerning accounts, records and memoranda as necessary or appropriate for the purposes of administering the FPA, NGA and the ICA. The Commission may prescribe a system of accounts for jurisdictional entities and, after notice and opportunity for hearing, may determine the accounts in which particular outlays and receipts will be entered, charged or credited.

[3] Part 101 Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act. *See* 18 CFR part 101 (2002).

[4] Part 201 Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act. *See* 18 CFR part 201 (2002).

[5] Part 352 Uniform System of Accounts Prescribed for Oil Pipeline Companies Subject to the Provisions of the Interstate Commerce Act. *See* 18 CFR part 352 (2002).

requirements are needed because these types of transactions and events are not clearly or consistently reported. This rule is part of the Commission's ongoing effort to address emerging accounting developments within the context of the Uniform Systems of Accounts.

5. The accounting for asset retirement obligations in this rule is consistent with the accounting and reporting requirements that jurisdictional entities will use in their general purpose financial statements provided to shareholders and the Securities Exchange Commission (*e.g.*, companies will separately account and report the liability for the asset retirement obligations, capitalize the asset retirement costs, charge earnings for depreciation of the asset and charge operating expense for the accretion of the liability).

6. The Commission is also revising its rate filing requirements to accommodate the above-mentioned changes. In that regard, the accounting for asset retirement obligations will not affect jurisdictional entities' ability to seek recovery of costs arising from asset retirement obligations in rates. However, if billings under formula rate tariffs are affected by the adoption of these accounting requirements, the jurisdictional entity must obtain approval from the Commission prior to implementing the change for tariff billing purposes.

7. Finally, the Commission is revising the following Annual Reports: FERC Form No. 1, Annual Report of Major Public Utilities, Licensees and Others (Form 1); FERC Form No. 1–F, Annual Report of Nonmajor Public Utilities and Licensees (Form 1–F); FERC Form No. 2, Annual Report of Major Natural Gas Companies (Form 2); FERC Form No. 2–A, Annual Report of Nonmajor Natural Gas Companies (Form 2–A); and FERC Form No. 6, Annual Report of Oil Pipeline Companies (Form 6) to include the new accounts and the revised schedules.[6]

II. Background

8. The recognition and measurement of legal liabilities associated with the retirement and decommissioning of long-lived assets by various entities, including Commission jurisdictional entities, have been inconsistent over the years. Some jurisdictional entities do not recognize asset retirement obligations in their accounts while other jurisdictional entities only recognize the amounts included in the rate setting process as a component of accumulated depreciation. The Commission, in an effort to eliminate the inconsistencies in accounting practices by jurisdictional entities for asset retirement obligations, issued its October 30, 2002 Notice of Proposed Rulemaking to revise the accounting regulations, FERC Annual Report Forms and rate filing requirements for asset retirement obligations.[7]

9. The scope of the NOPR covered certain legal obligations associated with the future retirement of long-lived assets. These obligations, generally referred to as asset retirement obligations, are legal obligations associated with the retirement of a tangible long-lived asset that an entity is required to settle as a result of an existing enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel.[8]

10. In the NOPR, the Commission broadly set forth the proposed accounting framework for asset retirement obligations as follows:

11. An entity essentially recognizes a liability for the fair value of an asset retirement obligation at the time the asset is constructed, acquired, or when a change in the law creates a legal obligation to perform the retirement activities. Upon initial recognition of that liability, an entity also increases the cost of the related asset that gives rise to the legal obligation by the same amount. The liability is increased over time until the actual retirement activity commences. Additionally, the asset retirement cost capitalized is depreciated over the same life of the related asset giving rise to the obligation. An entity is required to re-measure the liability due to the passage of time and certain other changes in the estimate of the liability.

12. Entities will be required to recognize the liabilities for asset retirement obligations and the related costs as if the new standard had been in effect for all prior periods. The difference between the amounts at the date of adoption and the amounts previously recorded for these items are to be included in net income unless the criteria for recognition of regulatory assets or liabilities are met under Order No. 552.[9]

III. Discussion

13. The Commission received 16 comments concerning various aspects of the proposed rule.[10] The majority of the commenters were generally supportive of the Commission's effort to provide interpretative guidance on the application of generally accepted accounting principles to jurisdictional entities that presently file financial information with the Commission in Annual Report Forms 1, 1–F, 2, 2–A, and 6.[11]

14. After careful consideration of the comments received, the Commission is adopting the changes and revisions as proposed with certain modifications and clarifications as discussed below.

A. Accounting for the Cumulative Effect Adjustment

15. Upon initial implementation of the new accounting requirements for asset retirement obligations the Commission proposed that jurisdictional entities establish in their accounts all of the amounts that would have been recorded therein had these new requirements always been in effect. The NOPR referred to the accounting entries required to implement this part of the proposal as "transition adjustments." In certain instances, the transition adjustments could result in a charge or credit to net income. This charge or credit is referred to as the "cumulative effect adjustment" because it represents the cumulative difference between all amounts charged to net income for asset retirement obligations in past periods under the prior accounting method and what would have been charged to net income in those periods had these new accounting requirements set forth in the NOPR always been in effect. For rate regulated entities the cumulative effect adjustment amounts will be recognized as a regulatory asset or liability if the requirements of Commission Order No. 552 are met.[12]

16. The Commission proposed to record the cumulative effect adjustment

[6] The FERC Annual Reports bear the following OMB approval control numbers: Form 1 has OMB approval number 1902–0021; Form 1–F has OMB approval number 1902–0029; Form 2 has OMB approval number 1902–0028; Form 2–A has OMB approval number 1902–0030; and Form 6 has OMB approval number 1902–0022.

[7] *See supra* note 1.

[8] *See* Financial Accounting Standards Statement (FAS) No. 143, Accounting for Asset Retirement Obligations, issued in June 2001. The accounting publication may be obtained from FASB at *http://www.fasb.org/*. Appendix A, paragraphs A2 through A5, contains a discussion of legal obligations.

[9] *See* Order No. 552, 58 FR 17982 (Apr. 7, 1993), FERC Stats. & Regs., Regulations Preambles January 1991–June 1996 ¶ 30,967 at pp. 30,823–26 (Mar. 31, 1993) for guidance on the recognition of regulatory assets and regulatory liabilities when certain conditions are met.

[10] *See* Appendix A for Listing of Commenters.

[11] *See* Arkansas PSC at p. 2, Deloitte & Touche at p. 1, FirstEnergy at p. 2, NASUCA at pp. 2–3, NRECA at pp. 3–4, Progress Energy at p. 1 and Southern at p. 1.

[12] *See* Order No. 552, *supra* note 9, for guidance on the recognition of regulatory assets and regulatory liabilities when certain conditions are met.

in two separate amounts. The first portion of the cumulative effect adjustment assumes that all amounts included in the accumulated depreciation accounts for previously recognized legal retirement obligations will be considered depreciation of the asset retirement costs capitalized under the proposed rule. The difference between the amount included in the accumulated depreciation for previously recognized legal retirement obligations and the accumulated depreciation on the capitalized asset retirement costs recognized under the new accounting requirements will be charged or credited, as appropriate, to net income or recognized as a regulatory asset or liability if the requirements of Order No. 552 are met. The second portion of the cumulative effect adjustment assumes that all amounts related to the accretion of the liability for the asset retirement obligation under the new requirements would be charged to net income or recognized as a regulatory asset if the requirements of Order No. 552 are met.

Comments Received

17. Two commenters assert that the NOPR was unclear as to the initial implementation details of the proposed accounting rules and seek clarification of this matter in the final rule.[13] The commenters request the Commission to clarify the components included in the cumulative effect adjustment. FirstEnergy asserts that the components of the cumulative effect adjustment may consist of the net of the cumulative accretion on the asset retirement obligation, the accumulated depreciation on the related capitalized asset retirement cost, and the reversal of any previously accrued legal retirement obligation.

18. FirstEnergy notes that the NOPR only addresses amounts included in accumulated depreciation for accruals of previously recognized legal retirement obligations of long-lived assets. The commenter submits that the Commission has permitted amounts related to legal liabilities associated with the retirement of assets to be recorded in a deferred credit or liability account rather than in accumulated depreciation. The commenter asserts further that accruals of previously recognized legal retirement obligations that were recorded in a deferred credit or in a liability account should be included in the computation of the cumulative effect adjustment in the final rule.

[13] *See* FirstEnergy at p. 2 and Progress Energy at p. 2.

Commission Response

19. The proposal to establish the cumulative effect adjustment was intended to simplify implementation of the accounting for asset retirement obligations. However, based on the comments received the Commission recognizes that the implementation proposal may have been confusing because the steps were somewhat different than the ones contained in FAS 143. However, the Commission notes that the cumulative effect determination under FAS 143 and this final rule will result in the use of the same components and produce the same cumulative effect adjustment amount.

20. The Commission finds that since both approaches produce the same cumulative effect adjustment for asset retirement obligations, jurisdictional entities may recognize the initial application of the new accounting rules for the cumulative effect adjustment as the difference between the amounts of previously accrued accumulated legal obligations associated with the retirement of the asset recognized in the balance sheet prior to adopting the new accounting requirements and the amount that will be recognized on the balance sheet under the new accounting requirements. The Commission also finds that in order to properly determine the proper cumulative effect adjustment, jurisdictional entities must include the amounts of previously accrued accumulated legal obligations associated with the retirement of assets recorded in other deferred credits accounts or other liability accounts in the computation of the cumulative effect adjustment.

B. Recognition of Regulatory Assets and Liabilities

21. The Commission proposed that public utilities, licensees and natural gas companies recognize regulatory assets and liabilities related to asset retirement obligations if the accounting requirements under Order No. 552 are met.[14]

Comments Received

22. Several commenters request that the Commission clarify in the final rule the accounting for the recognition of regulatory assets and liabilities for the effects on financial operations related to the initial implementation and the period-to-period accounting for any difference between amounts charged to net income for expenses related to asset retirement obligations and the amounts recovered in rates for asset retirement obligation costs.[15] The commenters assert that the proposed accounting for the recognition of the debit cumulative effect adjustment in account 182.3, Other regulatory assets, as a regulatory asset is not consistent with the accounting for the recognition of the credit cumulative effect adjustment as a regulatory liability in account 254, Other regulatory liabilities.[16] The commenters suggest that inconsistency arises because the Commission required that a credit cumulative effect adjustment must be recorded as a regulatory liability in account 254, Other regulatory liabilities, while a debit cumulative effect adjustment must be charged to net income in account 435, Extraordinary deductions, or recorded as a regulatory asset in account 182.3, Other regulatory assets, for part or all of the cumulative effect adjustment if the requirements of Order No. 552 are met. One commenter suggests that the Commission should provide for the recording of regulatory assets for debit cumulative effect adjustments as being probable of recovery as a general rule consistent with the Commission's proposed treatment of recording credit cumulative effect adjustments as regulatory liabilities.

23. Additionally, one commenter recommends that the Commission incorporate the accounting for the recognition of regulatory assets and liabilities for the initial adoption and the period-to-period accounting for asset retirement obligations in the requirements of the Uniform Systems of Accounts under Parts 101 and 201.[17]

Commission Response

24. The Commission declines to adopt the commenter's recommendation to amend the Uniform System of Accounts under part 101 and part 201 of the Commission regulations to include specific accounting instructions for the recognition of regulatory assets and liabilities for the initial adoption and the period-to-period accounting for asset retirement obligations. The accounting instruction for regulatory assets and liabilities as prescribed in the Uniform Systems of Accounts in part 101 and part 201 adequately addresses the requirements for regulatory assets or liabilities related to differences in the timing of recognition of asset retirement obligation expenses for financial

[14] *See* Order No. 552, *supra* note 9, for guidance on the recognition of regulatory assets and regulatory liabilities when certain conditions are met.

[15] *See* Deloitte & Touche at p. 1, EEI at pp. 3–4, Progress Energy at p. 2, and RUS at p. 3.

[16] *See* Deloitte & Touche at p. 1, EEI at pp. 3–4, Progress Energy at p. 2, and RUS at p. 3.

[17] *See* EEI at p. 6.

accounting purposes and their recovery in rates.

25. The Commission established the accounting requirements for recording regulatory assets and liabilities as set forth in the Uniform Systems of Accounts in part 101 and part 201 pursuant to Commission Order No. 552.[18] Under these requirements regulatory assets and liabilities are defined as assets and liabilities that result from ratemaking actions of regulators.[19] Regulatory assets and liabilities generally arise from specific revenues, expenses, gains, or losses that would have been included in net income determinations in one period under the general requirements of the Uniform System of Accounts but for it being probable they will be included in a different period(s) for purposes of developing the rates the utility is authorized to charge for its utility services or in the case of regulatory liabilities, for refunds to customers, not provided for in other accounts, that will be required.[20] The term ''probable,'' as used in Order No. 552 for the definition of regulatory assets or regulatory liabilities, refers to that which can be reasonably be expected or believed on the basis of available evidence or logic but is neither certain nor proved.[21]

26. Jurisdictional entities will initially recognize a cumulative effect adjustment and thereafter record the depreciation of the asset retirement costs in account 403.1, Depreciation expense for asset retirement costs, and the accretion of the liability for the asset retirement obligations in account 411.10, Accretion expense. The amounts for depreciation and accretion expense that will be recognized under the general requirements of the Uniform Systems of Accounts and the amount of asset retirement obligation costs included in cost of service for ratemaking purposes may be different. Recognition of such differences as regulatory assets and liabilities may be appropriate in some instances, but not in others. This determination however cannot be made in a generic accounting rulemaking proceeding. It must instead be made by each individual entity taking into consideration the jurisdictional entity's rate setting bodies, the specific agreements entered into between the jurisdictional entity and certain customers regarding the manner in which costs will be allocated among the parties or other relevant evidence. Therefore, if the requirements of Order No. 552 are met, a jurisdictional entity must recognize regulatory assets and liabilities for the cumulative effect adjustment and any differences between the recognition of asset retirement obligation expenses for financial accounting purposes and their recovery in rates.

C. Authority To Adjust Accumulated Depreciation (Accounts 108 and 110)

27. The Commission proposed granting public utilities, licensees and natural gas companies the requisite authority to remove any excess amounts[22] from accounts 108 and 110 provided that the amounts were transferred to account 254, Other regulatory liabilities.[23]

Comments Received

28. Certain commenters request that the Commission clarify the authority granted to jurisdictional entities to adjust the balances in accounts 108 and 110 for existing long-lived assets with legal retirement obligations.[24] However, one commenter requests that the Commission provide explicit authority to remove all of the previously accrued amounts for legal obligations to retire or dispose of the long-lived assets recorded in accounts 108 and 110. Another commenter requests the Commission allow transferring from accounts 108 and 110 to the new proposed account 230, Asset retirement obligations, any remaining amounts for previously accrued legal obligations to retire or dispose of the long-lived assets.

29. Another commenter agrees with the Commission's pregranting authority to public utilities, licensees and natural gas companies for the removal of amounts from accumulated depreciation accounts associated with asset retirement obligations. However, the commenter asserts that the Commission should still require public utilities, licensees and natural gas companies to notify the Commission by submitting a description and journal entries related to such adjustments to the Commission for amounts transferred from accounts 108 and 110 to account 254, Other regulatory liabilities, related to any existing asset with a legal retirement obligation.[25]

Commission Response

30. After considering the comments, the Commission will grant jurisdictional entities the authority to adjust accounts 108, 110 and 253 to properly recognize and record the liabilities for legal retirement obligations for existing assets, the asset retirement costs and related accumulated depreciation on the capitalized costs when the amounts that would otherwise be included in net income determinations meet the criteria for recognition as regulatory asset or liability.

31. The Commission notes that there may be instances where adjustments to accounts 108, 110 and 253 may be required as a result of this final rule but the criteria for the recognition of a regulatory asset or liability for the net income effect is not met. While we permit jurisdictional entities to make such adjustments our actions here should not be construed as approval.[26] Therefore, the Commission will require that jurisdictional entities file with the Commission their journal entries along with supporting information to record any adjustment that affects net income within 60 days of the effective date of this final rule. The filing must include a description and explanation of the full particulars for including the amounts in net income.

32. The filing must also include a statement by the public utility, licensee or natural gas company of the facts and circumstances and the explicit determinations made by the jurisdictional entity demonstrating that the amounts credited to net income are not required to be refunded to customers or required to be recorded as a regulatory liability and must be credited to net income and not included in account 254, Other regulatory liabilities.

[18] *See* Order No. 552, *supra* note 9, for guidance on the recognition of regulatory assets and regulatory liabilities when certain conditions are met.

[19] *See* paragraph A of account 182.3, Other regulatory assets, and paragraph A of account 254, Other regulatory liabilities, in 18 CFR part 101 (Public Utilities and Licensees), and paragraph A of account 182.3, Other regulatory assets, and paragraph A of account 254, Other regulatory liabilities, in 18 CFR part 201 (Natural Gas Companies).

[20] *See* Definition 30 in 18 CFR part 101 (Public Utilities and Licensees), and Definition 30 in 18 CFR part 201 (Natural Gas Companies).

[21] *See* FERC Stats. & Regs., Regulations Preambles January 1991–June 1996 ¶ 30,967 at 30,826 (1993).

[22] This excess amount results when the amount of accumulated depreciation recognized for prior accrued legal retirement obligations is greater than the accumulated depreciation recognized on the capitalized asset retirement costs under the new requirements.

[23] *See* paragraph E to account 108, Accumulated provision for depreciation of electric utility plant (Major only), and paragraph E to account 110, Accumulated provision for depreciation and amortization of electric utility plant (Nonmajor only), in 18 CFR part 101 (Public Utilities and Licensees).

[24] *See* EEI at pp. 2–3 and Progress Energy at p. 2.

[25] *See* MoPSC at p. 6.

[26] The income accounts used to record the cumulative effect adjustments are account 434, Extraordinary income, and account 435, Extraordinary deductions.

D. Accounting for Cost of Removal That Does Not Constitute a Legal Obligation

33. The Commission did not propose to change its accounting under parts 101, 201 and 352 for the cost of removal for amounts that result from other than asset retirement obligations.

Comments Received

34. Several commenters request that the Commission specify in the final rule that any cost of removal for non-legal retirement obligations remain in accumulated depreciation.[27] Certain other commenters suggest that the Commission should make certain modifications to the Uniforms Systems of Accounts under part 101 and part 201 to include the amount of cost of removal for non-legal obligations as regulatory liabilities in account 254, Other regulatory liabilities, instead of accumulated depreciation for public utilities, licensees and natural gas companies.[28]

35. One commenter recommends that the Commission exclude the cost of removal that does not qualify as a legal retirement obligation from the depreciation accrual and instead capitalize any removal costs related to the asset replaced as part of the costs of replacing the utility plant and if no replacement of the asset occurs, the cost of removal for non-legal retirement obligations should be expensed in the income statement.[29]

Commission Response

36. As proposed in the NOPR, the rule applies to legal obligations associated with the retirement of tangible long-lived assets. Under the existing requirements of the Uniform Systems of Accounts removal costs that are not asset retirement obligations are included as a component of the depreciation expense and recorded in accumulated depreciation.[30] The Commission notes that certain jurisdictional entities may have been receiving specific allowances for cost of removal for non-legal retirement obligations as a specific component in their rates approved by their regulators. The Commission did not propose any changes to its existing accounting requirements for cost of removal for non-legal retirement obligations. Accordingly, jurisdictional entities are accounting for such costs consistent with the requirements of the Uniform Systems of Accounts under part 101 for public utilities and licensees, part 201 for natural gas companies and part 352 for oil pipeline companies.

37. The purpose of this rule is to establish uniform accounting requirements for the recognition of liabilities for legal obligations associated with the retirement of tangible long-lived assets. The accounting for removal costs that do not qualify as legal retirement obligations falls outside the scope of this rule. The Commission is aware that there is an ongoing discussion in the accounting community as to whether the cost of removal should be considered as a component of depreciation. However, this issue is beyond the scope of this rule and we are not convinced that there is a need to fundamentally change accounting concepts at this time.

38. Instead we will require jurisdictional entities to maintain separate subsidiary records for cost of removal for non-legal retirement obligations that are included as specific identifiable allowances recorded in accumulated depreciation in order to separately identify such information to facilitate external reporting and for regulatory analysis, and rate setting purposes. Therefore, the Commission is amending the instructions of accounts 108 and 110 in parts 101, 201 and account 31, Accrued depreciation—Carrier property, in part 352 to require jurisdictional entities to maintain separate subsidiary records for the purpose of identifying the amount of specific allowances collected in rates for non-legal retirement obligations included in the depreciation accruals.

39. Jurisdictional entities must identify and quantify in separate subsidiary records the amounts, if any, of previous and current accrued accumulated removal costs for other than legal retirement obligations recorded as part of the depreciation accrual in accounts 108 and 110 for public utilities and licensees, account 108 for natural gas companies, and account 31 for oil pipeline companies. If jurisdictional entities do not have the required records to separately identify such prior accruals for specific identifiable allowances collected in rates for non-legal asset retirement obligations recorded in accumulated depreciation, the Commission will require that the jurisdictional entities separately identify and quantify prospectively the amount of current accruals for specific allowances collected in rates for non-legal retirement obligations.

E. Accounts Established for Recording Accretion of Asset Retirement Obligations and Depreciation of Asset Retirement Costs

40. The Commission proposed to add a new income statement account entitled account 411.10, Accretion expense, in the Uniform Systems of Accounts in part 101 and part 201 to record the accretion of the liability for the asset retirement obligation. The Commission also proposed to add a new income statement account entitled account 403.1, Depreciation expense for asset retirement costs, in part 101 and part 201 to identify the depreciation expense recorded for capitalized asset retirement costs.

Comments Received

41. Certain commenters recommend that the Commission's proposed new account 411.10, Accretion expense, should be renumbered as either account 411.11 or an account number within the range of account 405, Amortization of other electric plant, through account 407, Amortization of property losses, unrecovered plant and regulatory study costs, which relate to the amortization of utility plant.

42. Two commenters suggest that the Commission renumber its proposed new account 403.1 because it is already being used in the Rural Utilities Service's (RUS) Uniform System of Accounts.[31] The commenters suggest that the Commission use account 403.9 to accommodate the Uniform System of Accounts of RUS for its electric cooperatives.[32]

Commission Response

43. The Commission will not renumber the chart of accounts. The accounting structure of the Uniform Systems of Accounts in part 101 and part 201 is designed to meet the accounting and reporting needs of this Commission. Users are permitted to adapt the Commission's Uniforms Systems of Accounts for their own needs by allowing them to create new accounts and subaccounts. Such company generated accounts however, must be reconciled if and when the Commission subsequently determines to use that account number for its regulatory purposes. Therefore, jurisdictional entities must reconcile their account numbers accordingly, to

[27] *See* EEI at p. 3 and Southern at p. 2.

[28] *See* Deloitte & Touche at p. 2 and NASUCA at pp. 2–3.

[29] *See* NASUCA at pp. 15–17.

[30] *See* Definition 10 in 18 CFR part 101 (Public Utilities and Licensees), Definition 10 in 18 CFR part 201 (Natural Gas Companies), and Definition 12 in 18 CFR part 352 (Oil Pipeline Companies).

[31] *See* RUS at p. 2 and NRECA at p. 6.

[32] *See* Rural Utilities Service of the United States Department of Agriculture (RUS) Uniform System of Accounts, 7 CFR part 1767, Accounting Requirements for RUS Electric Borrowers.

the account numbers established by this rule.[33]

F. Accounts for Recording Asset Retirement Costs

44. The Commission proposed to add new primary plant accounts within each plant function to record the asset retirement costs.

Comments Received

45. Certain commenters object to the Commission's proposed new primary plant accounts within account 101 in part 101 and part 201[34] One commenter suggests the Commission create a new separate asset group called ''Asset Retirement Costs'' that separately identifies asset retirement costs in financial statements and would facilitate the exclusion of the asset retirement costs from the rate base in a rate change filing.

46. Another commenter suggests that capitalizing asset retirement costs in the new primary plant accounts could result in increasing personal property taxes for three of its utility operating companies that operate in one state. The commenter recommends that the asset retirement costs should be recorded as an intangible cost within account 101 under part 101 and part 201 in primary plant account 303, Miscellaneous intangible plant. As an alternative, the commenter also recommends that the Commission include the word ''intangible'' in the account instructions of the new asset retirement cost primary plant accounts proposed by the Commission.

47. One commenter suggests that the Commission's proposed new primary plant accounts entitled account 359.1, Asset retirement costs for transmission plant, and account 399.1, Asset retirement costs for general plant, should be renumbered to avoid leading users to expect these are subaccounts of account 359, Roads and trails, under the transmission plant function and 399, Other intangible plant, under the general plant function in part 101.[35] The commenter suggests that the Commission use account 351 which is currently a reserved account in the list of accounts for the transmission plant function. The commenter also suggests that the Commission use account 388 which is currently not an account used in the list of accounts for the general plant function.

Commission Response

48. The Commission finds that these recommendations are not consistent with the view that asset retirement costs are considered an integral part of the costs of the particular asset that gives rise to the asset retirement obligations, rather than separate and distinct assets.

49. The Commission notes that commenters' suggestions will not result in properly classifying asset retirement costs within the utility plant function associated with the actual plant assets that give rise to the legal retirement obligations. This result would be at odds with one of the objectives of the final rule, which is to provide proper accounting for legal obligations associated with the retirement costs.

G. Accounting for Gains and Losses for the Settlement of Asset Retirement Obligations Related to Electric and Gas Utility Plant

50. The Commission proposed to record gains or losses resulting from the settlement of asset retirement obligations for electric and gas utility plant in account 411.6, Gains from disposition of utility plant, and the account 411.7, Losses from disposition of utility plant, respectively.

Comments Received

51. Many of the commenters did not object the Commission's proposed treatment for gains and losses resulting from the settlement of asset retirement obligations for electric and gas utility plant.[36] Two commenters believe that the Commission's proposed treatment is inappropriate in the situation in which a jurisdictional entity has recorded, at the date of adoption of the final rule, a regulatory asset or liability for the full difference (including third party risk factor) between the asset retirement obligation determined for accounting purposes and the asset retirement obligation allowed for ratemaking purposes.[37] In this situation the commenters assert it is appropriate to offset any remaining regulatory asset or liability balance associated with the specific asset retirement obligation against the remaining asset retirement obligation liability balance before recording a gain or loss.

Commission Response

52. The Commission notes that the offsetting of any remaining regulatory asset or liability balance associated with the specific asset retirement obligation against the remaining associated asset retirement obligation liability balance before recording a gain or loss on the settlement is not appropriate because each of these transactions is a separate and distinct accounting transaction, and accordingly, should be accounted for as such. Therefore, the Commission will adopt the accounting as provided for in the NOPR.

H. Accounting for Gains and Losses for the Settlement of Asset Retirement Obligations Related to Nonutility Plant

53. The Commission proposed that any gains or losses relating to the settlement of asset retirement obligations for nonutility plant must be recorded directly in account 421, Miscellaneous nonoperating income, and account 426.5, Other deductions, respectively. The Commission also proposed to revise the text of accounts 421 and 426.5 in part 101 and part 201 of the Commission's regulations.

Comments Received

54. One commenter suggests that, although the use of these accounts are not necessarily objectionable, it would be more appropriate to record a gain or loss resulting from the settlement of asset retirement obligations for nonutility plant directly in account 421.1, Gain on disposition of property, or account 421.2, Loss on disposition of property, respectively.[38]

Commission Response

55. The instructions to Accounts 421.1 and 421.2 provide for gains or losses on the sale, conveyance, exchange, or transfer of utility or other property to another.[39] The settlement of an asset retirement obligation related to nonutility property does not result in the sale, conveyance, exchange, or transfer of such property to another party. Therefore, the Commission is of the view that the accounting for gains or losses resulting in the settlement of asset retirement obligations for nonutility property should be accounted for in accounts 421 and 426.5 as provided for in the NOPR.

I. Other Accounting Matters

56. Certain commenters raised concerns or seek Commission guidance concerning the use of group depreciation for asset retirement

[33] *See* General Instruction 3.C, Account Numbering System, in 18 CFR part 101 (Public Utilities and Licensees) and 18 CFR part 201 (Natural Gas Companies).

[34] *See* FirstEnergy at p. 1, MoPSC at pp. 4–5 and RUS at p. 2.

[35] *See* RUS at p. 2.

[36] *See* EEI at p. 6 and Southern at p. 2.

[37] *See* FAS 143, paragraph A20, for a discussion of third party risk.

[38] *See* EEI at p. 6.

[39] *See* account 421.1, Gain on disposition of property, or account 421.2, Loss on disposition of property, in 18 CFR part 101 (Public Utilities and Licensees) and 18 CFR part 201 (Natural Gas Companies).

obligations, and on how a jurisdictional entity should estimate a credit-adjusted risk-free rate where an entity has not found a need to obtain a credit rating.[40]

57. The Commission will not make policy calls in this final rule concerning the above matters. These matters are better resolved on a case-by-case basis based on the facts and circumstances of each jurisdictional entity. Additionally, jurisdictional entities may seek clarification from the Commission's Chief Accountant concerning the proper application or implementation of any accounting standard under the Commission's regulations.[41]

58. Finally, one commenter suggests that the NOPR does not address the current accounting for realized earnings from trust funds that have been established for the purpose of ultimately discharging the liability for asset retirement obligations.[42] The commenter notes that jurisdictional entities currently account for realized earnings on trust funds by crediting account 419, Interest and dividend income. The commenter recommends that the realized earnings on trust funds should be recorded to an appropriate above-the-line account.

59. The Commission notes that under certain circumstances jurisdictional entities have placed in a special fund amounts deposited with a trustee for future activities such as the decommissioning of a nuclear plant. Amounts placed in a special fund for this type of activity are recorded in account 128, Other special funds. Additionally, under the requirements of the Uniform Systems of Accounts, interest revenues on securities, special deposits, and all other interest bearing assets included in other special fund accounts are recorded in Account 419, Interest and dividend income. Realized earnings on trust funds are nonoperating in nature and are properly included in account 419. Therefore, the Commission declines to amend the Uniform Systems of Accounts.

J. Tariff Filing Requirements

1. Tariff Filing Requirements Under 18 CFR Part 35 and 18 CFR Part 154

60. In the NOPR, the Commission stated that the proposed rule will require public utilities, licensees or natural gas companies for accounting purposes to recognize asset retirement obligations. The Commission is not requiring jurisdictional entities with stated rate tariffs to make any tariff filings with the Commission due to this final rule at this time. However, public utilities, licensees and natural gas companies with formula rate tariffs must not include any cost components related to asset retirement obligations in their formula rate billing tariffs for automatic recovery in their billing determinations without obtaining Commission approval.

61. Various commenters have expressed support and concerns or asked for Commission decisions with respect to issues concerning the possible rate impact of the proposed rule. Two commenters state their support for the Commission's proposed rate treatment of asset retirement obligations.[43] Other commenters raised concerns or seek Commission policy calls concerning regulatory certainty for disposition of transition costs, external funds for amounts collected in rates for asset retirement obligations, adjustments to book depreciation rates for companies collecting cost of removal through current depreciation rates, the exclusion of accumulated depreciation and accretion for asset retirement obligations from rate base, recognizing previously established negative salvage allowances whether or not these retirement costs are recognized as asset retirement obligations, and the requirement of a detailed study in support of tariff filings reflecting asset retirement obligations.[44]

62. The Commission finds that the issue of whether, and to what extent, a particular asset retirement cost must be recovered through jurisdictional rates should be addressed on a case-by-case basis in the individual rate change filed by public utilities, licensees, and natural gas companies. To ensure that all rate base amounts related to asset retirement obligations can be identified and excluded from the rate base calculation in a rate change filing, the Commission adds §§ 35.18 and 154.315 to its rate change filing requirements. These new regulations require that public utilities, licensees, and natural gas companies who have recorded an asset retirement obligation on their books in accordance with this rule must, as part of any initial rate filing or general rate change filing, provide a schedule identifying all cost components related to the asset retirement obligation that are included in the book balances of all accounts reflected in the cost of service computation supporting the proposed rates. In addition, the regulations require that all asset retirement obligations related rate base items be removed from the rate base computation through an adjustment. If the public utility, licensee or natural gas company is seeking recovery of an asset retirement obligation in rates, it must also provide a detailed study supporting the amounts proposed to be collected in rates. If the public utility, licensee or natural gas company is not seeking recovery of the asset retirement obligation in rates, then it must remove all asset retirement obligation related cost components from its cost of service.

63. For natural gas companies currently collecting a negative salvage allowance in jurisdictional rates, negative salvage allowances that are not established due to an asset retirement obligation must be identified for rate making purposes separately from asset retirement obligation allowances. The current rate change filing requirement for natural gas companies at § 154.312(d), Statement D, requires that any authorized negative salvage must be maintained in a separate subaccount of account 108, Accumulated provision for depreciation of gas utility plant. The Commission is amending this section to ensure that this subaccount does not include any amounts related to asset retirement obligations.

64. The Commission will decline to make policy calls concerning regulatory certainty for disposition of transition costs, external funds for amounts collected in rates for asset retirement obligations, adjustments to book depreciation rates, and the exclusion of accumulated depreciation and accretion for asset retirement obligations from rate base are matters that are not subject to a one size fits all approach and are better resolved on a case-by-case basis in rate proceedings. The Commission is of the view that utilities will have the opportunity to seek recovery of qualified costs for asset retirement obligations in individual rate proceedings. This rule should not be construed as pregranted authority for rate recovery in a rate proceeding.

65. Finally this rule requires nothing new and nothing more with respect to the requirement for a detailed study. Complex depreciation and negative salvage studies are routinely filed or otherwise made available for review in rate proceedings. When utilities perform depreciation studies, a certain amount of detail is expected. It is incumbent upon the utility to provide sufficient detail to support depreciation rates, cost

[40] *See* Ferguson at p. 5 and NRECA at p. 6.

[41] *See* General Instruction 5, Submittal of Questions, in 18 CFR part 101 (Public Utilities and Licensees), General Instruction 5, Submittal of Questions, in 18 CFR part 201 (Natural Gas Companies), and General Instruction 1–11, Interpretation of rules, in 18 CFR part 352 (Oil Pipeline Companies).

[42] *See* EEI at p. 5.

[43] *See* MoPSC at p. 4 and NRECA at p. 7.

[44] *See* Northern Natural at pp. 1–2, MoPSC at p. 5, Deloitte & Touche at pp. 1–2, EEI at p. 9, Southern at pp. 2–3, and Ferguson at pp. 5 and 8.

of removal, and salvage estimates included in rates.[45] To the extent a utility believes materials are entitled to be non-public, protective orders are available to preserve confidentiality.

2. Tariff Filing Requirements Under 18 CFR Part 346

66. No comments were received objecting to the Commission's proposal to add a new § 346.3 to cost-of-service filing requirements for oil pipelines. Therefore, the Commission is implementing the provisions as noticed in the NOPR.

K. Implementation for Accounting and Reporting Purposes

67. The Commission proposed to implement the rule January 1, 2003, for accounting and reporting purposes for public utilities, licensees, natural gas companies and oil pipeline companies. This is the date jurisdictional entities that file FERC Forms 1, 1–F, 2, 2–A and 6, will measure the transition amounts for the asset retirement obligations.[46] The Commission also proposed that the reporting will be implemented for the FERC Forms 1, 1–F, 2, 2–A and 6 for the reporting year 2003.[47]

Comments Received

68. The majority of the commenters did not object to the Commission's proposed implementation date of January 1, 2003, for accounting and reporting purposes for public utilities, licensees, natural gas companies and oil pipeline companies. Two commenters assert that their fiscal year begins on April 1, 2003, rather than January 1, 2003. The commenters request the Commission clarify this requirement given that their fiscal year does not coincide with the calendar year, which they use for FERC reporting purposes. Both commenters request that the Commission consider allowing them to implement the proposed rule for accounting and reporting purposes on April 1, 2003, rather than the earlier date of January 1, 2003. The commenters assert that this would avoid the issue of retroactively applying the accounting rule to fiscal years prior to January 1, 2003.

69. One commenter recommends that the Commission allow jurisdictional entities to determine the differential in amounts between the two implementation dates, January 1, 2003 and the start of their fiscal year for FERC reporting purposes and footnote the difference in their FERC Annual Report.

Commission Response

70. The Commission is adopting the provisions in the NOPR for implementing the final rule for accounting and reporting purposes on January 1, 2003, except as clarified below for jurisdictional entities whose fiscal year begins after January 1, 2003. Upon considering the comments on this issue, the Commission will permit a jurisdictional entity for whose fiscal year begins after January 1, 2003, to apply the final rule on the first day of their fiscal year rather than on January 1, 2003 for accounting purposes and reporting in the FERC Forms 1, 1–F, 2, 2–A and 6 for the reporting year 2003. In adopting this provision, the Commission will require jurisdictional entities to determine the differential in amounts between the two implementation dates, January 1, 2003 and the jurisdictional entity's first day of their fiscal year of the adoption of the final rule in calendar year 2003 for accounting and FERC reporting purposes and footnote the difference in the FERC Annual Report for the reporting year 2003. Jurisdictional entities with fiscal years will continue to report to the Commission in FERC Annual Reports on a calendar year basis.

IV. FERC Annual Report Forms

71. The Commission proposed changes revising the existing schedules in the FERC Forms 1, 1–F, 2, 2–A, and 6 filed with the Commission. A table summarizing the changes to the various schedules is shown in Appendix B. The Commission also proposed that jurisdictional entities include certain disclosure for asset retirement obligations in the ''Notes to Financial Statements'' in the FERC Forms 1, 1–F, 2, 2–A and 6.[48]

72. No commenters object to the Commission's proposed revisions to the existing schedules in the FERC Annual Report and the proposed disclosure for asset retirement obligations in the ''Notes to Financial Statements'' in FERC Annual Reports. Therefore, the Commission will adopt the provisions as noticed.

V. Regulatory Flexibility Act Certification

73. The Regulatory Flexibility Act (RFA) requires agencies to prepare certain statements, descriptions, and analyses of rules that will have a significant economic impact on a substantial number of small entities.[49] The Commission is not required to make such analyses if a rule would not have such an effect.

74. The Commission does not believe that this rule will have such an impact on small entities. Most filing companies regulated by the Commission do not fall within the RFA's definition of a small entity.[50] Further, the Commission concludes that this reporting would not be a significant burden because the information jurisdictional entities will be required to report to the Commission specifically focuses on the activities of the jurisdictional entities that will be captured in their accounting systems and generally be reported to their shareholders and others at a company, or at a consolidated business level. Therefore, the Commission certifies that this rule will not have a significant economic impact on a substantial number of small entities.

75. However, if the reporting requirements represent an undue burden on small businesses, the entity affected may seek a waiver of the disclosure requirements from the Commission.

VI. Environmental Impact Statement

76. Commission regulations require that an environmental assessment or an environmental impact statement be prepared for any Commission action that may have a significant adverse effect on the human environment.[51] No environmental consideration is necessary for the promulgation of a rule that is clarifying, corrective, or procedural or does not substantially change the effect of legislation or regulation being amended,[52] and also

[45] When an electric utility files for a change in its jurisdictional rates, the Commission requires detailed studies in support of changes in annual depreciation rates if they are different from those supporting the utility's prior approved jurisdictional rate. (18 CFR 35.13(h)(10)(iv)).

[46] On February 20, 2002, the Commission's Chief Accountant issued interim guidance stating that jurisdictional entities may not adopt FAS 143 for financial accounting and reporting to the Commission before Commission action on this matter. *See* All Jurisdictional Public Utilities, Licensees, Natural Gas Companies, and Oil Pipeline Companies, 98 FERC ¶ 62,222 (2002).

[47] The FERC Forms 1–F and 2–A and 6 annual reports for the year 2003 are due on or before March 31, 2004. The FERC Forms 1 and 2 annual reports for the year 2003 are due on or before April 30, 2004.

[48] *See* the instructions to the Notes to Financial Statements schedule for FERC Forms 1, 1–F, 2, 2–A and 6 that requires respondents to report important notes and information related to the financial statements.

[49] 5 U.S.C. 601–612.

[50] 5 U.S.C. 601(3), citing to section 3 of the Small Business Act, 15 U.S.C. 632. Section 3 of the Small Business Act defines a ''small-business concern'' as a business which is independently owned and operated and which is not dominant in its field of operation.

[51] Regulations Implementing National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[52] 18 CFR 380.4(a)(2)(ii).

for information gathering, analysis, and dissemination.[53] The rule updates the Parts 35, 101, 154, 201, 346 and 352 of the Commission's regulations, and does not substantially change the effect of the underlying legislation or the regulations being revised or eliminated. In addition, the final rule involves information gathering, analysis and dissemination. Therefore, this final rule falls within categorical exemptions provided in the Commission's regulations. Consequently, neither an environmental impact statement nor an environmental assessment is required.

VII. Information Collection Statement

77. The Office of Management and Budget's (OMB) regulations in 5 CFR 1320.11 require that it approve certain reporting and recordkeeping requirements (collections of information) imposed by an agency. Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this Rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

78. The final rule will affect the following current data collections: FERC Form(s) 1, 1–F, 2, 2–A and 6, FERC–516 and FERC–545. In accordance with Section 3507(d) of the Paperwork Reduction Act of 1995,[54] the data requirements in the subject rule have been submitted to OMB for review.

Public Reporting Burden: The Commission provided burden estimates in order to implement the proposed requirements. Of the 16 commenters who responded to the NOPR, only one made specific comment concerning the Commission's burden estimates. This one commenter has misconstrued the intent of the rule to impose more time consuming requirements (*e.g.*, group depreciation method) than the final rule actually imposes. The Commission's responses to these comments are being addressed elsewhere in the final rule. The proposed requirements coincide with procedures already established by FAS 143 for companies to recognize a liability at fair value on their financial statements for a retirement obligation when it has occurred. The Commission is merely adjusting these industry standards to coordinate with its Uniform Systems of Accounts.

Data collection	No. of respondents	No. of responses per respondent	Hours per response	Total annual hours
Form 1	216	216	17	3,672
Form 1–F	27	27	8	216
Form 2	57	57	13	741
Form 2–A	53	53	8	424
Form 6	159	159	10	1,590
Totals	512	512	....	6,643

The total annual hours for these collections is 6,643 hours.

Information Collection Costs: The Commission is projecting only the costs associated with implementing the requirements of this rule.

Annualized Capital/Startup Costs: 6,643 hours ÷ 2,080 hours × $117,041 = $373,800.

Annualized Costs (Operations & Maintenance): It should be noted that the burden and corresponding costs of this final rule are to be implemented by jurisdictional entities to comply with the Commission's Uniform System of Accounts. These entities must already maintain much of this information in order to implement generally accepted accounting principles. The burden and corresponding costs are to account for only where there are differences between the generally accepted accounting principles and the Uniform System of Accounts.

79. FERC Information Collections FERC–516 and FERC–545 are also referenced because jurisdictional entities will be required to provide supporting documentation for the amounts to be collected in their rates when an asset retirement obligation has been recorded. This documentation is no different than jurisdictional entities already prepare in their detailed studies as currently required by the Commission to support changes in annual depreciation rates. The Commission is not requiring additional information as jurisdictional entities already prepare this information when quantifying studies and analyses on the cost of removal of an asset retirement obligation. Therefore, the Commission does anticipate that additional burden will be imposed under these two information collections.

80. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

Title: FERC Form 1 ''Annual Report of Major Electric Utilities, Licensees and Others''; FERC Form 1–F ''Annual Report of Nonmajor Public Utilities and Licensees''; FERC Form 2 ''Annual Report of Major Natural Gas Companies''; FERC Form 2–A ''Annual Report of Nonmajor Natural Gas Companies''; FERC Form 6 ''Annual Report of Oil Pipeline Companies''; FERC–516 ''Electric Rate Schedule Filings''; FERC–545 ''Gas Pipeline Rates: Rate Change.''

Action: Proposed data collections.

OMB Control Nos.: 1902–0021; 1902–0029; 1902–0028; 1902–0030; 1902–0022, 1902–0016 and 1902–0154.

Respondents: Public Utilities; Natural Gas Companies; oil pipeline companies (Business or other for profit, including small businesses).

Frequency of the information: Annually.

Necessity of the Information: The final rule amends the Commission's regulations to revise parts 35, 101, 154, 201, 346 and 352 of its regulations. The final rule amends the Commission's Uniform System of Accounts to revise or create definitions, instructions, balance sheet and income statement accounts. The addition of new accounts and changes to FERC Forms will add visibility, completeness and consistency of the accounting and reporting of liabilities for asset retirement obligations and the related asset retirement costs capitalized. The implementation of these requirements will enable the Commission to carry out its responsibilities under the FPA, NGA and ICA to ensure the protection of ratepayers. The Commission is of the view that such requirements are needed because the disclosures of these lack uniformity. For example, jurisdictional

[53] 18 CFR 380.4(a)(5).

[54] 44 U.S.C. 3507(d).

entities subject to the Commission's requirements use different approaches for accounting for retirement costs. Public utilities perform depreciation studies to support changes in their rates for the decommissioning of a nuclear facility as periodic depreciation expense while oil pipeline companies have used depletion rates for abandonment and removal of offshore facilities. The final rule will improve the consistency in the accounting and reporting of legal obligations to retire tangible long-lived assets by requiring entities to recognize at the onset the fair value of the liability. This information will provide a more transparent financial statement disclosure of the costs related to the legal obligation in the FERC Annual Reports.

81. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [Attention: Michael Miller, Office of the Executive Director, ED–30, (202) 502–8415, or *michael.miller@ferc.gov*] or by sending comments on the collections of information to the Office of Management and Budget, Office of Information and Regulatory Affairs, Attention: Desk Officer for the Federal Energy Regulatory Commission, 725 17th Street, NW., Washington, DC 20503. The Desk Officer can also be reached at (202) 395–7856, or fax: (202) 395–7285.

VIII. Document Availability

82. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (*http://www.ferc.gov*) and in FERC's Public Reference Room during normal business hours (8:30 a.m., to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

83. From FERC's Home Page on the Internet, this information is available in the Federal Energy Regulatory Records Information System (FERRIS). The full text of this document is available on FERRIS in PDF and WordPerfect format for viewing, printing, and/or downloading. To access this document in FERRIS, type the docket number of this document, excluding the last three digits in the docket number field. User assistance is available for FERRIS and the FERC's Web site during normal business hours from FERC Online Support at *FERCOnLineSupport@FERC.gov* or toll free at (866) 208–3676 or for TTY, contact (202) 502–8659.

IX. Effective Date and Congressional Notification

84. This Final Rule will take effect May 21, 2003. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of the Office of Management and Budget, that this rule is not a "major rule" within the meaning of section 251 of the Small Business Regulatory Enforcement Fairness Act of 1996.[55] The Commission will submit the Final Rule to both houses of Congress and the General Accounting Office.[56]

List of Subjects

18 CFR Part 35

Electric power rates, Electric utilities, Electricity, Reporting and recordkeeping requirements.

18 CFR Part 101

Electric power, Electric utilities, Reporting and recordkeeping requirements, Uniform System of Accounts.

18 CFR Part 154

Alaska, Natural gas, Natural gas companies, Pipelines, Rate schedules and tariffs, Reporting and recordkeeping requirements.

18 CFR Part 201

Natural gas, Reporting and recordkeeping requirements, Uniform System of Accounts.

18 CFR Part 346

Pipelines, Reporting and recordkeeping requirements.

18 CFR Part 352

Pipelines, Reporting and recordkeeping requirements, Uniform System of Accounts.

By the Commission.

Magalie R. Salas,

Secretary.

In consideration of the foregoing, the Commission amends parts 35, 101, 154, 201, 346 and 352, Chapter I, Title 18, *Code of Federal Regulations,* as follows.

Regulatory Text

PART 35—FILING OF RATE SCHEDULES

■ 1. The authority citation for part 35 continues to read as follows:

[55] 5 U.S.C. 804(2).

[56] 5 U.S.C. 801(a)(1)(A).

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ 2. Section 35.18 is added to read as follows:

§ 35.18 Asset retirement obligations.

(a) A public utility that files a rate schedule under § 35.12 or § 35.13 and has recorded an asset retirement obligation on its books must provide a schedule, as part of the supporting work papers, identifying all cost components related to the asset retirement obligations that are included in the book balances of all accounts reflected in the cost of service computation supporting the proposed rates. However, all cost components related to asset retirement obligations that would impact the calculation of rate base, such as electric plant and related accumulated depreciation and accumulated deferred income taxes, may not be reflected in rates and must be removed from the rate base calculation through a single adjustment.

(b) A public utility seeking to recover nonrate base costs related to asset retirement costs in rates must provide, with its filing under § 35.12 or § 35.13, a detailed study supporting the amounts proposed to be collected in rates.

(c) A public utility that has recorded asset retirement obligations on its books, but is not seeking recovery of the asset retirement costs in rates, must remove all asset-retirement-obligations-related cost components from the cost of service supporting its proposed rates.

PART 101—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR PUBLIC UTILITIES AND LICENSEES SUBJECT TO THE PROVISIONS OF THE FEDERAL POWER ACT

■ 3. The authority citation for part 101 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352, 7651–7651o.

■ 4. In Definitions, Definition 10 is revised to read as follows:

Definitions

* * * * *

10. *Cost of removal* means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto. It does not include the cost of removal activities associated with asset retirement obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation. (*See* General Instruction 25).

* * * * *

■ 5. In General Instructions, Instruction 20, paragraphs C. and D. are redesignated as paragraphs D. and E. and new paragraph C. is added; and a new Instruction 25 is added to read as follows:

General Instructions

* * * * *

20. *Accounting for leases*.

* * * * *

C. The utility, as a lessee, shall recognize an asset retirement obligation (*See* General Instruction 25) arising from the plant under a capital lease unless the obligation is recorded as an asset and liability under a capital lease. The utility shall record the asset retirement cost by debiting account 101.1, Property under capital leases, or account 120.6, Nuclear fuel under capital leases, or account 121, Nonutility property, as appropriate, and crediting the liability for the asset retirement obligation in account 230, Asset retirement obligations. Asset retirement costs recorded in account 101.1, account 120.6, or account 121 shall be amortized by charging rent expense (*See* Operating Expense Instruction 3), or account 518, Nuclear fuel expense (Major only), or account 421, Miscellaneous nonoperating income, as appropriate, and crediting a separate subaccount of the account in which the asset retirement costs are recorded. Charges for the periodic accretion of the liability in account 230, Asset retirement obligations, shall be recorded by a charge to account 411.10, Accretion expense, for electric utility plant, and account 421, Miscellaneous nonoperating income, for nonutility plant and a credit to account 230, Asset retirement obligations.

* * * * *

25. *Accounting for asset retirement obligations*.

A. An *asset retirement obligation* represents a liability for the legal obligation associated with the retirement of a tangible long-lived asset that a company is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. An *asset retirement cost* represents the amount capitalized when the liability is recognized for the long-lived asset that gives rise to the legal obligation. The amount recognized for the liability and an associated asset retirement cost shall be stated at the fair value of the asset retirement obligation in the period in which the obligation is incurred.

B. The utility shall initially record a liability for an asset retirement obligation in account 230, Asset retirement obligations, and charge the associated asset retirement costs to electric utility plant (including accounts 101.1 and 120.6), and nonutility plant, as appropriate, related to the plant that gives rise to the legal obligation. The asset retirement cost shall be depreciated over the useful life of the related asset that gives rise to the obligations. For periods subsequent to the initial recording of the asset retirement obligation, a utility shall recognize the period to period changes of the asset retirement obligation that result from the passage of time due to the accretion of the liability and any subsequent measurement changes to the initial liability for the legal obligation recorded in account 230, Asset retirement obligations, as follows:

(1) The utility shall record the accretion of the liability by debiting account 411.10, Accretion expense, for electric utility plant, account 413, Expenses of electric plant leased to others, for electric plant leased to others, and account 421, Miscellaneous nonoperating income, for nonutility plant and crediting account 230, Asset retirement obligations; and

(2) The utility shall recognize any subsequent measurement changes of the liability initially recorded in account 230, Asset retirement obligations, for each specific asset retirement obligation as an adjustment of that liability in account 230 with the corresponding adjustment to electric utility plant, electric plant leased to others, and nonutility plant, as appropriate. The utility shall on a timely basis monitor any measurement changes of the asset retirement obligations.

C. Gains or losses resulting from the settlement of asset retirement obligations associated with utility plant resulting from the difference between the amount of the liability for the asset retirement obligation included in account 230, Asset retirement obligations, and the actual amount paid to settle the obligation shall be accounted for as follows:

(1) Gains shall be credited to account 411.6, Gains from disposition of utility plant, and;

(2) Losses shall be charged to account 411.7, Losses from disposition of utility plant.

D. Gains or losses on the settlement of asset retirement obligations associated with nonutility plant resulting from the difference between the amount of the liability for the asset retirement obligation in account 230, Asset retirement obligations, and the amount paid to settle the obligation, shall be accounted for as follows:

(1) Gains shall be credited to account 421, Miscellaneous nonoperating income, and;

(2) Losses shall be charged to account 426.5, Other deductions.

E. Separate subsidiary records shall be maintained for each asset retirement obligation showing the initial liability and associated asset retirement cost, any incremental amounts of the liability incurred in subsequent reporting periods for additional layers of the original liability and related asset retirement cost, the accretion of the liability, the subsequent measurement changes to the asset retirement obligation, the depreciation and amortization of the asset retirement costs and related accumulated depreciation, and the settlement date and actual amount paid to settle the obligation. For purposes of analyses a utility shall maintain supporting documentation so as to be able to furnish accurately and expeditiously with respect to each asset retirement obligation the full details of the identity and nature of the legal obligation, the year incurred, the identity of the plant giving rise to the obligation, the full particulars relating to each component and supporting computations related to the measurement of the asset retirement obligation.

* * * * *

■ 6. In Electric Plant Instructions, paragraph 3.A.(17)(a) the W element is revised; and a new paragraph 3.A.(21) is added to read as follows:

Electric Plant Instructions

* * * * *

3. *Components of construction cost.*

A. * * *

(17) * * *

(a) * * *

W = Average balance in construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment and fabrication, less asset retirement costs (See General Instruction 25) related to plant under construction.

* * * * *

(21) *Asset retirement costs.* The costs recognized as a result of asset retirement obligations incurred during the construction and testing of utility plant shall constitute a component of construction costs.

* * * * *

■ 7. Balance Sheet Accounts are amended as follows:

■ (a) Account 101.1 is amended by adding a sentence to the end of paragraph C.;

■ (b) Account 103 paragraph C. is revised;

■ (c) Account 108 paragraph A.(2) through A.(7) are redesignated as paragraphs A.(3) through A.(8), a new paragraph A.(2) is added, and paragraph C. is amended by adding a sentence to the end of the paragraph;
■ (d) Account 110 paragraph A.(2) through A.(4) are redesignated as paragraphs A.(3) through A.(5), a new paragraph A.(2) is added, and paragraph C. is amended by adding a sentence to the end of the paragraph;
■ (e) Account 121, paragraph A. is amended by adding a sentence to the end of the paragraph; and
■ (f) Account 230 is added.

The revision and additions read as follows:

Balance Sheet Accounts

* * * * *

101.1 Property under capital leases.

* * * * *

C. * * * Records shall also be maintained for plant under a lease, to identify the asset retirement obligation and cost originally recognized for each lease and the periodic charges and credits made to the asset retirement obligations and asset retirement costs.

* * * * *

103 Experimental electric plant unclassified (Major only).

* * * * *

C. The depreciation on plant in this account shall be charged to account 403, Depreciation expense, and account 403.1, Depreciation expense for asset retirement costs, as appropriate, and credited to account 108, Accumulated provision for depreciation of electric utility plant (Major only). The amounts herein shall be depreciated over a period which corresponds to the estimated useful life of the relevant project considering the characteristics involved. However, when projects are transferred to account 101, Electric plant in service, a new depreciation rate based on the remaining service life and undepreciated amounts, will be established.

* * * * *

108 Accumulated provision for depreciation of electric utility plant (Major only).

A. * * *

(2) Amounts charged to account 403.1, Depreciation expense for asset retirement costs, for current depreciation expense related to asset retirement costs in electric plant in service in a separate subaccount.

* * * * *

C. * * * Separate subsidiary records shall be maintained for the amount of accrued cost of removal other than legal obligations for the retirement of plant recorded in account 108, Accumulated provision for depreciation of electric utility plant (Major only).

* * * * *

110 Accumulated provision for depreciation and amortization of electric utility plant (Nonmajor only).

A. * * *

(2) Amounts charged to account 403.1, Depreciation expense for asset retirement costs, in electric utility plant in service in a separate subaccount.

* * * * *

C. * * * Separate subsidiary records shall be maintained for the amount of accrued cost of removal other than legal obligations for the retirement of plant recorded in account 110, Accumulated provision for depreciation of electric utility plant (Nonmajor only).

* * * * *

121 Nonutility property.

A. * * * This account shall also include, where applicable, amounts recorded for asset retirement costs associated with nonutility plant.

* * * * *

230 Asset retirement obligations.

A. This account shall include the amount of liabilities for the recognition of asset retirement obligations related to electric utility plant and nonutility plant that gives rise to the obligations. This account shall be credited for the amount of the liabilities for asset retirement obligations with amounts charged to the appropriate electric utility plant accounts or nonutility plant account to record the related asset retirement costs.

B. The utility shall charge the accretion expense to account 411.10, Accretion expense, for electric utility plant, account 413, Expenses of electric plant leased to others, for electric plant leased to others, or account 421, Miscellaneous nonoperating income, for nonutility plant, as appropriate, and credit account 230, Asset retirement obligations.

C. This account shall be debited with amounts paid to settle the asset retirement obligations recorded herein.

D. The utility shall clear from this account any gains or losses resulting from the settlement of asset retirement obligations in accordance with the instructions prescribed in General Instruction 25.

* * * * *

■ 8. In Electric Plant Accounts, new primary plant accounts, 317, 326, 337, 347, 359.1, 374, and 399.1 are added to read as follows:

Electric Plant Accounts

* * * * *

317 Asset retirement costs for steam production plant.

This account shall include asset retirement costs on plant included in the steam production function.

* * * * *

326 Asset retirement costs for nuclear production plant (Major only).

This account shall include asset retirement costs on plant included in the nuclear production function.

* * * * *

337 Asset retirement costs for hydraulic production plant.

This account shall include asset retirement costs on plant included in the hydraulic production function.

* * * * *

347 Asset retirement costs for other production plant.

This account shall include asset retirement costs on plant included in the other production function.

* * * * *

359.1 Asset retirement costs for transmission plant.

This account shall include asset retirement costs on plant included in the transmission plant function.

* * * * *

374 Asset retirement costs for distribution plant.

This account shall include asset retirement costs on plant included in the distribution plant function.

* * * * *

399.1 Asset retirement costs for general plant.

This account shall include asset retirement costs on plant included in the general plant function.

* * * * *

■ 9. Amend Income Accounts as follows:
■ a. Account 403.1 is added,
■ b. Accounts 411.6 and 411.7 are amended by designating the current paragraph as A., and adding a new paragraph B.,
■ c. Account 411.10 is added,
■ d. In account 421, paragraphs 4. through 6. are added, and
■ e. In account 426.5 paragraph 6 is added.

The additions read as follows:

Income Accounts

* * * * *

403.1 Depreciation expense for asset retirement costs.

This account shall include the depreciation expense for asset retirement costs included in electric utility plant in service.

* * * * *

411.6 Gains from disposition of utility property.

A. * * *

B. The utility shall record in this account gains resulting from the settlement of asset retirement obligations related to utility plant in accordance with the accounting prescribed in General Instruction 25.

* * * * *

411.7 Losses from disposition of utility property.

A. * * *

B. The utility shall record in this account losses resulting from the settlement of asset retirement obligations related to utility plant in accordance with the accounting prescribed in General Instruction 25.

* * * * *

411.10 Accretion expense.

This account shall be charged for accretion expense on the liabilities associated with asset retirement obligations included in account 230, Asset retirement obligations, related to electric utility plant.

* * * * *

421 Miscellaneous nonoperating income.

* * * * *

4. This account shall include the accretion expense on the liability for an asset retirement obligation included in account 230, Asset retirement obligations, related to nonutility plant.

5. This account shall include the depreciation expense for asset retirement costs related to nonutility plant.

6. The utility shall record in this account gains resulting from the settlement of asset retirement obligations related to nonutility plant in accordance with the accounting prescribed in General Instruction 25.

* * * * *

426.5 Other deductions.

* * * * *

6. The utility shall record in this account losses resulting from the settlement of asset retirement obligations related to nonutility plant in accordance with the accounting prescribed in General Instruction 25.

* * * * *

PART 154—RATE SCHEDULES AND TARIFFS

■ 10. The authority citation for part 154 continues to read as follows:

Authority: 15 U.S.C. 717–717w; 31 U.S.C. 9701; 42 U.S.C. 7102–7352.

■ 11. In § 154.312 paragraph (d), introductory text, is amended by removing the sentence ''Any authorized negative salvage must be maintained in a separate subaccount of account 108,'' and adding in its place the following sentence to read as follows:

§ 154.312 Composition of Statements.

* * * * *

(d)* * * Any authorized negative salvage must be maintained in a separate subaccount of account 108, and shall not include any amounts related to asset retirement obligations. * * *

* * * * *

■ 12. Section 154.315 is added to subpart D to read as follows:

§ 154.315 Asset retirement obligations.

(a) A natural gas company that files a tariff change under this part and has recorded an asset retirement obligation on its books must provide a schedule, as part of the supporting workpapers, identifying all cost components related to the asset retirement obligations that are included in the book balances of all accounts reflected in the cost of service computation supporting the proposed rates. However, all cost components related to asset retirement obligations that would impact the calculation of rate base, such as gas plant and related accumulated depreciation and accumulated deferred income taxes, may not be reflected in rates and must be removed from the rate base calculation through a single adjustment.

(b) A natural gas company seeking to recover nonrate base costs related to asset retirement obligations in rates must provide, with its filing under § 154.312 or § 154.313, a detailed study supporting the amounts proposed to be collected in rates.

(c) A natural gas company who has recorded asset retirement obligations on its books but is not seeking recovery of the asset retirement costs in rates, must remove all asset retirement obligations related cost components from the cost of service supporting its proposed rates.

PART 201—UNIFORM SYSTEM OF ACCOUNTS PRESCRIBED FOR NATURAL GAS COMPANIES SUBJECT TO THE PROVISIONS OF THE NATURAL GAS ACT

■ 13. The authority citation for part 201 continues to read as follows:

Authority: 15 U.S.C. 717–717w, 3301–3432; 42 U.S.C. 7101–7352, 7651–7651o.

■ 14. In Definitions, Definition 10 is revised to read as follows:

Definitions

* * * * *

10. *Cost of removal* means the cost of demolishing, dismantling, tearing down or otherwise removing gas plant, including the cost of transportation and handling incidental thereto. It does not include the cost of removal activities associated with asset retirement obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation. (See General Instruction 24).

* * * * *

■ 15. In General Instructions, Instruction 20 paragraphs C. and D. are redesignated as paragraphs D. and E. and a new paragraph C. is added; and a new Instruction 24 is added to read as follows:

General Instructions

* * * * *

20. *Accounting for leases.*

* * * * *

C. The utility, as a lessee, shall recognize an asset retirement obligation (See General Instruction 24) arising from the plant under a capital lease unless the obligation is recorded as an asset and liability under a capital lease. The utility shall record the asset retirement cost by debiting account 101.1, Property under capital leases, or account 121, Nonutility property, as appropriate, and crediting the liability for the asset retirement obligation in account 230, Asset retirement obligations. Asset retirement costs recorded in account 101.1 or account 121 shall be amortized by charging rent expense (See Operating Expense Instruction 3) or account 421, Miscellaneous nonoperating income, as appropriate, and crediting a separate subaccount of the account in which the asset retirement costs are recorded. Charges for the periodic accretion of the liability in account 230, Asset retirement obligations, shall be recorded by a charge to account 411.10, Accretion expense, for gas utility plant, and account 421, Miscellaneous nonoperating income, for nonutility plant and a credit to account 230, Asset retirement obligations.

* * * * *

24. *Accounting for asset retirement obligations.*

A. An *asset retirement obligation* represents a liability for the legal obligation associated with the retirement of a tangible long-lived asset that a utility is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. An *asset retirement cost* represents the amount capitalized when the liability is recognized for the long-lived asset that gives rise to the legal obligation. The amount recognized for the liability and an associated asset retirement cost shall be stated at the fair value of the asset retirement obligation in the period in which the obligation is incurred.

B. The utility shall initially record a liability for an asset retirement obligation in account 230, Asset retirement obligations, and charge the associated asset retirement costs to gas utility plant and nonutility plant, as appropriate, related to the plant that gives rise to the legal obligation. The asset retirement cost shall be depreciated over the useful life of the related asset that gives rise to the obligations. For periods subsequent to the initial recording of the asset retirement obligation, a utility shall recognize the period to period changes of the asset retirement obligation that result from the passage of time due to the accretion of the liability and any subsequent measurement changes to the initial liability for the legal obligation recorded in account 230, Asset retirement obligations, as follows:

(1) The utility shall record the accretion of the liability by debiting account 411.10, Accretion expense, for gas utility plant, account 413, Expenses of gas plant leased to others, for gas plants leased to others, and account 421, Miscellaneous nonoperating income, for nonutility plant and crediting account 230, Asset retirement obligations; and

(2) The utility shall recognize any subsequent measurement changes of the liability initially recorded in account 230, Asset retirement obligations, for each specific asset retirement obligation as an adjustment of that liability in account 230 with the corresponding adjustment to gas utility plant, gas plant leased to others, and nonutility plant, as appropriate. The utility shall on a timely basis monitor any measurement changes of the asset retirement obligations.

C. Gains or losses resulting from the settlement of asset retirement obligations associated with utility plant resulting from the difference between the amount of the liability for the asset retirement obligation included in account 230, Asset retirement obligations, and the actual amount paid to settle the obligation shall be accounted for as follows:

(1) Gains shall be credited to account 411.6, Gains from disposition of utility plant, and;

(2) Losses shall be charged to account 411.7, Losses from disposition of utility plant.

D. Gains or losses on the settlement of the asset retirement obligations associated with nonutility plant resulting from the difference between the amount of the liability for the asset retirement obligation in account 230, Asset retirement obligations, and the amount paid to settle the obligation, shall be accounted for as follows:

(1) Gains shall be credited to account 421, Miscellaneous nonoperating income, and;

(2) Losses shall be charged to account 426.5, Other deductions.

E. Separate subsidiary records shall be maintained for each asset retirement obligation showing the initial liability and associated asset retirement cost, any incremental amounts of the liability incurred in subsequent reporting periods for additional layers of the original liability and related asset retirement cost, the accretion of the liability, the subsequent measurement changes to the asset retirement obligation, the depreciation and amortization of the asset retirement costs and related accumulated depreciation, and the settlement date and actual amount paid to settle the obligation. For purposes of analyses a utility shall maintain supporting documentation so as to be able to furnish accurately and expeditiously with respect to each asset retirement obligation the full details of the identity and nature of the legal obligation, the year incurred, the identity of the plant giving rise to the obligation, the full particulars relating to each component and supporting computations related to the measurement of the asset retirement obligation.

* * * * *

■ 16. In Gas Plant Instructions, paragraph 3.A.(17)(a) the W element is revised; and new paragraph 3.A.(23) is added to read as follows:

Gas Plant Instructions

* * * * *

3. *Components of construction cost.*

A. * * *

(17) * * *

(a) * * *

W = Average balance in construction work in progress less asset retirement costs (See General Instruction 24) related to plant under construction.

* * * * *

(23) ''Asset retirement costs.'' The costs recognized as a result of asset retirement obligations incurred during the construction and testing of utility plant shall constitute a component of construction costs.

* * * * *

■ 17. Balance Sheet Accounts are amended as follows:

■ (a) Account 101.1, is amended by adding a sentence to the end of paragraph C.;

■ (b) Account 103, paragraph C. is revised;

■ (c) Account 108, paragraphs A.(2) through A.(7) are redesignated as paragraphs A.(3) through A.(8), a new paragraph A.(2) is added, and paragraph C. is amended by adding a sentence to the end of the paragraph;

■ (d) Account 121, paragraph A. is amended by adding a sentence to the end of the paragraph; and

■ (e) Account 230 is added.

The additions and revisions read as follows:

Balance Sheet Accounts

* * * * *

101.1 Property under capital leases.

* * * * *

C. * * * Records shall also be maintained for plant under a lease, to identify the asset retirement obligation and cost originally recognized for each lease and the periodic charges and credits made to the asset retirement obligations and asset retirement costs.

* * * * *

103 Experimental gas plant unclassified.

* * * * *

C. The depreciation on plant in this account shall be charged to account 403, Depreciation expense, and account 403.1, Depreciation expense for asset retirement costs, as appropriate, and credited to account 108, Accumulated provision for depreciation of gas utility plant. The amounts herein shall be depreciated over a period which corresponds to the estimated useful life of the relevant project considering the characteristics involved. However, when projects are transferred to account 101, Gas plant in service, a new depreciation rate based on the remaining service life and undepreciated amounts, will be established.

* * * * *

108 Accumulated provision for depreciation of gas utility plant.

A. * * *

(2) Amounts charged to account 403.1, Depreciation expense for asset retirement costs, for current

depreciation expense related to asset retirement costs in gas plant in service in a separate subaccount.

* * * * *

C. * * * Separate subsidiary records shall be maintained for the amount of accrued cost of removal other than legal obligations for the retirement of plant recorded in account 108, Accumulated provision for depreciation of gas utility plant.

* * * * *

121 Nonutility property.

A. * * * This account shall also include, where applicable, amounts recorded for asset retirement costs associated with nonutility plant.

* * * * *

230 Asset retirement obligations.

A. This account shall include the amount of liabilities for the recognition of asset retirement obligations related to gas utility plant and nonutility plant that gives rise to the obligations. This account shall be credited for the amount of the liabilities for asset retirement obligations with amounts charged to the appropriate gas utility plant accounts or nonutility plant accounts to record the related asset retirement costs.

B. This account shall also include the period to period changes for the accretion of the liabilities in account 230, Asset retirement obligations. The utility shall charge the accretion expense to account 411.10, Accretion expense, for gas utility plant, account 413, Expenses of gas plant leased to others, for gas plant leased to others, or account 421, Miscellaneous nonoperating income, for nonutility plant, as appropriate, and credit account 230, Asset retirement obligations.

C. This account shall be debited with amounts paid to settle the asset retirement obligations recorded herein.

D. The utility shall clear from this account any gains or losses resulting from the settlement of asset retirement obligations in accordance with the instructions prescribed in General Instruction 24.

* * * * *

■ 18. In Gas Plant Accounts, new primary plant accounts, 321, 339, 348, 358, 363.6, 372, 388, and 399.1 are added to read as follows:

Gas Plant Accounts

* * * * *

321 Asset retirement costs for manufactured gas production plant.

This account shall include asset retirement costs on plant included in the manufactured gas production plant function.

* * * * *

339 Asset retirement costs for natural gas production and gathering plant.

This account shall include asset retirement costs on plant included in the natural gas production and gathering plant function.

* * * * *

348 Asset retirement costs for products extraction plant.

This account shall include asset retirement costs on plant included in the products extraction plant function.

* * * * *

358 Asset retirement costs for underground storage plant.

This account shall include asset retirement costs on plant included in the underground storage plant function.

* * * * *

363.6 Asset retirement costs for other storage plant.

This account shall include asset retirement costs on plant included in the other storage plant function.

* * * * *

372 Asset retirement costs for transmission plant.

This account shall include asset retirement costs on plant included in the transmission plant function.

* * * * *

388 Asset retirement costs for distribution plant.

This account shall include asset retirement costs on plant included in the distribution plant function.

* * * * *

399.1 Asset retirement costs for general plant.

This account shall include asset retirement costs on plant included in the general plant function.

* * * * *

■ 19. Income Accounts are amended as follows:

■ a. Account 403.1 is added,

■ b. Accounts 411.6 and 411.7 are amended by designating the current paragraph as A. and adding a new paragraph B.,

■ c. Account 411.10 is added,

■ d. In Account 421, paragraphs 4. through 6. are added, and

■ e. In Account 426.5 paragraph 6. is added.

The additions read as follows:

Income Accounts

* * * * *

403.1 Depreciation expense for asset retirement costs.

This account shall include the depreciation expense for asset retirement costs included in gas utility plant in service.

* * * * *

411.6 Gains from disposition of utility property.

A. * * *

B. The utility shall record in this account gains resulting from the settlement of asset retirement obligations related to utility plant in accordance with the accounting prescribed in General Instruction 24.

* * * * *

411.7 Losses from disposition of utility property.

A. * * *

B. The utility shall record in this account losses resulting from the settlement of asset retirement obligations related to utility plant in accordance with the accounting prescribed in General Instruction 24.

* * * * *

411.10 Accretion expense.

This account shall be charged for accretion expense on the liabilities associated with asset retirement obligations included in account 230, Asset retirement obligations, related to gas utility plant.

* * * * *

421 Miscellaneous nonoperating income.

* * * * *

4. This account shall include the accretion expense on the liability for an asset retirement obligation included in account 230, Asset retirement obligations, related to nonutility plant.

5. This account shall include the depreciation expense for asset retirement costs related to nonutility plant.

6. The utility shall record in this account gains resulting from the settlement of asset retirement obligations related to nonutility plant in accordance with the accounting prescribed in General Instruction 24.

* * * * *

426.5 Other deductions.

* * * * *

6. The utility shall record in this account losses resulting from the settlement of asset retirement obligations related to nonutility plant in

accordance with the accounting prescribed in General Instruction 24.

* * * * *

PART 346–OIL PIPELINE COST-OF-SERVICE FILING REQUIREMENTS

■ 20. The authority citation for part 346 continues to read as follows:

Authority: 42 U.S.C. 7101–7352; 49 U.S.C. 60502; 49 App. U.S.C. 1–85.

■ 21. Section 346.3 is added to read as follows:

§ 346.3 Asset retirement obligations.

(a) A carrier that files material in support of initial rates or change in rates under § 346.2 and has recorded asset retirement obligations on its books must provide a schedule, as part of the supporting workpapers, identifying all cost components related to the asset retirement obligations that are included in the book balances of all accounts reflected in the cost of service computation supporting the proposed rates. However, all cost components related to asset retirement obligations that would impact the calculation of rate base, such as carrier property and related accumulated depreciation and accumulated deferred income taxes, may not be reflected in rates and must be removed from the rate base calculation through a single adjustment.

(b) A carrier seeking to recover nonrate base costs related to asset retirement costs in rates must provide, with its filing under § 346.2 of this part, a detailed study supporting the amounts proposed to be collected in rates.

(c) A carrier who has recorded asset retirement obligations on its books but is not seeking recovery of the asset retirement costs in rates, must remove all asset retirement obligations related cost components from the cost of service supporting its proposed rates.

PART 352—UNIFORM SYSTEMS OF ACCOUNTS PRESCRIBED FOR OIL PIPELINE COMPANIES SUBJECT TO THE PROVISIONS OF THE INTERSTATE COMMERCE ACT

■ 22. The authority citation for part 352 continues to read as follows:

Authority: 49 U.S.C. 60502; 49 App. U.S.C. 1–85 (1988).

■ 23. In List of Instructions and Accounts, under Definitions, Definition 12 is revised to read as follows:

Definitions. * * *

12. *Cost of removal* means cost of demolishing, dismantling, tearing down, or otherwise removing property including costs of handling and transportation. It does not include the cost of removal activities associated with asset retirement obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation. (*See* General Instruction 1–19).

* * * * *

■ 24. In General Instructions, paragraph 1–19 is added to read as follows:

General Instructions

* * * * *

1–19 *Accounting for asset retirement obligations.*

(a) An *asset retirement obligation* represents a liability for the legal obligation associated with the retirement of a tangible long-lived asset that a utility is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. An *asset retirement cost* represents the amount capitalized when the liability is recognized for the long-lived asset that gives rise to the legal obligation. The amount recognized for the liability and an associated asset retirement cost shall be stated at the fair value of the asset retirement obligation in the period in which the obligation is incurred.

(b) The carrier shall initially record a liability for an asset retirement obligation in account 67, Asset retirement obligations, and charge the associated asset retirement costs to account 30, Carrier property, and account 34, Noncarrier property, as appropriate, related to the property that gives rise to the legal obligation. The asset retirement cost shall be depreciated over the useful life of the related asset that gives rise to the obligations. For periods subsequent to the initial recording of the asset retirement obligation, a carrier shall recognize the period to period changes of the asset retirement obligation that result from the passage of time due to the accretion of the liability and any subsequent measurement revisions to the initial liability for the legal obligation recorded in account 67, Asset retirement obligations, as follows:

(1) The carrier shall record the accretion of the liability by debiting account 591, Accretion expense, for carrier property, account 620, Income (net) from noncarrier property, for noncarrier property and crediting account 67, Asset retirement obligations; and

(2) The carrier shall recognize any subsequent measurement changes of the liability initially recorded in account 67, Asset retirement obligations, for each specific asset retirement obligation as an adjustment of that liability in account 67 with the corresponding adjustment to carrier property and noncarrier property accounts, as appropriate. The utility shall on a timely basis monitor any measurement changes of the asset retirement obligations.

(c) Gains or losses resulting from the final settlement of asset retirement obligations for carrier plant resulting from the difference between the amount of the liability for the asset retirement obligation in account 67, Asset retirement obligations, and the actual amount to settle the obligation, shall be recorded in account 592, Gains or losses on asset retirement obligations.

(d) Gains or losses resulting from the final settlement of asset retirement obligations for noncarrier plant resulting from the difference between the amount of the liability for the asset retirement obligation in account 67, Asset retirement obligations, and the actual amount to settle the obligation, shall be recorded in account 620, Income (net) from noncarrier property.

(e) Separate subsidiary records shall be maintained for each asset retirement obligation showing the initial liability and associated asset retirement cost, any incremental amounts of the liability incurred in subsequent reporting periods for additional layers of the original liability and related asset retirement cost, the accretion of the liability, the subsequent measurement changes to the asset retirement obligation, the depreciation and amortization of the asset retirement costs and related accumulated depreciation, and the settlement date and actual amount paid to settle the obligation. For purposes of analyses a carrier shall maintain supporting documentation so as to be able to furnish accurately and expeditiously with respect to each asset retirement obligation the full details of the identity and nature of the legal obligation, the year incurred, the identity of the plant giving rise to the obligation, the full particulars relating to each component and supporting computations related to the measurement of the asset retirement obligation.

* * * * *

■ 25. In Instructions for Carrier Property Accounts, Instruction 3–3, paragraph (11)(iii) and paragraph (13) are added to read as follows:

Instructions for Carrier Property Accounts

* * * * *

3–3 *Cost of property constructed.* * * *

(11) * * *

(iii) Interest during construction shall not be recognized on the asset retirement costs incurred during the construction of carrier and noncarrier property.

* * * * *

(13) Asset retirement costs that are recognized as a result of asset retirement obligations incurred during construction shall be included in the cost of construction costs.

* * * * *

■ 26. In Balance Sheet Accounts, account 31 is amended by adding a sentence to the end of paragraph, account 34 is amended by adding a sentence to the end of paragraph and account 67 is added to read as follows:

Balance Sheet Accounts

* * * * *

31 * * * Separate subsidiary records shall be maintained for the amount of accrued cost of removal other than legal obligations for the retirement of property recorded in account 31, Accrued depreciation—Carrier property.

* * * * *

34 * * * This account shall also include, amounts recorded for asset retirement costs associated with noncarrier property.

* * * * *

67 Asset retirement obligations.

(a) This account shall include liabilities arising from the recognition of asset retirement obligations. The carrier shall credit account 67, Asset retirement obligations, for the liabilities for asset retirement obligations and charge the appropriate carrier property accounts or noncarrier property accounts to record the related asset retirement costs.

(b) This account shall also include the period to period changes for the accretion of the liabilities in account 67, Asset retirement obligations. The carrier shall charge the accretion expense to account 591, Accretion expense, for carrier property, and account 620, Income (net) from noncarrier property, for noncarrier property, as appropriate, and credit account 67, Asset retirement obligations.

(c) This account shall be debited with amounts paid to settle the asset retirement obligations recorded herein.

(d) The utility shall clear from this account any gains or losses resulting from the settlement of asset retirement obligations in accordance with the instructions prescribed in General Instruction 1–19.

* * * * *

■ 27. In Carrier Property Accounts, accounts 117, 167, and 186.1 are added to read as follows:

Carrier Property Accounts

* * * * *

117, 167, 186.1 *Asset retirement costs.*

This account shall include asset retirement costs on plans included in carrier property.

* * * * *

■ 28. In Operating Expenses, accounts 541, 591 and 592 are added to read as follows:

Operating Expenses

* * * * *

541 Depreciation expense for asset retirement costs.

This account shall include charges for the depreciation of asset retirement costs related to transportation property.

* * * * *

591 Accretion expense.

This account shall be charged for accretion expense on the liabilities associated with asset retirement obligations included in account 67, Asset retirement obligations. The carrier shall record in this account the settlement amounts for asset retirement obligations related to carrier property in accordance with the accounting prescribed in General Instruction 1–19.

592 Gains or losses on asset retirement obligations.

The carrier shall record in this account gains or losses resulting from the settlement amounts for asset retirement obligations related to carrier property plant. (*See* General Instruction 1–19).

* * * * *

Note: The following appendices will not be published in the Code of Federal Regulations.

APPENDIX A

LIST OF COMMENTERS

Respondent	Abbreviation
1. Arkansas Public Service Commission.	Arkansas PSC.
2. Don Bjerke	Bjerke.
3. Deloitte & Touche LLP.	Deloitte & Touche.
4. Edison Electric Institute.	EEI.
5. FirstEnergy Corp.	FirstEnergy.
6. John S. Ferguson	Ferguson.
7. K. C. Martin	K.C. Martin.
8. Missouri Public Service Commission.	MoPSC.
9. National Association of State Utility Consumer Advocates.	NASUCA.
10. National Grid USA.	National Grid.
11. National Rural Electric Cooperative Assn..	NRECA.
12. Northern Natural Gas Company.	Northern Natural.
13. PacifiCorp	PacifiCorp.
14. Progress Energy, Inc..	Progress Energy.
15. Rural Utilities Service.	RUS.
16. Southern Company.	Southern.

Appendix B

SUMMARY OF CHANGES TO SCHEDULES FOR FORMS 1, 1–F, 2, 2–A AND 6

Schedule title	Forms 1 and 1–F public utilities and licensees	Forms 2 and 2A natural gas companies	Form 6 oil pipeline companies
1 List of Schedules	Revise to show schedule changes.	Same as Public Utilities and Licensees.	Same as Public Utilities and Licensees.
2 Comparative Balance Sheet	Add new account 230 to report asset retirement obligations.	Same as Public Utilities and Licensees.	Add account 67 to report asset retirement obligations.
3 Statement of Income for the Year	Add new accounts 403.1, to report depreciation expense and 411.10, to report accretion expense.	Same as Public Utilities and Licensees.	Add accounts 541, to report depreciation expense, 591, to report accretion expense, and 592, to report gains or losses on asset retirement obligations.

SUMMARY OF CHANGES TO SCHEDULES FOR FORMS 1, 1–F, 2, 2–A AND 6—Continued

Schedule title	Forms 1 and 1–F public utilities and licensees	Forms 2 and 2A natural gas companies	Form 6 oil pipeline companies
4 Plant in Service	Add new Instruction 4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) addition and reductions in column (e) adjustments.	Same as Public Utilities and Licensees.	N/A
	Add new primary asset retirement accounts, 317, 326, 337, 347, 359.1, 374 and 399.1, for each plant function.	Add new primary asset retirement accounts, 339, 348, 358, 363.6, 364.9, 372, 388, 399.1, for each plant function.	N/A
5 Undivided Joint Interest Property	N/A	N/A	Add new primary asset retirement accounts, 117, 167, and 186.1, for each carrier property account function.
6 Accumulated Provision for Depreciation of Utility Plant	Added lines to report ''403.1 Depreciation Expense for Asset Retirement Costs'' and ''Book Cost of Asset Retirement Costs Retired.''	Same as Public Utilities and Licensees.	N/A
7 Accrued Depreciation—Carrier Property	N/A	N/A	Add new primary asset retirement accounts, 117, 167, and 186.1, for each carrier property account function and revise column (c) to read Debits to Accounts 540 and 541 of USofA (in dollars).
8 Accrued Depreciation—Undivided Joint Interest Property	N/A	N/A	Same as above for Accrued Depreciation—Carrier Property.
9 Depreciation and Amortization of Plant (Except Amortization of Acquisition Adjustments)	Add new Column (c), Depreciation Expense for Asset Retirement Costs (403.1).	Same as Public Utilities and Licenses. Form 2–A N/A	N/A
10 Amortization Base and Reserve	N/A	N/A	Revise header over columns (b), (c), (d) and (e) to read (Base 540 and 541).
11 Steam-Electric Generating Plant Statistics (Large Plants)	Form 1—Revise to report Asset Retirement Costs. Form 1–F N/A	N/A	N/A
12 Hydroelectric Generating Plant Statistics (Large Plants)	Form 1—Revise to report Asset Retirement Costs. Form 1–F N/A	N/A	N/A
13 Pumped Storage Generating Plant Statistics (Large Plants)	Form 1—Revise to report Asset Retirement Costs. Form 1–F N/A	N/A	N/A
14 Generating Plant Statistics (Small Plants) (Continued)	Form 1—Revise Column (g), to read ''Plant Cost (Including Asset Retirement Costs) Per MW Installed Capacity.'' Form 1–F N/A	N/A	N/A
15 Transmission Lines Added During the Year	Form 1—Add column (o) ''Asset Retirement Costs'' to report asset retirement costs as part of line cost. Form 1–F N/A	N/A	N/A

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19628 **Federal Register** / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -87-

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, ____

LIST OF SCHEDULES (Electric Utility)

Enter in column (d) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
GENERAL CORPORATE INFORMATION AND FINANCIAL STATEMENTS			
General Information	101	Ed. 12-87	
Control Over Respondent	102	Ed. 12-96	
Corporations Controlled by Respondent	103	Ed. 12-96	
Officers	104	Ed. 12-96	
Directors	105	Ed. 12-95	
Security Holders and Voting Powers	106-107	Ed. 12-96	
Important Changes During the Year	108-109	Ed. 12-96	
Comparative Balance Sheet	110-113	Rev. 12-02	
Statement of Income for the Year	114-117	Rev. 12-02	
Statement of Retained Earnings for the Year	118-119	Ed. 12-96	
Statement of Cash Flows	120-121	Ed. 12-96	
Statement of Accumulated Comprehensive Income and Hedging Activities	122 (a) (b)	New 12-02	
Notes to Financial Statements	123	Ed. 12-02	
BALANCE SHEET SUPPORTING SCHEDULES (Assets and Other Debits)			
Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization, and Depletion	200-201	Ed. 12-89	
Nuclear Fuel Materials	202-203	Ed. 12-89	
Electric Plant in Service	204-207	Rev. 12-02	
Electric Plant Leased to Others	213	Rev. 12-95	
Electric Plant Held for Future Use	214	Ed. 12-89	
Construction work in Progress -- Electric	216	Ed. 12-87	
Construction Overheads -- Electric	217	Ed. 12-89	
General Description of Construction Overhead Procedure	218	Ed. 12-88	
Accumulated Provision for Depreciation of Electric Utility Plant.	219	Ed. 12-02	
Nonutility Property	221	Rev. 12-95	
investment in Subsidiary Companies	224-225	Ed. 12-89	
Materials and Supplies	227	Ed. 12-87	
Allowances	228-229	Ed. 12-89	
Extraordinary Property Losses	230	Ed. 12-88	
Unrecovered Plant and Regulatory Study Costs	230	Ed. 12-88	
Other Regulatory Assets	232	Ed. 12-95	
Miscellaneous Deferred Debits	233	Ed. 12-94	
Accumulated Deferred Income Taxes (Account 190)	234	Ed. 12-88	
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits)			
Capital Stock	250-251	Ed. 12-91	
Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and installments Received on Capital Stock	252	Rev. 12-95	
Other Paid-in Capital	253	Ed. 12-87	
Discount on Capital Stock	254	Ed. 12-87	
Capital Stock Expense	254	Ed. 12-86	
Long-Term Debt.	256-257	Ed. 12-96	

Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations 19629

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

LIST OF SCHEDULES (Electric Utility) (Continued)

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, ____

LIST OF SCHEDULES (Electric Utility) (Continued)

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
ELECTRIC PLANT STATISTICAL DATA (Continued)			
Transmission Lines Statistics	422-423	Ed. 12-87	
Transmission Lines Added During Year	424-425	Ed. 12-02	
Substations	426-427	Ed. 12-96	
Electric Distribution Meters and Line Transformers	429	Ed. 12-88	
Environmental protection Facilities	430	Ed. 12-88	
Environmental Protection Expenses	431	Ed. 12-88	
Footnote Data	450	Ed. 12-87	
Stockholders' Reports Check appropriate box:			
[ ] Four copies will be submitted.			
[ ] No annual report to stockholders is prepared.			

Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations 19631

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of year (c)	Balance at End of Year (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251		
3	Preferred Stock Issued (204)	250-251		
4	Capital Stock Subscribed (202, 205)	252		
5	Stock Liability for Conversion (203, 206)	252		
6	Premium on Capital Stock (207)	252		
7	Other Paid in Capital (208-211)	253		
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock expense (214)	254		
11	Retained Earnings (215, 215.1, 216)	118-119		
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119		
13	(Less) Reacquired Capital Stock (217)	250-251		
14	Accumulated Other Comprehensive Income (219)	122 (a) (b)		
15	TOTAL Proprietary Capital (Enter Total of Lines 2 thru 14)	-		
16	LONG-TERM DEBT			
17	Bonds (221)	256-257		
18	(Less) Reacquired Bonds (222)	256-257		
19	Advances from Associated Companies (223)	256-257		
20	Other Long-Term Debt (224)	256-257		
21	Unamortized Premium on Long-Term Debt (225)	-		
22	(Less) Unamortized Discount on Long-Term Debt-Debit (226)	-		
23	TOTAL Long-Term Debt (Enter Total of Lines 16 thru 21)	-		
24	OTHER NONCURRENT LIABILITIES			
25	Obligations Under Capital Leases-Noncurrent (227)	-		
26	Accumulated Provision for Property Insurance (228.1)	-		
27	Accumulated Provision for Injuries and damages (228.2)	-		
28	Accumulated Provision for Pensions and Benefits (228.3)	-		
29	Accumulated Miscellaneous Operating Provision (228.4)	-		
30	Accumulated Provision for Rate Refunds (229)	-		
31	Asset Retirement Obligations (230)	-		
32	TOTAL OTHER Noncurrent Liabilities (Enter Total of Lines 24 thru 30)			
33	CURRENT AND ACCRUED LIABILITIES			
34	Notes Payable (231)	-		
35	Accounts Payable (232)	-		
36	Notes Payable to Associated Companies (233)	-		
37	Account Payable to Associated Companies (234)	-		
38	Customer Deposits (235)	-		
39	Taxes Accrued (236)	262-263		
40	Interest Accrued (237)	-		
41	Dividends Declared (238)	-		
42	Matured Long-Term Debt (239)	-		
43	Matured Interests (240)	-		
44	Tax Collections Payable (241)	-		
45	Miscellaneous Current and Accrued Liabilities(242)			
46	Obligations Under Capital Leases-Current (243)			

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, _____

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of year (c)	Balance at End of Year (d)
47	Derivative Instrument Liabilities (244)			
48	Derivative Instrument Liabilities - Hedging (245)			
49	TOTAL Current and Accrued Liabilities (Enter Total of Lines 34 thru 48)			
50	DEFERRED CREDITS			
51	Customer Advances for Construction (252)			
52	Accumulate Deferred Investment Tax Credits (255)	266-267		
53	Deferred Gains from Disposition of Utility Plant (256)			
54	Other Deferred Credits (253)	269		
55	Other Regulatory Liabilities (254)	278		
55	Unamortized Gain on Reacquired Debt (257)	269		
56	Accumulated Deferred Income Taxes (281-283)	272-277		
57	TOTAL Deferred Credits (Enter Total of Lines 48 thru 54)			
58				
59				
60				
61				
62				
63				
64				
65				
66				
67				
68				
69				
70				
	TOTAL Liabilities and Other Credits (Enter Total of Lines 15, 23, 32,49 and 57)			

Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations 19633

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another Utility column (i,k,m,o) in a similar manner to a utility department. Spread the amount(s) over Lines 02 thru 24 as appropriate. include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 8, 10, and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
4. Use page 123 for important notes regarding the statement of income or any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year.

Line No	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of year (c)	Balance at End of Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301		
3	Operating Expenses			
4	Operation Expenses (401)	320-323		
5	Maintenance Expenses (402)	320-323		
6	Depreciation Expenses (403)	336-337		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337		
8	Amortization. & Depletion of Utility Plant (404-405)	336-337		
9	Amortization of Utility Plant Acquisition Adjustment (406)	336-337		
10	Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)			
11	Amortization of Conversion Expenses (407)			
12	Regulatory Debits (407.3)			
13	(Less) Regulatory Credits (407.4)			
14	Taxes Other than Income Taxes (408.1)	262-263		
15	Income Taxes - Federal (409.1)	262-263		
16	- Other (409.1)	262-263		
17	Provision for deferred Income Taxes (410.1)	234,272-277		
18	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	234,272-277		
19	Investment Tax Credit Adj. - Net (411.4)	266		
20	(Less) Gains from Disp. Of Utility Plant (411.6)			
21	Losses from Disp. Of Utility Plant (411.7)			
22	(Less) Gains from Disposition of Allowances (411.8)			
23	Losses from Disposition of Allowances (411.9)			
24	Accretion Expense (411.10)			
25	TOTAL Utility Operating Expenses (Enter Total of Lines 4 thru 24)			
26	Net Utility Operating Income (Enter Total of line 2 less 25) (Carry forward to page 117, line 25)			

19634 Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

STATEMENT OF INCOME FOR THE YEAR (Continued)

resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, ard a summary *of* the adjustments made to balance sheet, income, and expense accounts.

7. if any notes appearing in the report to stockholders are applicable to this Statement *of* Income, such notes should be included on page 123.

B. Enter on page 123 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportiorunents from those used in the precedingl year. Also give the approximate dollar effect of such changes.

9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information on page.123 or in a footnote.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year (e)	Previous Year (f)	Current Year (g)	Previous Year (h)	Current Year (i)	Previous Year (j)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						17
						18
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						21
						22
						23
						24
						25
						26

Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations **19635**

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, ____

STATEMENT OF INCOME FOR THE YEAR (Continued)

	OTHER UTILITY		OTHER UTILITY		OTHER UTILITY	
Line No.	Current Year (k)	Previous Year (l)	Current Year (m)	Previous Year (n)	Current Yar (o)	Previous Year (p)
1						
2						
3						
4						
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Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -95-

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
27	Net Utility Operating Income (Carried forward from page 114)	--		
28	Other Income and Deductions			
29	Other Income			
30	Nonutility Operating Income			
31	Revenues From Merchandising, Jobbing and Contract Work (415)			
32	(Less) Costs and Exp. Of Merchandising, Job & Contract Work (416)			
33	Revenues From Nonutility Operations (417)			
34	(Less) Expenses of Nonutility Operations (417.1)			
35	Nonoperating Rental Income (418)			
36	Equity in Earnings of Subsidiary Companies (418.1)	119		
37	Interest and Dividend Income (419)			
38	Allowance for Other Funds Used During Construction (419.1)			
39	Miscellaneous Nonoperating Income (421)			
40	Gain on Disposition of Property (421.2)			
41	TOTAL Other Income (Enter Total of Lines 31 thru 40)			
42	Other Income Deductions			
43	Loss on Disposition of Property (421.2)			
44	Miscellaneous Amortization (425)	340		
45	Miscellaneous Income Deductions (426.1-426.5)	340		
46	TOTAL Other Income Deductions (Total of Lines 43 thru 45)			
47	Taxes Applicable To Other Income and Deductions			
48	Taxes Other than Income Taxes (408.2)	262-263		
49	Income Taxes - Federal (409.2)	262-263		
50	Income Taxes - Other (409.2)	262-263		
51	Provision for Deferred Inc. Taxes (410.2)	234,272-277		
52	(Less) Provision for Deferred Income Taxes - Credit (411.2)	234,272-277		
53	Investment Tax Credit Adj. - Net (411.5)			
54	(Less) Investment Tax Credits (420)			
55	TOTAL Taxes on Other Income and Deductions (Total of 48 thru 54)			
56	Net Other Income and Deductions (Enter Total of Lines 41, 46, 55)			
57	Interest Charges			
58	Interest on Long-Term Debt (427)			
59	Amort. Of Debt Disc. And Expense (428)			
60	Amortization of Loss on Reacquired Debt (428.1)			
61	(Less) Amort. Of Premium on Debt - credit (429)			
62	(Less) Amortization of Gain on Reacquired Debt - Credit (429.1)			
63	Interest on Debt to Assoc. Companies (430)	340		
64	Other Interest Expense (431)	340		
65	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)			
66	Net Interest Charges (Enter Total of Liens 58 thru 65)			
67	Income Before Extraordinary Items (Total of Lines 27, 56 and 66)			
68	Extraordinary Items			
69	Extraordinary Income (434)			
70	(Less) Extraordinary Deductions (435)			
71	Net Extraordinary Items (Enter Total of Line 69 less Line 70)			
72	Income Taxes-Federal and Other (409.3)	262-263		
73	Extraordinary Items After Taxes (Enter Total of Line 71 less Line 72)			
74	Net Income (Enter Total of Lines 67 and 73)			

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, ____

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed ac- counts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in

Line No	Account (a)	Balance at Beginning of year (b)	Addition (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of Lines 2, 3, and 4)		
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Tubogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of Lines 8 thru 15)		
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbo generator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of Lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power Plant Equipment		
33	(336) Roads, Railroad, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of Lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

column (d) reversals of tentative distributions of prior year of unclassified retirements. Show in a footnote the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column(f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
				(301)	2
				(302)	3
				(303)	4
					5
					6
					7
				(310)	8
				(311)	9
				(312)	10
				(313)	11
				(314)	12
				(315)	13
				(316)	14
				(317)	15
					16
					17
				(320)	18
				(321)	19
				(322)	20
				(323)	21
				(324)	22
				(325)	23
				(326)	24
					25
					26
				(330)	27
				(331)	28
				(332)	29
				(333)	30
				(334)	31
				(335)	32
				(336)	33
				(337)	34
					35
					36
				(340)	37
				(341)	38
				(342)	39
				(343)	40
				(344)	41
				(345)	42

Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations 19639

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

Line No	Account (a)	Balance at Beginning of year (b)	Addition (c)
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of Lines 37 thru 44)		
46	TOTAL Prod. Plant (Enter Total of Lines 16, 25, 35, and 45)		
47	3. TRANSMISSION PLANT		
48	(350) land and Land Rights		
49	(352) Structures and Improvements		
50	(353)Station Equipment		
51	(354)Towers and Fixtures		
52	(355)Poles and Fixtures		
53	(356) Overhead Conductors and Devices		
54	(357) Underground conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of Lines 44 thru 52)		
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights		
61	(361) Structures and Improvements		
62	(362) Station Equipment		
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures		
65	(365) Overhead Conductors and Devices		
66	(366) Underground Conduit		
67	(367) Underground Conductors and Devices		
68	(368) Line Transformers		
69	(369) Services		
70	(370) Meters		
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems		
74	(374) Asset Retirement Costs for Distribution Plant		
75	Total Distribution Plant (Enter Total of Lines 60 thru 74)		
76	5. GENERAL PLANT		
77	(389) Land and Land Rights		
78	(390) Structures and Improvements		
79	(391) Office Furniture and Equipment		
80	(392) Transportation Equipment		
81	(393) Stores Equipment		
82	(394) Tools, Shop and Garage Equipment		
83	(395) Laboratory, Equipment		
84	(396)Power Operated Equipment		
85	(397) Communication Equipment		
86	(398) Miscellaneous Equipment		
87	SUBTOTAL (Enter Total of Lines 77 thru 86)		
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		
90	TOTAL General Plant (Enter Total of Lines 87, 88, and 89)		
91	TOTAL (Accounts 101 and 106) (Lines 5, 16, 25, 35, 45, 58, 75,90)		
92	(102) Electric Plant Purchased (See Instr. 8)		
93	(Less) (102) Electric Plant Sold (See Instr. 8)		
94	(103) Experimental Plant Unclassified		
95	TOTAL Electric Plant in Service (Enter Total of Lines 91 thru 94)		

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
				(346)	43
				(347)	44
					45
					46
					47
				(350)	48
				(352)	49
				(353)	50
				(354)	51
				(355)	52
				(356)	53
				(357)	54
				(358)	55
				(359)	56
				(359.1)	57
					58
					59
				(360)	60
				(361)	61
				(362)	62
				(363)	63
				(364)	64
				(365)	65
				(366)	66
				(367)	67
				(368)	68
				(369)	69
				(370)	70
				(371)	71
				(372)	72
				(373)	73
				(374)	74
					75
					76
				(389)	77
				(390)	78
				(391)	79
				(392)	80
				(393)	81
				(394)	82
				(395)	83
				(396)	84
				(397)	85
				(398)	86
					87
				(399)	88
				(399.1)	89
					90
					91
				(102)	92
					93
				(103)	94
					95

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -100-

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column (d), excluding retirements of nondepreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year				
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense				
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Expense of Electric Plant Leased to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify):				
9					
10	Total Depreciation, Provision For Year (Enter Total of Lines 3 thru 9)				
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired				
13	Cost of Removal				
14	Salvage (Credit)				
15	TOTAL Net Charges For Plant Retired (Enter Total of Lines 12 thru 14)				
16	Other Debit or Credit Items (Describe):				
17					
18	Book Cost of Asset Retirement Costs Retired				
19	Balance End of Year (Enter Total of lines 1, 10, 15, 16 and 18)				
	Section B. Balances at End of Year According to Functional Classifications				
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission				
26	Distribution				
27	General				
28	TOTAL (Enter Total of Lines 20 thru 27)				

19642 Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, ____

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 403.1, 404, 405)
(Except Amortization of Acquisition Adjustments)

1. Report in Section A for the year the amounts for: (a) Depreciation Expense (Account 403); (b) Amortization of Limited-Term Electric Plant (Account 404); and (c) Amortization of Other Electric Plant (Account 405).
2. Report in section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of section C the type of plant included in any subaccount used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant.
If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of. the provisions and the plant items to which related.

A. Summary of depreciation and Amortization Charges

Line No	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited-Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Account 405) (e)	Total (f)
1	Intangible Plant					
2	Steam Production Plant					
3	Nuclear Production Plant					
4	Hydraulic Production Plant -- Conventional					
5	Hydraulic Production Plant -- Pumped Storage					
6	Other Production Plant					
7	Transmission Plant					
8	Distribution Plant					
9	General Plant					
10	Common Plant -- Electric					
11	TOTAL					

B. Basis for Amortization Charges

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -102-

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, ____

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 KW or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility.
4. If net peak demand for 60 minutes is not available. Give data which is available, specifying period.
5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant
6. If gas is used and purchased on a therm basis report the Btu content of the gas and the quantity of fuel burned converted to Mct.
7. Quantities of fuel burned (line 38) and average cost per unit of fuel burned (line 41) must be consistent with charges to expense accounts 501 and 547 (line 42) as show on line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Steam, Internal Combustion, Gas Turbine or Nuclear)						
2	Type of Plant Construction (Convention, Outdoor Boiler, Full Outdoor, Etc.)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Capacity (Maximum Generator Name Plate Ratings in MW)						
6	Next Peak Demand on Plant -- MW (60 minutes)						
7	Plant Hours Connected to Load						
8	Net Continuous Plant Capability (Megawatts)						
9	When not Limited by Condenser Water						
10	When Limited by Condenser Water						
11	Average Number of Employees						
12	Net Generation, Exclusive of Plant Use --KWh						
13	Cost of Plant: Land and Land Rights						
14	Structures and Improvements						
15	Equipment Costs						
16	Asset Retirement Costs						
17	Total Cost						
18	Cost per KW of Installed Capacity (Line 17/ Line 5) including Asset Retirement Costs						
19	Production Expenses: Oper. Supv. & Engr.						
20	Fuel						
21	Coolants and Water (Nuclear Plants Only)						
22	Steam Expenses						
23	Steam From Other Sources						
24	Steam Transferred (Cr.)						
25	Electric Expenses						
26	Misc. Steam (or Nuclear) Power Expenses						
27	Rents						
28	Allowances						
29	Maintenance Supervision and Engineering						
30	Maintenance of Structures						
31	Maintenance of Boiler (Or Reactor) Plant						
32	Maintenance of Electric Plant						
33	Maintenance Misc. Steam (or Nuclear) Plant						
34	Total Production Expenses						
35	Expenses per Net KWh						
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit: (Coal-tons of 2,000 lb.) (Oil-barrels of 42 gals.) (Gas=Mcf) (Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned						
39	Avg. Heat Cont. Of Fuel Burned (Btu per lb. Of coal per gal. Of oil or per Mcf of gas) (Give unit if nuclear)						
40	Average Cost of Fuel per Unit, as Delivered f. o. b. Plant During Year						
41	Average Cost of Fuel per Unit Burned						
42	Avg. Cost of Fuel Burned per Million Btu						
43	Avg. Cost of Fuel Burned per Kwh Net Generation						
44	Average Btu per Kwh Net Generation						

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -103-

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

9. Items under Cost of Plant are based on U.S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses.
10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on line 32. "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants.
11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas -turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant.
12. If a nuclear power generating plat, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
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Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations 19645

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plan, report on line 11 the approximate average number of employees assignable to each plant.

Line No	Item (a)	FERC Licensed Project No. Plant Name: (b)	FERC Licensed Project No. Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Type of Plant Construction (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total Installed Capacity (Generator Name Plate Rating in MW)		
6	Net Peak Demand on Plant-Megawatts (60 minutes)		
7	Plant Hours Connected to Load		
8	Net Plant Capability (in megawatts)		
9	(a) Under the Most Favorable Operating Conditions		
10	(b) Under the Most Adverse Operating Conditions		
11	Average Number of Employees		
12	Net Generation, Exclusive of Plant Use-KWh		
13	Cost of Plant:		
14	Land and Land Rights		
15	Structures and Improvements		
16	Reservoirs, Dams, and Waterways		
17	Equipments Costs		
18	Roads, Railroads, and Bridges		
19	Asset Retirement Costs		
20	TOTAL Cost (Enter Total of Lines 14 thru 19)		
21	Cost per KW of Installed Capacity (Line 5) including Asset Retirement Costs		
22	Production Expenses:		
23	Operation Supervision and Engineering		
24	Water for Power		
25	Hydraulic Expenses		
26	Electric Expenses		
27	Misc. Hydraulic Power Generation Expenses		
28	Rents		
29	Maintenance Supervision and Engineering		
30	Maintenance of Structures		
31	Maintenance of Reservoirs, Dams, and Waterways		
32	Maintenance of Electric Plant		
33	Maintenance of Misc. Hydraulic Plant		
34	Total Production Expenses (Total lines 23 thru 33)		
35	Expenses per net KWh		

19646 Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, ____

HYDROELECTRIC GENERATING PLANT STATISTICS (large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	FERC Licensed Project No. Plant Name: (f)	Line No
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			29
			30
			31
			32
			33
			34
			35

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -106-

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings).
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total Installed Capacity (Generator Name Plate Ratings in MW)	
5	Net Peak Demand on Plant-Megawatts (60 minutes)	
6	Plant Hours Connected to Load While Generating	
7	Net Plant Capability (In megawatts):	
8	Average Number of Employees	
9	Generation Exclusive of Plant Use-KWh	
10	Energy Used for Pumping-KWH	
11	Net Output for Load (Line 9 minus Line 10)-KWh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplants Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	TOTAL Cost (Enter Total of Lines 13 thru 20)	
22	Cost per KW of installed Capacity (Line 21 ÷ Line 4) including Asset Retirement Costs	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc. Pumped Storage Power Generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc. Pumped Storage Plant	
35	Production Exp. Before Pumping Exp. (Enter Total of Lines 24 thru 34)	
36	Pumping Expenses	
37	Total Production Expenses (Enter Total of Lines 35 and 36)	
38	Expenses per Kwh (Enter result of line 37 divided by Line 9)	

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (line 10) is that energy measured as input to the-plant for pumping purposes.
7. Include on line 35 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 35, 36 and 37 blank and footnote the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	FERC Licensed Project No. Plant Name: (f)	Line No
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
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			21
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			36
			37
			38
			39

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -108-

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, page 403:
4. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Including Asset Retirement Costs) Per MW Installed Capacity (g)	Operation Excluding . Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Cost (In cents per million Btu) (l)	Line No
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
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						29
						30
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						41
						42
						43
						44
						45
						46

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, ____

TRANSMISSION LINES ADDED DURING YEAR

7. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and underground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (p), it is permissible to report in these columns the estimated final completion.

Line No	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number Per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
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31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, ____

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m)

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS				LINE COST					
Size (h)	Specification (i)	Configuration and Spacing (j)	Voltage KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Device (n)	Asset Retirement Costs (o)	Total (p)	Line No.
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
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									43
									44

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

PART III: COMPARATIVE BALANCE SHEET (Continued)

	Liabilities and Other Credits *(a)*	Balance at Beginning of year *(b)*	Balance at End of Year *(c)*
01	Common Stock Issued *(201)*		
02	Preferred Stock Issued *(204)*		
03	Miscellaneous Paid-in Capital *(211)*		
04	Installments Received on Capital Stock *(212)*		
05	Discount on Capital Stock - Debit *(213)*		
06	Capital Stock Expenses - Debit *(214)*		
07	Retained Earnings *(215-216)*		
08	Reacquired Capital Stock - Debit *(217)*		
09	Noncorporate Proprietorship *(218)*		
10	Accumulated Other Comprehensive Income *(219)*		
11	TOTAL PROPRIETARY CAPITAL *(Enter total of lines 01 thru 10)*		
12	Bonds *(221)*		
13	Advances From Associated Companies *(223)*		
14	Other Long-term Debt (Specify in footnote) *(224)*		
15	Unamortized Premium on Long-term Debt *(225)*		
16	Unamortized Discount on Long-term Debt - Debit (226)		
17	TOTAL LONG-TERM DEBT *(Enter total of lines 12 thru 16)*		
18	Other Noncurrent Liabilities:		
19	Obligations Under Capital Leases - Noncurrent *(227)*		
20	Accumulated Provision tor Property Insurance *(228, 1)*		
21	Accumulated Provision for Injuries and Damages *(228.2)*		
22	Accumulated Provision for Pensions and Benefits (228.3)		
23	Accumulated Miscellaneous Operating Provisions *(228.4)*		
24	Accumulated Provision for Rate Refunds *(229)*		
25	Asset Retirement Obligations (*230*)		
26	*TOTAL OTHER NONCURRENT LIABILITIES (Enter Total of Lines 19 thru 25)*		
27	Current and Accrued Liabilities:		
28	Notes and Accounts Payable (Report amounts applicable to associated companies in a footnote) *(231* to *234)*		
29	Customer Debits *(235)*		
30	Taxes Accrued (*236)*		
31	Interest Accrued *(237)*		
32	Miscellaneous Current and Accrued Liabilities *(242)*		
33	Obligations Under Capital Leases-Current *(243)*		
34	Derivative Instrument Liabilities *(244)*		
35	Derivative Instrument Liabilities - Hedges *(245)*		
36	TOTAL CURRENT AND ACCRUED LIABILITIES *(Enter total of* lines *28* thru *35)*		
37	Deferred Credits:		
38	Customer Advances for Construction *(252)*		
39	Other Deferred Credits *(253)*		
40	Other Regulatory Liabilities *(254)*		
41	Accumulated Deferred Investment Tax Credits *(255)*		
42	Deferred Gains from Disposition of Utility Plant *(256)*		
43	Unamortized Gain on Reacquired Debt *(257)*		
44	Accumulated Deferred Income Taxes *(281-283)*		
45	TOTAL DEFERRED CREDITS *(Enter total of lines 38 thru 44)*		
46	TOTAL LIABILITIES AND OTHER CREDITS *(Enter total of lines 11, 17, 26, 36 and 45)*		

Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations 19653

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

PART IV: STATEMENT OF INCOME FOR THE YEAR (Continued)

1. Report amounts for accounts 412 and 413, Revenues and expenses from Utility Plant Leased to Others, in the Other Utility column (h, I or j, k) in a similar manner to a utility department. Spread the amount(s) over lines 01 to 22 as appropriate. Include these amounts in column (b) and (c) totals.
2. Report amounts for account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413.
3. Provide an explanation in Part VII. Notes to Financial Statements, of such unsettled rate proceedings where a contingency exists that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects; include an explanation for the major factors which affect the rights of the utility to retain such revenues or to recover amounts paid with respect to power or gas purchases.

	Account (a)	Total (d to k)		Electric Utility	
		Current Year (b)	Change From Previous Year (c)	Current Year (d)	Change From previous Year (e)
01	UTILITY OPERATING INCOME				
02	Operating Revenues (400)				
03	Operating Expenses:				
04	Operating Expenses (401)				
05	Maintenance Expense (402)				
06	Depreciation Expense (403)				
07	Depreciation Expense for Asset Retirement Costs (403.1)				
08	Amortization Expense (Specify by account)				
09					
10	Regulatory Debits (407.3)				
11	(Less) Regulatory Credits (407.4)				
12	Taxes Other Than Income Taxes (408.1)				
13	Federal Income Taxes (409.1)				
14	Other Income Taxes (409. 1)				
15	Provision For Deferred Income Taxes (410.1)				
16	Provision For Deferred Income Taxes - Credit (411.1)				
17	Investment Tax Credit Adjustments - Net (411.4)				
18	Gains From Disposition of Utility Plant (411.6)				
19	Losses From Disposition of Utility Plant (411.7)				
20	Gains From Disposition of Allowances (411.8)				
21	Losses From Disposition of Allowances (411.9)				
22	Accretion Expense (411.10)				
23	TOTAL UTILITY OPERATING EXPENSES *(Enter total of lines 04 thru 22)*				
24	Net Utility Operating Income *(Enter total of* line 02 less 23)				

19654 Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

PART IV: STATEMENT OF INCOME FOR THE YEAR (Continued)

4. Provide an explanation in Part VII, Notes to Financial Statements, of significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenued received for costs incurred for power or gas purchases and a summary of the adjustment made to balance sheet, income, and expense accounts.

5. If any note appearing in the report to stockholders are applicable to the statement of income, either include such note in an attachment, or enter such data in Part VII.

6. Provide an explanation in Part VII, Notes to Financial Statements of only those changes in account methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the approximate dollar effects of such changes.

Gas Utility		Other Utility		Other utility		Account	
Current Year (f)	Change From Previous Year (g)	Current Year (h)	Change From Previous Year (i)	Current Year (j)	Change From Previous Year (k)		
							01
						(400)	02
							03
						(401)	04
						(402)	05
						(403)	06
						(403.1)	07
							08
							09
						(407.3)	10
						(407.4	11
						(408.1)	12
						(409.1)	13
						(409.1)	14
						(410.1)	15
						(411.1)	16
						(411.4)	17
						(411.6)	18
						(411.7)	19
						(411.8)	20
						(411.9)	21
						(411.10)	22
						TOTAL	23
						NET	24

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -114-

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, _____

PART IV: STATEMENT OF INCOME FOR THE YEAR (Continued)

	Account (a)	Total	
		Current Year (b)	Change From Previous Year (c)
24	Net Utility Operating Income *(Carrier Forward from line 24, page 6)*		
25	OTHER INCOME AND DEDUCTIONS		
26	Other Income:		
27	Nonutility Operating Income *(415-418)*		
28	Interest and Dividend Income *(419)*		
29	Allowance for Other Funds Used During Construction *(419.1)*		
30	Miscellaneous Nonoperating Income *(421)*		
31	Gain on Disposition of Property *(415-418)*		
32	TOTAL OTHER INCOME *(Enter Total of lines 27 thru 31)*		
33	Other Income Deductions:		
34	Loss on Disposition of Property *(421.2)*		
35	Miscellaneous Amortization *(425)*		
36	Miscellaneous Income Deductions *(426.1 - 426.5)*		
37	TOTAL OTHER INCOME DEDUCTIONS *(Enter total of lines 34 thru 36)*		
38	Taxes Applicable to Other Income and Deductions:		
39	Taxes Applicable to Other Income and Deductions:		
40	Federal Income Taxes *(409.2)*		
41	Other Income Taxes *(409.2)*		
42	Provision for Deferred Income Taxes *(410.2)*		
43	Provision for Deferred Income *(411.2)*		
44	Investment Tax Credit Adjustments - Net *(411.5)*		
45	Investment Tax Credits *(420)*		
46	TOTAL TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS *(Enter total of lines 40 thru 45)*		
47	Net Other Income and Deductions *(Enter total of line 32 less 37 and 46)*		
48	INTEREST CHARGES		
49	Interest on Long-term Debt *(427)*		
50	Amortization of Debt Discount and Expense *(428)*		
51	Amortization of Loss on Reacquired Debt *(428.1)*		
52	Amortization of Premium on Debt - Credit *(429)*		
53	Amortization of Gain on Reacquired Debt - Credit *(429. 1)*		
54	Interest on Debt to Associated Companies *(430)*		
55	Other Interest Expense *(431)*		
56	Allowance For Borrowed Funds Used During Construction - Credit *(432)*		
57	Net Interest Charge *(Enter total of lines 49 thru 56)*		
58	Income Before Extraordinary Items *(Enter total of lines 24 and 47, less 57)*		
59	EXTRAORDINARY ITEMS		
60	Extraordinary Income *(434)*		
61	Extraordinary Deduction - Debit *(435)*		
62	Net Extraordinary Items *(Enter total of line 60 less 61)*		
63	Income Taxes - *(409.3)*		
64	Extraordinary Items After Taxes *(Enter total of line 62 less 63)*		
65	Net Income *(Enter total of* lines *58 and* 64)		

(SUBSTITUTE PAGE FOR PART III)

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, _____

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251		
3	Preferred Stock Issued (204)	250-251		
4	Capital Stock Subscribed (202, 205)	252		
5	Stock Liability for Conversion (203, 206)	252		
6	Premium on-Capital Stock (207)	252		
7	Other Paid-In Capital (208-211)	253		
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254		
11	Retained Earnings (215, 215.1, 216)	118-119		
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119		
13	(Less) Reacquired Capital Stock (217)	250-251		
14	Accumulated Other Comprehensive Income *(219)*	122 (a) (b)		
15	TOTAL Proprietary Capital *(Enter Total of* lines 2 *thru 14)*	-		
16	LONG-TERM DEBT			
17	Bonds (221)	256-257		
18	(Less) Reacquired Bonds (222)	256-257		
19	Advances from Associated Companies (223)	256-257		
20	Other Long-Term Debt (224)	256-257		
21	Unamortized Premium on Long-Term Debt (225)	-		
22	(Less) Unamortized Discount on Long-Term Debt-Debit (226)	-		
23	TOTAL Long-Term Debt (Enter Total *of* lines 17 thru 22)	-		
24	OTHER NONCURRENT LIABILITIES			
25	Obligations Under Capital Leases - Noncurrent (227)	-		
26	Accumulated Provision for Property Insurance (228.1)	-		
27	Accumulated Provision for Injuries and Damages (228.2)	-		
28	Accumulated Provision for Pensions and Benefits (228.3)	-		
29	Accumulated Miscellaneous Operating Provisions (228.4)	-		
30	Accumulated Provision for Rate Refunds (229)	-		
31	Asset Retirement Obligations (230)	-		
32	TOTAL Other Noncurrent Liabilities (Enter Total *of* lines 25 thru 31)			
33	CURRENT AND ACCRUED LIABILITIES			
34	Notes Payable (231)	-		
35	Accounts Payable (232)	-		
36	Notes Payable to Associated Companies (233)	-		
37	Accounts Payable to Associated Companies (234)	-		
38	Customer Deposits (235)	-		
39	Taxes Accrued (236)	262-263		
40	Interest Accrued (237)	-		
41	Dividends Declared (238)	-		
42	Matured Long-Term Debt (239)	-		
43	Matured Interest (240)	-		
44	Tax Collections Payable (241)	-		
45	Miscellaneous Current and Accrued Liabilities (242)	-		
46	Obligations Under Capital Leases-Current (243)	-		

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -116-

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, _____

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
47	Derivative Instrument Liabilities (244)			
48	Derivative Instrument Liabilities - Hedging (245)			
49	TOTAL Current and Accrued Liabilities *(Enter Total of* lines 34 *thru 48)*			
50	DEFERRED CREDITS			
51	Customer Advances for Construction (252)			
52	Accumulated Deferred Investment Tax Credits (255)	266-267		
53	Deferred Gains from Disposition of Utility Plant (256)			
54	Other Deferred Credits (253)	269		
55	Other Regulatory Liabilities (254)	278		
56	Unamortized Gain on Reacquired Debt (257)			
57	Accumulated Deferred Income Taxes (281-283)	272-277		
58	TOTAL Deferred Credits *(Enter Total of lines 51 thru 57)*			
59				
60				
61				
62				
63				
64				
65				
66				
67				
68				
69				
70				
71				
72	TOTAL Liabilities and Other Credits *(Enter Total of lines 15, 23, 32, 49 and 58)*			

19658 Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6

(SUBSTITUTE PAGE FOR PART IV)

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, ____

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts *412* and *413, Revenue and Expenses from Utility Plant Leased* to Others, in another utility column (l, k, m, o) in a similar manner to a utility department. Spread the amount(s) over lines *02* thru *24* as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account *414*, Other *Utility* Operating Income, in the same manner as accounts *412* and *413* above.
3. Report data for lines 8, 10, and 11 for Natural Gas companies using accounts *404.1, 404.2, 404.3, 407. 1,* and *407.2.*
4. Use page *122* for important notes regarding the statement of income or any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year

Line No.	Title of Account (a)	Ref Page No (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301		
3	Operating Expenses			
4	Operation Expenses (401)	320-325		
5	Maintenance Expenses (402)	320-325		
6	Depreciation Expense (403)	336-338		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-338		
8	Amortization & Depletion of Utility Plant (404-405)	336-338		
9	Amortization of Utility Plant Acquisition Adjustment (406)	336-338		
10	Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)			
11	Amortization of Conversion Expenses (407)			
12	Regulatory Debits (407-3)			
13	(Less) Regulatory Credits (407.4)			
14	Taxes Other Than Income Taxes (408.1)	262-263		
15	Income Taxes - Federal (409.1)	262-263		
16	- Other (409.1)	262-263		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277		
19	Investment Tax Credit Adjustment - Net (411.4)	266		
20	(Less) Gains from Disp. of Utility Plant (411.6)			
21	Losses from Disp. of Utility Plant (411.7)			
22	(Less) Gains from Disposition of Allowances (411.8)			
23	Losses from Disposition of Allowances (411.9)			
24	Accretion Expense (411.10)			
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)			
26	Net Utility Operating Income (Enter Total of line 2 less 25) (Carry forward to page 117, line 27)			

Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations **19659**

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6

(SUBSTITUTE PAGE FOR PART IV)

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Title of Account (a)	Ref Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
27	Net Utility Operating Income *(Carried forward from page 114)*	-		
28	Other Income and Deductions			
29	Other Income			
30	Nonutiity Operating Income			
31	Revenues From Merchandising, Jobbing and Contract Work (415)			
32	(Less) Costs and Expenses of Merchandising, Jobbing & Contract Work (416)			
33	Revenues From Nonutlity Operations (417)			
34	(Less) Expenses of Nonutility operations (417.1,)			
35	Nonoperating Rental Income (418)			
36	Equity in Earnings of Subsidiary Companies (418.1)	119		
38	Interest and Dividend Income (419)			
39	Allowance for Other Funds Used During Construction (411.1)			
40	Gain on Disposition of Property (421.1)			
41	TOTAL Other income *(Enter Total of lines 31 thru 40)*			
42	Other Income Deductions			
43	Loss on Disposition of Property (421.2)			
44	Miscellaneous Amortization (425)	340		
45	Miscellaneous Income Deductions (426.1 thru 426.5)	340		
46	TOTAL Other Income Deductions(Total of lines 43 thru 45)			
47	Taxes Applicable to Other Income and Deductions			
48	Taxes Other Than income Taxes (408.2)	262-263		
49	Income Taxes-Federal (409.2)	262-263		
50	Income Taxes-Other (409.2)	262-263		
51	Provision for Deferred Inc. Taxes (410.2)	234,272-277		
52	(Less) Provision for Deferred Income Taxes--Cr. (411.2)	234,272-277		
53	Investment Tax Credit Adjustment - Net (411.5)			
54	(Less) Investment Tax Credits (420)			
55	TOTAL Taxes on Other Income and Deductions (Enter Total of 48 thru 54)			
56	Net Other Income and Deductions (Enter Total of lines 41, 46, 55)			
57	Interest Charges			
58	Interest on Long-Term Debt (427)			
59	Amort. of Debt Disc. and Expense (428)			
60	Amortization of Loss on Reacquired Debt (428.1)			
61	(Less) Amortization of Premium on Debt-Credit (429)			
62	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)			
63	Interest on Debt to Assoc. Companies (430)	340		
64	Other Interest Expense (431)	340		
65	(Less) Allowance for Borrowed Funds Used During Construction--Cr. (432)			
66	Net Interest Charges (Enter Total of lines 58 thru 65)			
67	Income Before Extraordinary Items (Enter Total of lines 27, 56 and 66)			
68	Extraordinary Items			
69	Extraordinary income (434)			
70	(Less) Extraordinary Deductions (435)			
71	Net Extraordinary Items (Enter Total of line 69 less line 70)			
72	Income Taxes-Federal and Other (409.3)	262-263		
73	Extraordinary Items After Taxes (Enter Total *of line 71* less line 72)			
74	Net Income *(Enter Total of lines 67 and 73)*			

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -119-

(SUBSTITUTE PAGE FOR PART XX)

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, _____

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments 5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements.

Line No	Account (a)	Balance at Beginning of year (b)	Addition (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents		
4	(303) Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of Lines 2, 3, and 4)		
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine-Driven Generators		
12	(314) Tubogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of Lines 8 thru 15)		
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbo generator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of Lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power Plant Equipment		
33	(336) Roads, Railroad, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of Lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		

Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations 19661

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -120

(SUBSTITUTE PAGE FOR PART XX)

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, ______

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Show in a footnote the account distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount, footnote and provide a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
				(301)	2
				(302)	3
				(303)	4
					5
					6
					7
				(310)	8
				(311)	9
				(312)	10
				(313)	11
				(314)	12
				(315)	13
				(316)	14
				(317)	15
					16
					17
				(320)	18
				(321)	19
				(322)	20
				(323)	21
				(324)	22
				(325)	23
				(326)	24
					25
					26
				(330)	27
				(331)	28
				(332)	29
				(333)	30
				(334)	31
				(335)	32
				(336)	33
				(337)	34
					35
					36
				(340)	37
				(341)	38
				(342)	39
				(343)	40
				(344)	41
				(345)	42

(SUBSTITUTE PAGE FOR PART XX)

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, _____

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106)

Line No	Account (a)	Balance at Beginning of year (b)	Addition (c)
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Production Plant (Enter Total of Lines 37 thru 44)		
46	TOTAL Production Plant (Enter Total of Lines 16, 25, 35, and 45)		
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights		
49	(352) Structures and Improvements		
50	(353) Station Equipment		
51	(354) Towers and Fixtures		
52	(355) Poles and Fixtures		
53	(356) Overhead Conductors and Devices		
54	(357) Underground conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of Liens 48 thru 57)		
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights		
61	(361) Structures and Improvements		
62	(362) Station Equipment		
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures		
65	(365) Overhead Conductors and Devices		
66	(366) Underground Conduit		
67	(367) Underground Conductors and Devices		
68	(368) Line Transformers		
69	(369) Services		
70	(370) Meters		
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems		
74	(374) Asset Retirement Costs for Distribution Plant		
75	Total Distribution Plant (Enter Total of lines 60 thru 75)		
76	5. GENERAL PLANT		
77	(389) Land and Land Rights		
78	(390) Structures and Improvements		
79	(391) Office Furniture and Equipment		
80	(392) Transportation Equipment		
81	(393) Stores Equipment		
82	(394) Tools, Shop and Garage Equipment		
83	(395) Laboratory, Equipment		
84	(396)Power Operated Equipment		
85	(397) Communication Equipment		
86	(398) Miscellaneous Equipment		
87	SUBTOTAL (Enter Total of Lines 77 thru 86)		
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		
90	TOTAL General Plant (Enter Total of Lines 87, 88, and 89)		
91	TOTAL (Accounts 101 and 106) (Lines 5, 16, 25, 35, 45, 58, 75, and 90)		
92	(102) Electric Plant Purchased (See Instr. 8)		
93	(Less) (102) Electric Plant Sold (See Instr. 8)		
94	(103) Experimental Plant Unclassified		
95	TOTAL Electric Plant in Service (Enter Total of Lines 91 thru 94)		

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -122-

(SUBSTITUTE PAGE FOR PART XX)

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
				(346)	43
				(347)	44
					45
					46
					47
				(650)	48
				(352)	49
				(353)	50
				(354)	51
				(355)	52
				(356)	53
				(357)	54
				(358)	55
				(359)	56
				(359.1)	57
					58
					59
				(360)	60
				(361)	61
				(362)	62
				(363)	63
				(364)	64
				(365)	65
				(366)	66
				(367)	67
				(368)	68
				(369)	69
				(370)	70
				(371)	71
				(372)	72
				(373)	73
				(374)	74
					75
					76
				(389)	77
				(390)	78
				(391)	79
				(392)	60
				(393)	81
				(394)	82
				(395)	83
				(396)	84
				(397)	85
				(398)	86
					87
				(399)	88
				(399.1)	89
					90
					91
				(102)	92
					93
				(103)	94
					95

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -123-

(SUBSTITUTE PAGE FOR PART XII)

Name of Respondent	This Report is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of nondepreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant leased to Others (e)
1	Balance Beginning of Year				
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense				
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Expenses of Electric Plant Leased to Others				
6	Transportation Expenses - Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify):				
9					
10	Total Depreciation Provision For Year (Enter Total of Lines 3 thru 9)				
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired				
13	Cost of Removal				
14	Salvage (Credit)				
15	TOTAL Net Charges For Plant Retired (Enter Total of Lines 12 thru 14)				
16	Other Debit or Credit Items (Describe):				
17					
18	Book Cost of Asset Retirement Costs				
19	Balance End of Year (Enter Total of lines 1, 10, 15, 16, and 18)				

Section B. Balances at End of Year According to Functional Classifications

Line No	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant leased to Others (e)
20	Steam Production				
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission				
26	Distribution				
27	General				
28	TOTAL (Enter Total of Lines 20 thru 27)				

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -124-

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

LIST OF SCHEDULES (Natural Gas Company)

Enter in column (d) the terms "none," "not applicable," or "NA" as appropriate, where no information or amounts have been reported for certain pages Omit pages where the responses are "none," "not applicable," or "NA

Line No	Title of Schedule	Reference Page No (b)	Date Revised (c)	Remarks (d)
	GENERAL CORPORATE INFORMATION AND FINANCIAL STATEMENTS			
1	General Information	101		
2	Control Over Respondent	102		
3	Corporations Controlled by Respondent	103		
4	Security Holders and Voting Powers	107		
5	Important Changes During the Year	108		
6	Comparative Balance Sheet	110-113		
7	Statement of Income for the Year	114-116		
8	Statement of Accumulated Comprehensive Income and Hedging Activities	117(a)(b)		
9	Statement of Retained Earnings for the Year	118-119		
10	Statements of Cash Flows	120-121		
11	Notes to Financial Statements	122		
	BALANCE SHEET SUPPORTING SCHEDULES (Assets and Other Debits)			
12	Summary of Utility Plant and Accumulated Provisions for Depreciation, Amortization, and Depletion	200-201		
13	Gas Plant in Service	204-209		
14	Gas Property and Capacity Leased from Others	212		
15	Gas Property and Capacity Leased to Others	213		
16	Gas Plant Held for Future Use	214		
17	Construction Work in Progress-Gas	216		
18	General Description of Construction Overhead Procedure	218		
19	Accumulated Provision for Depreciation of Gas Utility Plant	219		
20	Gas Stored	220		
21	Investments	222-223		
22	Investments in Subsidiary Companies	224-225		
23	Prepayment	230		
24	Extraordinary Property Losses	230		
25	Unrecovered Plant and Regulatory Study Costs	230		
26	Other Regulatory Assets	232		
27	Miscellaneous Deferred Debits	233		
28	Accumulated Deferred Income Taxes	234-235		
	BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits)			
29	Capital Stock	230-251		
30	Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and Installments Received on Capital Stock	252		
31	Other Paid-in Capital	253		
32	Discount on Capital Stock	254		
33	Capital Stock Expense	254		
34	Securities issued or Assumed and Securities Refunded or Retired During the Year	255		
35	Long-Term Debt	256-257		
36	Unamortized Debt Expense, Premium, and Discount on Long-Term Debt	258-259		
37	Unamortized Loss and Gain on Reacquired Debt	260		
38	Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261		

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -125-

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, ____

LIST OF SCHEDULES (Natural Gas Company)

Enter in column (d) the terms "none," "not applicable," or "NA" as appropriate, where no information or amounts have been reported for certain pages Omit pages where the responses are "none," "not applicable," or "NA

Line No	Title of Schedule	Reference Page No (b)	Date Revised (c)	Remarks (d)
	BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits) (Continued)			
39	Taxes Accrued, Prepaid, and Charged During Year	262-263		
40	Miscellaneous Current and Accrued Liabilities	268		
41	Other Deferred Credits	269		
42	Accumulated Deferred Income Taxes-Other Property	274-275		
43	Accumulated Deferred Income Taxes-Other	276-277		
44	Other Regulatory Liabilities	278		
	INCOME ACCOUNT SUPPORTING SCHEDULES			
45	Gas Operating Revenues	300-301		
46	Revenues from Transportation of Gas of Others Through Gathering Facilities	302-303		
47	Revenues from Transportation of Gas of Others Through Transmission Facilities	304-305		
48	Revenues from Storage Gas of Others			
49	Other Gas Revenues	306-307		
50	Gas Operation and Maintenance Expenses	308		
51	Exchange and Imbalance Transactions	317-325		
52	Gas Used in Utility Operations	328		
53	Transmission and Compression of Gas by Others	331		
54	Other Gas Supply Expenses	332		
55	Miscellaneous General Expenses-Gas	334		
56	Depreciation, Depletion, and Amortization of Gas Plant	335		
57	Particulars Concerning Certain income Deduction and Interest Charges Accounts	336-338 340		
	COMMON SECTION			
58	Regulatory Commission Expenses			
59	Distribution of Salaries and Wages	350-351		
60	Charges for Outside Professional and Other Consultative Services	354-355 357		
	GAS PLANT STATISTICAL DATA			
61	Compressor Stations	508-509		
62	Gas Storage Projects	512-513		
63	Transmission Lines	514		
64	Transmission System Peak Deliveries	518		
65	Auxiliary Peaking Facilities	519		
66	Gas Account-Natural Gas	520		
67	System Map	522		
68	Footnote Reference	551		
69	Footnote Text	552		
70	Stockholders' Reports (check appropriate box) ☐ Four copies will be submitted ☐ No annual report to stockholders is prepared			

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -126-

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Reference Page Number (b)	Balance at End of Current Year (in dollars) (c)	Balance at End of Previous Year (in dollars) (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251		
3	Preferred Stock Issued (204)	250-251		
4	Capital Stock Subscribed (202, 205)	252		
5	Stock Liability for Conversion (203, 206)	252		
6	Premium on Capital Stock (207)	252		
7	Other Paid-In Capital (208-211)	253		
8	Installments Received on Capital Stock (212)	252		
9	*(Less)* Discount on Capital Stock (213)	254		
10	*(Less)* Capital Stock Expense (214)	254		
11	Retained Earnings (215, 215 1, 216)	118-119		
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119		
13	*(Less)* Reacquired Capital (217)	250-251		
14	Accumulated Other Comprehensive Income (219)	118 (a) (b)		
15	TOTAL Proprietary Capital (Total of line 2 thru 14)			
16	LONG TERM DEBT			
17	Bonds (221)	256-257		
18	*(Less)* Reacquired Bonds (222)	256-257		
19	Advances from Associated Companies (223)	256-257		
20	Other Long-Term Debt (224)	256-257		
21	Unamortized Premium on Long-Term Debt (225)	258-259		
22	(Less) Unamortized Discount on Long-Term Debt-Dr (226)	258-259		
23	(Less) Current Portion of Long-Term Debt			
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)			
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases -- Noncurrent (227)			
27	Accumulated Provision for Property Insurance (228 1)			
28	Accumulated provision for Injuries and Damages (228 2)			
29	Accumulated Provision for Pensions and Benefits (228 3)			
30	Accumulated Miscellaneous Operating Provision (228 4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Asset Retirement Obligations (230)			
33	TOTAL Other Noncurrent Liabilities (total of lines 26 thru 32)			

19668 Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, ____

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) (Continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Balance at End of Current Year (in dollars) (c)	Balance at End of Previous Year (in dollars) (d)
34	CURRENT AND ACCRUED LIABILITIES			
35	Current Portion of Long-Term Debt			
36	Notes Payable (231)			
37	Accounts Payable (232)			
38	Notes Payable to Associated Companies (233)			
39	Accounts Payable to Associated Companies (234)			
40	Customer Deposits (235)			
41	Taxes Accrued (236)	262-263		
42	Interest Accrued (237)			
43	Dividends Declared (238)			
44	Matured Long-Term Debt (239)			
45	Matured Interest (240)			
46	Tax Collections Payable (241)			
47	Miscellaneous Current and Accrued Liabilities (242)	268		
48	Obligations Under Capital Leases -- Current (243)			
49	Derivative Instrument Liabilities (244)			
50	Derivative Instrument Liabilities - Hedges (245)			
51	TOTAL Current and Accrued Liabilities (Total of lines 35 thru 50)			
52	DEFERRED CREDITS			
53	Customer Advances for Construction (252)			
54	Accumulated Deferred Investment Tax Credits (255)			
55	Deferred Gains from Disposition of Utility Plant (256)			
56	Other Deferred Credits (253)	269		
57	Other Regulatory Liabilities (254)	278		
58	Unamortized Gain on Reacquired Debt (257)	260		
59	Accumulated Deferred Income Taxes (281-283)			
60	TOTAL Deferred Credits (Total of lines 53 thru 59)			
61	TOTAL Liabilities and Other Credits (Total of lines 15, 24, 33, 51, and 60)			

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -128-

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, _____

STATEMENT OF INCOME FOR THE YEAR

1 Report amounts for accounts 412 and 413, *Revenue and Expenses from Utility Plant Leased to Others,* in another utility column (i,j) in a similar manner to a utility department Spread the amount(s) over lines 2 thru 24 as appropriate Include these amounts in columns (c) and (d) totals

2 Report amounts in discount 414, *Other Utility Operating Income,* in the same manner as accounts 412 and 413 above

3 Report data for lines 7, 9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407 1, and 407. 2

Line No.	Title of Account (a)	Reference Page Number (b)	Balance at End of Current Year (in dollars) (c)	Balance at End of Previous Year (in dollars) (d)
1	UTILITY OPERATING INCOME			
2	Gas Operating Revenues (400}	300-301		
3	Operating Expenses			
4	Operation Expenses (401)	317-325		
5	Maintenance Expenses (402)	317-325		
6	Depreciation Expenses (403)	336-338		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-338		
8	Amortization and Depletion of Utility Plant (404-405)	336-338		
9	Amortization of Utility Plant Acu Adjustment (406)	336-338		
10	Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs (407.1)			
11	Amortization of Conversion Expenses (407.2)			
12	Regulatory Debits (407.3)			
13	(Less) Regulatory Credits (407.4)			
14	Taxes Other than Income Taxes (408.1)	262-263		
15	Income Taxes -- Federal (409.1)	262-263		
16	Income Taxes -- Other (409.1)	262-263		
17	Provision of Deferred Income Taxes (410.1)	234-235		
18	(Less) Provision for Deferred Income Taxes -- Credit (411.1)	234-235		
19	Investment Tax Credit Adjustment -- Net (411.4)			
20	(Less) Gains from Disposition of Utility Plant (411.6)			
21	Losses from Disposition of Utility Plant (411.7)			
22	(Less) Gains from Disposition of Allowances (411.8)			
23	Losses from Disposition of Allowances (411.9)			
24	Accretion Expense (411.10)			
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)			
26	Net Utility Operating Income (Total of lines 2 less 24) (Carry forward to page 116, line 27)			

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Balance at End of Current Year (in dollars) (c)	Balance at End of Previous Year (in dollars) (d)
27	Net Utility Operating Income (Carrier forward from page 114)			
28	OTHER INCOME AND DEDUCTIONS			
29	Other Income			
30	Nonutility Operating Income			
31	Revenues form Merchandising, Jobbing and Contract Work (415)			
32	*(Less)* Costs and Expenses of Merchandising, Jobbing & Contract Work (416)			
33	Revenues from Nonutility Operations (417)			
34	*(Less)* Expenses of Nonutility Operations (417.1)			
35	Nonoperating Rental Income			
36	Equity in Earnings of Subsidiary Companies (418.1)	119		
37	Interest and Dividend Income (419)			
38	Allowance for Other Funds Used During Construction (419.1)			
39	Miscellaneous Nonoperating Income (421)			
40	Gain on Disposition of Property (421.1)			
41	TOTAL Other Income (Total of lines 31 thru 40)			
42	Other Income Deductions			
43	Loss on Disposition of Property (421.2)			
44	Miscellaneous Amortization (425)			
45	Miscellaneous Income Deductions (426.1 thru 426.5)	340		
46	TOTAL Other Income Deductions (Total of lines 43 thru 45)	340		
47	Taxes Applicable to Other Income and Deductions			
48	Taxes Other than Income Taxes (406.2)	262-263		
49	Income Taxes -- Federal (409.2)	262-263		
50	Income Taxes -- Other (409.2)	262-263		
51	Provision for Deferred Income Taxes (410.2)	234-235		
52	*(Less)* Provision for Deferred Income Taxes- Credit (411.2)	234-235		
53	Investment Tax Credit Adjustments--Net (411.5)			
54	*(Less)* Investment Tax Credits (420)			
55	TOTAL Taxes on Other Income and Deductions (Total of lines 48-54)			
56	Net Other Income and Deductions (Total of lines 41, 46, and 55)			
57	INTEREST CHARGES			
58	Interest on Long-Term Debt (427)			
59	Amortization of Debt Discount and Expense (428)	258-259		
60	Amortization of Loss on Reacquired Debt (428.1)			
61	*(Less)* Amortization of Premium on Debt-Credit (429)	258-259		
62	*(Less)* Amortization of Gain on Reacquired Debt- Credit (429.1)			
63	Interest on Debt to Associated Companies (430)	340		
64	Other Interest Expense (431)	340		
65	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)			
66	Net Interest Charges (Total of lines 58 thru 65)			
67	Income Before Extraordinary Items (Total of lines 27, 56 and 66)			
68	EXTRAORDINARY ITEMS			
69	Extraordinary Income (434)			
70	*(Less)* Extraordinary Deductions (435)			
71	Net Extraordinary Items (Total of line 69 less 70)			
72	Income Taxes--Federal and Other (409.3)	262-263		
73	Extraordinary Items after Taxes (Total of line 71 less line 72)			
74	Net Income (Total of lines 67 and 73)			

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -130-

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, _____

GAS PLANT IN SERVICE (ACCOUNTS 101, 102, 103, AND 106)

1 Report below the original cost of gas plant in service according to the prescribed accounts
2 In addition to Account 101, *Gas Plant in Service (Classified)*, this page and the next include Account 102, Gas Plant Purchased or Sold, Account 103, Experimental Gas Plant Unclassified, and Account 106, Complete Construction Not Classified-Gas
3 Include in column © and (d), as appropriate corrections of additions and retirements for the current or preceding year
4. Include subsequent measurement revisions to the asset retirement costs capitalized in column (e) adjustments
5. Enclose in parenthesis credit adjustments of plant accounts to indicate the negative effect of such accounts

6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c) Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b) Like wise, if the respondent has a significant amount of plant retirement which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirement, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision Include also in column (d) reversals of tentative distributions of prior year's unclassified retirement Attach supplemental statement showing the account distributions of these tentative classifications in column (c) and (d),

Line No	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	INTANGIBLE PLANT		
2	301 Organization		
3	302 Franchises and Consents		
4	303 Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of lines 2 thru 4)		
6	PRODUCTION PLANT		
7	Natural Gas Production and Gathering Plant		
8	325.1 Producing Lands		
9	325.2 Producing Leaseholds		
10	325.3 Gas Rights		
11	325.4 Rights-of-Way		
12	325.5 Other Land and Land Rights		
13	326 Gas Well Structures		
14	327 Field Compressor Station Structures		
15	328 Field Measuring and Regulating Station Equipment		
16	329 Other Structures		
17	330 Producing Gas Wells-Well Construction		
18	331 Producing Gas Wells-Well Equipment		
19	332 Field Lines		
20	333 Field Compressor Station Equipment		
21	334 Field Measuring and Regulating Station Equipment		
22	335 Drilling and Cleaning Equipment		
23	336 Purification Equipment		
24	337 Other Equipment		
25	338 Unsuccessful Exploration and Development Costs		
26	339 Asset Retirement Costs for Natural Gas Production and Gathering Plant		
27	TOTAL Production and Gathering Plant (Enter Total of lines 8 thru 26)		
28	PRODUCTS EXTRACTION PLANT		
29	340 Land and Land Rights		
30	341 Structures and Improvements		
31	342 Extraction and Refining Equipment		
32	343 Pipe Lines		
33	344 Extracted Products Storage Equipment		
34	345 Compressor Equipment		

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -131-

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

GAS PLANT IN SERVICE (ACCOUNTS 101, 102, 103, AND 106) (Continued)

Line No	Account (a)	Balance at Beginning of Year (b)	Additions (c)
35	346 Gas Measuring and Regulating Equipment		
36	347 Other Equipment		
37	348 Asset Retirement Costs for Products Extraction Plant		
38	TOTAL Products Extraction Plant (Enter Total of lines 29 thru 37)		
39	TOTAL Natural Gas Production Plant (Enter Total of lines 27 and 38)		
40	Manufactured Gas Production Plant *(Submit Supplementary Statement)*		
41	TOTAL Production Plant (Enter Total of lines 39 and 40)		
42	NATURAL GAS STORAGE AND PROCESSING PLANT		
43	Underground Storage Plant		
44	350.1 Land		
45	350.2 Rights-of-Way		
46	351 Structures and Improvements		
47	352 Wells		
48	352.1 Storage Leaseholds and Rights		
49	352.2 Reservoirs		
50	352.3 Non-recoverable Natural Gas		
51	353 Lines		
52	354 Compressor Station Equipment		
53	355 Measuring and Regulating Equipment		
54	356 Purification Equipment		
55	357 Other Equipment		
56	358 Asset Retirement Costs for Underground Storage Plant		
57	TOTAL Underground Storage Plant (Enter Total of lines 43 thru 56)		
58	359 Other Storage Plant		
59	360 Land and Land Rights		
60	361 Structures and Improvements		
61	362 Gas Holders		
62	363 Purification Equipment		
63	363.1 Liquefaction Equipment		
64	363.2 Vaporizing Equipment		
65	363.2 Compressor Equipment		
66	363.4 Measuring and Regulating Equipment		
67	363.5 Other Equipment		
68	363.6 Asset Retirement Costs for Other Storage Plant		
69	TOTAL Other Storage Plant (Enter Total of lines 58 thru 68)		
70	Base Load Liquefied Natural Gas Terminaling and Processing Plant		
71	364.1 Land and Land Rights		
72	364.2 Structures and Improvements		
73	364.3 LNG Processing Terminal Equipment		
74	364.4 LNG Transportation Equipment		
75	364.5 Measuring and Regulating Equipment		
76	364.6 Compressor Station Equipment		
77	364.7 Communications Equipment		
78	364.8 Other Equipment		
79	364.9 Asset Retirement Costs for Base Load Liquefied Natural Gas Terminaling and Processing Plant		
80	TOTAL Base Load Liquefied Natural Gas Terminaling and Processing Plant (Lines 71 thru 79)		
81	TOTAL Natural Gas Storage and Processing Plant (Total of lines 57, 69 and 80)		
82	TRANSMISSION PLANT		
83	365,1 Land and Land Rights		
84	365.2 Right-of-Way		
85	366 Structures and Improvements		

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -132-

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

GAS PLANT IN SERVICE (ACCOUNTS 101, 102, 103, AND 106) (Continued)

Line No	Account (a)	Balance at Beginning of Year (b)	Additions (c)
86	367 Mains		
87	368 Compressor Station Equipment		
88	369 Measuring and Regulating Station Equipment		
89	370 Communication Equipment		
90	371 Other Equipment		
91	372 Asset Retirement Costs for Transmission Plant		
92	TOTAL Transmission Plant (Enter Totals of lines 83 thru 91)		
93	DISTRIBUTION PLANT		
94	374 Land and Land Rights		
95	375 Structures and Improvements		
96	376 Mains		
97	377 Compressor Station Equipment		
98	378 Measuring and Regulating Station Equipment-General		
99	379 Measuring and Regulating Station Equipment-City Gate		
100	380 Services		
101	381 Meters		
102	382 Meter Installations		
103	383 House Regulators		
104	384 House Regulator Installations		
105	385 Industrial Measuring and Regulating Station Equipment		
106	386 Other Property on Customers' Premises		
107	387 Other Equipment		
108	388 Asset Retirement Costs for Distribution Plant		
109	TOTAL Distribution Plant (Enter Total of lines 94 thru 108)		
1110	GENERAL PLANT		
111	389 Land and Land Rights		
112	390 Structures and Improvements		
113	391 Office Furniture and Equipment		
114	392 transportation Equipment		
115	393 Stores Equipment		
116	394 Tools, Shop, and Garage Equipment		
117	395 Laboratory Equipment		
118	396 Power Operated Equipment		
119	397 Communication Equipment		
120	398 Miscellaneous Equipment		
121	Subtotal (Enter Total of lines 111 thru 120)		
122	399 Other Tangible Property		
123	399.1 Asset Retirement Costs for General Plant		
124	TOTAL General Plant (Enter Total of lines 121, 122 and 123)		
125	TOTAL (Accounts 101 and 106)		
126	Gas Plant Purchased (See Instruction 8)		
127	*(Less)* Gas Plant Sold (See Instruction 8)		
128	Experimental Gas Plant Unclassified		
129	TOTAL Gas Plant in Service (Enter Total of lines 125 thru 128)		

19674 Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, ____

ACCUMULATED PROVISION FOR DEPRECIATION OF GAS UTILITY PLANT (ACCOUNT 108)

1 Explain in a footnote any important adjustments during year
2 Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for gas plant in service, page 204-209, column (d), excluding retirements of nondepreciable property
3 The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service If the respondent has a significant amount of plant retired at year end which had not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications
4 Show separately interest credits under a sinking fund or similar method of depreciation accounting
5 At lines 8 and 15, add rows as necessary to report all data Additional rows should be numbered in sequence, e g, 8. 01, 8.02, etc.

Line No	Item (a)	Total (c + d + e) (b)	Gas Plant in Service (c)	Gas Plant Heid for Future Use (d)	Gas Plant Leased to Others (e)
	Section A. BALANCES AND CHANGES DURING YEAR				
1	Balance Beginning of Year				
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense				
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Expense of Gas Plant Leased to Others				
6	Transportation Expenses - Clearing				
7	Other Clearing Accounts				
8	Other Clearing (Specify):				
8.01					
9	TOTAL Depreciation Provision For Year (Total of Lines 3 thru 8)				
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired				
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Charges for Plant Retirements (Total of Lines 11 thru13)				
15	Other Debit or Credit Items (Describe):				
15.01					
16	Book Cost of Asset Retirement Costs				
17	Balance End of Year (Total of lines 1, 9, 14, 15, and16)				
	Section B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS				
18	Productions-Manufactured Gas				
19	Production and Gathering -Natural Gas				
20	Products Extraction-Natural Gas				
21	Underground Gas Storage				
22	Other Storage Plant				
23	Base Load LNG Terminating and Processing Plant				
24	Transmission				
25	Distribution				
26	General				
27	TOTAL (Total of lines 18 thru 26)				

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -134-

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, ____

DEPRECIATION, DEPLETION, AND AMORTIZATION OF GAS PLANT (ACCOUNTS 403, 403.1, 404 1, 404 2, 404 3, 405) *(Except Amortization of Acquisition Adjustments)*

1 Report in Section A the amounts of depreciation expense depletion and amortization for the accounts indicated and classified according to the plant functional groups shown

2 Report in Section B, column (b) all depreciable or amortizable plant balances to which rates are applied and show a composite total (If more desirable, report by plant account, subaccount or functional classifications other than those pre-printed in column (a) Indicate in a footnote the manner in which column (b) balances are

Section A. Summary of Depreciation, Depletion, and Amortization Charges

Line No	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization and Depletion of Production Natural Gas Land and Land Rights (Account 404.1) (d)	Amortization of Underground Storage Land and Land Rights (Account 404.2) (e)
1	Intangible plant				
2	Production plant, manufactured gas				
3	Production and gathering plant, natural gas				
4	Products extraction plant				
5	Underground gas storage plant				
6	Other storage plant				
7	Base load LNG terminaling and processing plant				
8	Transmission plant				
9	Distribution plant				
10	General plant				
11	Common plant-gas				
12	TOTAL				

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, ____

DEPRECIATION, DEPLETION, AND AMORTIZATION OF GAS PLANT (ACCOUNTS 403, 403.1 404 1, 404 2, 404 3, 405) *(Except Amortization of Acquisition Adjustments)* (Continued)

obtained If average balances are used, state the method of averaging used For column (c) report available information for each plant functional classification listed in column (a) If composite depreciation accounting is used, report available information called for in columns (b) and (d) on this basis Where the unit-of-production method is used to determine depreciation charges, shown in a footnote any revisions made to estimated gas reserves.

3 If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state in a footnote the amounts and nature of the provisions and the plant items to which related.

Section A. Summary of Depreciation, Depletion, and Amortization Charges

Amortization of Other Limited-term Gas Plant (Account 404 3) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total (b to g) (h)	Functional Classification (a)	Line No
			Intangible plant	1
			Production plant, manufactured gas	2
			Production and gathering plant, natural gas	3
			Products extraction plant	4
			Underground gas storage plant	5
			Other storage plant	6
			Base Load LNG terminaling and processing plant	7
			Transmission plant	8
			Distribution plant	9
			General plant	10
			Common plant-gas	11
			TOTAL	12

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -136-

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of R eport *(Mo, Da, Yr)*	Year of Report Dec 31, ____

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Reference Page Number (b)	Balance at End of Current Year (in dollars) (c)	Balance at End of Previous Year (in dollars) (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251		
3	Preferred Stock Issued (204)	250-251		
4	Capital Stock Subscribed (202, 205)	252		
5	Stock Liability for Conversion (203, 206)	252		
6	Premium on Capital Stock (207)	252		
7	Other Paid-In Capital (208-211)	253		
8	Installments Received on Capital Stock (212)	252		
9	*(Less)* Discount on Capital Stock (213)	254		
10	*(Less)* Capital Stock Expense (214)	254		
11	Retained Earnings (215, 215 1, 216)	118-119		
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119		
13	*(Less)* Reacquired Capital (217)	250-251		
14	Accumulated Other Comprehensive Income (219)	117		
15	TOTAL Proprietary Capital (Total of line 2 thru 14)			
16	LONG TERM DEBT			
17	Bonds (221)	256-257		
18	*(Less)* Reacquired Bonds (222)	256-257		
19	Advances from Associated Companies (223)	256-257		
20	Other Long-Term Debt (224)	256-257		
21	Unamortized Premium on Long-Term Debt (225)	258-259		
22	(Less) Unamortized Discount on Long-Term Debt-Dr (226)	258-259		
23	(Less) Current Portion of Long-Term Debt			
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)			
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases -- Noncurrent (227)			
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated provision for Injuries and Damages (228.2)			
29	Accumulated Provision for Pensions and Benefits (228.3)			
30	Accumulated Miscellaneous Operating Provision (228.4)			
31	Accumulated Provision for Rate Refunds (229)			
32	Asset Retirement Obligations (230)			
33	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 32)			

19678 Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, ____

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Balance at End of Current Year (in dollars) (c)	Balance at End of Previous Year (in dollars) (d)
34	CURRENT AND ACCRUED LIABILITIES			
35	Current Portion of Long-Term Debt			
36	Notes Payable (231)			
37	Accounts Payable (232)			
38	Notes Payable to Associated Companies (233)			
39	Accounts Payable to Associated Companies (234)			
40	Customer Deposits (235)			
41	Taxes Accrued (236)	262-263		
42	Interest Accrued (237)			
43	Dividends Declared (238)			
44	Matured Long-Term Debt (239)			
45	Matured Interest (240)			
46	Tax Collections Payable (241)			
47	Miscellaneous Current and Accrued Liabilities (242)	268		
48	Obligations Under Capital Leases -- Current (243)			
49	Derivative Instrument Liabilities (244)			
50	Derivative Instrument Liabilities - Hedges (245)			
51	TOTAL Current and Accrued Liabilities (Total of lines 35 thru 50)			
52	DEFERRED CREDITS			
53	Customer Advances for Construction (252)			
54	Accumulated Deferred Investment Tax Credits (255)			
55	Deferred Gains from Disposition of Utility Plant (256)			
56	Other Deferred Credits (253)	269		
57	Other Regulatory Liabilities (254)	278		
58	Unamortized Gain on Reacquired Debt (257)	260		
59	Accumulated Deferred Income Taxes (281-283)			
60	TOTAL Deferred Credits (Total of lines 53 thru 59)			
61	TOTAL Liabilities and Other Credits (Total of lines 15, 24, 33, 51, and 60)			

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, _____

STATEMENT OF INCOME FOR THE YEAR

1 Report amounts for accounts 412 and 413, *Revenue and Expenses from Utility Plant Leased to Others,* in another utility column (i,j) in a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals

2 Report amounts in discount 414, *Other Utility Operating Income,* in the same manner as accounts 412 and 413 above

3 Report data for lines 8, 10, and 11 for Natural Gas companies using accounts 404 1, 404 2, 404.3, 407.1, and 407.2

Line No.	Title of Account (a)	Reference Page Number (b)	Balance at End of Current Year (in dollars) (c)	Balance at End of Previous Year (in dollars) (d)
1	UTILITY OPERATING INCOME			
2	Gas Operating Revenues (400)	300-301		
3	Operating Expenses			
4	Operation Expenses (401)	317-325		
5	Maintenance Expenses (402)	317-325		
6	Depreciation Expense (403)	336-338		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-338		
8	Amortization and Depletion of Utility Plant (404-405)	336-338		
9	Amortization of Utility Plant Acquisition Adjustment (406)	336-338		
10	Amort of Prop Losses, Unrecovered Plant and Reg Study Costs (407.1)			
11	Amortization of Conversion Expenses (407.2)			
12	Regulatory Debits (407.3)			
13	(Less) Regulatory Credits (407.4)			
14	Taxes Other than Income Taxes (408.1)	262-263		
15	Income Taxes -- Federal (409.1)	262-263		
16	Income Taxes -- Other (409.1)	262-263		
17	Provision of Deferred Income Taxes (410.1)	234-235		
18	(Less) Provision for Deferred Income Taxes -- Credit (411.1)	234-235		
19	Investment Tax Credit Adjustment -- Net (411.4)			
20	(Less) Gains from Disposition of Utility Plant (411.6)			
21	Losses from Disposition of Utility Plant (411.7)			
22	(Less) Gains from Disposition of Allowances (411.8)			
23	Losses from Disposition of Allowances (411.9)			
24	Accretion Expense (411.10)			
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)			
26	Net Utility Operating Income (Total of lines 2 less 25) (Carry forward to page 116, line 27)			

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, ____

STATEMENT OF INCOME FOR THE YEAR (Continued)

4 Explain in a footnote if the previous year's figures are different from those reported in prior reports

5 If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 26, and report the information on page 122 or in a supplemental statement.

Electric Utility Current Yea (in dollars)	Electric Utility Previous Year (in dollars)	Gas Utility Current Year (In dollars)	Gas Utility Current Year (in dollars)	Other Utility Current Tear (in dollars)	Other Utility Previous Year (in dollars)	
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
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Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -140-

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Balance at End of Current Year (in dollars) (c)	Balance at End of Previous Year (in dollars) (d)
27	Net Utility Operating Income (Carrier forward from page 114)			
28	OTHER INCOME AND DEDUCTIONS			
29	Other Income			
30	Nonutility Operating Income			
31	Revenues form Merchandising, Jobbing and Contract Work (415)			
32	*(Less)* Costs and Expense of Merchandising, Job & Contract Work (415.1)			
33	Revenues from Nonutility Operations (417)			
34	*(Less)* Expenses of Nonutility Operations (417.1)			
35	Nonoperating Rental Income			
36	Equity in Earnings of Subsidiary Companies (418.1)	119		
37	Interest and Dividend Income (419)			
38	Allowance for Other Funds Used During Construction (419.1)			
39	Miscellaneous Nonoperating Income (421)			
40	Gain on Disposition of Property (421.1)			
41	TOTAL Other Income (Total of lines 29 thru 40)			
42	Other Income Deductions			
43	Loss on Disposition of Property (421 2)			
44	Miscellaneous Amortization (425)			
45	Miscellaneous Income Deductions (426.1 thru 426.5)	340		
46	TOTAL Other Income Deductions (Total of lines 43 thru 45)	340		
47	Taxes Applicable to Other Income and Deductions			
48	Taxes Other than Income Taxes (406.2)	262-263		
49	Income Taxes -- Federal (409.2)	262-263		
50	Income Taxes -- Other (409.2)	262-263		
51	Provision for Deferred Income Taxes (410.2)	234-235		
52	*(Less)* Provision for Deferred Income Taxes-Credit (410. 2)	234-235		
53	Investment Tax Credit Adjustments--Net (411.5)			
54	*(Less)* Investment Tax Credits (420)			
55	TOTAL Taxes on Other Income and Deductions (Total of lines 48-54)			
56	Net Other Income and Deductions (Total of lines 41, 46, and 55)			
57	INTEREST CHARGES			
58	Interest on Long-Term Debt (427)			
59	Amortization of Debt Disc and Expense (428)	258-259		
60	Amortization of Loss on Reacquired Debt (428.1)			
61	*(Less)* Amortization of Premium on Debt-Credit (429)	258-259		
62	*(Less)* Amortization of Gain on Reacquired Debt-Credit (429.1)			
63	Interest on Debt to Associated Companies (430)	340		
64	Other Interest Expense (431)	340		
65	(Less) Allowance for Borrowed Funds Used During Construction- Credit			
66	Net Interest Charges (Total of lines 58 thru 65)			
67	Income Before Extraordinary Items (Total of lines 27, 56 and 66)			
68	EXTRAORDINARY ITEMS			
69	Extraordinary Income (434)			
70	*(Less)* Extraordinary Deductions (435)			
71	Net Extraordinary Items (Total of line 69 less 70)			
72	Income Taxes--Federal and Other (409.3)	262-263		
73	Extraordinary Items after Taxes (Total of line 71 less line 72)			
74	Net Income (Total of lines 67and 73)			

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

GAS PLANT IN SERVICE (ACCOUNTS 101, 102, 103, AND 106)

1 Report below the original cost of gas plant in service according to the prescribed accounts.
2 In addition to Account 101, *Gas Plant in Service (Classified)*, this page and the next include Account 102, Gas Plant Purchased or Sold, Account 103, Experimental Gas Plant Unclassified, and Account 106, Completed Construction Not Classified-Gas.
3 Include in column (c) and (d), as appropriate corrections of additions and retirements for the current or preceding year
4. For subsequent measurement revisions to initial asset retirement costs capitalized include any net increase or net decrease amount by primary plant account for the asset retirement costs in column (c) additions.
4 Enclose in parenthesis credit adjustments of plant accounts to indicate the negative effect of such accounts
5 Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c) Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b) Like wise, if the respondent has a significant amount of plant retirement which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirement, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision Include also in column (d) reversals of tentative distributions of prior year's unclassified retirement Attach supplemental statement showing the account distributions of these tentative classifications in column (c) and (d),

Line No	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	INTANGIBLE PLANT		
2	301 Organization		
3	302 Franchises and Consents		
4	303 Miscellaneous Intangible Plant		
5	TOTAL Intangible Plant (Enter Total of lines 2 thru 4)		
6	PRODUCTION PLANT		
7	Natural Gas Production and Gathering Plant		
8	325.1 Producing Lands		
9	325.2 Producing Leaseholds		
10	325.3 Gas Rights		
11	325.4 Rights-of-Way		
12	325.5 Other Land and Land Rights		
13	326 Gas Well Structures		
14	327 Field Compressor Station Structures		
15	328 Field Measuring and Regulating Station Equipment		
16	329 Other Structures		
17	330 Producing Gas Wells-Well Construction		
18	331 Producing Gas Wells-Well Equipment		
19	332 Field Lines		
20	333 Field Compressor Station Equipment		
21	334 Field Measuring and Regulating Station Equipment		
22	335 Drilling and Cleaning Equipment		
23	336 Purification Equipment		
24	337 Other Equipment		
25	338 Unsuccessful Exploration and Development Costs		
26	339 Asset Retirement Costs for Natural Gas Production & Gathering Plant		
27	TOTAL Production and Gathering Plant (Enter Total of lines 8 thru 26)		
28	PRODUCTS EXTRACTION PLANT		
29	340 Land and Land Rights		
30	341 Structures and Improvements		
31	342 Extraction and Refining Equipment		
32	343 Pipe Lines		
33	344 Extracted Products Storage Equipment		
34	345 Compressor Equipment		

Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations 19683

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -142-

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, ____

PLANT IN SERVICE (ACCOUNTS 101, 102, 103, AND 106 (Continued)

including the reversals of the prior years tentative account distributions of these amounts Careful observance of the above instructions and the texts of Account 101 and 106 will avoid serious omissions of respondent's reported amount for plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., And show in column (f) only the offset to the debits or credits to primary account classifications

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction If proposed journal entries have been filed with the commission as required by the Uniform System of Accounts, give date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No
				1
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Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

GAS PLANT IN SERVICE (ACCOUNTS 101, 102, 103, AND 106) (Continued)

Line No	Account (a)	Balance at Beginning of Year (b)	Additions (c)
35	346 Gas Measuring and Regulating Equipment		
36	347 Other Equipment		
37	348 Asset Retirement Costs for Products Extraction Plant		
38	TOTAL Products Extraction Plant (Enter Total of lines 29 thru 37)		
39	TOTAL Natural Gas Production Plant (Enter Total of lines 27 and 38)		
40	Manufactured Gas Production Plant *(Submit Supplementary Statement)*		
41	TOTAL Production Plant (Enter Total of lines 39 and 40)		
42	NATURAL GAS STORAGE AND PROCESSING PLANT		
43	Underground Storage Plant		
44	350.1 Land		
45	350.2 Rights-of-Way		
46	351 Structures and Improvements		
47	352 Wells		
48	352.1 Storage Leaseholds and Rights		
49	352.2 Reservoirs		
50	352.3 Non-recoverable Natural Gas		
51	353 Lines		
52	354 Compressor Station Equipment		
53	355 Measuring and Regulating Equipment		
54	356 Purification Equipment		
55	357 Other Equipment		
56	358 Asset Retirement Costs for Underground Storage Plant		
57	TOTAL Underground Storage Plant (Enter Total of lines 44 thru 56)		
58	Other Storage Plant		
59	360 Land and Land Rights		
60	361 Structures and Improvements		
61	362 Gas Holders		
62	363 Purification Equipment		
63	363.1 Liquefaction Equipment		
64	363.2 Vaporizing Equipment		
65	363.2 Compressor Equipment		
66	363.4 Measuring and Regulating Equipment		
67	363.5 Other Equipment		
68	363.6 Asset Retirement Costs for Other Storage Plant		
69	TOTAL Other Storage Plant (Enter Total of lines 59 thru 68)		
70	Base Load Liquefied Natural Gas Terminating and Processing Plant		
71	364.1 Land and Land Rights		
72	364.2 Structures and Improvements		
73	364.3 LNG Processing Terminal Equipment		
74	364.4 LNG Transportation Equipment		
75	364.5 Measuring and Regulating Equipment		
76	364.6 Compressor Station Equipment		
77	364.7 Communications Equipment		
78	364.8 Other Equipment		
79	364.9 Asset Retirement Costs for Base Load Liquefied Natural Gas Terminaling and Processing Plant		
80	TOTAL Base Load Liquefied Natural Gas, Terminating and Processing Plant (Lines 71 thru 79)		
81	TOTAL Natural Gas Storage and Processing Plant (Total of lines 57, 69 and 80)		
82	TRANSMISSION PLANT		
83	365.1 Land and Land Rights		
84	365.2 Rights-of-Way		
85	366 Structures and Improvements		

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -144-

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, _____

GAS PLANT IN SERVICE (ACCOUNTS 101, 102, 103, AND 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No
				35
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19686 Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -145-

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec 31, _____

GAS PLANT IN SERVICE (ACCOUNTS 101, 102, 103, AND 106) (Continued)

Line No	Account (a)	Balance at Beginning of Year (b)	Additions (c)
86	367 Mains		
87	368 Compressor Station Equipment		
88	369 Measuring and Regulating Station Equipment		
89	370 Communication Equipment		
90	371 Other Equipment		
91	372 Asset Retirement Costs for Transmission Plant		
92	TOTAL Transmission Plant (Enter Totals of lines 83 thru 91)		
93	DISTRIBUTION PLANT		
94	374 Land and Land Rights		
95	375 Structures and Improvements		
96	376 Mains		
97	377 Compressor Station Equipment		
98	378 Measuring and Regulating Station Equipment-General		
99	379 Measuring and Regulating Station Equipment-City Gate		
100	380 Services		
101	381 Meters		
102	382 Meter Installations		
103	383 House Regulators		
104	384 House Regulator Installations		
105	385 Industrial Measuring and Regulating Station Equipment		
106	386 Other Property on Customers' Premises		
107	387 Other Equipment		
108	388 Asset Retirement Costs for Distribution Plant		
109	TOTAL Distribution Plant (Enter Total of lines 94 thru 108)		
110	GENERAL PLANT		
111	389 Land and Land Rights		
112	390 Structures and Improvements		
113	391 Office Furniture and Equipment		
114	392 transportation Equipment		
115	393 Stores Equipment		
116	394 Tools, Shop, and Garage Equipment		
117	395 Laboratory Equipment		
118	396 Power Operated Equipment		
119	397 Communication Equipment		
120	398 Miscellaneous Equipment		
121	Subtotal (Enter Total of lines 111 thru 120)		
122	399 Other Tangible Property		
123	399.1 Asset Retirement Costs for General Plant		
124	TOTAL General Plant (Enter Total of lines 121, 122 and 123)		
125	TOTAL (Accounts 101 and 106)		
126	Gas Plant Purchased (See Instruction 8)		
127	*(Less)* Gas Plant Sold (See Instruction 8)		
128	Experimental Gas Plant Unclassified		
129	TOTAL Gas Plant in Service (Enter Total of lines 125 thru 128)		

Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations 19687

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

GAS PLANT IN SERVICE (ACCOUNTS 101, 102, 103, AND 106 (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No
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Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6

Name of Respondent	This Report is: ☐ An Original ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec 31, _____

ACCUMULATED PROVISION FOR DEPRECIATION OF GAS UTILITY PLANT (ACCOUNT 108)

1 Explain in a footnote any important adjustments during year
2 Explain in a footnote any difference between the amount for book cost of plant retired, line 11, column (c), and that reported for gas plant in service, page 204-209, column (d), excluding retirements of nondepreciable property.
3 The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service If the respondent has a significant amount of plant retired at year end which had not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications
4 Show separately interest credits under a sinking fund or similar method of depreciation accounting
5 At lines 8 and 15, add rows as necessary to report all data Additional rows should be numbered in sequence, e g, 8.01, 8.02, etc.

Line No	Item (a)	Total (c + d + e) (b)	Gas Plant in Service (c)	Gas Plant Held for Future Use (d)	Gas Plant Leased to Others (e)
	Section A. BALANCES AND CHANGES DURING YEAR				
1	Balance Beginning of Year				
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense				
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Expense of Gas Plant Leased to Others				
6	Transportation Expenses - Clearing				
7	Other Clearing Accounts				
8	Other Clearing (Specify):				
8.01					
9	TOTAL Depreciation Provision For Year (Total of lines 3 thru 7)				
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired				
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Charges for Plant Ret. (Total of lines 11 thru 13)				
15	Other Debit or Credit Items (Describe):				
15.01					
16	Book Cost of Asset Retirement Costs Retired				
17	Balance End of Year (Total of lines 1, 9, 14, 15 and 16)				
	Section B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS				
18	Productions-Manufactured Gas				
19	Production and Gathering -Natural Gas				
20	Products Extraction-Natural Gas				
21	Underground Gas Storage				
22	Other Storage Plant				
23	Base Load LNG Terminating and Processing Plant				
24	Transmission				
25	Distribution				
26	General				
27	TOTAL (Total of lines 18 thru 26)				

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -148-

Name of Respondent	This Report Is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 20___

LIST OF SCHEDULES

Enter in column (d) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the responses are "none," "not applicable," or "NA."

Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
GENERAL CORPORATE INFORMATION AND FINANCIAL STATEMENTS			
General Information	101	ED 12-91	
Control Over Respondent	102	REV 12-95	
Companies Controlled by Respondent	103	NEW 12-95	
Principal General Officers	104	ED 12-91	
Directors	105	REV 12-95	
Important Changes During the Year	108-109	REV 12-95	
Comparative Balance Sheet Statement	110-113	REV 12-02	
Income Statement	114	REV 12-02	
Statement of Accumulated Comprehensive Income and Hedging Activities	115 (a) (b)	NEW 12-02	
Appropriated Retained Income	118	REV 12-95	
Unappropriated Retained Income Statement	119	REV 12-95	
Dividend Appropriations of Retained Income	119	REV 12-95	
Statement of Cash Flows	120-121	REV 12-95	
Notes to Financial Statements	122-123	REV 12-95	
BALANCE SHEET SUPPORTING SCHEDULES (Assets and Other Debts)			
Receivables From Affiliated Companies	200	REV 12-00	
General Instructions Concerning Schedules 202 thru 205	201	REV 12-95	
Investments in Affiliated Companies	202-203	ED 12-91	
Investments in Common Stocks of Affiliated Companies	204-205	ED 12-91	
Companies Controlled Directly by Respondent Other Than Through Title to Securities	204-205	ED 12-02	
Instructions for Schedules 212 Thru 217	211	REV 12-00	
Carrier Property	212-213	REV 12-02	
Undivided Joint Interest Property	214-215	REV 12-02	
Accrued Depreciation-Carrier Property	216	REV 12-02	
Accrued Depreciation-Undivided Joint Interest Property	217	REV 12-02	
Amortization Base and Reserve	218-219	REV 12-02	
Noncarrier Property	220	REV 12-00	
Other Deferred Charges	221	REV 12-00	
BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits)			
Payables to Affiliated Companies	225	REV 12-00	
Long-Term Debt	226-227	ED 12-00	
Analysis of Federal Income and Other Taxes Deferred	230-231	REV 12-00	
Capital Stock	250-251	REV 12-95	
Capital Stock Changes During the Year	252-253	ED 12-91	
Additional Paid-in Capital	254	ED 12-87	

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 20___

COMPARATIVE BALANCE SHEET STATEMENT - LIABILITIES (Continued)

For instructions covering this schedule, see the text and instructions pertaining to Balance Sheet Accounts in the USofA. The entries in this balance sheet should be consistent with those in the supporting schedules on the pages indicated.

Line No.	Item (a)	Reference Page No. (b)	Balance at End of Current Year (In dollars) (c)	Balance at End of Previous Year (In dollars) (d)
	CURRENT LIABILITIES			
47	Notes Payable (50)			
48	Payables to Affiliated Companies (51)			
49	Accounts Payable (52)			
50	Salaries and Wages Payable (53)			
51	Interest Payable (54)			
52	Dividends Payable (55)			
53	Taxes Payable (56)			
54	Long - Term Debt - Payable Within One Year (57)	226-227		
55	Other Current Liabilities (58)			
56	Deferred Income Tax Liabilities (59)	230-231		
57	TOTAL Current Liabilities *(Total of lines 47 thru 56)*			
	NONCURRENT LIABILITIES			
58	Long-Term Debt - Payable After One Year (60)	226-227		
59	Unamortized Premium on Long-Term Debt (61)			
60	(Less) Unamortized Discount on Long-Term Debt-Dr. (62)			
61	Other Noncurrent Liabilities (63)			
62	Accumulated Deferred Income Tax Liabilities (64)	230-231		
63	Derivative Instrument Liabilities (65)			
64	Derivative Instrument Liabilities - Hedges (66)			
65	Asset Retirement Obligations (67)			
66	TOTAL Noncurrent Liabilities *(Total of lines 58 thru 65)*			
67	TOTAL Liabilities *(Total of lines 57 and 66)*			
	STOCKHOLDERS' EQUITY			
68	Capital Stock (70)	250-251		
69	Premiums on Capital Stock (71)			
70	Capital Stock Subscriptions (72)			
71	Additional Paid-In Capital (73)	254		
72	Appropriated Retained Income (74)	118		
73	Unappropriated Retained Income (75)	119		
74	(Less) Unrealized Loss on Noncarrier Marketable Equity-Securities (75.5)			
75	(Less) Treasury Stock (76)			
76	TOTAL Stockholders' Equity *(Total of lines 68 thru 75)*			
77	TOTAL Liabilities and Stockholders' Equity (*Total of lines 67 and 76*)			

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -150-

INSTRUCTIONS FOR SCHEDULES 212-213

1.) Give an analysis of changes during the year in Account No. 30, *Carrier Property*, by carrier property accounts, excluding investments in undivided joint interest property reported on pages 214 and 215. The total carrier property reported on page 213 (column i, line 44) and the total undivided joint interest property reported on all pages 215 (column i, line 44) should represent all carrier property owned by the reporting entity at year end.

2.) Enter in column (c) the cost of newly constructed property, additions, and improvements made to existing property. Include amounts distributed to carrier property accounts during the year which were previously charged to Account No. 187, *Construction Work in Progress*. In column (d) enter expenditures for existing pipeline property purchased or otherwise acquired. Enter in column (e) - property sold, abandoned, or otherwise retired during the year. This will generally be a positive number, so that the calculation in column (f) works properly.

3.) If pipeline operating property was acquired from or sold to some other company during the year, footnote the acquisition or sale if it exceeded $250,000. Include the following in the footnote: the name of the company the property was acquired from or sold to, the mileage acquired or sold, and the date of acquisition or sale. Include termini, the original cost of property acquired from an affiliate or other common carrier (see Instruction 3-1, Property acquired, Instructions for Carrier Property Accounts in Uniform System of Accounts), and the cost of the property to the respondent. Also give the amount debited or credited to each company account representing such property acquired or disposed of.

4.) Enter in column (g) for each account the net of all other accounting adjustments, transfers, and clearances applicable to prior years' accounting.

5.) Explain fully each adjustment, clearance, or transfer in excess of $500,000 in a footnote. Explain transfers to or from Account No. 34, *Noncarrier Property,* in Schedule 219.

6.) Indicate in parenthesis any entry in columns (f), (g), or (h) which represents an excess of credits over debits.

INSTRUCTIONS FOR SCHEDULES 214-215

1.) Give an analysis of changes during the year in Account No. 30, *Carrier Property*, by carrier property accounts, for investments in undivided joint interest property. The respondent will only report its portion of the carrier property of any undivided joint interest pipeline in which it has an interest. If the respondent owns an interest in multiple undivided joint interest pipelines, prepare and submit a separate schedule 214-215 for each undivided joint interest pipeline in which it has an interest. If multiple schedules 214-215 are submitted, number all schedules subsequent to the first with a number and letter page designator (For example ... 214, 215; 214a, 215a; 214b, 215b; etc...).

2.) Enter in column (c) the cost of newly constructed property, additions, and improvements made to existing property. Include amounts distributed to carrier property accounts during the year which were previously charged to Account No. 187*Construction Work in Progress.* In column (d) enter expenditures for existing pipeline property purchased or otherwise acquired. Enter in column (e) property sold, abandoned, or otherwise retired during the year. This will generally be a positive number so that the calculation in column (f) works properly.

3.) If pipeline operating property was acquired from or sold to some other company during the year, footnote the acquisition or sale if it exceeded $250,000. Include the following in the footnote: the name of the company the property was acquired from or sold to, the mileage acquired or sold, and the date of acquisition or sale. Include termini, the original cost of property acquired from an affiliate or other common carrier (see Instruction 3-1, Property acquired, Instructions for Carrier Property Accounts in Uniform System of Accounts), and the cost of the property to the respondent. Also give the amount debited or credited to each company account representing such property acquired or disposed of.

4.) Enter in column (g) for each account the net of all other accounting adjustments, transfers, and clearances applicable to prior years' accounting.

5.) Explain fully each adjustment, clearance, or transfer in excess of $500,000 in a footnote. Explain transfers to or from Account No. 34, *Noncarrier Property,* in Schedule 219.

6.) Indicate in parenthesis any entry in columns (f), (g), or (h) which represents an excess of credits over debits.

INSTRUCTIONS FOR SCHEDULES 216-217

1.) On schedule 216, give an analysis of changes during the year in Account No. 31, *Accrued Depreciation - Carrier Property*, by carrier property accounts, excluding depreciation on undivided joint interest property reported on page 217.

On schedule 217, give an analysis of changes during the year in Account No. 31, *Accrued Depreciation - Carrier Property*, by carrier property accounts for property owned as part of an undivided joint interest pipeline. If the respondent owns an interest in multiple undivided joint interest pipelines, prepare and submit a separate schedule 217 for each undivided joint interest pipeline in which it has an interest. If multiple schedules 217 are submitted, number all schedules subsequent to the first with a number and letter page designator (For example ... 217, 217a, 217b, etc...).

2.) In column (c), enter debits by carrier property account to Account No. 540, *Depreciation and Amortization*, and 541, *Depreciation Expense for Asset Retirement Costs* , during the year.

3.) In column (d), enter all debits to Account No. 31, *Accrued Depreciation - Carrier Property*, during the year resulting from the retirement of carrier property.

4.) In column (e), enter the net of any other debits and credits made to Account No. 31, *Accrued Depreciation - Carrier Property*, during the year.

5.) If composite annual depreciation rates are prescribed, enter those in effect at the end of the year in column (g). If component rates are prescribed, the composite rates entered in column (g) should be computed from the charges developed for December by using the prescribed component rates. Whether component or composite rates are prescribed, the entries on lines 17, 34, 42, and 43 of column (g) should be computed from December depreciation charges.

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -151-

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 20___

CARRIER PROPERTY

			PROPERTY CHANGES DURING THE YEAR (In dollars)	
Line No.	Account (a)	Balance at Beginning of Year (In dollars) (b)	Expenditures for New Construction, Additions, and Improvements (c)	Expenditures for Existing Property Purchased or Otherwise Acquired (d)
	GATHERING LINES			
1	Land (101)			
2	Right of Way (102)			
3	Line Pipe (103)			
4	Line Pipe Fittings (104)			
5	Pipeline Construction (105)			
6	Buildings (106)			
7	Boilers (107)			
8	Pumping Equipment (108)			
9	Machine Tools and Machinery (109)			
10	Other Station Equipment (110)			
11	Oil Tanks (111)			
12	Delivery Facilities (112)			
13	Communication Systems (113)			
14	Office Furniture and Equipment (114)			
15	Vehicles and Other Work Equipment (115)			
16	Other Property (116)			
17	Asset Retirement Costs for Gathering Lines (117)			
18	TOTAL *(Lines 1 thru 17)*			
	TRUNK LINES			
19	Land (151)			
20	Right of Way (152)			
21	Line Pipe (153)			
22	Line Pipe Fittings (154)			
23	Pipeline Construction (155)			
24	Buildings (156)			
25	Boilers (157)			
26	Pumping Equipment (158)			
27	Machine Tools and Machinery (159)			
28	Other Station Equipment (160)			
29	Oil Tanks (161)			
30	Delivery Facilities (162)			
31	Communication Systems (163)			
32	Office Furniture and Equipment (164)			
33	Vehicles and Other Work Equipment (165)			
34	Other Property (166)			
35	Asset Retirement Costs for Trunk Lines (167)			
36	TOTAL *(Lines 19 thru 35)*			
	GENERAL			
37	Land (171)			
38	Buildings (176)			
39	Machine Tools and Machinery (179)			
40	Communication Systems (183)			
41	Office Furniture and Equipment (184)			
42	Vehicles and Other Work Equipment (185)			
43	Other Property (186)			
44	Asset Retirement Costs for General Property (186.1)			
45	Construction Work in Progress (187)			
46	TOTAL (Lines 37 thru 45)			
47	GRAND TOTAL (Lines 18, 36 and 46)			

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -152-

Name of Respondent	This Report Is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 20___

CARRIER PROPERTY (Continued)

PROPERTY CHANGES DURING					
Property Sold, Abandoned, or Otherwise Retired During the Year *(e)*	Net (c + d - e) *(f)*	Other Adjustments, Transfers and Clearances *(In dollars)* *(g)*	Increase or Decrease During the Year (f ± g) *(In dollars)* *(h)*	Balance at End of Year (b ± h) *(In dollars)* *(i)*	Line No.
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Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 20__

UNDIVIDED JOINT INTEREST PROPERTY

Name of Undivided Joint Interest Pipeline:

Line No.	Account (a)	Balance at Beginning of Year (in dollars) (b)	PROPERTY CHANGES DURING THE YEAR (in dollars) Expenditures for New Construction, Additions, and Improvements (c)	Expenditures for Existing Property Purchased or Otherwise Acquired (d)
	GATHERING LINES			
1	Land (101)			
2	Right of Way (102)			
3	Line Pipe (103)			
4	Line Pipe Fittings (104)			
5	Pipeline Construction (105)			
6	Buildings (106)			
7	Boilers (107)			
8	Pumping Equipment (108)			
9	Machine Tools and Machinery (109)			
10	Other Station Equipment (110)			
11	Oil Tanks (111)			
12	Delivery Facilities (112)			
13	Communication Systems (113)			
14	Office Furniture and Equipment (114)			
15	Vehicles and Other Work Equipment (115)			
16	Other Property (116)			
17	Asset Retirement Costs for Gathering Lines (117)			
18	TOTAL (Lines 1 thru 17)			
	TRUNK LINES			
19	Land (151)			
20	Right of Way (152)			
21	Line Pipe (153)			
22	Line Pipe Fittings (154)			
23	Pipeline Construction (155)			
24	Buildings (156)			
25	Boilers (157)			
26	Pumping Equipment (158)			
27	Machine Tools and Machinery (159)			
28	Other Station Equipment (160)			
29	Oil Tanks (161)			
30	Delivery Facilities (162)			
31	Communication Systems (163)			
32	Office Furniture and Equipment (164)			
33	Vehicles and Other Work Equipment (165)			
34	Other Property (166)			
35	Asset Retirement Costs for Trunk Lines (167)			
36	TOTALS (Lines 19 thru 35)			
	GENERAL			
37	Land (171)			
38	Buildings (176)			
39	Machine Tools and Machinery (179)			
40	Communication Systems (180)			
41	Office Furniture and Equipment (184)			
42	Vehicles and Other Work Equipment (185)			
43	Other Property (186)			
44	Asset Retirement Costs for General Property (186.1)			
45	Construction Work in Progress (187)			
46	TOTAL (Lines 37 thru 45)			
47	GRAND TOTAL (Lines 18, 36, and 46)			

Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations 19695

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -154-

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 20___

UNDIVIDED JOINT INTEREST PROPERTY (Continued)

PROPERTY CHANGES DURING THE YEAR (In dollars)					
Property Sold, Abandoned, or Otherwise Retired During the Year (e)	Net (c+d-e) (f)	Other Adjustments, Transfers, and Clearances (In dollars) (g)	Increase or Decrease During the Year (f ± g) (In dollars) (h)	Balance at End of Year (b ± h) (In dollars) (i)	Line No.
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Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -155-

Name of Respondent	This Report Is: (1) □ An Original (2) □ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 20___

ACCRUED DEPRECIATION - CARRIER PROPERTY
(EXCLUSIVE OF DEPRECIATION ON UNDIVIDED JOINT INTEREST PROPERTY REPORTED IN SCHEDULE 217)

Give particulars (details) of the credits and debits to Account No. 31, *Accrued Depreciation - Carrier Property*, during the year.

Line No.	Account (a)	Balance at Beginning of Year *(In dollars)* *(b)*	Debits to Accounts No. 540 and 541 of USofA *(In dollars)* *(c)*	Net Debit From Retirement of Carrier Property *(In dollars)* *(d)*	Other Debits and Credits-Net *(In dollars)* *(e)*	Balance at End of Year (b + c + d + e) *(In dollars)* *(f)*	Annual Composite/ Component Rates *(In percent)* *(g)*
	GATHERING LINES						
1	Right of Way (102)						
2	Line Pipe (103)						
3	Line Pipe Fittings (104)						
4	Pipeline Construction (105)						
5	Buildings (106)						
6	Boilers (107)						
7	Pumping Equipment (108)						
8	Machine Tools and Machinery (109)						
9	Other Station Equipment (110)						
10	Oil Tanks (111)						
11	Delivery Facilities (112)						
12	Communication Systems (113)						
13	Office Furniture and Equip (114)						
14	Vehicles and Other Work Equip (115)						
15	Other Property (116)						
16	Asset Retirement Costs for Gathering Lines (117)						
17	TOTAL *(Lines 1 thru 16)*						
	TRUNK LINES						
18	Right of Way (152)						
19	Line Pipe (153)						
20	Line Pipe Fittings (154)						
21	Pipeline Construction (155)						
22	Buildings (156)						
23	Boilers (157)						
24	Pumping Equipment (158)						
25	Machine Tools and Machinery (159)						
26	Other Station Equipment (160)						
27	Oil Tanks (161)						
28	Delivery Facilities (162)						
29	Communication Systems (163)						
30	Office Fumiture and Equip (164)						
31	Vehicles and Other Work Equip (165)						
32	Other Property (166)						
33	Asset Retirement Costs for Trunk Lines (167)						
34	TOTAL *(Lines 18 thru 33)*						
	GENERAL						
35	Buildings (176)						
36	Machine Tools and Machinery (179)						
37	Communication Systems (183)						
38	Office Furniture and Equip (184)						
39	Vehicles and Other Work Equip (185)						
40	Other Property (186)						
41	Asset Retirement Costs for General Property (186.1)						
42	TOTAL *(Lines 35 thru 41)*						
43	GRAND TOTAL *(Lines 17, 34, 42)*						

Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations 19697

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -156-

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report *(Mo, Da, Yr)*	Year of Report Dec. 31, 20___

ACCRUED DEPRECIATION - UNDIVIDED JOINT INTEREST PROPERTY

Give particulars (details) of the credits and debits to Account No. 31, *Accrued Depreciation - Carrier Property*, during the year.

Name of Undivided Joint Interest Pipeline:

Line No.	Account *(a)*	Balance at Beginning of Year *(In dollars)* *(b)*	Debits to Accounts No. 540 and 541 of USofA *(In dollars)* *(c)*	Net Debit From Retirement of Carrier Property *(In dollars)* *(d)*	Other Debits and Credits-Net *(In dollars)* *(e)*	Balance at End of Year (b + c + d + e) *(In dollars)* *(f)*	Annual Composite/ Component Rates *(In percent)* *(g)*
	GATHERING LINES						
1	Right of Way (102)						
2	Line Pipe (103)						
3	Line Pipe Fittings (104)						
4	Pipeline Construction (105)						
5	Buildings (106)						
6	Boilers (107)						
7	Pumping Equipment (108)						
8	Machine Tools and Machinery (109)						
9	Other Station Equipment (110)						
10	Oil Tanks (111)						
11	Delivery Facilities (112)						
12	Communication Systems (113)						
13	Office Furniture and Equip. (114)						
14	Vehicles and Other Work Equip. (115)						
15	Other Property (116)						
16	Asset Retirement Costs for Gathering Lines (117)						
17	TOTAL *(Lines 1 thru 16)*						
	TRUNK LINES						
18	Right of Way (152)						
19	Line Pipe (153)						
20	Line Pipe Fittings (154)						
21	Pipeline Construction (155)						
22	Buildings (156)						
23	Boilers (157)						
24	Pumping Equipment (158)						
25	Machine Tools and Machinery (159)						
26	Other Station Equipment (160)						
27	Oil Tanks (161)						
28	Delivery Facilities (162)						
29	Communication Systems (163)						
30	Office Furniture and Equip. (164)						
31	Vehicles and Other Work Equip. (165)						
32	Other Property (166)						
33	Asset Retirement Costs for Trunk Lines (167)						
34	TOTAL (Lines 18 thru 33)						
	GENERAL						
35	Buildings (176)						
36	Machine Tools and Machinery (179)						
37	Communication Systems (183)						
38	Office Furniture and Equip. (184)						
39	Vehicles and Other Work Equip. (185)						
40	Other Property (186)						
41	Asset Retirement Costs for General Property (186.1)						
42	TOTAL (Lines 35 thru 41)						
43	GRAND TOTAL *(Lines 17, 34, 42)*						

19698 Federal Register / Vol. 68, No. 76 / Monday, April 21, 2003 / Rules and Regulations

Appendix C Revised Schedules for FERC Forms 1, 1-F, 2, 2-A, and 6 -157-

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 20___

AMORTIZATION BASE AND RESERVE

1.) Enter in columns (b) thru (e) the cost of pipeline property used as the base in computing amortization charges included in Account 540, *Depreciation and Amortization*, and Account 541, *Depreciation Expense for Asset Retirement Costs* of the accounting company.
2.) Enter in columns (f) thru (i) the balances at the beginning and end of the year and the total credits and debits during the year in Account No. 32, *Accrued Amortization - Carrier Property*.
3.) The information requested for columns (b) thru (i) may be shown by projects or for totals only.
4.) If reporting by project, briefly describe in a foot-

Line No.	Items (a)	BASE (540 and 541) Balance at Beginning of Year (In dollars) (b)	Debits During Year (In dollars) (c)	Credits During Year (In dollars) (d)	Balance at End of Year (In dollars) (e)
1					
2					
3					
4					
5					
6					
7					
8					
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11					
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44					
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46					
47	TOTAL				

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 20___

AMORTIZATION BASE AND RESERVE (Continued)

note each project amounting to $100,000 or more. Reference the kind of property reported, do not include location. Items less than $100,000 may be combined in a single entry titled Minor items, each less than $100,000.
5.) If the amounts in column (g) do not correspond to the amounts actually charged to Account No. 540 and/or 541, explain such differences in a footnote.
6.) Explain in a footnote adjustments included in column (h) that affect operating expenses.

RESERVE (32)				
Balance at Beginning of Year (in dollars) (f)	Credits During Year (in dollars) (g)	Debits During Year (in dollars) (h)	Balance at End of Year (in dollars) (i)	Line No.
				1
				2
				3
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Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 20___

OPERATING EXPENSE ACCOUNTS (Account 610)

Report the respondent's pipeline operating expenses for the year, classifying them in accordance with the USofA.

Line No.	Operating Expense Accounts	CRUDE OIL (In dollars)			
	(a)	Gathering (b)	Trunk (c)	Delivery (d)	Total (b + c + d) (e)
	OPERATIONS and MAINTENANCE				
1	Salaries and Wages (300)				
2	Materials and Supplies (310)				
3	Outside Services (320)				
4	Operating Fuel and Power (330)				
5	Oil Losses and Shortages (340)				
6	Rentals (350)				
7	Other Expenses (390)				
8	TOTAL Operations and Maintenance Expenses				
	GENERAL				
9	Salaries and Wages (500)				
10	Materials and Supplies (510)				
11	Outside Services (520)				
12	Rentals (530)				
13	Depreciation and Amortization (540)				
14	Depreciation Expense for Asset Retirement Costs (541)				
15	Employee Benefits (550)				
16	Insurance (560)				
17	Casualty and Other Losses (570)				
18	Pipeline Taxes (580)				
19	Other Expenses (590)				
20	Accretion Expense (591)				
21	Gains or losses on Asset Retirement Obligations (592)				
22	TOTAL General Expenses				
23	GRAND TOTALS				

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report Dec. 31, 20___

OPERATING EXPENSE ACCOUNTS (Continued)

Line No.	Products (in dollars)			
	Trunk (f)	Delivery (g)	Total (f+g) (h)	Grand Total (e+h) (I)
1				
2				
3				
4				
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[FR Doc. 03–9260 Filed 4–18–03; 8:45 am]
BILLING CODE 6717–01–C

MEMORANDUM

TO: Shannon Charnas
Sara Wiseman -- E.ON U.S. Accounting Dept

COPY: Patricia Leenerts

FROM: John Fendig -- E.ON U.S. Law Dept.

DATE: January 16, 2006

SUBJECT: FASB Financial Interpretation No. 47

This memorandum provides initial legal input in connection with LG&E Energy LLC's and subsidiaries' (collectively "LEL's") analysis and implementation of FASB Financial Interpretation No. 47 (March 2005). Reference is also made to the EEI/AGA Industry White Paper (July 2005) regarding FIN 47.

This memorandum also makes reference to the earlier legal memorandum (March 18, 2003) delivered in connection with LEL's original analysis and implementation of FASB SFAS 143 during 2002-2003.

The analysis and conclusions hereunder are provided solely for the purposes of SFAS 143 and FIN 47 and related uses, should not be deemed binding or conclusive for any other purpose and are not intended to constitute a waiver of right or admission against interest in any other context.

COAL DOCKS

Western Kentucky Energy "Sebree or Energy" Dock -- It was previously determined that a legal obligation exists due to the lease with Powell Holdings, as well as under the Kentucky Division of Water, Coast Guard and Army Corps of Engineers permits.

No change is proposed in this analysis. This legal obligation suggests that an ARO should be established.

LG&E and KU Coal Docks -- Coal docks exist on navigable waterways at a number of LG&E and KU plants, including Mill Creek, Trimble County and Ghent. After reasonable inquiry to line-of-business and shared-service departments which may have historical information or documents, we are unable to locate definitive data (ground leases, permits, etc.) or applicable rules (USCG, ACOE, etc.) positively indicating any legal obligations exist upon non-use. Due to this fact, it is appropriate to conclude that no known legal obligation exists.

(At appropriate times, we will continue our investigation on this issue and, if and when, any indications of legal obligations are found, we will so report.)

BRIDGES AND TUNNELS

It was previously determined that state and federal regulation generally imposes discretionary, rather than obligatory remediation requirements upon abandonment. That is, the state or federal regulator may require removal or other remediation, at its option, but equally might not.

Due to this substantial uncertainty as to fact or type of remediation, it is reasonable to state that no current legal obligation exists.

GAS STORAGE WELLS AND PIPES

Prior analysis indicates that legal obligations exist due to state and federal regulations requiring purging and capping (sealing) of abandoned gas pipes and plugging of wells.

No change is proposed in this analysis. This legal obligation suggests that an ARO should be established.

GAS STORAGE COMPRESSOR STATIONS

Prior analysis indicates that (except for the Riggs site), no definitive legal obligation exist upon non-use. The lease forms appear to give LG&E the option, but not the requirement, to remove equipment or simply allow it to become the property of the USA. Regarding a 1 acre portion of the Riggs site, a 1979 letter appears to requires a return to prior condition upon any abandonment. Thus, LG&E should determine what (if any) structures exist upon this parcel and the potential cost for removal, etc..

No change proposed in analysis. The Riggs document indicates a legal obligation for one parcel of our compressor station properties. This legal obligation suggests that an ARO should be established regarding the site on this parcel.

GAS DISTRIBUTION ASSETS
ELECTRIC TRANSMISSION AND DISTRIBUTION ASSETS

Prior analysis indicated that no legal obligations generally existed upon abandonment, other than (a) the purging and capping of gas lines and (b) normal maintenance of unused electric lines. Historically, both of the above have been accounted for as current costs, rather than ARO-type liabilities.

For gas distribution, the purging and capping represents a legal obligation. As these pipes and their retirement may be a "mass asset" or reoccurring event, it may be possible to set up an ARO similar to that of electric poles, using average lifespan or retirement calculations.

For electric transmission and distribution, the maintenance requirement of unused lines is the same as regarding active lines, so this would not constitute a new legal obligation upon retirement.

HYDRO FACILITIES

Prior analysis indicated that although hydro U.S. Army Corps of Engineers permits and FERC licenses do not list or enumerate specific or detailed remediation steps upon abandonment, general regulatory or statutory rules and frameworks, and certain permits, do clearly allow for agencies to require remediation in the discretion of the agency. Thus, legal obligations may and likely do exist. However, due to the uncertainty as to the actual regulatory decisions, if any, upon retirement, it may not be possible to reasonably estimate the settlement periods, methods or costs.

Regarding obligations to private parties, Ohio Falls rests in a public waterway and lands, so no private leases exist. Dix Dam and the resulting lake are on KU-owned property, so no private leases exist. Thus, there are no legal obligations upon retirement due to any contracts with private parties.

WATER PUMP STRUCTURES

Prior analysis focused on the Brown water pump structures, which are located in a lake owned by KU so no legal obligations were found to exist. No change is suggested in this analysis.

Regarding water pump/intake structures which may exist in navigable waterways (Ohio River, Green River, etc.) at other LG&E, KU or WKE sites. After reasonable inquiry to line-of-business and shared-service departments which may have historical information or documents (USCG, ACOE, etc.), we are unable to locate any data positively indicating any legal obligations exist upon non-use. Due to this fact, it is appropriate to conclude that no known legal obligation exists.

(At appropriate times, we will repeat our investigation on this issue and, if and when, any indications of legal obligations are found, we will so report.)

Wiseman, Sara

From: Scott, Valerie
Sent: Wednesday, February 02, 2005 7:42 PM
To: Wiseman, Sara; Strange, Vicki; Conrad, Teresa; Dalton, LaStacia; Williams, Scott; Clark, Lynda; Newton, Gretchen
Cc: Hudson, Rusty; Miller, Ron
Subject: FW: FASB Agenda Discussion - February 2
Attachments: 02-02-05 FASB Handouts.pdf; footer

FYI

Valerie

-----Original Message-----
From: Stringfellow, David [mailto:DStringfellow@eei.org]
Sent: Wednesday, February 02, 2005 5:03 PM
To: Accounting Standards Committee
Subject: FASB Agenda Discussion - February 2

TO: EEI Accounting Standards Committee Members

The Financial Accounting Standards Board had a discussion at today's (February 2) meeting on whether to add a project to its agenda based on the recommendations from the Accounting Standards Executive Committee (AcSEC) that the Board issue some stand alone, near-term guidance on accounting for property, plant, and Equipment (PP&E). The short handout on this Board discussion item is the last page of the attachment.

Specifically the Board was asked to add a project on accounting for planned major maintenance activities. The Board did not agree to add this as an agenda item at today's meeting - but directed the Staff to rescope and redefine the proposed project to ensure that the project is a narrow one and not a project on depreciation. This will be brought back for a discussion and agenda decision at a future Board meeting.

Three other possible topics for inclusion in a property, plant and equipment Board project were presented by the Staff for Board decisions - accounting for rental costs that are incurred during construction, accounting for liquidated damages, and the threshold for beginning to capitalize PP&E. The Board decided not to take up any of those three topics in an accounting for property, plant and equipment project.

David Stringfellow
Edison Electric Institute

Financial Accounting Standards Board

Board Meeting Handout
Fair Value Option
February 2, 2005

The purpose of this meeting is to discuss whether the fair value option project should be expanded to permit entities to elect to recognize the change in fair value attributable to only certain selected risks (rather than the total change in fair value).

As background for today's meeting, the staff will briefly discuss the fundamental objectives of the fair value project, which include the following:

a. To mitigate problems for reported earnings caused by the mixed-attribute model
b. To enable entities to achieve an offset accounting effect for the changes in the fair values of related assets and liabilities without having to apply more complex hedge accounting provisions, thereby providing some simplicity in the accounting guidance for this area
c. To achieve further convergence with the IASB
d. To expand the use of the fair value measurement attribute, particularly for financial instruments.

The Principal Issue

The principal issue to be discussed by the Board at today's meeting is whether the fair value project should be expanded to permit entities to elect (outside of Statement 133's hedge accounting) to recognize in earnings the change in an asset's or liability's fair value attributable to only certain selected risks (rather than the total change in fair value).

A principal advantage of such an expansion would be to enable entities to continue obtaining hedging-like results related to only the designated hedged risks but without all of the complex requirements of Statement 133. Many entities use derivatives to hedge only selected risks under Statement 133, not the risk of total changes in the hedged item's fair value or the hedged transaction's cash flows. They may also use other derivatives and nonderivatives to economically hedge only selected risks. The proposed expansion would enable entities to avoid exposure to volatility in earnings attributable to recognizing the effect of changes in an unhedged risk.

A principal disadvantage of such an expansion would likely be losing this opportunity for simplicity in the accounting guidance through the use of the fair value measurement attribute. It is expected that the proposed expansion of this project to permit recognizing fair value changes attributable to only certain

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The staff prepares Board meeting handouts to facilitate the audience's understanding of the issues to be addressed at the Board meeting. This material is presented for discussion purposes only; it is not intended to reflect the views of the FASB or its staff. Official positions of the FASB are determined only after extensive due process and deliberations.

selected risks will create a less restrictive, effectiveness-test-free approach that would still require resolution of numerous standard-setting and implementation issues. In addition, the proposed expansion would undermine convergence efforts with the IASB because it would expand the differences with international standards because the fair value option for financial instruments in IAS 39, *Financial Instruments: Recognition and Measurement,* uses only the fair value measurement attribute.

Financial Accounting Standards Board

Board Meeting Handout

Potential Statement 133 Implementation Issue No. B38: Evaluation of Net Settlement with Respect to Embedded Prepayment Options in Certain Debt Instruments

February 2, 2005

At the February 2, 2005, Board meeting, the staff will discuss with the Board Statement 133 Implementation Issue No. B38, "Evaluation of Net Settlement with Respect to Embedded Prepayment Options in Certain Debt Instruments" (Issue B38). The objective of this meeting is for the Board to discuss Issue B38 and decide whether the staff should expose the tentative guidance in Implementation Issue B38 for public comment. If the Board decides the staff should expose Implementation Issue B38 for public comment, the Board will also discuss the appropriate transition and effective date guidance.

Background

In accordance with FASB Statement No. 133, *Accounting For Derivative Instruments and Hedging Activities* (as amended), an embedded derivative is required to be bifurcated and accounted for separately as a derivative instrument pursuant to Statement 133 if and only if *all* of the requirements in paragraph 12 are met, as follows:

a. The economic characteristics and risks of the embedded derivative instrument are not clearly and closely related to the economic characteristics and risks of the host contract....

b. The contract ("the hybrid instrument") that embodies both the embedded derivative instrument and the host contract is not remeasured at fair value under otherwise applicable generally accepted accounting principles with changes in fair value reported in earnings as they occur.

c. A separate instrument with the same terms as the embedded derivative instrument would, pursuant to paragraphs 6–11, be a derivative instrument subject to the requirements of this Statement. (The initial net investment

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> for the hybrid instrument shall not be considered to be the initial net investment for the embedded derivative.) However, this criterion is not met if the separate instrument with the same terms as the embedded derivative instrument would be classified as a liability (or an asset in some circumstances) under the provisions of Statement 150 but would be classified in stockholders' equity absent the provisions in Statement 150. [Footnote reference omitted.]

Paragraph 13 of Statement 133 provides guidance as to whether an embedded derivative instrument in which the underlying is an interest rate or interest rate index that alters net interest payments that otherwise would be paid or received on an interest-bearing host contract is considered to be clearly and closely related to the host contract.

Paragraph 9(a) of Statement 133 states, in part:

> Neither party is required to deliver an asset that is associated with the underlying and that has a principal amount, stated amount, face value, number of shares, or other denomination that is equal to the notional amount (or the notional amount plus a premium or minus a discount).

Guidance in Issue B38

Issue B38 provides guidance with respect to the application of paragraph 12(c) to a prepayment option embedded in a debt instrument and focuses specifically on the net settlement criterion in paragraph 9(a). In the assumed situation cited in the question, an analysis under paragraph 12(c) is required because the embedded prepayment option is not considered to be clearly and closely related to the debt host under paragraph 12(a) based on an analysis performed in paragraph 13. The question addressed in Implementation Issue B38 is whether the potential settlement of the debtor's obligation to the creditor that would occur upon exercise of the prepayment option meets the net settlement criterion in paragraph 9(a) of Statement 133. The tentative guidance in Implementation Issue B38 concludes that the potential settlement of the debtor's obligation to the creditor that would occur upon exercise of the prepayment option meets the net settlement criterion in paragraph 9(a). The debtor's settlement of its liability by prepaying the debt should be considered as not involving the delivery of an asset associated with the underlying.

Transition Alternatives

If the Board decides the staff should expose Issue B38 for public comment, there are two alternatives with respect to transition guidance that the staff believes the Board should consider:

Alternative A—Cumulative Effect Adjustment:

Follow the transition guidance in Section II.A of Statement 133 Implementation Issue No. K5, *Transition Provisions for Applying the Guidance in Statement 133 Implementation Issues*, which states (in part):

> An entity that has or has not separately accounted for an embedded derivative in a manner that is different from the requirements of the newly issued cleared implementation guidance should account for the effects of initially complying with that new implementation guidance prospectively, for all existing contracts and future transactions, as of the effective date, except for the existing contracts that qualify for the grandfathering provisions of paragraph 50 that exempt certain hybrid instruments from the embedded derivative provisions of Statement 133 on an all-or-none basis.

Alternative B—Prospective Only:

This guidance should be applicable prospectively to all new or modified instruments, without a cumulative effect adjustment.

Financial Accounting Standards Board

Board Meeting Handout
Agenda Decision: Property, Plant, and Equipment
February 2, 2005

The Board will consider whether to add a project to its agenda based on AcSEC's recommendations that the Board issue certain stand alone, near-term guidance on the accounting for property, plant, and equipment (PP&E). Specifically, the Board will consider the following topics:

(1) Accounting for planned major maintenance activities

(2) Accounting for rental costs that are incurred during construction

(3) Accounting for liquidated damages

(4) The threshold for beginning to capitalize PP&E.

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Wiseman, Sara

From: Scott, Valerie
Sent: Wednesday, March 30, 2005 7:06 PM
To: Charnas, Shannon; Wiseman, Sara
Subject: FW: FASB Interpretation No. 47 Accounting for Conditional Asset Retirement Obligations
Attachments: FIN 47.pdf; footer

Shannon & Sara,

It's finally out! This could be ugly. It requires adoption by 12/31/05 so we are not overdone with time. We need to get on top of this ASAP to figure out how we will identify the affected assets and work with legal, operations and other personnel to determine the removal costs. The calculations should be consistent with the original AROs, but we'll need to verify this point.

The fun continues!

Valerie

-----Original Message-----
From: Stringfellow, David [mailto:DStringfellow@eei.org]
Sent: Wednesday, March 30, 2005 1:33 PM
To: Accounting Standards Committee
Subject: FASB Interpretation No. 47 Accounting for Conditional Asset Retirement Obligations

TO: EEI Accounting Standards Committee Members

The FASB has now issued its Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (attached) . There will be an EEI white paper prepared to help with the implementation of FIN 47. Please let me know if you wish to be a part of the group preparing that white paper.

David Stringfellow
Edison Electric Institute

NO. 266-B | MARCH 2005

Financial Accounting Series

FASB Interpretation No. 47

Accounting for Conditional Asset Retirement Obligations

an interpretation of FASB Statement No. 143

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FASB Interpretation No. 47

Accounting for Conditional Asset Retirement Obligations

an interpretation of FASB Statement No. 143

March 2005

Financial Accounting Standards Board
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Summary

This Interpretation clarifies that the term *conditional asset retirement obligation* as used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations,* refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation should be recognized when incurred—generally upon acquisition, construction, or development and (or) through the normal operation of the asset. Uncertainty about the timing and (or) method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. Statement 143 acknowledges that in some cases, sufficient information may not be available to reasonably estimate the fair value of an asset retirement obligation. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

Reason for Issuing This Interpretation

Diverse accounting practices have developed with respect to the timing of liability recognition for legal obligations associated with the retirement of a tangible long-lived asset when the timing and (or) method of settlement of the obligation are conditional on a future event. For example, some entities recognize the fair value of the obligation prior to the retirement of the asset with the uncertainty about the timing and (or) method of settlement incorporated into the liability's fair value. Other entities recognize the fair value of the obligation only when it is probable the asset will be retired as of a specified date using a specified method or when the asset is actually retired. This Interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the liability's fair value can be reasonably estimated. Questions also arose about when sufficient information may not be available to make a reasonable estimate of the fair value of an asset retirement obligation. This Interpretation clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

How This Interpretation Will Improve Financial Reporting

Application of this Interpretation will result in (a) more consistent recognition of liabilities relating to asset retirement obligations, (b) more information about expected future cash outflows associated with those obligations, and (c) more information about investments in long-lived assets because additional asset retirement costs will be recognized as part of the carrying amounts of the assets.

How the Conclusions in This Interpretation Relate to the Conceptual Framework

FASB Concepts Statement No. 6, *Elements of Financial Statements,* states that "liabilities are probable future sacrifices of economic benefits arising from present obligations of a particular entity to transfer assets or provide services to other entities in the future as a result of past transactions or events." The Board concluded that asset retirement obligations within the scope of Statement 143 that meet the definition of a liability in Concepts Statement 6 should be recognized as a liability at fair value if fair value can be reasonably estimated. The Board believes that when an existing law, regulation, or contract requires an entity to perform an asset retirement activity, an unambiguous requirement to perform the retirement activity exists, even if that activity can be deferred indefinitely. At some point, deferral is no longer possible, because no tangible asset will last forever (except land). Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. The use of an expected value technique to measure the fair value of the liability reflects any uncertainty about the amount and timing of future cash outflows. The clarification of when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation should improve the relevance, reliability, and comparability of the amounts recognized in the financial statements.

The Effective Date of This Interpretation

This Interpretation is effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year enterprises). Retrospective application for interim financial information is permitted but is not required. Early adoption of this Interpretation is encouraged.

FASB Interpretation No. 47

Accounting for Conditional Asset Retirement Obligations

an interpretation of FASB Statement No. 143

March 2005

CONTENTS

FASB Interpretation No. 47

Accounting for Conditional Asset Retirement Obligations

an interpretation of FASB Statement No. 143

March 2005

INTRODUCTION

1. Paragraph 3 of FASB Statement No. 143, *Accounting for Asset Retirement Obligations,* states, "An entity shall recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made."[1] Diverse accounting practices have developed with respect to the timing of liability recognition for legal obligations associated with the retirement of a tangible long-lived asset when the timing and (or) method of settlement are conditional on a future event. For example, some entities recognize the fair value of the obligation prior to the retirement of the asset with the uncertainty about the timing and (or) method of settlement incorporated into the liability's fair value. Other entities recognize the fair value of the obligation only when it is probable the asset will be retired as of a specified date using a specified method or when the asset is actually retired. Questions also arose about when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

INTERPRETATION

2. Statement 143 applies to legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, except as explained in paragraph 17 of that Statement for certain obligations of lessees. The term *retirement*[2] encompasses sale, abandonment, recycling, or disposal in some other manner.

[1][Under Statement 143,] if a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation shall be recognized at the asset's acquisition date as if that obligation were incurred on that date.

[2]In Statement 143, the term *retirement* is defined as the other-than-temporary removal of a long-lived asset from service. The term does not encompass the temporary idling of a long-lived asset.

3. The term *conditional asset retirement obligation* as used in paragraph A23 of Statement 143 refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity shall recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. Statement 143 requires an entity to recognize the fair value of a legal obligation to perform asset retirement activities when the obligation is incurred—generally upon acquisition, construction, or development and (or) through the normal operation of the asset.

4. An entity shall identify all its asset retirement obligations. If an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation, it must recognize a liability at the time the liability is incurred. An asset retirement obligation would be reasonably estimable if (a) it is evident that the fair value of the obligation is embodied in the acquisition price of the asset,[3] (b) an active market exists for the transfer of the obligation, or (c) sufficient information exists to apply an expected present value technique.[4] An expected present value technique incorporates uncertainty about the timing and method of settlement into the fair value measurement. However, in some cases, sufficient information about the timing and (or) method of settlement may not be available to reasonably estimate fair value. Examples 1 and 2 in Appendix A illustrate the application of this Interpretation when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation at the time the obligation is incurred.

5. An entity would have sufficient information to apply an expected present value technique and therefore an asset retirement obligation would be reasonably estimable if either of the following conditions exists:

a. The settlement date and method of settlement for the obligation have been specified by others. For example, the law, regulation, or contract that gives rise to the legal obligation specifies the settlement date and method of settlement. In this situation, the settlement

[3]Paragraph 17 of FASB Concepts Statement No. 7, *Using Cash Flow Information and Present Value in Accounting Measurements,* states, "If a price for an asset or liability or an essentially similar asset or liability can be observed in the marketplace, there is no need to use present value measurements. The marketplace assessment of present value is already embodied in such prices."

[4]If the fair value of the liability cannot be estimated based on the acquisition price or on an observable market price, the entity should apply the present value techniques discussed in paragraphs 39–54 and 75–88 of Concepts Statement 7. Paragraph 5 of this Interpretation discusses those situations in which an entity would have sufficient information to apply an expected present value technique.

date and method of settlement are known and therefore the only uncertainty is whether the obligation will be enforced (that is, whether performance will be required). Uncertainty about whether performance will be required does not defer the recognition of an asset retirement obligation because a legal obligation to stand ready to perform the retirement activities still exists, and it does not prevent the determination of a reasonable estimate of fair value because the only uncertainty is whether performance will be required.[5] In certain cases, determining the settlement date for the obligation that has been specified by others is a matter of judgment that depends on the relevant facts and circumstances.[6]

b. The information is available to reasonably estimate (1) the settlement date or the range of potential settlement dates, (2) the method of settlement or potential methods of settlement,[7] and (3) the probabilities associated with the potential settlement dates and potential methods of settlement.[8] Examples of information that is expected to provide a basis for estimating the potential settlement dates, potential methods of settlement, and the associated probabilities include, but are not limited to, information that is derived from the entity's past practice, industry practice, management's intent, or the asset's

[5]There are two possible outcomes in situations in which the only uncertainty is whether performance will be required—the entity will be required to perform or the entity will not be required to perform. If there is no information about which outcome is more probable, paragraph A23 of Statement 143 requires a 50 percent likelihood for each outcome to be used until additional information is available.

[6]For example, a contract that provides the entity with an ability to extend its term through renewal should be evaluated to determine whether the settlement date should take into consideration renewal periods.

[7]The term *potential methods of settlement* refers to methods of settling the obligation that are currently available to the entity. Therefore, uncertainty about future methods yet to be developed would not prevent the entity from estimating the fair value of the asset retirement obligation.

[8]The entity should have a reasonable basis for assigning probabilities to the potential settlement dates and potential methods of settlement to reasonably estimate the fair value of the asset retirement obligation. If the entity does not have a reasonable basis of assigning probabilities, it is expected that the entity would still be able to reasonably estimate fair value when the range of time over which the entity may settle the obligation is so narrow and (or) the cash flows associated with each potential method of settlement are so similar that assigning probabilities without having a reasonable basis for doing so would not have a material impact on the fair value of the asset retirement obligation.

estimated economic life.[9] In many cases, the determination as to whether the entity has the information to reasonably estimate the fair value of the asset retirement obligation is a matter of judgment that depends on the relevant facts and circumstances.[10]

6. If sufficient information is not available at the time the liability is incurred, paragraph 3 of Statement 143 requires a liability to be recognized initially in the period in which sufficient information becomes available to estimate its fair value. Paragraph 22 of Statement 143 requires that if the liability's fair value cannot be reasonably estimated, that fact and the reasons shall be disclosed. Example 3 in Appendix A illustrates the application of this Interpretation when an entity does not have sufficient information to reasonably estimate the fair value of an asset retirement obligation. Example 4 in Appendix A illustrates the application of this Interpretation when an entity initially does not have sufficient information but later has sufficient information to reasonably estimate the fair value of an asset retirement obligation.

7. Statement 143 provides guidance for adjusting the liability for revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

EFFECTIVE DATE AND TRANSITION

8. This Interpretation shall be effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year enterprises). Retrospective application of interim financial information is permitted but is not required. Early adoption of this Interpretation is encouraged.

9. For amounts recognized upon the initial application of this Interpretation, an entity shall recognize the following items in its statement of financial position: (a) a liability for any existing asset retirement obligation(s) adjusted for cumulative accretion to the date of adoption of this Interpretation, (b) an asset retirement cost capitalized as an increase to the carrying amount of the associated long-lived asset(s), and (c) accumulated depreciation on

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[9]The estimated economic life of the asset might indicate a potential settlement date for the asset retirement obligation. However, the original estimated economic life of the asset may not, in and of itself, establish that date because the entity may intend to make improvements to the asset that could extend the life of the asset or the entity could defer settlement of the obligation beyond the economic life of the asset. In those situations, the entity would look beyond the economic life of the asset in determining the settlement date or range of potential settlement dates to use when estimating the fair value of the asset retirement obligation.

[10]It is expected that the narrower the range of time over which the entity may settle the obligation and the fewer potential methods of settlement the entity has available to it, the more likely it is that the entity will have the information to reasonably estimate the fair value of an asset retirement obligation.

that capitalized cost. Amounts resulting from initial application of this Interpretation shall be measured using current (that is, as of the date of adoption of this Interpretation) information, current assumptions, and current interest rates. The amount recognized as an asset retirement cost shall be measured as of the date the asset retirement obligation was incurred. Cumulative accretion and accumulated depreciation shall be recorded for the time period from the date the liability would have been recognized had the provisions of this Interpretation been in effect when the liability was incurred to the date of adoption of this Interpretation.

10. An entity shall recognize the cumulative effect of initially applying this Interpretation as a change in accounting principle. The amount to be reported as a cumulative-effect adjustment in the statement of operations is the difference between the amounts, if any, recognized in the statement of financial position prior to the application of this Interpretation and the net amount that is recognized in the statement of financial position pursuant to paragraph 9.

11. In addition to disclosures required by paragraphs 19(c), 19(d), and 21 of APB Opinion No. 20, *Accounting Changes,* an entity shall compute on a pro forma basis and disclose in the footnotes to the financial statements for the beginning of the earliest year presented and at the end of all years presented the amount of the liability for asset retirement obligations as if this Interpretation had been applied during all periods affected. The pro forma amounts of that liability shall be measured using the information, assumptions, and interest rates used to measure the obligation recognized upon adoption of this Interpretation.

The provisions of this Interpretation need not be applied to immaterial items.

This Interpretation was adopted by the unanimous vote of the seven members of the Financial Accounting Standards Board:

Robert H. Herz, *Chairman*
George J. Batavick
G. Michael Crooch
Katherine Schipper
Leslie F. Seidman
Edward W. Trott
Donald M. Young

Appendix A

ILLUSTRATIVE EXAMPLES

A1. This appendix includes four examples that illustrate the application of this Interpretation specifically relating to when an entity would be required to recognize the fair value of an asset retirement obligation. The examples do not provide specific guidance for determining when an entity has sufficient information to reasonably estimate the fair value of the asset retirement obligation. The determination as to when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation should be based on the guidance in paragraphs 4 and 5 of this Interpretation. Examples 1 and 2 illustrate the recognition provisions when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation at the time the obligation is incurred. Example 3 illustrates the application of this Interpretation when an entity does not have sufficient information to reasonably estimate the fair value of an asset retirement obligation at the time the obligation is incurred. Example 4 illustrates the recognition provisions when an entity initially does not have sufficient information and later has sufficient information to reasonably estimate the fair value of an asset retirement obligation. The examples illustrate the initial recognition of a conditional asset retirement obligation based on the facts presented. Any differences in facts from those presented in the examples may result in different conclusions.

Example 1

A2. A telecommunications entity owns and operates a communication network that utilizes wood poles that are treated with certain chemicals. There is no legal requirement to remove the poles from the ground. However, the owner may replace the poles periodically for a number of operational reasons. Once the poles are removed from the ground, they may be disposed of, sold, or reused as part of other activities. There is existing legislation that requires special disposal procedures for the poles in the particular state in which the entity operates.

A3. At the date of purchase of the treated poles, the entity has the information to estimate a range of potential settlement dates, the potential methods of settlement, and the probabilities associated with the potential settlement dates and methods based on established industry practice. Therefore, at the date of purchase, the entity is able to estimate the fair value of the liability for the required disposal procedures using an expected present value technique.

A4. Although the timing of the performance of the asset retirement activity is conditional on removing the poles from the ground and disposing of them, existing legislation creates a duty or responsibility for the entity to dispose of the poles in accordance with special procedures, and the obligating event occurs when the entity purchases the treated poles. Although the entity may decide not to remove the poles from the ground or may decide to reuse the poles and thereby defer settlement of the obligation, the ability to defer settlement does not relieve the entity of the obligation. The poles will eventually need to be disposed of using special procedures, because the poles will not last forever. Additionally, the ability of the entity to sell the poles prior to disposal does not relieve the entity of its present duty or responsibility to settle the obligation. The sale of the poles transfers the obligation to another entity. The assumption of the obligation by the buyer affects the exchange price. The bargaining of the exchange price reflects the buyer's and seller's individual estimates of the timing and (or) amount of the cost to extinguish the obligation.

A5. The asset retirement obligation should be recognized when the entity purchases the poles because the entity has sufficient information to estimate the fair value of the asset retirement obligation. Because the legal requirement relates only to the disposal of the treated poles, the cost to remove the poles is not included in the asset retirement obligation. However, if there was a legal requirement to remove the treated poles, the cost of removal would be included.

Example 2

A6. An entity recently purchased several kilns lined with a special type of brick. As of the date of purchase, the kilns had not yet been used in any smelting processes. The kilns have a long useful life, but the bricks are replaced periodically. Because the bricks become contaminated with hazardous chemicals while the kiln is operated, a state law requires that when the bricks are removed, they must be disposed of at a special hazardous waste site. The entity has the information to estimate a range of potential settlement dates, the method of settlement, and the probabilities associated with the potential settlement dates based on its past practice of replacing the bricks to maintain the efficient operation of the kiln. Therefore, at the date the bricks become contaminated because of the operation of the kiln, the entity is able to estimate the fair value of the liability for the required disposal procedures using an expected present value technique.

A7. Although performance of the asset retirement activity is conditional on removing the bricks from the kiln, existing legislation creates a duty or responsibility for the entity to dispose of the bricks at a special hazardous waste site, and the obligating event occurs when the entity contaminates the bricks. As of the purchase date, the kilns have not yet been used in any smelting processes, and the bricks have not yet been contaminated. Therefore, at the date of purchase, no obligation exists because the bricks have not been contaminated and could be disposed of without performing any special disposal activities.

A8. The fair value of the asset retirement obligation should be recognized once the kilns have been placed into operation and the bricks are contaminated. Although the entity may decide not to remove the bricks from the kiln and thereby defer settlement of the obligation, the ability to defer settlement does not relieve the entity of the obligation. The contaminated bricks will eventually need to be removed and disposed of at a special hazardous waste site, because a kiln will not last forever. Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing of settlement. An asset retirement obligation should be recognized once the kilns have been placed into operation and the bricks are contaminated because the entity has sufficient information to estimate the fair value of the asset retirement obligation. The asset retirement obligation is the requirement to dispose of the contaminated bricks at a special hazardous waste site. The cost to remove the bricks is not part of the obligation and should be accounted for as a maintenance or replacement activity.

Example 3

A9. An entity acquires a factory that contains asbestos. After the acquisition date, regulations are put in place that require the entity to handle and dispose of this type of asbestos in a special manner if the factory undergoes major renovations or is demolished. Otherwise, the entity is not required to remove the asbestos from the factory. The entity has several options to retire the factory in the future including demolishing, selling, or abandoning it. The entity believes it does not have sufficient information to estimate the fair value of the asset retirement obligation because the settlement date or the range of potential settlement dates has not been specified by others and information is not available to apply an expected present value technique. For example, there are no plans or expectation of plans to undertake a major renovation that would require removal of the asbestos or demolition of the factory. The factory is expected to be maintained by repairs and maintenance activities that would not involve the removal of the asbestos. Also, the need for major renovations caused by technology changes, operational changes, or other factors has not been identified.

A10. Although the timing of the performance of the asset retirement activity is conditional on the factory undergoing major renovations or being demolished, existing regulations create a duty or responsibility for the entity to remove and dispose of asbestos in a special manner, and the obligating event occurs when the regulations are put in place. Therefore, an asset retirement obligation should be recognized when regulations are put in place if the entity can reasonably estimate the fair value of the liability. In this example, the entity believes that there is an indeterminate settlement date for the asset retirement obligation because the range of time over which the entity may settle the obligation is unknown or cannot be estimated. Therefore, the entity cannot reasonably estimate the fair value of the liability. Accordingly, the entity would not recognize a liability for the asset retirement obligation when regulations are put in place, but it should disclose (a) a description of the obligation, (b) the fact that a liability has not been recognized because the fair value cannot be reasonably estimated, and (c) the reasons why fair value cannot be reasonably estimated. The company would recognize a liability in the period in which sufficient information is available to reasonably estimate its fair value.

Example 4

A11. An entity acquires a factory that contains asbestos. At the acquisition date, regulations are in place that require the entity to handle and dispose of this type of asbestos in a special manner if the factory undergoes major renovations or is demolished. Otherwise, the entity is not required to remove the asbestos from the factory. The entity has several options to retire the factory in the future including demolishing, selling, or abandoning it. At the acquisition date, it is not evident that the fair value of the obligation is embodied in the acquisition price of the factory because both the seller and the buyer of the factory believed the obligation had an indeterminate settlement date, an active market does not exist for the transfer of the obligation, and sufficient information does not exist to apply an expected present value technique. Ten years after the acquisition date, the entity obtains additional information based on changes in demand for the products manufactured at that factory. At that time, the entity has the information to estimate a range of potential settlement dates, the potential methods of settlement, and the probabilities associated with the potential settlement dates and potential methods of settlement. Therefore, at that time the entity is able to estimate the fair value of the liability for the special handling of the asbestos using an expected present value technique.

A12. Although timing of the performance of the asset retirement activity is conditional on the factory undergoing major renovations or being demolished, existing regulations create a duty or responsibility for the entity to remove and dispose of asbestos in a special manner, and the obligating event occurs when the entity acquires the factory.[11] Although the entity may decide to abandon the factory and thereby defer settlement of the obligation for the foreseeable future, the ability to defer settlement does not relieve the entity of the obligation. The asbestos will eventually need to be removed and disposed of in a special manner,

[11] In this example, regulations are in place at the date of acquisition that require the entity to handle and dispose of the asbestos in a special manner. Therefore, the obligating event is the acquisition of the factory. If regulations were enacted after the date of acquisition, the obligating event would be the enactment of the regulations. Refer to Example 3.

because no building will last forever. Additionally, the ability of the entity to sell the factory does not relieve the entity of its present duty or responsibility to settle the obligation. The sale of the asset would transfer the obligation to another entity and that transfer would affect the selling price. Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and method of settlement.

A13. In this example, an asset retirement obligation is not recognized when the entity acquires the factory because the entity does not have sufficient information to estimate the fair value of the obligation. The entity would disclose (a) a description of the obligation, (b) the fact that a liability has not been recognized because the fair value cannot be reasonably estimated, and (c) the reasons why fair value cannot be reasonably estimated. An asset retirement obligation would be recognized by this entity 10 years after the acquisition date because that is when the entity has sufficient information to estimate the fair value of the asset retirement obligation.

Appendix B

BACKGROUND INFORMATION AND BASIS FOR CONCLUSIONS

CONTENTS

Appendix B

BACKGROUND INFORMATION AND BASIS FOR CONCLUSIONS

Introduction

B1. This appendix summarizes considerations that Board members deemed significant in reaching the conclusions in this Interpretation. It includes reasons for accepting certain approaches and rejecting others. Individual Board members gave greater weight to some factors than to others.

Background

B2. Diverse accounting practices have developed with respect to the timing of liability recognition for legal obligations associated with the retirement of a tangible long-lived asset when the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. Some entities recognize the fair value of the obligation prior to the retirement of the asset with the uncertainty about the timing and (or) method of settlement incorporated into the liability's fair value. Other entities recognize the fair value of the obligation only when it is probable the asset will be retired as of a specified date using a specified method or when the asset is actually retired.

B3. The FASB staff issued a proposed FASB Staff Position (FSP) FAS 143-x, "Applicability of FASB Statement No. 143, *Accounting for Asset Retirement Obligations,* to Legislative Requirements on Property Owners to Remove and Dispose of Asbestos or Asbestos-Containing Materials," in July 2003. That proposed FSP concluded:

a. The enactment or existence of asbestos legislation creates a duty or responsibility to remove and dispose of asbestos.
b. If such legislation already exists, the obligating event is the acquisition (or construction) of the asset, or if the asset is owned when that legislation is enacted, then the enactment of the legislation is the obligating event.
c. An entity should recognize a liability for this obligation when the obligating event occurs.

B4. The FASB staff evaluated the comment letters received on that proposed FSP. Because of the diverse views expressed and constituents' concerns that there is a broader issue underlying the issue addressed in the proposed FSP, the FASB staff withdrew that proposed FSP. The FASB staff confirmed the diversity in practice with a questionnaire to selected constituents. Because of the diversity in practice and constituents' concern about the broader nature of this issue, the Board added a project to its agenda to address the issue of whether Statement 143 requires an entity to recognize a liability for a legal obligation to perform asset retirement activities when the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity and, if so, the timing of that recognition.

B5. On June 17, 2004, the Board issued an Exposure Draft, *Accounting for Conditional Asset Retirement Obligations*. The Board received 34 comment letters on the Exposure Draft. The Board considered all comments and concerns raised by respondents and constituents during its redeliberations of the issues addressed by the Exposure Draft in a public meeting in August 2004. This Interpretation reflects the results of those deliberations. The Board received comments requesting that the Board reconsider Statement 143 in its entirety. At a public meeting in January 2005, the Board decided not to reconsider Statement 143. The Board decided to provide additional guidance for evaluating whether sufficient information is available to reasonably estimate the fair value of an asset retirement obligation.

Objective of This Interpretation

B6. The objective of this Interpretation is to clarify that the term *conditional asset retirement obligation* as used in Statement 143 refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. In this situation, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Accordingly, an entity should recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the fair value of the liability can be reasonably estimated. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

Scope

B7. Statement 143 applies to legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, except as explained in paragraph 17 of Statement 143. As used in Statement 143, a legal obligation is an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. As discussed in paragraphs A2–A5 of Statement 143, whether a legal obligation exists will usually be unambiguous. However, questions arose about whether a liability should be recognized when a legal obligation exists but the timing and (or) method of settlement are conditional on future events. Based on diversity in practice and the broad nature of this issue, the Board decided that this Interpretation should apply to all entities that have legal obligations to perform asset retirement activities in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity.

B8. During the redeliberations of this Interpretation, questions also arose about when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. Paragraph A20 of Statement 143 states that "it is expected that uncertainties about the amount and timing of future cash flows can be accommodated by using the expected cash flow technique and therefore will not prevent the determination of a reasonable estimate of fair value." Some constituents believe paragraph A20 contradicts paragraph 3 of Statement 143, which states that "if a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of fair value can be made." As a result, the Board decided that this Interpretation should clarify that uncertainties about the amount and timing of future cash flows can be accommodated by using the expected cash flow technique when sufficient information exists. The Board decided to provide additional guidance in this Interpretation for evaluating whether sufficient information is available to reasonably estimate the fair value of an asset retirement obligation.

Recognition of a Liability for a Conditional Asset Retirement Obligation

Characteristics of a Liability

B9. FASB Concepts Statement No. 6, *Elements of Financial Statements,* defines *liabilities* as "probable future sacrifices of economic benefits arising from present obligations of a particular entity to transfer assets or provide services to other entities in the future as a result of past transactions or events." *Probable* is used with its usual general meaning, rather than in a specific accounting or technical sense (such as that in FASB Statement No. 5, *Accounting for Contingencies*), and refers to that which can reasonably be expected or believed on the basis of available evidence or logic but is neither certain nor proved. Its inclusion in the definition is intended to acknowledge that business and other economic activities occur in an environment characterized by uncertainty. The Board concluded that all asset retirement obligations within the scope of Statement 143 that meet the definition of a liability in Concepts Statement 6 should be recognized as liabilities if the fair value of the liabilities can be reasonably estimated.

B10. Concepts Statement 6 states that a liability has three essential characteristics. The first characteristic of a liability is that an entity has a present duty or responsibility to one or more other entities that entails settlement by probable future transfer or use of assets at a specified or determinable date, on occurrence of a specified event, or on demand. A duty or responsibility becomes a present duty or responsibility when an obligating event occurs that leaves the entity little or no discretion to avoid a future transfer or use of assets. A present duty or responsibility does not mean that the obligation must be satisfied immediately. Rather, if events or circumstances have occurred that give an entity little or no discretion to avoid a future transfer or use of assets, that entity has a present duty or responsibility. If an entity is required by current laws, regulations, or contracts to settle an asset retirement obligation upon retirement of the asset, that requirement imposes a present duty.

B11. The second characteristic of a liability is that the duty or responsibility obligates a particular entity, leaving it little or no discretion to avoid the future sacrifice. The ability of an entity to indefinitely defer settlement of an asset retirement obligation does not provide the entity discretion to avoid the future sacrifice, nor does it relieve the entity of the obligation. Implicit in this conclusion is the belief that no tangible asset will last forever (except land) and, accordingly, the asset retirement activities will eventually be performed. Furthermore, the ability of an entity to sell the asset prior to its disposal does not relieve the entity of its present duty or responsibility to settle the obligation. In paragraph B47 of Statement 143, the Board noted that "if the asset for which there is an associated asset retirement obligation were to be sold, the price a buyer would consent to pay for that asset would reflect an estimate of the fair value of the asset retirement obligation. Because that asset retirement obligation meets the definition of a liability, however, the Board believes that reporting it as a liability with a corresponding increase in the carrying amount of the asset for the asset retirement costs, which has the same net effect as incorporating the fair value of the costs to settle the liability in the valuation of the asset, is more representationally faithful and in concert with Concepts Statement 6."

B12. The third characteristic of a liability is that the event obligating the entity has already occurred. The definition of a liability distinguishes between present obligations and future obligations. Only present obligations are liabilities under the definition, and they are liabilities of a particular entity as a result of the occurrence of transactions or other events affecting the entity. Identifying the obligating event may be difficult in situations that involve a series of transactions or other events affecting the entity. For example, in the case of an asset retirement obligation, a law or an entity's promise may create a duty or responsibility, but that law or promise in and of itself may not be the obligating event that results in an entity having little or no discretion to avoid a future transfer or use of assets. Statement 143 states that the obligating event is the acquisition, construction, or development and (or) the normal operation of the long-lived asset when a law or promise exists that creates a duty or responsibility relating to the retirement of the asset. At this point, the obligation cannot be realistically avoided if the asset is operated for its intended use. The obligating event does not depend on the ultimate retirement of the asset.

B13. A number of respondents to the Exposure Draft questioned the view that conditional asset retirement obligations require "probable future sacrifices of economic benefits." Although Concepts Statement 6 does not use the Statement 5 definition of probable in its definition of a liability (as discussed in paragraph 5 of Statement 143), these respondents suggested that a Statement 5 definition be used for evaluating when an asset retirement obligation should be recognized. The Board considered this issue in both its deliberations and its redeliberations of Statement 143 and decided not to use the Statement 5 definition for the same reasons discussed in paragraph B17 of this Interpretation. In addition, in developing Statement 143, the Board decided that incorporating uncertainty in the measurement attribute (fair value) results in higher quality financial reporting than incorporating uncertainty into the timing of the recognition of the asset retirement obligation, if sufficient information exists to develop a reasonable estimate of fair value.

B14. Other respondents suggested that the obligating event, and therefore the recognition of a conditional asset retirement obligation, occurs when a decision or event provides more certainty about the timing and method of settlement of the obligation. In deliberating Statement 143, the Board considered the following alternatives for the obligating event: (a) the existence of law or an entity's promise to do something, (b) the creation of the situation that the law or promise relates to (for example, contamination or acquisition of the asset), and (c) events that would trigger the settlement of the obligation (for example, demolishment). The Board decided that the existence of a law or promise, combined with the creation of the situation that the law or promise relates to, provides the obligating event as described in paragraph B31 of Statement 143. Thus, if sufficient information exists, any uncertainty about the timing of the event that would trigger the settlement of the obligation should affect the measurement of the liability rather than the timing of recognition of the obligation. Although the timing and (or) method of settlement of the asset retirement obligation may depend on events that will occur after the obligating event has occurred, an obligation still exists. Therefore, conditional asset retirement obligations are within the scope of Statement 143 as discussed in paragraphs A17 and A18 of Statement 143, and a liability must be recognized before the event that requires performance occurs. This Interpretation clarifies that point.

Uncertainty and the Fair Value Measurement Objective

B15. This Interpretation is consistent with the fair value measurement objective of Statement 143. During the deliberations of Statement 143, the Board concluded that the initial measurement objective for an asset retirement obligation is fair value. The Board acknowledged that liability recognition under a fair value measurement objective differs from recognition under Statement 5, which requires an entity to consider uncertainty in its determination of whether to recognize a liability. In contrast, Statement 143 requires an entity to consider uncertainty in its fair value measurement of the liability when sufficient information exists to develop a reasonable estimate. Because of the Board's decision that the initial measurement objective is fair value and, therefore, uncertainty is considered in the measurement of the liability, the guidance in Statement 5 is not applicable.

B16. To assist in understanding the differences between the fair value approach and the Statement 5 approach, the Board provided the following explanation in paragraph B36 of Statement 143:

> The objective of recognizing the fair value of an asset retirement obligation will result in recognition of some asset retirement obligations for which the likelihood of future settlement, although more than zero, is less than probable from a Statement 5 perspective. A third party would charge a price to assume an uncertain liability even though the likelihood of a future sacrifice is less than probable. . . . Thus, this Statement does not retain the criterion . . . that a future transfer of assets associated with the obligation is probable for recognition purposes. [Footnote reference omitted.]

B17. Additionally, the Board specifically addressed conditional obligations in paragraph A17 of the implementation guidance for Statement 143 and concluded, consistent with the fair value measurement objective, that an entity should recognize a liability for a legal obligation to perform asset retirement activities in which the timing and (or) method of settlement are conditional on a future event. The implementation guidance for Statement 143 also provides an example in which a third party has the right to require an entity to perform asset retirement activities; however, uncertainty exists as to whether the third party will require performance. Some have interpreted that example to mean that the Board intended for conditional obligations to be recognized only when a third party could require performance, not when the timing and method of settlement are at least partly under the control of the entity. However, the Board concluded that although the timing and method of settlement of the retirement obligation may depend on future events that may or may not be within the control of the entity, a legal obligation to stand ready to perform retirement activities still exists. The entity should consider the uncertainty about the timing and method of settlement in the measurement of the liability, consistent with a fair value measurement objective, regardless of whether the event that will trigger the settlement is partially or wholly under the control of the entity.

B18. A number of respondents questioned why the Board believes that financial reporting is improved by incorporating uncertainty in measurement by recording the liability initially at fair value, rather than by using as the recognition trigger a high probability that a transfer or use of assets will occur, combined with the ability to measure the ultimate settlement amount of the retirement obligation. Fair value is not an estimate of the ultimate settlement amount or the present value of an estimate of the ultimate settlement amount. Paragraph 7 of Statement 143 states that "the fair value of a liability for an asset retirement obligation is the amount at which that liability could be settled in a current transaction between willing parties, that is, other than in a forced or liquidation transaction." Fair value reflects uncertainty, as of the initial recognition date, about the timing, method, and ultimate amount of the asset retirement settlement. A single best estimate of the settlement outcome, or the bottom of a range of possible ultimate settlement outcomes as required by Statement 5 and FASB Interpretation No. 14, *Reasonable Estimation of the Amount of a Loss,* does not reflect that uncertainty. Using a higher level of certainty as to the ultimate settlement amount as a trigger for recognition in the balance sheet (and consequently in the income statement) would delay recognition of the asset retirement obligation, and thereby reduce the information content of the financial statements. Uncertainty about the timing and method of settling the existing obligation is information that should be reflected in the amounts recognized in the financial statements. In developing Statement 143, the Board concluded that not recognizing the liability and providing the Statement 5 disclosures for a contingent loss is not an adequate substitute for recognizing the fair value of the obligation.

Uncertainty about the Timing and Method of Settlement

B19. Some respondents to the Exposure Draft of Statement 143 questioned whether asset retirement obligations with indeterminate settlement dates or asset retirement obligations with multiple methods of settlement are within the scope of the Statement. In developing Statement 143, the Board decided that uncertainty about the timing and (or) method of settlement does not change the fact that an entity has a legal obligation. The Board acknowledged in paragraph A16 of Statement 143 that measurement of an existing obligation might not be possible if insufficient information exists about the timing and method of settlement of that obligation. However, information about the timing and method of settlement of an asset retirement obligation will become available as time goes by. The Board decided that an entity should measure and recognize the fair value of an asset retirement obligation when enough information is available to develop assumptions about the potential timing and amounts of cash flows.

B20. Some respondents to the Exposure Draft of the Interpretation requested specific criteria for determining when it would not be possible to reasonably estimate the fair value of an asset retirement obligation. The Board decided to provide general guidelines rather than specific criteria because the determination of whether a reasonable estimate can be made is a matter of judgment. Additionally, each situation is unique and providing specific criteria would not encompass all possible situations. The Board discussed situations that might lead to a conclusion that sufficient information does not exist to estimate the fair value of an asset retirement obligation.

B21. The Board believes that an entity would have sufficient information to apply a present value technique if the timing and method of settlement are specified by others. In these situations, the only uncertainty is whether performance will be required. As explained in paragraphs A17 and A18 of Statement 143, uncertainty about whether performance will be required does not defer the recognition of an asset retirement obligation because a legal obligation to stand ready to perform the retirement activities still exists, and that uncertainty does not prevent the determination of a reasonable estimate of fair value.

B22. For situations where the timing and method of settlement are not specified by others, the Board decided that an asset retirement obligation would be reasonably estimable if information is available to estimate the settlement date or the range of potential settlement dates, the method of settlement or potential methods of settlement, and the probabilities associated with the potential settlement dates and methods of settlement. Judgment is involved in determining whether uncertainties about the timing and method of settlement would prevent an entity from reasonably estimating the fair value of an asset retirement obligation. The Board believes that uncertainty about future methods of settlement that have yet to be developed should not prevent an entity from reasonably estimating fair value because methods may change as time goes by. The Board does not believe it is appropriate to delay recognition until all potential methods of settlement are known. This Interpretation provides examples of information (some of which are based on entity-specific assumptions) that is expected to provide a basis for forming expectations about the potential settlement dates, potential methods of settlement, and associated probabilities. The Board believes that entity-specific assumptions may be used in the absence of information that a marketplace participant would use about the timing and method of settlement of the asset retirement obligation as long as no contrary data indicates that marketplace participants would use different assumptions. If such data exist, the entity must adjust its assumptions to incorporate that market information.

B23. The Board also discussed whether sufficient information might not be available to estimate a range of potential cash flows associated with the potential methods of settlement that are currently available to the entity. The Board concluded that an entity would generally have the ability to estimate a range of potential cash flows based on the current costs to perform the asset retirement activities under different methods of settlement that are currently available to the entity.

B24. Some respondents to FSP FAS 143-x questioned whether an obligation to perform asset retirement activities is within the scope of Statement 143 if an entity has alternatives to retiring the asset without settling the obligation. This Interpretation reiterates the conclusions reached during the deliberations of Statement 143:

> . . . an unambiguous requirement that gives rise to an asset retirement obligation coupled with a low likelihood of required performance still requires recognition of a liability. Uncertainty about the conditional outcome of the obligation is incorporated into the measurement of the fair value of that liability, not the recognition decision. [Statement 143, paragraph A24]

The Board believes that if a current law, regulation, or contract requires an entity to perform an asset retirement activity when an asset is dismantled or demolished, there is an unambiguous requirement to perform the retirement activity even if that activity can be indefinitely deferred. At some time deferral will no longer be possible, because no tangible asset will last forever (except land). Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement.

B25. If an entity entered into a contract to pay another entity to assume the asset retirement obligation, there would be little dispute that the contract provides the measurement of the obligation that should be reported in the financial statements, even if the cash payment to the other entity had not been made at the reporting date. Also, the amount demanded by the other entity would incorporate uncertainty about the timing, method, and ultimate amount of the settlement. Statement 143 requires that the asset retirement obligation be recognized and measured in the financial statements using the perspective of participants currently negotiating such a hypothetical contract.

B26. A number of respondents stated that an entity should recognize a liability for a legal obligation when it can reasonably estimate the fair value of the asset retirement obligation and that fair value cannot be reasonably estimated unless it is probable the entity will have to perform the asset retirement activities as of a specific time. The Board believes that an inability to reasonably estimate the fair value of the liability is a measurement issue rather than a recognition issue. When there is an unambiguous requirement to perform asset retirement activities upon the removal of a long-lived asset from service, an asset retirement obligation exists.

B27. As stated in paragraph B19 of Statement 143, the Board decided that asset retirement obligations with indeterminate settlement dates should be included within the scope of Statement 143. Uncertainty about the timing of the settlement date does not change the fact that an entity has a legal obligation. The Board acknowledged that although there is an obligation, measurement of that obligation might not be possible if insufficient information exists about the timing of settlement. However, information about the timing of the settlement of a retirement obligation will become available as time goes by. The Board decided that an entity should measure and recognize the fair value of an obligation when information is available to develop various assumptions about the potential timing of cash flows.

Effective Date and Transition

B28. The Board decided that this Interpretation should be effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year enterprises). The Board considered four alternatives for the effective date of this Interpretation. The three other alternatives were for financial statements issued for fiscal years (a) ending after December 15, 2004, (b) beginning after December 15, 2004, and (c) beginning after December 15, 2005. During its deliberations of the effective date requirements, the Board weighed the need to provide entities with sufficient time to make the necessary measurements with the need to provide investors, creditors, and others with information that is relevant to the assessment of the effects of asset retirement obligations.

B29. Some respondents expressed concern over the effective date requirements in the Exposure Draft. Specifically, they stated that retrospective application promotes inconsistent treatment of interim financial information. The Board agreed with those respondents and decided to permit, but not require, retrospective application of interim financial information during any period of adoption. Early adoption of the Interpretation is encouraged.

B30. While deliberating the transition provisions for Statement 143, the Board reasoned that although some entities may have access to data and assumptions related to measurements that are already being made (for example, under the provisions of FASB Statement No. 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*), they may not have access to sufficient information to retroactively apply the fair value measurement approach required by Statement 143. Furthermore, while deliberating the transition provisions for this Interpretation, the Board acknowledged that some entities that are required to apply the provisions of Statement 143 have not been accounting for conditional asset retirement obligations. The Board concluded that it would be costly and difficult, if not impossible, to reconstruct historical data and assumptions without incorporating the benefit of hindsight.

B31. The Board decided that the provisions for recognition of transition amounts of this Interpretation should be consistent with the recognition provisions of Statement 143. While deliberating the transition provisions for Statement 143, the Board discussed whether a cumulative-effect approach and retrospective application provide equally useful financial statement information. The Board acknowledged that retrospective application would provide more useful information because prior-period balance sheet amounts and prior-period income statement amounts would be restated to reflect the provisions of Statement 143. However, during the deliberations of Statement 143, some rate-regulated entities expressed concern that if retrospective application resulted in recognition of additional expenses in prior periods, those expenses might not be recovered in current or future rates. The Board decided for this Interpretation that a cumulative-effect approach would provide sufficient information if, in addition to disclosing the pro forma income statement amounts, an entity also disclosed on a pro forma basis, for the beginning of the earliest year presented and for the ends of all years presented, the balance sheet amounts for the liability for asset retirement obligations as if this Interpretation had been applied during all periods affected.

Benefits and Costs

B32. The mission of the FASB is to establish and improve standards of financial accounting and reporting for the guidance and education of the public, including preparers, auditors, and users of financial information. In fulfilling that mission, the Board endeavors to determine that a standard will fill a significant need and that the costs imposed to apply that standard, as compared with other alternatives, are justified in relation to the overall benefits of the resulting information. Although the costs to implement a new standard may not be borne evenly, investors and creditors—both present and potential—and other users of financial information benefit from improvements in financial reporting, thereby facilitating the functioning of markets for capital and credit and the efficient allocation of resources in the economy.

B33. The Board's assessment of the benefits and costs of clarifying Statement 143 was based on discussions with preparers and auditors of financial statements and on consideration of the needs of users for more consistent application of that Statement. The Board acknowledges that this Interpretation may increase the costs of applying Statement 143. The expected benefit of this Interpretation is improved financial reporting resulting from a more consistent application of Statement 143 to conditional asset retirement obligations. Financial statements of different entities will be more comparable because all asset retirement obligations that are within the scope of this Interpretation and their related asset retirement costs will be recognized using a clearer threshold. Asset retirement obligations in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity will be recognized as liabilities when they are incurred if the fair value of the liabilities can be reasonably estimated. Application of this Interpretation will result in (a) more consistent recognition of liabilities for asset retirement obligations, (b) more information about expected future cash outflows associated with those obligations, and (c) more information about investments in long-lived assets because additional asset retirement costs will be recognized as part of the carrying amounts of the assets.

Wiseman, Sara

From: Valliere, Julia [JValliere@eei.org]

Sent: Friday, April 01, 2005 2:47 PM

To: alina.rocha@pseg.com; andy.krebs@pgnmail.com; avaske@atcllc.com; bdoble@nevp.com; betty.mincer@conectiv.com; bruce.bollert@pse.com; bruce.friedman@peco-energy.com; bullerja@oge.com; cappiellope@coned.com; catherine.mueller@avistacorp.com; cbillingsley@tnpe.com; cindy.perdue@cleco.com; cindy.reed@aquila.com; cjcounci@duke-energy.com; cneff@itctransco.com; cscheafnocker@ameren.com; daniel.reardon@northwestern.com; daniel.zielezinski@exeloncorp.com; darren.zurawski@exeloncorp.com; dcoit@empiredistrict.com; demiller@midamerican.com; devavold@otpco.com; dlblaloc@southernco.com; dlkutsunis@midamerican.com; dlwilker@southernco.com; duncams@nu.com; durban@epcor.ca; eortlieb@cenhud.com; everett_lawrence@illinoispower.com; fstibor@itctransco.com; jadupree@pepco.com; jcarpen@pnm.com; jeff_beasley@wr.com; jehenderson@aep.com; jfrelic@wpsr.com; jhjenson@mge.com; jpnitsche@pplweb.com; jvalliere@eei.org; jxjackso@southernco.com; kemcdani@southernco.com; kenmenge@alliant-energy.com; laura.rockenberger@aps.com; lawrence_poore@nstaronline.com; ldabell@entergy.com; leonard.a.delozier@bge.com; lhancock@epelectric.com; lisa.h.perkett@xcelenergy.com; ltuckness@idahopower.com; mdonahue@mnpower.com; michelle.koyanagi@heco.com; mpenn@wpsr.com; mrizk@cvps.com; paul.bienek@mdu.com; pgillam@entergy.com; pgrant@blackhillspower.com; plaub@cinergy.com; pmfitzgerald@cmsenergy.com; rawalker@tecoenergy.com; rhansen@otpco.com; rick.baldauf@we-energies.com; rob.pierce@sce.com; robert.pontau@energyeast.com; robin.hettrick@uinet.com; Wiseman, Sara; skramer@duqlight.com; stackjp@nu.com; steven.peters@kcpl.com; throbke@wcnoc.com; tlsimons@cmsenergy.com; tony_cuba@fpl.com; tschad@gpu.com; wftyson@southernco.com

Cc: Seeholzer, Ronald; Stringfellow, David

Subject: FASB Interpretation No. 47 - an Interpretation of FASB Statement No. 143

Attachments: FIN 47.pdf

TO: EEI Property Accounting & Valuation, EEI Corporate Accounting & EEI Budgeting & Financial Forecasting Committee

This week, FASB released the long-anticipated FIN 47 - Accounting for Conditional Asset Retirement Obligations - an Interpretation of FASB Statement No. 143. The document is attached for your review.

EEI is planning on analyzing the Interpretation and developing a White Paper that will, in effect, "interpret the Interpretation" similar to the White Paper developed in 2002 when Statement No. 143 was released. We hope the paper will be available in mid-May.

Please let me know if you have any questions.

Julia Valliere
Senior Industry Accounting Analyst
Edison Electric Institute
701 Pennsylvania Avenue N.W.
Washington, DC 20004
(202) 508-5449
(202) 508-5542 FAX
jvalliere@eei.org

Wiseman, Sara

From: Scott, Valerie
Sent: Tuesday, April 19, 2005 2:44 PM
To: Wiseman, Sara; Charnas, Shannon
Subject: FW: May 10 Accounting for Conditional Asset Retirement Obligations E-Forum

fyi

Valerie

From: bounce-asc-175405@ls.eei.org [mailto:bounce-asc-175405@ls.eei.org] **On Behalf Of** Stringfellow, David
Sent: Tuesday, April 19, 2005 2:06 PM
To: Accounting Standards Committee
Subject: May 10 Accounting for Conditional Asset Retirement Obligations E-Forum

Announcing an E-Forum on
Accounting for Conditional
Asset Retirement Obligations

Edison Electric Institute (EEI) and American Gas Association (AGA) are presenting a special E-Forum to cover the Financial Accounting Standards Board's new Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No 143.

When: Tuesday, May 10, 1:00 to 2:00 p.m. Eastern Daylight Time.

Speaker: Casey Herman, Partner, PricewaterhouseCoopers LLP, Accounting and Auditing Leader in PricewaterhouseCoopers' Utilities Practice

Participants may receive 1 continuing professional education (CPE) credit for this seminar.

Details on the E-Forum are available at
http://www.eei.org/meetings/nonav_2005-05-10-ds/index.htm

David Stringfellow
Director, Accounting
Edison Electric Institute
202/508-5494
e-mail: dstringfellow@eei.org

You are currently subscribed to asc as: [valerie.scott@lgeenergy.com]
To unsubscribe, forward this message to leave-asc-175405J@ls.eei.org

Wiseman, Sara

From: King, Kim [KKing@eei.org]

Sent: Friday, May 06, 2005 4:12 PM

To: mary.harms@wecacct.com; thomas.barina@we-energies.com; Wiseman, Sara; amount1@entergy.com; amox@alleghenyenergy.com; amy.sheppard@cinergy.com; amy_leong@transcanada.com; aschick@wpsr.com; brett.ritchie@cinergy.com; bullerja@oge.com; cathy.muszynski@xcelenergy.com; cjcounci@duke-energy.com; daniel_delmonte@nstaronline.com; derek.dirisio@pseg.com; dljacobs@duke-energy.com; dlwilker@southernco.com; frank.stanbrough@swgas.com; gmcnall@nicor.com; howard_lyon@rgcresources.com; jan_anderson@cmsenergy.com; jdwiles@duke-energy.com; jgwolfe@southernco.com; jharold@nisource.com; jjhodnet@southernco.com; jlegge@otpco.com; jon.veurink@exeloncorp.com; jrobbins@aeci.org; k_taggart@wfec.com; kendall.kliewer@northwestern.com; kent.ipson@pacificorp.com; laura.rockenberger@aps.com; laurafow@yahoo.com; lcsa@pge.com; lee_wages@wr.com; lisa.h.perkett@xcelenergy.com; lori.wright@kcpl.com; lswilson@firstenergycorp.com; lyle.geiger@sce.com; mark.j.kunkel@constellation.com; marzena.walker@exeloncorp.com; matthew.giesecke@exeloncorp.com; mloughan@cvps.com; mlyons@ameren.com; pat.cass@ey.com; patsy.nanbu@heco.com; pfarr@pplweb.com; ricciardik@coned.com; roy.centrella@swgas.com; rrtunning@midamerican.com; srinivasan.sridharan@pseg.com; sszlaud1@txu.com; stacy.stubbs@cleco.com; steendw@yahoo.com

Cc: Stringfellow, David; Seeholzer, Ronald; Martin, Joe; Hussey, Laura; Wooten, Chris; King, Kim

Subject: May 10, 2005 FASB E-Forum

This is a reminder that you are registered for the Edison Electric Institute (EEI) and American Gas Association (AGA) E-Forum to cover the Financial Accounting Standards Board's new Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No 143.

When: Tuesday, May 10, 1:00 to 2:00 p.m. Eastern Daylight Time.

Speaker: Casey Herman, Partner, PricewaterhouseCoopers LLP, Accounting and Auditing Leader in PricewaterhouseCoopers' Utilities Practice

Participants may receive 1 continuing professional education (CPE) credit for this seminar.

All instructions will be forward to you on Monday before the end of business day.

If you have any questions or concerns please let us know.

Have a great weekend.

Kim King
202-508-5493

Wiseman, Sara

From: King, Kim [KKing@eei.org]

Sent: Monday, May 09, 2005 4:48 PM

To: sjloredo@cpsenergy.com; dking@oneok.com; kbareksten@deloitte.com; james.tencza@ey.com; amount1@entergy.com; amox@alleghenyenergy.com; amy.sheppard@cinergy.com; amy_leong@transcanada.com; aschick@wpsr.com; bmalaski@edisonsault.com; brett.ritchie@cinergy.com; bullerja@oge.com; cathy.muszynski@xcelenergy.com; daignca@nu.com; dan.thobe@dplinc.com; daniel_delmonte@nstaronline.com; derek.dirisio@pseg.com; dljacobs@duke-energy.com; dlwilker@southernco.com; frank.stanbrough@swgas.com; gmcnall@nicor.com; howard_lyon@rgcresources.com; jan_anderson@cmsenergy.com; jdwiles@duke-energy.com; jgwolfe@southernco.com; jharold@nisource.com; jjhodnet@southernco.com; jlegge@otpco.com; jon.veurink@exeloncorp.com; jrobbins@aeci.org; juliewilke@electricenergyinc.com; k_taggart@wfec.com; kendall.kliewer@northwestern.com; kent.ipson@pacificorp.com; laura.rockenberger@aps.com; laura_fowler@fpl.com; lcsa@pge.com; lee_wages@wr.com; lisa.h.perkett@xcelenergy.com; lori.wright@kcpl.com; lswilson@firstenergycorp.com; lyle.geiger@sce.com; mark.j.kunkel@constellation.com; mary.harms@wecacct.com; marzena.walker@exeloncorp.com; matthew.giesecke@exeloncorp.com; mike.demas@questar.com; mloughan@cvps.com; mlyons@ameren.com; pat.cass@ey.com; patsy.nanbu@heco.com; pfarr@pplweb.com; rgrzywana@nisource.com; ricciardik@coned.com; roy.centrella@swgas.com; rrtunning@midamerican.com; Wiseman, Sara; srinivasan.sridharan@pseg.com; sszlaud1@txu.com; stacy.stubbs@cleco.com; steendw@yahoo.com; thomas.barina@we-energies.com; wgaldri@michigan.gov

Cc: Stringfellow, David; Seeholzer, Ronald; Hussey, Laura; Martin, Joe

Subject: May 10, 2005 FASB E-Forum

Attachments: Evaluation of EEI.doc; 5-10-05 FIN 47 E-Forum presentation.ppt; Sample E-Forum Instructions (2).rtf; CPE_eforum_5-10-05.pdf; E-forum Sign-in Sheet.doc

Dear E-Forum Participant,

Attached are the following documents:

1. Slide presentation for tomorrow's E-Forum on FASB Interpretation No.47 Accounting for Conditional Asset Retirement Obligations an Interpretation of FASB Statement No. 143 (FIN 47). Please make copies for those in attendance at your site.

2. E-Forum sign-in sheet.

3. CPE Request Form.

4. E-Forum Evaluation Form.

5. Instructions for accessing the E-Forum (Internet and audio portions).

Please make copies of the evaluation form and CPE Request form as needed for each participant at your location. At the conclusion of the E-Forum, the sign-in sheet, CPE Request forms, and evaluations can be returned to Kim King, FAX number 202-508-5542. Please return the sign-in sheet and CPE Request form no later than 6 p.m. Eastern Daytime tomorrow.

If you have any questions or need further assistance, please contact me at 202-508-5493.

Kim King

EDISON ELECTRIC INSTITUTE

American Gas Association

Evaluation
FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143 (FIN 47)
May 10th, 2005

Recently you participated in an EEI Accounting E-Forum. In order to improve our E-Forums, we would appreciate your feedback on this event. Please complete this evaluation form and return by **FAX to Kim King, EEI, 202-508-5542**.

All results are confidential. Please make this form available to anyone else who attended the E-Forum.

1) Your E-mail address: ______________________________

Please rate each of the following using a scale where 5 is excellent and 1 is poor.

2) The content of the E-Forum presentation:

Excellent				**Poor**
5	4	3	2	1

3) The question and answer sessions:

Excellent				**Poor**
5	4	3	2	1

4) The Microsoft Office Live Meeting software and web site in terms of being easy for you to use:

Excellent				**Poor**
5	4	3	2	1

5) How valuable was the information presented at this E-Forum to you? Please use a scale where 5 is very valuable and 1 is not at all valuable.

Very valuable				**Not at all valuable**
5	4	3	2	1

6) How effectively did the E-Forum meet the announced objective of presenting an overview of FIN 47? Please use a scale where 5 is very effectively and 1 is not at all effectively.

Very effectively				**Not at all effectively**
5	4	3	2	1

7) How relevant to the topic was the presented material? Please use a scale where 5 is very relevant and 1 is not at all relevant.

Very relevant				**Not at all relevant**
5	4	3	2	1

8) How effectively did the instructors present the course material? Please use a scale where 5 is very effectively and 1 is not at all effectively.

a) Casey Herman

Very effectively			**Not at all effectively**	
5	4	3	2	1

b) Andrea Larsen

Very effectively			**Not at all effectively**	
5	4	3	2	1

c) Miles Mooney

Very effectively			**Not at all effectively**	
5	4	3	2	1

9) How likely are you to participate in another E-Forum? Please use a scale of 1 to 5, where 1 is not at all likely and 5 is very likely.

Very likely				**Not at all likely**
5	4	3	2	1

10) How would your rate your overall satisfaction with this E-Forum? Please use a scale where 5 is very satisfied and 1 is not at all satisfied.

Very satisfied				**Not at all satisfied**
5	4	3	2	1

11) Overall, what did you find most valuable about this E-Forum?

____

____

12) What did you find least valuable about this E-Forum?

____

____

13) What other topics or subjects would you like to see covered in a future E-Forum?

____

____

14) Please add any suggestions you may have to improve EEI's E-Forums.

____

____

15) Would you like to be notified of future EEI Accounting E-Forums? Yes No

Thank you for your time. If you have any questions about this evaluation or EEI's E-Forums, please contact David Stringfellow, dstringfellow@eei.org or 202-508-5494.

PLEASE FAX THIS FORM TO KIM KING, EEI, 202-508-5542

FIN 47, Conditional Asset Retirement Obligations

Edison Electric Institute

E-Forum

May 10, 2005

PricewaterhouseCoopers LLP

Casey Herman	312.298.4462
Miles Mooney	314.206.8255
Andrea Larsen	312.298.2565

PRICEWATERHOUSECOOPERS

Agenda

- Recap of FAS 143, Asset Retirement Obligations
- Summary of FIN 47, Conditional Asset Retirement Obligations
  - Requirements and transition provisions
  - Implementation issues
  - Day 2 accounting issues

PRICEWATERHOUSECOOPERS

FAS 143 - Asset Retirement Obligations

- Recognition of ARO liabilities at fair value when incurred
  - Applies to unavoidable existing legal obligations associated with retirement as a result of:
    - Law or regulation
    - Contractual obligation
    - Promissory estoppel
- Asset retirement cost (ARC) capitalized as part of related asset cost, then depreciated systematically and rationally

PRICEWATERHOUSECOOPERS

FAS 143 - Asset Retirement Obligations

- ARO could be incurred at acquisition, ratably over life, or upon enactment of new requirements
- Recognition of subsequent changes to ARO due to: (i) passage of time; and (ii) changes in amount and timing of estimated cash flows
- Special recognition situations - AROs with indeterminate settlement dates:
  - Within the scope of the standard
  - Not recognized if not estimable
  - Recognized when amount becomes estimable

PRICEWATERHOUSECOOPERS

FAS 143 - Asset Retirement Obligations

Question 1 – What has been your greatest challenge in connection with the implementation of FAS 143?

A. Assembling initial inventory of possible AROs
B. Initial valuation of AROs
C. Original implementation accounting
D. Ongoing accounting

PRICEWATERHOUSECOOPERS

FAS 143 - Asset Retirement Obligations

Question 2 – What do you foresee as your greatest challenge in connection with the implementation of FIN 47?

A. Identification of conditional AROs
B. Initial valuation of conditional AROs
C. Original implementation accounting
D. Ongoing accounting

PRICEWATERHOUSECOOPERS

FIN 47 – Accounting for Conditional Retirement Obligations

- Issued March 2005 with minimal changes from the exposure draft
- Effective date and transition
  - No later than the end of fiscal years ending after December 15, 2005
  - Recorded as a cumulative effect
  - Retrospective application for interim periods in 2005 is permitted, but not required.

PRICEWATERHOUSECOOPERS

FIN 47 Summary

- Clarifies that a legal obligation associated with the retirement of a long-lived asset who's (i) timing and (or) (ii) method of settlement are conditional on a future event is within the scope of FAS 143.
  - The obligation is unconditional even though uncertainty exists about the timing or method of settlement

PRICEWATERHOUSECOOPERS

FIN 47 Summary

- Accordingly, entities are required to recognize a liability for an ARO that is conditional on a future event if a fair value can be reasonably estimated.
- Uncertainty surrounding the timing and method of settlement would be factored into the measurement of the liability rather than the recognition of the liability.

PRICEWATERHOUSECOOPERS

Please print the following instructions and have them available on Tuesday, May 10, to help you join the E-Forum. *This Office Live Meeting invitation is a personal invitation meant only for you. It should not be forwarded. If you received this email by mistake or require Live Meeting Assistance, please refer to the Live Meeting Assistance Center at:*
http://r.office.microsoft.com/r/rlidLiveMeeting?p1=7&p2=en_US&p3=LMInfo&p4=support

To Join The E-Forum: You will need to access the presenter's slides on the Internet, and you will dial in to a conference call for the audio portion.

- **Internet Portion**: Click on the following link to Join Meeting.
- **Audio Information**: Dial 1-412-858-4600 and ask for the EEI call hosted by David Stringfellow.

Alternate Instructions for accessing Internet Portion:
Go to: https://www.livemeeting.com/cc/edisonelectric/join
Your Name: (enter your name)
Meeting ID: MSP73C
Meeting Password: SZJ74D

To Ask Questions During The E-Forum

There are two ways to ask questions: 1) verbally, through the conference call; or 2) in writing, through the Microsoft LiveMeeting screen.

To ask questions through the conference call operator:

1. Wait for the operator to announce that questions are being taken.
2. Press * then 1 on your phone (must be a touch tone phone).
3. An operator will come on and ask your name, and then connect you so that other participants can hear your question. (It is recommended that you speak into the handset, not through a speaker phone, when asking a question.)
4. To withdraw yourself from the queue before asking your question, press * then 2.

To ask questions through the Microsoft LiveMeeting software:

1. Type your question into the box at the bottom of the screen at any time during the presentation.
2. The question will appear in a list on the moderator's screen. Other participants will not see the question.
3. The moderator will read the question aloud for the speaker to answer.

EDISON ELECTRIC INSTITUTE

E-Forum: FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143 (FIN 47)

Request for CPE Credit

If you participated in the May 10, 2005, E-Forum on *FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations*, an Interpretation of FASB Statemement No. 143 (FIN 47) and would like to receive a Certificate of Completion for Continuing Professional Education credit (1.0 CPE credit), please:

- Complete the following form.
- Attach payment.

If you have questions, contact Kim King at 202-508-5493.

- FAX to: **202-508-5542**

-OR-

MAIL to: Meeting Registration Office
Edison Electric Institute
701 Pennsylvania Avenue, NW
Washington, DC 20004-2696

Participant Information

Name

Address (Line 1)

Address (Line 2)

City State ZIP

Phone

E-mail

Verification

I participated in the May 10, 2005, E-Forum on *FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143 (FIN 47)*.

(signature)

Edison Electric Institute NASBA Sponsor Number: 103121

Edison Electric Institute is registered with the National Association of State Boards of Accountancy (NASBA). as a sponsor of continuing professional education on the National Registry of CPE Sponsors. State boards of accountancy have final authority on the acceptance of individual courses for CPE credit. Complaints regarding registered sponsors may be addressed to the National Registry of CPE Sponsors. 150 Fourth Avenue North. Suite 700, Nashville. TN 37219-2417 NASBA Web site: www.nasba.org

Payment Information

There is a $25.00 administrative fee for all E-Forum participants who request a Certificate of Completion, payable by check or credit card (Visa, MasterCard, or American Express).

I am paying by:
☐ check (Please attach to this form and mail to above address)
☐ credit card (if credit card, complete information below)

I authorize EEI to charge $25.00 to my: ☐ MasterCard ☐ Visa ☐ AMEX

Account Number Expiration Date

Billing Address City State ZIP

Cardholder Name (as it appears on card)

Item Code: 13-1430 | Account Code: 1-40-11/13-1430/431-0/99/37

EDISON ELECTRIC INSTITUTE

E-Forum on FASB Interpretation No. 47
Accounting for Conditional Asset Retirement Obligations
an Interpretation of FASB Statement No. 143 (FIN 47)
May 10th, 2005

Individual Sign-in Sheet to Receive CPE Credit

Each individual at your site who will be requesting CPE credit for participation in this seminar **MUST** print their name and sign this form. **The form for your site must be faxed by 6:00 P.M. Eastern Daylight Time on May 10 to Kim King, Edison Electric Institute, fax number 202-508-5542.** Make additional copies of this page as needed.

Each Individual requesting CPE credit should also fax or mail the "Request for CPE Credit Form" with payment information.

Company Name: ______________________________

Registrant/Organizer: ______________________________

Phone Number: ______________________________

Participants Who will Request CPE Credit

Name	**Signature**

Wiseman, Sara

From:	Riggs, Eric
Sent:	Thursday, May 12, 2005 12:58 PM
To:	Winkler, Michael; Medina, Roger
Cc:	Wiseman, Sara
Subject:	Conditional Asset Retirement Obligations - FIN 47
Importance:	High
Follow Up Flag:	Follow up
Flag Status:	Flagged
Attachments:	FASB Interpretation No. 47.pdf; FAS 143 Interpretation Exposure Draft Attachment I.doc; FAS 143 Interpretation Exposure Draft Attachment II.xls; FAS 143 Interpretation Exposure Draft.doc

Gentlemen,

You may recall that around August 2004, you helped get information relating to any and all capital assets that required special handling when disposed. I have attached the results that were sent to E.On, along with other files relating to the FASB 47 interpretation.

E.On is now requesting that this information be updated and that the costs associated with its implementation be determined. Would you please review that attached documentation so that we might get together ASAP? I believe the first two tasks that need to be addressed are: 1) Updating the list. 2) Determining assets on the books relating to the criteria.

If I need to send this email to someone else, please let me know or feel free to forward it to anyone you choose.

FASB Interpretation No. 47.pdf...

FAS 143 terpretation Exposui

FAS 143 terpretation Exposui

FAS 143 terpretation Exposui

Thanks,
Eric Riggs

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Telephone 202-508-5527

EDISON ELECTRIC
INSTITUTE

July 30, 2004

Mr. Lawrence Smith
Director – Technical Application & Implementation Activities
Financial Accounting Standards Board
401 Merritt 7
P.O. Box 5116
Norwalk, CT 06856-5116

Subject: File Reference No. 1099-001

Dear Mr. Smith:

The Edison Electric Institute (EEI) appreciates the opportunity to comment on the Financial Accounting Standards Board's (FASB or the Board) Exposure Draft (ED) of a Proposed Interpretation, *Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143* (Statement 143).

EEI is the association of the United States investor-owned electric utilities and industry affiliates and associates worldwide. Its U.S. members serve over 90 percent of all customers served by the investor-owned segment of the industry. They generate approximately three-quarters of all the electricity generated by electric utilities in the country and serve approximately 70 percent of all ultimate customers in the nation. EEI members own a majority of the transmission and generation facilities in the nation.

EEI supports the Board's desire to promote consistent application of Statement 143 and commends the Board for this effort. However, we believe that the proposed Interpretation will result in more diversity in practice in the application of Statement 143 than currently exists today. Although the proposed Interpretation includes examples of various types of conditional asset retirement obligations (AROs), a company's individual facts and circumstances could change the determination of whether a conditional ARO exists. The determination of whether a settlement date is indeterminate could vary from company-to-company and the calculation of how to include a measurement of uncertainty in the calculation of the ARO would likely vary from one company to the next.

EEI believes that the current requirements to record obligations for which a company could be held legally liable will yield a more consistent result. Statement 143, versus the proposed Interpretation, provides a more objective basis on which to determine whether an ARO exists because it is based upon legal requirements. The law will remove much of the subjectivity in determining whether an ARO exists. In connection with the initial adoption of Statement 143, legal counsel was consulted to identify asset retirement obligations. Application of the proposed Interpretation would likely result in the recording of obligations on the financial statements that are not considered obligations from a legal perspective, resulting in internal inconsistencies.

Further, the scope of Statement 143 includes any obligations under the doctrine of promissory estoppel. The current exposure draft intends to expand liability recognition such that any requirement to handle waste appropriately upon the removal of the asset or any component of the asset should fall within the scope of an ARO. Some parties could interpret the recording of these types of liabilities, for which a company is not legally liable, as a promise to perform a future action or event. This would then scope these liabilities, not previously legally required, into the category of legally required liabilities through the doctrine of promissory estoppel, *e.g.,* examples 1 through 3 in the exposure draft or any other similar instances where a legal obligation under Statement 143 does not currently exist. EEI believes that this proposed accounting could expose companies to risk in this respect and is an inappropriate and unintended result.

Issue 1: *The Board concluded that the uncertainty surrounding the timing and method of settlement should not affect whether the fair value of a liability for a conditional asset retirement obligation would be recognized but rather, should be factored into the measurement of the liability. Do you agree with the Board's conclusion? If not, please provide your alternative view and the basis for it.*

EEI agrees, in general, with the Board's re-affirmation in Issue 1 of the ED of the paragraph A17 as found in Statement 143, which defines a conditional ARO. However, EEI fundamentally *disagrees* with the Board's specific *interpretation* of a conditional obligation as stated in the ED. EEI understands that Statement 143 provides that uncertainty regarding the amount and timing of cash flows of a *legal obligation*, does not exempt a company from recognizing a conditional ARO. However, the proposed Interpretation incorrectly scopes an ARO obligation that does not meet the definition of Concepts No. 6 as follows:

1. The entity has a present duty or responsibility to one or more other entities that entails settlement by probable future transfer or use of assets at a specified or determinable date, on occurrence of a specified event, or on demand.

Paragraph B9 states that "if an entity is required by current laws, regulations, or contracts to settle an asset retirement obligation upon retirement of the asset, that requirement imposes a present duty." When a company is constructing or acquiring a facility, the event that imposes the duty to perform certain activities has not yet occurred. In the example of asbestos, the specific event that actually and legally obligates the entity to incur costs is when the asbestos becomes friable, or when that company elects to demolish the facility, at which point the determination that asbestos will be removed has been made. Up to that point, there are no legal obligations that would require the removal of asbestos. A company does not record a liability on the day it acquires or constructs a facility for the costs, excluding asbestos, to demolish or dismantle the facility because, under SFAS 143, there is no legal requirement for this activity to occur. It seems inconsistent that the timing of the obligating event is viewed differently for certain components of the facility (normal demolition cost versus asbestos related costs) solely because of the nature of the costs to be incurred. FASB's proposed Interpretation should not generalize issues to fit every situation. Statement 143 relies on legal review of obligations by attorneys representing a particular company. It appears that FASB may be imposing their own definition of a legal commitment that obligates a company on top of a company's legal analysis.

2. The duty or responsibility obligates a particular entity, leaving it little or no discretion to avoid the future sacrifice.

Paragraph B10 indicates that the Board believes that a company's ability to indefinitely defer settlement of an ARO does not provide the entity discretion to avoid the future sacrifice and that, implicit in this conclusion, is the belief that no tangible asset will last forever. EEI does not agree with the Board's conclusion. A company does have discretion on whether or not it will remove an asset to the extent that there is no legal obligation for the company to remove that facility. While a company may not be able to operate a facility indefinitely, or may determine to discontinue operations early because of performance or economics of the unit, a company may elect to mothball a facility indefinitely and would not elect to incur dismantling/disposal costs unless it was economically feasible to do so or some other event occurred which would trigger a requirement or decision to dismantle the facility.

3. The transaction or other event obligating the entity has already happened.

Paragraph B11 concludes that "Statement 143 states that the obligating event is the acquisition, construction, or development and (or) the normal operation of the long-lived asset. Thus, the obligating event occurs when there is a duty or responsibility and the existence of the condition relating to the duty or responsibility. The obligating event is not the retirement of the asset."

As discussed above, EEI does not believe that the obligating event has occurred until the point in time where a company elects to demolish a facility. The discussion of Statement 143 relating to the existence of a condition relating to the duty or responsibility is still based upon the existence of a legal obligation for the company to incur such costs at a future point in time. If a company has placed a facility in reserve shutdown, or mothballed a facility indefinitely, as long as the unit is not demolished, there would be no law that would require the company to incur these costs. In the example of treated utility poles, a company has no legal liability to remediate the poles when the poles are removed from service unless it elects to dispose of the pole as a solid waste. A company also may decide to donate or sell that pole to another user for use as a treated wood product and would have no liability regarding treatment or disposal of the pole. Because there is no legal requirement for these types of costs, based upon the normal use or operation of the asset, EEI does not believe they would qualify as an ARO under Statement 143.

Issue 2: *Are there instances where law or regulation obligates an entity to perform retirement activities but allows the entity to permanently avoid settling the obligation? If so, please provide specific examples.*

Most environmental regulations of which EEI is aware require an entity to dispose of certain materials in a particular fashion to the extent that the material

Attachment I

is considered contaminated. EEI is not aware of specific regulations that allow a company to permanently avoid settling an obligation of this sort, to the extent that an event has occurred, which requires disposal under the appropriate regulations. However as noted above, an item such as a treated utility pole may be settled by removing the pole from service and selling or donating the pole in its current condition to another user (for use in parking lots or some other form of secondary use). EEI's understanding is that any future liability regarding the disposal of the pole would transfer to the party who took possession of the pole and that liability is not triggered until when, and if, the party that owns the pole decides to dispose of it as a solid waste. Additionally utility transformers, which may contain polychlorinated biphenyls (PCBs), are typically taken out of service when one fails or will be replaced for operational reasons. A company may elect to warehouse or store that transformer without removing the PCBs thereby avoiding any obligation as the disposal regulations covering this material are not triggered unless the oil is removed or is spilled, or the electrical device is scrapped or recycled.

Additionally, as also discussed above, a company may permanently avoid settling an obligation such as asbestos to the extent the facility is left intact and no issues arise which require clean up of a spill or release of a material such as friable asbestos.

EEI commends FASB in providing diverse examples in the ED. However, EEI believes that Example 2 should be changed to reflect the indeterminate useful life of wood poles (consistent with Example 4 on oil refineries) and, as covered in these comments, a company may have no liability to remediate the poles when they are finally removed from service.

EEI appreciates the opportunity to respond to the proposed Interpretation. We hope that our comments will be helpful and look forward to working with the Board in the future.

Sincerely,

/ s /

David K. Owens
Executive Vice President, Business Operations

Kentucky Utilities / Louisville Gas and Electric Company
Assets Requiring Special Disposal Treatment

Asset	Legal Requirement - Code of Federal Regulations (1)	Notes
Capacitors - Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. 10% of these units are likely to contain PCBs
Reclosers - Fluid Filled	40 CFR 761	All units older than 1980 must tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Breakers - Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. Fluid is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Bushings - Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. Units are sealed and therefore the fluid is not replaced during maintenance. Approximately 25% of these assets are likely to contain PCB's
Regulators - Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Switches -Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Substation Transformers - Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Residential Transformers - Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. Units are operated until they fail. Approximately 10% of these assets are likely to contain PCB's
Batteries	40 CFR 270	These units are sent to a recycle center.
Cable - Oil Filled	40 CFR 761	All oil filled cable older than 1980 must be tested when taken out of service. Less than 5% of these assets are likely to contain PCB's
Wood Poles	40 CFR 240-299	The landfill must be notified that these units contain harmful chemicals. Additional costs are charged by the landfill operators for disposal.
Cross Arms	40 CFR 240-299	The landfill must be notified that these units contain harmful chemicals. Additional costs are charged by the landfill operators for disposal.
Large Diameter Gas Steel Pipe	40 CFR 761	All steel pipe is tested for PCB presence when taken out of service. Historical data indicates very infrequent PCB presence in distribution or storage field piping 4-inches in diameter or more. Less than 5% of pipe is estimated to have PCB contamination.
Residential Gas Pipe	40 CFR 761	All steel pipe is tested for PCB presence when taken out of service. All pipe with less than 4-inch diameter must be disposed of as scrap or in a landfill. Additional costs are charged by landfill operators for disposal. If left in place, pipe is to be grouted or otherwise filled to prohibit reuse.

(1)
Resource Conservation and Recovery Act - 40 CFR Parts 240-299
Toxic Substance Control Act - Parts 40 CFR 761

Kentucky Utilities Company
Louisville Gas and Electric Company
Proposed Interpretation of SFAS 143, Accounting for Asset Retirement Obligations
August 16, 2004

On June 17, 2004, the Financial Accounting Standards Board issued an exposure draft for an interpretation of SFAS 143, Accounting for Asset Retirement Obligations. The exposure draft is titled "*Accounting for Conditional Asset Retirement Obligations*".

Summary of Exposure Draft

This exposure draft was issued to address the timing of recognizing liabilities for legal obligations when the retirement activity is dependent on another event (i.e. the date of retirement is currently unknown and based on a future determination or unplanned). The proposed interpretation indicates that asset retirement obligations must be recognized if the fair value of the liability can be reasonably estimated. The exposure draft indicates that "uncertainty surrounding the timing and method of settlement that may be conditional on events occurring in the future should be factored into the measurement of the liability rather than the recognition of the liability".

The expected effective date for this interpretation is fiscal years ended after December 15, 2005, or December 31, 2005 for KU and LG&E. Amounts recorded as a result of this interpretation would be accounted for as a change in accounting principle and would result in a cumulative effect adjustment similar to that recorded when SFAS 143 was initially adopted. The Companies will ask for regulatory asset and regulatory liability treatment upon the adoption of this interpretation from the Kentucky Public Service Commission so that the initial adoption would have no impact on their net incomes.

Contrary to the adoption of SFAS 143, upon adoption of this interpretation, prior years would be restated on a pro forma basis at implementation, consistent with APB Opinion No. 20, *Accounting Changes*. The Companies would not be required to restate prior 2005 quarterly results if the interpretation is adopted in the first or last quarter of 2005.

The Edison Electric Institute, an industry group, in which the Companies are members, commented on the exposure draft. A copy of that comment letter is attached as Attachment I.

Potential Obligations Identified (not included with the adoption of SFAS 143)

After an extensive review by accounting, legal, environmental, operations and senior management personnel, the following potential obligations were not included in the adoption of SFAS 143 at January 1, 2003, but could be included in the adoption of the current exposure draft interpretation:

- LG&E operates its Ohio Falls plant under a 30-year licensing agreement with the U.S. Army Corps of Engineers. This agreement requires the dam to be restored to the Corps' specifications upon abandonment of the plant. The cost of this restoration was estimated at $8 million in 2002. The Company has renewed the licensing agreement with the Corps of Engineers continually since the plants' construction and expects to renew the agreement continually at each expiration date. Because the hydro plant has an indeterminate retirement date no ARO liability was established.

- KU owns two hydro facilities, Dix Dam and Lock 7. Estimated decommissioning costs for these plants in 2002 were $1.3 million and $3.4 million, respectively; however, a legal review the hydro licenses found no specific legal obligation upon the final decommissioning of these plants. It should be noted that the permitting authorities, particularly FERC, have significant inherent discretion in setting conditions to allow a surrender of a permit. These conditions are based upon the specific facts, issues and concerns at the time of decommissioning. In the case of Lock 7, a study determined that it was likely that surrender of the FERC permit would involve both removal of generation equipment and demolition of station down to water line. Because no specific legal liability was identified and the retirement date is indeterminate no ARO liability was established at January 1, 2003.

- Some components of the Companies' Transmission and Distribution business have retirement obligations associated with them due to environmental or other contractual agreements. KU and LG&E have certain electrical equipment containing PCBs, such as transformers and capacitors, which require special disposal. Both Companies undertook a program in the 1980's to replace most of this PCB impaired equipment. Thus the Companies have few remaining obligations related to PCB contamination. The retirements related to these assets were addressed for frequency and materiality in 2002 to determine if the interim retirement would fall within the scope of SFAS 143 as described below.

    - Some substation equipment such as bushings, breakers, etc., may have retirement obligation related to PCB contaminants. If so, this equipment must be disposed of per EPA regulation. However the cost, generally less than $20K per year, is immaterial. In 2002, the Company disposed of four assets at a cost of $17K. Specific assets impacted are not identifiable until failure or replacement. See Attachment II for a listing of these assets.

    - PCB contaminated line transformers must be disposed of per environmental regulation. The company disposes of PCB contaminated line transformers through a third party vendor. LG&E costs were approximately $10K in 2002. KU costs were approximately $42K in 2002. Based on 2002 disposals the cost of this activity on an annual basis is immaterial. In addition, specific assets impacted are not identifiable until failure or replacement.

- LG&E operates wells in its gas storage system that must be plugged if abandoned, per Kentucky mines & minerals law/regulations. Because LG&E intends to operate the wells in perpetuity and the retirement date is indeterminate, no ARO was established as of January 1, 2003. The estimated cost of plugging the 546 wells was $17K per well or $9.2 million in total in 2002.

- LG&E also operates 4 above ground gas compressor stations under perpetual lease agreements. The ground leases for the Muldraugh KY, Cedar Fields IN, and Brandenburg KY (Riggs and Doe Run sites) were reviewed for contractual obligations. A 1946 letter of agreement related to one acre of the 40 acres of the Brandenburg KY (Riggs site) lease requires LG&E to "return it to lessor on the expiration of the lease in approximately the same condition as found at the present time." The estimated cost to dismantle and remove the Brandenburg station was $48K in 2002.

- Kentucky statutes and regulations govern highways and rights-of-way.

  - Kentucky State Highway rules require all encroachments on public highways to be permitted. Upon any expiration or revocation of a permit the state may require removal or relocation of the encroachment at the expense of the permit holder. Given the uncertainty of the state requiring such removal or relocation, the Companies do not believe any retirement obligation exists.

  - The state may order any level railroad crossing closed for public safety and the closure is to occur at the owners' expense. However, no statute or rule states that an abandoned or unused crossing, due solely to its abandonment or non-use and absent other circumstances, is to be considered unsafe or required to be closed. Given the uncertainty of the state requiring closure, the Companies do not believe any retirement obligation exists.

  - For overpasses and bridges air space permit can be issued. One section of air space permitting requires that any structures or attachments must be removed at the permit holder's expense upon expiration or cancellation, while two other sections provided only that the state had the discretion to require removal, relocation or restoration regarding the air space structures. The Companies do not believe any retirement obligations exist and that the obligation as primarily discretionary, rather than obligatory.

- The Department of Transportation regulations require the cutting of pipes, purging of gas and capping for gas transportation pipelines when abandoned. Since these pipelines are expected to be used in perpetuity no ARO liability was established at January 1, 2002.

- The National Electric Safety Code does not differentiate between abandoned (de-energized) or functioning (energized) electric transmission and distribution facilities. Both are to comply with the same safety and serviceability standards. Our current obligations of maintenance and repair would continue after abandonment (de-energizing) and no new or specific obligations on abandonment arise. Since these assets are expected to be used in perpetuity no ARO liability was established at January 1, 2002.

- Personal computer monitors contain metals that require special disposal. The Companies are negotiating a new contract to dispose of used personal computer equipment that will address these potential costs.

- Many buildings built prior to the early 1980's contain some asbestos in the building materials. Asbestos requires special processes to remove, if it is disturbed. The Companies' position has generally been to retire facilities intact and to incur the costs to remove them only if necessary; accordingly, no ARO liability was established at January 1, 2002, but one would be established should plans for a building change.

EDISON ELECTRIC INSTITUTE

American Gas Association

DRAFT

FASB Interpretation No. 47
Accounting for Conditional Asset Retirement Obligations
An Industry White Paper

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Introduction

"This Interpretation clarifies that the term *conditional asset retirement* obligation as used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform the asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event."

This white paper has been written with an eye toward the Electric and Gas utility business. It is intended to assist one in doing the investigation and review necessary to properly recognize and disclose any new asset retirement obligations resulting from the adoption of this Interpretation. Each company will need to work through their particular issues and review all assumptions with their legal staff to assure proper representation of this topic. At first glance, this Interpretation can appear overwhelming. But one needs to approach this in a thoughtful and reasonable manner that represents the intent and purpose of the Interpretation without getting so lost in the details that the accounting becomes impossible to maintain within a cost effective manner. Without careful thought to the intent and the process to achieve it, the accounting for this Interpretation may not be manageable as the issue moves throughout time.

Another white paper was prepared by EEI and AGA shortly after SFAS 143 was issued. This white paper is supplemental to that earlier one. The following terms and acronyms are used throughout this document.

Term or Acronym	Description
ARC	Asset Retirement Cost (Plant Asset)
ARO	Asset Retirement Obligations
FERC Order 631	Accounting, Financial Reporting, and Rate Filing Docket No. RM02-7-000, *Requirements for Asset Retirement Obligations*
FERC Order 552	Revision to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2-A
FIN 47 or Interpretation	FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*
FSP	FASB Statement of Position
SAB 99	SEC Staff Accounting Bulletin No. 99, *Materiality*
SFAS 71	FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation*
SFAS 143	FASB Statement No. 143, *Accounting for Asset Retirement Obligations*

Reasons for an Interpretation

Diverse accounting practices have been developed with respect to the timing of liability recognition for legal obligations associated with the retirement of a tangible long-lived asset when the timing and (or) method of settlement of the obligation are conditional on a future event. For example, some entities have recognized the fair value of the obligation prior to the retirement of the asset with the uncertainty about the timing and (or) method of settlement incorporated into the liability's fair value. Other entities, however, have recognized the fair value of the obligation only when it is probable the asset will be retired as of a specified date using a specified method or when the asset is actually retired.

The Interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO when incurred if the liability's fair value can be reasonably estimated. The Interpretation clarifies when an entity would have sufficient information to reasonably estimate the fair value of the ARO. This clarification should improve the relevance, reliability, and comparability of the amounts recognized in the financial statements.

The FASB believes application of the Interpretation will result in a more consistent recognition of liabilities relating to AROs, in more information about expected future cash outflows associated with those obligations, and in more information about investments in long-lived assets because additional asset retirement costs will be recognized as part of the carrying amounts of the assets. At the January 26, 2005 meeting, the FASB addressed a request to reconsider the entire concept of recording AROs (see FASB Board minutes at *www.fasb.org/board_meeting_minutes/board_meeting_minutes.shtml*). This discussion provides significant insight to the FASB's expectations and considerable support for the role of management's judgment and reasonableness in the recognition of AROs. In summary, the FASB essentially establishes what disclosure is expected whenever there is an ARO while also narrowing the circumstances in which the measurement could be avoided.

Sufficient Information

In SFAS 143, the term *retirement* is defined as the other-than-temporary removal of a long-lived asset from service. The term *retirement* encompasses sale, abandonment, recycling, or disposal in some other manner. The term does not encompass the temporary idling of a long-lived asset.

- "If an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation, it must recognize a liability at the time the liability is incurred. An asset retirement obligation would be reasonably estimable if (a) it is evident that the fair value of the obligation is embodied in the acquisition price of the asset, (b) an active market exists for the transfer of the obligation, or (c) sufficient information exists to apply an expected present value technique." This is from paragraph 4 of the Interpretation.
- The Interpretation states that when the method of settlement and settlement date have been specified by others such as in a law, regulation or contract, the entity has sufficient information to apply an expected present value technique. Therefore the ARO would be reasonably estimable and a liability must be recorded. The only uncertainty in these situations is whether performance will be required.

From paragraph 5a, "uncertainty about whether performance will be required does not defer the recognition of an asset retirement obligation because a legal obligation to stand ready to perform the retirement activities still exists", and that uncertainty does not prevent the determination of a reasonable estimate of fair value. There are two possible outcomes in situations in which the only uncertainty is whether performance will be required—the entity will be required to perform or the entity will not be required to perform.

If there is no information about which outcome is more probable, paragraph A23 of SFAS 143 requires 50 percent likelihood for each outcome to be used until additional information is available. In certain cases, determining the settlement date for the obligation that has been specified by others is a matter of judgment that depends on the relevant facts and circumstances.

- In situations where the date and method of settlement are not specified by others, if information is available to reasonably estimate (1) the settlement date or the range of potential settlement dates, (2) the method of settlement or potential methods of settlement **and** (3) the probabilities associated with the potential settlement dates and potential methods of settlement, the FASB believes sufficient information is present to apply an expected present value technique. Therefore, the ARO would be reasonably estimable and a liability must be recorded.

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Information that is derived from an entity's past practice, industry practice, and management's intent can provide a basis for estimating the potential methods of settlement. Entities must take into account only the methods of settling the obligation that are currently available to the entity.

The ability of an entity to indefinitely defer settlement of an ARO does not relieve the entity of the obligation. Implicit in this conclusion is the belief that no tangible asset will last forever (except land) and, accordingly, the asset retirement activities will eventually be performed. Furthermore, the ability of an entity to sell the asset prior to its disposal does not relieve the entity of its present duty or responsibility to settle the obligation. The sale would cause the buyer to assume the obligation, in turn affecting the sales price.

Change in the Way Disposal is Viewed

The FASB believes that if a current law, regulation, or contract requires an entity to perform an asset retirement activity; there is an unambiguous requirement to perform the retirement activity even if that activity can be indefinitely deferred. As noted above, no tangible asset will last forever (except land) and, accordingly, the asset retirement activities will eventually be performed. Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement.

- A law or entity's promise may create a duty or responsibility, but that law or promise in and of itself may not be the obligating event that results in an entity having little or no discretion to avoid a future transfer or use of assets.
- SFAS 143 states that the obligating event is the acquisition, construction, or development and (or) the normal operation of the long-lived asset when a law or promise exists that creates a

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duty or responsibility relating to the retirement of the asset. At this point, the obligation cannot be realistically avoided if the asset is operated for its intended use.

All companies are subject to federal and state solid waste disposal requirements for non-hazardous materials and refuse[1]. These laws require such materials to be disposed in a licensed public landfill with other household garbage. Although there is no legal obligation to retire assets under these solid waste laws, these retired and dismantled assets must be transported to licensed public landfills. Companies regularly incur monthly expenses for use of these public landfills for disposal of non-hazardous materials and refuse (i.e. garbage) which in most cases would cover disposal of non-hazardous retired assets.

The scope of SFAS 143 and FIN 47 focuses on "special" requirements for disposal of retired assets that would add incremental costs to the retirement of those assets above what a company expenses monthly for non-hazardous material and refuse disposal. This is evidenced by the reference to "special" requirements in the examples to FIN 47 and the proposed FSP on SFAS 143 relating to the European Union (EU) Directive on Waste Electrical and Electronic Equipment that requires EU members to adopt legislation for environmentally sound disposal of electrical and electronic waste equipment.

This white paper assumes that even though some legal obligation may exist to dispose of non-hazardous materials and refuse resulting from retirements of fixed assets, the disposal costs for non-hazardous materials and refuse may be inconsequential for many assets and may not add significant incremental costs to the asset retirement activities. A company may decide that there is not a legal obligation for removal whereby an asset is disposed within the cost boundaries of the standard garbage fees and only incremental charges above this standard may constitute a removal obligation. And, the incremental charge associated with additional service may be considered part of the standard costs.

As always, a full review of the company position on this issue is paramount to defining the magnitude of potential AROs. Each company needs to decide if these laws constitute a legal obligation in respect to the SFAS 143 and the Interpretation. In instances where the legal requirement relates only to the disposal of the asset subject to the ARO, the cost to remove the asset is not included in the ARO. However, if there were a legal requirement to remove the asset, the cost of removal would be included.

Date of Obligating Event

There has been some discussion around when the obligating event occurs. Quickly, most would point to the in-service date of the asset if a law, regulation, or contract creating the obligation was in place before the in-service date. Similarly, one would choose the date the law, regulation, or contract created the obligation if it came to be after the in-service date. However, SFAS 143 refers to obligations that "result from the acquisition, construction, or development and (or) the normal operation of the long-lived asset". One could question if this infers the purchase of material during the construction process or to inventory. Whereby, the company may have incurred a legal obligation before the in-service date of the asset.

[1] These rules federal and state regulations are governed under Subtitle D of the Resource Conservation and Recovery Act. Subtitle D regulates garbage, refuse, sludge from waste treatment plants, non-hazardous industrial waste and other discard materials including solid, semi-solid and liquid materials resulting form commercial and industrial activities (e.g. demolition debris, mining waste, oil & gas waste).

Timing of the recognition of the ARO, as discussed in paragraphs 3-10 and B32-B41 of SFAS 143, is when all the following criteria are met:

- The obligation meets the definition of a liability in paragraph 35 of Concepts Statement 6.
- A future transfer of assets associated with the obligation is probable.
- The amount of the liability can be reasonably estimated.

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During construction of long-lived assets, such as a steam generating plant, legal obligations to eventually retire the plant may be incurred and measurement of those obligations may be prudent during the construction phase. It is important to remember that the obligating event has to have already happened to create a liability. In the case of a nuclear power facility, the obligation to remove the facility may not exist until the facility is operated and contamination occurs. Thus, the contamination constitutes the obligating event. Along with these two instances provided, work performed on leased property also may create a legal obligation during the construction phase. Furthermore, the amount of the liability may grow in subsequent periods as the construction of the asset continues. These changes in the amount of the original estimate may need to be recognized as an increase in the carrying amount of the liability.

Another example may be a treated pole purchased to inventory. One could argue that the obligating event has occurred at the purchase of the pole even though it is held for a time in the inventory account before moving through construction work in progress to plant in-service. The assumption presupposes that the manufacturer treated the pole before the company purchased it. The scenario would change if the company treats its poles itself. This component can add more complexity to an already multifarious process.

The definition for the obligating date needs to be fully thought out and clear as to the materiality of and the ability to recognize the obligation before the in-service date. One may likely conclude that the obligation will be flagged during construction or when in inventory only for those exceptionally large items. Otherwise, the in-service date will prevail. For any decision, either for this section or for others throughout this document, one needs to assure that it is legally reviewed and representative of management's judgment as to the correct application of the Interpretation and SFAS 143.

Indefinite Life

The first sentence in paragraph B22 of the Interpretation provides specific guidance in three clauses where FASB considers an ARO is reasonably estimable, "if information is available":

1. "To estimate the settlement date or the range of potential settlement dates,"
2. "The method of settlement or potential methods of settlement," **and** (*emphasis added*).
3. "The probabilities associated with potential settlement dates and methods of settlement."

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The third clause would seem to imply that the **probable** service lives and estimated net salvage developed from utility depreciation studies could lead to the conclusion that an ARO is reasonably estimable. Paragraph B19 through B27 also provided more specific language than originally addressed in SFAS 143, which substantially narrowed the circumstance that would lead to a conclusion that an ARO is not estimable.

The current utility industry position is that a company cannot calculate an ARO for its distribution and transmission **systems** because each system has an indefinite life. A depreciation study develops probabilities of life and net salvage for a large group of similar assets, and that many cycles of replacements occur to the group or system. A power line or gas line between two points will probably have multiple retirements and replacement additions, particularly if a portion of the line is moved for any reason, but the line itself generally continues long afterwards. In addition, it is part of a larger group of assets when life analysis is done; all similar power lines or gas lines are considered together. In other words, the probable lives in a depreciation study are on the interim retirements and additions to the line, and not representative of the probable life of the line (or the system). Further, it has been suggested that retirement of the **system** would invoke other accounting pronouncement governing status as an ongoing entity, impairment of an asset, or accounting for discontinued operations.

Accordingly, sufficient information may not be available to reasonably estimate the ARO liability on transmission or distribution property. The industry also does not believe that an ARO should be calculated for such interim retirements because there may not be an obligation for that specific interim retirement or a company would not know when a specific interim retirement with an obligation would take place. The third characteristic of a liability is that the transaction or other event obligating the entity has already happened. One does not know what portion of a distribution or transmission system will be retired until an event such as a gas leak, storm damage, or a road widening requires work on the asset, which may or may not result in capital replacement. When these obligating events do occur, it generally is corrected or recorded in the same accounting period so no liability would be accrued.

However, FIN 47 provides further interpretation of FAS 143 that may require a reassessment of the indefinite life concept. Example 1 specifically addresses this mass asset system versus individual asset contrast and clearly attempts to close the loophole that a system has an infinite life, therefore no ARO can be measured. FIN 47 requires that the fair value of an ARO be recognized when it can be reasonably estimated. It also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. For most utilities, data derived from their most current depreciation study would be a potential source to provide information to calculate an estimated ARO for distribution and transmission assets. This data is used to recover property costs (including removal cost) for regulatory purposes and also may serve as a platform for calculating the expected ARO liability. Depreciation study data is used in the Snapshot example within the Mass Assets, Electric and Gas section of this paper.

An argument also can be made that depreciation study data does not provide sufficient information to estimate a reasonable ARO liability. Depreciation data is utilized to provide for matching of existing property cost with the customer benefiting from that property cost. It is not designed, in concept, to provide an estimated liability for the permanent removal of the entire distribution and transmission system. The assumption is the entity will continue to be a going concern. As such, depreciation study data may need to be used cautiously as it may not be an appropriate mechanism to use when calculating all ARO liabilities. Discarding the depreciation study data, no data would be available to reasonably estimate the ARO liability.

Given this quandary, the indefinite life concept currently used by most utilities may continue in effect for the ultimate retirement of the system. But again, it was very clear that a "do nothing" scenario for any mass asset with a definable disposal requirement might have to be recognized even though the larger

FIN 47 Summary

- An ARO would be reasonably estimable if:
  - It's evident that the fv of the obligation is embodied in the acquisition price of the asset,
  - An active market exists for the transfer of the obligation
  - Sufficient information exists to apply an expected present value technique

FIN 47 Summary

- Sufficient information to apply PV techniques exists if either:
  - The settlement date and method of settlement are specified by others. For example by law, regulation or contract.
  - Information is available to reasonably estimate: (i) settlement date or range of potential settlement dates; (ii) method or potential method of settlement; (iii) probabilities associated the potential dates and methods.

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FIN 47 Summary

- If sufficient information is not available at the time the ARO is incurred, recognition would be required in the period that sufficient information becomes available, and disclosure of the facts and reasons for the inability to estimate shall be disclosed.

FIN 47 Examples

- Example 1 – Chemically Treated Poles
  - A telecommunications network utilizes chemically treated wood poles. There is no legal requirement to remove poles, but the owner replaces the poles periodically for operational reasons. Once removed from the ground, special disposal procedures are required.
    - "Although the entity may decide not to remove the poles…or may decide to reuse the poles…, the ability to defer settlement does not relieve the entity of the obligation. "
    - "The poles will eventually need to be removed and disposed of … since the poles will not last forever."
    - **Conclusion:** Therefore, an ARO should be recognized when the poles are installed. Uncertainty surrounding the timing and method of settlement should be factored into the measurement. If there was a legal requirement to remove the poles, the cost of removal would be included.

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FIN 47 Examples

- Example 3 – Factory with Asbestos
  - The factory is maintained by activities that does not involve asbestos removal. There is no special disposal of asbestos unless factory undergoes renovation or is demolished. "**The entity believes it does not have sufficient information to estimate the fair value of the ARO because the settlement date or range of potential settlement dates has not been specified by others and info is not available to apply a PV technique.**
    - Although the timing of the performance of the ARO is conditional on potential renovation or demolish, existing regulations establish a duty to the dispose the asbestos in a special manner.
    - **Conclusion:** An ARO will not be recognized until the range of settlement dates can be estimated. The entity should disclose the description of the obligation, the fact that the liability can not be estimated and the reasons why the liability can not be estimated.

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FIN 47 Examples

- Example 4 – Factory with Asbestos
  - Same facts as example three. “**Ten years after the acquisition date, the entity obtains additional information based on changes in demand for products manufactured at that factory. At that time, the entity has the information to estimate a range of potential settlement dates, the potential methods of settlement, and the [associated probabilities].**”
    - **Conclusion:** An ARO would be recognized by this entity 10 years after the acquisition date because that is when the entity has sufficient information to estimate the fair value of the ARO.

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FIN 47 Implementation Issues

- Reconsideration all ARO's previously considered inestimable.
- Input from operational, environmental, legal groups.
- Sources of information - engineering studies, depreciation studies, regulatory filings.
- Use of expected cash flow approach (CON 7) - multiple cash flow scenarios reflecting a range of possible outcomes, discounted at a credit-adjusted risk free rate.
- Many valuation challenges - when will it be removed? how will it be removed? how much will it cost?

FIN 47 Implementation Issues

- Poles - example valuation approach:
  - Determine expected life of poles
  - Group poles by vintage years (or some other method?)
  - Determine removal dates (or range of dates)
  - Determine the method(s) of disposal and the cost
  - PV the disposal cost for each group

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FIN 47 Implementation Issues

- Asbestos - example valuation approach:
  - Determine the extent of asbestos in owned facilities
  - Determine whether or not asbestos can be indefinitely contained
  - Determine a range of possible removal dates
  - Determine the method(s) of removal and cost
  - Apply CON 7 model based on multiple scenarios

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FIN 47 Implementation Issues

- Nuclear generator –Does ARO include removal of component, storage or only the disposal cost?
- Spent nuclear fuel – Interim storage?
- PCB Transformer – Often removed as maintenance?
- Pipeline compressor – PCB damage not required until right of way abandoned
- Power plants - hydro-electric facilities or water intake systems under FERC, state or other regulatory licenses?
- Coal plants - ash disposal ponds?
- Natural gas fired power plants and natural gas pipelines or storage facilities as part of license agreements?

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FIN 47 Implementation Issues

Question 3 – What asset group do you foresee as the most problematic in regards to FIN 47 implementation efforts?

A. Utility pole removal
B. Asbestos removal
C. Other utility plant obligations
D. Non-utility plant obligations

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Rate Recovery Considerations

- Differences between amounts collected in rates and amounts recognized in accordance with FIN 47 should be reflected as a regulatory assets and liabilities, if the requirements of FAS 71 are met.
- Current regulatory liabilities may already reflect rate recovery for obligations to be recognized in accordance with FIN 47 (i.e. poles).
- Possible reclassification of regulatory liabilities to asset removal obligation liabilities.
- Profit margin embedded in the cost valuation of the obligation may not be probable of recovery in rates.

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Rate Recovery Considerations

Question 4 – For rate recovery purposes, is the cost of removal and/or disposal included in depreciation (i.e. recovered over the life of the asset)?

A. Yes
B. No

FIN 47 Day 2 Accounting Matters

- Research and measurement of conditional ARO's
  - Component-level assets
    - » ARO or repairs & maintenance expense
  - Regulatory recovery of depreciation and accretion expense
  - Salvage values and removal costs imbedded in accumulated depreciation
- Record-keeping and reporting
  - Unit of accounting / property records
    - » Mass-units of property
  - Existing regulatory liability for cost of removal
  - Changes in estimate

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FIN 47 Day 2 Accounting Matters

Question 5 – At what level are plant components tracked in your accounting records?

A. By unit per the property unit catalogue
B. Total dollar value by category
C. Both A and B depending on the asset

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FIN 47 Day 2 Accounting Matters

Example -

You have completed the implementation of FIN 47. You are now incurring costs associated with the removal and disposal process:

Property Cost (10 poles at $100 each)	$1,000
ARC	100
Acc. Depreciation	(800)
ARO (cost of disposal)	(80)
Regulatory Liability (cost of removal)	(100)

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FIN 47 Day 2 Accounting Matters

Example (continued)-

During the period, you have incurred $100 in costs to dispose and remove 5 poles.

Entry 1 – To record disposal of the asset

DR. Plant	$500	
CR. A/D		$500

Consistent with historical application of composite based depreciation.

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FIN 47 Day 2 Accounting Matters

Example (continued)-

During the period, you have incurred $100 in costs to dispose and remove 5 poles.

Entry 2 – To record the cost of disposal of the asset

DR. ARO	???	
DR. Reg. Liability	???	
DR. Gain/loss on removal	???	
CR. Cash		$100

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FIN 47 Day 2 Accounting Matters

Key Considerations:

- How many poles and which vintage years were disposed of?
- What is the split between removal costs and legally mandated disposal costs?
- Should you record a gain or loss related to differences between budget and actual? Differences between internal costs and external estimates?
- What is the impact on regulatory liability due for removal costs?
- Does significant changes in the costs incurred from budget reflect the need for revaluation of existing ARO?
- System issues/constraints

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FIN 47 Day 2 Accounting Matters

Question 6 – Does your property system track the number of poles by vintage year?

A. Yes

B. No, only by total dollar value by vintage year

C. No, only tracked by total dollar

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Questions?

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retirement obligation on the entire system may not. Any conclusion needs to be supported with full documentation and justification for the indefinite life choice and should be disclosed.

Materiality

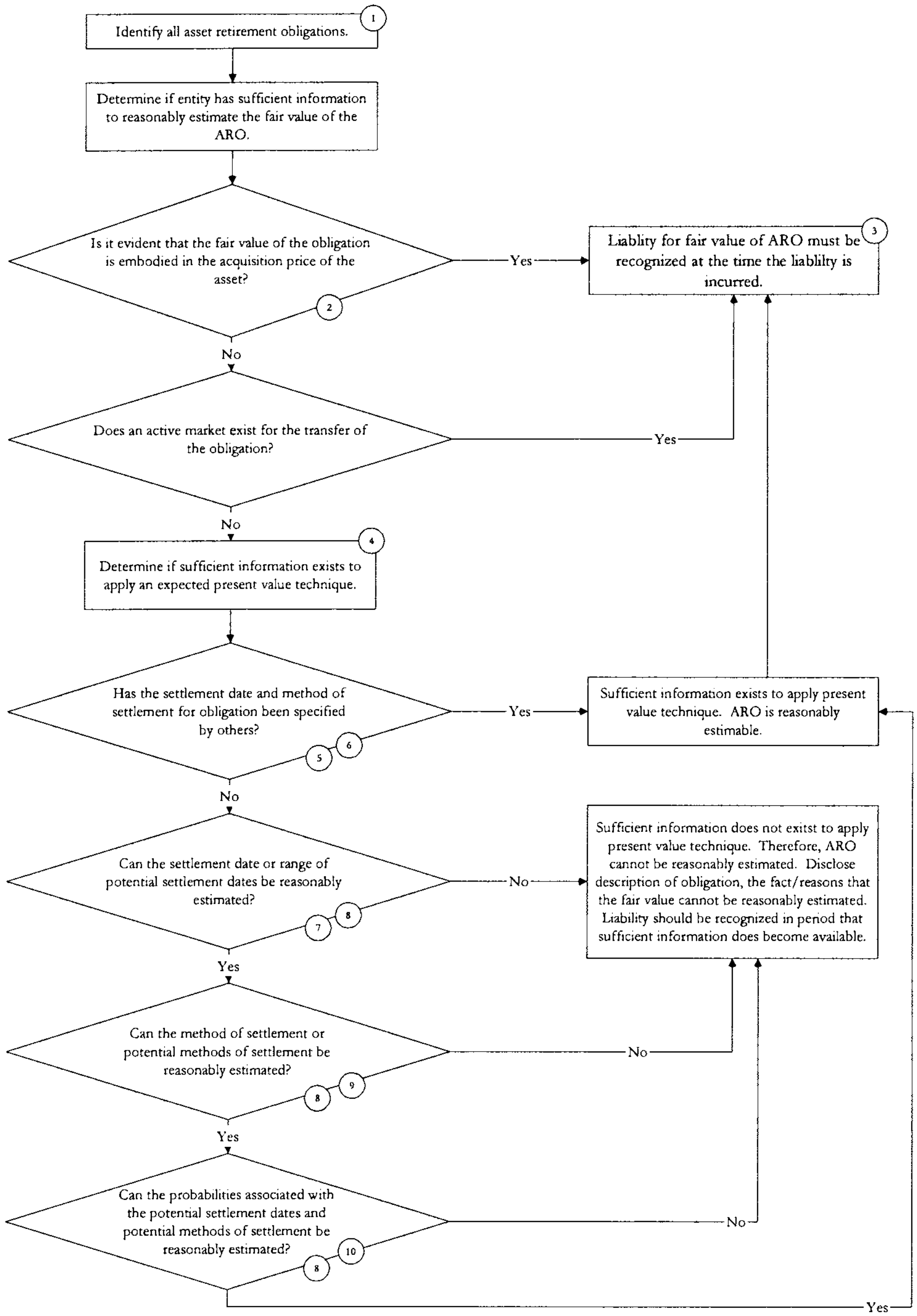
FIN 47 clearly states, "The provisions of this Interpretation need not be applied to immaterial items." However, many immaterial items may constitute in aggregate a material item. Determination of materiality is company specific and often an issue-specific routine. It should be defined and documented for each segment of the business. Along with the materiality threshold, a company should define the way in which assets will be summed to test materiality. It is assumed that the test will be for balance sheet materiality, as most utilities will offset any income statement effect with regulatory accounting. When the ARO does impact the income statement, an income statement materiality test may be used. For example, one must decide if distribution assets will be combined with nuclear assets in determining materiality. Perhaps a company will sum all asset obligations relative to a segment of the utility business keeping the nuclear AROs separate from the distribution calculation. Defining the materiality test to a lower level than function should be a decision based on propriety and not with the intent of avoiding this Interpretation. Additional guidance on materiality can be found in the Securities and Exchange Commission's SAB No. 99.

For those companies that have more than one legal entity, the materiality should be done at the individual legal entity and not at the consolidated level. Now, one legal entity may have an ARO and another may not for the same class of assets because of the variety in the rules and regulation as well as the difference in size of the companies. This white paper does not advocate a consolidated materiality review of AROs where multiple legal entities exist within the corporation. The obligation is clearly the responsibility of the originating legal entity and it should be maintained at that level. However, the disclosures may be more detailed on the utility reports and summarized at the parent level.

Decision Tree

In general, a more substantive review of regulations, laws, and contract obligations will be required to assure that conditional AROs are properly recognized. Each company will need to assess its particular facts and circumstances as the same general situation may play out differently depending on the legal documents and company policies that surround it. To help facilitate this review, a decision tree for analyzing each situation is provided below.

Decision Tree



Decision Tree Notes

1. Paragraph 3 of FIN 47 advises to include all legal obligations to perform an asset retirement activity, even those in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement.

   Paragraph B7 of the Interpretation states, "As used in Statement 143, a legal obligation is an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel."

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2. Paragraph 4 of the Interpretation references paragraph 17 of FASB Concepts Statement No. 7, *Using Cash Flow Information and Present Value in Accounting Measurements*, which states, "If a price for an asset or liability or an essentially similar asset or liability can be observed in the marketplace, there is no need to use present value measurements. The marketplace assessment of present value is already embodied in such prices."

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3. Paragraph 3 of the Interpretation reiterates the SFAS 143 requirement that the fair value of an asset retirement obligation be recognized when the obligation is incurred—generally upon acquisition, construction, or development and (or) through the normal operation of the asset.

4. Present value techniques are discussed in paragraphs 39–54 and 75–88 of Concepts Statement 7. These techniques, which incorporate uncertainty about the timing and method of settlement into the fair value measurement, should be used when the fair value of the liability cannot be estimated based on the acquisition price or on an observable market price.

5. For example, specified in a law, regulation or contract (Paragraph 5a of the Interpretation).

6. Paragraph 5a of the Interpretation states that uncertainty about whether performance will be required does **not** defer the recognition of an asset retirement obligation because a legal obligation to stand ready to perform the retirement activities still exists, and it does not prevent the determination of a reasonable estimate of fair value because the only uncertainty is whether performance will be required.

   There are two possible outcomes in situations in which the only uncertainty is whether performance will be required—the entity will be required to perform or the entity will not be required to perform. If there is no information about which outcome is more probable, paragraph A23 of Statement 143 requires 50 percent likelihood for each outcome to be used until additional information is available.

   In certain cases, determining the settlement date for the obligation that has been specified by others is a matter of judgment that depends on the relevant facts and circumstances. For example, a contract that provides the entity with an ability to extend its term through renewal should be evaluated to determine whether the settlement date should take into consideration renewal periods.

7. Paragraph 5b of the Interpretation states that the estimated economic life of the asset might indicate a potential settlement date for the asset retirement obligation. However, the original estimated economic life of the asset might not establish, in and of itself, that date because the entity may intend to make improvements to the asset that could extend the life of the asset or the entity could defer settlement of the obligation beyond the economic life of the asset. In those situations, the entity would look beyond the economic life of the asset in determining

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the settlement date or range of potential settlement dates to use when estimating the fair value of the asset retirement obligation.

8. Paragraph 5b gives examples of information that is expected to provide a basis for estimating the potential settlement dates, potential methods of settlement, and the associated probabilities. Examples include, but are not limited to, information that is derived from an entity's past practice, industry practice, management's intent, or the asset's estimated economic life.

9. Paragraph 5b of the Interpretation limits "potential methods of settlement" to those methods that are currently available to the entity. Therefore, uncertainty about future methods yet to be developed would not prevent the entity from estimating the fair value of the asset retirement obligation.

10. Paragraph 5b of the Interpretation states that the entity should have a reasonable basis for assigning probabilities to the potential settlement dates and potential methods of settlement to reasonably estimate the fair value of the asset retirement obligation. If the entity does not have a reasonable basis of assigning probabilities, it is expected that the entity would still be able to reasonably estimate fair value when the range of time over which the entity may settle the obligation is so narrow and (or) the cash flows associated with each potential method of settlement are so similar that assigning probabilities without having a reasonable basis for doing so would not have a material impact on the fair value of the asset retirement obligation.

Specific Property Considerations

Four examples were included in FIN 47. This white paper discusses those examples in the context of the Electric and Gas utility business. The examples are as follows:

1. Telecommunication poles
2. Bricks in a kiln
3. Factory with asbestos and regulations go into effect after purchase
4. Factory with asbestos and regulations are in place at acquisition

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Basically, the premise put forward by the FASB in this Interpretation was that no tangible asset, except land, would last forever and accordingly, asset retirement activities will eventually be performed. In completing the retirement work, if a company is required to dispose of the asset in a specific manner or could be required to perform any one of a number of different methods of settlement, to be chosen at some later date, the company will need to evaluate the asset's retirement obligations. The four examples provided were meant to cover various situations a company may face. To bring the examples into the context of the energy industry, the list has been tailored to the potential issues for the Electric and Gas business. The following are the asset issues discussed in the remaining document:

1. Mass assets, electric and gas ***(Telecommunication poles)***

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2. Minor Items *(Bricks in a kiln)*
3. Asbestos, PCBs, and other contaminants ***(Factory with asbestos and regulations go into effect after purchase or in place at acquisition)***
4. Rights-of-Way and franchises
5. General equipment
6. Hydro generation

Mass Assets, Electric and Gas

Example 1 of Appendix A, Illustrative Examples, provides specific discussion on wood pole treated with certain chemicals. However, the circumstances may be comparable to other utility property generally described as mass asset property. The following summarizes Example 1, followed by a discussion of comparability and applicability to other mass assets, and finally a discussion of various issues for utilities to consider in their implementation of FIN 47.

Summary of Example 1 of Appendix A
Example 1 discusses a situation in which a utility is using treated wood poles and where there is existing legislation that requires special disposal procedures in the state in which the utility operates. The example recognizes that the poles may be removed from the ground for a variety of operational reasons other than disposal, and further recognizes that the disposal obligation is not triggered by removal of the pole. Once a pole is removed from the ground, it may be disposed of, sold, or reused as part of other activities. In this example, the disposal obligation is not triggered by removal of the pole. Based on that premise, Example 1 includes specific guidance that requires an assessment of AROs related to treated wood poles. That guidance suggests assessing the ARO and related accounting based on the following:

1. The **recognition point begins with the purchase** of the pole, rather than when the pole was placed into service (in-service date is when the pole first became a long-lived fixed asset). See obligating event and materiality above.
2. That **reuse does not change the obligation**, only defers it (common industry practice is to retire the pole at time of removal, not track it while in inventory, and considered a new addition when reused and placed in the ground again).
3. The **utility already has the information necessary to estimate** a range of settlement dates, methods of settlement, and the related probabilities **based on entity-specific practices, industry practices, management's intent, or the asset's estimated economic life.** (It is important to note that only in the example did the entity have sufficient information to estimate the fair value of the liability for the ARO. Each entity will have to make their own determination as to whether they have sufficient information.)
4. The utility is **not relieved of the obligation by selling** the pole to another party through the assertion that the exchange price reflects the estimated fair value of the obligation.

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Impact On Asset Retirement Obligations Accounting
Example 1 of FIN 47 represents a utility that has a legal requirement to follow special procedures for disposal of treated wood poles. In this example, the utility is presumed to have all the information

necessary to calculate an asset retirement obligation and is expected to make appropriate disclosure. Therefore, the asset retirement obligation should be recognized when the entity purchases the pole. This may result in a significant change from the requirements under FAS 143, where previous estimates and disclosures were not made because: 1) most disposal activities were performed by third parties so there were no future direct costs to be expended by the utility, 2) it was not reasonable to track the obligation (and settlement) due to reuse and different options for disposal, or 3) that the obligation was conditional due to circumstances known only at the time of removing the pole from the ground. There were no future costs because most utilities could give the poles away to third parties at no cost to the utility, but under FIN 47 even the ultimate disposal cost to a third party is to be considered (that net zero would be bifurcated into the avoided future disposal removal cost and the salvage – remember salvage is not recognizable for ARO purposes.)

Example 1 could apply to other mass asset property where a portion of the asset may be subject to special disposal procedures. Some examples might be property containing PCBs, mercury, lead, or any chemical considered hazardous. In other words, FIN 47 requires that if a utility has a special procedure requirement at ultimate disposal, then the utility either would have a measurable ARO with all the related accounting requirements, which should be recognized if the entity has sufficient information to estimate the fair value of the obligation. If the entity does not have sufficient information to reasonably estimate the obligation, the entity only has a disclosure requirement until sufficient information becomes available.

Concerns and Issues

This raises several concerns and issues for both the individual utility and for the industry:

1. Initial determination of legal obligation – The language seems to indicate that if there is a special disposal procedure, that there will be a cost of performing that disposal activity and therefore, an asset retirement obligation. The legal obligation review may need to be expanded to other assets containing materials, which are considered hazardous with special disposal procedures required by some legal mandate.

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2. Record keeping and reporting changes – Many if not most utilities track poles as assets from the date put in the ground until the next time it is removed rather than from purchase to disposal. Time in inventory (initially and upon salvage for reuse) is often not tracked – much less details on how many were treated and what happened to the treated portion at disposal. An individual utility may have to develop such tracking details.
3. Third party disposal – Example 1 states that the "ability to sell the poles prior to disposal does not relieve the entity of its …obligation", and states that "the assumption of the obligation affects the exchange price". This could be a significant issue in compliance for some utilities. It implies that the utility is not relieved of the obligation; and, therefore, should attempt to measure the ARO. However, it would seem that knowledge of how subsequent owners plan to use the pole would be necessary to estimate the effect on the sales price.

   The use of the pole would affect disposal requirements, as Example 1 clearly requires a company to identify that future disposal cost for third parties. Therefore, unless there is a market price available, the company would need to apply present value techniques, which requires knowing how long the third party will use the pole before disposal. It appears ridiculous and unreasonable, but is clear in the Interpretation. Such information about that future transaction may be particularly hard to estimate when the utility purchases the pole and needs to record the obligation.

4. SEC transfer of other provisions for accrued cost of removal – Any change because of reassessing the ARO for treated wood poles also would affect any recognition of the SEC interpretation on depreciation accruals for future removal costs.

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Background: SFAS 143 does not allow a provision for future removal costs to be included in depreciation reserves or current expense. FERC Order 631 provides that utilities that qualify to apply SFAS 71 and if the requirements for Order 552 are met, any provisions for future removal cost would be transferred to a regulatory liability. However, FERC Order 631 continues to allow provision for future removal costs for assets that do not have an existing legal retirement obligation. A conflict may exist because many utilities also have adopted the unofficial SEC interpretation that SFAS 143 does not allow for any accrual of future removal costs, and all provisions for future removal costs should be excluded from accumulated reserves (or transferred to a regulatory liability if eligible for SFAS 71). There is inherent contradiction for many utility assets whereby it needs to be recognized in two different ways for reporting the same activity to the two different entities.

FERC Order 631 requires that only for accounts where an ARO is recognized, then previous provisions for future removal costs should be transferred from the accumulated reserve (and carried as a regulatory obligation under SFAS 71, if the requirements for Order 552 are met). Many utilities have also adopted the unofficial SEC interpretation that SFAS 143 does not allow for any accrual of future removal costs, and all provisions for future removal costs should be excluded from accumulated reserves (or transferred to a regulatory liability if eligible for SFAS 71).

The cumulative effect adjustment for SEC reporting will be the difference between the amount previously recognized prior to FIN 47 and the amount recognized following the advice in FIN 47 (as mentioned under Transition Accounting below). FERC reporting will be governed by any new advice that FERC may issue prior to adoption of FIN 47.

Recommendation

Since ARO compliance for this category of plant type, mass assets, may be quite onerous, a recommendation is offered for consideration to achieve the intent of the Interpretation without excess burden to the company and the accounting personnel. Each company will need to decide if the recommendation is feasible for their books and records. The FIN 47 or SFAS 143 calls for an ARO on individual assets. This is not practical for large transmission and distribution utilities that use group accounting. Therefore, the recommendation is to approximate the literal compliance with FIN 47 with an approximation that uses a statistical based method in order to achieve the **intent** of the statements without incurring undue burden on the accounting personnel.

1. Statistical Method – There are varying levels of information available to the individual utility from their depreciation studies from Simulated Plant Record to Equal Life Group study methods applied property data from individual accounts/sub accounts to functional categories like distribution plant. Even availability of details (such as separating net salvage into removal cost or into removal cost just for treated poles) will vary for different utilities. The following are general descriptions of possible approximation procedures that might be used:

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a. Modified group property/modified depreciation study. Using the latest available depreciation study, the utility could develop the percentage adjustments to indicated life and negative salvage estimates to approximate the timing and the amount of the future removal cash flow. Many utilities have property records that provide the age of existing property and combined with average age, a future cash flow estimate could be prepared for each vintage of property (average age less current age result in the time to expected removal). There may be a standard length of time between removal from service until actual disposal and that could be added to remaining life.

It may be necessary to analyze the property in the pole account as not all the units may be part of the retirement obligation and to identify a percentage adjustment to approximate the proportion of obligating poles that are treated to all others and adjust the future cash flows to represent only the legally required disposal.

If dispersion curves were used in the study, the related retirement curves also could be used to approximate the period of disposal. When time estimates and future cash flows are estimated, then one can compute the various ARO elements (ARC, depreciation and accretion tables, and associated regulatory assets). For the first year, monthly entries are made based on that estimate only. In subsequent years and if vintaged retirements are available, it would be possible to go through the individual settlement calculations for each ARO vintage group plus recognize any layers if disposal cost estimates change or a new study is performed. If vintage retirement data is not available, do exactly the same calculation, but true up the components (which would eliminate all the subsequent measurements and layering).

b. Fin 47 requires the use of current assumptions. It may be necessary to perform a new depreciation study to obtain current information on expected lives and removal costs for existing property. Negative salvage estimates that have been taken from depreciation studies reflect previous assumptions. In other words, the study reflects removal costs that have already happened and may not even reflect costs or methods of disposal under a new or recent legal requirement (or only partially reflect it). To the extent that previous assumptions are the same as current assumptions, the depreciation study may be used.

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The gross removal portion of the negative net salvage amount also may contain a removal component that may or may not be part of the retirement obligation. Use of the approved rate to determine the obligation under this Interpretation could result in an inflated obligation. In either case, it should be updated to reflect current assumptions, based on management's intent, the asset's estimated economic life as well as entity and industry practices. Be sure to exclude gross salvage value from estimated removal costs and to split the removal costs into its components in order to identify only those pieces that represent the retirement obligation.

c. Snapshot. If immaterial or one is unable to modify or perform annual studies, work with what is available at the end of each year. Then compute the ARO by taking a snapshot each year and true up for differences.

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2. Detail Method – If detailed records exist or it is feasible to create detailed records and reporting just for treated wood poles (or like mass assets), then it would be possible to fully comply with SFAS 143 and FIN 47.

3. For either method, one may want to:

a. Re-examine the legal obligation to determine if there is a specific obligation due to the type of treatment on the poles along with other mass assets **and** that complying will result in a cost. For some locations, there are no "special" disposal tracking or fees. Examine the disposal fee for poles to determine if it is related to special facilities or just additional cost for garbage service. No cost means no accruals need to be booked.

b. Determine if the future fee could qualify as immaterial. For example, a $5 fee or a 50-cent information sheet to buyers could be immaterial on the surface. However, balance sheet materiality would apply and it is the fair value of the ARO items as grouped that may determine materiality.

c. Review the additional reporting and record keeping requirements of the full application to determine if the cost of keeping records is unreasonable for the effort and that an alternative method may yield a reasonable estimate. For example, if one can match disposal to vintaged purchases, then one should be able to comply using the Detailed Method instead of developing a statistical approximation.

d. Similar to above, review whether the depreciation studies are reasonably compatible. Remember FIN 47 "example 1" is concerned with "purchase to disposal" total life versus studies based upon "site life" and in-service time (does not recognize reuse.) Similarly, then, approximation methods might be reasonable. Paragraph 2 of SFAS 143 states that this "applies to legal obligations associated with the *retirement*[2] of a tangible long-lived asset that results from **the acquisition, construction or development...**" This sentence has two interpretations - the first half indicates it only applies to plant in-service, while the second half adds the purchase or construction to the point of application. This review may want to include making a determination on the reasonableness and materiality of the difference between in-service date versus the date of construction or purchase.

e. Alternative approaches also may be justified if one qualifies as a regulated utility. As a regulated utility, the entire ARO compliance effort may result only in balance sheet adjustments with no earning impacts. The most reasonable application of managerial judgment might involve only a high-level, rough estimate of the current obligation without all the various kinds of offsetting regulatory assets and regulatory liabilities. It may be that all those offsetting line items and calculations provides only confusion and a good description of the circumstances is the most appropriate disclosure, especially if preliminary efforts indicate that full compliance results in an immaterial impact.

An example of a possible "snapshot" follows. Utilities with recent, extensive, and detailed studies may have such particulars and resources to develop a very close approximation of full ARO accounting. Many utilities will have very limited information available from latest depreciation studies and property records. This example is intended to show how to approximate an ARO calculation with the bare minimum of information.

Assuming that the utility depreciation study only provides an average service life and net salvage (no basis for a split for removal costs), has a count or estimate of treated poles in service, and vintage or estimate of age of those poles:

For Year 1 (2005) the following applies:

- Surviving plant is equal to 100,000 poles,
- Average service life is estimated to be 50 years,

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- Average age of existing poles is 30 years (average remaining life is 20 years)
- Disposal cost is $15 per pole fee set by law in 2000 at a local waste management facility.
- Future removal cost in 20 years would be $1.5 million ($15 times 100,000). Note, apply an inflation factor as well if disposal fee can increase due to inflation.
- Apply a current discount rate (credit adjusted risk free rate) back to the year that the obligation began (in this example it is the year 2000) to determine ARC.
- Set up schedules to determine ARC depreciation, accumulated reserve, accretion table, and current value of ARO in year 2005 (also determine regulatory accounting to offset any expenses or income if eligible for SFAS 71 treatment – FERC Accounts 182.3 and 407.4 for regulatory assets, FERC Accounts 254 and 407.3 for regulatory liabilities).

For Year 2 (it is now 2006) the following occurs:

- Surviving plant has been reduced to 95,000 poles (additions and retirement led to a net reduction.
- Average service life is still estimated to be 50 years.
- Average age of existing poles has changed due to the additions and retirements – and is now 29.5 years (average remaining life is now 21.5 years)
- Disposal cost is still $15 per pole fee set by law at a local waste management facility back in year 2000 (watch for whether this should be inflated).
- Future removal cost in 21.5 years would be $1.425 million (15 times 95,000).
- Apply a current discount rate (credit adjusted risk-free rate) back to year 2000 to determine ARC (FERC account 359.1 or 374).
- Set up schedules to determine ARC depreciation, accumulated reserve, accretion table, and current value of ARO now in year **2006** (also determine regulatory accounting to offset any expenses or income if eligible for SFAS 71 treatment – FERC Accounts 182.3 and 407.4 for regulatory assets, FERC Accounts 254 and 407.3 for regulatory liabilities).
- Compare the Year 2 (2006) results to Year 1 (2005) results:
    1. Adjust both the ARC asset, ARC accumulated reserve, and the ARO liability to the new numbers.
    2. The remaining differences (accretion, depreciation, and affect of the change upon the current) will be recognized as a gain or loss or deferred under regulatory accounting (adjust previously recorded amount – difference may change the amount from an asset to a liability which should be a reversal of the prior year entry and a new entry in order to keep the connection between 407.3 and 254 or 407.4 and 182.3 as appropriate).
    3. Layering is being ignored for both because this is only an approximation and this does recognize that the forecast future date of cash flows has changed for all assets and in the long run will achieve a more appropriate obligation at the time of disposal.

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In the situation where more information is available (such as vintage data), and the effort reasonable, then the above "snapshot" approach could be applied to each vintage. If service life is estimated using dispersion curves such as Iowa Curves, another enhancement would be to use the "retirement rate" percentages from those curves to develop the estimated time for future retirements. Such an enhancement may be unreasonable (especially if being computed manually) because it would be many times more complicated with the number of vintages involved and it may result in an immaterial difference to the results. These are issues subject to that managerial judgment discussed at the beginning of this document.

Questions for Review: Mass Assets, Electric and Gas

1. Which mass assets are subject to this section?
2. What actuarial assumptions has the company been using with those assets identified as falling within FIN 47?
3. Are the state laws or federal ones defining the disposal restrictions related to any of these minor items?
4. Can one determine a reasonable estimate the current disposal costs and does that apply to all or most in the mass asset group?
5. Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?
6. Is the ARO associated with this mass assets material enough to spur recognition in the books and records or should its presence just be disclosed?

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Minor Items

SFAS 143 applies to legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, development, or normal operations of the asset itself. In the utility business, property accountants break the huge investment in fixed assets into retirement units, whereby anything less than a retirement unit is not significant enough to be a unit of property. These items that are less than a retirement unit are often called minor items. When construction ensues to install one or more retirement units, minor items directly associated with the retirement units are often part of the construction cost. However, a minor item is not replaced with future construction dollars just because its original cost was part of fixed assets. These items are replaced using maintenance dollars or the replacement is expensed at that time. Minor items to the utility business are basically our "bricks in a kiln".

So it can easily be seen that these minor items can be a quandary when determining a conditional ARO. In some respects, these minor items can consist of the contaminants discussed below. Replacing these in the course of normal operations may be construed as impossible to determine as not enough facts are available to measure the conditional ARO. One would need to know when in the course of operations these minor items will be replaced. However, a more routine maintenance replacement may not be as difficult to predict than an item that perchance could fail. For example, if oil is replaced after every certain number of hours of operation, then one may be able to estimate the disposal obligation. The bricks example infers that the disposal of these bricks, because it is known and routine, may constitute an ARO.

A company needs to decide if any of the minor items, those that are part of the asset on installation, but are replaced on maintenance throughout the life of the asset, qualify for conditional ARO treatment. Minimally, the proper removal of oil may be a legal obligation upon retirement of the asset.

However, one keeps coming back to the idea that these items are not fixed assets in exclusion of the retirement unit. Oil sitting on the shelf (i.e. inventory) does not fall within the scope of SFAS 143. If the installation of the oil is expensed at the time it is added to the fixed asset, one could conclude that it is not part of the fixed asset cost and perhaps the only retirement obligation is the one associated with the retirement of the asset either interim or final. Assuming this conclusion, the replacement of a minor item during operation in exclusion of the retirement unit would be considered normal maintenance and not subject to ARO accounting. Whereas, the retirement of the asset including the minor item could constitute an ARO, conditional or otherwise, if the minor item causes the asset retirement to meet the rules of SFAS 143 or FIN 47.

Recommendation

Before minor items are recognized as an ARO, make sure that the component is not part of an ARO established for the asset to which the minor item relates. For example, the bricks in the kiln were replaced many times over the life of the kiln's useful life. If an ARO exists for the final disposal of the kiln in its entirety, one would not want to set up an ARO for the disposal of the final set of bricks. Clearly define the minor items that should be included and test early on in this process for materiality. One may have bricks, but the bricks represent such a small component of one's balance sheet and income statement that the inclusion of such in the ARO process may be immaterial at all times, especially if the asset (the kiln) has no ARO. Keep track of the asset to which these minor items relate in order to determine if a future ARO will be warranted by association. Lastly, document the minor items with possible AROs that are routinely replaced versus those where replacement cannot be predicted.

Some Questions for Review: Minor Items

1. Can the minor items be identified that could cause an ARO situation to occur when it is removed with the asset retirement?
2. Does the company have a definitive list of minor units of property?
3. Are the state laws or federal ones defining the disposal restrictions related to any of these minor items?
4. Can a one make a reasonable estimate of when the asset will be retired and whether the minor item will exist as part of the asset at that retirement date?
5. Does any of the guidance from AICPA Statement of Position (SOP) 96-1, "Environmental Remediation Liabilities" supersede the application of SFAS 143 or FIN 47?
6. Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?
7. Is the ARO associated with this minor item material enough to spur recognition in the books and records?

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Asbestos, PCBs, and Other Contaminants

Asbestos

Assets constructed before 1980 may have used asbestos as insulation or fire retardant. Typical removal of this substance involves extensive effort to protect workers and the environment from harm along with very specific disposal rules. For that matter, any asset with asbestos may have an ARO associated with it. The determination of whether the removal is performed as a part of normal ongoing maintenance during the life of the asset or is present at the time of retirement may need to be factored into the fair value analysis.

For non-real property, the ability to determine the amount of contamination may be an issue and a costly one at that. The engineering staff generally can determine if the asset being worked on contains asbestos, but determining the amount of contamination may not be feasible. This may make the process more difficult in applying FIN 47, but it may not preclude recognition in the financial statements. At the minimum, disclosure may be necessary for specific assets that are contaminated.

Real estate may be easier to estimate if one knows the extent of the contamination. It may be that when the building was first constructed asbestos was throughout every floor. Many years later, some of the asbestos may have been removed in past maintenance on various sections of the building. The engineers familiar with the building should know the relative extent of the contamination. If the building has been through a recent assessment, it may be possible to estimate the loss in market value of the building because of the asbestos. However, asbestos abatement may not be comparable to the loss in market value, and this loss should be weighed with the potential for undertaking the removal oneself.

Estimation of retirement, as with all assets falling within the scope of this Interpretation, can be quite difficult as some of the assets contaminated also are the longest living assets. Even with the loss in value due to selling the building with the contamination, one still may have a difficult time determining retirement parameters. Non-real property may be easier to estimate, as there often exists a manufacturing life on most retirement units.

Polychlorinated Biphenyls (PCBs)

PCBs are man-made chemical compounds previously used in the manufacture of products to make them flexible and heat resistant. Because of these fire retardant qualities, manufacturers sometimes used it in the insulating oil of capacitors, transformers and other electrical equipment. PCBs also can be found in hydraulic fluids, lubricants, paints, sealants, carbonless paper, ink, caulking compounds, and plastics.

PCBs are very stable and do not readily break down in the environment and therefore require special care during handling and disposal. The use of PCBs is regulated under the Federal Toxic Substances Control Act (TSCA). The Environmental Protection Agency (EPA) has set strict regulations regarding the manufacture, use, storage, transportation and disposal of specific levels of PCBs. PCB concentrations below specified levels are not regulated under TSCA.

The existence of regulations related to disposal of PCBs creates a duty to dispose of PCBs in a prescribed manner. The obligation to perform this asset retirement activity is unconditional even though uncertainty may exist about the timing and (or) method of settlement.

The Interpretation states an entity shall recognize a liability for the fair value of the conditional Asset Retirement Obligation (ARO) if the fair value of the liability can be reasonably estimated. If one has assets that contain PCBs and one has sufficient information to reasonably estimate the fair value of the ARO, then the PCB ARO must be recorded. Sufficient information needed to reasonably estimate the fair value includes:

- Settlement date, or information to estimate a range of potential settlement dates
- Method of settlement or potential method of settlement, and
- The probability associated with the potential settlement dates and method of settlement.

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The ability to defer settlement, such as storing PCB containing equipment, does not relieve the entity of the obligation. The PCB will eventually need to be disposed of following EPA prescribed procedures. The obligation to perform the asset retirement activity is unconditional even though uncertainty may exist about the timing or method of settlement. The PCB ARO is the cost to dispose of the PCBs as required by the EPA.

Example 1 included in Appendix A of the Interpretation indicates that the ability to sell the PCB containing equipment or facility prior to disposal does not relieve the entity of its present duty to settle the obligation. The sale of the equipment or facility transfers the obligation to another entity. The assumption of the obligation by the buyer affects the sale price. Therefore, an ARO should be recorded once known; when the asset is sold, the ARO liability is debited and the sale price is adjusted to reflect the transfer of the ARO obligation. It is assumed that the utility has factored into the calculation of the ARO, the probability that not all of the assets may be contaminated upon sale.

An entity does not have sufficient information to estimate the fair value of the ARO if:

- The settlement date is indeterminate (the range of time over which the entity may settle the obligation is unknown or cannot be estimated),
- Method of settlement is unknown, and
- Sufficient information is not available to apply an expected present value technique

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In this case, an entity will record an ARO when sufficient information exists. It currently qualifies as an ARO, albeit not measurable, and it would be subject to certain accounting and disclosure requirements related to reserves and provisions for cost of future removal. Example 3 included in Appendix A of the Interpretation illustrates this point. However, paragraph 22 of Statement 143 requires that if the liability's fair value cannot be reasonably estimated, that fact and the reasons shall be disclosed.

Electrical equipment damaged by a car, lightning or other incident, which result in a spill of insulating oil containing PCBs will be out-of-scope of this Interpretation since the spill is not considered normal operations. Paragraph 2 of the Interpretations states that "Statement 143 applies to legal obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, except as explained in paragraph 17 of that Statement for certain obligations of lessees."

Other Contaminants

As part of the normal operations for a utility, other contaminants may exist in fixed assets that would require "special" disposal procedures under federal and state regulations. Below are examples of these assets that may contain other contaminants:

Generation

- Groundwater contamination in ***ash ponds*** from metals such as nickel, chromium and arsenic
- Groundwater and soil contamination from unlined ***chemical cleaning basins*** (i.e. boiler cleaning waste basins)
- Soil and ground water contamination associated with ***above and below ground storage tanks*** (i.e. petroleum or other contamination)
- ***Solid waste landfills*** that require installation of a final cover system, grading the final cover, and establish vegetation on the final cover
- ***Septic tanks*** that must be drained an filled with sand prior to closure
- ***Wastewater and sewage treatment facilities*** that may contain hazardous wastewater treatment sludge or sewage

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Transmission & distribution

- Soil contamination from arsenic at ***substations***
- Soil contamination from mineral oil at ***substations*** from ***non-PCB transformers***

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Other

- ***Equipment*** containing sulfur hexafluoride (SF_6) gas

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This is not an exhaustive list of potential contaminates resulting from normal operations of utilities. Each company should consult with environmental experts and legal counsel to properly assess these and other contaminants for potential AROs. Care should be given to ensure that contaminants at these facilities do not fall under the scope of SOP 96-1, *Environmental Remediation Liabilities*, and that these contaminants resulted from normal operations.

Recommendation

EEI and AGA issued a White Paper entitled *Asset Retirement Obligation Implementation White Paper* late 2002, which recommended a team approach to identifying and estimating AROs. That approach can be used for the implementation of FIN 47. Listed below are some of the main points included in the White Paper:

- Use a team approach, ARO team members should include representatives from various company operating departments,
- Develop an inventory of potential AROs,
- Accounting and Legal departments must review and discuss these potential AROs to determine if a legal obligation exists,

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- Once it is determined that the obligation falls within the scope of SFAS 143 and FIN 47, the next step is measurement of the ARO liability. The amount of the ARO liability is to be measured at fair value.

Refer to the 2002 EEI and AGA White paper section entitled "Calculation Process Overview" for suggested ARO calculation guidelines and examples. The White Paper also includes journal entry examples and record keeping suggestions.

Questions for Review: Asbestos, PCBs, and Other Contaminants

1. Can all the assets be identified that contain asbestos, PCBs, or is otherwise contaminated and can it be determined the amount of asbestos that is contained in the asset?
2. Does the company treat these contaminants as a major or minor unit of property?
3. Are the state laws more onerous than the federal ones?
4. Can a market value of the asset be determined with and without the contaminant?
5. Does any of the guidance from AICPA Statement of Position (SOP) 96-1, "Environmental Remediation Liabilities" supersede the application of SFAS 143, Accounting for Retirement Obligations or FIN 47?
6. Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

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Rights-of-Way and Franchises

Land is specifically excluded from scope of SFAS 143 and FIN 47. Rights of way and easements are land related intangible assets that also are excluded from the scope of SFAS 143 and FIN 47. However, consideration should be given to whether there is a conditional obligation that can be associated to specific, existing, long-lived assets within rights-of-way and franchise areas. It should be noted that there is no asset retirement obligation associated with the franchise (or right-of-way) itself. If it is determined that there is an ARO, it only will be with the assets located within that franchise (or right-of-way).

Typically, utilities are granted franchises by each local jurisdiction in which they have distribution and transmission assets. Typically, the local jurisdiction retains the right to require the removal of the utility's assets, at the discretion of the local jurisdiction. Consequently, the wording in the franchise imposes certain requirements due to revocation of ordinances and road relocations. Just as typically, however, the intent of the utility and the local jurisdiction is for the utility to continue to provide service on a permanent basis in the service area, and the utility is required to remove its assets only when necessary to allow the local jurisdiction to perform some public work.

Generally, the wording in such franchises indicates that there is a possibility that any individual asset could be required to be moved at any time, but the wording neither identifies specific assets to be removed nor sets a specific time that the removal is required. Furthermore, the franchise wording typically indicates that the franchise is either perpetual or renewable.

Paragraph 3 of FASB Interpretation No. 47 states:

> "The term *conditional asset retirement obligation* as used in paragraph A23 of Statement 143 refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exist about the timing and (or) method of settlement."

This definition identifies three variables: "If", "When" and "How/How Much".

- The "If" is satisfied if it has been determined that an asset will have to be retired at some future date', i.e. the obligating event has occurred.
- The "When" is the date or range of dates when the retirement will/must occur.
- The "How" is the method (and by extension, the cost) associated with the retirement.

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In the case of franchises, the obligating event would be the determination by the local jurisdiction that an asset or group of assets must be removed. In granting a franchise, however, the presumption by both the utility and the local jurisdiction is that this event will never occur. The fact that this event does occur on occasion (road widening, for example) is not sufficient to negate this presumption.

In this situation, a conditional ARO does not exist, because the obligating event has not yet occurred. The possibility exists that the obligating event will occur, but the possibility alone is not itself an obligating event. The questions of "when" and "how/how much" do not even come into play, because it has not been established that any asset or group of assets will have to be removed. It is impossible to calculate an asset retirement amount, so journal entries are not required. Furthermore, the possibility that an ARO could come into existence need not be disclosed in a footnote.

It should be noted that franchise language typically requires a utility to remove its assets from a given location, not retire those assets. Theoretically, the utility could satisfy the requirements of the franchise by simply moving those assets. In the case of a road widening, for example, the utility could just pick up all of its poles and wires and move them. In reality, new poles and wire are installed and the old poles and wire are removed. But, the decision to install the new and then remove the old is a management decision, to allow for continuous service while the assets are being "relocated". And in some cases, those assets being removed could be re-used elsewhere (poles, for example). There is no asset retirement obligation, because there is no obligation to retire assets.

This situation can change for major projects, however. If a jurisdiction notifies a utility that it must remove specific assets, for any reason, and assuming the utility will retire those assets, the obligating event for those specific assets will have occurred, and an ARO would exist at that point. If the timing and method of removal can be reasonably estimated (and it probably could be), then the utility would be required to calculate and record an ARO. For example, if the utility is notified that a given section of a subway system is to be extended in five years, and that the utility will have to relocate its poles, wires, buried cable or gas mains along the route of the subway extension, all of the requirements of an ARO will have been met. At this point the utility would be required to record an asset retirement obligation for these assets.

It is not uncommon for local jurisdictions to reimburse the utility some or all of the cost of removal when that local jurisdiction requires that assets be relocated. Such reimbursements are not salvage; they are, in fact, a reduction of the cost of removal. Since the cost of removal is the basis for calculating the amount of the asset retirement obligation, any such reimbursement must be reflected (as a reduction) in the ARO calculation. This could substantially reduce the amount of the ARO (or in the case of a 100% reimbursement, totally eliminate it).

Rights-of-Way are similar to franchises, but on a smaller scale. Rights-of-Way typically are granted by individual citizens or companies, cover smaller areas of land, and may be for shorter periods than franchises. The logic in applying the criteria for establishing an ARO is the same, however. If and when an obligating event occurs, an ARO would have to be recognized if sufficient information exists to estimate the fair value of the obligation or disclosed (if sufficient information does not exist). The determination that a Right-of-Way will not be renewed would be an obligating event. Until that time, no calculations or disclosure by the utility would be required.

If it is determined that an asset retirement obligation does exist, it is important that companies do not double-count or double-record the ARO amount. For example, companies may have a program to identify and track asset retirement obligations for the disposal of treated poles. If a treated pole is in a franchise area or right-of-way and must be removed, and it is deemed that an ARO does exist, the cost of disposing of the treated pole should not be counted twice – once under the program to identify costs of disposing of treated poles, and then again as part of the cost of removing an asset from a franchise area or right-of-way. Property accounting personnel should take care to coordinate the ARO identification and measurement efforts to ensure that all ARO costs are recorded, but that those costs are recorded only once.

Recommendation

The costs of franchises and rights-of-way do not themselves incur an asset retirement obligation. Generally, the assets within the franchise area or right-of-way do not incur an asset liability solely because those assets are subject to the franchise or right-of-way. Under certain circumstances, however, those assets could incur an asset retirement obligation. If it is deemed that an asset retirement obligation does exist for certain assets in a franchise area or right-of-way, care should be taken not to include costs that have been included under another ARO identification program within the company.

Questions for Review: Rights-of-Way and Franchises

1. Who maintains the file of all franchises and rights-of-way agreements?
2. What is the exact wording in the franchises and rights-of-way agreements? (Specifically, what do it require the company to do?)
3. Can one identify al of the assets in the franchise and rights-of way areas?
4. Are the assets in the franchise and rights-of way areas covered under some other ARO identification program within the company?
5. Do the company have procedures in place to make sure that one is not double-counting the ARO?

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6. Can one reasonably estimate the amount of reimbursements the company will receive for any required cost of removal?

General Property

The possible changes in ARO accounting as indicated in the guidance and examples provided in FIN 47 also may apply to utility property classified under the General Plant function. Recently, the lead and mercury content in personal computers have been drawing attention of lawmakers, environmental agencies, and disposal sites. There are other potential issues like the mercury in fluorescent light bulbs and chemicals in common batteries. Individual utilities may want to assess ARO requirements as modified by FIN 47.

It may be possible that each of the four examples could apply depending upon the circumstances of the legal obligation and property accounting issues such as whether the obligation relates to a retirement unit, a minor item, or a smaller portion of an asset. For example the coatings or trace elements in a personal computer might be comparable to the chemicals in the treated wood poles in Example 1 in Appendix A of FIN 47. If the obligation relates to specific components of the computer, Examples 3 and 4 may be more applicable.

There may be an additional complication in applying FIN 47 to General Plant property. Many utilities have adopted amortization accounting (such as allowed under Federal Energy Regulatory Commission Accounting Release No. 15, "Vintage Year Accounting For General Plant Accounts"). A main objective of adopting amortization accounting was often to eliminate the relatively unreasonable cost of tracking the status of large volumes of low cost property. Under amortization accounting, the cost of the long-lived asset is given an assumed life and reporting of movement or disposition of the property ceases.

While there may be insufficient information in the property records, there may be alternative sources of information. In the personal computer circumstance, a utility may already have a policy of storing the PC prior to disposal – possibly to be in compliance or anticipation of compliance with disposal obligation. The assessment of application of FIN 47 might include evaluation of the existing availability of such alternative information or of possibly creating such information to facilitate compliance with both the legal obligation and the accounting requirements.

Recommendation

1. Review the circumstances for each account – identify the legal obligation, availability of the information to determine the estimated future removal cost, and the property accounting method (item property, group property, or amortization accounting).

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2. Amortization accounting would represent a unique situation, because it was probably adopted because of a determination that it was unreasonable to maintain detailed record keeping under group or item property. There may still be a basis for recording an ARO, if alternative information is available and the effort reasonable or not considered immaterial.

   a. For example, company using amortization accounting with a policy that requires that unused PCs are returned to a central location for disposal with a known disposal cost. If quantities are kept with the unamortized period, then it is possible to estimate a total liability (quantity unamortized plus quantity waiting for disposal multiplied by the disposal fee). All that is necessary is to estimate the timing of the disposals.

b. Some utilities may keep other records on such items outside of the accounting record, which may provide sufficient information to calculate the exposure quantity and approximate timing of disposal.

3. The possible situations are numerous, but if information is available and cost is large enough, then one of the methods described above (such as used for mass assets) may be applicable for making the calculation.

Questions for Review: General Property

1. Can one define the legal requirements for removal for the general assets?
2. Does the company use AR-15, amortization of general property?
3. Can one estimate potential future retirements?
4. Are the obligations for this category material?
5. If immaterial, is it appropriate to group these AROs with others to determine materiality?
6. Can you estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

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Hydro Generation

Hydro dams and facilities fall into conditional obligations primarily due to three factors:

1. An exceptionally long life of the total facility,
2. The large magnitude of costs and complications associated with removal, and
3. The uneven probabilities involved.

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In some circumstances, however, the obligation may already provide the information to support recording an estimate. In other circumstances, there may be legitimacy in asserting that too much uncertainty exists to make a reasonable estimate.

Hydro facilities (generation equipment, dam, reservoir, and other plant) typically have an extremely long life. That life may also involve multiple steps, in that the dam may continue to provide service long after generation ceases, and may be rebuilt or repaired multiple times in order to maintain the reservoir for conservation or flood control purposes. That combined total facility life may be so long that "there are no boundaries of time or an extremely lengthy period of time, that bears on a person's ability to make a reasonable estimate of the timing and the amount of the cash flows" [1] (Minutes of January 26, 2005 Board Meeting, www.fasb.org). Estimating life may be further complicated by whether the obligation is identified (individually or overlapping) by multiple jurisdictions (a FERC license, a Corp of Engineers building permit, an act of Congress, state law, or even promissory estoppel).

The exceptionally long life expectancy will typically represent the greatest obstacle to developing a reasonable estimate of ARO. Many reservoirs can be traced to the early history of the United States, so it is reasonable for a total life of a hydro facility to be measured in hundreds of years. Another complication may be multiple legal jurisdictions involved in the obligation over different phases of that total life. Further, economics may support a truly indefinite life since the magnitude of a repair/rebuild may be the clear option of choice compared to the magnitude of the cost of removal of the facility - at any point in time when a removal consideration is being faced.

The long-life combined with the economics favoring indefinite repair over removal creates a time frame in which acts of gods (unprecedented floods, earthquake, etc.) would have to be included in setting probabilities of life. Statistical models may not be applicable when a long life would also involve such random factors – not only for the life, but also the wide range of possible methods of removal complicated by varying relationships to the cause of removal.

Recommendation

Understanding the nature and timing of the current legal obligation is a critical first step, but one that may be particularly difficult to determine. With Hydro licenses, the requirement to remove the dam and flowage structure, albeit purportedly required by the FERC, may not occur if the environment has adapted and become accustom to the dam. One may have to rely more on local data that is in relation to a legal obligation to define the possible course of action.

A conditional ARO is a judgment-based process and if it results in no ARO recognition, then documentation of such conclusion must be done. If a life or range of lives can be identified, the next step is to review the extent of possible methods for meeting the obligation. If life and method of settlement can be identified, the next step would be to identify the availability of other critical elements in estimating an ARO.

Questions for Review: Hydro Generation

1. What is the nature of the legal obligation(s) involved – does it apply to only a portion of the hydro or to the full facility?
2. Can a life or a range of lives be reasonably identified with any degree of statistical validity?
3. Can the methods of settlement be identified with reasonable estimates of probability?
4. Can a market value of the asset be determined with and without asbestos?
5. If all of the above exists, can costs and cash flows be reasonably estimable with any degree of statistical validity?
6. And, can inflation be reliably predicted from present to the time of removal?
7. Does a risk-free interest rate exist for such a period and will credit adjustments be applicable to determine the rate necessary to convert the ARO into the capitalized asset retirement cost and accretion models necessary under SFAS 143?
8. Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

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Overall Recommendation

There will be no single way to estimate the conditional ARO on the property that was excluded in the earlier review. Several recommendations have been provided within this white paper, but as always, each company will need to decide the appropriate conditional ARO. This review includes the determination of the potential liability, the costing and probability of occurrence, the method for calculating the liability and asset, the materiality of the ARO, forward processing, and the appropriate disclosure. The basic concept throughout was to define the property and to encourage one to find a way to provide for the intent of the accounting without creating unbearable duress in doing the calculation. Also, the calculation for the first recognition at the end of this year should be one consideration, but the process used should define the ongoing revision of the conditional liability and the eventual settlement.

The whole process used should be defined and documented to support audit review and to satisfy any Sarbanes/Oxley provisions within the company. Even if one chooses to disclose and not to account, the documentation for the first and subsequent measurements must be such that it will completely support that decision. Overall, proper management and design of the process keeping a keen site on the form and intent should enable one to fully represent the conditional ARO without creating a nightmare of a process.

Effective Date

Effective Date

Paragraph 8 of the Interpretation specifies the effective date and states:

> The Interpretation shall be effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year enterprises). Retrospective application of interim financial information is permitted but is not required. Early adoption of the Interpretation is encouraged.

Transition Accounting:

Paragraphs 9 and 10 of the Interpretation provide requirements for transitional accounting and state:

> "For amounts recognized upon the initial application of the Interpretation, an entity shall recognize the following items in its statement of financial position: (a) a liability for any existing AROs adjusted for cumulative accretion to the date of adoption of the Interpretation, (b) an asset retirement cost capitalized as an increase to the carrying amount of the associated long-lived asset(s), and (c) accumulated depreciation on that capitalized cost."

> "Amounts resulting from initial application of the Interpretation shall be measured using current (that is, as of the date of adoption of the Interpretation) information, current assumptions, and current interest rates. The amount recognized as an asset retirement cost shall be measured as of the date the asset retirement obligation was incurred. Cumulative accretion and accumulated depreciation shall be recorded for the time period from the date

> the liability would have been recognized had the provisions of the Interpretation been in effect when the liability was incurred to the date of adoption of the Interpretation."
>
> "An entity shall recognize the cumulative effect of initially applying the Interpretation as a change in accounting principle. The amount to be reported as a cumulative-effect adjustment in the statement of operations is the difference between the amounts, if any, recognized in the statement of financial position prior to the application of the Interpretation and the net amount that is recognized in the statement of financial position pursuant to paragraph 9 of the Interpretation."

Thus, the recognition of new AROs due to adopting this Interpretation is similar to the first recognition done for SFAS 143. This first time routine is assumed to be applicable to any ARO that was previously disclosed as immeasurable, but now can be measured. Once the full accounting is established for an ARO, the change in estimate routine from SFAS 143 is used for all subsequent layers. For mass assets and other AROs recognized in aggregate, the change in the obligation acknowledged in the second and successive years may be defined as a new layer. This would have to be discussed and agreed upon by management and your auditors as an appropriate treatment.

Transition Disclosures:
Paragraph 11 of the Interpretation provides requirements for transitional disclosures and states:

> In addition to disclosures required by paragraphs 19(c), 19(d), and 21 of APB Opinion No. 20, *Accounting Changes*, an entity shall compute on a pro forma basis and disclose in the footnotes to the financial statements for the beginning of the earliest year presented and at the end of all years presented the amount of the liability for AROs as if the Interpretation had been applied during all periods affected. The pro forma amounts of that liability shall be measured using the information, assumptions, and interest rates used to measure the obligation recognized upon adoption of the Interpretation.

Until the Interpretation is implemented, there is a disclosure requirement for adoption of new accounting pronouncements (SAB 74). Basically, an entity is to provide qualitative or quantitative information, when available, about the expected impact of implementation, updated quarterly.

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Introduction¶
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AGA American Gas Association

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FASB Interpretation No. 47
Accounting for Conditional Asset Retirement Obligations
An Industry White Paper

Introduction

"This Interpretation clarifies that the term *conditional asset retirement* obligation as used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform the asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event."

This white paper has been written with an eye toward the Electric and Gas utility business. It is intended to assist one in doing the investigation and review necessary to properly recognize and disclose any new asset retirement obligations resulting from the adoption of this Interpretation. Each company will need to work through their particular issues and review all assumptions with their legal staff to assure proper representation of this topic. At first glance, this Interpretation can appear overwhelming. But one needs to approach this in a thoughtful and reasonable manner that represents the intent and purpose of the Interpretation without getting so lost in the details that the accounting becomes impossible to maintain within a cost effective manner. Without careful thought to the intent and the process to achieve it, the accounting for this Interpretation may not be manageable as the issue moves throughout time.

Another white paper was prepared by EEI and AGA shortly after SFAS 143 was issued. This white paper is supplemental to that earlier one. The following terms and acronyms are used throughout this document.

Term or Acronym	Description
ARC	Asset Retirement Cost (Plant Asset)
ARO	Asset Retirement Obligations
FERC Order 631	Accounting, Financial Reporting, and Rate Filing Docket No. RM02-7-000, *Requirements for Asset Retirement Obligations*
FERC Order 552	Revision to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2-A
FIN 47 or Interpretation	FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*
FSP	FASB Statement of Position
SAB 99	SEC Staff Accounting Bulletin No. 99, *Materiality*
SFAS 71	FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation*

Term or Acronym	Description
SFAS 143	FASB Statement No. 143, *Accounting for Asset Retirement Obligations*

Reasons for an Interpretation

Diverse accounting practices have been developed with respect to the timing of liability recognition for legal obligations associated with the retirement of a tangible long-lived asset when the timing and (or) method of settlement of the obligation are conditional on a future event. For example, some entities have recognized the fair value of the obligation prior to the retirement of the asset with the uncertainty about the timing and (or) method of settlement incorporated into the liability's fair value. Other entities, however, have recognized the fair value of the obligation only when it is probable the asset will be retired as of a specified date using a specified method or when the asset is actually retired.

The Interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO when incurred if the liability's fair value can be reasonably estimated. The Interpretation clarifies when an entity would have sufficient information to reasonably estimate the fair value of the ARO. This clarification should improve the relevance, reliability, and comparability of the amounts recognized in the financial statements.

The FASB believes application of the Interpretation will result in a more consistent recognition of liabilities relating to AROs, in more information about expected future cash outflows associated with those obligations, and in more information about investments in long-lived assets because additional asset retirement costs will be recognized as part of the carrying amounts of the assets. At the January 26, 2005 meeting, the FASB addressed a request to reconsider the entire concept of recording AROs (see FASB Board minutes at *www.fasb.org/board_meeting_minutes/board_meeting_minutes.shtml*). This discussion provides significant insight to the FASB's expectations and considerable support for the role of management's judgment and reasonableness in the recognition of AROs. In summary, the FASB essentially establishes what disclosure is expected whenever there is an ARO while also narrowing the circumstances in which the measurement could be avoided.

Sufficient Information

In SFAS 143, the term *retirement* is defined as the other-than-temporary removal of a long-lived asset from service. The term *retirement* encompasses sale, abandonment, recycling, or disposal in some other manner. The term does not encompass the temporary idling of a long-lived asset.

"If an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation, it must recognize a liability at the time the liability is incurred. An asset retirement obligation would be reasonably estimable if (a) it is evident that the fair value of the obligation is embodied in the acquisition price of the asset, (b) an active market exists for the transfer of the obligation, or (c) sufficient information exists to apply an expected present value technique." This is from paragraph 4 of the Interpretation.

The Interpretation states that when the method of settlement and settlement date have been specified by others such as in a law, regulation or contract, the entity has sufficient information to apply an expected present value technique. Therefore the ARO would be reasonably estimable and a liability must be recorded. The only uncertainty in these situations is whether performance will be required.

From paragraph 5a, "uncertainty about whether performance will be required does not defer the recognition of an asset retirement obligation because a legal obligation to stand ready to perform the retirement activities still exists", and that uncertainty does not prevent the determination of a reasonable estimate of fair value. There are two possible outcomes in situations in which the only uncertainty is whether performance will be required—the entity will be required to perform or the entity will not be required to perform.

If there is no information about which outcome is more probable, paragraph A23 of SFAS 143 requires 50 percent likelihood for each outcome to be used until additional information is available. In certain cases, determining the settlement date for the obligation that has been specified by others is a matter of judgment that depends on the relevant facts and circumstances.

In situations where the date and method of settlement are not specified by others, if information is available to reasonably estimate (1) the settlement date or the range of potential settlement dates, (2) the method of settlement or potential methods of settlement **and** (3) the probabilities associated with the potential settlement dates and potential methods of settlement, the FASB believes sufficient information is present to apply an expected present value technique. Therefore, the ARO would be reasonably estimable and a liability must be recorded.

Information that is derived from an entity's past practice, industry practice, and management's intent can provide a basis for estimating the potential methods of settlement. Entities must take into account only the methods of settling the obligation that are currently available to the entity.

The ability of an entity to indefinitely defer settlement of an ARO does not relieve the entity of the obligation. Implicit in this conclusion is the belief that no tangible asset will last forever (except land) and, accordingly, the asset retirement activities will eventually be performed. Furthermore, the ability of an entity to sell the asset prior to its disposal does not relieve the entity of its present duty or responsibility to settle the obligation. The sale would cause the buyer to assume the obligation, in turn affecting the sales price.

Change in the Way Disposal is Viewed

The FASB believes that if a current law, regulation, or contract requires an entity to perform an asset retirement activity; there is an unambiguous requirement to perform the retirement activity even if that activity can be indefinitely deferred. As noted above, no tangible asset will last forever (except land) and, accordingly, the asset retirement activities will eventually be performed. Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement.

> A law or entity's promise may create a duty or responsibility, but that law or promise in and of itself may not be the obligating event that results in an entity having little or no discretion to avoid a future transfer or use of assets.
>
> SFAS 143 states that the obligating event is the acquisition, construction, or development and (or) the normal operation of the long-lived asset when a law or promise exists that creates a duty or responsibility relating to the retirement of the asset. At this point, the obligation cannot be realistically avoided if the asset is operated for its intended use.

All companies are subject to federal and state solid waste disposal requirements for non-hazardous materials and refuse[1]. These laws require such materials to be disposed in a licensed public landfill with other household garbage. Although there is no legal obligation to retire assets under these solid waste laws, these retired and dismantled assets must be transported to licensed public landfills. Companies regularly incur monthly expenses for use of these public landfills for disposal of non-hazardous materials and refuse (i.e. garbage) which in most cases would cover disposal of non-hazardous retired assets.

The scope of SFAS 143 and FIN 47 focuses on "special" requirements for disposal of retired assets that would add incremental costs to the retirement of those assets above what a company expenses monthly for non-hazardous material and refuse disposal. This is evidenced by the reference to "special" requirements in the examples to FIN 47 and the proposed FSP on SFAS 143 relating to the European Union (EU) Directive on Waste Electrical and Electronic Equipment that requires EU members to adopt legislation for environmentally sound disposal of electrical and electronic waste equipment.

This white paper assumes that even though some legal obligation may exist to dispose of non-hazardous materials and refuse resulting from retirements of fixed assets, the disposal costs for non-hazardous materials and refuse may be inconsequential for many assets and may not add significant incremental costs to the asset retirement activities. A company may decide that there is not a legal obligation for removal whereby an asset is disposed within the

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[1] These rules federal and state regulations are governed under Subtitle D of the Resource Conservation and Recovery Act. Subtitle D regulates garbage, refuse, sludge from waste treatment plants, non-hazardous industrial waste and other discard materials including solid, semi-solid and liquid materials resulting form commercial and industrial activities (e.g. demolition debris, mining waste, oil & gas waste).

cost boundaries of the standard garbage fees and only incremental charges above this standard may constitute a removal obligation. And, the incremental charge associated with additional service may be considered part of the standard costs.

As always, a full review of the company position on this issue is paramount to defining the magnitude of potential AROs. Each company needs to decide if these laws constitute a legal obligation in respect to the SFAS 143 and the Interpretation. In instances where the legal requirement relates only to the disposal of the asset subject to the ARO, the cost to remove the asset is not included in the ARO. However, if there were a legal requirement to remove the asset, the cost of removal would be included.

Date of Obligating Event

There has been some discussion around when the obligating event occurs. Quickly, most would point to the in-service date of the asset if a law, regulation, or contract creating the obligation was in place before the in-service date. Similarly, one would choose the date the law, regulation, or contract created the obligation if it came to be after the in-service date. However, SFAS 143 refers to obligations that "result from the acquisition, construction, or development and (or) the normal operation of the long-lived asset". One could question if this infers the purchase of material during the construction process or to inventory. Whereby, the company may have incurred a legal obligation before the in-service date of the asset. Timing of the recognition of the ARO, as discussed in paragraphs 3-10 and B32-B41 of SFAS 143, is when all the following criteria are met:

The obligation meets the definition of a liability in paragraph 35 of Concepts Statement 6.

A future transfer of assets associated with the obligation is probable.

The amount of the liability can be reasonably estimated.

During construction of long-lived assets, such as a steam generating plant, legal obligations to eventually retire the plant may be incurred and measurement of those obligations may be prudent during the construction phase. It is important to remember that the obligating event has to have already happened to create a liability. In the case of a nuclear power facility, the obligation to remove the facility may not exist until the facility is operated and contamination occurs. Thus, the contamination constitutes the obligating event. Along with these two instances provided, work performed on leased property also may create a legal obligation during the construction phase. Furthermore, the amount of the liability may grow in subsequent periods as the construction of the asset continues. These changes in the amount of the original estimate may need to be recognized as an increase in the carrying amount of the liability.

Another example may be a treated pole purchased to inventory. One could argue that the obligating event has occurred at the purchase of the pole even though it is held for a time in the inventory account before moving through construction work in progress to plant in-service. The assumption presupposes that the manufacturer treated the pole before the company purchased it. The scenario would change if the company treats its poles itself. This component can add more complexity to an already multifarious process.

The definition for the obligating date needs to be fully thought out and clear as to the materiality of and the ability to recognize the obligation before the in-service date. One may likely conclude that the obligation will be flagged during construction or when in inventory only for those exceptionally large items. Otherwise, the in-service date will prevail. For any decision, either for this section or for others throughout this document, one needs to assure that it is legally reviewed and representative of management's judgment as to the correct application of the Interpretation and SFAS 143.

Indefinite Life

The first sentence in paragraph B22 of the Interpretation provides specific guidance in three clauses where FASB considers an ARO is reasonably estimable, "if information is available":

"To estimate the settlement date or the range of potential settlement dates,"

"The method of settlement or potential methods of settlement," **and** (*emphasis added).*

"The probabilities associated with potential settlement dates and methods of settlement."

The third clause would seem to imply that the **probable** service lives and estimated net salvage developed from utility depreciation studies could lead to the conclusion that an ARO is reasonably estimable. Paragraph B19 through B27 also provided more specific language than originally addressed in SFAS 143, which substantially narrowed the circumstance that would lead to a conclusion that an ARO is not estimable.

The current utility industry position is that a company cannot calculate an ARO for its distribution and transmission **systems** because each system has an indefinite life. A depreciation study develops probabilities of life and net salvage for a large group of similar assets, and that many cycles of replacements occur to the group or system. A power line or gas line between two points will probably have multiple retirements and replacement additions, particularly if a portion of the line is moved for any reason, but the line itself generally continues long afterwards. In addition, it is part of a larger group of assets when life analysis is done; all similar power lines or gas lines are considered together. In other words, the probable lives in a depreciation study are on the interim retirements and additions to the line, and not representative of the probable life of the line (or the system). Further, it has been suggested that retirement of the **system** would invoke other accounting pronouncement governing status as an ongoing entity, impairment of an asset, or accounting for discontinued operations.

Accordingly, sufficient information may not be available to reasonably estimate the ARO liability on transmission or distribution property. The industry also does not believe that an ARO should be calculated for such interim retirements because there may not be an obligation for that specific interim retirement or a company would not know when a specific interim retirement with an obligation would take place. The third characteristic of a liability is that the transaction or other event obligating the entity has already happened. One does not know what portion of a distribution or transmission system will be retired until an event such as a gas leak, storm damage, or a road widening requires work on the asset, which may or may not result in capital replacement. When these obligating events do occur, it generally is corrected or recorded in the same accounting period so no liability would be accrued.

However, FIN 47 provides further interpretation of FAS 143 that may require a reassessment of the indefinite life concept. Example 1 specifically addresses this mass asset system versus individual asset contrast and clearly attempts to close the loophole that a system has an infinite life, therefore no ARO can be measured. FIN 47 requires that the fair value of an ARO be recognized when it can be reasonably estimated. It also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. For most utilities, data derived from their most current depreciation study would be a potential source to provide information to calculate an estimated ARO for distribution and transmission assets. This data is used to recover property costs (including removal cost) for regulatory purposes and also may serve as a platform for calculating the expected ARO liability. Depreciation study data is used in the Snapshot example within the Mass Assets, Electric and Gas section of this paper.

An argument also can be made that depreciation study data does not provide sufficient information to estimate a reasonable ARO liability. Depreciation data is utilized to provide for matching of existing property cost with the customer benefiting from that property cost. It is not designed, in concept, to provide an estimated liability for the permanent removal of the entire distribution and transmission system. The assumption is the entity will continue to be a going concern. As such, depreciation study data may need to be used cautiously as it may not be an appropriate mechanism to use when calculating all ARO liabilities. Discarding the depreciation study data, no data would be available to reasonably estimate the ARO liability.

Given this quandary, the indefinite life concept currently used by most utilities may continue in effect for the ultimate retirement of the system. But again, it was very clear that a "do nothing" scenario for any mass asset with a definable disposal requirement might have to be recognized even though the larger retirement obligation on the entire system may not. Any conclusion needs to be supported with full documentation and justification for the indefinite life choice and should be disclosed.

Materiality

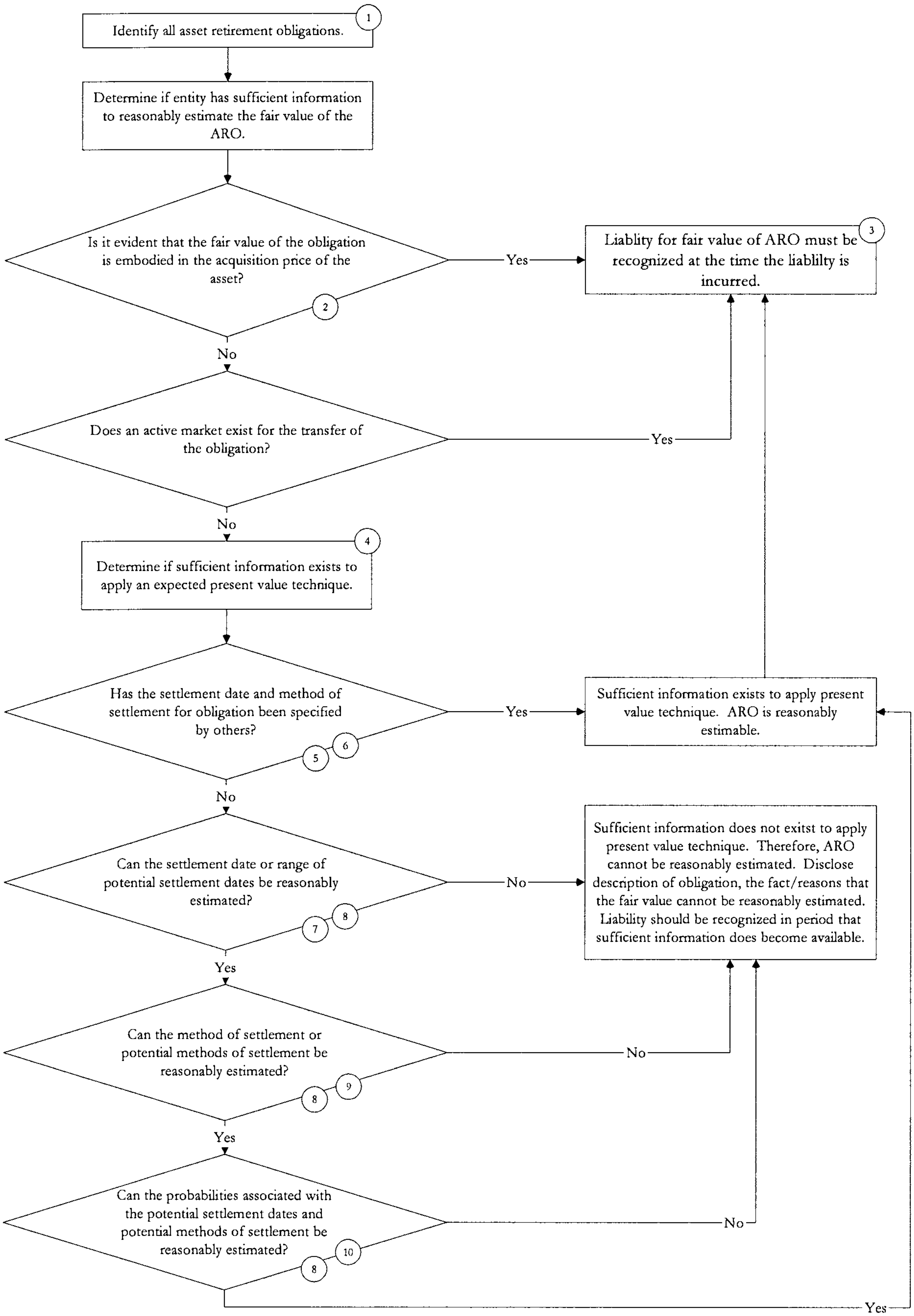
FIN 47 clearly states, "The provisions of this Interpretation need not be applied to immaterial items." However, many immaterial items may constitute in aggregate a material item. Determination of materiality is company specific and often an issue-specific routine. It should be defined and documented for each segment of the business. Along with the materiality threshold, a company should define the way in which assets will be summed to test materiality. It is assumed that the test will be for balance sheet materiality, as most utilities will offset any income statement effect with regulatory accounting. When the ARO does impact the income statement, an income statement materiality test may be used. For example, one must decide if distribution assets will be combined with nuclear assets in determining materiality. Perhaps a company will sum all asset obligations relative to a segment of the utility business keeping the nuclear AROs separate from the distribution calculation. Defining the materiality test to a lower level than function should be a decision based on propriety and not with the intent of avoiding this Interpretation. Additional guidance on materiality can be found in the Securities and Exchange Commission's SAB No. 99.

For those companies that have more than one legal entity, the materiality should be done at the individual legal entity and not at the consolidated level. Now, one legal entity may have an ARO and another may not for the same class of assets because of the variety in the rules and regulation as well as the difference in size of the companies. This white paper does not advocate a consolidated materiality review of AROs where multiple legal entities exist within the corporation. The obligation is clearly the responsibility of the originating legal entity and it should be maintained at that level. However, the disclosures may be more detailed on the utility reports and summarized at the parent level.

Decision Tree

In general, a more substantive review of regulations, laws, and contract obligations will be required to assure that conditional AROs are properly recognized. Each company will need to assess its particular facts and circumstances as the same general situation may play out differently depending on the legal documents and company policies that surround it. To help facilitate this review, a decision tree for analyzing each situation is provided below.

Decision Tree



Decision Tree Notes

Paragraph 3 of FIN 47 advises to include all legal obligations to perform an asset retirement activity, even those in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement.

Paragraph B7 of the Interpretation states, "As used in Statement 143, a legal obligation is an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel."

Paragraph 4 of the Interpretation references paragraph 17 of FASB Concepts Statement No. 7, *Using Cash Flow Information and Present Value in Accounting Measurements,* which states, "If a price for an asset or liability or an essentially similar asset or liability can be observed in the marketplace, there is no need to use present value measurements. The marketplace assessment of present value is already embodied in such prices."

Paragraph 3 of the Interpretation reiterates the SFAS 143 requirement that the fair value of an asset retirement obligation be recognized when the obligation is incurred—generally upon acquisition, construction, or development and (or) through the normal operation of the asset.

Present value techniques are discussed in paragraphs 39–54 and 75–88 of Concepts Statement 7. These techniques, which incorporate uncertainty about the timing and method of settlement into the fair value measurement, should be used when the fair value of the liability cannot be estimated based on the acquisition price or on an observable market price.

For example, specified in a law, regulation or contract (Paragraph 5a of the Interpretation).

Paragraph 5a of the Interpretation states that uncertainty about whether performance will be required does **not** defer the recognition of an asset retirement obligation because a legal obligation to stand ready to perform the retirement activities still exists, and it does not prevent the determination of a reasonable estimate of fair value because the only uncertainty is whether performance will be required.

There are two possible outcomes in situations in which the only uncertainty is whether performance will be required—the entity will be required to perform or the entity will not be required to perform. If there is no information about which outcome is more probable, paragraph A23 of Statement 143 requires 50 percent likelihood for each outcome to be used until additional information is available.

In certain cases, determining the settlement date for the obligation that has been specified by others is a matter of judgment that depends on the relevant facts and circumstances. For example, a contract that provides the entity with an ability to extend its term through renewal should be evaluated to determine whether the settlement date should take into consideration renewal periods.

Paragraph 5b of the Interpretation states that the estimated economic life of the asset might indicate a potential settlement date for the asset retirement obligation. However, the original estimated economic life of the asset might not establish, in and of itself, that date because the entity may intend to make improvements to the asset that could extend the life of the asset or the entity could defer settlement of the obligation beyond the economic life of the asset. In those situations, the entity would look beyond the economic life of the asset in determining the settlement date or range of potential settlement dates to use when estimating the fair value of the asset retirement obligation.

Paragraph 5b gives examples of information that is expected to provide a basis for estimating the potential settlement dates, potential methods of settlement, and the associated probabilities. Examples include, but are not limited to, information that is derived from an entity's past practice, industry practice, management's intent, or the asset's estimated economic life.

Paragraph 5b of the Interpretation limits "potential methods of settlement" to those methods that are currently available to the entity. Therefore, uncertainty about future methods yet to be developed would not prevent the entity from estimating the fair value of the asset retirement obligation.

Paragraph 5b of the Interpretation states that the entity should have a reasonable basis for assigning probabilities to the potential settlement dates and potential methods of settlement to reasonably estimate the fair value of the asset retirement obligation. If the entity does not have a reasonable basis of assigning probabilities, it is expected that the entity would still be able to reasonably estimate fair value when the range of time over which the entity may settle the obligation is so narrow and (or) the cash flows associated with each potential method of settlement are so similar that assigning probabilities without having a reasonable basis for doing so would not have a material impact on the fair value of the asset retirement obligation.

Specific Property Considerations

Four examples were included in FIN 47. This white paper discusses those examples in the context of the Electric and Gas utility business. The examples are as follows:

Telecommunication poles

Bricks in a kiln

Factory with asbestos and regulations go into effect after purchase

Factory with asbestos and regulations are in place at acquisition

Basically, the premise put forward by the FASB in this Interpretation was that no tangible asset, except land, would last forever and accordingly, asset retirement activities will eventually be performed. In completing the retirement work, if a company is required to dispose of the asset in a specific manner or could be required to perform any one of a number of different methods of settlement, to be chosen at some later date, the company will need to evaluate the asset's retirement obligations. The four examples provided were meant to cover various situations a company may face. To bring the examples into the context of the energy industry, the list has been tailored to the potential issues for the Electric and Gas business. The following are the asset issues discussed in the remaining document:

Mass assets, electric and gas ***(Telecommunication poles)***

Minor Items ***(Bricks in a kiln)***

Asbestos, PCBs, and other contaminants ***(Factory with asbestos and regulations go into effect after purchase or in place at acquisition)***

Rights-of-Way and franchises

General equipment

Hydro generation

Mass Assets, Electric and Gas

Example 1 of Appendix A, Illustrative Examples, provides specific discussion on wood pole treated with certain chemicals. However, the circumstances may be comparable to other utility property generally described as mass asset property. The following summarizes Example 1, followed by a discussion of comparability and applicability to other mass assets, and finally a discussion of various issues for utilities to consider in their implementation of FIN 47.

Summary of Example 1 of Appendix A

Example 1 discusses a situation in which a utility is using treated wood poles and where there is existing legislation that requires special disposal procedures in the state in which the utility operates. The example recognizes that the poles may be removed from the ground for a variety of operational reasons other than disposal, and further recognizes that the disposal obligation is not triggered by removal of the pole. Once a pole is removed from the ground, it may be disposed of, sold, or reused as part of other activities. In this example, the disposal obligation is not triggered by removal of the pole. Based on that premise, Example 1 includes specific guidance that requires an assessment of AROs related to treated wood poles. That guidance suggests assessing the ARO and related accounting based on the following:

The **recognition point begins with the purchase** of the pole, rather than when the pole was placed into service (in-service date is when the pole first became a long-lived fixed asset). See obligating event and materiality above.

That **reuse does not change the obligation**, only defers it (common industry practice is to retire the pole at time of removal, not track it while in inventory, and considered a new addition when reused and placed in the ground again).

The **utility already has the information necessary to estimate** a range of settlement dates, methods of settlement, and the related probabilities **based on entity-specific practices, industry practices, management's intent, or the asset's estimated economic life.** (It is important to note that only in the example did the entity have sufficient information to estimate the fair value of the liability for the ARO. Each entity will have to make their own determination as to whether they have sufficient information.)

The utility is **not relieved of the obligation by selling** the pole to another party through the assertion that the exchange price reflects the estimated fair value of the obligation.

Impact On Asset Retirement Obligations Accounting

Example 1 of FIN 47 represents a utility that has a legal requirement to follow special procedures for disposal of treated wood poles. In this example, the utility is presumed to have all the information necessary to calculate an asset retirement obligation and is expected to make appropriate disclosure. Therefore, the asset retirement obligation should be recognized when the entity purchases the pole. This may result in a significant change from the requirements under FAS 143, where previous estimates and disclosures were not made because: 1) most disposal activities were performed by third parties so there were no future direct costs to be expended by the utility, 2) it was not reasonable to track the obligation (and settlement) due to reuse and different options for disposal, or 3) that the obligation was conditional due to circumstances known only at the time of removing the pole from the ground. There were no future costs because most utilities could give the poles away to third parties at no cost to the utility, but under FIN 47 even the ultimate disposal cost to a third party is to be considered (that net zero would be bifurcated into the avoided future disposal removal cost and the salvage – remember salvage is not recognizable for ARO purposes.)

Example 1 could apply to other mass asset property where a portion of the asset may be subject to special disposal procedures. Some examples might be property containing PCBs, mercury, lead, or any chemical considered hazardous. In other words, FIN 47 requires that if a utility has a special procedure requirement at ultimate disposal, then the utility either would have a measurable ARO with all the related accounting requirements, which should be recognized if the entity has sufficient information to estimate the fair value of the obligation. If the entity does not have sufficient information to reasonably estimate the obligation, the entity only has a disclosure requirement until sufficient information becomes available.

Concerns and Issues

This raises several concerns and issues for both the individual utility and for the industry:

Initial determination of legal obligation – The language seems to indicate that if there is a special disposal procedure, that there will be a cost of performing that disposal activity and therefore, an asset retirement obligation. The legal obligation review may need to be expanded to other assets containing materials, which are considered hazardous with special disposal procedures required by some legal mandate.

Record keeping and reporting changes – Many if not most utilities track poles as assets from the date put in the ground until the next time it is removed rather than from purchase to disposal. Time in inventory (initially and upon salvage for reuse) is often not tracked – much less details on how many were treated and what happened to the treated portion at disposal. An individual utility may have to develop such tracking details.

Third party disposal – Example 1 states that the "ability to sell the poles prior to disposal does not relieve the entity of its ...obligation", and states that "the assumption of the obligation affects the exchange price". This could be a significant issue in compliance for some utilities. It implies that the utility is not relieved of the obligation; and, therefore, should attempt to measure the ARO. However, it would seem that knowledge of how subsequent owners plan to use the pole would be necessary to estimate the effect on the sales price.

The use of the pole would affect disposal requirements, as Example 1 clearly requires a company to identify that future disposal cost for third parties. Therefore, unless there is a market price available, the company would need to apply present value techniques, which requires knowing how long the third party will use the pole before disposal. It appears ridiculous and unreasonable, but is clear in the Interpretation. Such information about that future transaction may be particularly hard to estimate when the utility purchases the pole and needs to record the obligation.

SEC transfer of other provisions for accrued cost of removal – Any change because of reassessing the ARO for treated wood poles also would affect any recognition of the SEC interpretation on depreciation accruals for future removal costs.

Background: SFAS 143 does not allow a provision for future removal costs to be included in depreciation reserves or current expense. FERC Order 631 provides that utilities that qualify to apply SFAS 71 and if the requirements for Order 552 are met, any provisions for future removal cost would be transferred to a regulatory liability. However, FERC Order 631 continues to allow provision for future removal costs for assets that do not have an existing legal retirement obligation. A conflict may exist because many utilities also have adopted the unofficial SEC interpretation that SFAS 143 does not allow for any accrual of future removal costs, and all provisions for future removal costs should be excluded from accumulated reserves (or transferred to a regulatory liability if eligible for SFAS 71). There is inherent contradiction for many utility assets whereby it needs to be recognized in two different ways for reporting the same activity to the two different entities.

FERC Order 631 requires that only for accounts where an ARO is recognized, then previous provisions for future removal costs should be transferred from the accumulated reserve (and carried as a regulatory obligation under SFAS 71, if the requirements for Order 552 are met). Many utilities have also adopted the unofficial SEC interpretation that SFAS 143 does not allow for any accrual of future removal costs, and all provisions for future removal costs should be excluded from accumulated reserves (or transferred to a regulatory liability if eligible for SFAS 71).

The cumulative effect adjustment for SEC reporting will be the difference between the amount previously recognized prior to FIN 47 and the amount recognized following the advice in FIN 47 (as mentioned under Transition Accounting below). FERC reporting will be governed by any new advice that FERC may issue prior to adoption of FIN 47.

Recommendation

Since ARO compliance for this category of plant type, mass assets, may be quite onerous, a recommendation is offered for consideration to achieve the intent of the Interpretation without excess burden to the company and the accounting personnel. Each company will need to decide if the recommendation is feasible for their books and records. The FIN 47 or SFAS 143 calls for an ARO on individual assets. This is not practical for large transmission and distribution utilities that use group accounting. Therefore, the recommendation is to approximate the literal compliance with FIN 47 with an approximation that uses a statistical based method in order to achieve the **intent** of the statements without incurring undue burden on the accounting personnel.

Statistical Method – There are varying levels of information available to the individual utility from their depreciation studies from Simulated Plant Record to Equal Life Group study methods applied property data from individual accounts/sub accounts to functional categories like distribution plant. Even availability of details (such as separating net salvage into removal cost or into removal cost just for treated poles) will vary for different utilities. The following are general descriptions of possible approximation procedures that might be used:

Modified group property/modified depreciation study. Using the latest available depreciation study, the utility could develop the percentage adjustments to indicated life and negative salvage estimates to approximate the timing and the amount of the future removal cash flow. Many utilities have property records that provide the age of existing property and combined with average age, a future cash flow estimate could be prepared for each vintage of property (average age less current age result in the time to expected removal). There may be a standard length of time between removal from service until actual disposal and that could be added to remaining life.

It may be necessary to analyze the property in the pole account as not all the units may be part of the retirement obligation and to identify a percentage adjustment to approximate the proportion of obligating poles that are treated to all others and adjust the future cash flows to represent only the legally required disposal.

If dispersion curves were used in the study, the related retirement curves also could be used to approximate the period of disposal. When time estimates and future cash flows are estimated, then one can compute the various ARO elements (ARC, depreciation and accretion tables, and associated regulatory assets). For the first year, monthly entries are made based on that estimate only. In subsequent years and if vintaged retirements are available, it would be possible to go through the individual settlement calculations for each ARO vintage group plus recognize any layers if disposal cost estimates change or a new study is performed. If vintage retirement data is not available, do exactly the same calculation, but true up the components (which would eliminate all the subsequent measurements and layering).

Fin 47 requires the use of current assumptions. It may be necessary to perform a new depreciation study to obtain current information on expected lives and removal costs for existing property. Negative salvage estimates that have been taken from depreciation studies reflect previous assumptions. In other words, the study reflects removal costs that have already happened and may not even reflect costs or methods of disposal under a new or recent legal requirement (or only partially reflect it). To the extent that previous assumptions are the same as current assumptions, the depreciation study may be used.

The gross removal portion of the negative net salvage amount also may contain a removal component that may or may not be part of the retirement obligation. Use of the approved rate to determine the obligation under this Interpretation could result in an inflated obligation. In either case, it should be updated to reflect current assumptions, based on management's intent, the asset's estimated economic life as well as entity and industry practices. Be sure to exclude gross salvage value from estimated removal costs and to split the removal costs into its components in order to identify only those pieces that represent the retirement obligation.

Snapshot. If immaterial or one is unable to modify or perform annual studies, work with what is available at the end of each year. Then compute the ARO by taking a snapshot each year and true up for differences.

Detail Method – If detailed records exist or it is feasible to create detailed records and reporting just for treated wood poles (or like mass assets), then it would be possible to fully comply with SFAS 143 and FIN 47.

For either method, one may want to:

Re-examine the legal obligation to determine if there is a specific obligation due to the type of treatment on the poles along with other mass assets **and** that complying will result in a cost. For some locations, there are no "special" disposal tracking or fees. Examine the disposal fee for poles to determine if it is related to special facilities or just additional cost for garbage service. No cost means no accruals need to be booked.

Determine if the future fee could qualify as immaterial. For example, a $5 fee or a 50-cent information sheet to buyers could be immaterial on the surface. However, balance sheet materiality would apply and it is the fair value of the ARO items as grouped that may determine materiality.

Review the additional reporting and record keeping requirements of the full application to determine if the cost of keeping records is unreasonable for the effort and that an alternative method may yield a reasonable estimate. For example, if one can match disposal to vintaged purchases, then one should be able to comply using the Detailed Method instead of developing a statistical approximation.

Similar to above, review whether the depreciation studies are reasonably compatible. Remember FIN 47 "example 1" is concerned with "purchase to disposal" total life versus studies based upon "site life" and in-service time (does not recognize reuse.) Similarly, then, approximation methods might be reasonable. Paragraph 2 of SFAS 143 states that this "applies to legal obligations associated with the *retirement*[2] of a tangible long-lived asset that results from **the acquisition, construction or development...**" This sentence has two interpretations - the first half indicates it only applies to plant in-service, while the second half adds the purchase or construction to the point of application. This review may want to include making a determination on the reasonableness and materiality of the difference between in-service date versus the date of construction or purchase.

Alternative approaches also may be justified if one qualifies as a regulated utility. As a regulated utility, the entire ARO compliance effort may result only in balance sheet adjustments with no earning impacts. The most reasonable application of managerial judgment might involve only a high-level, rough estimate of the current obligation without all the various kinds of offsetting regulatory assets and regulatory liabilities. It may be that all those offsetting line items and calculations provides only confusion and a good description of the circumstances is the most appropriate disclosure, especially if preliminary efforts indicate that full compliance results in an immaterial impact.

An example of a possible "snapshot" follows. Utilities with recent, extensive, and detailed studies may have such particulars and resources to develop a very close approximation of full ARO accounting. Many utilities will have very limited information available from latest depreciation studies and property records. This example is intended to show how to approximate an ARO calculation with the bare minimum of information.

Assuming that the utility depreciation study only provides an average service life and net salvage (no basis for a split for removal costs), has a count or estimate of treated poles in service, and vintage or estimate of age of those poles:

For Year 1 (2005) the following applies:

Surviving plant is equal to 100,000 poles,

Average service life is estimated to be 50 years,

Average age of existing poles is 30 years (average remaining life is 20 years)

Disposal cost is $15 per pole fee set by law in 2000 at a local waste management facility.

Future removal cost in 20 years would be $1.5 million ($15 times 100,000). Note, apply an inflation factor as well if disposal fee can increase due to inflation,

Apply a current discount rate (credit adjusted risk free rate) back to the year that the obligation began (in this example it is the year 2000) to determine ARC,

Set up schedules to determine ARC depreciation, accumulated reserve, accretion table, and current value of ARO in year 2005 (also determine regulatory accounting to offset any expenses or income if eligible for SFAS 71 treatment – FERC Accounts 182.3 and 407.4 for regulatory assets, FERC Accounts 254 and 407.3 for regulatory liabilities).

For Year 2 (it is now 2006) the following occurs:

Surviving plant has been reduced to 95,000 poles (additions and retirement led to a net reduction,

Average service life is still estimated to be 50 years,

Average age of existing poles has changed due to the additions and retirements – and is now 29.5 years (average remaining life is now 21.5 years)

Disposal cost is still $15 per pole fee set by law at a local waste management facility back in year 2000 (watch for whether this should be inflated),

Future removal cost in 21.5 years would be $1.425 million (15 times 95,000),

Apply a current discount rate (credit adjusted risk-free rate) back to year 2000 to determine ARC (FERC account 359.1 or 374),

Set up schedules to determine ARC depreciation, accumulated reserve, accretion table, and current value of ARO now in year **2006** (also determine regulatory accounting to offset any expenses or income if eligible for SFAS 71 treatment – FERC Accounts 182.3 and 407.4 for regulatory assets, FERC Accounts 254 and 407.3 for regulatory liabilities).

Compare the Year 2 (2006) results to Year 1 (2005) results:

Adjust both the ARC asset, ARC accumulated reserve, and the ARO liability to the new numbers.

The remaining differences (accretion, depreciation, and affect of the change upon the current) will be recognized as a gain or loss or deferred under regulatory accounting (adjust previously recorded amount – difference may change the amount from an asset to a liability which should be a reversal of the prior year entry and a new entry in order to keep the connection between 407.3 and 254 or 407.4 and 182.3 as appropriate).

Layering is being ignored for both because this is only an approximation and this does recognize that the forecast future date of cash flows has changed for all assets and in the long run will achieve a more appropriate obligation at the time of disposal.

In the situation where more information is available (such as vintage data), and the effort reasonable, then the above "snapshot" approach could be applied to each vintage. If service life is estimated using dispersion curves such as Iowa Curves, another enhancement would be to use the "retirement rate" percentages from those curves to develop the estimated time for future retirements. Such an enhancement may be unreasonable (especially if being computed manually) because it would be many times more complicated with the number of vintages involved and it may result in an immaterial difference to the results. These are issues subject to that managerial judgment discussed at the beginning of this document.

Questions for Review: Mass Assets, Electric and Gas

Which mass assets are subject to this section?

What actuarial assumptions has the company been using with those assets identified as falling within FIN 47?

Are the state laws or federal ones defining the disposal restrictions related to any of these minor items?

Can one determine a reasonable estimate the current disposal costs and does that apply to all or most in the mass asset group?

Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

Is the ARO associated with this mass assets material enough to spur recognition in the books and records or should its presence just be disclosed?

Minor Items

SFAS 143 applies to legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, development, or normal operations of the asset itself. In the utility business, property accountants break the huge investment in fixed assets into retirement units, whereby anything less than a retirement unit is not significant enough to be a unit of property. These items that are less than a retirement unit are often called minor items. When construction ensues to install one or more retirement units, minor items directly associated with the retirement units are often part of the construction cost. However, a minor item is not replaced with future construction dollars just because its original cost was part of fixed assets. These items are replaced using maintenance dollars or the replacement is expensed at that time. Minor items to the utility business are basically our "bricks in a kiln".

So it can easily be seen that these minor items can be a quandary when determining a conditional ARO. In some respects, these minor items can consist of the contaminants discussed below. Replacing these in the course of normal operations may be construed as impossible to determine as not enough facts are available to measure the conditional ARO. One would need to know when in the course of operations these minor items will be replaced. However, a more routine maintenance replacement may not be as difficult to predict than an item that perchance could fail. For example, if oil is replaced after every certain number of hours of operation, then one may be able to estimate the disposal obligation. The bricks example infers that the disposal of these bricks, because it is known and routine, may constitute an ARO. A company needs to decide if any of the minor items, those that are part of the asset on installation, but are replaced on maintenance throughout the life of the asset, qualify for conditional ARO treatment. Minimally, the proper removal of oil may be a legal obligation upon retirement of the asset.

However, one keeps coming back to the idea that these items are not fixed assets in exclusion of the retirement unit. Oil sitting on the shelf (i.e. inventory) does not fall within the scope of SFAS 143. If the installation of the oil is expensed at the time it is added to the fixed asset, one could conclude that it is not part of the fixed asset cost and perhaps the only retirement obligation is the one associated with the retirement of the asset either interim or final. Assuming this conclusion, the replacement of a minor item during operation in exclusion of the retirement unit would be considered normal maintenance and not subject to ARO accounting. Whereas, the retirement of the asset including the minor item could constitute an ARO, conditional or otherwise, if the minor item causes the asset retirement to meet the rules of SFAS 143 or FIN 47.

Recommendation

Before minor items are recognized as an ARO, make sure that the component is not part of an ARO established for the asset to which the minor item relates. For example, the bricks in the kiln were replaced many times over the life of the kiln's useful life. If an ARO exists for the final disposal of the kiln in its entirety, one would not want to set up an ARO for the disposal of the final set of bricks. Clearly define the minor items that should be included and test early on in this process for materiality. One may have bricks, but the bricks represent such a small component of one's balance sheet and income statement that the inclusion of such in the ARO process may be immaterial at all times, especially if the asset (the kiln) has no ARO. Keep track of the asset to which these minor items relate in order to determine if a future ARO will be warranted by association. Lastly, document the minor items with possible AROs that are routinely replaced versus those where replacement cannot be predicted.

Some Questions for Review: Minor Items

Can the minor items be identified that could cause an ARO situation to occur when it is removed with the asset retirement?

Does the company have a definitive list of minor units of property?

Are the state laws or federal ones defining the disposal restrictions related to any of these minor items?

Can a one make a reasonable estimate of when the asset will be retired and whether the minor item will exist as part of the asset at that retirement date?

Does any of the guidance from AICPA Statement of Position (SOP) 96-1, "Environmental Remediation Liabilities" supersede the application of SFAS 143 or FIN 47?

Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

Is the ARO associated with this minor item material enough to spur recognition in the books and records?

Asbestos, PCBs, and Other Contaminants

Asbestos

Assets constructed before 1980 may have used asbestos as insulation or fire retardant. Typical removal of this substance involves extensive effort to protect workers and the environment from harm along with very specific disposal rules. For that matter, any asset with asbestos may have an ARO associated with it. The determination of whether the removal is performed as a part of normal ongoing maintenance during the life of the asset or is present at the time of retirement may need to be factored into the fair value analysis.

For non-real property, the ability to determine the amount of contamination may be an issue and a costly one at that. The engineering staff generally can determine if the asset being worked on contains asbestos, but determining the amount of contamination may not be feasible. This may make the process more difficult in applying FIN 47, but it may not preclude recognition in the financial statements. At the minimum, disclosure may be necessary for specific assets that are contaminated.

Real estate may be easier to estimate if one knows the extent of the contamination. It may be that when the building was first constructed asbestos was throughout every floor. Many years later, some of the asbestos may have been removed in past maintenance on various sections of the building. The engineers familiar with the building should know the relative extent of the contamination. If the building has been through a recent assessment, it may be possible to estimate the loss in market value of the building because of the asbestos. However, asbestos abatement may not be comparable to the loss in market value, and this loss should be weighed with the potential for undertaking the removal oneself.

Estimation of retirement, as with all assets falling within the scope of this Interpretation, can be quite difficult as some of the assets contaminated also are the longest living assets. Even with the loss in value due to selling the building with the contamination, one still may have a difficult time determining retirement parameters. Non-real property may be easier to estimate, as there often exists a manufacturing life on most retirement units.

Polychlorinated Biphenyls (PCBs)

PCBs are man-made chemical compounds previously used in the manufacture of products to make them flexible and heat resistant. Because of these fire retardant qualities, manufacturers sometimes used it in the insulating oil of capacitors, transformers and other electrical equipment. PCBs also can be found in hydraulic fluids, lubricants, paints, sealants, carbonless paper, ink, caulking compounds, and plastics.

PCBs are very stable and do not readily break down in the environment and therefore require special care during handling and disposal. The use of PCBs is regulated under the Federal Toxic Substances Control Act (TSCA). The Environmental Protection Agency (EPA) has set strict regulations regarding the manufacture, use, storage, transportation and disposal of specific levels of PCBs. PCB concentrations below specified levels are not regulated under TSCA.

The existence of regulations related to disposal of PCBs creates a duty to dispose of PCBs in a prescribed manner. The obligation to perform this asset retirement activity is unconditional even though uncertainty may exist about the timing and (or) method of settlement.

The Interpretation states an entity shall recognize a liability for the fair value of the conditional Asset Retirement Obligation (ARO) if the fair value of the liability can be reasonably estimated. If one has assets that contain PCBs and one has sufficient information to reasonably estimate the fair value of the ARO, then the PCB ARO must be recorded. Sufficient information needed to reasonably estimate the fair value includes:

Settlement date, or information to estimate a range of potential settlement dates

Method of settlement or potential method of settlement, and

The probability associated with the potential settlement dates and method of settlement.

The ability to defer settlement, such as storing PCB containing equipment, does not relieve the entity of the obligation. The PCB will eventually need to be disposed of following EPA prescribed procedures. The obligation to perform the asset retirement activity is unconditional even though uncertainty may exist about the timing or method of settlement. The PCB ARO is the cost to dispose of the PCBs as required by the EPA.

Example 1 included in Appendix A of the Interpretation indicates that the ability to sell the PCB containing equipment or facility prior to disposal does not relieve the entity of its present duty to settle the obligation. The sale of the equipment or facility transfers the obligation to another entity. The assumption of the obligation by the buyer affects the sale price. Therefore, an ARO should be recorded once known; when the asset is sold, the ARO liability is debited and the sale price is adjusted to reflect the transfer of the ARO obligation. It is assumed that the utility has factored into the calculation of the ARO, the probability that not all of the assets may be contaminated upon sale.

An entity does not have sufficient information to estimate the fair value of the ARO if:

The settlement date is indeterminate (the range of time over which the entity may settle the obligation is unknown or cannot be estimated),

Method of settlement is unknown, and

Sufficient information is not available to apply an expected present value technique

In this case, an entity will record an ARO when sufficient information exists. It currently qualifies as an ARO, albeit not measurable, and it would be subject to certain accounting and disclosure requirements related to reserves and provisions for cost of future removal. Example 3 included in Appendix A of the Interpretation illustrates this point. However, paragraph 22 of Statement 143 requires that if the liability's fair value cannot be reasonably estimated, that fact and the reasons shall be disclosed.

Electrical equipment damaged by a car, lightning or other incident, which result in a spill of insulating oil containing PCBs will be out-of-scope of this Interpretation since the spill is not considered normal operations. Paragraph 2 of the Interpretations states that "Statement 143 applies to legal obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, except as explained in paragraph 17 of that Statement for certain obligations of lessees."

Other Contaminants

As part of the normal operations for a utility, other contaminants may exist in fixed assets that would require "special" disposal procedures under federal and state regulations. Below are examples of these assets that may contain other contaminants:

Generation

Groundwater contamination in ***ash ponds*** from metals such as nickel, chromium and arsenic

Groundwater and soil contamination from unlined ***chemical cleaning basins*** (i.e. boiler cleaning waste basins)

Soil and ground water contamination associated with ***above and below ground storage tanks*** (i.e. petroleum or other contamination)

Solid waste landfills that require installation of a final cover system, grading the final cover, and establish vegetation on the final cover

Septic tanks that must be drained an filled with sand prior to closure

Wastewater and sewage treatment facilities that may contain hazardous wastewater treatment sludge or sewage

Transmission & distribution

Soil contamination from arsenic at ***substations***

Soil contamination from mineral oil at ***substations*** from ***non-PCB transformers***

Other

Equipment containing sulfur hexafluoride (SF_6) gas

This is not an exhaustive list of potential contaminates resulting from normal operations of utilities. Each company should consult with environmental experts and legal counsel to properly assess these and other contaminants for potential AROs. Care should be given to ensure that contaminants at these facilities do not fall under the scope of SOP 96-1, *Environmental Remediation Liabilities*, and that these contaminants resulted from normal operations.

Recommendation

EEI and AGA issued a White Paper entitled *Asset Retirement Obligation Implementation White Paper* late 2002, which recommended a team approach to identifying and estimating AROs. That approach can be used for the implementation of FIN 47. Listed below are some of the main points included in the White Paper:

- Use a team approach, ARO team members should include representatives from various company operating departments,
- Develop an inventory of potential AROs,
- Accounting and Legal departments must review and discuss these potential AROs to determine if a legal obligation exists,
- Once it is determined that the obligation falls within the scope of SFAS 143 and FIN 47, the next step is measurement of the ARO liability. The amount of the ARO liability is to be measured at fair value.

Refer to the 2002 EEI and AGA White paper section entitled "Calculation Process Overview" for suggested ARO calculation guidelines and examples. The White Paper also includes journal entry examples and record keeping suggestions.

Questions for Review: Asbestos, PCBs, and Other Contaminants

- Can all the assets be identified that contain asbestos, PCBs, or is otherwise contaminated and can it be determined the amount of asbestos that is contained in the asset?
- Does the company treat these contaminants as a major or minor unit of property?
- Are the state laws more onerous than the federal ones?
- Can a market value of the asset be determined with and without the contaminant?
- Does any of the guidance from AICPA Statement of Position (SOP) 96-1, "Environmental Remediation Liabilities" supersede the application of SFAS 143, Accounting for Retirement Obligations or FIN 47?
- Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

Rights-of-Way and Franchises

Land is specifically excluded from scope of SFAS 143 and FIN 47. Rights of way and easements are land related intangible assets that also are excluded from the scope of SFAS

143 and FIN 47. However, consideration should be given to whether there is a conditional obligation that can be associated to specific, existing, long-lived assets within rights-of-way and franchise areas. It should be noted that there is no asset retirement obligation associated with the franchise (or right-of-way) itself. If it is determined that there is an ARO, it only will be with the assets located within that franchise (or right-of-way).

Typically, utilities are granted franchises by each local jurisdiction in which they have distribution and transmission assets. Typically, the local jurisdiction retains the right to require the removal of the utility's assets, at the discretion of the local jurisdiction. Consequently, the wording in the franchise imposes certain requirements due to revocation of ordinances and road relocations. Just as typically, however, the intent of the utility and the local jurisdiction is for the utility to continue to provide service on a permanent basis in the service area, and the utility is required to remove its assets only when necessary to allow the local jurisdiction to perform some public work.

Generally, the wording in such franchises indicates that there is a <u>possibility</u> that any individual asset could be required to be moved at any time, but the wording neither identifies specific assets to be removed nor sets a specific time that the removal is required. Furthermore, the franchise wording typically indicates that the franchise is either perpetual or renewable.

Paragraph 3 of FASB Interpretation No. 47 states:

> "The term *conditional asset retirement obligation* as used in paragraph A23 of Statement 143 refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exist about the timing and (or) method of settlement."

This definition identifies three variables: "If", "When" and "How/How Much".

The "If" is satisfied if it has been determined that an asset <u>will</u> have to be retired at some future date', i.e. the obligating event has occurred.

The "When" is the date or range of dates when the retirement will/must occur.

The "How" is the method (and by extension, the cost) associated with the retirement.

In the case of franchises, the obligating event would be the determination by the local jurisdiction that an asset or group of assets must be removed. In granting a franchise, however, the <u>presumption</u> by both the utility and the local jurisdiction is that this event will never occur. The fact that this event does occur on occasion (road widening, for example) is not sufficient to negate this presumption.

In this situation, a conditional ARO does not exist, because the obligating event has not yet occurred. The possibility exists that the obligating event will occur, but the possibility alone is not itself an obligating event. The questions of "when" and "how/how much" do not even come into play, because it has not been established that any asset or group of assets will have to be removed. It is impossible to calculate an asset retirement amount, so journal entries are not required. Furthermore, the possibility that an ARO could come into existence need not be disclosed in a footnote.

It should be noted that franchise language typically requires a utility to remove its assets from a given location, not retire those assets. Theoretically, the utility could satisfy the requirements of the franchise by simply moving those assets. In the case of a road widening, for example, the utility could just pick up all of its poles and wires and move them. In reality, new poles and wire are installed and the old poles and wire are removed. But, the decision to install the new and then remove the old is a management decision, to allow for continuous service while the assets are being "relocated". And in some cases, those assets being removed could be re-used elsewhere (poles, for example). There is no asset retirement obligation, because there is no obligation to retire assets.

This situation can change for major projects, however. If a jurisdiction notifies a utility that it must remove specific assets, for any reason, and assuming the utility will retire those assets, the obligating event for those specific assets will have occurred, and an ARO would exist at that point. If the timing and method of removal can be reasonably estimated (and it probably could be), then the utility would be required to calculate and record an ARO. For example, if the utility is notified that a given section of a subway system is to be extended in five years, and that the utility will have to relocate its poles, wires, buried cable or gas mains along the route of the subway extension, all of the requirements of an ARO will have been met. At this point the utility would be required to record an asset retirement obligation for these assets.

It is not uncommon for local jurisdictions to reimburse the utility some or all of the cost of removal when that local jurisdiction requires that assets be relocated. Such reimbursements are not salvage; they are, in fact, a reduction of the cost of removal. Since the cost of removal is the basis for calculating the amount of the asset retirement obligation, any such reimbursement must be reflected (as a reduction) in the ARO calculation. This could substantially reduce the amount of the ARO (or in the case of a 100% reimbursement, totally eliminate it).

Rights-of-Way are similar to franchises, but on a smaller scale. Rights-of-Way typically are granted by individual citizens or companies, cover smaller areas of land, and may be for shorter periods than franchises. The logic in applying the criteria for establishing an ARO is the same, however. If and when an obligating event occurs, an ARO would have to be recognized if sufficient information exists to estimate the fair value of the obligation or disclosed (if sufficient information does not exist). The determination that a Right-of-Way will not be renewed would be an obligating event. Until that time, no calculations or disclosure by the utility would be required.

If it is determined that an asset retirement obligation does exist, it is important that companies do not double-count or double-record the ARO amount. For example, companies may have a program to identify and track asset retirement obligations for the disposal of treated poles. If a treated pole is in a franchise area or right-of-way and must be removed, and it is deemed that an ARO does exist, the cost of disposing of the treated pole should not be counted twice – once under the program to identify costs of disposing of treated poles, and then again as part of the cost of removing an asset from a franchise area or right-of-way. Property accounting personnel should take care to coordinate the ARO identification and measurement efforts to ensure that all ARO costs are recorded, but that those costs are recorded only once.

Recommendation

The costs of franchises and rights-of-way do not themselves incur an asset retirement obligation. Generally, the assets within the franchise area or right-of-way do not incur an asset liability solely because those assets are subject to the franchise or right-of-way. Under certain circumstances, however, those assets could incur an asset retirement obligation. If it is deemed that an asset retirement obligation does exist for certain assets in a franchise area or right-of-way, care should be taken not to include costs that have been included under another ARO identification program within the company.

Questions for Review: Rights-of-Way and Franchises

Who maintains the file of all franchises and rights-of-way agreements?

What is the exact wording in the franchises and rights-of-way agreements? (Specifically, what do it require the company to do?)

Can one identify al of the assets in the franchise and rights-of way areas?

Are the assets in the franchise and rights-of way areas covered under some other ARO identification program within the company?

Do the company have procedures in place to make sure that one is not double-counting the ARO?

Can one reasonably estimate the amount of reimbursements the company will receive for any required cost of removal?

General Property

The possible changes in ARO accounting as indicated in the guidance and examples provided in FIN 47 also may apply to utility property classified under the General Plant function. Recently, the lead and mercury content in personal computers have been drawing attention of lawmakers, environmental agencies, and disposal sites. There are other potential issues like the mercury in fluorescent light bulbs and chemicals in common batteries. Individual utilities may want to assess ARO requirements as modified by FIN 47.

It may be possible that each of the four examples could apply depending upon the circumstances of the legal obligation and property accounting issues such as whether the obligation relates to a retirement unit, a minor item, or a smaller portion of an asset. For example the coatings or trace elements in a personal computer might be comparable to the chemicals in the treated wood poles in Example 1 in Appendix A of FIN 47. If the obligation relates to specific components of the computer, Examples 3 and 4 may be more applicable.

There may be an additional complication in applying FIN 47 to General Plant property. Many utilities have adopted amortization accounting (such as allowed under Federal Energy Regulatory Commission Accounting Release No. 15, "Vintage Year Accounting For General Plant Accounts"). A main objective of adopting amortization accounting was often to eliminate the relatively unreasonable cost of tracking the status of large volumes of low cost property. Under amortization accounting, the cost of the long-lived asset is given an assumed life and reporting of movement or disposition of the property ceases.

While there may be insufficient information in the property records, there may be alternative sources of information. In the personal computer circumstance, a utility may already have a policy of storing the PC prior to disposal – possibly to be in compliance or anticipation of compliance with disposal obligation. The assessment of application of FIN 47 might include evaluation of the existing availability of such alternative information or of possibly creating such information to facilitate compliance with both the legal obligation and the accounting requirements.

Recommendation

Review the circumstances for each account – identify the legal obligation, availability of the information to determine the estimated future removal cost, and the property accounting method (item property, group property, or amortization accounting).

Amortization accounting would represent a unique situation, because it was probably adopted because of a determination that it was unreasonable to maintain detailed record keeping under group or item property. There may still be a basis for recording an ARO, if alternative information is available and the effort reasonable or not considered immaterial.

For example, company using amortization accounting with a policy that requires that unused PCs are returned to a central location for disposal with a known disposal cost. If quantities are kept with the unamortized period, then it is possible to estimate a total liability (quantity unamortized plus quantity waiting for disposal multiplied by the disposal fee). All that is necessary is to estimate the timing of the disposals.

Some utilities may keep other records on such items outside of the accounting record, which may provide sufficient information to calculate the exposure quantity and approximate timing of disposal.

The possible situations are numerous, but if information is available and cost is large enough, then one of the methods described above (such as used for mass assets) may be applicable for making the calculation.

Questions for Review: General Property

Can one define the legal requirements for removal for the general assets?

Does the company use AR-15, amortization of general property?

Can one estimate potential future retirements?

Are the obligations for this category material?

If immaterial, is it appropriate to group these AROs with others to determine materiality?

Can you estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

Hydro Generation

Hydro dams and facilities fall into conditional obligations primarily due to three factors:

An exceptionally long life of the total facility,

The large magnitude of costs and complications associated with removal, and

The uneven probabilities involved.

In some circumstances, however, the obligation may already provide the information to support recording an estimate. In other circumstances, there may be legitimacy in asserting that too much uncertainty exists to make a reasonable estimate.

Hydro facilities (generation equipment, dam, reservoir, and other plant) typically have an extremely long life. That life may also involve multiple steps, in that the dam may continue to provide service long after generation ceases, and may be rebuilt or repaired multiple times in order to maintain the reservoir for conservation or flood control purposes. That combined total facility life may be so long that "there are no boundaries of time or an extremely lengthy period of time, that bears on a person's ability to make a reasonable estimate of the timing and the amount of the cash flows" [1] (Minutes of January 26, 2005 Board Meeting, wwwfasb.org). Estimating life may be further complicated by whether the obligation is identified (individually or overlapping) by multiple jurisdictions (a FERC license, a Corp of Engineers building permit, an act of Congress, state law, or even promissory estoppel).

The exceptionally long life expectancy will typically represent the greatest obstacle to developing a reasonable estimate of ARO. Many reservoirs can be traced to the early history of the United States, so it is reasonable for a total life of a hydro facility to be measured in hundreds of years. Another complication may be multiple legal jurisdictions involved in the obligation over different phases of that total life. Further, economics may support a truly indefinite life since the magnitude of a repair/rebuild may be the clear option of choice compared to the magnitude of the cost of removal of the facility - at any point in time when a removal consideration is being faced.

The long-life combined with the economics favoring indefinite repair over removal creates a time frame in which acts of gods (unprecedented floods, earthquake, etc.) would have to be included in setting probabilities of life. Statistical models may not be applicable when a long life would also involve such random factors – not only for the life, but also the wide range of possible methods of removal complicated by varying relationships to the cause of removal.

Recommendation

Understanding the nature and timing of the current legal obligation is a critical first step, but one that may be particularly difficult to determine. With Hydro licenses, the requirement to remove the dam and flowage structure, albeit purportedly required by the FERC, may not occur if the environment has adapted and become accustom to the dam. One may have to rely more on local data that is in relation to a legal obligation to define the possible course of action.

A conditional ARO is a judgment-based process and if it results in no ARO recognition, then documentation of such conclusion must be done. If a life or range of lives can be identified, the next step is to review the extent of possible methods for meeting the obligation. If life and method of settlement can be identified, the next step would be to identify the availability of other critical elements in estimating an ARO.

Questions for Review: Hydro Generation

What is the nature of the legal obligation(s) involved – does it apply to only a portion of the hydro or to the full facility?

Can a life or a range of lives be reasonably identified with any degree of statistical validity?

Can the methods of settlement be identified with reasonable estimates of probability?

Can a market value of the asset be determined with and without asbestos?

If all of the above exists, can costs and cash flows be reasonably estimable with any degree of statistical validity?

And, can inflation be reliably predicted from present to the time of removal?

Does a risk-free interest rate exist for such a period and will credit adjustments be applicable to determine the rate necessary to convert the ARO into the capitalized asset retirement cost and accretion models necessary under SFAS 143?

Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

Overall Recommendation

There will be no single way to estimate the conditional ARO on the property that was excluded in the earlier review. Several recommendations have been provided within this white paper, but as always, each company will need to decide the appropriate conditional ARO. This review includes the determination of the potential liability, the costing and probability of occurrence, the method for calculating the liability and asset, the materiality of the ARO, forward processing, and the appropriate disclosure. The basic concept throughout was to define the property and to encourage one to find a way to provide for the intent of the accounting without creating unbearable duress in doing the calculation. Also, the calculation for the first recognition at the end of this year should be one consideration, but the process used should define the ongoing revision of the conditional liability and the eventual settlement.

The whole process used should be defined and documented to support audit review and to satisfy any Sarbanes/Oxley provisions within the company. Even if one chooses to disclose and not to account, the documentation for the first and subsequent measurements must be such that it will completely support that decision. Overall, proper management and design of the process keeping a keen site on the form and intent should enable one to fully represent the conditional ARO without creating a nightmare of a process.

Effective Date

Effective Date

Paragraph 8 of the Interpretation specifies the effective date and states:

> The Interpretation shall be effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year enterprises). Retrospective application of interim financial information is permitted but is not required. Early adoption of the Interpretation is encouraged.

Transition Accounting:

Paragraphs 9 and 10 of the Interpretation provide requirements for transitional accounting and state:

> "For amounts recognized upon the initial application of the Interpretation, an entity shall recognize the following items in its statement of financial position: (a) a liability for any existing AROs adjusted for cumulative accretion to the date of adoption of the Interpretation, (b) an asset retirement cost capitalized as an increase to the carrying amount of the associated long-lived asset(s), and (c) accumulated depreciation on that capitalized cost."

> "Amounts resulting from initial application of the Interpretation shall be measured using current (that is, as of the date of adoption of the Interpretation) information, current assumptions, and current interest rates. The amount recognized as an asset retirement cost shall be measured as of the date the asset retirement obligation was incurred. Cumulative accretion and accumulated depreciation shall be recorded for the time period from the date

> the liability would have been recognized had the provisions of the Interpretation been in effect when the liability was incurred to the date of adoption of the Interpretation."
>
> "An entity shall recognize the cumulative effect of initially applying the Interpretation as a change in accounting principle. The amount to be reported as a cumulative-effect adjustment in the statement of operations is the difference between the amounts, if any, recognized in the statement of financial position prior to the application of the Interpretation and the net amount that is recognized in the statement of financial position pursuant to paragraph 9 of the Interpretation."

Thus, the recognition of new AROs due to adopting this Interpretation is similar to the first recognition done for SFAS 143. This first time routine is assumed to be applicable to any ARO that was previously disclosed as immeasurable, but now can be measured. Once the full accounting is established for an ARO, the change in estimate routine from SFAS 143 is used for all subsequent layers. For mass assets and other AROs recognized in aggregate, the change in the obligation acknowledged in the second and successive years may be defined as a new layer. This would have to be discussed and agreed upon by management and your auditors as an appropriate treatment.

Transition Disclosures:

Paragraph 11 of the Interpretation provides requirements for transitional disclosures and states:

> In addition to disclosures required by paragraphs 19(c), 19(d), and 21 of APB Opinion No. 20, *Accounting Changes,* an entity shall compute on a pro forma basis and disclose in the footnotes to the financial statements for the beginning of the earliest year presented and at the end of all years presented the amount of the liability for AROs as if the Interpretation had been applied during all periods affected. The pro forma amounts of that liability shall be measured using the information, assumptions, and interest rates used to measure the obligation recognized upon adoption of the Interpretation.

Until the Interpretation is implemented, there is a disclosure requirement for adoption of new accounting pronouncements (SAB 74). Basically, an entity is to provide qualitative or quantitative information, when available, about the expected impact of implementation, updated quarterly.

Wiseman, Sara

From: Charnas, Shannon
Sent: Sunday, May 15, 2005 10:58 AM
To: Wiseman, Sara
Subject: FIN 47

Tracking:

Recipient	Message Status
Wiseman, Sara	

Sara-

I had a few more thoughts on FIN 47... I think you and Eric have already mentioned this, but we need to add Ohio Falls and Dix Dam if they haven't already been included in SFAS No. 143 calculations. Lock 7 should be sold by the end of the year (last I heard June or July is when it should close), so it shouldn't be an issue. We just need to check on the status to make sure the sale happens. We will need to document our position on FIN 47 in detail. I would still like to think we can somehow get out of quantifying the asbestos issue, but the more I think about it, the more doubtful I am. Since FIN 47 made such a big deal about the fact we did it wrong the first time, I'm sure that a number is expected for the asbestos issue, not just a disclosure. You and Eric may get a better feel as you research. Please let me know by the end of the week what progress you have been able to make on it. Valerie and I are planning to talk to Brian Jungwirth briefly sometime this week about the information we need to provide to E.ON. Since I will be out May 23 - May 31, I would like to ask him if we can have until at least June 3 to provide E.ON the information they requested by the 31st. Also, we wanted to discuss the asbestos issue, that we may not be able to quantify it by May 31, because it will likely require more research than can be done by then. I'll let you know what comes of the discussion.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

Wiseman, Sara

From: Riggs, Eric
Sent: Friday, May 20, 2005 2:04 PM
To: Mills, Les
Cc: Sanders, Tim; Wiseman, Sara; Kinder, Debra
Subject: Assets Requiring Special Disposal

Les,

There is a new accounting pronouncement that requires LG&E and KU to recognize the future liability associated with assets that require special disposal treatment. We have been told that wood poles and wood cross arms require special treatment. Can you provide me with a current cost of disposing wood poles and cross arms? Can you tell me what the Company has spent on disposing wood poles and cross arms in the past on a year by year basis? Do you have separate numbers for the Company and Contractors (Like PIKE).

Are there any other assets that you can think of that would have special treatment due to environmental concerns? Any help you can give me would be greatly appreciated. We are having to update upper management on Monday, May 23, 2005 at 2:00 PM. (The day you get back from vacation.) Any numbers would be helpful, but if you can't, you can't. Just let me know how long you think it would take to get us numbers for the past few years. Also, please let me know who your counterparts are at the other facilities that I might send them this email.

Thanks,
Eric Riggs
627-2822

Wiseman, Sara

From: Riggs, Eric
Sent: Friday, May 20, 2005 3:05 PM
To: Johnson, Andre
Cc: Wiseman, Sara; Kinder, Debra
Subject: Assets Requiring Special Disposal Treatment

Andre,

There is new accounting pronounce met that requires LG&E and KU to recognize the liability associated with assets that require special disposal treatment. The environmental group has identified several assets that are fluid filled. These items include: Line Transformers, Substation Transformers, Capacitors, Reclosers, Breakers, Bushings, Regulators, Switches, and Oil-filled Cable. Can you identify the cost associated with the disposing of these assets? Do you have any prior year costs? Any help you can provide would be greatly appreciated.

We are having a meeting to update upper management on Monday at 2:00 PM. If you can get us any numbers by then it would be great, but if you can't, you can't. Please let us know what and when you can provide us with some data.

Thanks,
Eric Riggs

Wiseman, Sara

From: Scott, Valerie
Sent: Monday, June 13, 2005 7:03 PM
To: Charnas, Shannon; Wiseman, Sara
Subject: FW: FIN 47 White Paper
Attachments: FIN 47 Whitepaper_061305.doc

fyi

Valerie

From: bounce-238418-175405@ls.eei.org [mailto:bounce-238418-175405@ls.eei.org] **On Behalf Of** Stringfellow, David
Sent: Monday, June 13, 2005 2:52 PM
To: Accounting Standards Committee
Cc: dallen@aga.org; Perkett, Lisa H
Subject: FIN 47 White Paper

TO: EEI Accounting Standards Committee Members

A Task Force with members from the Property Accounting & Valuation Committee and the Accounting Standards Committee has prepared a White Paper on FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations. The White Paper is designed to help with the implementation of FIN 47 by utilities. Attached is the current draft of the White Paper for your review and comment. Any review comments should be sent by the end of Friday, June 17 to Lisa Perkett at Xcel Energy at lisa.h.perkett@xcelenergy.com and to David Stringfellow at EEI at dstringfellow@eei.org.

Thank you.

David Stringfellow
Edison Electric Institute
dstringfellow@eei.org
202/508-5494

You are currently subscribed to asc as: [valerie.scott@lgeenergy.com]
To unsubscribe, forward this message to leave-asc-175405J@ls.eei.org

Wiseman, Sara

From: Charnas, Shannon
Sent: Wednesday, June 15, 2005 1:10 PM
To: Scott, Valerie; Wiseman, Sara
Subject: RE: FIN 47 - Accounting for Conditional AROs Survey

I may not have mentioned it, but I did respond to this survey while Sara was out and this document does include our responses.

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Scott, Valerie
Sent: Monday, June 13, 2005 7:02 PM
To: Charnas, Shannon; Wiseman, Sara
Subject: FW: FIN 47 - Accounting for Conditional AROs Survey

fyi

Valerie

From: bounce-238375-175405@ls.eei.org [mailto:bounce-238375-175405@ls.eei.org] **On Behalf Of** Stringfellow, David
Sent: Monday, June 13, 2005 9:25 AM
To: Accounting Standards Committee
Cc: Criscuolo, Julia; Elizabeth_L_Farley@dom.com; mark.j.kunkel@constellation.com; Blinder, Calvin L
Subject: FIN 47 - Accounting for Conditional AROs Survey

TO: EEI Accounting Standards Committee Members

Attached is a summary of the FIN 47 - Accounting for Conditional Asset Retirement Obligations Survey. Thanks to all who participated in responding to the survey.

David Stringfellow
Edison Electric Institute
dstringfellow@eei.org
202/508-5494

You are currently subscribed to asc as: [valerie.scott@lgeenergy.com]

To unsubscribe, forward this message to leave-asc-175405J@ls.eei.org

Wiseman, Sara

From: Riggs, Eric
Sent: Tuesday, July 05, 2005 9:07 AM
To: Miller, Jon; Phaup, Angela
Cc: Wiseman, Sara
Subject: RE: ARO

Attachments: FIN 47 Meeting Agenda june 24.doc; FIN47 FAS 143 Interpretation Exposure Draft.doc; Non Generation - FAS 143 Conditional Meeting.xls; FIN 47 Whitepaper_061305.doc

Angela, Jon,

Attached are copies of the handouts from the meeting.

FIN 47 Meeting Agenda june 24....

FIN47 FAS 143 Interpretation E...

Non Generation - FAS 143 Cond...

FIN 47 hitepaper_061305.d

Thanks,
Eric Riggs

From: Miller, Jon
Sent: Friday, July 01, 2005 10:37 AM
To: Riggs, Eric
Subject: ARO

Eric,

I was taliking to Angela Phaup at WKE about the meeting we had earlier in the week on FIN 47 and she would like to have a copy of the material that we discussed at the meeting. Can you please send her a copy of the handouts?

Jon

FIN 47 Meeting Agenda – June 24, 2005

1. FASB Interpretation No. 47

    Financial Accounting Series

    EEI/AGA white paper

2. List of Identified Assets

    Generation

    Non-Generation

3. Parameters to identify

    Asset Description

    Quantity by year of installation

    Removal cost per asset

    Incremental cost of disposal

4. Information to be returned

    July 15, 2005

FIN 47 Meeting Agenda – June 24, 2005

1. FASB Interpretation No. 47

   Financial Accounting Series

   EEI/AGA white paper

2. List of Identified Assets

   Generation

   Non-Generation

3. Parameters to identify

   Asset Description

   Quantity by year of installation

   Removal cost per asset

   Incremental cost of disposal

4. Information to be returned

   July 15, 2005

Kentucky Utilities Company
Louisville Gas and Electric Company
FASB Interpretation No. 47 "Accounting for Conditional Asset Retirement Obligations"
June 20, 2005

In March 2005,, the Financial Accounting Standards Board issued FIN 47, an interpretation of SFAS 143, Accounting for Asset Retirement Obligations.

Summary

FIN 47 was issued to address the timing of recognizing liabilities for legal obligations when the retirement activity is dependent on another event (i.e. the date of retirement is currently unknown and based on a future determination or unplanned). This interpretation indicates that asset retirement obligations must be recognized if the fair value of the liability can be reasonably estimated. FIN 47 indicates that "uncertainty surrounding the timing and method of settlement that may be conditional on events occurring in the future should be factored into the measurement of the liability rather than the recognition of the liability".

The effective date for this interpretation is fiscal years ended after December 15, 2005, or December 31, 2005 for KU and LG&E. Amounts recorded as a result of this interpretation would be accounted for as a change in accounting principle and would result in a cumulative effect adjustment similar to that recorded when SFAS 143 was initially adopted. The Companies will ask for regulatory asset and regulatory liability treatment upon the adoption of this interpretation from the Kentucky Public Service Commission so that the initial adoption would have no impact on their net incomes.

Contrary to the adoption of SFAS 143, upon adoption of this interpretation, prior years would be restated on a pro forma basis at implementation, consistent with APB Opinion No. 20, *Accounting Changes*. The Companies would not be required to restate prior 2005 quarterly results if the interpretation is adopted in the first or last quarter of 2005.

Potential Obligations Identified (not included with the adoption of SFAS 143)

After an extensive review by accounting, legal, environmental, operations and senior management personnel, the following potential obligations were not included in the adoption of SFAS 143 at January 1, 2003, but could be included in the adoption of the current interpretation:

- LG&E operates its Ohio Falls plant under a 30-year licensing agreement with the U.S. Army Corps of Engineers. This agreement requires the dam to be restored to the Corps' specifications upon abandonment of the plant. The cost of this restoration was estimated at $8 million in 2002. The Company has renewed the licensing agreement with the Corps of Engineers continually since the plants' construction and expects to renew the agreement continually at each expiration date. Because the hydro plant has an indeterminate retirement date no ARO liability was established.

- KU owns two hydro facilities, Dix Dam and Lock 7. Estimated decommissioning costs for these plants in 2002 were $1.3 million and $3.4 million, respectively; however, a legal review of the hydro licenses found no specific legal obligation upon the final decommissioning of these plants. It should be noted that the permitting authorities, particularly FERC, have significant inherent discretion in setting conditions to allow a surrender of a permit. These conditions are based upon the specific facts, issues and concerns at the time of decommissioning. In the case of Lock 7, a study determined that it was likely that surrender of the FERC permit would involve both removal of generation equipment and demolition of station down to water line. Because no specific legal liability was identified and the retirement date is indeterminate no ARO liability was established at January 1, 2003.

- Some components of the Companies' Transmission and Distribution business have retirement obligations associated with them due to environmental or other contractual agreements. KU and LG&E have certain electrical equipment containing PCBs, such as transformers and capacitors, which require special disposal. Both Companies undertook a program in the 1980's to replace most of this PCB impaired equipment. Thus the Companies have few remaining obligations related to PCB contamination. The retirements related to these assets were addressed for frequency and materiality in 2002 to determine if the interim retirement would fall within the scope of SFAS 143 as described below.

    - Some substation equipment such as bushings, breakers, etc., may have retirement obligation related to PCB contaminants. If so, this equipment must be disposed of per EPA regulation. However the cost, generally less than $20K per year, is immaterial. In 2002, the Company disposed of four assets at a cost of $17K. Specific assets impacted are not identifiable until failure or replacement.

    - PCB contaminated line transformers must be disposed of per environmental regulation. The company disposes of PCB contaminated line transformers through a third party vendor. LG&E costs were approximately $10K in 2002. KU costs were approximately $42K in 2002. Based on 2002 disposals the cost of this activity on an annual basis is immaterial. In addition, specific assets impacted are not identifiable until failure or replacement.

- LG&E operates wells in its gas storage system that must be plugged if abandoned, per Kentucky mines & minerals law/regulations. Because LG&E intends to operate the wells in perpetuity and the retirement date is indeterminate, no ARO was established as of January 1, 2003. The estimated cost of plugging the 546 wells was $17K per well or $9.2 million in total in 2002.

- LG&E also operates 4 above ground gas compressor stations under perpetual lease agreements. The ground leases for the Muldraugh KY, Cedar Fields IN, and Brandenburg KY (Riggs and Doe Run sites) were reviewed for contractual obligations. A 1946 letter of agreement related to one acre of the 40 acres of the Brandenburg KY (Riggs site) lease requires LG&E to "return it to lessor on the expiration of the lease in approximately the same condition as found at the present time." The estimated cost to dismantle and remove the Brandenburg station was $48K in 2002.

- Kentucky statutes and regulations govern highways and rights-of-way.

  - Kentucky State Highway rules require all encroachments on public highways to be permitted. Upon any expiration or revocation of a permit the state may require removal or relocation of the encroachment at the expense of the permit holder. Given the uncertainty of the state requiring such removal or relocation, the Companies do not believe any retirement obligation exists.

  - The state may order any level railroad crossing closed for public safety and the closure is to occur at the owners' expense. However, no statute or rule states that an abandoned or unused crossing, due solely to its abandonment or non-use and absent other circumstances, is to be considered unsafe or required to be closed. Given the uncertainty of the state requiring closure, the Companies do not believe any retirement obligation exists.

  - For overpasses and bridges air space permit can be issued. One section of air space permitting requires that any structures or attachments must be removed at the permit holder's expense upon expiration or cancellation, while two other sections provided only that the state had the discretion to require removal, relocation or restoration regarding the air space structures. The Companies do not believe any retirement obligations exist and that the obligation as primarily discretionary, rather than obligatory.

- The Department of Transportation regulations require the cutting of pipes, purging of gas and capping for gas transportation pipelines when abandoned. Since these pipelines are expected to be used in perpetuity no ARO liability was established at January 1, 2002.

- The National Electric Safety Code does not differentiate between abandoned (de-energized) or functioning (energized) electric transmission and distribution facilities. Both are to comply with the same safety and serviceability standards. Our current obligations of maintenance and repair would continue after abandonment (de-energizing) and no new or specific obligations on abandonment arise. Since these assets are expected to be used in perpetuity no ARO liability was established at January 1, 2002.

- Personal computer monitors contain metals that require special disposal. The Companies are negotiating a new contract to dispose of used personal computer equipment that will address these potential costs.

- Many buildings built prior to the early 1980's contain some asbestos in the building materials. Asbestos requires special processes to remove, if it is disturbed. The Companies' position has generally been to retire facilities intact and to incur the costs to remove them only if necessary; accordingly, no ARO liability was established at January 1, 2002, but one would be established should plans for a building change.

Kentucky Utilities / Louisville Gas and Electric Company
Assets Requiring Special Disposal Treatment

Asset	Notes
Capacitors - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. 10% of these units are likely to contain PCBs
Reclosers - Fluid Filled	All units older than 1980 must tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Breakers - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Fluid is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Bushings - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Units are sealed and therefore the fluid is not replaced during maintenance. Approximately 25% of these assets are likely to contain PCB's
Regulators - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Switches -Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Substation Transformers - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Residential Transformers - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Units are operated until they fail. Approximately 10% of these assets are likely to contain PCB's
Batteries	These units are sent to a recycle center.
Cable - Oil Filled	All oil filled cable older than 1980 must be tested when taken out of service. Less than 5% of these assets are likely to contain PCB's
Wood Poles	The landfill must be notified that these units contain harmful chemicals. Additional costs are charged by the landfill operators for disposal.
Cross Arms	The landfill must be notified that these units contain harmful chemicals. Additional costs are charged by the landfill operators for disposal.
Large Diameter Gas Steel Pipe	All steel pipe is tested for PCB presence when taken out of service. Historical data indicates very infrequent PCB presence in distribution or storage field piping 4-inches in diameter or more. Less than 5% of pipe is estimated to have PCB contamination.
Residential Gas Pipe	All steel pipe is tested for PCB presence when taken out of service. All pipe with less than 4-inch diameter must be disposed of as scrap or in a landfill. Additional costs are charged by landfill operators for disposal. If left in place, pipe is to be grouted or otherwise filled to prohibit reuse.

(1)
Resource Conservation and Recovery Act - 40 CFR Parts 240-299
Toxic Substance Control Act - Parts 40 CFR 761

Wiseman, Sara

From: Riggs, Eric
Sent: Tuesday, July 05, 2005 8:27 AM
To: Wiseman, Sara
Subject: FW: FIN 47

FYI

From: Fraley, Jeffrey
Sent: Friday, July 01, 2005 4:19 PM
To: Miller, Jon
Cc: Riggs, Eric; Joyce, Jeff; Moore, Thomas (KU); Troost, Tom; Kirkland, Mike; Turner, Steven; Crutcher, Tom
Subject: RE: FIN 47

Please define "reasonable" and "detailed". What you're asking would take far more than two weeks to complete. Estimates for a well defined abatement scope takes two weeks. Brown and Tyrone have asbestos in almost every piece of equipment, including all of the boiler skin and refractory, almost all runs of ductwork, tile, roofing, pipe insulation, etc. You also state that we are required to report if the fair market value can be reasonably estimated. In my opinion it can't be reasonably estimated without unreasonable effort and cost. I would be extremely reluctant to put my name on something like this knowing the quality that would result if only two weeks were spent on it. I have far more to say about this request, so perhaps we should talk in person.

Jeff

From: Miller, Jon
Sent: Friday, July 01, 2005 3:08 PM
To: Fraley, Jeffrey
Subject: RE: FIN 47

Jeff,

With respect to Dix, back in 2002 a legal review of the hydro license determined that we had no legal obligation upon the final decommissioning of Dix, we do have legal obligations for any oil or asbestos that is in the facility and will need to include these items in the study.

Jon

From: Miller, Jon
Sent: Friday, July 01, 2005 3:03 PM
To: Jeff Joyce; Jeffrey Fraley; Mike Kirkland; Tom Crutcher; Tom Troost; Turner, Steven
Cc: Voyles, John
Subject: FIN 47

All,

As a requirement of accounting pronouncement FIN 47 we are required to identify and setup a liability for all assets that have a legal retirement obligation. While this was looked at under SFAS 143, there were certain areas that were not clear if they had to be included (such as asbestos abatement) and subsequently were not included. Under FIN 47, the Financial Accounting Standards Board (FASB) has provided further clarification on what needs to be included. Under SFAS 143 some entities were recognizing the fair value of the retirement obligations only when it was probable the asset would be retired as of a specified date or when the asset is actually retired. FIN 47 clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the liability's fair value can be reasonably estimated.

Property Accounting is working to compile a detailed list for LG&E Energy of all company AROs. In order to assist Property Accounting, Generation needs to provide a detailed list of items that the companies have a legal retirement obligation. Known items that should be included are batteries, oil in equipment being retired, PCBs, and asbestos (were these reviewed but previously excluded under SFAS 143), please include any other items that you think we have a legal retirement obligation.

I have attached a spreadsheet that should be used to list the items that fall under FIN 47 (you do not need to include previously listed under SFAS 143). I also have attached the file for each location that was compiled during the SFAS 143 analysis.

When estimating costs (such as asbestos abatement) within a given area of the plant, please be specific as to the location and include any estimation methodology. For example if you are estimating that there is asbestos within certain ductwork please include the area of the ductwork and % that you are assuming contains asbestos (or other estimation methodology). I think that this information will be reviewed periodically (annually?) and the more details we have regarding the data the easier will be to update in the future.

I will need this information returned by July 14, 2005. I know this date gives you little time to complete the work, however, Property Accounting has a good deal of work that will need to be completed once we turn in our information.

If you have any questions, please give me a call or you can contact Eric Riggs in Property Accounting.

Thank you,
Jon

<< File: Fin 47 Template.xls >> << File: 143 model-Tyrone.xls >> << File: 143 model-Brown.xls >> << File: 143 model-Cane Run.xls >> << File: 143 model-Ghent.xls >> << File: 143 model-Green River.xls >> << File: 143 model-Mill Creek.xls >> << File: 143 model-Trimble.xls >>

Wiseman, Sara

From: Charnas, Shannon
Sent: Wednesday, July 13, 2005 1:57 PM
To: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FW: FIN 47

Attachments: FW: K-070503 (KU-Brown) AB Abate 100 MegWatt Unit July05; Asbestos removal for retirement of unit

FYI

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Fraley, Jeffrey
Sent: Wednesday, July 13, 2005 1:43 PM
To: Miller, Jon; Charnas, Shannon; Crutcher, Tom; Kirkland, Mike; Turner, Steven; Troost, Tom
Subject: FW: FIN 47

Folks,
Here's further input from another abatement contractor. It looks as if they are willing to take the time to do this even if we aren't planning to do the work in the near term.

Jeff

FW: K-070503
KU-Brown) AB Aba..

From: Fraley, Jeffrey
Sent: Tuesday, July 12, 2005 4:13 PM
To: Miller, Jon; Charnas, Shannon
Cc: Voyles, John; Joyce, Jeff; Kirkland, Mike; Crutcher, Tom; Troost, Tom; Turner, Steven
Subject: RE: FIN 47

Jon/Shannon,
Attached is an estimate developed by NEC for abatement of a single 100 MW unit. We can discuss whether or not a scaling of this data might suffice for units of a different size.

Jeff

Asbestos removal
for retiremen...

From: Miller, Jon
Sent: Friday, July 01, 2005 3:03 PM
To: Jeff Joyce; Jeffrey Fraley; Mike Kirkland; Tom Crutcher; Tom Troost; Turner, Steven
Cc: Voyles, John
Subject: FIN 47

All,

As a requirement of accounting pronouncement FIN 47 we are required to identify and setup a liability for all assets that have a legal retirement obligation. While this was looked at under SFAS 143, there were certain areas that were not clear if they had to be included (such as asbestos abatement) and subsequently were not included. Under FIN 47, the Financial Accounting Standards Board (FASB) has provided further clarification on what needs to be included. Under SFAS 143 some entities were recognizing the fair value of the retirement obligations only when it was probable the asset would be retired as of a specified date or when the asset is actually retired. FIN 47 clarifies that an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the liability's fair value can be reasonably estimated.

Property Accounting is working to compile a detailed list for LG&E Energy of all company AROs. In order to assist Property Accounting, Generation needs to provide a detailed list of items that the companies have a legal retirement obligation. Known items that should be included are batteries, oil in equipment being retired, PCBs, and asbestos (were these reviewed but previously excluded under SFAS 143), please include any other items that you think we have a legal retirement obligation.

I have attached a spreadsheet that should be used to list the items that fall under FIN 47 (you do not need to include previously listed under SFAS 143). I also have attached the file for each location that was compiled during the SFAS 143 analysis.

When estimating costs (such as asbestos abatement) within a given area of the plant, please be specific as to the location and include any estimation methodology. For example if you are estimating that there is asbestos within certain ductwork please include the area of the ductwork and % that you are assuming contains asbestos (or other estimation methodology). I think that this information will be reviewed periodically (annually?) and the more details we have regarding the data the easier will be to update in the future.

I will need this information returned by July 14, 2005. I know this date gives you little time to complete the work, however, Property Accounting has a good deal of work that will need to be completed once we turn in our information.

If you have any questions, please give me a call or you can contact Eric Riggs in Property Accounting.

Thank you,
Jon

<< File: Fin 47 Template.xls >> << File: 143 model-Tyrone.xls >> << File: 143 model-Brown.xls >> << File: 143 model-Cane Run.xls >> << File: 143 model-Ghent.xls >> << File: 143 model-Green River.xls >> << File: 143 model-Mill Creek.xls >> << File: 143 model-Trimble.xls >>

Wiseman, Sara

From: Sarantakos, Constantine
Sent: Wednesday, July 13, 2005 12:23 PM
To: Fraley, Jeffrey
Cc: Sumner, Brian
Subject: FW: K-070503 (KU-Brown) AB Abate 100 MegWatt Unit July05

Here is a competitive bid based on previous projects. A linear cost relationship can be drawn for larger units.

From: Carla [mailto:carla@incorpinc.net]
Sent: Wednesday, July 13, 2005 11:50 AM
To: Sarantakos, Constantine
Cc: bryon@incorpinc.net
Subject: K-070503 (KU-Brown) AB Abate 100 MegWatt Unit July05

July 12, 2005
K-070503

Kentucky Utilities Company
EW Brown Generating Station
815 Dix Dam Road
Harrodsburg, KY 40330

Attention: Mr. Deano Sarantakos

Subject: Asbestos Abatement 100 Meg Watt Unit

INCORP, Inc. is pleased to submit budget cost to abate one Kentucky Utilities 100 Meg Watt boiler. The below budget cost also includes critical piping, turbine miscellaneous piping, ductwork and building heat system.

Total: $ 1,080,000.00

Asbestos Abatement:	**$ 104,000.00**	**Critical Piping**
Asbestos Abatement:	**$ 420,000.00**	**Boiler**
Asbestos Abatement:	**$ 97,000.00**	**Turbine Misc. Piping**
Asbestos Abatement:	**$ 397,000.00**	**Ductwork**
Asbestos Abatement:	**$ 62,000.00**	**Building Heat Piping**

Clarifications:

- Price includes labor, material, equipment and supervision.
- Price includes state notification and engineering designer costs.
- Price includes air monitoring, disposal and landfill costs.
- Price includes scaffold rental and E/D labor costs.
- Price does not include internal boiler areas or systems outside the boiler enclosure area.
- Price is based on all non-essential equipment being removed prior to abatement activities.
- Price is based on standard shift, Monday-Friday, 10 hours per day.

INCORP appreciates the opportunity to be of service and if you should require additional information, please give us a call.

Sincerely,

Bryon C. Cowan

Bryon C. Cowan
Project Manager

As quoted above
Net 30 days

Wiseman, Sara

From:	Sarantakos, Constantine
Sent:	Tuesday, July 12, 2005 12:31 PM
To:	Fraley, Jeffrey
Cc:	Sumner, Brian
Subject:	Asbestos removal for retirement of unit
Attachments:	Asbestos Budget Number for unit retirement.pdf

Please see the attached. Let me know if this is sufficient information.

Deano

Asbestos Budget
Number for un...

National Environmental Contracting, Inc.
2660 Technology Drive • Louisville, KY 40299-6424
Office: 502.261.0800
800.650.8893 • Fax: 502.261.0828

Estimate Cost for Asbestos Abatement of a Typical 100 MW Coal Fired Unit

Penthouse	300 ManDays @ $500.00 Per Day	$150,000.00
External Furnace (incl. Reheat Sect.)	1500 ManDays @ $500.00 Per Day	$750,000.00
External Piping (Oper. Floor Up)	500 ManDays @ $500.00 Per Day	$250,000.00
External Ductwork (Oper. Floor Up)	400 ManDays @ $500.00 Per Day	$200,000.00
Pipe & Equipment Under Oper. Floor	600 ManDays @ $500.00 Per Day	$300,000.00
Pipe & Equipment Under Oper. Floor	300 ManDays @ $500.00 Per Day	$150,000.00
Survey, Air Testing, Permits, etc.		$100,000.00
Contingency (Boiler Internals, Refractory, Unforseen)		$400,000.00
ESTIMATED TOTAL COST (in 2005 $$)		**$2,300,000.00**

Kinder, Debra

From: Stringfellow, David [DStringfellow@eei.org]
Sent: Thursday, July 21, 2005 4:36 PM
To: Kinder, Debra
Subject: RE: FIN 47 - Asbestos treatment

'he final EEI-AGA White Paper on implementing FIN 47 will likely be sent out next week to the members of the EEI Property .ccounting & Valuation Committee.

---

rom: Kinder, Debra [mailto:Debra.Kinder@lgeenergy.com]
ent: Thursday, July 21, 2005 12:56 PM
'o: Stringfellow, David
:c: Wiseman, Sara; Riggs, Eric
ubject: FIN 47 - Asbestos treatment

'avid,

have been asked to contact you on behalf of Sara Wiseman, Property Accounting Manager for Louisville Gas and Electric.

Ve are very interested in knowing how other utilities intend to satisfy FIN 47 requirements regarding asbestos. Have you seen uestions or comments in reference to this topic from other members? If not, could we pose this question for member responses?

)ebra A. Kinder
'roperty Accounting Analyst
ouisville Gas & Electric
502) 627-3369

Wiseman, Sara

From: Kinder, Debra
Sent: Friday, July 22, 2005 8:37 AM
To: Wiseman, Sara; Riggs, Eric
Subject: FW: FIN 47 - Asbestos treatment

From: Stringfellow, David [mailto:DStringfellow@eei.org]
Sent: Thursday, July 21, 2005 4:36 PM
To: Kinder, Debra
Subject: RE: FIN 47 - Asbestos treatment

The final EEI-AGA White Paper on implementing FIN 47 will likely be sent out next week to the members of the EEI Property Accounting & Valuation Committee.

From: Kinder, Debra [mailto:Debra.Kinder@lgeenergy.com]
Sent: Thursday, July 21, 2005 12:56 PM
To: Stringfellow, David
Cc: Wiseman, Sara; Riggs, Eric
Subject: FIN 47 - Asbestos treatment

David,

I have been asked to contact you on behalf of Sara Wiseman, Property Accounting Manager for Louisville Gas and Electric.

We are very interested in knowing how other utilities intend to satisfy FIN 47 requirements regarding asbestos. Have you seen questions or comments in reference to this topic from other members? If not, could we pose this question for member responses?

Debra A. Kinder
Property Accounting Analyst
Louisville Gas & Electric
(502) 627-3369

Wiseman, Sara

From:	Miller, Jon
Sent:	Wednesday, July 27, 2005 8:44 AM
To:	Charnas, Shannon
Cc:	Wiseman, Sara; Riggs, Eric; Kinder, Debra
Subject:	Fin 47 Template - Cane Run
Attachments:	Fin 47 Template (2).xls

Shannon,

I did receive information from Steve Turner for Cane Run, Paddy's, Canal, and Waterside (NEC provided the estimates). Steve also mentioned that Burns and Mack indicated that they are familiar with this FIN47 thorugh work with other utilities. Whenever you can, please let me know if this is along the lines of the level of detail you were looking for.

Jon

Fin 47 Template (2).xls

Location						
Asset Retirement Obligations			($000's)			
Asset Description	Location	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date	
Asbestos						
Cane Run						
CR1 Asbestos Abatement	Cane Run Unit 1 Plant		2,700	60		Ductwork, Equip. External, Operating Floor up $300k; Ductwork External, Under Operating Floor $200k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $400k; Penthouse $150k; Furnace External $750k; Air Testing, permits, survey $100k; Boiler misc. $400k; Coal Handling $150k
CR2 Asbestos Abatement	Cane Run Unit 2 Plant		2,550	50		Ductwork, Equip. External, Operating Floor up $300k; Ductwork External, Under Operating Floor $200k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $400k; Penthouse $150k; Furnace External $750k; Air Testing, permits, survey $100k; Boiler misc. $400k
CR3 Asbestos Abatement	Cane Run Unit 3 Plant		2,700	50		Ductwork, Equip. External, Operating Floor up $300k; Ductwork External, Under Operating Floor $200k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $400k; Penthouse $150k; Furnace External $850k; Air Testing, permits, survey $100k; Boiler misc. $450k
CR4 Asbestos Abatement	Cane Run Unit 4 Plant		2,750	50		Ductwork, Equip. External, Operating Floor up $500k; Ductwork External, Under Operating Floor $350k; Piping External, Opererating Floor up $150k; Pipe and Equip. Under Opererating Floor $300k; Penthouse $150k; Furnace External $900k; Air Testing, permits, survey $100k; Boiler misc. $300k
CR5 Asbestos Abatement	Cane Run Unit 5 Plant		2,150	40		Ductwork, Equip. External, Operating Floor up $500k; Ductwork External, Under Operating Floor $300k; Piping External, Opererating Floor up $150k; Pipe and Equip. Under Opererating Floor $200k; Penthouse $100k; Furnace External $500k; Air Testing, permits, survey $100k; Boiler misc. $300k
CR6 Asbestos Abatement	Cane Run Unit 6 Plant		2,500	50		Ductwork, Equip. External, Operating Floor up $700k; Ductwork External, Under Operating Floor $400k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $300k; Penthouse $150k; Furnace External $200k; Air Testing, permits, survey $100k; Boiler misc. $400k
Paddy's Run						
Plant Asbestos Abatement	Total Plant		11,000	100		
Canal						
Plant Asbestos Abatement	Total Plant		6,000	75		
Waterside						
Plant Asbestos Abatement	Total Plant		4,000	50		
Battery						
Cane Run						
Emergency Battery No. 1 (1&2)	Unit 1 basement	60	3.5	1		
Emergency Battery No. 2 (3&4)	Unit 3 1st landing	60	3.5	1		
Emergency Battery No. 3 (6)	Unit 6 basement	60	3.5	1		
Station Battery No. 1	No. 1 Breaker House	60	3.5	1		
Station Battery No. 2	Unit 1 basement	60	3.5	1		
Station Battery No. 3	Unit 3 1st landing	60	3.5	1		
Station Battery No. 4	Unit 6 basement	60	3.5	1		
Unit 4 UPS Battery	Unit 4 turbine floor	30	2	0.5		
Unit 5 UPS Battery	Unit 6 turbine floor	30	2	0.5		
Unit 6 UPS Battery	Unit 6 turbine floor	30	2	0.5		
Communications Battery	Old Control House (rear)	24	2	0.5		
4&5 SPP Batteries	4&5 SPP Elect. Room	10	1	0.5		
Jefferson County Gas Turbines						
Paddy's 13 DC	SFC/SES Room	60	3.5	1		
Paddy's 12 DC	PR-12 Building	60	3.5	1		
Paddy's 11 DC	PR-11 Under Control Rm	14	1	0.5		
Control house DC	Control House	60	3.5	1		
Cane Run GT-11	GT-11 Building	60	3.5	1		

Oil						
Cane Run Station	Plant/GT-11		10	1		Turbine Reservoir/Mill/Fluid Drive/Screenhouse Oil Accumulator, Misc.
Paddy's Run Station	Plant/CT's		15	1		Turbine Reservoir/Mill/Fluid Drive/Screenhouse Oil Accumulator, Misc.
Canal Station	Plant		5	1		Turbine Reservoir/Mill/, Misc.
Waterside	Plant/CT		5	1		Gas Turbine/Misc. Plant Equipment

Wiseman, Sara

From: Riggs, Eric
Sent: Wednesday, July 27, 2005 1:00 PM
To: Wiseman, Sara; Kinder, Debra
Subject: FW: ARO Property

FYI

From: McDonald, Pam
Sent: Wednesday, July 27, 2005 12:08 PM
To: Riggs, Eric
Cc: Miller, Jon
Subject: RE: ARO Property

Eric,

After our last meeting, I have read through the documentation and developed an action plan. Most of the people I need to talk to have been on vacation or busy with other priorities. I will try to work on it next week and give you an update. Sorry for the delay.

Pam

Pam McDonald
Energy Delivery Budgeting
Ext. 2850

From: Riggs, Eric
Sent: Wednesday, July 27, 2005 11:15 AM
To: McDonald, Pam
Subject: RE: ARO Property

Pam,

No, He didn't provide any documentation to me. When this first got started last August, he provided the list that I handed out at the last meeting. Where or from whom he got that information I don't know. In the meeting we had today with just Sara, Debbie, myself, and Shannon, we were asked to contact Jon Miller and yourself to see where you stood with the items.

Thanks,
Eric

From: McDonald, Pam
Sent: Wednesday, July 27, 2005 10:49 AM
To: Riggs, Eric
Subject: ARO Property

Eric,

Did Mr. Winkler provide what you needed for this documentation?

Thanks,
Pam

Pam McDonald
Energy Delivery Budgeting
Ext. 2850

Wiseman, Sara

From: Charnas, Shannon
Sent: Wednesday, July 27, 2005 11:28 AM
To: Kinder, Debra
Cc: Riggs, Eric; Wiseman, Sara
Subject: FW: ARO
Attachments: Final Weighted ARO Settlement 3-03-24.xls

Tracking:

Recipient	Message Status
Kinder, Debra	
Riggs, Eric	
Wiseman, Sara	

Debbie-

This is the final list I had from Gerald, which, I believe, is the same one you have, but now you can have a soft copy. This is pretty much the last thing I have from back then.

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Skaggs, Gerald
Sent: Tuesday, April 29, 2003 4:27 PM
To: Charnas, Shannon
Subject: RE: ARO

Shannon,

Attached is the final ARO inventory. There are no GSU costs at Tyrone. Let me know if you have questions.

G

> -----Original Message-----
> **From:** Charnas, Shannon
> **Sent:** Monday, April 21, 2003 2:26 PM
> **To:** Skaggs, Gerald
> **Subject:** ARO
>
> Gerald-
>
> Would you please send me the final version of the ARO summary? I was looking at it for something else and noticed something odd. TY was listed as having $1.2M in retirement costs associated with removal of GSU and transformer oil. Many other sites had large numbers for this as well. I had thought we determined virtually all of these items would be saleable or have very little associated cost. I thought maybe I had an old version of the spreadsheet.

Thanks,

Shannon Charnas
Manager Finance & Budgeting - Energy Services
shannon.charnas@lgeenergy.com
phone (502) 627-4978
fax (502) 627-2665

Asset Retirement Obligation
Probability Weighted Settlement Estimates

				Cost ($000s)				
Probability of Occurrence			5%	85%	10%			
Location	**Description**	**Legal Requirement**				**Weighted Cost**	**Comment**	**Support**
GR	Ash Pond Remediation	Clean Water Act	$ 8,740	$ 9,711	$ 10,682	$ 9,760	$83k/acre at 117 acres Acreage verified by Paul Puckett-Environmental Dept	FSMS estimate of $75k/acre per study during Pineville retirement
GR	Coal Storage Pile Remediation	Clean Water Act	$ 81	$ 90	$ 99	$ 90	Coal pile is 6 acres. Common to the plant divide evenly among the units. Acreage verified by Delbert Billiter-Fuels Dept.	Based on Pineville estimate - $15k/acre
GR	Oil Storage Tanks	Clean Water Act	$ 9	$ 10	$ 11	$ 10	Based on $0.22 gallon (41,700 gallons) plus removal of underground line $1K/100 feet.	Based on Ghent estimate. **Supported by email from Evergreen USA**
GR	Underground Storage Tanks	Comprehensive Emergency Response and Liability Act	$ 12	$ 13	$ 14	$ 13	Based on Ghent estimate.	**Supported by email from Evergreen USA**
GR 1/2	Mercury Switches - All Units	Resource Conservation and Recovery Act	$ 2	$ 2	$ 2	$ 2	Based on approx. 100 mercury sources (total) and some pre-existing on-site mercury storage from years past.	**Supported by ENSCO quote provided by Mike Winkler**
GR	Sewage Treatment Plant	Clean Water Act	$ 5	$ 5	$ 6	$ 5	Common - divide evenly among the units. Estimated cost to pump out tank, fill tank with soil, and grade land.	Based on Pineville estimate of $1k for 50 people, assumed $1k for 50 people and additional fee for equipment use. **Supported by PMR invoice**
GR	Switchyard transformers, OCB's, etc.	Clean Water Act Toxic Substances Control Act	$ 23	$ 25	$ 28	$ 25	41,700 gallons at $0.60 per gallon. Allocate evenly across all units	**Supported by invoice from American Enviro Services**
GR	Acid Tank Disposal	Clean Water Act Toxic Substances Control Act	$ 3	$ 3	$ 3	$ 3	Common to the plant divide evenly among the units	$75/hr company employee to neutralize chemicals and dispose of in ash pond. ($3,000) Tank removal for scrap $0. **Supported by Shannon Charnas email**
GR	Caustic Tank Disposal	Clean Water Act Toxic Substances Control Act	$ 3	$ 3	$ 3	$ 3	Common to the plant divide evenly among the units	$75/hr company employee to neutralize chemicals and dispose of in ash pond. ($3,000) Tank removal for scrap $0. **Supported by Shannon Charnas email**
GR	Lime Storage Silo	Clean Water Act	$ 5	$ 6	$ 7	$ 6		80 manhours at $75 per hour internal burdened labor rate. **Supported by Shannon Charnas email**
GR	Nuclear Source	The Cabinet for Human Resources - KRS 211.844, regulation 902 KAR Chapter 100	$ 1	$ 1	$ 1	$ 1	Plant has one nuclear source at the scrubber.	$1k/nuclear source based on Ghent's 12/02 phone estimate from nuclear disposal co. **Supported by email from OHMART**
Total				**$ 9,869**		**$ 9,918**		

Wiseman, Sara

From: Stringfellow, David [DStringfellow@eei.org]

Sent: Friday, July 29, 2005 5:04 PM

To: alina.rocha@pseg.com; andy.krebs@pgnmail.com; avaske@atcllc.com; betty.mincer@conectiv.com; bruce.bollert@pse.com; bruce.friedman@peco-energy.com; bullerja@oge.com; cappiellope@coned.com; catherine.mueller@avistacorp.com; cbillingsley@tnpe.com; charles.stegner@uinet.com; cindy.perdue@cleco.com; cindy.reed@aquila.com; cjcounci@duke-energy.com; cmcelwee@sppc.com; cneff@itctransco.com; dane.watson@txu.com; daniel.reardon@northwestern.com; daniel.zielezinski@exeloncorp.com; darren.zurawski@exeloncorp.com; dcoit@empiredistrict.com; demiller@midamerican.com; devavold@otpco.com; dlblaloc@southernco.com; dlkutsunis@midamerican.com; eortlieb@cenhud.com; everett_lawrence@illinoispower.com; fstibor@itctransco.com; jcarpen@pnm.com; jeff_beasley@wr.com; jehenderson@aep.com; jfrelic@wpsr.com; jhjenson@mge.com; jpnitsche@pplweb.com; jxjackso@southernco.com; kemcdani@southernco.com; kenmenge@alliant-energy.com; laura.rockenberger@aps.com; lawrence_poore@nstaronline.com; ldabell@entergy.com; leonard.a.delozier@bge.com; lhancock@epelectric.com; lisa.h.perkett@xcelenergy.com; ltuckness@idahopower.com; mdonahue@mnpower.com; mgetz@ameren.com; michelle.koyanagi@heco.com; mpenn@wpsr.com; mrizk@cvps.com; paul.bienek@mdu.com; pgillam@entergy.com; pgrant@blackhillspower.com; plaub@cinergy.com; pmfitzgerald@cmsenergy.com; rawalker@tecoenergy.com; rhansen@otpco.com; rick.baldauf@we-energies.com; rob.pierce@sce.com; robert.pontau@energyeast.com; Wiseman, Sara; skramer@duqlight.com; stackjp@nu.com; sylvia_green@dom.com; throbke@wcnoc.com; tlsimons@cmsenergy.com; tony_cuba@fpl.com; tschad@gpu.com; wftyson@southernco.com; bgonzal@pnm.com; cabymun@southernco.com; daignca@nu.com; david.githae@constellation.com; joseph.freedman@kcpl.com; mary.tenenbaum@bge.com; ssims@tep.com

Cc: Allen, Doug

Subject: August 30 - ARO Seminar: FASB FIN 47 Interpretation

Attachments: FIN 47 Meeting 2005.pdf

EEI and AGA are pleased to announce a special one-day seminar to cover FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations.*

Registration is available now for

Accounting for Conditional Asset Retirement Obligations Seminar:
Understanding and Implementing FASB Interpretation No. 47

August 30, 2005
Renaissance Chicago O'Hare
Chicago, IL

The seminar highlights include:

- **An overview presentation on FASB Interpretation No. 47;**
- **Auditor's perspective by a panel of Big 4 partners;**

- A discussion of the white paper developed to address implementing the new Interpretation.

The cutoff date for hotel reservations is Monday, August 15, 2005.

The deadline for registering for the course with AGA is Friday, August 19th.

Registration for this workshop is limited to EEI and AGA members.

David Stringfellow, Edison Electric Institute

dstringfellow@eei.org ; (202) 508-5494

Wiseman, Sara

From: Stringfellow, David [DStringfellow@eei.org]

Sent: Friday, July 29, 2005 5:02 PM

To: alina.rocha@pseg.com; andy.krebs@pgnmail.com; avaske@atcllc.com; betty.mincer@conectiv.com; bruce.bollert@pse.com; bruce.friedman@peco-energy.com; bullerja@oge.com; cappiellope@coned.com; catherine.mueller@avistacorp.com; cbillingsley@tnpe.com; charles.stegner@uinet.com; cindy.perdue@cleco.com; cindy.reed@aquila.com; cjcounci@duke-energy.com; cmcelwee@sppc.com; cneff@itctransco.com; dane.watson@txu.com; daniel.reardon@northwestern.com; daniel.zielezinski@exeloncorp.com; darren.zurawski@exeloncorp.com; dcoit@empiredistrict.com; demiller@midamerican.com; devavold@otpco.com; dlblaloc@southernco.com; dlkutsunis@midamerican.com; eortlieb@cenhud.com; everett_lawrence@illinoispower.com; fstibor@itctransco.com; jcarpen@pnm.com; jeff_beasley@wr.com; jehenderson@aep.com; jfrelic@wpsr.com; jhjenson@mge.com; jpnitsche@pplweb.com; jxjackso@southernco.com; kemcdani@southernco.com; kenmenge@alliant-energy.com; laura.rockenberger@aps.com; lawrence_poore@nstaronline.com; ldabell@entergy.com; leonard.a.delozier@bge.com; lhancock@epelectric.com; lisa.h.perkett@xcelenergy.com; ltuckness@idahopower.com; mdonahue@mnpower.com; mgetz@ameren.com; michelle.koyanagi@heco.com; mpenn@wpsr.com; mrizk@cvps.com; paul.bienek@mdu.com; pgillam@entergy.com; pgrant@blackhillspower.com; plaub@cinergy.com; pmfitzgerald@cmsenergy.com; rawalker@tecoenergy.com; rhansen@otpco.com; rick.baldauf@we-energies.com; rob.pierce@sce.com; robert.pontau@energyeast.com; Wiseman, Sara; skramer@duqlight.com; stackjp@nu.com; sylvia_green@dom.com; throbke@wcnoc.com; tlsimons@cmsenergy.com; tony_cuba@fpl.com; tschad@gpu.com; wftyson@southernco.com; bgonzal@pnm.com; cabymun@southernco.com; daignca@nu.com; david.githae@constellation.com; joseph.freedman@kcpl.com; mary.tenenbaum@bge.com; ssims@tep.com

Subject: EEI-AGA FIN 47 White Paper

Attachments: FIN 47 Whitepaper_0705.pdf

TO: EEI Property Accounting & Valuation Committee Members

Attached is the EEI-AGA FASB Interpretation No. 47 Accounting for Conditional Asset Retirement Obligations White Paper prepared by an industry task force.

EEI and AGA will have a FIN 47 Seminar on August 30 in Chicago, Illinois. Information on the Seminar will follow.

David Stringfellow
Edison Electric Institute
dstringfelow@eei.org
202/508-5494

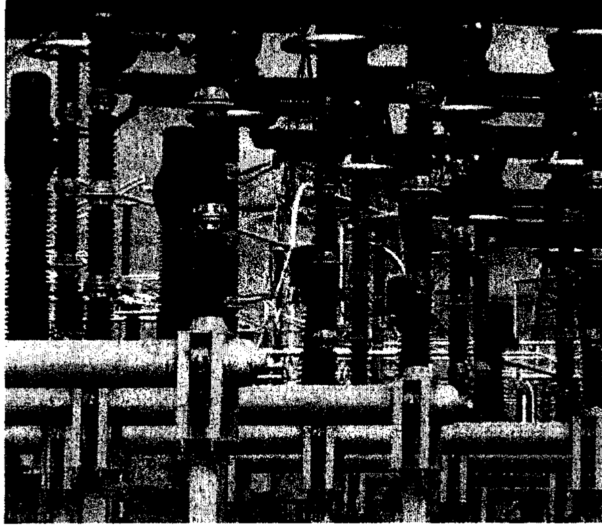
EDISON ELECTRIC INSTITUTE

AGA American Gas Association

FASB Interpretation No. 47

Accounting for Conditional Asset Retirement Obligations

An Industry White Paper



July 2005

EDISON ELECTRIC INSTITUTE

American Gas Association

FASB Interpretation No. 47
Accounting for Conditional Asset Retirement Obligations
An Industry White Paper

Introduction

"This Interpretation clarifies that the term *conditional asset retirement* obligation as used in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*, refers to a legal obligation to perform the asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event."

This white paper has been written with an eye toward the Electric and Gas utility business. It is intended to assist one in doing the investigation and review necessary to properly recognize and disclose any new asset retirement obligations resulting from the adoption of this Interpretation. Each company will need to work through their particular issues and review all assumptions with their legal staff to assure proper representation of this topic. At first glance, this Interpretation can appear overwhelming. But one needs to approach this in a thoughtful and reasonable manner that represents the intent and purpose of the Interpretation without getting so lost in the details that the accounting becomes impossible to maintain within a cost effective manner. Without careful thought to the intent and the process to achieve it, the accounting for this Interpretation may not be manageable as the issue moves throughout time.

FASB Statement No. 143, *Accounting for Asset Retirement Obligations* provides a complex process for determining recognition criteria, measurement procedures, and accounting and disclosure requirements for the financial implications of an obligation related to the future retirement of existing property. Because FIN 47 represents clarification of a limited, but important, concept within the broad scope of accounting for asset retirement obligations, this document is limited to discussing compliance within this new interpretation. It is beyond the scope of this document to attempt to provide a comprehensive discussion of all the provisions of FASB Statement No. 143.

Another white paper was prepared by EEI and AGA shortly after SFAS 143 was issued. This white paper is supplemental to that earlier one. The following terms and acronyms are used throughout this document.

Term or Acronym	Description
ARC	Asset Retirement Cost (Plant Asset)
ARO	Asset Retirement Obligations
FERC Order 631	Accounting, Financial Reporting, and Rate Filing Docket No. RM02-7-000, *Requirements for Asset Retirement Obligations*
FERC Order 552	Revision to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2-A
FIN 47 or Interpretation	FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations*
FSP	FASB Statement of Position
SAB 99	SEC Staff Accounting Bulletin No. 99, *Materiality*
SFAS 71	FASB Statement No. 71, *Accounting for the*

Term or Acronym	Description
	Effects of Certain Types of Regulation
SFAS 143	FASB Statement No. 143, *Accounting for Asset Retirement Obligations*

Reasons for an Interpretation

Diverse accounting practices have been developed with respect to the timing of liability recognition for legal obligations associated with the retirement of a tangible long-lived asset when the timing and (or) method of settlement of the obligation are conditional on a future event. For example, some entities have recognized the fair value of the obligation prior to the retirement of the asset with the uncertainty about the timing and (or) method of settlement incorporated into the liability's fair value. Other entities, however, have recognized the fair value of the obligation only when it is probable the asset will be retired as of a specified date using a specified method or when the asset is actually retired.

The Interpretation clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO when incurred if the liability's fair value can be reasonably estimated. The Interpretation clarifies when an entity would have sufficient information to reasonably estimate the fair value of the ARO. This clarification should improve the relevance, reliability, and comparability of the amounts recognized in the financial statements.

The FASB believes application of the Interpretation will result in a more consistent recognition of liabilities relating to AROs, in more information about expected future cash outflows associated with those obligations, and in more information about investments in long-lived assets because additional asset retirement costs will be recognized as part of the carrying amounts of the assets. At the January 26, 2005 meeting, the FASB addressed a request to reconsider the entire concept of recording AROs (see FASB Board minutes at *www.fasb.org/board_meeting_minutes/board_meeting_minutes.shtml*). This discussion provides significant insight to the FASB's expectations and considerable support for the role of management's judgment and reasonableness in the recognition of AROs. In summary, the FASB essentially establishes what disclosure is expected whenever there is an ARO while also narrowing the circumstances in which the measurement could be avoided.

Sufficient Information

In SFAS 143, the term *retirement* is defined as the other-than-temporary removal of a long-lived asset from service. The term *retirement* encompasses sale, abandonment, recycling, or disposal in some other manner. The term does not encompass the temporary idling of a long-lived asset.

- "If an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation, it must recognize a liability at the time the liability is incurred. An asset retirement obligation would be reasonably estimable if (a) it is evident that the fair value of the obligation is embodied in the acquisition price of the asset, (b) an active market exists for the transfer of the obligation, or (c) sufficient information exists to apply an expected present value technique." This is from paragraph 4 of the Interpretation.

- The Interpretation states that when the method of settlement and settlement date have been specified by others such as in a law, regulation or contract, the entity has sufficient information to apply an expected present value technique. Therefore the ARO would be reasonably estimable and a liability must be recorded. The only uncertainty in these situations is whether performance will be required.

  From paragraph 5a, "uncertainty about whether performance will be required does not defer the recognition of an asset retirement obligation because a legal obligation to stand ready to perform the retirement activities still exists", and that uncertainty does not prevent the determination of a reasonable estimate of fair value. There are two possible outcomes in situations in which the only uncertainty is whether performance will be required—the entity will be required to perform or the entity will not be required to perform.

  If there is no information about which outcome is more probable, paragraph A23 of SFAS 143 requires 50 percent likelihood for each outcome to be used until additional information is available. In certain cases, determining the settlement date for the obligation that has been specified by others is a matter of judgment that depends on the relevant facts and circumstances.

- In situations where the date and method of settlement are not specified by others, if information is available to reasonably estimate (1) the settlement date or the range of potential settlement dates, (2) the method of settlement or potential methods of settlement **and** (3) the probabilities associated with the potential settlement dates and potential methods of settlement, the FASB believes sufficient information is present to apply an expected present value technique. Therefore, the ARO would be reasonably estimable and a liability must be recorded.

Information that is derived from an entity's past practice, industry practice, and management's intent can provide a basis for estimating the potential methods of settlement. Entities must take into account only the methods of settling the obligation that are currently available to the entity.

The ability of an entity to indefinitely defer settlement of an ARO does not relieve the entity of the obligation. Implicit in this conclusion is the belief that no tangible asset will last forever (except land) and, accordingly, the asset retirement activities will eventually be performed. Furthermore, the ability of an entity to sell the asset prior to its disposal does not relieve the entity of its present duty or responsibility to settle the obligation. The sale would cause the buyer to assume the obligation, in turn affecting the sales price.

Change in the Way Disposal is Viewed

The FASB believes that if a current law, regulation, or contract requires an entity to perform an asset retirement activity; there is an unambiguous requirement to perform the retirement activity even if that activity can be indefinitely deferred. As noted above, no tangible asset will last forever (except land) and, accordingly, the asset retirement activities will eventually be performed. Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement.

- A law or entity's promise may create a duty or responsibility, but that law or promise in and of itself may not be the obligating event that results in an entity having little or no discretion to avoid a future transfer or use of assets.
- SFAS 143 states that the obligating event is the acquisition, construction, or development and (or) the normal operation of the long-lived asset when a law or promise exists that creates a duty or responsibility relating to the retirement of the asset. At this point, the obligation cannot be realistically avoided if the asset is operated for its intended use.

All companies are subject to federal and state solid waste disposal requirements for non-hazardous materials and refuse[1]. These laws require such materials to be disposed in a licensed public landfill with other household garbage. Although there is no legal obligation to retire assets under these solid waste laws, these retired and dismantled assets must be transported to licensed public landfills. Companies regularly incur monthly expenses for use of these public landfills for disposal of non-hazardous materials and refuse (i.e. garbage) which in most cases would cover disposal of non-hazardous retired assets.

The scope of SFAS 143 and FIN 47 focuses on "special" requirements for disposal of retired assets that would add incremental costs to the retirement of those assets above what a company expenses monthly for non-hazardous material and refuse disposal. This is evidenced by the reference to "special" requirements in the examples to FIN 47 and the proposed FSP on SFAS 143 relating to the European Union (EU) Directive on Waste Electrical and Electronic Equipment that requires EU members to adopt legislation for environmentally sound disposal of electrical and electronic waste equipment.

This white paper assumes that even though some legal obligation may exist to dispose of non-hazardous materials and refuse resulting from retirements of fixed assets, the disposal costs for non-hazardous materials and refuse may be inconsequential for many assets and may not add significant incremental costs to the asset retirement activities. A company may decide that there is not a legal obligation for removal whereby an asset is disposed within the cost boundaries of the standard garbage fees and only incremental charges above this standard may constitute a removal obligation. Moreover, the incremental charge associated with additional service may be considered part of the standard costs. To illustrate this analysis with an example, consider the following removal activities typical for a treated and a non-treated pole:

__Pole Removal Example__

		Non-treated	Treated
1.	Labor to removal the pole and haul it to the yard	$75	$75
2.	Grinding the pole into small pieces (not required by regular landfill)	0	10
3.	Transporting the pole to the landfill	15	15
4.	Landfill Fees	10	40

[1] These rules federal and state regulations are governed under Subtitle D of the Resource Conservation and Recovery Act. Subtitle D regulates garbage, refuse, sludge from waste treatment plants, non-hazardous industrial waste and other discard materials including solid, semi-solid and liquid materials resulting form commercial and industrial activities (e.g. demolition debris, mining waste, oil & gas waste).

The costs to remove and transport the pole, for both types of pole, would not be considered an ARO in this example. The landfill fees for the treated pole would be considered an ARO, but one would need to determine if the incremental cost would be the ARO basis or would one use the total cost. If the landfill accepting the treated pole is different than the one accepting the non-treated pole, the total cost would be used and if the same facility then the incremental would be applicable. Lastly, the cost to grind the pole would be considered part of the ARO, as this cost is not incurred for non-treated poles.

As always, a full review of the company position on this issue is paramount to defining the magnitude of potential AROs. Each company needs to decide if these laws constitute a legal obligation in respect to the SFAS 143 and the Interpretation. In instances where the legal requirement relates only to the disposal of the asset subject to the ARO, the cost to remove the asset is not included in the ARO. However, if there were a legal requirement to remove the asset, the cost of removal would be included.

Date of Obligating Event

There has been some discussion around when the obligating event occurs. Quickly, most would point to the in-service date of the asset if a law, regulation, or contract creating the obligation was in place before the in-service date. Similarly, one would choose the date the law, regulation, or contract created the obligation if it came to be after the in-service date. However, SFAS 143 refers to obligations that "result from the acquisition, construction, or development and (or) the normal operation of the long-lived asset". One could question if this infers the purchase of material during the construction process or to inventory. Whereby, the company may have incurred a legal obligation before the in-service date of the asset. Timing of the recognition of the ARO, as discussed in paragraphs 3-10 and B32-B41 of SFAS 143, is when all the following criteria are met:

- The obligation meets the definition of a liability in paragraph 35 of Concepts Statement 6.
- A future transfer of assets associated with the obligation is probable.
- The amount of the liability can be reasonably estimated.

During construction of long-lived assets, such as a steam generating plant, legal obligations to eventually retire the plant may be incurred and measurement of those obligations may be prudent during the construction phase. It is important to remember that the obligating event has to have already happened to create a liability. In the case of a nuclear power facility, the obligation to remove the facility may not exist until the facility is operated and contamination occurs. Thus, the contamination constitutes the obligating event. Along with these two instances provided, work performed on leased property also may create a legal obligation during the construction phase. Furthermore, the amount of the liability may grow in subsequent periods as the construction of the asset continues. These changes, in the amount of the original estimate, may need to be recognized as an increase in the carrying amount of the liability.

Another example may be a treated pole purchased to inventory. One could argue that the obligating event has occurred at the purchase of the pole even though it is held for a time in the inventory account before moving through construction work in progress to plant in-service. The assumption presupposes that the manufacturer treated the pole before the company purchased it. The scenario would change if the company treats its poles itself. This component can add more complexity to an already multifarious process.

The definition for the obligating date needs to be fully thought out and clear as to the materiality of and the ability to recognize the obligation before the in-service date. One may likely conclude that the obligation will be flagged during construction or when in inventory only for those exceptionally large items. Otherwise, the in-service date will prevail. For any decision, either for this section or for others throughout this document, one needs to assure that it is legally reviewed and representative of management's judgment as to the correct application of the Interpretation and SFAS 143.

Indefinite Life

FIN 47 does not eliminate the recognition of an indefinite life, but rather distinguishes uncertainty from indefinite. The first sentence in paragraph B22 of the Interpretation provides specific guidance in three clauses where FASB considers an ARO is reasonably estimable, "if information is available":

1. "To estimate the settlement date or the range of potential settlement dates,"
2. "The method of settlement or potential methods of settlement," **and** (*emphasis added).*
3. "The probabilities associated with potential settlement dates and methods of settlement."

The third clause would seem to imply that the **probable** service lives and estimated net salvage developed from utility depreciation studies could lead to the conclusion that an ARO is reasonably estimable. Paragraph B19 through B27 also provided more specific language than originally addressed in SFAS 143, which substantially narrowed the circumstance that would lead to a conclusion that an ARO is not estimable.

The current utility industry position, prior to the release of this Interpretation, is that a company cannot calculate an ARO for the ultimate retirement of its distribution and transmission **systems** because each system has an indefinite life. A depreciation study develops probabilities of life and net salvage for a large group of similar assets, and that many cycles of replacements occur to the group or system. An example of the distinction between a "group of similar assets" versus a "system"; a power line or gas line between two points will probably have multiple retirements and replacement additions (items in a group), particularly if a portion of the line is moved for any reason, but the line itself generally continues long afterwards (as a system). In addition, it is part of a larger group of assets when life analysis is done; all similar power lines or gas lines are considered together. In other words, the probable lives in a depreciation study are on the interim retirements and additions to the line, and not representative of the probable life of the line (or the system). Further, it has been suggested that retirement of the **system** would invoke other accounting pronouncement governing status as an ongoing entity, impairment of an asset, or accounting for discontinued operations.

Accordingly, sufficient information may not be available to reasonably estimate the ARO liability on the ultimate retirement of transmission or distribution property. The industry also does not believe that an ARO should be calculated for such interim retirements when there is not an obligation for that specific interim retirement or when a company cannot reasonable estimate when a specific interim retirement with an obligation would take place. The third characteristic of a liability is that the transaction or other event obligating the entity has already happened. One does not know what portion of a distribution or transmission system will be retired until an event such as a gas leak, storm damage, or a road widening requires work on the asset, making it difficult to estimate the costs and timing. This generally is corrected or recorded in the same accounting period so no liability would be accrued.

However, FIN 47 provides further interpretation of FAS 143 that may require a reassessment of the indefinite life concept. Example 1 specifically addresses this mass asset system versus individual asset contrast and clearly attempts to close the loophole that a system has an infinite life, therefore no ARO can be measured. FIN 47 requires that the fair value of an ARO be recognized when it can be reasonably estimated. It also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. For some utilities, data derived from their most current depreciation study possibly could be a potential source to provide information to calculate an estimated ARO for distribution and transmission assets that constitute an entire system. This data is used to recover property costs (including removal cost) for regulatory purposes and also may serve as a platform for calculating the expected ARO liability. Depreciation study data is used in the Snapshot example within the Mass Assets, Electric and Gas section of this paper.

An argument also can be made that depreciation study data does not provide sufficient information to estimate a reasonable ARO liability. Depreciation data is utilized to provide for matching of existing property cost with the customer benefiting from that property cost. It is not designed, in concept, to provide an estimated liability for the permanent removal of the entire distribution and transmission system. The assumption is the entity will continue to be a going concern. As such, depreciation study data may need to be used cautiously as it may not be an appropriate mechanism to use when calculating all ARO liabilities. Discarding the depreciation study data, no data may be available to reasonably estimate the ARO liability.

Given this quandary, the indefinite life concept currently used by most utilities may continue in effect for the ultimate retirement of the system, but the individual assets comprising the system may not have indefinite life. Again, it was very clear that a "do nothing" scenario might not be a defendable position and that material obligations should be recognized or disclosed if a legal retirement obligation applies to the interim retirement of a system and the timing and method of settlement can be reasonably estimated. Any conclusion needs to be supported with full documentation and justification for the indefinite life choice and should be disclosed.

Materiality

FIN 47 clearly states, "The provisions of this Interpretation need not be applied to immaterial items." However, many immaterial items may constitute, in aggregate, a material item. Determination of materiality is company specific and often an issue-specific routine. It should be defined and documented for each segment of the business. Along with the materiality threshold, a company should define the way in which assets will be summed to test materiality. It is assumed that the test will be for balance sheet materiality, as most utilities will offset any income statement effect with regulatory accounting. When the ARO does impact the income statement, an income statement materiality test may be used. For example, one must decide if distribution assets will be combined with nuclear assets in determining materiality. Perhaps a company will sum all asset obligations relative to a segment of the utility business keeping the nuclear AROs separate from the distribution calculation. Defining the materiality test to a lower level than function should be a decision based on propriety and not with the intent of avoiding this Interpretation. Additional guidance on materiality can be found in the Securities and Exchange Commission's SAB No. 99.

For those companies that have more than one legal entity, the materiality should be done at the individual legal entity and not at the consolidated level. Now, one legal entity may have an ARO and another may not for the same class of assets because of the variety in the rules and regulation as well as the difference in size of the companies. This white paper does not advocate a consolidated materiality review of AROs where multiple legal entities exist within the corporation. The obligation is clearly the responsibility of the originating legal entity and it should be maintained at that level. However, the disclosures may be more detailed on the utility reports and summarized at the parent level.

Decision Tree

In general, a more substantive review of regulations, laws, and contract obligations will be required to assure that conditional AROs are properly recognized. Each company will need to assess its particular facts and circumstances as the same general situation may play out differently depending on the legal documents and company policies that surround it. To help facilitate this review, a decision tree for analyzing each situation is provided below.

Decision Tree Notes

1. Paragraph 3 of FIN 47 advises to include all legal obligations to perform an asset retirement activity, even those in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement.

   Paragraph B7 of the Interpretation states, "As used in Statement 143, a legal obligation is an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel."

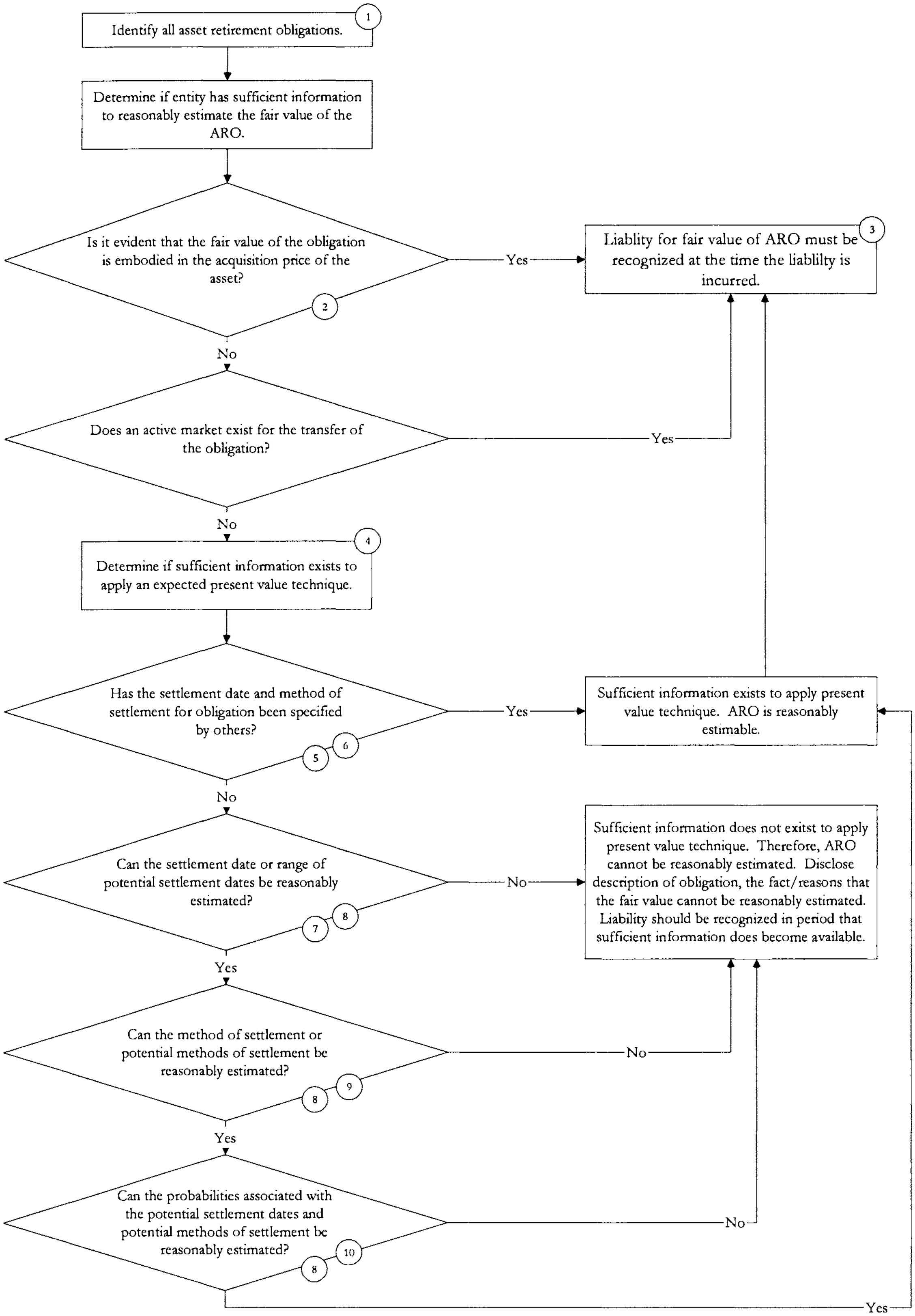
2. Paragraph 4 of the Interpretation references paragraph 17 of FASB Concepts Statement No. 7, *Using Cash Flow Information and Present Value in Accounting Measurements,* which states, "If a price for an asset or liability or an essentially similar asset or liability can be observed in the marketplace, there is no need to use present value measurements. The marketplace assessment of present value is already embodied in such prices."

3. Paragraph 3 of the Interpretation reiterates the SFAS 143 requirement that the fair value of an asset retirement obligation be recognized when the obligation is incurred—generally upon acquisition, construction, or development and (or) through the normal operation of the asset.

4. Present value techniques are discussed in paragraphs 39–54 and 75–88 of Concepts Statement 7. These techniques, which incorporate uncertainty about the timing and method of settlement into the fair value measurement, should be used when the fair value of the liability cannot be estimated based on the acquisition price or on an observable market price.

5. For example, specified in a law, regulation or contract (Paragraph 5a of the Interpretation).

Decision Tree



Decision Tree Notes Continued:

6. Paragraph 5a of the Interpretation states that uncertainty about whether performance will be required does **not** defer the recognition of an asset retirement obligation because a legal obligation to stand ready to perform the retirement activities still exists, and it does not prevent the determination of a reasonable estimate of fair value because the only uncertainty is whether performance will be required.

   There are two possible outcomes in situations in which the only uncertainty is whether performance will be required—the entity will be required to perform or the entity will not be required to perform. If there is no information about which outcome is more probable, paragraph A23 of Statement 143 requires 50 percent likelihood for each outcome to be used until additional information is available.

   In certain cases, determining the settlement date for the obligation that has been specified by others is a matter of judgment that depends on the relevant facts and circumstances. For example, a contract that provides the entity with an ability to extend its term through renewal should be evaluated to determine whether the settlement date should take into consideration renewal periods.

7. Paragraph 5b of the Interpretation states that the estimated economic life of the asset might indicate a potential settlement date for the asset retirement obligation. However, the original estimated economic life of the asset might not establish, in and of itself, that date because the entity may intend to make improvements to the asset that could extend the life of the asset or the entity could defer settlement of the obligation beyond the economic life of the asset. In those situations, the entity would look beyond the economic life of the asset in determining the settlement date or range of potential settlement dates to use when estimating the fair value of the asset retirement obligation.

8. Paragraph 5b gives examples of information that is expected to provide a basis for estimating the potential settlement dates, potential methods of settlement, and the associated probabilities. Examples include, but are not limited to, information that is derived from an entity's past practice, industry practice, management's intent, or the asset's estimated economic life.

9. Paragraph 5b of the Interpretation limits "potential methods of settlement" to those methods that are currently available to the entity. Therefore, uncertainty about future methods yet to be developed would not prevent the entity from estimating the fair value of the asset retirement obligation.

10. Paragraph 5b of the Interpretation states that the entity should have a reasonable basis for assigning probabilities to the potential settlement dates and potential methods of settlement to reasonably estimate the fair value of the asset retirement obligation. If the entity does not have a reasonable basis of assigning probabilities, it is expected that the entity would still be able to reasonably estimate fair value when the range of time over which the entity may settle the obligation is so narrow and (or) the cash flows associated with each potential method of settlement are so similar that assigning probabilities without having a reasonable basis for doing so would not have a material impact on the fair value of the asset retirement obligation.

Specific Property Considerations

Four examples were included in FIN 47. This white paper discusses those examples in the context of the Electric and Gas utility business. The examples are as follows:

1. Telecommunication poles
2. Bricks in a kiln
3. Factory with asbestos and regulations go into effect after purchase
4. Factory with asbestos and regulations are in place at acquisition

Basically, the premise put forward by the FASB in this Interpretation was that no tangible asset, except land, would last forever and accordingly, asset retirement activities will eventually be performed. In completing the retirement work, if a company is required to dispose of the asset in a specific manner or could be required to perform any one of a number of different methods of settlement, to be chosen at some later date, the company will need to evaluate the asset's retirement obligations. The four examples provided were meant to cover various situations a company may face. To bring the examples into the context of the energy industry, the list has been tailored to the potential issues for the Electric and Gas business. The following are the asset issues discussed in the remaining document:

1. Mass assets, electric and gas ***(Telecommunication poles)***
2. Minor Items ***(Bricks in a kiln)***
3. Asbestos, PCBs, and other contaminants ***(Factory with asbestos and regulations go into effect after purchase or in place at acquisition)***
4. Rights-of-Way and franchises
5. General equipment
6. Hydro generation

Mass Assets, Electric and Gas

Example 1 of Appendix A, Illustrative Examples, provides specific discussion on wood pole treated with certain chemicals. However, the circumstances may be comparable to other utility property generally described as mass asset property. The following summarizes Example 1, followed by a discussion of comparability and applicability to other mass assets, and finally a discussion of various issues for utilities to consider in their implementation of FIN 47.

Summary of Example 1 of Appendix A

Example 1 discusses a situation in which a utility is using treated wood poles and where there is existing legislation that requires special disposal procedures in the state in which the utility operates. The example recognizes that the poles may be removed from the ground for a variety of operational reasons other than disposal, and further recognizes that the disposal obligation is not triggered by removal of the pole. Once a pole is removed from the ground, it may be disposed of, sold, or reused as part of other activities. In this example, the disposal obligation is not triggered by removal of the pole. Based on that premise, Example 1 includes specific guidance that requires an assessment of AROs related to treated wood poles. That guidance suggests assessing the ARO and related accounting based on the following:

1. The **recognition point begins with the purchase** of the pole, rather than when the pole was placed into service (in-service date is when the pole first became a long-lived fixed asset). See obligating event and materiality above.
2. That **reuse does not change the obligation**, only defers it (common industry practice is to retire the pole at time of removal, not track it while in inventory, and considered a new addition when reused and placed in the ground again).
3. The **utility already has the information necessary to estimate** a range of settlement dates, methods of settlement, and the related probabilities **based on entity-specific practices, industry practices, management's intent, or the asset's estimated economic life.** (It is important to note that only in the example did the entity have sufficient information to estimate the fair value of the liability for the ARO. Each entity will have to make their own determination as to whether they have sufficient information.)
4. The utility is **not relieved of the obligation by selling** the pole to another party through the assertion that the exchange price reflects the estimated fair value of the obligation.

Impact On Asset Retirement Obligations Accounting

Example 1 of FIN 47 represents a utility that has a legal requirement to follow special procedures for disposal of treated wood poles. In this example, the utility is presumed to have all the information necessary to calculate an asset retirement obligation and is expected to make appropriate disclosure. Therefore, the asset retirement obligation should be recognized when the entity purchases the pole. This may result in a significant change from the requirements under FAS 143, where previous estimates and disclosures were not made because: 1) most disposal activities were performed by third parties so there were no future direct costs to be expended by the utility, 2) it was not reasonable to track the obligation (and settlement) due to reuse and different options for disposal, or 3) that the obligation was conditional due to circumstances known only at the time of removing the pole from the ground. There were no future costs because most utilities could give the poles away to third parties at no cost to the utility, but under FIN 47 even the ultimate disposal cost to a third party is to be considered (that net zero would be bifurcated into the avoided future disposal removal cost and the salvage – remember salvage is not recognizable for ARO purposes.)

Example 1 could apply to other mass asset property where a portion of the asset may be subject to special disposal procedures. Some examples might be property containing PCBs, mercury, lead, or any chemical considered hazardous. In the case of natural gas pipelines, specific activities are legally mandated for abandonment or removal and disposal. The ARO may include the cost of testing, removal, disposal or decontamination of pipeline segments and liquids. In other words, FIN 47 requires that if a utility has a special procedure requirement at ultimate disposal, then the utility either would have a measurable ARO with all the related accounting requirements, which should be recognized if the entity has sufficient information to estimate the fair value of the obligation. If the entity does not have sufficient information to reasonably estimate the obligation, the entity only has a disclosure requirement until sufficient information becomes available.

Concerns and Issues

This raises several concerns and issues for both the individual utility and for the industry:

1. Initial determination of legal obligation – The language seems to indicate that if there is a special disposal procedure, that there will be a cost of performing that disposal activity and therefore, an asset retirement obligation. The legal obligation review may need to be expanded to other assets containing materials, which are considered hazardous with special disposal procedures required by some legal mandate.

2. Record keeping and reporting changes – Many if not most utilities track poles as assets from the date put in the ground until the next time it is removed rather than from purchase to disposal. Time in inventory (initially and upon salvage for reuse) is often not tracked – much less details on how many were treated and what happened to the treated portion at disposal. An individual utility may have to develop such tracking details.

3. Third party disposal – Example 1 states that the "ability to sell the poles prior to disposal does not relieve the entity of its ...obligation", and states that "the assumption of the obligation affects the exchange price". This could be a significant issue in compliance for some utilities. It implies that the utility is not relieved of the obligation; and, therefore, should attempt to measure the ARO.

   The use of the pole would affect disposal requirements, as Example 1 clearly requires a company to identify future disposal costs. Therefore, unless there is a market price available, the company would need to apply present value techniques, estimating the life of the pole before disposal. Such information about that future transaction may be particularly hard to estimate when the utility purchases the pole and needs to record the obligation.

4. SEC transfer of other provisions for accrued cost of removal – Any change because of reassessing the ARO for treated wood poles also would affect any recognition of the SEC interpretation on depreciation accruals for future removal costs.

   Background: SFAS 143 does not allow a provision for future removal costs to be included in depreciation reserves. FERC Order 631 provides that utilities that qualify to apply SFAS 71 and if the requirements for Order 552 are met, any provisions for future removal cost would be transferred to a regulatory liability. However, FERC Order 631 continues to allow provision for future removal costs for assets that do not have an existing legal retirement obligation. A conflict may exist because many utilities also have adopted the unofficial SEC interpretation that SFAS 143 does not allow for any accrual of future removal costs, and all provisions for future removal costs should be excluded from accumulated reserves (or transferred to a regulatory liability if eligible for SFAS 71). There is inherent contradiction for many utility assets whereby it needs to be recognized in two different ways for reporting the same activity to the two different entities.

   FERC Order 631 requires that only for accounts where an ARO is recognized, then previous provisions for future removal costs should be transferred from the accumulated reserve (and carried as a regulatory obligation under SFAS 71, if the requirements for Order 552 are met). Many utilities have also adopted the unofficial SEC interpretation that SFAS 143 does not allow for any accrual of future removal costs, and all provisions for future removal costs should be excluded from accumulated reserves (or transferred to a regulatory liability if eligible for SFAS 71).

The cumulative effect adjustment for SEC reporting will be the difference between the amount previously recognized prior to FIN 47 and the amount recognized following the advice in FIN 47 (as mentioned under Transition Accounting below). FERC reporting will be governed by any new advice that FERC may issue prior to adoption of FIN 47.

Recommendation

Since ARO compliance for this category of plant type, mass assets, may be quite onerous, a recommendation is offered for consideration to achieve the intent of the Interpretation without excess burden to the company and the accounting personnel. Each company will need to decide if the recommendation is feasible for their books and records. SFAS 143 (paragraph A22) permits the use of estimates and computational shortcuts that are consistent with the fair value measurement objective when computing an aggregate asset retirement obligation for assets that are components of a larger group of assets. This is appropriate for large transmission and distribution utilities that use group accounting. Therefore, the recommendation is to approximate the literal compliance with FIN 47 with an approximation that uses a statistical based method in order to achieve the **intent** of the statements without incurring undue burden on the accounting personnel.

1. Statistical Method – There are varying levels of information available to the individual utility from their depreciation studies from Simulated Plant Record to Equal Life Group study methods applied property data from individual accounts/sub accounts to functional categories like distribution plant. Even availability of details (such as separating net salvage into removal cost or into removal cost just for treated poles) will vary for different utilities. The following are general descriptions of possible approximation procedures that might be used:

   a. Modified group property/modified depreciation study. Using the latest available depreciation study, the utility could develop the percentage adjustments to indicated life and negative salvage estimates to approximate the timing and the amount of the future removal cash flow. Many utilities have property records that provide the age of existing property and combined with average age, a future cash flow estimate could be prepared for each vintage of property (average age less current age result in the time to expected removal). There may be a standard length of time between removal from service until actual disposal and that could be added to remaining life.

   It may be necessary to analyze the property in the pole account as not all the units may be part of the retirement obligation and to identify a percentage adjustment to approximate the proportion of obligating poles that are treated to all others and adjust the future cash flows to represent only the legally required disposal.

   If dispersion curves were used in the study, the related retirement curves also could be used to approximate the period of disposal. When time estimates and future cash flows are estimated, then one can compute the various ARO elements (ARC, depreciation and accretion tables, and associated regulatory assets). For the first year, monthly entries are made based on that estimate only. In subsequent years and if vintaged retirements are available, it would be possible to go through the individual settlement calculations for each ARO vintage group plus recognize any layers if disposal cost estimates change or a new study is performed. If vintage retirement data is not available, do exactly the same calculation, but true up the components (which would eliminate all the subsequent measurements and layering).

b. Fin 47 requires the use of current assumptions. It may be necessary to perform a new depreciation study to obtain current information on expected lives and removal costs for existing property. Negative salvage estimates that have been taken from depreciation studies reflect previous assumptions. In other words, the study reflects removal costs that have already happened and may not even reflect costs or methods of disposal under a new or recent legal requirement (or only partially reflect it). To the extent that previous assumptions are the same as current assumptions, the depreciation study may be used.

   The gross removal portion of the negative net salvage amount also may contain a removal component that may or may not be part of the retirement obligation. Use of the approved rate to determine the obligation under this Interpretation could result in an inflated obligation. In either case, it should be updated to reflect current assumptions, based on management's intent, the asset's estimated economic life as well as entity and industry practices. Be sure to exclude gross salvage value from estimated removal costs and to split the removal costs into its components in order to identify only those pieces that represent the retirement obligation.

c. Snapshot. If immaterial or one is unable to modify or perform annual studies, work with what is available at the end of each year. Then compute the ARO by taking a snapshot each year and true up for differences.

2. Detail Method – If detailed records exist or it is feasible to create detailed records and reporting just for treated wood poles (or like mass assets), and then it would be possible to fully comply with SFAS 143 and FIN 47.

3. For either method, one may want to:

   a. Re-examine the legal obligation to determine if there is a specific obligation due to the type of treatment on the poles along with other mass assets **and** that complying will result in a cost. For some locations, there are no "special" disposal tracking or fees. Examine the disposal fee for poles to determine if it is related to special facilities or just additional cost for garbage service. No cost means no accruals need to be booked.

   b. Determine if the future fee could qualify as immaterial. For example, a $5 fee or a 50-cent information sheet to buyers could be immaterial on the surface. However, balance sheet materiality would apply and it is the fair value of the ARO items as grouped that may determine materiality.

   c. Review the additional reporting and record keeping requirements of the full application to determine if the cost of keeping records is unreasonable for the effort and that an alternative method may yield a reasonable estimate. For example, if one can match disposal to vintaged purchases, then one should be able to comply using the Detailed Method instead of developing a statistical approximation.

   d. Similar to above, review whether the depreciation studies are reasonably compatible. Remember FIN 47 "example 1" is concerned with "purchase to disposal" total life versus studies based upon "site life" and in-service time (does not recognize reuse.) Similarly, then, approximation methods might be reasonable. Paragraph 2 of SFAS 143 states that this "applies to legal obligations associated with the *retirement*[2] of a tangible long-lived asset that results from **the acquisition, construction or development…**" This sentence has two interpretations - the first half indicates it only applies to plant in-service, while the second half adds the purchase or construction to the point of application. This review may want to include making a determination on the reasonableness and materiality of the difference between in-service date versus the date of construction or purchase.

e. Alternative approaches also may be justified if one qualifies as a regulated utility. As a regulated utility, the entire ARO compliance effort may result only in balance sheet adjustments with no earning impacts. The most reasonable application of managerial judgment might involve only a high-level, rough estimate of the current obligation without all the various kinds of offsetting regulatory assets and regulatory liabilities. It may be that all those offsetting line items and calculations provides only confusion and a good description of the circumstances is the most appropriate disclosure, especially if preliminary efforts indicate that full compliance results in an immaterial impact.

An example of a possible "snapshot" follows. Utilities with recent, extensive, and detailed studies may have such particulars and resources to develop a very close approximation of full ARO accounting. Many utilities will have very limited information available from latest depreciation studies and property records. This example is intended to show how to approximate an ARO calculation with the bare minimum of information.

Assuming that the utility depreciation study only provides an average service life and net salvage (no basis for a split for removal costs), has a count or estimate of treated poles in service, and vintage or estimate of age of those poles:

For Year 1 (2005) the following applies:

- Surviving plant is equal to 100,000 poles,
- Average service life is estimated to be 50 years,
- Average age of existing poles is 30 years (assume the average remaining life is 20 years even though it most likely would be closer to 25 years using Iowa Curves)
- Disposal cost is $15 per pole fee set by law in 2000 at a local waste management facility.
- Future removal cost in 20 years would be $1.5 million ($15 times 100,000). Note, apply an inflation factor as well if disposal fee can increase due to inflation,
- Apply a current discount rate (credit adjusted risk free rate) back to the year that the obligation began (in this example it is the year 2000) to determine ARC,
- Set up schedules to determine ARC depreciation, accumulated reserve, accretion table, and current value of ARO in year 2005 (also determine regulatory accounting to offset any expenses or income if eligible for SFAS 71 treatment – FERC Accounts 182.3 and 407.4 for regulatory assets, FERC Accounts 254 and 407.3 for regulatory liabilities).

For Year 2 (it is now 2006) the following occurs:

- Surviving plant has been reduced to 95,000 poles (additions and retirement led to a net reduction,
- Average service life is still estimated to be 50 years,

- Average age of existing poles has changed due to the additions and retirements – and is now 29.5 years (average remaining life is now 21.5 years)
- Disposal cost is still $15 per pole fee set by law at a local waste management facility back in year 2000 (watch for whether this should be inflated),
- Future removal cost in 21.5 years would be $1.425 million (15 times 95,000),
- Apply a current discount rate (credit adjusted risk-free rate) back to year 2000 to determine ARC (FERC account 359.1 or 374),
- Set up schedules to determine ARC depreciation, accumulated reserve, accretion table, and current value of ARO now in year **2006** (also determine regulatory accounting to offset any expenses or income if eligible for SFAS 71 treatment – FERC Accounts 182.3 and 407.4 for regulatory assets, FERC Accounts 254 and 407.3 for regulatory liabilities).
- Compare the Year 2 (2006) results to Year 1 (2005) results:
  1. Adjust both the ARC asset, ARC accumulated reserve, and the ARO liability to the new numbers.
  2. The remaining differences (accretion, depreciation, and affect of the change upon the current) will be recognized as a gain or loss or deferred under regulatory accounting (adjust previously recorded amount – difference may change the amount from an asset to a liability which should be a reversal of the prior year entry and a new entry in order to keep the connection between 407.3 and 254 or 407.4 and 182.3 as appropriate).
  3. Layering is being ignored for both because this is only an approximation and this does recognize that the forecast future date of cash flows has changed for all assets and in the long run will achieve a more appropriate obligation at the time of disposal.

In the situation where more information is available (such as vintage data), and the effort reasonable, then the above "snapshot" approach could be applied to each vintage. If service life is estimated using dispersion curves such as Iowa Curves, another enhancement would be to use the "retirement rate" percentages from those curves to develop the estimated time for future retirements. Such an enhancement may be unreasonable (especially if being computed manually) because it would be many times more complicated with the number of vintages involved and it may result in an immaterial difference to the results. These are issues subject to that managerial judgment discussed at the beginning of this document.

Questions for Review: Mass Assets, Electric and Gas

1. Which mass assets are subject to this section?
2. What actuarial assumptions has the company been using with those assets identified as falling within FIN 47?
3. Are the state laws or federal ones defining the disposal restrictions related to any of these minor items?
4. Can one determine a reasonable estimate the current disposal costs and does that apply to all or most in the mass asset group?
5. Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

6. Is the ARO associated with this mass assets material enough to spur recognition in the books and records or should its presence just be disclosed?

Minor Items

SFAS 143 applies to legal obligations associated with the retirement of a tangible long-lived asset that result from the acquisition, construction, development, or normal operations of the asset itself. In the utility business, property accountants break the huge investment in fixed assets into retirement units, whereby anything less than a retirement unit is not significant enough to be a unit of property. These items that are less than a retirement unit are often called minor items. When construction ensues to install one or more retirement units, minor items directly associated with the retirement units are often part of the construction cost. However, a minor item is not replaced with future construction dollars just because its original cost was part of fixed assets. These items are replaced using maintenance dollars or the replacement is expensed at that time. Minor items to the utility business are basically our "bricks in a kiln".

So it can easily be seen that these minor items can be a quandary when determining a conditional ARO. In some respects, these minor items can consist of the contaminants discussed below. Replacing these in the course of normal operations may be construed as impossible to determine as not enough facts are available to measure the conditional ARO. One would need to know when in the course of operations these minor items will be replaced. However, a more routine maintenance replacement may not be as difficult to predict than an item that perchance could fail. For example, if oil is replaced after every certain number of hours of operation, then one may be able to estimate the disposal obligation. The bricks example infers that the disposal of these bricks, because it is known and routine, may constitute an ARO. A company needs to decide if any of the minor items, those that are part of the asset on installation, but are replaced on maintenance throughout the life of the asset, qualify for conditional ARO treatment. Minimally, the proper removal of oil may be a legal obligation upon retirement of the asset.

However, one keeps coming back to the idea that these items are not fixed assets in exclusion of the retirement unit. Oil sitting on the shelf (i.e. inventory not specifically a property unit) does not fall within the scope of SFAS 143. If the installation of the oil is expensed at the time it is added to the fixed asset, one could conclude that it is not part of the fixed asset cost and perhaps the only retirement obligation is the one associated with the retirement of the asset either interim or final. Assuming this conclusion, the replacement of a minor item during operation in exclusion of the retirement unit would be considered normal maintenance and not subject to ARO accounting. Whereas, the retirement of the asset including the minor item could constitute an ARO, conditional or otherwise, if the minor item causes the asset retirement to meet the rules of SFAS 143 or FIN 47.

Recommendation

Before minor items are recognized as an ARO, make sure that the component is not part of an ARO established for the asset to which the minor item relates. For example, the bricks in the kiln were replaced many times over the life of the kiln's useful life. If an ARO exists for the final disposal of the kiln in its entirety, one would not want to set up an ARO for the disposal of the final set of bricks. Clearly define the minor items that should be included and test early on in this process for materiality. One may have bricks, but the bricks represent such a small component of one's balance sheet and income statement that the inclusion of such in the ARO process may be immaterial at all times, especially if the asset (the kiln) has no ARO. Keep track of the asset to which these minor items relate in order to determine if a future ARO will be warranted by association. Lastly, document the minor items with possible AROs that are routinely replaced versus those where replacement cannot be predicted.

Some Questions for Review: Minor Items

1. Can the minor items be identified that could cause an ARO situation to occur when it is removed with the asset retirement?
2. Does the company have a definitive list of minor units of property?
3. Are the state laws or federal ones defining the disposal restrictions related to any of these minor items?
4. Can a one make a reasonable estimate of when the asset will be retired and whether the minor item will exist as part of the asset at that retirement date?
5. Does any of the guidance from AICPA Statement of Position (SOP) 96-1, "Environmental Remediation Liabilities" supersede the application of SFAS 143 or FIN 47?
6. Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?
7. Is the ARO associated with this minor item material enough to spur recognition in the books and records?

Asbestos, PCBs, and Other Contaminants

Asbestos

Assets constructed before 1980 may have used asbestos as insulation or fire retardant. Typical removal of this substance involves extensive effort to protect workers and the environment from harm along with very specific disposal rules. For that matter, any asset with asbestos may have an ARO associated with it. The determination of whether the removal is performed as a part of normal ongoing maintenance during the life of the asset or is present at the time of retirement may need to be factored into the fair value analysis.

For non-real property, the ability to determine the amount of contamination may be an issue and a costly one at that. The engineering staff generally can determine if the asset being worked on contains asbestos, but determining the amount of contamination may not be feasible. This may make the process more difficult in applying FIN 47, but it may not preclude recognition in the financial statements. At the minimum, disclosure may be necessary for specific assets that are contaminated. For instance, the amount of existing asbestos in a generating facility may not be known and the timing of the removal of it during normal maintenance may be difficult to forecast. The obligation, in this circumstance may be measurable only after the work has been defined. If the ARO is known, measurable, and satisfied all during the same accounting period, then perhaps only a disclosure is necessary for these instances.

Real estate may be easier to estimate if one knows the extent of the contamination. It may be that when the building was first constructed asbestos was throughout every floor. Many years later, some of the asbestos may have been removed in past maintenance on various sections of the building. The engineers familiar with the building should know the relative extent of the contamination. If the building has been through a recent assessment, it may be possible to estimate the loss in market value of the building because of the asbestos. However, asbestos abatement may not be comparable to the loss in market value, and this loss should be weighed with the potential for undertaking the removal oneself.

Estimation of retirement, as with all assets falling within the scope of this Interpretation, can be quite difficult as some of the assets contaminated also are the longest living assets. Even with the loss in value due to selling the building with the contamination, one still may have a difficult time determining retirement parameters. Non-real property may be easier to estimate, as there often exists a manufacturing life on most retirement units.

Polychlorinated Biphenyls (PCBs)

PCBs are man-made chemical compounds previously used in the manufacture of products to make them flexible and heat resistant. Because of these fire retardant qualities, manufacturers sometimes used it in the insulating oil of capacitors, transformers and other electrical equipment. PCBs also can be found in hydraulic fluids, lubricants, paints, sealants, carbonless paper, ink, caulking compounds, and plastics.

PCBs are very stable and do not readily break down in the environment and therefore require special care during handling and disposal. The use of PCBs is regulated under the Federal Toxic Substances Control Act (TSCA). The Environmental Protection Agency (EPA) has set strict regulations regarding the manufacture, use, storage, transportation and disposal of specific levels of PCBs. PCB concentrations below specified levels are not regulated under TSCA.

The existence of regulations related to disposal of PCBs creates a duty to dispose of PCBs in a prescribed manner. The obligation to perform this asset retirement activity is unconditional even though uncertainty may exist about the timing and (or) method of settlement.

The Interpretation states an entity shall recognize a liability for the fair value of the conditional Asset Retirement Obligation (ARO) if the fair value of the liability can be reasonably estimated. If one has assets that contain PCBs and one has sufficient information to reasonably estimate the fair value of the ARO, then the PCB ARO must be recorded. Sufficient information needed to reasonably estimate the fair value includes:

- Settlement date, or information to estimate a range of potential settlement dates
- Method of settlement or potential method of settlement, and
- The probability associated with the potential settlement dates and method of settlement.

The ability to defer settlement, such as storing PCB containing equipment, does not relieve the entity of the obligation. The PCB will eventually need to be disposed of following EPA prescribed procedures. The obligation to perform the asset retirement activity is unconditional even though uncertainty may exist about the timing or method of settlement. The PCB ARO is the cost to dispose of the PCBs as required by the EPA.

Example 1 included in Appendix A of the Interpretation indicates that the ability to sell the PCB containing equipment or facility prior to disposal does not relieve the entity of its present duty to settle the obligation. The sale of the equipment or facility transfers the obligation to another entity. The assumption of the obligation by the buyer affects the sale price. Therefore, an ARO should be recorded once known; when the asset is sold, the ARO liability is debited and the sale price is adjusted to reflect the transfer of the ARO obligation. It is assumed that the utility has factored into the calculation of the ARO, the probability that not all of the assets may be contaminated upon sale.

An entity does not have sufficient information to estimate the fair value of the ARO if:

- The settlement date is indeterminate (the range of time over which the entity may settle the obligation is unknown or cannot be estimated),
- Method of settlement is unknown, and
- Sufficient information is not available to apply an expected present value technique

In this case, an entity will record an ARO when sufficient information exists. It currently qualifies as an ARO, albeit not measurable, and it would be subject to certain accounting and disclosure requirements related to reserves and provisions for cost of future removal. Example 3 included in Appendix A of the Interpretation illustrates this point. However, paragraph 22 of Statement 143 requires that if the liability's fair value cannot be reasonably estimated, that fact and the reasons shall be disclosed.

Electrical equipment damaged by a car, lightning or other incident, which result in a spill of insulating oil containing PCBs will be out-of-scope of this Interpretation since the spill is not considered normal operations. Paragraph 2 of the Interpretations states that "Statement 143 applies to legal obligations associated with the retirement of tangible long-lived assets that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, except as explained in paragraph 17 of that Statement for certain obligations of lessees."

Other Contaminants

As part of the normal operations for a utility, other contaminants may exist in fixed assets that would require "special" disposal procedures under federal and state regulations. Below are examples of these assets that may contain other contaminants:

Generation

- Groundwater contamination in ***ash ponds*** from metals such as nickel, chromium and arsenic
- Groundwater and soil contamination from unlined ***chemical cleaning basins*** (i.e. boiler cleaning waste basins)
- Soil and ground water contamination associated with ***above and below ground storage tanks*** (i.e. petroleum or other contamination)
- ***Solid waste landfills*** that require installation of a final cover system, grading the final cover, and establish vegetation on the final cover
- ***Septic tanks*** that must be drained and filled with sand prior to closure
- ***Wastewater and sewage treatment facilities*** that may contain hazardous wastewater treatment sludge or sewage

Transmission & distribution

- Soil contamination from arsenic at ***substations***
- Soil contamination from mineral oil at ***substations*** from ***non-PCB transformers***

Other

- ***Equipment*** containing sulfur hexafluoride (SF_6) gas

This is not an exhaustive list of potential contaminates resulting from normal operations of utilities. Each company should consult with environmental experts and legal counsel to properly assess these and other contaminants for potential AROs. Care should be given to ensure that contaminants at these facilities do not fall under the scope of SOP 96-1, *Environmental Remediation Liabilities*, and that these contaminants resulted from normal operations.

Recommendation

EEI and AGA issued a White Paper entitled *Asset Retirement Obligation Implementation White Paper* late 2002, which recommended a team approach to identifying and estimating AROs. That approach can be used for the implementation of FIN 47. Listed below are some of the main points included in the White Paper:

- Use a team approach, ARO team members should include representatives from various company operating departments,
- Develop an inventory of potential AROs,
- Accounting and Legal departments must review and discuss these potential AROs to determine if a legal obligation exists,
- Once it is determined that the obligation falls within the scope of SFAS 143 and FIN 47, the next step is measurement of the ARO liability. The amount of the ARO liability is to be measured at fair value.

Refer to the 2002 EEI and AGA White paper section entitled "Calculation Process Overview" for suggested ARO calculation guidelines and examples. The White Paper also includes journal entry examples and record keeping suggestions.

Questions for Review: Asbestos, PCBs, and Other Contaminants

1. Can all the assets be identified that contain asbestos, PCBs, or other contaminants and can the amount of asbestos that is contained in the asset be determined?
2. Does the company treat these contaminants as a major or minor unit of property?
3. Are the state laws more onerous than the federal ones?
4. Can a market value of the asset be determined with and without the contaminant?
5. Does any of the guidance from AICPA Statement of Position (SOP) 96-1, "Environmental Remediation Liabilities" supersede the application of SFAS 143, Accounting for Retirement Obligations or FIN 47?
6. Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

Rights-of-Way and Franchises

Land, although not specifically excluded from scope of SFAS 143 and FIN 47, is perhaps the one asset that can live forever. Rights of way and easements are land related intangible assets that also are excluded from the scope of SFAS 143 and FIN 47. However, consideration should be given to whether there is a conditional obligation that can be associated to specific, existing, long-lived assets within rights-of-way and franchise areas. It should be noted that there is no asset retirement obligation associated with the franchise (or right-of-way) itself. If it is determined that there is an ARO, it only will be with the assets located within that franchise (or right-of-way). Similar situations may exist with leased land or leasehold improvements, however this section is dealing with the intangible asset created by the right-of-way or franchise agreement. An ARO associated with a lease may be more determinable due to the language of the legal agreement.

Typically, utilities are granted franchises by each local jurisdiction in which they have distribution and transmission assets. Typically, the local jurisdiction retains the right to require the removal of the utility's assets, at the discretion of the local jurisdiction. Consequently, the wording in the franchise imposes certain requirements due to revocation of ordinances and road relocations. Just as typically, however, the intent of the utility and the local jurisdiction is for the utility to continue to provide service on a permanent basis in the service area, and the utility is required to remove its assets only when necessary to allow the local jurisdiction to perform some public work.

Generally, the wording in such franchises indicates that there is a possibility that any individual asset could be required to be moved at any time, but the wording neither identifies specific assets to be removed nor sets a specific time that the removal is required. Furthermore, the franchise wording typically indicates that the franchise is either perpetual or renewable.

Paragraph 3 of FASB Interpretation No. 47 states:

> "The term *conditional asset retirement obligation* as used in paragraph A23 of Statement 143 refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exist about the timing and (or) method of settlement."

This definition identifies three variables: "If", "When" and "How/How Much".

- The "If" is satisfied if it has been determined that an asset will have to be retired at some future date', i.e. the obligating event has occurred.
- The "When" is the date or range of dates when the retirement will/must occur.
- The "How" is the method (and by extension, the cost) associated with the retirement.

In the case of franchises, the obligating event would be the determination by the local jurisdiction that an asset or group of assets must be removed. In granting a franchise, however, the presumption by both the utility and the local jurisdiction is that this event will never occur. The fact that this event does occur on occasion (road widening, for example) is not sufficient to negate this presumption.

In a franchise situation, a conditional ARO does not exist, because the obligating event has not yet occurred. The possibility exists that the obligating event will occur, but the possibility alone is not itself an obligating event. The questions of "when" and "how/how much" do not even come into play, because it has not been established that any asset or group of assets will have to be removed. It is impossible to calculate an asset retirement amount, so journal entries are not required. Furthermore, the possibility that an ARO could come into existence need not be disclosed in a footnote.

It should be noted that franchise language typically requires a utility to remove its assets from a given location, not retire those assets. Theoretically, the utility could satisfy the requirements of the franchise by simply moving those assets. In the case of a road widening, for example, the utility could just pick up all of its poles and wires and move them. In reality, new poles and wire are installed and the old poles and wire are removed. But, the decision to install the new and then remove the old is a management decision, to allow for continuous service while the assets are being "relocated". And in some cases, those assets being removed could be re-used elsewhere (poles, for example). There is no asset retirement obligation, because there is no obligation to retire assets.

This situation can change for major projects, however. If a jurisdiction notifies a utility that it must remove specific assets, for any reason, and assuming the utility will retire those assets, the obligating event for those specific assets will have occurred, and an ARO would exist at that point. If the timing and method of removal can be reasonably estimated (and it probably could be), then the utility would be required to calculate and record an ARO. For example, if the utility is notified that a given section of a subway system is to be extended in five years, and that the utility will have to relocate its poles, wires, buried cable or gas mains along the route of the subway extension, all of the requirements of an ARO will have been met. At this point the utility would be required to record an asset retirement obligation for these assets.

It is not uncommon for local jurisdictions to reimburse the utility some or all of the cost of removal when that local jurisdiction requires that assets be relocated. Such reimbursements are not salvage; they are, in fact, a reduction of the cost of removal. Since the cost of removal is the basis for calculating the amount of the asset retirement obligation, any such reimbursement must be reflected (as a reduction) in the ARO calculation. This could substantially reduce the amount of the ARO (or in the case of a 100% reimbursement, totally eliminate it).

Rights-of-Way are similar to franchises, but on a smaller scale. Rights-of-Way typically are granted by individual citizens or companies, cover smaller areas of land, and may be for shorter periods than franchises. The logic in applying the criteria for establishing an ARO is the same, however. If and when an obligating event occurs, an ARO would have to be recognized if sufficient information exists to estimate the fair value of the obligation or disclosed (if sufficient information does not exist). The determination that a Right-of-Way will not be renewed would be an obligating event. Until that time, no calculations or disclosure by the utility would be required.

If it is determined that an asset retirement obligation does exist, it is important that companies do not double-count or double-record the ARO amount. For example, companies may have a program to identify and track asset retirement obligations for the disposal of treated poles. If a treated pole is in a franchise area or right-of-way and must be removed, and it is deemed that an ARO does exist, the cost of disposing of the treated pole should not be counted twice – once under the program to identify costs of disposing of treated poles, and then again as part of the cost of removing an asset from a franchise area or right-of-way. Property accounting personnel should take care to coordinate the ARO identification and measurement efforts to ensure that all ARO costs are recorded, but that those costs are recorded only once.

Recommendation

The costs of franchises and rights-of-way do not themselves incur an asset retirement obligation. Generally, the assets within the franchise area or right-of-way do not incur an asset liability solely because those assets are subject to the franchise or right-of-way. Under certain circumstances, however, those assets could incur an asset retirement obligation. If it is deemed that an asset retirement obligation does exist for certain assets in a franchise area or right-of-way, care should be taken not to include costs that have been included under another ARO identification program within the company.

Questions for Review: Rights-of-Way and Franchises

1. Who maintains the file of all franchises and rights-of-way agreements?
2. What is the exact wording in the franchises and rights-of-way agreements? (Specifically, what do it require the company to do?)
3. Can one identify al of the assets in the franchise and rights-of way areas?
4. Are the assets in the franchise and rights-of way areas covered under some other ARO identification program within the company?
5. Do the company have procedures in place to make sure that one is not double-counting the ARO?
6. Can one reasonably estimate the amount of reimbursements the company will receive for any required cost of removal?

General Property

The possible changes in ARO accounting as indicated in the guidance and examples provided in FIN 47 also may apply to utility property classified under the General Plant function. Recently, the lead and mercury content in personal computers have been drawing attention of lawmakers, environmental agencies, and disposal sites. There are other potential issues like the mercury in fluorescent light bulbs and chemicals in common batteries. Individual utilities may want to assess ARO requirements as modified by FIN 47.

It may be possible that each of the four examples could apply depending upon the circumstances of the legal obligation and property accounting issues such as whether the obligation relates to a retirement unit, a minor item, or a smaller portion of an asset. For example the coatings or trace elements in a personal computer might be comparable to the chemicals in the treated wood poles in Example 1 in Appendix A of FIN 47. If the obligation relates to specific components of the computer, Examples 3 and 4 may be more applicable.

There may be an additional complication in applying FIN 47 to General Plant property. Many utilities have adopted amortization accounting (such as allowed under Federal Energy Regulatory Commission Accounting Release No. 15, "Vintage Year Accounting For General Plant Accounts"). A main objective of adopting amortization accounting was often to eliminate the relatively unreasonable cost of tracking the status of large volumes of low cost property. Under amortization accounting, the cost of the long-lived asset is given an assumed life and reporting of movement or disposition of the property ceases.

While there may be insufficient information in the property records, there may be alternative sources of information. In the personal computer circumstance, a utility may already have a policy of storing the PC prior to disposal – possibly to be in compliance or anticipation of compliance with disposal obligation. The assessment of application of FIN 47 might include evaluation of the existing availability of such alternative information or of possibly creating such information to facilitate compliance with both the legal obligation and the accounting requirements.

Recommendation

1. Review the circumstances for each account – identify the legal obligation, availability of the information to determine the estimated future removal cost, and the property accounting method (item property, group property, or amortization accounting).
2. Amortization accounting would represent a unique situation, because it was probably adopted because of a determination that it was unreasonable to maintain detailed record keeping under group or item property. There may still be a basis for recording an ARO, if alternative information is available and the effort reasonable or not considered immaterial.
   a. For example, company using amortization accounting with a policy that requires that unused PCs be returned to a central location for disposal with a known disposal cost. If quantities are kept with the unamortized period, then it is possible to estimate a total liability (quantity unamortized plus quantity waiting for disposal multiplied by the disposal fee). All that is necessary is to estimate the timing of the disposals.
   b. Some utilities may keep other records on such items outside of the accounting, which may provide sufficient information to calculate the exposure quantity and approximate timing of disposal.
   c. This accounting method is designed to alleviate the record keeping burden on small value, high volume assets and one should attempt to maintain this simplicity in the ARO analysis and calculation.
3. The possible situations are numerous, but if information is available and cost is large enough, then one of the methods described above (such as used for mass assets) may be applicable for making the calculation.

Questions for Review: General Property

1. Can one define the legal requirements for removal for the general assets?
2. Does the company use AR-15, amortization of general property?
3. Can one estimate potential future retirements?
4. Are the obligations for this category material?
5. If immaterial, is it appropriate to group these AROs with others to determine materiality?
6. Can you estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

Hydro Generation

Hydro dams and facilities fall into conditional obligations primarily due to three factors:

1. An exceptionally long life of the total facility,
2. The large magnitude of costs and complications associated with removal, and
3. The uneven probabilities involved.

In some circumstances, however, the obligation may already provide the information to support recording an estimate. In other circumstances, there may be legitimacy in asserting that too much uncertainty exists to make a reasonable estimate.

Hydro facilities (generation equipment, dam, reservoir, and other plant) typically have an extremely long life. That life may also involve multiple steps, in that the dam may continue to provide service long after generation ceases, and may be rebuilt or repaired multiple times in order to maintain the reservoir for conservation or flood control purposes. That combined total facility life may be so long that "there are no boundaries of time or an extremely lengthy period of time, that bears on a person's ability to make a reasonable estimate of the timing and the amount of the cash flows" [1] (Minutes of January 26, 2005 Board Meeting, wwwfasb.org). Estimating life may be further complicated by whether the obligation is identified (individually or overlapping) by multiple jurisdictions (a FERC license, a Corp of Engineers building permit, an act of Congress, state law, or even promissory estoppel).

The exceptionally long life expectancy will typically represent the greatest obstacle to developing a reasonable estimate of ARO. Many reservoirs can be traced to the early history of the United States, so it is reasonable for a total life of a hydro facility to be measured in hundreds of years. Another complication may be multiple legal jurisdictions involved in the obligation over different phases of that total life. Further, economics may support a truly indefinite life since the magnitude of a repair/rebuild may be the clear option of choice compared to the magnitude of the cost of removal of the facility - at any point in time when a removal consideration is being faced.

The long-life combined with the economics favoring indefinite repair over removal creates a time frame in which acts of gods (unprecedented floods, earthquake, etc.) would have to be included in setting probabilities of life. Statistical models may not be applicable when a long life would also involve such random factors – not only for the life, but also the wide range of possible methods of removal complicated by varying relationships to the cause of removal.

Recommendation

Understanding the nature and timing of the current legal obligation is a critical first step, but one that may be particularly difficult to determine. With Hydro licenses, the requirement to remove the dam and flowage structure, albeit purportedly required by the FERC, may not occur if the environment has adapted and become accustom to the dam. One may have to rely more on local data that is in relation to a legal obligation to define the possible course of action.

A conditional ARO is a judgment-based process and if it results in no ARO recognition, then documentation of such conclusion must be done. If a life or range of lives can be identified, the next step is to review the extent of possible methods for meeting the obligation. If life and method of settlement can be identified, the next step would be to identify the availability of other critical elements in estimating an ARO.

Questions for Review: Hydro Generation

1. What is the nature of the legal obligation(s) involved – does it apply to only a portion of the hydro or to the full facility?
2. Can a life or a range of lives be reasonably identified with any degree of statistical validity?
3. Can the methods of settlement be identified with reasonable estimates of probability?
4. Can a market value of the asset be determined with and without asbestos?
5. If all of the above exists, can costs and cash flows be reasonably estimable with any degree of statistical validity?
6. And, can inflation be reliably predicted from present to the time of removal?
7. Does a risk-free interest rate exist for such a period and will credit adjustments be applicable to determine the rate necessary to convert the ARO into the capitalized asset retirement cost and accretion models necessary under SFAS 143?
8. Can one estimate the retirement possibilities such that the choices would meet current audit and accounting standards for supporting evidence?

Overall Recommendation

There will be no single way to estimate the conditional ARO on the property that was excluded in the earlier review. Several recommendations have been provided within this white paper, but as always, each company will need to decide the appropriate conditional ARO. This review includes the determination of the potential liability, the costing and probability of occurrence, the method for calculating the liability and asset, the materiality of the ARO, forward processing, and the appropriate disclosure. The basic concept throughout was to define the property and to encourage one to find a way to provide for the intent of the accounting without creating unbearable duress in doing the calculation. Also, the calculation for the first recognition at the end of this year should be one consideration, but the process used should define the ongoing revision of the conditional liability and the eventual settlement.

The whole process used should be defined and documented to support audit review and to satisfy any Sarbanes/Oxley provisions within the company. Even if one chooses to disclose and not to account, the documentation for the first and subsequent measurements must be such that it will completely support that decision. Overall, proper management and design of the process keeping a keen site on the form and intent should enable one to fully represent the conditional ARO without creating a nightmare of a process.

Effective Date

Effective Date

Paragraph 8 of the Interpretation specifies the effective date and states:

> The Interpretation shall be effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year enterprises). Retrospective application of interim financial information is permitted but is not required. Early adoption of the Interpretation is encouraged.

Transition Accounting:

Paragraphs 9 and 10 of the Interpretation provide requirements for transitional accounting and state:

> "For amounts recognized upon the initial application of the Interpretation, an entity shall recognize the following items in its statement of financial position: (a) a liability for any existing AROs adjusted for cumulative accretion to the date of adoption of the Interpretation, (b) an asset retirement cost capitalized as an increase to the carrying amount of the associated long-lived asset(s), and (c) accumulated depreciation on that capitalized cost."
>
> "Amounts resulting from initial application of the Interpretation shall be measured using current (that is, as of the date of adoption of the Interpretation) information, current assumptions, and current interest rates. The amount recognized as an asset retirement cost shall be measured as of the date the asset retirement obligation was incurred. Cumulative accretion and accumulated depreciation shall be recorded for the time period from the date the liability would have been recognized had the provisions of the Interpretation been in effect when the liability was incurred to the date of adoption of the Interpretation."
>
> "An entity shall recognize the cumulative effect of initially applying the Interpretation as a change in accounting principle. The amount to be reported as a cumulative-effect adjustment in the statement of operations is the difference between the amounts, if any, recognized in the statement of financial position prior to the application of the Interpretation and the net amount that is recognized in the statement of financial position pursuant to paragraph 9 of the Interpretation."

Thus, the recognition of new AROs due to adopting this Interpretation is similar to the first recognition done for SFAS 143. Once the full accounting is established for an ARO, the change in estimate routine from SFAS 143 is used for all subsequent layers. For mass assets and other AROs recognized in aggregate, the change in the obligation acknowledged in the second and successive years may be defined as a new layer. This would have to be discussed and agreed upon by management and your auditors as an appropriate treatment.

Subsequent Accounting for Indeterminate AROs:

As has occurred throughout this issue, a quandary seems to exist relating to subsequent recognition if a previously indeterminate ARO becomes measurable and material such that one must invoke the full accounting treatment, not just the disclosure part. The question that has been difficult to get a consensus on is as follows:

Should transition accounting be used in future years to record the initial measurement of an ARO, which was previously treated as indeterminate or would the measurement of this ARO constitute a change in estimate and thus the accounting for a subsequent layer be applicable?

There does not seem to be agreement on this point and it may be a common occurrence. A survey of 18 EEI companies (by Constellation) showed responses that were split down the middle as to whether transition accounting would apply when asset retirement costs were first being measured (previously immeasurable) in years after adoption of FIN 47.

It would seem that transition accounting would not be used in years following adoption of FIN 47. Both FAS 143's paragraph 25 and FIN 47's paragraph 9 on transitional accounting specifically refer to measuring an asset retirement cost (as of the date the obligation was incurred) and provide for accumulated depreciation "to the date of adoption of this Statement" or "Interpretation". Neither FAS 143's paragraph B19 nor Fin 47's paragraph B27 specifically provide a method for asset retirement costs when it states that obligations should be measured at the point where information becomes available.

FIN 47 paragraph 9 ends by stating: "Cumulative accretion and accumulated depreciation shall be recorded for the time period from the date the liability would have been recognized had the provisions of this Interpretation been in effect when the liability was incurred to the date of adoption of this Interpretation." (Emphasis added.) Since the date of subsequent measurement of a specific ARO is not the date of adoption of the pronouncement, it would seem that transition accounting would not be applicable. To rely on this premise, it is assumed that the following is true:

1. An asset was defined as either having an ARO or not based on the legal review at time of adoption
2. Of those assets with an ARO, the ones that were measurable and material were accounted for and disclosed in the financial statements
3. The remaining assets with an ARO were immeasurable, immaterial, or indeterminate in nature, such that only a disclosure was presented in the financial statements
4. A new legal obligation created in the current period for an asset would start the ARO accounting in the current period and no transitional or layer would apply
5. An asset with an ARO would use the cumulative-effect accounting upon adoption of FIN 47 or did use this accounting upon adoption of SFAS 143
6. Any change in estimate, a new layer is created. With an asset where only a disclosure existed, the new layer is done based on a zero layer from adoption.

FIN 47 seems to constitute new rules regarding the determination of when an ARO exists, and how (or what information can be used) to measure that ARO. When booking entries, which adopt these new rules, it explicitly directs one to discount the asset retirement cost back to the origination of the obligation. However, neither SFAS 143 nor FIN 47 requires this when new facts result in a change in the measurement of an existing ARO. In future years, if an immeasurable ARO becomes measurable, this is due to a change in facts rather than a change in the rules. Therefore, it seems more closely aligned with the prospective treatment given to a new layer. It seems likely that if the FASB wanted transition accounting for this situation, it would have explicitly required it in SFAS 143 paragraph B19 and FIN 47 paragraphs B19 and 27. This elucidation has not been tested through any audit and each company will need to decide if this accounting is appropriate for their financial statements.

Transition Disclosures:

Paragraph 11 of the Interpretation provides requirements for transitional disclosures and states:

> In addition to disclosures required by paragraphs 19(c), 19(d), and 21 of APB Opinion No. 20, *Accounting Changes,* an entity shall compute on a pro forma basis and disclose in the footnotes to the financial statements for the beginning of the earliest year presented and at the end of all years presented the amount of the liability for AROs as if the Interpretation had been applied during all periods affected. The pro forma amounts of that liability shall be measured using the information, assumptions, and interest rates used to measure the obligation recognized upon adoption of the Interpretation.

Until the Interpretation is implemented, there is a disclosure requirement for adoption of new accounting pronouncements (SAB 74). Basically, an entity is to provide qualitative or quantitative information, when available, about the expected impact of implementation, updated quarterly.

EDISON ELECTRIC INSTITUTE

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
202-508-5000
www.eei.org

AGA
American Gas Association

Kinder, Debra

From: Laub, Peggy [Peggy.Laub@Cinergy.COM]

Sent: Thursday, August 11, 2005 12:35 PM

To: Kinder, Debra; Melendez, Brenda

Subject: RE: FIN 47 Compliance

ıebra,

Brenda Melendez has replaced me as Cinergy's representative on the property accounting committee and is working on FIN47.

ırenda - can you reply to Debra?

hanks

---

rom: Kinder, Debra [mailto:Debra.Kinder@lgeenergy.com]
ent: Thursday, August 11, 2005 11:18 AM
'o: Laub, Peggy
:c: Wiseman, Sara; Riggs, Eric
ubject: FIN 47 Compliance

'eggy,

work within the Property Accounting department of LG&E Energy. We are currently trying to refine our approach to complying with IN 47.As part of our research we are contacting several other utilities to see what our neighbors in the industry are identifying as onditional asset retirement obligations and how they plan to quantify the costs of removal.

ı the intial implementation of FASB 143, LG&E Energy identified ash ponds, landfills, GSU transformers,underground fuel oil tanks nd piping as AROs. To comply with FIN 47, our legal department is currently investigating legal obligations related to bridges, ınnels, gas wells, gas piping, hydro facilities, and asbestos. We also are considering any asset containing oil, wood poles and atteries.

Ve would appreciate your input regarding Cinergy's FIN 47 plans and we will gladly supply you with the responses we receive from ther utilities contacted.

hank you,

ıebra A. Kinder
'roperty Accounting Analyst
ouisville Gas & Electric
502) 627-3369

Wiseman, Sara

From: Riggs, Eric
Sent: Thursday, August 11, 2005 1:19 PM
To: 'leonard.a.delozier@bge.com'
Cc: Wiseman, Sara; Kinder, Debra
Subject: FIN 47

Mr. Delozier,

I found your name in the EEI Accounting Committees Membership directory. I have some questions regarding FIN 47 and hope that you or someone in your Property Accounting area will be able to take a few minutes to respond.

I work within the Property Accounting department of LG&E Energy. We are currently trying to refine our approach to complying with FIN 47. As part of our research we are contacting several other utilities to see what our neighbors in the industry are identifying as conditional asset retirement obligations and how they plan to quantify the costs of removal.

In the initial implementation of FASB 143, LG&E Energy identified ash ponds, landfills, GSU transformers, underground fuel oil tanks and piping as AROs. To comply with FIN 47, our legal department is currently investigating legal obligations related to bridges, tunnels, gas wells, gas piping, hydro facilities, and asbestos. We also are considering any asset containing oil, wood poles and batteries.

We would appreciate your input regarding BG&E's FIN 47 plans and we will gladly supply you with the responses we receive from other utilities contacted.

Thank you,

Eric Riggs
Senior Accounting Analyst
Louisville Gas & Electric/Kentucky Utilities
(502) 627-2822

Wiseman, Sara

From:	Riggs, Eric
Sent:	Friday, August 12, 2005 2:53 PM
To:	McDonald, Pam; Miller, Jon
Cc:	Wiseman, Sara; Kinder, Debra; Charnas, Shannon
Subject:	FIN 47
Attachments:	Data Requirements for FIN 47.doc

Pam, Jon,

Would you provide an update on the progress being made in regards to FIN47? I have attached a file listing general requirements that we believe that will be necessary in order for us to make the necessary calculations.

Data Requirements
for FIN 47.d...

Thanks,
Eric Riggs

From:	McDonald, Pam
Sent:	Wednesday, July 27, 2005 12:08 PM
To:	Riggs, Eric
Cc:	Miller, Jon
Subject:	RE: ARO Property

Eric,

After our last meeting, I have read through the documentation and developed an action plan. Most of the people I need to talk to have been on vacation or busy with other priorities. I will try to work on it next week and give you an update. Sorry for the delay.

Pam

Pam McDonald
Energy Delivery Budgeting
Ext. 2850

From:	Riggs, Eric
Sent:	Wednesday, July 27, 2005 11:15 AM
To:	McDonald, Pam
Subject:	RE: ARO Property

Pam,

No, He didn't provide any documentation to me. When this first got started last August, he provided the list that I handed out at the last meeting. Where or from whom he got that information I don't know. In the meeting we had today with just Sara, Debbie, myself, and Shannon, we were asked to contact Jon Miller and yourself to see where you stood with the items.

Thanks,
Eric

From:	McDonald, Pam
Sent:	Wednesday, July 27, 2005 10:49 AM

To: Riggs, Eric
Subject: ARO Property

Eric,

Did Mr. Winkler provide what you needed for this documentation?

Thanks,
Pam

Pam McDonald
Energy Delivery Budgeting
Ext. 2850

Data Requirements for FIN 47

Assets under consideration:
- Asbestos
- Assets containing oil
- Poles/Cross Arms
- Gas Pipe
- Batteries

Information Required:
Asset Description
Asset Quantity
Year Installed
Removal Costs – Required if a legal requirement exists to remove the asset
  Costs associated to dispose of non-contaminated asset
  Costs associated to dispose of same-kind contaminated asset
  Detailed assumptions made in connection with costs
    I.e., Labor, transportation, landfill fees, unit of measure, etc.

Location
Asset Retirement Obligations

Asset Description	Location	Legal Requirement	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date	Comments	Support

Wiseman, Sara

From: Charnas, Shannon
Sent: Monday, August 15, 2005 9:09 AM
To: Miller, Jon; Riggs, Eric; McDonald, Pam
Cc: Wiseman, Sara; Kinder, Debra
Subject: RE: FIN 47

Jon-

I believe the only issue that Property Accounting was looking into was asbestos. We need to know the status of the other items. We will have a follow-up on asbestos.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Miller, Jon
Sent: Monday, August 15, 2005 7:30 AM
To: Riggs, Eric; McDonald, Pam
Cc: Wiseman, Sara; Kinder, Debra; Charnas, Shannon
Subject: RE: FIN 47

Eric,

My understanding was that further information was still needed to determine how detailed the study needed to be and that Property Accounting was looking into this. I have been waiting to hear back from your group on this issue. Please let me know if this is not the case.

Jon

From: Riggs, Eric
Sent: Friday, August 12, 2005 2:53 PM
To: McDonald, Pam; Miller, Jon
Cc: Wiseman, Sara; Kinder, Debra; Charnas, Shannon
Subject: FIN 47

Pam, Jon,

Would you provide an update on the progress being made in regards to FIN47? I have attached a file listing general requirements that we believe that will be necessary in order for us to make the necessary calculations.

<< File: Data Requirements for FIN 47.doc >>

Thanks,
Eric Riggs

From: McDonald, Pam
Sent: Wednesday, July 27, 2005 12:08 PM
To: Riggs, Eric
Cc: Miller, Jon
Subject: RE: ARO Property

Eric,

After our last meeting, I have read through the documentation and developed an action plan. Most of the people I need to talk to have been on vacation or busy with other priorities. I will try to work on it next week and give you an update. Sorry for the delay.

Pam

Pam McDonald
Energy Delivery Budgeting
Ext. 2850

From: Riggs, Eric
Sent: Wednesday, July 27, 2005 11:15 AM
To: McDonald, Pam
Subject: RE: ARO Property

Pam,

No, He didn't provide any documentation to me. When this first got started last August, he provided the list that I handed out at the last meeting. Where or from whom he got that information I don't know. In the meeting we had today with just Sara, Debbie, myself, and Shannon, we were asked to contact Jon Miller and yourself to see where you stood with the items.

Thanks,
Eric

From: McDonald, Pam
Sent: Wednesday, July 27, 2005 10:49 AM
To: Riggs, Eric
Subject: ARO Property

Eric,

Did Mr. Winkler provide what you needed for this documentation?

Thanks,
Pam

Pam McDonald
Energy Delivery Budgeting
Ext. 2850

Tracking:

Recipient
Miller, Jon
Riggs, Eric
McDonald, Pam
Wiseman, Sara
Kinder, Debra

Wiseman, Sara

From: Taylor, Craig A [Craig.Taylor@DPLINC.com]

Sent: Thursday, August 18, 2005 9:19 PM

To: Wiseman, Sara

Subject: RE: FIN 47 Compliance

Sara,

In the initial application of FASB 143, we identified river structures and ash landfills as our legal obligations. Surveys and discussions along with an outside consultant were used to determine what our legal obligations actually were.

In the process of determining our conditional obligations, we are going to revisit concerns relating to fuel storage tanks, pole disposal, pcbs in transformers, and even look at computer equipment disposal. So, we are in the starting process of our review with our Legal Department and Environmental Department. We will be sending some representatives to the Chicago conference on FIN 47, August 30, sponsored by AGA/EEI that should also assist us as we go forward in our compliance.

I hope that this provides some assistance per your request.

Sincerely,

Craig Taylor
Tax Department
Dayton Power and Light Company
(937) 259-7295

From: Henry, Timothy
Sent: Thursday, August 11, 2005 1:49 PM
To: McFarland, Nancy; Perrin, Rachele; Taylor, Craig A
Subject: RE: FIN 47 Compliance

Craig,
Since you did the research on this for Dan. Can you respond.

Thanks
Tim

From: McFarland, Nancy
Sent: Thursday, August 11, 2005 1:04 PM
To: Henry, Timothy; Perrin, Rachele
Subject: FW: FIN 47 Compliance

Do you two wish to respond? Thanks!

Nancy

From: Wiseman, Sara [mailto:Sara.Wiseman@lgeenergy.com]
Sent: Thursday, August 11, 2005 12:44 PM
To: McFarland, Nancy
Cc: Kinder, Debra; Riggs, Eric
Subject: FW: FIN 47 Compliance

Ms. McFarland,

I found your name in the EEI Accounting Committees Membership directory. I have some questions regarding FIN 47 and hope that you or someone in your Property Accounting area will be able to take a few minutes to respond.

I work within the Property Accounting department of LG&E Energy. We are currently trying to refine our approach to complying with FIN 47. As part of our research we are contacting several other utilities to see what our neighbors in the industry are identifying as conditional asset retirement obligations and how they plan to quantify the costs of removal.

In the intial implementation of FASB 143, LG&E Energy identified ash ponds, landfills, GSU transformers,underground fuel oil tanks and piping as AROs. To comply with FIN 47, our legal department is currently investigating legal obligations related to bridges, tunnels, gas wells, gas piping, hydro facilities, and asbestos. We also are considering any asset containing oil, wood poles and batteries.

We would appreciate your input regarding DPL's FIN 47 plans and we will gladly supply you with the responses we receive from other utilities contacted.

Thank you,

Sara Wiseman
Manager, Property Accounting
Louisville Gas & Electric/Kentucky Utilities
(502) 627-3189

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*** DPL, Inc. ***

Wiseman, Sara

From:	Miller, Jon
Sent:	Monday, August 22, 2005 4:21 PM
To:	Riggs, Eric
Cc:	Wiseman, Sara; Kinder, Debra
Subject:	RE: FIN 47

Eric,

I had told the folks at the plants that the deadline had been postponed until we had further clarification on the requirements. I misunderstood that this was only related to the asbestos issue. I have since asked for all other information by 8/31/05.

For the information that was provided for Cane Run on July 27, 2005, are any changes required or is that information sufficient?

Sorry for the delay.
Jon

From:	Riggs, Eric
Sent:	Monday, August 22, 2005 3:11 PM
To:	McDonald, Pam; Miller, Jon
Cc:	Wiseman, Sara; Kinder, Debra
Subject:	RE: FIN 47

Pam, Jon,

We are fast closing in on the deadline to provide information to EON on this issue. Do you have anything as of yet? Please let us know where you stand, regardless of where that might be, by Wednesday.

Thanks,
Eric

From:	Riggs, Eric
Sent:	Friday, August 12, 2005 2:53 PM
To:	McDonald, Pam; Miller, Jon
Cc:	Wiseman, Sara; Kinder, Debra; Charnas, Shannon
Subject:	FIN 47

Pam, Jon,

Would you provide an update on the progress being made in regards to FIN47? I have attached a file listing general requirements that we believe that will be necessary in order for us to make the necessary calculations.

<< File: Data Requirements for FIN 47.doc >>

Thanks,
Eric Riggs

From:	McDonald, Pam
Sent:	Wednesday, July 27, 2005 12:08 PM
To:	Riggs, Eric
Cc:	Miller, Jon
Subject:	RE: ARO Property

Eric,

After our last meeting, I have read through the documentation and developed an action plan. Most of the people I need to talk to have been on vacation or busy with other priorities. I will try to work on it next week and give you an update. Sorry for the delay.

Wiseman, Sara

From:	Miller, Jon
Sent:	Friday, August 26, 2005 12:05 PM
To:	Wiseman, Sara; Riggs, Eric; Kinder, Debra
Subject:	FW: Fin 47 Template (2).xls
Follow Up Flag:	Follow up
Flag Status:	Completed
Attachments:	Fin 47 Template.xls; Fin 47 Template (2).xls

Attached below is the response for Cane Run with the blank template as well as the blank template. If you want to make any changes to the template, go ahead and make them and send me the revised file.

Jon

Fin 47 Template.xls

From: Turner, Steven
Sent: Thursday, July 14, 2005 3:06 PM
To: Miller, Jon
Subject: FW: Fin 47 Template (2).xls

Per your request.

From: Legler, Steve
Sent: Thursday, July 14, 2005 9:21 AM
To: Turner, Steven
Subject: Fin 47 Template (2).xls

Fin 47 Template (2).xls

Steve,

This is what I have for the FIN 47 request from Jon Miller.

Please review. I believe we were to send something to Jon today.

Steve

Location						
Asset Retirement Obligations			($000's)			
Asset Description	Location	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date	
Asbestos						
Cane Run						
CR1 Asbestos Abatement	Cane Run Unit 1 Plant		2,700	60		Ductwork, Equip. External, Operating Floor up $300k; Ductwork External, Under Operating Floor $200k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $400k; Penthouse $150k; Furnace External $750k; Air Testing, permits, survey $100k; Boiler misc. $400k; Coal Handling $150k
CR2 Asbestos Abatement	Cane Run Unit 2 Plant		2,550	50		Ductwork, Equip. External, Operating Floor up $300k; Ductwork External, Under Operating Floor $200k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $400k; Penthouse $150k; Furnace External $750k; Air Testing, permits, survey $100k; Boiler misc. $400k
CR3 Asbestos Abatement	Cane Run Unit 3 Plant		2,700	50		Ductwork, Equip. External, Operating Floor up $300k; Ductwork External, Under Operating Floor $200k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $400k; Penthouse $150k; Furnace External $850k; Air Testing, permits, survey $100k; Boiler misc. $450k
CR4 Asbestos Abatement	Cane Run Unit 4 Plant		2,750	50		Ductwork, Equip. External, Operating Floor up $500k; Ductwork External, Under Operating Floor $350k; Piping External, Opererating Floor up $150k; Pipe and Equip. Under Opererating Floor $300k; Penthouse $150k; Furnace External $900k; Air Testing, permits, survey $100k; Boiler misc. $300k
CR5 Asbestos Abatement	Cane Run Unit 5 Plant		2,150	40		Ductwork, Equip. External, Operating Floor up $500k; Ductwork External, Under Operating Floor $300k; Piping External, Opererating Floor up $150k; Pipe and Equip. Under Opererating Floor $200k; Penthouse $100k; Furnace External $500k; Air Testing, permits, survey $100k; Boiler misc. $300k
CR6 Asbestos Abatement	Cane Run Unit 6 Plant		2,500	50		Ductwork, Equip. External, Operating Floor up $700k; Ductwork External, Under Operating Floor $400k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $300k; Penthouse $150k; Furnace External $200k; Air Testing, permits, survey $100k; Boiler misc. $400k
Paddy's Run						
Plant Asbestos Abatement	Total Plant		11,000	100		
Canal						
Plant Asbestos Abatement	Total Plant		6,000	75		
Waterside						
Plant Asbestos Abatement	Total Plant		4,000	50		
Battery						
Cane Run						
Emergency Battery No. 1 (1&2)	Unit 1 basement	60	3.5	1		
Emergency Battery No. 2 (3&4)	Unit 3 1st landing	60	3.5	1		
Emergency Battery No. 3 (6)	Unit 6 basement	60	3.5	1		
Station Battery No. 1	No. 1 Breaker House	60	3.5	1		
Station Battery No. 2	Unit 1 basement	60	3.5	1		
Station Battery No. 3	Unit 3 1st landing	60	3.5	1		
Station Battery No. 4	Unit 6 basement	60	3.5	1		
Unit 4 UPS Battery	Unit 4 turbine floor	30	2	0.5		
Unit 5 UPS Battery	Unit 6 turbine floor	30	2	0.5		
Unit 6 UPS Battery	Unit 6 turbine floor	30	2	0.5		
Communications Battery	Old Control House (rear)	24	2	0.5		
4&5 SPP Batteries	4&5 SPP Elect. Room	10	1	0.5		
Jefferson County Gas Turbines						
Paddy's 13 DC	SFC/SES Room	60	3.5	1		
Paddy's 12 DC	PR-12 Building	60	3.5	1		
Paddy's 11 DC	PR-11 Under Control Rm	14	1	0.5		
Control house DC	Control House	60	3.5	1		
Cane Run GT-11	GT-11 Building	60	3.5	1		

Oil						
Cane Run Station	Plant/GT-11		10	1		Turbine Reservoir/Mill/Fluid Drive/Screenhouse Oil Accumulator, Misc.
Paddy's Run Station	Plant/CT's		15	1		Turbine Reservoir/Mill/Fluid Drive/Screenhouse Oil Accumulator, Misc.
Canal Station	Plant		5	1		Turbine Reservoir/Mill/, Misc.
Waterside	Plant/CT		5	1		Gas Turbine/Misc. Plant Equipment

Wiseman, Sara

From:	Miller, Jon
Sent:	Tuesday, August 30, 2005 9:06 AM
To:	Wiseman, Sara; Riggs, Eric; Kinder, Debra
Cc:	Jackson, Fred; Joyce, Jeff
Subject:	FW: FIN 47 Template
Follow Up Flag:	Follow up
Flag Status:	Completed
Attachments:	Fin 47 Ghent Station 083005.xls

Sara,

Attached is the first cut of the FIN 47 information for Ghent. Please review and let Fred and me know if any changes should be made. Fred is going to add batteries to the report as well and should have that information by the end of the week.

Fred,

The cost information is included in the comment section, can you show it within the "Removal Cost per Asset" column?

Jon

From:	Jackson, Fred
Sent:	Tuesday, August 30, 2005 7:03 AM
To:	Miller, Jon
Cc:	Joyce, Jeff
Subject:	FIN 47 Template

Jon,

Attached is an attempt to complete the FIN 47 template for the Ghent Station. I have listed the asbestos items but have not completed the cost estimates yet. I will forward an updated copy with the asbestos cost information as soon as I complete. Please let me know if questions.

Thanks.
Fred

Fin 47 Ghent
Station 083005.xl...

Location
Asset Retirement Obligations

Asset Description	Location	Legal Requirement	Quantity by year of installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date	Comments	Support
Ash Pond ATB I	GH	**Resource Conservation and Recovery Act**	1974			End of Plant Life	$90K/Acre at 125 Acres	2002 FMSM Estimate of $83K/acre inflated at 3%/yr. The FMSM estimate from study during Pineville retirement.
Ash Pond ATB II	GH	**Resource Conservation and Recovery Act**	1994			End of Plant Life	$90K/Acre at 146 Acres	2002 FMSM Estimate of $83K/acre inflated at 3%/yr. The FMSM estimate from study during Pineville retirement.
Gypsum Stack	GH	**Clean Water Act**	1994			End of Plant Life	Assume closure similar to Ash Pond; $90K/acre at 10 acres	2002 FMSM Estimate of $83K/acre inflated at 3%/yr. The FMSM estimate from study during Pineville retirement.
Radiation Sources - Cesium	GH	**The Cabinet for Human Resources - KRS 211.844, Reg 902 KAR Chapter 100**	170 Total: 26 Unit 1 1974, 41 Unit 2 1977, 27 Unit 3 1981, 32 Unit 4 1984, 15 Scrubber 1994, 29 Coal Yard 1974			End of Plant Life or as fail	Total removal/disposal costs for all 170 sources is $118833. Sources are being replaced with non radiation sources as they fail.	Cost estimate based on e mail from Ohmart dated 8/25/05.
Radiation Sources - Radium	GH	**The Cabinet for Human Resources - KRS 211.844, Reg 902 KAR Chapter 100**	42 Total; 6 Unit 1 1974, 12 Unit 2 1977, 12 Unit 3 1981, 12 Unit 4 1984.			End of Plant Life	Total removal/disposal costs for all 42 sources is $49K.	Cost estimate based on e mail from Ohmart dated 8/25/05.
Remediation of Underground Fuel Oil Piping	GH	**Comprehensive Emergency Response and Liability Act**	25% Unit 1 1974, 25% Unit 2 1977, 25% Unit 3 1981, 25% Unit 4 1984			End of Plant Life	Total cost to remediate in place is $4.4K common to the site or divided equally across the four units.	2002 Evergreen email estimate of $4K inflated at 3%/yr.
Station Oil Reserves	GH	**Clean Water Act** **Toxic Substances Control Act**	Common to Plant			End of Plant Life	226,000 gallons on site - Cost of $0.60 per gallon for approx. 20,000 gallons of contaminated oils at the time of closure. Allocate evenly across all units (there will likely be some contaminated oils on site that will require a charge). Most oil will be recycled at no cost. **Note: *Cost Basis was 2002***.	American Enviro Services will reclaim some oils at $0.60 per gallon if contaminated, including up to 50 ppm pf PCB (based on work performed in 12/02 & confirming phone interview). There is no charge for uncontaminated oil. It is estimated a portion of the oils will be contaminated, some with non-PCB oil at <50 ppm. **Supported by Enviro-Services invoice. *Note: Cost Basis was 2002***
Chemical Tank Clean up	GH	**Clean Water Act**	1 10,000 gallon acid tank, and 1 10,000 gallon caustic tank 1974, '1 40,000 gallon acid tank and 1 10,00 gallon caustic tank 1981.			End of Plant Life	Total Cost Estimate $14K. Anticipate needing to work with 1 40,000 gallon acid tank, 1 10,000 gallon acid tank, and 2 10,000 gallon caustic tanks.	2002 Evergreen email estimate of $13K inflated at 3%/yr.
Sewage Plant	GH	**Clean Water Act**	1974			End of Plant Life	Estimated cost to pump out tank, fill tank with soil, and grade land.	Based on Pineville estimate of $1k for 50 people, assumed $4k for 200 people and additional fee for equipment use. **Supported by PMR invoice. Note: Cost Basis was 2002**
Coal Yard Covering	GH	**Clean Water Act**	1974			End of Plant Life	Not unit specific	Based on Pineville estimate - $15k/acre for 45 acres **Acreage verified by Delbert Billiter-Fuels Dept. Note: Cost Basis was 2002**
Asbestos Piping/Vessels	GH		1974			End of Plant Life or as required for maintenance		
Asbestos Floor Tile	GH		1974			End of Plant Life or as required for maintenance		
Asbestos Siding	GH		1974			End of Plant Life or as required for maintenance		

Wiseman, Sara

From: Riggs, Eric
Sent: Tuesday, August 30, 2005 9:19 AM
To: McDonald, Pam
Cc: Wiseman, Sara; Kinder, Debra
Subject: FW: FIN 47 Template

Attachments: Fin 47 Ghent Station 083005.xls

Pam,

Sara asked that I forward the file listed below to you. It is a template that you might want to use in compiling the FIN47 information.

Thanks,
Eric

From: Miller, Jon
Sent: Tuesday, August 30, 2005 9:06 AM
To: Wiseman, Sara; Riggs, Eric; Kinder, Debra
Cc: Jackson, Fred; Joyce, Jeff
Subject: FW: FIN 47 Template

Sara,

Attached is the first cut of the FIN 47 information for Ghent. Please review and let Fred and me know if any changes should be made. Fred is going to add batteries to the report as well and should have that information by the end of the week.

Fred,

The cost information is included in the comment section, can you show it within the "Removal Cost per Asset" column?

Jon

From: Jackson, Fred
Sent: Tuesday, August 30, 2005 7:03 AM
To: Miller, Jon
Cc: Joyce, Jeff
Subject: FIN 47 Template

Jon,

Attached is an attempt to complete the FIN 47 template for the Ghent Station. I have listed the asbestos items but have not completed the cost estimates yet. I will forward an updated copy with the asbestos cost information as soon as I complete. Please let me know if questions.

Thanks.
Fred

Fin 47 Ghent
Station 083005.xl...

Location
Asset Retirement Obligations

Asset Description	Location	Legal Requirement	Quantity by year of installation	Removal Cost per Asset ($'s)	Incremental Cost of Disposal ($'s)	Estimated Retirement Date	Comments	Support
Ash Pond ATB I	GH	Resource Conservation and Recovery Act	1974			End of Plant Life	$90K/Acre at 125 Acres	2002 FMSM Estimate of $83K/acre inflated at 3%/yr. The FMSM estimate from study during Pineville retirement.
Ash Pond ATB II	GH	Resource Conservation and Recovery Act	1994			End of Plant Life	$90K/Acre at 146 Acres	2002 FMSM Estimate of $83K/acre inflated at 3%/yr. The FMSM estimate from study during Pineville retirement.
Gypsum Stack	GH	Clean Water Act	1994			End of Plant Life	Assume closure similar to Ash Pond; $90K/acre at 10 acres	2002 FMSM Estimate of $83K/acre inflated at 3%/yr. The FMSM estimate from study during Pineville retirement.
Radiation Sources - Cesium	GH	The Cabinet for Human Resources - KRS 211.844, Reg 902 KAR Chapter 100	170 Total. 26 Unit 1 1974, 41 Unit 2 1977, 27 Unit 3 1981, 32 Unit 4 1984, 15 Scrubber 1994, 29 Coal Yard 1974			End of Plant Life or as fail	Total removal/disposal costs for all 170 sources is $118833. Sources are being replaced with non radiation sources as they fail.	Cost estimate based on e mail from Ohmart dated 8/25/05.
Radiation Sources - Radium	GH	The Cabinet for Human Resources - KRS 211.844, Reg 902 KAR Chapter 100	42 Total; 6 Unit 1 1974, 12 Unit 2 1977, 12 Unit 3 1981, 12 Unit 4 1984.			End of Plant Life	Total removal/disposal costs for all 42 sources is $49K.	Cost estimate based on e mail from Ohmart dated 8/25/05.
Remediation of Underground Fuel Oil Piping	GH	Comprehensive Emergency Response and Liability Act	25% Unit 1 1974, 25% Unit 2 1977, 25% Unit 3 1981, 25% Unit 4 1984			End of Plant Life	Total cost to remediate in place is $4.4K common to the site or divided equally across the four units.	2002 Evergreen email estimate of $4K inflated at 3%/yr.
Station Oil Reserves	GH	Clean Water Act Toxic Substances Control Act	Common to Plant			End of Plant Life	226,000 gallons on site - Cost of $0.60 per gallon for approx. 20,000 gallons of contaminated oils at the time of closure. Allocate evenly across all units (there will likely be some contaminated oils on site that will require a charge). Most oil will be recycled at no cost. **Note: *Cost Basis was 2002*.**	American Enviro Services will reclaim some oils at $0.60 per gallon if contaminated, including up to 50 ppm pf PCB (based on work performed in 12/02 & confirming phone interview). There is no charge for uncontaminated oil. It is estimated a portion of the oils will be contaminated, some with non-PCB oil at <50 ppm. **Supported by Enviro-Services Invoice. *Note: Cost Basis was 2002***
Chemical Tank Clean up	GH	Clean Water Act	1 10,000 gallon acid tank, and 1 10,000 gallon caustic tank 1974, '1 40,000 gallon acid tank and 1 10,00 gallon caustic tank 1981.			End of Plant Life	Total Cost Estimate $14K. Anticipate needing to work with 1 40,000 gallon acid tank, 1 10,000 gallon acid tank, and 2 10,000 gallon caustic tanks.	2002 Evergreen email estimate of $13K inflated at 3%/yr.
Sewage Plant	GH	Clean Water Act	1974			End of Plant Life	Estimated cost to pump out tank, fill tank with soil, and grade land.	Based on Pineville estimate of $1k for 50 people, assumed $4k for 200 people and additional fee for equipment use. **Supported by PMR invoice. Note: Cost Basis was 2002**
Coal Yard Covering	GH	Clean Water Act	1974			End of Plant Life	Not unit specific	Based on Pineville estimate - $15k/acre for 45 acres **Acreage verified by Delbert Billiter-Fuels Dept. Note: Cost Basis was 2002**
Asbestos Piping/Vessels	GH		1974			End of Plant Life or as required for maintenance		
Asbestos Floor Tile	GH		1974			End of Plant Life or as required for maintenance		
Asbestos Siding	GH		1974			End of Plant Life or as required for maintenance		

Kinder, Debra

From: Riggs, Eric
Sent: Wednesday, September 07, 2005 2:51 PM
To: Kinder, Debra
Subject: FW: ARO Property

Attachments: ARO Property.xls

From: McDonald, Pam
Sent: Friday, September 02, 2005 11:36 AM
To: Riggs, Eric
Cc: Wiseman, Sara; Paciorek, Marcelo
Subject: ARO Property

Eric,

As we expected, Energy Delivery has very little of this equipment remaining in service. Attached is our findings and the contact person who provided the information.

Pam

ARO Property.xls

Pam McDonald
Energy Delivery Budgeting
Ext. 2850

Kentucky Utilities / Louisville Gas and Electric Company
Assets Requiring Special Disposal Treatment

Asset	Description of Asset	Disposal Explanation	Incremental Removal Cost
Capacitors - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. 10% of these units are likely to contain PCBs.	Contact Person: Andre Johnson. We have not encountered any retirements of these units containing PCB's in the last 3 years. Location of any items still in service and the associated removal cost is unknown.	None
Reclosers - Fluid Filled	All units older than 1980 must tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's.	Contact Person: Andre Johnson. Retirements of these units containing PCB's is rare. The location of these items still in service and the associated removal cost is unknown.	None
Breakers - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Fluid is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's	Contact Person: Andre Johnson. In our record history, we have not encountered any retirements of these units that are contaminated. The location of any items still in service and the associated removal cost is unknown.	None
Bushings - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Units are sealed and therefore the fluid is not replaced during maintenance. Approximately 25% of these assets are likely to contain PCB's	Contact Person: Andre Johnson. In the past 3 years, we have not encountered any retirements of these units. The location of any items still in service and the associated removal cost is unknown.	None
Regulators - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's	Contact Person: Andre Johnson. In the past 3 years, we have not encountered any retirements of these units. The location of any items still in service and the associated removal cost is unknown.	None
Switches -Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's	Contact Person: Andre Johnson. In our record history, we have not encountered any retirements of these units that are contaminated. The location of any items still in service and the associated removal cost is unknown.	None
Substation Transformers - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's	Contact Person: Andre Johnson. All of these units should be retired.	None
Residential Transformers - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Units are operated until they fail. Approximately 10% of these assets are likely to contain PCB's	Contact Person: Andre Johnson. All of these units should be retired.	None
Batteries	These units are sent to a recycle center.	Contact Person: Andre Johnson. These items are sent to the recycle center. The salvage value received for these units offsets the disposal cost.	Zero Net Removal Cost
Cable - Oil Filled	All oil filled cable older than 1980 must be tested when taken out of service. Less than 5% of these assets are likely to contain PCB's	Contact Person: John Wolfe. The removal of this cable is less than 1,000 ft. per year. The contractor disposes of this material.	None

Asset	Description of Asset	Disposal Explanation	Incremental Removal Cost
Wood Poles	The landfill must be notified that these units contain harmful chemicals. Additional costs are charged by the landfill operators for disposal.	Contact Person: Les Mills.	$38K per year
Cross Arms	The landfill must be notified that these units contain harmful chemicals. Additional costs are charged by the landfill operators for disposal.	Contact Person: Les Mills.	$4K per year
Large Diameter Gas Steel Pipe	All steel pipe is tested for PCB presence when taken out of service. Historical data indicates very infrequent PCB presence in distribution or storage field piping 4-inches in diameter or more. Less than 5% of pipe is estimated to have PCB contamination.	Contact Person: Pete Clyde. We take wipe samples every time we retire a main, but he does not recall ever having to dispose of PCB pipe or grout mains due to PCBs. We therefore do not have any data to generate an estimate of the disposal cost.	None
Residential Gas Pipe	All steel pipe is tested for PCB presence when taken out of service. All pipe with less than 4-inch diameter must be disposed of as scrap or in a landfill. Additional costs are charged by landfill operators for disposal. If left in place, pipe is to be grouted or otherwise filled to prohibit reuse.	Contact Person: Pete Clyde. We take wipe samples every time we retire a main, but he does not recall ever having to dispose of PCB pipe or grout mains due to PCBs. We therefore do not have any data to generate an estimate of the disposal cost.	None

Kentucky Utilities / Louisville Gas and Electric Company
Assets Requiring Special Disposal Treatment

Asset	Description of Asset
Capacitors - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. 10% of these units are likely to contain PCBs.
Reclosers - Fluid Filled	All units older than 1980 must tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's.
Breakers - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Fluid is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Bushings - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Units are sealed and therefore the fluid is not replaced during maintenance. Approximately 25% of these assets are likely to contain PCB's
Regulators - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's

Switches -Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Substation Transformers - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Residential Transformers - Fluid Filled	All units older than 1980 must be tested when the units are taken off line. Units are operated until they fail. Approximately 10% of these assets are likely to contain PCB's
Batteries	These units are sent to a recycle center.
Cable - Oil Filled	All oil filled cable older than 1980 must be tested when taken out of service. Less than 5% of these assets are likely to contain PCB's
Wood Poles	The landfill must be notified that these units contain harmful chemicals. Additional costs are charged by the landfill operators for disposal.
Cross Arms	The landfill must be notified that these units contain harmful chemicals. Additional costs are charged by the landfill operators for disposal.

Large Diameter Gas Steel Pipe	All steel pipe is tested for PCB presence when taken out of service. Historical data indicates very infrequent PCB presence in distribution or storage field piping 4-inches in diameter or more. Less than 5% of pipe is estimated to have PCB contamination.
Residential Gas Pipe	All steel pipe is tested for PCB presence when taken out of service. All pipe with less than 4-inch diameter must be disposed of as scrap or in a landfill. Additional costs are charged by landfill operators for disposal. If left in place, pipe is to be grouted or otherwise filled to prohibit reuse.

Disposal Explanation	Incremental Removal Cost
Contact Person: Andre Johnson. We have not encountered any retirements of these units containing PCB's in the last 3 years. Location of any items still in service and the associated removal cost is unknown.	None
Contact Person: Andre Johnson. Retirements of these units containing PCB's is rare. The location of these items still in service and the associated removal cost is unknown.	None
Contact Person: Andre Johnson. In our record history, we have not encountered any retirements of these units that are contaminated. The location of any items still in service and the associated removal cost is unknown.	None
Contact Person: Andre Johnson. In the past 3 years, we have not encountered any retirements of these units. The location of any items still in service and the associated removal cost is unknown.	None
Contact Person: Andre Johnson. In the past 3 years, we have not encountered any retirements of these units. The location of any items still in service and the associated removal cost is unknown.	None

Contact Person: Andre Johnson. In our record history, we have not encountered any retirements of these units that are contaminated. The location of any items still in service and the associated removal cost is unknown.	None
Contact Person: Andre Johnson. All of these units should be retired.	None
Contact Person: Andre Johnson. All of these units should be retired.	None
Contact Person: Andre Johnson. These items are sent to the recycle center. The salvage value received for these units offsets the disposal cost.	Zero Net Removal Cost
Contact Person: John Wolfe. The removal of this cable is less than 1,000 ft. per year. The contractor disposes of this material.	None
Contact Person: Les Mills.	$38K per year
Contact Person: Les Mills.	$4K per year

Contact Person: Pete Clyde. We take wipe samples every time we retire a main, but he does not recall ever having to dispose of PCB pipe or grout mains due to PCBs. We therefore do not have any data to generate an estimate of the disposal cost.	None
Contact Person: Pete Clyde. We take wipe samples every time we retire a main, but he does not recall ever having to dispose of PCB pipe or grout mains due to PCBs. We therefore do not have any data to generate an estimate of the disposal cost.	None

Wiseman, Sara

From: Riggs, Eric
Sent: Tuesday, September 20, 2005 12:21 PM
To: Charnas, Shannon; Miller, Jon; Wiseman, Sara; Kinder, Debra
Subject: RE: FIN 47 meeting

Shannon,

I believe that Jerry Grant would be the best person to have at the asbestos meeting. If we can't get him, then I would suggest that we still have the meeting and get his thoughts afterward.

Thanks,
Eric

From: Charnas, Shannon
Sent: Tuesday, September 20, 2005 11:56 AM
To: Miller, Jon; Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FIN 47 meeting

I noticed that Pam McDonald was not invited to our FIN 47 meeting on Thursday, although it is critical that we get all areas wrapped up for asbestos quickly. Per her calendar she is on vacation all this week. Any thoughts as to whether we should proceed without her and set up another meeting or reschedule? Is there someone else who could attend in her place? Do we need Jerry Grant who may have historical information on building asbestos abatement? Please let me know your thoughts ASAP.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

Wiseman, Sara

From: Charnas, Shannon
Sent: Wednesday, September 21, 2005 7:47 AM
To: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: RE: FIN 47 meeting

I was able to talk to Jerry Grant yesterday and he can attend the meeting on Thursday. He has some information on prior abatements that he is going to pull and try to think about the other buildings that we have and how we may be able to address them. I was concerned that he mentioned he had talked to Eric, but he said he was not asked to do anything to try to quantify the asbestos costs. He also had not been working with Pam. I'm sure it was some kind of misunderstanding, but when we have these fairly large requests of other departments we need to make sure they understand exactly what we need, when we need it, and keep following up with them. I informed him of our short timeframe and after our discussion I think he will be able to provide some information to quantify other buildings as well as possibly help extrapolate costs related to generation buildings. We'll see how the meeting goes on Thursday.

We will still need to follow up with Pam next week (sooner rather than later) to ensure she can finalize the information for Energy Delivery that we need. Please make sure you get with her to discuss this.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Wiseman, Sara
Sent: Wednesday, September 21, 2005 7:40 AM
To: Charnas, Shannon; Miller, Jon; Kinder, Debra; Riggs, Eric
Subject: RE: FIN 47 meeting

I think we can take care of meeting with Pam separately, as need be. We can see how this week's meeting comes out and follow up with her next week.

Sara Wiseman
Manager-Property Accounting
502.627.3189

From: Charnas, Shannon
Sent: Tuesday, September 20, 2005 11:56 AM
To: Miller, Jon; Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FIN 47 meeting

I noticed that Pam McDonald was not invited to our FIN 47 meeting on Thursday, although it is critical that we get all areas wrapped up for asbestos quickly. Per her calendar she is on vacation all this week. Any thoughts as to whether we should proceed without her and set up another meeting or reschedule? Is there someone else who could attend in her place? Do we need Jerry Grant who may have historical information on building asbestos abatement? Please let me know your thoughts ASAP.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

Wiseman, Sara

From: Riggs, Eric
Sent: Wednesday, September 21, 2005 10:39 AM
To: Miller, Jon; McDonald, Pam
Cc: Charnas, Shannon; Wiseman, Sara
Subject: Substation Asbestos

Pam, Jon,

It has been brought up that there may be an issue with asbestos in the substation control houses. The main area of concern relates to the roofs. I know that a number of LG&E substations have had the roofs replaced over the years. Would you please check with your contacts and see what substations at KU and LG&E have asbestos issues that have not been remediated. We would need to know the location and related assets to get the cost from the fixed asset system.

Thanks,
Eric Riggs
2822

Wiseman, Sara

From: Charnas, Shannon
Sent: Saturday, September 24, 2005 9:36 AM
To: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: ARO

I placed a short ARO document from KPMG on your chair. The last page has a good discussion on transition accounting - cumulative effect.

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

Kinder, Debra

From: Charnas, Shannon
Sent: Monday, September 26, 2005 5:25 PM
To: Legler, Steve
Cc: Miller, Jon; Riggs, Eric; Kremer, Dan; Turner, Steven; Crutcher, Tom; Fraley, Jeffrey; Pence, Mark; Kinder, Debra; Jackson, Fred; Carr, Sam; Baker, Bryan
Subject: RE: FIN-47

Steve-

Thanks very much for the information, however, we are looking for a little more than this. For example, for penthouse abatement you have $150k for CR 1-4 and CR6, but $100k for CR5. All except CR1 & 2 have different MW capacity. I assume you made some kind of adjustments for work that had been done in that area for some units and the size of the unit. This is detail we would like to be added to the explanation, such as started with 100 MW estimate and multiplied by 2.5 to increase for size of unit and subtracted x due to prior work done on the unit. The more detail you can provide, the better.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Legler, Steve
Sent: Monday, September 26, 2005 4:29 PM
To: Miller, Jon; Charnas, Shannon; Riggs, Eric; Kremer, Dan; Turner, Steven; Crutcher, Tom; Fraley, Jeffrey; Pence, Mark; Kinder, Debra; Jackson, Fred; Carr, Sam; Baker, Bryan
Subject: FW: FIN-47

All,

Dan Kremer asked that I put together a methodology for determining FIN-47 asbestos abatement costs. I have attached details of my approach as well as an estimate from National Environmental Contracting for this type work.

Feel free to contact me if you have questions.

Steve Legler
449-8844

<< File: FIN-47 Abatement Methodolgy.doc >> << File: LG&E KU 100 Meg Budget.pdf >>

From: Kremer, Dan
Sent: Thursday, September 22, 2005 2:35 PM
To: Legler, Steve
Cc: Turner, Steven
Subject: FIN-47

Steve, the conference call went fairly smooth from my viewpoint. They liked the approach that we used to come up with our asbestos estimates but Shannon says we need to provide more details as to how the numbers were developed. They want to use our approach and send to the other plants to possibly use the same method to calculate their costs. They would like to be consistent across the plants on how we arrive at the figures so that when the auditors come in they see the same methodology being used.

They asked that you put together the step-by-step approach that you took to get our numbers. This can be a list of bullet points or simply a narrative that will be attached to the cost spreadsheet. Start with the estimate provided by NEC along with as much detail of how they arrived at their cost estimate. Then explain how you then adjusted for known abatement on other units etc. I believe what you need to give then is basically a documentation of the conversation you and I had earlier on your approach. If you have the written quotes from ONEC, include them also.

Once you put this document together please send it to everyone that was included on the distribution list for the conference call plus David Cosby. They are hoping to get something from you tomorrow if possible.

Shannon or Jon will be setting up a follow-up conference call Tuesday or Wednesday of next week to see if there are any questions, issues or problems. Target date for getting the information to Shannon is September 30 or possibly 1-2 days into October but no later.

Since I will be out of the office tomorrow, I would suggest calling Shannon if you have any questions or are unsure about what to do.

Dan Kremer
Manager Commercial Operations
Cane Run Station
(502) 449-8808
dan.kremer@lgeenergy.com

Wiseman, Sara

From: Riggs, Eric
Sent: Monday, September 26, 2005 4:14 PM
To: Wiseman, Sara; Kinder, Debra
Subject: FIN47 Listing - All.xls

Attachments: FIN47 Listing - All.xls

FIN47 Listing - All.xls

Sara, Debbie,

I have this file on the I drive under FASB143/FIN47. It contains all the latest excel worksheets we have received to date. Let me know if you have something that I should add.

Thanks,
Eric

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES SUMMARY

BUSINESS AREA	ESTIMATED REMOVAL COSTS - FIN 47
GENERAL FACILITIES	1,450,000
GENERATION	85,660,000
GAS	11,788,000
TRANSMISSION	769,000
DISTRIBUTION	1,665,000
Grand Total	101,332,000

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location
General Facilities	Jerry Grant	Big Stone Gap Substation
	Karan Kapp	Campbellsville Concrete Block Bldg
		Carrollton 1-1/2 Story Brick Bldg
		Carrolton Storeroom
		Danville 2 Story Facility
		Dawson Springs Storeroom
		Earlington - Wood Frame Bldg
		Eddyville
		Georgetown - 2 Bldgs
		Greenville
		Lexington Meter Dept.
		Lexington Meter Dept. Storage
		Lexington Substation/Relay Dept.
		London Storeroom
		Maysville
		Middlesboro 2 Story Brick
		Middlesboro Storeroom
		Morehead
		Morganfield 2 Story Brick
		Mt. Sterling - 2 Story Brick
		Mt. Sterling Storeroom
		Paris - 1 Story Brick
		Paris Storeroom
		Richmond
		Seventh and Ormsby
		Shelbyville Storeroom
		Somerset Wood Frame
		Somerset Storeroom
		Stone Rd Main Bldg
		Winchester 1 Story Brick
		Winchester Storeroom

Liability Source	Field Rem/Disp Estimate
Asbestos	29,000
Asbestos	3,000
Asbestos	7,000
Asbestos	7,000
Asbestos	76,000
Asbestos	14,000
Asbestos	44,000
Asbestos	7,000
Asbestos	18,000
Asbestos	14,000
Asbestos	102,000
Asbestos	88,000
Asbestos	106,000
Asbestos	9,000
Asbestos	8,000
Asbestos	118,000
Asbestos	95,000
Asbestos	28,000
Asbestos	9,000
Asbestos	26,000
Asbestos	8,000
Asbestos	8,000
Asbestos	7,000
Asbestos	24,000
Asbestos	425,000
Asbestos	24,000
Asbestos	41,000
Asbestos	26,000
Asbestos	34,000
Asbestos	38,000
Asbestos	7,000
Total Facilities	**1,450,000**

FIN 47 - ASSET RETIREMENT OBLIG/
FIELD ESTIMATES

Business Area	Contacts
Generation	**Jon Miller**
	Steve Legler
	Steve Legler
	Dave Cook
	Dave Cook
	Dave Cook
	Dave Cook
	Fred Jackson
	Fred Jackson
	Fred Jackson
	Fred Jackson
	Steve Legler
	Steve Legler
	Steve Legler
	Steve Legler
	Steve Legler
	Steve Legler
	David Cosby
	Sam Carr
	Sam Carr
	Sam Carr
	Steve Legler
	Sam Carr
	Sam Carr
	Sam Carr
	Sam Carr
	Steve Legler
	Steve Legler
	Steve Legler
	Steve Legler
	Steve Legler
	Fred Jackson
	Fred Jackson
	Fred Jackson
	Steve Legler
	Steve Legler
	Steve Legler

Steve Legler
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Steve Legler
Steve Legler
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Steve Legler

Sam Carr
Sam Carr
Sam Carr
Sam Carr
Sam Carr
Sam Carr
Sam Carr
Sam Carr

Sam Carr

Sam Carr
Sam Carr

Steve Legler
Steve Legler

Fred Jackson
Steve Legler

Steve Legler

ATION ANALYSIS

Location	Liability Source	Field Rem/Disp Estimate
Waterside	Asbestos	4,000,000
Paddy's Run	Asbestos	11,000,000
Mill Creek Unit 1 - 356 MW	Asbestos	3,555,000
Mill Creek Unit 2 - 356 MW	Asbestos	3,100,000
Mill Creek Unit 3 - 463 MW	Asbestos	2,350,000
Mill Creek Unit 4 - 543 MW	Asbestos	2,600,000
Ghent Unit 1 - 511 MW	Asbestos	6,517,000
Ghent Unit 2 - 511 MW	Asbestos	8,637,000
Ghent Unit 3 - 511 MW	Asbestos	1,532,000
Ghent Unit 4 - 511 MW	Asbestos	1,532,000
Cane Run Unit 1	Asbestos	2,700,000
Cane Run Unit 2	Asbestos	2,550,000
Cane Run Unit 3	Asbestos	2,700,000
Cane Run Unit 4	Asbestos	2,750,000
Cane Run Unit 5	Asbestos	2,150,000
Cane Run Unit 6	Asbestos	2,500,000
Trimble	Asbestos	0
Green River	Asbestos	
Brown Unit 1 - 108 MW	Asbestos	2,055,700
Brown Unit 2 - 178 MW	Asbestos	3,295,700
Brown Unit 3 - 454 MW	Asbestos	7,435,200
Zorn	Asbestos	
Canal	Asbestos	6,000,000
Tyronne Unit 1 - 30 MW	Asbestos	1,458,700
Tyronne Unit 2 - 30 MW	Asbestos	1,458,700
Tyronne Unit 3 - 75 MW	Asbestos	2,106,700
Pineville Unit 1 - 38 MW	Asbestos	1,534,200
Haefling	Asbestos	
Ohio Falls	Asbestos	
Dix Dam	Asbestos	
Lock 7 - Pending Sale	Asbestos	
Waterside	Batteries	
Paddy's Run - 13 DC - SFC/SES Room	Batteries	3,500
Paddy's Run - 12 DC - PR-12 Building	Batteries	3,500
Paddy's Run - 11 DC - PR-11 Under Control Room	Batteries	1,000
Paddy's Control House DC - Substation	Batteries	3,500
Mill Creek	Batteries	
Ghent Lead Acid - 4 sets Station Batteries	Batteries	16,000
Ghent Lead Acid - Equip Rooms, Scrubber, SCR	Batteries	2,000
Ghent Misc. Dry Cell	Batteries	10,000
Cane Run Unit 1 Basement - Emer. No. 1 (1 & 2)	Batteries	3,500
Cane Run Unit 3 1st Landing - Emer. No. 2 (3 & 4)	Batteries	3,500
Cane Run Unit 6 Basement - Emer. No. 3 (6)	Batteries	3,500

Cane Run No. 1 Breaker House - Station No. 1	Batteries	3,500
Cane Run Unit 1 Basement - Station No. 2	Batteries	3,500
Cane Run Unit 3 1st Landing - Station No. 3	Batteries	3,500
Cane Run Unit 6 Basement - Station No. 4	Batteries	3,500
Cane Run Unit 4 Turbine Floor - UPS	Batteries	2,000
Cane Run Unit 5 Turbine Floor - UPS	Batteries	2,000
Cane Run Unit 6 Turbine Floor - UPS	Batteries	2,000
Cane Run Old Control House, Rear - Communications	Batteries	2,000
Cane Run 4 & 5 SPP Elect. Room	Batteries	1,000
Cane Run Gas Turbine - GT 11	Batteries	3,500
Trimble	Batteries	
Green River	Batteries	
Brown 1 Station Batteries	Batteries	2,000
Brown 2 Station Batteries	Batteries	2,000
Brown 3 Station Batteries	Batteries	2,000
Brown ST - West Cliff	Batteries	2,000
Brown ST - North Sub	Batteries	2,000
Brown 3 Computer Batteries	Batteries	480
Brown 1 Computer Batteries	Batteries	240
Brown ST Slurry Room	Batteries	480
Zorn	Batteries	
Canal	Batteries	
Tyronne - UOP 05049	Batteries	2,700
Pineville	Batteries	
Haefling - UOP 05049	Batteries	2,700
Dix Station Batteries	Batteries	2,000
Ohio Falls	Batteries	
Lock 7 - Pending Sale	Batteries	
Waterside	PCB (Oil)	5,000
Paddy's Run	PCB (Oil)	15,000
Mill Creek	PCB (Oil)	
Ghent - Station Oil Reserves	PCB (Oil)	12,000
Cane Run	PCB (Oil)	10,000
Trimble	PCB (Oil)	
Green River	PCB (Oil)	
Brown	PCB (Oil)	
Zorn	PCB (Oil)	
Canal	PCB (Oil)	5,000
Tyronne	PCB (Oil)	
Pineville	PCB (Oil)	
Haefling	PCB (Oil)	
Ohio Falls	PCB (Oil)	
Dix Dam	PCB (Oil)	
Lock 7 - Pending Sale	PCB (Oil)	
	Total Generation	**85,660,000**

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location
Gas		
	Glenn Sundheimer	Magnolia Deep - 72 Wells
	Glenn Sundheimer	Magnolia Upper - 91 Wells
	Glenn Sundheimer	Center - 225 Wells
	Glenn Sundheimer	Muldraugh - 60 Wells
	Glenn Sundheimer	Doe Run - 145 Wells
	Steve Beatty	Muldraugh - IM&E Office
	Steve Beatty	Muldraugh - Kewanee Boiler Room
	Steve Beatty	Muldraugh - Purifier 1
	Steve Beatty	Muldraugh - Compressor Bldg
	Steve Beatty	Muldraugh - Purifier 2
	Steve Beatty	Muldraugh - Purifier 3
	Steve Beatty	Muldraugh - Abandoned H2S Incinerator
	Steve Beatty	Muldraugh - Locker Room
	Steve Beatty	Muldraugh - Station Valves
	Steve Beatty	Muldraugh - Station Piping
	Steve Beatty	Muldraugh - Field Valves
	Steve Beatty	Muldraugh - Field Piping
	Steve Beatty	Doe Run - Field Valves
	Steve Beatty	Doe Run - Field Piping
	Steve Beatty	Doe Run - Deep Field Valves
	Steve Beatty	Doe Run - Deep Field Piping
	Steve Beatty	Muldraugh - Distribution
	Tom Rieth	Magnolia Compressor Station Paneling, Roofing
	Tom Rieth	Magnolia Compressor Station Auxillary Bldg
	Tom Rieth	Magnolia compressor Station Field Shop
	Tom Rieth	Magnolia Compressor Station Piping Insulation
	Tom Rieth	Magnolia Compressor Station #1 Purifier Reactivator
	Tom Rieth	Magnolia Station Field Valves
	Tom Rieth	Magnolia Station and Field Piping
	Tom Rieth	Misc. Distribution - gaskets, valve legs, coal tar, gaskets
	Mark Satkamp	City Gate - Preston Station - Meter Bldg
	Mark Satkamp	City Gate - Preston Station - Contro Bldg
	Mark Satkamp	City Gate - Doe Run Station
	Bob Ehrler	

Liability Source	Field Rem/Disp Estimate
Well Plugging	1,383,000
Well Plugging	1,948,000
Well Plugging	3,736,000
Well Plugging	967,000
Well Plugging	2,835,000
Asbestos	38,000
Asbestos	15,000
Asbestos	30,000
Asbestos	20,000
Asbestos	32,000
Asbestos	59,000
Asbestos	21,000
Asbestos	11,000
Asbestos	4,000
Asbestos	76,000
Asbestos	6,000
Asbestos	67,000
Asbestos	5,000
Asbestos	134,000
Asbestos	1,000
Asbestos	56,000
Asbestos	11,000
Asbestos	40,000
Asbestos	18,000
Asbestos	9,000
Asbestos	7,000
Asbestos	26,000
Asbestos	33,000
Asbestos	113,000
Asbestos	56,000
Asbestos	9,000
Asbestos	6,000
Asbestos	16,000
Gas Pipeline	0
Total Gas	**11,788,000**

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location	Liability Source	Field Rem/Disp Estimate
Transmission				
	Elaine Welsh	Paddy's Run	Asbestos	14,000
	Elaine Welsh	LGE Substations (approx. 10 substations)	Asbestos	83,000
	Elaine Welsh	KU Substations (69 Substations)	Asbestos	624,000
	Elaine Welsh	Estimated Annual Cost based on past history	Wood Poles	38,000
	Elaine Welsh	Estimated Annual Cost bsed on past history	Cross Arms	10,000
			Total Transmission	**769,000**

Hillcrest	Asbestos	20,000
Hurstborne	Asbestos	15,000
International	Asbestos	3,000
Jeffersontown	Asbestos	15,000
Kenwood	Asbestos	15,000
Knob Creek	Asbestos	61,000
Locust	Asbestos	39,000
Logan	Asbestos	8,000
Louisville Downs	Asbestos	8,000
Lynn	Asbestos	8,000
Magazine	Asbestos	26,000
Manslick	Asbestos	19,000
Muldraugh	Asbestos	14,000
Nachand	Asbestos	15,000
Okolona	Asbestos	3,000
Ormsby	Asbestos	9,000
Pirtle	Asbestos	8,000
Plainview	Asbestos	16,000
Pleasure Ridge	Asbestos	15,000
Seventh Street	Asbestos	8,000
Sheperdsville	Asbestos	15,000
Skylight	Asbestos	15,000
Smyrna	Asbestos	15,000
Solite	Asbestos	3,000
South Park	Asbestos	15,000
Southern	Asbestos	40,000
Southern Baptist Seminary	Asbestos	12,000
Stewart	Asbestos	15,000
Trimble Cty Sw. Rm (12 kv)	Asbestos	15,000
Terry	Asbestos	15,000
Vermont	Asbestos	12,000
Waterside (D)	Asbestos	36,000
Westpoint	Asbestos	12,000
Western	Asbestos	12,000
WHAS	Asbestos	15,000
Worthington	Asbestos	3,000
Zorn	Asbestos	13,000

KU

478 Substations 10% or 47 Estimated to have Asbestos Contamination	Asbestos	599,000
Estimated Annual Cost based or	Wood Poles	38,000
Estimated Annual Cost bsed on	Cross Arms	10,000
	Total Distribution	**1,665,000**

RETIREMENT AND ABANDONMENT ESTIMATE
RIGGS JUNCTION GAS TRANSMISSION FACILITY

Description:

This estimate is being developed at the request of Property Accounting in compliance with new FERC rules that require the expenses to restore sites after facilities are abandoned be accounted. The lease for the facilities at Riggs Junction requires that LG&E restore the facility to greenspace if the area is ever abandoned.

The Riggs Junction facility contains a valve nest that interconnects two gas transmission pipelines to three Doe Run Upper Storage Field gathering mains and one high-pressure gas distribution main that feeds the City of Brandenburg. The facility also contains two pressure regulating stations; Brandenburg High Pressure Station and Riggs Junction Regulator Assembly. In 1998, a shale recovery compressor, named the Riggs Junction Compressor, was relocated from the site to a new shale recovery site in Laconia, IN. The existing building was demolished, but the building foundation remains. The foundation has not been demolished as it could possibly be used as a foundation for pig traps for the two transmission pipelines.

This estimate is developed solely for the purpose of meeting the new FERC rules. There are no plans to abandon this site to date.

Scope:

1. Demolish existing concrete foundation from Riggs Junction Shale Compressor.
2. Remove existing Brandenburg HP Regulator Station.
3. Remove all of the aboveground piping of the existing valve nest at Riggs Junction. Cap all pipe below grade. The 12" and/or 16" Doe Run Lines, the 3 - 12" Storage Field Gathering Mains, and the 12" Distribution Main will be abandoned in place.
4. The Riggs Junction Regulator Assembly will be removed. The 2" Thin-Mill Steel inlet piping and the 4" PE outlet piping will be capped and abandoned in place.

MATERIALS						
50	lbs, 'Electrodes, Welding, E6010, 5P, 1/8", SFA 5.1	$2.00	$	100.00		
3	Anode, 9 lb, Magnesium	$45.00	$	135.00		
70	pkg, Wax Tape	$12.00	$	840.00		
24	gallons, Wax Tape Primer	$25.00	$	600.00		
2	Caps, 2" Forged Steel	$8.00	$	16.00		
1	Caps, 4" PE	$8.00	$	8.00		
4	Caps, 12", Steel	$80.00	$	320.00		
2	Caps, 16", Steel	$120.00	$	240.00		
2	Bags, Seed, 50 lbs	$90.00	$	180.00		
25	Bails, Straw	$6.00	$	150.00		
20	yds, Clean backfill	$25.00	$	500.00		
1	lot, Miscellaneous Materials	$300.00	$	300.00		
		Subtotal =	$	3,389.00		
		Consumables =	$	169.45		
		Miscellaneous =	$	169.45		
		Subtotal =	$	3,727.90		
		G & A Overheads =	$	37.28		
		KY Sales Tax =	$	223.67		
		Total Materials =			$	3,988.85
COMPANY LABOR						
80	hr, Inspector (Assume PG-12)	$27.23	$	2,178.40		
4	hr, Records Coordinator	$22.85	$	91.40		
16	hr, Distribution Mechanic A	$25.17	$	402.72		
		Unloaded Total Company Labor =	$	2,672.52		
		96% Co. Labor Loading =	$	2,576.44		
		Total Company Labor =			$	5,248.96

TRANSPORTATION AND EQUIPMENT				
	Transportation and Equipment Costs =		$ 1,049.79	
	Total T & E Expense =			$ 1,049.79
CONTRACT LABOR				
4	hrs, Supervisor	$49.06	$ 196.24	
40	hrs, Foreman	$38.73	$ 1,549.20	
80	hrs, Welder	$39.01	$ 3,120.80	
80	hrs, Laborer	$21.16	$ 1,692.80	
40	hrs, Equipment Operator	$33.09	$ 1,323.60	
40	hrs, Dump Truck Driver	$24.33	$ 973.20	
80	hrs, Equipment Charge, Welding Truck	$16.97	$ 1,357.60	
80	hrs, Equipment Charge, Backhoe	$18.74	$ 1,499.20	
80	hrs, Equipment Charge, Excavator with hoe ram	$195.05	$ 15,604.00	
80	hrs, Equipment Charge, Compressor	$7.02	$ 561.60	
80	hrs, Equipment Charge, Dump Truck	$40.98	$ 3,278.40	
40	hrs, Equipment Charge, Tractor and Trailer	$40.98	$ 1,639.20	
8	hrs, Equipment Charge, Strawblower	$6.82	$ 54.56	
1	lot, Contractor consumables, safety supplies, misc. materials	$1,000.00	$ 1,000.00	
16	crew hrs, NDT Contractor Expense	$80.00	$ 1,280.00	
500	miles, NDT Contractor Travel Expense	$0.85	$ 425.00	
1	lot, NDT Contractor Material Expense	$280.00	$ 280.00	
	Subtotal =		$ 35,835.40	
	G & A Overheads =		$ 358.35	
	Total Contract Labor =			$ 36,193.75
MISCELLANEOUS				
6	IBEW 2100 Meal Tickets	$6.00	$ 36.00	
630	mscf, lost gas during blowdowns	$12.00	$ 7,560.00	
1	lot, Construction Debris Disposal	$500.00	$ 500.00	
1	lot, PCB Analysis	$50.00	$ 50.00	
1	lot, Asbestos Pipe Disposal.	$1,200.00	$ 1,200.00	
	Subtotal =		$ 9,346.00	
	G & A Overheads =		$ 93.46	
	Total Miscellaneous =			$ 9,439.46
	Subtotal =			$ 55,920.82
	8% LOCAL ENGINEERING =			$ 4,473.67
	10% CONTINGENCY =			$ 5,592.08
	TOTAL PROJECT COSTS =			**$ 65,986.57**

Assumptions:

1. T&E charges are based upon 20% of Company Labor Charges.
2. Local Engineering will cover LG&E supervision labor and is based upon 8% of the total project subtotal.
3. BU Capital overheads are assumed to be 96.405% of base labor.
4. Assume that disposal is required for asbestos pipe coating.
5. Assume that there are no disposal costs for PCB contamination or any other hazardous materials.
6. The 12" and 16" Doe Run Lines, the 3 - 12" Storage Field Gathering Mains, and the 12" Distribution Main will be abandoned in place. Ignore all customer service requirement issues. Assume service will be provided via another means.
7. Assume there will be no scrap value from the recovered pipe, valves and fittings.

Estimated by S. A. Beatty, 10/13/05

Wiseman, Sara

From: Miller, Jon
Sent: Monday, September 26, 2005 5:15 PM
To: Legler, Steve; Charnas, Shannon; Riggs, Eric; Kremer, Dan; Turner, Steven; Crutcher, Tom; Fraley, Jeffrey; Pence, Mark; Kinder, Debra; Jackson, Fred; Carr, Sam; Baker, Bryan; Cook, Dave; Cecil, Ray; Cosby, David; Wiseman, Sara
Subject: RE: FIN-47

Attachments: FW: Asbestos bids

Attached is a file that contains a template for calculating the cost of Asbestos removal. The following tabs are included in the file:

Potential Items List: Contains a list of items that may contain asbestos, based on input from Ray Cecil at Mill Creek and various other individuals.
All-In Cost: The calculation template modeled after the Facilities template using the Ghent cost for asbestos removal and disposal.
Ghent: The removal and disposal costs provided by Fred Jackson of Ghent.
Cost by Function: The Facilities model that uses a bottoms up approach to calculating the the removal cost and disposal cost separately.
Other Assumptions: Assumptions used by Facilities.

I'm also attaching the Incorp and NEC estimates from Brown.

Please review this information prior to our meeting tomorrow afternoon.

Jon

FW: Asbestos bids

From: Legler, Steve
Sent: Monday, September 26, 2005 4:29 PM
To: Miller, Jon; Charnas, Shannon; Riggs, Eric; Kremer, Dan; Turner, Steven; Crutcher, Tom; Fraley, Jeffrey; Pence, Mark; Kinder, Debra; Jackson, Fred; Carr, Sam; Baker, Bryan
Subject: FW: FIN-47

All,

Dan Kremer asked that I put together a methodology for determining FIN-47 asbestos abatement costs. I have attached details of my approach as well as an estimate from National Environmental Contracting for this type work.

Feel free to contact me if you have questions.

Steve Legler
449-8844

<< File: FIN-47 Abatement Methodolgy.doc >> << File: LG&E KU 100 Meg Budget.pdf >>

From: Kremer, Dan
Sent: Thursday, September 22, 2005 2:35 PM
To: Legler, Steve
Cc: Turner, Steven
Subject: FIN-47

Steve, the conference call went fairly smooth from my viewpoint. They liked the approach that we used to come up with our asbestos estimates but Shannon says we need to provide more details as to how the numbers were developed. They want to use our approach and send to the other plants to possibly use the same method to calculate their costs. They would like to be consistent across the plants on how we arrive at the figures so that when the auditors come in they see the same methodology being used.

They asked that you put together the step-by-step approach that you took to get our numbers. This can be a list of bullet points or simply a narrative that will be attached to the cost spreadsheet. Start with the estimate provided by NEC along with as much detail of how they arrived at their cost estimate. Then explain how you then adjusted for known abatement on other units etc. I believe what you need to give then is basically a documentation of the conversation you and I had earlier on your approach. If you have the written quotes from NEC, include them also.

Once you put this document together please send it to everyone that was included on the distribution list for the conference call plus David Cosby. They are hoping to get something from you tomorrow if possible.

Shannon or Jon will be setting up a follow-up conference call Tuesday or Wednesday of next week to see if there are any questions, issues or problems. Target date for getting the information to Shannon is September 30 or possibly 1-2 days into October but no later.

Since I will be out of the office tomorrow, I would suggest calling Shannon if you have any questions or are unsure about what to do.

Dan Kremer
Manager Commercial Operations
Cane Run Station
(502) 449-8808
dan.kremer@lgeenergy.com

Wiseman, Sara

From: Carr, Sam
Sent: Monday, September 26, 2005 1:03 PM
To: Miller, Jon
Subject: FW: Asbestos bids

Attachments: K-070503 (KU-Brown) AB Abate 100 MegWatt Unit July05.htm; Asbestos Budget Number for unit retirement.pdf

Jon,

FYI - In case there is interest from the other plants, attached are the prior bids that Brown received from Incorp and NEC for asbestos abatement work.

Sam

From: Sarantakos, Constantine
Sent: Monday, September 26, 2005 7:47 AM
To: Carr, Sam
Subject: RE: Asbestos bids

The bids are linear of megawatt per dollar

K-070503 J-Brown) AB Abate : Asbestos Budget Number for un...

From: Carr, Sam
Sent: Friday, September 23, 2005 10:51 AM
To: Sarantakos, Constantine
Subject: Asbestos bids

Deano,

Do you have information on asbestos abatement estimates for the plant? Jeff indicated that you had received bids from Incorp or NEC on the costs for full unit abatement associated with retirement of the plant.

Sam

From: Carla [carla@incorpinc.net]
Sent: Wednesday, July 13, 2005 11:50 AM
To: Sarantakos, Constantine
Cc: bryon@incorpinc.net
Subject: K-070503 (KU-Brown) AB Abate 100 MegWatt Unit July05

July 12, 2005
K-070503

Kentucky Utilities Company
EW Brown Generating Station
815 Dix Dam Road
Harrodsburg, KY 40330

Attention: Mr. Deano Sarantakos

Subject: Asbestos Abatement 100 Meg Watt Unit

INCORP, Inc. is pleased to submit budget cost to abate one Kentucky Utilities 100 Meg Watt boiler. The below budget cost also includes critical piping, turbine miscellaneous piping, ductwork and building heat system.

Total:	**$ 1,080,000.00**	
Asbestos Abatement:	**$ 104,000.00**	**Critical Piping**
Asbestos Abatement:	**$ 420,000.00**	**Boiler**
Asbestos Abatement:	**$ 97,000.00**	**Turbine Misc. Piping**
Asbestos Abatement:	**$ 397,000.00**	**Ductwork**
Asbestos Abatement:	**$ 62,000.00**	**Building Heat Piping**

Clarifications:

- Price includes labor, material, equipment and supervision.
- Price includes state notification and engineering designer costs.
- Price includes air monitoring, disposal and landfill costs.
- Price includes scaffold rental and E/D labor costs.
- Price does not include internal boiler areas or systems outside the boiler enclosure area.
- Price is based on all non-essential equipment being removed prior to abatement activities.
- Price is based on standard shift, Monday-Friday, 10 hours per day.

INCORP appreciates the opportunity to be of service and if you should require additional information, please give us a call.

Sincerely,

Bryon C. Cowan

Bryon C. Cowan
Project Manager

As quoted above
Net 30 days

National Environmental Contracting, Inc.
2660 Technology Drive • Louisville, KY 40299-6424
Office: 502.261.0800
800.650.8893 • Fax: 502.261.0828

Estimate Cost for Asbestos Abatement of a Typical 100 MW Coal Fired Unit

Penthouse	300 ManDays @ $500.00 Per Day	$150,000.00
External Furnace (incl. Reheat Sect.)	1500 ManDays @ $500.00 Per Day	$750,000.00
External Piping (Oper. Floor Up)	500 ManDays @ $500.00 Per Day	$250,000.00
External Ductwork (Oper. Floor Up)	400 ManDays @ $500.00 Per Day	$200,000.00
Pipe & Equipment Under Oper. Floor	600 ManDays @ $500.00 Per Day	$300,000.00
Pipe & Equipment Under Oper. Floor	300 ManDays @ $500.00 Per Day	$150,000.00
Survey, Air Testing, Permits, etc.		$100,000.00
Contingency (Boiler Internals, Refractory, Unforseen)		$400,000.00
ESTIMATED TOTAL COST (in 2005 $$)		**$2,300,000.00**

Wiseman, Sara

From: Jessee, Tom
Sent: Monday, September 26, 2005 4:10 PM
To: Kinder, Debra
Cc: Wiseman, Sara; Charnas, Shannon; Riggs, Eric
Subject: RE: Identifying Asbestos Removal and Disposal Liabilities

Below is a response I gave to Pam McDonald to essentially the same question. I don't have any historical abatement information to go by, Environmental might. I can tell you abestos is not frequently encountered and I would not expect to have significant liabilities in the future. But I can't say it's zero.

"There is potential for asbestos to be in roofs, floor tiles and wire insulation. We deal with asbestos on a case by case basis and there has not been a comprehensive review of substations to identify where asbestos exists. Without physically taking samples and performing testing, it is not possible to definitively answer Eric's request. I believe it's safe to assume that the majority of control house roofs in LG&E's service territory have been replaced and don't contain asbestos, but I can't say that there are none. We do occasionally come across asbestos control wiring and floor tile but not frequently.

As far as KU goes, distribution substations typically do not have control houses. The transmission substations typically have metal control buildings with sealed concrete floors. Asbestos issues in KU subs will be limited primarily to old wire insulation. But, as at LG&E, I'm unaware of any comprehensive review that could identify locations where asbestos is known to exist."

Tom

From: Kinder, Debra
Sent: Monday, September 26, 2005 3:54 PM
To: Jessee, Tom
Cc: Wiseman, Sara; Charnas, Shannon; Riggs, Eric
Subject: Identifying Asbestos Removal and Disposal Liabilities

Tom,

It is necessary for us to identify all sources of asbestos and estimate the current value of removal and disposal costs associated with assets containing asbestos in order to comply with FIN 47 (FASB Interpretation No. 47) which encompasses all legal retirement obligations. Do our distribution substations contain asbestos insulation, roofing, siding, or other sources? If so, do you have historical abatement information that could be used to estimate current removal and disposal liabilities of contaminated assets? I would appreciate a quick response regarding your thoughts on this issue as we need to report our findings to E.ON relatively soon. If there are details we need to discuss I will set up a meeting this week.

Thanks for your help,
Debbie

Wiseman, Sara

From: Beatty, Stephen
Sent: Monday, September 26, 2005 6:11 PM
To: Kinder, Debra; Walker, Barry
Cc: Wiseman, Sara; Charnas, Shannon; Riggs, Eric
Subject: RE: Identifying Asbestos Removal and Disposal Liabilities

Debra:

The gas plants have ACM and I cannot speak for the City Gates. I suggest talking to Mark Satkamp regarding city gates.

Muldraugh should have the disposal records but I don't know exactly what you want. If you set up a meeting include David Harmeling. If you want to include Magnolia, include John Skaggs.

Steve

From: Kinder, Debra
Sent: Monday, September 26, 2005 4:11 PM
To: Walker, Barry; Beatty, Stephen
Cc: Wiseman, Sara; Charnas, Shannon; Riggs, Eric
Subject: Identifying Asbestos Removal and Disposal Liabilities

Steve,

It is necessary for us to identify all sources of asbestos and estimate the current value of removal and disposal costs associated with assets containing asbestos in order to comply with FIN 47 (FASB Interpretation No. 47) which encompasses all legal retirement obligations. Do our gas plants or city gates contain asbestos insulation, roofing, siding, or other sources? If so, do you have historical abatement information that could be used to estimate current removal and disposal liabilities of contaminated assets? I would appreciate a quick response regarding your thoughts on this issue as we need to report our findings to E.ON relatively soon. If there are details we need to discuss I will set up a meeting this week.

Thanks for your help,
Debbie

Debra A. Kinder
Property Accounting Analyst
Louisville Gas & Electric
(502) 627-3369

Kinder, Debra

From: Kremer, Dan
Sent: Tuesday, September 27, 2005 3:31 PM
To: Miller, Jon; Charnas, Shannon; Riggs, Eric; Kremer, Dan; Turner, Steven; Crutcher, Tom; Fraley, Jeffrey; Pence, Mark; Kinder, Debra; Jackson, Fred; Carr, Sam; Baker, Bryan
Subject: FW: FIN-47_2.xls

Attachments: FIN-47_2.xls

Here is the latest file that Steve put together.

Dan Kremer
Manager Commercial Operations
Cane Run Station
(502) 449-8808
dan.kremer@lgeenergy.com

From: Kremer, Dan
Sent: Tuesday, September 27, 2005 1:42 PM
To: Charnas, Shannon; Miller, Jon
Cc: Turner, Steven; Legler, Steve
Subject: FW: FIN-47_2.xls

Here is the latest spreadsheet that Steve Legler put together for FIN-47. Basically he received a quote form NEC to abate CR1 (100MW) unit that has had virtually no asbestos removed from the unit. The cost to abate a 200 MW unit as compared to a 100 MW unit would not be twice the cost. NEC estimates that for every increase of 25 MW the cost would increase 15% above the cost to abate a 100 MW unit. What Steve did on the CR units is started with a base cost of $2.3 million. He then added a multiple based upon the 15% for every 25 MW increase. From this new total he adjusted each unit for known asbestos removal already completed and for additional pieces of equipment that were not on the 100 MW unit. Steve made comments as to what he added or deleted from the estimate next to each area being abated.

Hope this helps and/or provides more information as to how he came up with the forecast. We can discuss further this afternoon if necessary. Unfortunately Steve is out of the office again this afternoon so he will not participate in our meeting.

Dan Kremer
Manager Commercial Operations
Cane Run Station
(502) 449-8808
dan.kremer@lgeenergy.com

From: Legler, Steve
Sent: Tuesday, September 27, 2005 11:31 AM
To: Kremer, Dan
Subject: FIN-47_2.xls

FIN-47_2.xls

The latest.

FIN-47 ASBESTOS REMOVAL ESTIMATE METHODOLOGY

National Environmental Contracting (NEC) provided an asbestos abatement estimate to remove all asbestos containing material from a typical 100MW coal fired unit. This estimate was based on their familiarization of similar sized units such as CR1 & 2, BR1, and units at Paddy's Run,

I have detailed below how I arrived at the FIN-47 removal numbers for Cane Run. Using NEC's estimate as a base, I adjusted the sub-totals to match specific Cane Run unit size, equipment configuration, and known asbestos location.

Cane Run Unit 1 – 100 MW

- **Penthouse – $150k** - Full enclosure of penthouse. All headers, walls, floor, drum all require abatement.
- **External Furnace - $750k** — Removal of asbestos block from boiler wall. Block located between tube refractory and outer metal casing.
- **Piping, External - Operating Floor up – $250k** - High energy, sootblower, heater extraction, downcomers, etc.
- **Pipe and Equipment, below Operating floor - $400k** – Adder of $250k to cover all FW heaters, turbine, mills, condenser, heater extraction pipe, etc.
- **Ductwork, Equipment, Operating floor up - $300k** – Air heater, side headers, Air/Gas ductwork, windbox, ash hoppers, deaerator heater and storage tank, fans, precipitator.
- **Ductwork, under Operating floor - $200k** – Air Duct, PA Duct.
- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $400k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces, refractory, additional contingency for difficulty of removing boiler furnace block insulation.
- **Coal Handling - $150k** – Transite siding removal $60k, scaffolding to access siding, $90k.

Cane Run Unit 2 – 100 MW

- **Penthouse – $150k** - Full enclosure of penthouse. All headers, walls, floor, drum all require abatement.
- **External Furnace - $750k** — Removal of asbestos block from boiler wall. Block located between tube refractory and outer metal casing.
- **Piping, External - Operating Floor up – $250k** - High energy, sootblower, heater extraction, downcomers, etc.
- **Pipe and Equipment, below Operating floor - $400k** – Adder of $250k to cover all FW heaters, turbine, mills, condenser, heater extraction pipe, etc.
- **Ductwork, Equipment, Operating floor up - $300k** – Air Heater, side headers, Air/Gas ductwork, windbox, ash hoppers, deaerator heater and storage tank, fans, precipitator.
- **Ductwork, under Operating floor - $200k** – Air Duct, PA Duct.
- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $400k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces, refractory, additional contingency for difficulty of removing boiler furnace block insulation.

Cane Run Unit 3 – 125 MW

- **Penthouse – $150k** - Full enclosure of penthouse. All headers, walls, floor, drum all require abatement.
- **External Furnace - $850k** — Removal of asbestos block from boiler wall. Block located between tube refractory and outer metal casing.
- **Piping, External - Operating Floor up – $250k** - High energy, sootblower, heater extraction, downcomers, etc.
- **Pipe and Equipment, below Operating floor - $400k** – Adder of $250k to cover all FW heaters, turbine, mills, heater extraction pipe, condenser, etc.
- **Ductwork, Equipment, Operating floor up - $300k** – Air Heater, side headers, Air/Gas ductwork, windbox, ash hoppers, deaerator heater and storage tank, fans, precipitator.
- **Ductwork, under Operating floor - $200k** – Air Duct, PA Duct.

- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $450k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces, refractory, additional contingency for difficulty of removing boiler furnace block insulation.

Cane Run Unit 4 – 170 MW

- **Penthouse – $150k** – Only walls, floor, and drum require abatement. Headers abated.
- **External Furnace - $900k** — Removal of asbestos block from boiler wall. Block located between tube refractory and outer metal casing.
- **Piping, External - Operating Floor up – $150k** - Sootblower, heater extraction, downcomers, other. High Energy Piping abated.
- **Pipe and Equipment, below Operating floor - $300k** – Adder of $100k to cover Gas Recirculating Fan, Condenser. FW heaters, mills, turbine, high energy piping abated.
- **Ductwork, Equipment, Operating floor up - $500k** – Air Heater, side headers, Air/Gas ductwork, windbox, ash hoppers, deaerator storage tank. Deaerator heater, steam coils, precipitator, large portions of duct, fans abated.
- **Ductwork, under Operating floor - $350k** – Air Duct, PA Duct.
- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $300k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces, refractory.

Cane Run Unit 5 – 181 MW

- **Penthouse – $100k** – Only floor and drum require abatement. Headers abated.
- **External Furnace - $500k** — Removal of asbestos mud from seams of mineral wool blankets. Large portions of furnace insulation already abated.
- **Piping, External - Operating Floor up – $150k** - Sootblower, heater extraction, downcomers, other. High Energy Piping abated.
- **Pipe and Equipment, below Operating floor - $200k** – Fans, condenser, economizer hoppers, heater extraction pipe. FW heaters, mills, turbine, steam coils abated.
- **Ductwork, Equipment, Operating floor up - $500k** – Air/Gas ductwork, windbox, ash hoppers, deaerator storage tank. Deaerator heater, precipitator, large portions of duct, fans abated.
- **Ductwork, under Operating floor - $300k** – Air/Gas duct.
- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $300k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces.

Cane Run Unit 6 – 260 MW

- **Penthouse – $150k** – Only floor and drum require abatement. Headers abated.
- **External Furnace - $200k** — Removal of asbestos from dead air spaces, mud at backpass transition to duct.
- **Piping, External - Operating Floor up – $250k** - Sootblower, downcomers, other. High Energy Piping abated.
- **Pipe and Equipment, below Operating floor - $300k** – Fans, condenser, duct hoppers, heater extraction pipe. FW heaters, mills, turbine abated.
- **Ductwork, Equipment, Operating floor up - $700k** – Air/Gas ductwork, windbox, ash hoppers, deaerator storage tank.
- **Ductwork, under Operating floor - $400k** – Air/Gas duct.
- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $400k** – Wiring, Bunker room piping, Turbine/Boiler room roofs.

National Environmental Contracting, Inc.
2660 Technology Drive • Louisville, KY 40299-6424
Office: 502.261.0800
800.650.8893 • Fax: 502.261.0828

Estimate Cost for Asbestos Abatement of a Typical 100 MW Coal Fired Unit

Penthouse	300 ManDays @ $500.00 Per Day	$150,000.00
External Furnace (incl. Reheat Sect.)	1500 ManDays @ $500.00 Per Day	$750,000.00
External Piping (Oper. Floor Up)	500 ManDays @ $500.00 Per Day	$250,000.00
External Ductwork (Oper. Floor Up)	400 ManDays @ $500.00 Per Day	$200,000.00
Pipe & Equipment Under Oper. Floor	600 ManDays @ $500.00 Per Day	$300,000.00
Pipe & Equipment Under Oper. Floor	300 ManDays @ $500.00 Per Day	$150,000.00
Survey, Air Testing, Permits, etc.		$100,000.00
Contingency (Boiler Internals, Refractory, Unforseen)		$400,000.00
ESTIMATED TOTAL COST (in 2005 $$)		**$2,300,000.00**

Kinder, Debra

From: Charnas, Shannon
Sent: Tuesday, September 27, 2005 9:21 AM
To: Kinder, Debra
Subject: RE: Identifying Asbestos Removal and Disposal Liabilities

Debbie-

Are you going to talk to Mark and John?

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Kinder, Debra
Sent: Tuesday, September 27, 2005 8:39 AM
To: Wiseman, Sara; Charnas, Shannon; Riggs, Eric
Subject: FW: Identifying Asbestos Removal and Disposal Liabilities

---

From: Walker, Barry
Sent: Tuesday, September 27, 2005 8:16 AM
To: Kinder, Debra
Cc: Satkamp, Mark; Skaggs, John; Beatty, Stephen
Subject: RE: Identifying Asbestos Removal and Disposal Liabilities

Debra,

I recommend that you contact Mark Satkamp and John Skaggs as we have asbestos issues in both their areas of responsibility in addition to Steve Beatty's area of responsibility. You probably need to set up a meeting with either the managers or their designated employees to discuss the accuracy of the estimates, the level of supporting details, and the time frame that the estimates are needed. To develop an accurate estimate for the compressor stations it would take considerable engineering analysis and estimating.

Barry Walker
Director, Gas Storage, Control & Compliance
Louisville Gas and Electric Company
820 West Broadway
Louisville, KY 40202
502-627-3038 Office
502-627-3699 Fax
barry.walker@lgeenergy.com

From: Kinder, Debra
Sent: Monday, September 26, 2005 4:11 PM
To: Walker, Barry; Beatty, Stephen
Cc: Wiseman, Sara; Charnas, Shannon; Riggs, Eric
Subject: Identifying Asbestos Removal and Disposal Liabilities

Steve,

It is necessary for us to identify all sources of asbestos and estimate the current value of removal and disposal costs associated with assets containing asbestos in order to comply with FIN 47 (FASB Interpretation No. 47) which encompasses all legal retirement obligations. Do our gas plants or city gates contain asbestos insulation, roofing, siding, or other sources? If so, do you have historical abatement information that could be used to estimate current removal and disposal liabilities of contaminated assets? I would appreciate a quick response regarding your thoughts on this issue as we need to report our findings to E.ON relatively soon. If there are details we need to discuss I will set up a meeting this week.

Thanks for your help,
Debbie

Debra A. Kinder
Property Accounting Analyst
Louisville Gas & Electric
(502) 627-3369

Wiseman, Sara

From: Kinder, Debra
Sent: Tuesday, September 27, 2005 4:10 PM
To: Wiseman, Sara
Subject: FW: FIN-47

Attachments: FIN-47 Abatement Methodolgy.doc; LG&E KU 100 Meg Budget.pdf

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From: Legler, Steve
Sent: Monday, September 26, 2005 4:29 PM
To: Miller, Jon; Charnas, Shannon; Riggs, Eric; Kremer, Dan; Turner, Steven; Crutcher, Tom; Fraley, Jeffrey; Pence, Mark; Kinder, Debra; Jackson, Fred; Carr, Sam; Baker, Bryan
Subject: FW: FIN-47

All,

Dan Kremer asked that I put together a methodology for determining FIN-47 asbestos abatement costs. I have attached details of my approach as well as an estimate from National Environmental Contracting for this type work.

Feel free to contact me if you have questions.

Steve Legler
449-8844

FIN-47 Abatement Methodolgy.do... LG&E KU 100 Meg Budget.pdf

From: Kremer, Dan
Sent: Thursday, September 22, 2005 2:35 PM
To: Legler, Steve
Cc: Turner, Steven
Subject: FIN-47

Steve, the conference call went fairly smooth from my viewpoint. They liked the approach that we used to come up with our asbestos estimates but Shannon says we need to provide more details as to how the numbers were developed. They want to use our approach and send to the other plants to possibly use the same method to calculate their costs. They would like to be consistent across the plants on how we arrive at the figures so that when the auditors come in they see the same methodology being used.

They asked that you put together the step-by-step approach that you took to get our numbers. This can be a list of bullet points or simply a narrative that will be attached to the cost spreadsheet. Start with the estimate provided by NEC along with as much detail of how they arrived at their cost estimate. Then explain how you then adjusted for known abatement on other units etc. I believe what you need to give then is basically a documentation of the conversation you and I had earlier on your approach. If you have the written quotes from NEC, include them also.

Once you put this document together please send it to everyone that was included on the distribution list for the conference call plus David Cosby. They are hoping to get something from you tomorrow if possible.

Shannon or Jon will be setting up a follow-up conference call Tuesday or Wednesday of next week to see if there are any questions, issues or problems. Target date for getting the information to Shannon is September 30 or possibly 1-2 days into October but no later.

Since I will be out of the office tomorrow, I would suggest calling Shannon if you have any questions or are unsure about what to do.

Dan Kremer
Manager Commercial Operations
Cane Run Station
(502) 449-8808
dan.kremer@lgeenergy.com

Wiseman, Sara

From:	Kinder, Debra
Sent:	Tuesday, September 27, 2005 9:13 AM
To:	Toll, Michael
Cc:	Wiseman, Sara; Charnas, Shannon; Riggs, Eric
Subject:	Identifying Asbestos Disposal and Removal Liabilities

Mike,

It is necessary for us to identify all sources of asbestos and estimate the current value of removal and disposal costs associated with assets containing asbestos in order to comply with FIN 47 (FASB Interpretation No. 47) which encompasses all legal retirement obligations. Do our transmission substations contain asbestos insulation, roofing, siding, or other sources? If so, do you have historical abatement information that could be used to estimate current removal and disposal liabilities of contaminated assets? I would appreciate a quick response regarding your thoughts on this issue as we need to report our findings to E.ON relatively soon. If there are details we need to discuss I will set up a meeting this week.

Thanks for your help,
Debbie

Debra A. Kinder
Property Accounting Analyst
Louisville Gas & Electric
(502) 627-3369

Wiseman, Sara

From: Kinder, Debra
Sent: Tuesday, September 27, 2005 8:39 AM
To: Wiseman, Sara; Charnas, Shannon; Riggs, Eric
Subject: FW: Identifying Asbestos Removal and Disposal Liabilities

---

From: Walker, Barry
Sent: Tuesday, September 27, 2005 8:16 AM
To: Kinder, Debra
Cc: Satkamp, Mark; Skaggs, John; Beatty, Stephen
Subject: RE: Identifying Asbestos Removal and Disposal Liabilities

Debra,

I recommend that you contact Mark Satkamp and John Skaggs as we have asbestos issues in both their areas of responsibility in addition to Steve Beatty's area of responsibility. You probably need to set up a meeting with either the managers or their designated employees to discuss the accuracy of the estimates, the level of supporting details, and the time frame that the estimates are needed. To develop an accurate estimate for the compressor stations it would take considerable engineering analysis and estimating.

Barry Walker
Director, Gas Storage, Control & Compliance
Louisville Gas and Electric Company
820 West Broadway
Louisville, KY 40202
502-627-3038 Office
502-627-3699 Fax
barry.walker@lgeenergy.com

From: Kinder, Debra
Sent: Monday, September 26, 2005 4:11 PM
To: Walker, Barry; Beatty, Stephen
Cc: Wiseman, Sara; Charnas, Shannon; Riggs, Eric
Subject: Identifying Asbestos Removal and Disposal Liabilities

Steve,

It is necessary for us to identify all sources of asbestos and estimate the current value of removal and disposal costs associated with assets containing asbestos in order to comply with FIN 47 (FASB Interpretation No. 47) which encompasses all legal retirement obligations. Do our gas plants or city gates contain asbestos insulation, roofing, siding, or other sources? If so, do you have historical abatement information that could be used to estimate current removal and disposal liabilities of contaminated assets? I would appreciate a quick response regarding your thoughts on this issue as we need to report our findings to E.ON relatively soon. If there are details we need to discuss I will set up a meeting this week.

Thanks for your help,
Debbie

Debra A. Kinder
Property Accounting Analyst

Louisville Gas & Electric
(502) 627-3369

Kinder, Debra

From: Satkamp, Mark
Sent: Wednesday, September 28, 2005 10:42 AM
To: Kinder, Debra
Cc: Collins, Mike; Lawson, William
Subject: RE: Identifying Asbestos Removal and Disposal Liabilities

Debra,

Some of the buildings at our city gate and large regulator stations are believed to have fiberboard inside the buildings which contains asbestos. We are not sure about the roofs. We think we have about 13 interior rooms with this type of fiberboard. We have not abated the walls from these types of buildings before and therefore don't know what the costs would be. A lot of costs would be associated with temporarily relocating all of our equipment from the buildings while the abatement work was being completed, or constructing new buildings and permanently relocating our equipment. I would guess that it could cost $50k or more per room for this type of work to be completed. Also, we have one heater at the Doe Run city gate station with asbestos insulation. I would guess that it might cost $50k to abate the heater insulation, or it might make sense to replace the heater for around $150k. Please note that these numbers would be considered very rough estimates as detailed work scopes to complete this type of work have not been completed.

Thanks,

Mark Satkamp
Manager, Gas Control
502-627-3135 Office

From: Kinder, Debra
Sent: Tuesday, September 27, 2005 10:53 AM
To: Satkamp, Mark; Skaggs, John; Harmeling, Dave
Cc: Wiseman, Sara; Riggs, Eric; Charnas, Shannon
Subject: Identifying Asbestos Removal and Disposal Liabilities

All,

It is necessary for us to identify all sources of asbestos and estimate the current value of removal and disposal costs associated with assets containing asbestos in order to comply with FIN 47 (FASB Interpretation No. 47) which encompasses all legal retirement obligations. Do our gas plants or city gates contain asbestos insulation, roofing, siding, or other sources? If so, do you have historical abatement information that could be used to estimate current removal and disposal liabilities of contaminated assets? I would appreciate a quick response regarding your thoughts on this issue as we need to report our findings to E.ON relatively soon. It is becoming apparent that I will need to schedule a meeting this week to facilitate the gathering of needed data. Can any of you suggest other individuals that could contribute to this discussion?

Thanks for your help,
Debbie

Debra A. Kinder
Property Accounting Analyst
Louisville Gas & Electric
(502) 627-3369

Wiseman, Sara

From: Kinder, Debra
Sent: Wednesday, September 28, 2005 10:47 AM
To: Wiseman, Sara; Charnas, Shannon; Riggs, Eric
Subject: FW: Identifying Asbestos Removal and Disposal Liabilities

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From: Satkamp, Mark
Sent: Wednesday, September 28, 2005 10:42 AM
To: Kinder, Debra
Cc: Collins, Mike; Lawson, William
Subject: RE: Identifying Asbestos Removal and Disposal Liabilities

Debra,

Some of the buildings at our city gate and large regulator stations are believed to have fiberboard inside the buildings which contains asbestos. We are not sure about the roofs. We think we have about 13 interior rooms with this type of fiberboard. We have not abated the walls from these types of buildings before and therefore don't know what the costs would be. A lot of costs would be associated with temporarily relocating all of our equipment from the buildings while the abatement work was being completed, or constructing new buildings and permanently relocating our equipment. I would guess that it could cost $50k or more per room for this type of work to be completed. Also, we have one heater at the Doe Run city gate station with asbestos insulation. I would guess that it might cost $50k to abate the heater insulation, or it might make sense to replace the heater for around $150k. Please note that these numbers would be considered very rough estimates as detailed work scopes to complete this type of work have not been completed.

Thanks,

Mark Satkamp
Manager, Gas Control
502-627-3135 Office

From: Kinder, Debra
Sent: Tuesday, September 27, 2005 10:53 AM
To: Satkamp, Mark; Skaggs, John; Harmeling, Dave
Cc: Wiseman, Sara; Riggs, Eric; Charnas, Shannon
Subject: Identifying Asbestos Removal and Disposal Liabilities

All,

It is necessary for us to identify all sources of asbestos and estimate the current value of removal and disposal costs associated with assets containing asbestos in order to comply with FIN 47 (FASB Interpretation No. 47) which encompasses all legal retirement obligations. Do our gas plants or city gates contain asbestos insulation, roofing, siding, or other sources? If so, do you have historical abatement information that could be used to estimate current removal and disposal liabilities of contaminated assets? I would appreciate a quick response regarding your thoughts on this issue as we need to report our findings to E.ON relatively soon. It is becoming apparent that I will need to schedule a meeting this week to facilitate the gathering of needed data. Can any of you suggest other individuals that could contribute to this discussion?

Thanks for your help,
Debbie

Debra A. Kinder
Property Accounting Analyst
Louisville Gas & Electric
(502) 627-3369

Wiseman, Sara

From: Charnas, Shannon
Sent: Wednesday, September 28, 2005 9:51 PM
To: Kinder, Debra; Wiseman, Sara; Riggs, Eric
Subject: RE: Identifying Asbestos Removal and Disposal Liabilities

I haven't seen a meeting notice yet to get with the substation, Distribution, gas, & city gate group. I assume that we still need to have one. Would it be possible to get that set up for Thursday, we are running out of time.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Kinder, Debra
Sent: Wednesday, September 28, 2005 10:47 AM
To: Wiseman, Sara; Charnas, Shannon; Riggs, Eric
Subject: FW: Identifying Asbestos Removal and Disposal Liabilities

---

From: Satkamp, Mark
Sent: Wednesday, September 28, 2005 10:42 AM
To: Kinder, Debra
Cc: Collins, Mike; Lawson, William
Subject: RE: Identifying Asbestos Removal and Disposal Liabilities

Debra,

Some of the buildings at our city gate and large regulator stations are believed to have fiberboard inside the buildings which contains asbestos. We are not sure about the roofs. We think we have about 13 interior rooms with this type of fiberboard. We have not abated the walls from these types of buildings before and therefore don't know what the costs would be. A lot of costs would be associated with temporarily relocating all of our equipment from the buildings while the abatement work was being completed, or constructing new buildings and permanently relocating our equipment. I would guess that it could cost $50k or more per room for this type of work to be completed. Also, we have one heater at the Doe Run city gate station with asbestos insulation. I would guess that it might cost $50k to abate the heater insulation, or it might make sense to replace the heater for around $150k. Please note that these numbers would be considered very rough estimates as detailed work scopes to complete this type of work have not been completed.

Thanks,

Mark Satkamp
Manager, Gas Control
502-627-3135 Office

From: Kinder, Debra
Sent: Tuesday, September 27, 2005 10:53 AM
To: Satkamp, Mark; Skaggs, John; Harmeling, Dave
Cc: Wiseman, Sara; Riggs, Eric; Charnas, Shannon
Subject: Identifying Asbestos Removal and Disposal Liabilities

All,

It is necessary for us to identify all sources of asbestos and estimate the current value of removal and disposal costs associated with assets containing asbestos in order to comply with FIN 47 (FASB Interpretation No. 47) which encompasses all legal retirement obligations. Do our gas plants or city gates contain asbestos insulation, roofing, siding, or other sources? If so, do you have historical abatement information that could be used to estimate current removal and disposal liabilities of contaminated assets? I would appreciate a quick response regarding your thoughts on this issue as we need to report our findings to E.ON relatively soon. It is becoming apparent that I will need to schedule a meeting this week to facilitate the gathering of needed data. Can any of you suggest other individuals that could contribute to this discussion?

Thanks for your help,
Debbie

Debra A. Kinder
Property Accounting Analyst
Louisville Gas & Electric
(502) 627-3369

Kinder, Debra

From:	Skaggs, John
Sent:	Thursday, September 29, 2005 2:37 PM
To:	Kinder, Debra
Cc:	Rieth, Tom
Subject:	RE: Identifying Asbestos Removal and Disposal Liabilities

Debra,

Our original buildings here at Magnolia are made of asbestos: walls (interior & exterior), roofing, etc. In addition there is some asbestos on the piping in the gas processing facility. I think a meeting would be necessary to understand the entire scope of this project. Tom Rieth should be included, as well.

Thanks,
John
502/364-**8791**
No Compromise
Let's stay on a ROLL - over ~~1,200, . . . 1,700,~~ 1,800 days and counting
Our Behaviors: Customer Orientation, Drive for Excellent Performance, Change Initiation, Teamwork, Leadership and Diversity & Development

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From:	Kinder, Debra
Sent:	Tuesday, September 27, 2005 10:53 AM
To:	Satkamp, Mark; Skaggs, John; Harmeling, Dave
Cc:	Wiseman, Sara; Riggs, Eric; Charnas, Shannon
Subject:	Identifying Asbestos Removal and Disposal Liabilities

All,

It is necessary for us to identify all sources of asbestos and estimate the current value of removal and disposal costs associated with assets containing asbestos in order to comply with FIN 47 (FASB Interpretation No. 47) which encompasses all legal retirement obligations. Do our gas plants or city gates contain asbestos insulation, roofing, siding, or other sources? If so, do you have historical abatement information that could be used to estimate current removal and disposal liabilities of contaminated assets? I would appreciate a quick response regarding your thoughts on this issue as we need to report our findings to E.ON relatively soon. It is becoming apparent that I will need to schedule a meeting this week to facilitate the gathering of needed data. Can any of you suggest other individuals that could contribute to this discussion?

Thanks for your help,
Debbie

Debra A. Kinder
Property Accounting Analyst
Louisville Gas & Electric
(502) 627-3369

Wiseman, Sara

From: Riggs, Eric
Sent: Thursday, September 29, 2005 3:17 PM
To: Scott, Valerie
Cc: Wiseman, Sara; Kinder, Debra
Subject: ECR/ARO Assets

Valerie,

The three ECR assets that were established as ARO's in Case No. 2003-00427 were part of the 1994 ECR Plan. In regards to the ECR filings, the depreciation rate used for these assets has been the regulatory depreciation rate, not the ARO depreciation rate.

The 1994 ECR Plan has been fully incorporated into KU's base rate as part of the Commission's Order on June 30, 2004 in Case No. 2003-00434.

Thanks,
Eric Riggs

Wiseman, Sara

From: Scott, Valerie
Sent: Thursday, September 29, 2005 6:25 PM
To: Wiseman, Sara
Cc: Charnas, Shannon
Subject: FW: FIN 47 Survey Question

Sara,

Do we know the answers for these questions yet for ourselves? If so, would you give me our responses so I can forward them on?

Valerie

-----Original Message-----
From: bounce-244660-175405@ls.eei.org [mailto:bounce-244660-175405@ls.eei.org]
Sent: Thursday, September 29, 2005 10:33 AM
To: Accounting Standards Committee
Subject: FIN 47 Survey Question

To The EEI Accounting Standards Committee:
I would like to pose the following questions regarding your implementation of FIN 47 as it relates to asbestos removal. Thanks...

> Consolidated Edison Company of New York has over 400 locations that contain asbestos. For a small percentage of locations we have definite plans for asbestos removal. For most of the others, we have no current plans to remove asbestos, renovate, retire or sell the facility. There are no surveys done to determine the amount and condition of existing asbestos. In addition, we also have approximately 280,000 underground system structures with asbestos that are usually retired in place.
>
> Can you please answer the following questions:
> 1. Are you recording an ARO liability in the following circumstances:
> a. There is a current plan for asbestos abatement, sale or retirement.
> b. Asset is known to contain asbestos, but there is no current plan for abatement, sale or retirement. The amount of existing asbestos is not known.
> i. If recording an ARO liability, on what basis are you determining the amount of the future liability and;
> ii. Since there is no plan for abatement, what time period are you using for the estimated retirement date?
> c. Asset containing asbestos has already been retired in place (original cost is no longer on the books) and asbestos abatement may be done sometime in the future, although the timing is not known. The amount of existing asbestos is also not known.
> d. Underground system structures containing asbestos that are generally retired in place.
>
> 2. Did you set a materiality threshold for recording ARO> '> s? What are the factors you considered when determining materiality?
>
> 3. If you are recording an ARO for regulated utility operations, how are you calculating the asbestos removal cost in the accumulated depreciation reserve?
>
>
>

Grace Scarpitta
Consolidated Edison Company of New York
212-460-6693

You are currently subscribed to asc as: [valerie.scott@lgeenergy.com] To unsubscribe, forward this message to leave-244660-175405J@ls.eei.org

Wiseman, Sara

From: Scott, Valerie
Sent: Friday, September 30, 2005 5:19 PM
To: Wiseman, Sara
Cc: Charnas, Shannon
Subject: FW: FIN 47 Survey Question

fyi

Valerie

-----Original Message-----
From: bounce-244720-175405@ls.eei.org [mailto:bounce-244720-175405@ls.eei.org]
Sent: Friday, September 30, 2005 2:48 PM
To: Accounting Standards Committee
Subject: RE: FIN 47 Survey Question

Responses from Xcel Energy:

1. Although we are investigating the asbestos abatement issue for FIN 47 we have not reached any firm conclusions at this time.

2. We will be setting materiality thresholds, but these have not been confirmed as well.

3. For the depreciation reserve, we have segregated any regulatory recovery for asbestos removal that may be contained in our overall removal rate as approved by the commissions. This will not change if we determine we will have a conditional ARO associated with asbestos. We will layer in the ARO accounting and marry the two methods together with regulatory assets or liabilities. We maintain the two methods in separate buckets because of the need to report proper rate base using the approved regulatory recovery.

Kathy McNulty Kropp
Manager, Regulatory Accounting Policy & Reporting
Phone: (303) 294-2335
Fax: (303) 294-2422

-----Original Message-----
From: bounce-244660-33409@ls.eei.org
[mailto:bounce-244660-33409@ls.eei.org]On Behalf Of Scarpitta, Grace
Sent: Thursday, September 29, 2005 8:33 AM
To: Accounting Standards Committee
Subject: FIN 47 Survey Question

To The EEI Accounting Standards Committee:
I would like to pose the following questions regarding your implementation of FIN 47 as it relates to asbestos removal. Thanks...

> Consolidated Edison Company of New York has over 400 locations that contain asbestos. For a small percentage of locations we have definite plans for asbestos removal. For most of the others, we have no current plans to remove asbestos, renovate, retire or sell the facility. There are no surveys done to determine the amount and condition of existing asbestos. In addition, we also have approximately 280,000 underground system structures with asbestos that are usually retired in place.
>
> Can you please answer the following questions:
> 1. Are you recording an ARO liability in the following circumstances:
> a. There is a current plan for asbestos abatement, sale or retirement.
> b. Asset is known to contain asbestos, but there is no current plan for abatement, sale or retirement. The amount of existing asbestos is not known.

\> i. If recording an ARO liability, on what basis are you determining the amount of the future liability and;
\> ii. Since there is no plan for abatement, what time period are you using for the estimated retirement date?
\> c. Asset containing asbestos has already been retired in place (original cost is no longer on the books) and asbestos abatement may be done sometime in the future, although the timing is not known. The amount of existing asbestos is also not known.
\> d. Underground system structures containing asbestos that are generally retired in place.
\>
\> 2. Did you set a materiality threshold for recording ARO> '> s? What are the factors you considered when determining materiality?
\>
\> 3. If you are recording an ARO for regulated utility operations, how are you calculating the asbestos removal cost in the accumulated depreciation reserve?
\>
\>
\>

Grace Scarpitta
Consolidated Edison Company of New York
212-460-6693

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Wiseman, Sara

From: Scott, Valerie
Sent: Friday, September 30, 2005 5:20 PM
To: Wiseman, Sara
Cc: Charnas, Shannon
Subject: FW: FIN 47 Survey Question

fyi

Valerie

From: bounce-244739-175405@ls.eei.org [mailto:bounce-244739-175405@ls.eei.org]
Sent: Friday, September 30, 2005 5:10 PM
To: Accounting Standards Committee
Subject: RE: FIN 47 Survey Question

Constellation responses below.

Randall

-----Original Message-----
From: bounce-244660-189477@ls.eei.org [mailto:bounce-244660-189477@ls.eei.org] On Behalf Of Scarpitta, Grace
Sent: Thursday, September 29, 2005 10:33 AM
To: Accounting Standards Committee
Subject: FIN 47 Survey Question

To The EEI Accounting Standards Committee:

I would like to pose the following questions regarding your implementation of FIN 47 as it relates to asbestos removal. Thanks...

> Consolidated Edison Company of New York has over 400 locations that contain asbestos. For a small percentage of locations we have definite plans for asbestos removal. For most of the others, we have no current plans to remove asbestos, renovate, retire or sell the facility. There are no surveys done to determine the amount and condition of existing asbestos. In addition, we also have approximately 280,000 underground system structures with asbestos that are usually retired in place.

>

> > Can you please answer the following questions:

> 1. Are you recording an ARO liability in the following circumstances:

> a. There is a current plan for asbestos abatement, sale or retirement.

Response: We plan to record an ARO liability for asbestos removal in these cases. This applies primarily to power plants retired in place. We hired a contractor to do a walk through of these power plants containing asbestos to get a cost estimate for asbestos removal.

> b. Asset is known to contain asbestos, but there is no current plan for abatement, sale or retirement. The amount of existing asbestos is not known.

> i. If recording an ARO liability, on what basis are you determining the amount of the future liability and;

> ii. Since there is no plan for abatement, what time period are you using for the estimated retirement date?

Response: For our operating power plants that contain asbestos, we plan to record an ARO liability associated with asbestos removal. The remaining economic life of the plants is derived from impairment analyses required as well as depreciation lives, + additional years added for the period after the sites are expected to be retired in place. We hired a contractor to do a walk through of our power plants containing asbestos to get a cost estimate for asbestos removal. Our ARO liability reflects an expected PV approach. In cases where we have a third party estimate, the scenarios reflect different timing of asbestos removal. We got our generation management to sign off on the expected settlement dates.

We have a modest amount of asbestos at most of our substations constructed prior to 1981. We do not plan to retire our substations but maintain them for an indefinite period in the future. The amount of asbestos and associated cost at each facility is not known. We are conducting a limited sample study of a few representative substations to get an estimated cost for special handling and disposal of asbestos at these facilities. We would use that data to estimate the approximate cost of asbestos removal for all of our substations. Depending on the magnitude (TBD), we may or may not disclose that we have this obligation in our 10-K.

> c. Asset containing asbestos has already been retired in place (original cost is no longer on the books) and asbestos abatement may be done sometime in the future, although the timing is not known. The amount of existing asbestos is also not known.

Response: Your answer may be fine as long as you indicate what checking was done to convince yourself that the settlement date is indeterminate. See what we are doing for our retired power plants.

> d. Underground system structures containing asbestos that are generally retired in place.

> Response: We also have asbestos in underground ducts. The amount of asbestos is not known. These ducts, whether in service or retired, are retired in place. Therefore, there is no special handling and disposal cost for asbestos associated with the retirement of the ducts. We have concluded that the settlement date, if any, is indeterminate. We do not plan to disclose this in the 10-K. One could argue whether or not there is still an obligation associated with this material, but even if one is conservative and says there is, its settlement date is indeterminate.

> 2. Did you set a materiality threshold for recording ARO> '> s? What are the factors you considered when determining materiality?

Response: We have not finalized the materiality threshold but are looking at AROs as a % of net income, EPS, +++total assets, total liabilities, and long term liabilities.

>

> 3. If you are recording an ARO for regulated utility operations, how are you calculating the asbestos removal cost in the accumulated depreciation reserve?

> Response: We are assuming that the asbestos removal cost is incremental to the normal cost of removal component included in depreciation expense, so there is no offset to accumulated depreciation. The ARO for the regulated utility is a regulatory liability.

>

>

>

Grace Scarpitta

Consolidated Edison Company of New York

212-460-6693

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Wiseman, Sara

From:	Beatty, Stephen
Sent:	Friday, September 30, 2005 2:46 PM
To:	Wiseman, Sara
Subject:	RE: Identifying Asbestos Removal and Disposal Liabilities

Sara:

I have been reassigned to another meeting. Tom Rieth will be representing Barry Walker and me. I will attempt to make the second half of the meeting if my first meeting ends in time.

Sorry for the late change.

Steve

From:	Lay, Barbara **On Behalf Of** Wiseman, Sara
Sent:	Thursday, September 29, 2005 4:01 PM
To:	Wiseman, Sara; Kinder, Debra; Riggs, Eric; Charnas, Shannon; Miller, Jon; Welsh, Elaine; Sanchez, Susan; McDonald, Pam; Grant, Jerry; Kapp, Karan; Toll, Michael; Jessee, Tom; Walker, Barry; Satkamp, Mark; Skaggs, John; Beatty, Stephen; Rieth, Tom; LGEB14 South/Video
Cc:	Durbin, Tony
Subject:	Updated: Identifying Asbestos Removal and Disposal Liabilities
When:	Monday, October 03, 2005 8:30 AM-10:00 AM (GMT-05:00) Eastern Time (US & Canada).
Where:	LGE 14 South (video) Conference Room

NOTE: THE MEETING WILL BE HELD ON THE 14TH FLOOR OF THE LGE BUILDING. (14 SOUTH VIDEO CONFERENCE ROOM).

Conference Bridge #:

LGE Internal: 2526
Louisville area local call: 627-2526
North America Long Distance: 502-627-2526
North America Toll Free: 866-877-4571

Participant Code: 1892

If you are unable to attend, please send someone else in your group. Thanks.

Wiseman, Sara

From: Kapp, Karan
Sent: Friday, September 30, 2005 4:29 PM
To: Satkamp, Mark
Cc: Charnas, Shannon; Wiseman, Sara; Riggs, Eric; Kinder, Debra; Grant, Jerry
Subject: RE: Identifying Asbestos Removal and Disposal Liabilities

Attachments: ASBESTOS REMOVAL EST COSTS FOR FACILITIES.xls

I just spoke to NEC to verify a dollar amount to use for the transite walls / mastic. Neil of NEC said $3.00 + depending on the environment (warehouse, office area, etc) plus and additional 10% disposal. We are using $5.00 a sq. ft. which he said should cover most cases.

As for the other costs you mentioned, such as relocating equipment and replacement of items - I spoke to Eric Riggs the other day and we're not including any of those costs in our estimates. Only actual costs to remove and then dispose of asbestos materials.

I'm also including the spreadsheet that we're using. I don't know if it will help you or not. We sent it to NEC for them to glance over the numbers and methodology and hope to get a response back from them Monday or Tuesday to make certain we're in the ballpark with our calculations.

ASBESTOS
OVAL EST COSTS F(

From: Kinder, Debra
Sent: Friday, September 30, 2005 3:47 PM
To: Grant, Jerry; Kapp, Karan
Cc: Charnas, Shannon; Wiseman, Sara; Riggs, Eric; Satkamp, Mark
Subject: FW: Identifying Asbestos Removal and Disposal Liabilities

Jerry / Karan,

Could any of your resource materials assist with quantifying disposal for the types of contaminated assets mentioned in Marks response?

Thanks,
Debbie

From: Satkamp, Mark
Sent: Wednesday, September 28, 2005 10:42 AM
To: Kinder, Debra
Cc: Collins, Mike; Lawson, William
Subject: RE: Identifying Asbestos Removal and Disposal Liabilities

Debra,

Some of the buildings at our city gate and large regulator stations are believed to have fiberboard inside the buildings which contains asbestos. We are not sure about the roofs. We think we have about 13 interior rooms with this type of fiberboard. We have not abated the walls from these types of buildings before and therefore don't know what the costs would be. A lot of costs would be associated with temporarily relocating all of our equipment from the buildings while the abatement work was being completed, or constructing new buildings and permanently relocating our equipment. I would guess that it could cost $50k or more per room for this type of work to be completed. Also, we have one heater at the Doe Run city gate station with asbestos insulation. I would guess that it might cost $50k to abate the heater insulation, or it might make sense to replace the heater for around $150k. Please note that these numbers would be considered very rough estimates as detailed work scopes to complete this type of work have not been completed.

Thanks,

Mark Satkamp
Manager, Gas Control
502-627-3135 Office

From: Kinder, Debra
Sent: Tuesday, September 27, 2005 10:53 AM
To: Satkamp, Mark; Skaggs, John; Harmeling, Dave
Cc: Wiseman, Sara; Riggs, Eric; Charnas, Shannon
Subject: Identifying Asbestos Removal and Disposal Liabilities

All,

It is necessary for us to identify all sources of asbestos and estimate the current value of removal and disposal costs associated with assets containing asbestos in order to comply with FIN 47 (FASB Interpretation No. 47) which encompasses all legal retirement obligations. Do our gas plants or city gates contain asbestos insulation, roofing, siding, or other sources? If so, do you have historical abatement information that could be used to estimate current removal and disposal liabilities of contaminated assets? I would appreciate a quick response regarding your thoughts on this issue as we need to report our findings to E.ON relatively soon. It is becoming apparent that I will need to schedule a meeting this week to facilitate the gathering of needed data. Can any of you suggest other individuals that could contribute to this discussion?

Thanks for your help,
Debbie

Debra A. Kinder
Property Accounting Analyst
Louisville Gas & Electric
(502) 627-3369

FACILITY ASSUMPTIONS

Any Facility constructed before 1985 will have asbestos, unless abatement has been completed

SMALL BUSINESS OFFICES & OPER CTRS- L. F. is calculated based on 8% of total sq. ft. for removal of pipe & ductwork insulation @ $65/LN. FT. or SQ. FT. (Includes removal & air monitoring costs) Costs per Ln. Ftl is based on recent invoicing for work performed by NEC.

STOREROOMS - L. F. is calculated based on 3% of total sq. ft. for pipe and ductwork insulation @ $65/LN.FT. or SQ. FT. (Includes removal and air monitoring costs). Cost per Ln. Ft. is based on recent invoicing for work performed by NEC.

Cost to remove VCT is based on actual invoicing from NEC for work performed at South Service Center in 1994. The same costs were applied to removal of ceiling tiles.

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
No known asbestos remaining. Renovations have been completed removing known asbestos.	Auburndale Op Ctr	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1965. which has been renovated and there are no signs of asbestos.	Barlow	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
There are 3 wood framed, metal siding and metal roof structures with a combined total of 2,496 sq. ft. Buildings were constructed in 1970; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Barlow Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Facility constructed in 1978 and is a pre-engineered metal building on slab with 3,200 sq. ft. Office area has VCT and drop ceiling which due to age of facility may be asbestos.	Big Stone Gap Substation	$1.90	1,600	**$3,040**	$1.95	1,600	**$3,120**	$1.95	1,600	**$3,120**	$65.00	256	**$16,640**
This facility has been renovated throughout and asbestos removed during the process	Broadway Office Complex	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1957. which has been renovated but possible asbestos in roof.	Campbellsville	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
There are 3 wood framed, metal siding and metal roof structures with ~~a combined total of 6,450 sq. ft.~~ Buildings were constructed in 1960; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Campbellsville Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
The facility is a one-story metal on concrete slab structure with 555 sq. ft. constructed in 1980. No visible signs of asbestos	Carlise Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This is a 1-1/2 story brick building with 3,500 sq. ft. constructed in approx. 1970. Shingle roof system installed over original roof (could be asbestos).	Carrollton	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
One story , 2,644 sq. ft. concrete block building constructed in 1970 with 24' walls and 3 garage doors. Possible asbestos in roof.	Carrollton Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This is a 2 story facility was constructed in 1961 with 3,984 sq. ft.; an addition of 2,200 sq. ft. was added above the drive thru in approx 1980. Due to age of facility asbestos is suspected (excluding roof, which was installed in 2004).	Danville	$1.90	3,984	**$7,570**	$1.95	3,984	**$7,769**	$1.95	3,984	**$7,769**	$65.00	319	**$20,717**
This is a 10,560 sq. ft. pre-engineered metal building on a concrete slab constructed in 1998. Due to the age of the building asbestos is not suspected.	Danville Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
This is a 20,800 sq. ft. pre-engineered metal building on a ~~concrete slab constructed in 1988.~~ Due to the age of the building asbestos is not suspected.	Danville Substation & Meter Dept.	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
The building was constructed between 1975 - 1980 and consists of a wood frame with metal façade and metal roof. Total sq. ft. of 1,900 and is divided into 3 sections - truck parking, office, storage. Heating / Cooling with heat pumps approx 9 yrs. old. Due to the age of the building it may contain asbestos.	Dawson Springs Storeroom	$1.90	627	**$1,191**	$1.95	627	**$1,223**	$1.95	627	**$1,223**	$65.00		**$0**
This facility was constructed in 1970. The office building is a wood frame structure with brick façade with approx. 3,840 sq. ft. Age of the facility indicate potential asbestos.	Earlington	$1.90	3,200	**$6,080**	$1.95	3,200	**$6,240**	$1.95	3,200	**$6,240**	$65.00	256	**$16,640**
This facility has a metal office and storage building with 11,500 sq. ft. constructed in 1990. Due to the age of the building asbestos is not suspected.	Earlington-Parkway Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Bldg constructed in 1995 (approx. 25,000 sq. ft.)- Due to age of building asbestos is not suspected	Earlington-Western Technical Services	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
There is no known asbestos in this facility.	East Oper Ctr	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Possible Asbestos in roof.	Eddyville	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	**Total Cost to Install / Remove Enclosure**	Cost per Sq. Ft	# Sq. Ft.	**Total Cost to Remove Ceiling Tiles**	Cost per Sq. Ft	# Sq. Ft.	**Total Cost to Remove VCT**	Cost per L F.	# L.F.	**Total Cost to Remove Duct & Pipe Insulation**
This is a pre-engineered metal building with brick veneer, constructed in 1992 (approx. 3,000 sq. ft.)- Due to age of building asbestos is not suspected	Eddyville Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
	Elizabethtown	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
	Elizabethtown Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
There are 2 buildings at this site. The first bldg was constructed in 1950 with 3,150 sq. ft. The second bldg was constructed in 1980 with 1,280 sq. ft.. Renovations have been made to this facility - but possible asbestos in roof.	Georgetown	$1.90	4,430	**$8,417**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Bldg constructed in 1996 - however, roof inspectors noted possible asbestos in roof	Greenville	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Greenville Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Approx. 4,800 sq. ft. storeroom and office area was constructed between late 1960 - early 1970. It is a pre-engineered metal building on a slab. Asbestos does not appear to be present	Harlan Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Irvine Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

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Main Bldg Brick masonary, constructed in 1920 and remodeled in 1970. Tile floors, drop ceiling tiles and painted drywall and block walls. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Lexington Meter Dept.	$1.90	9,024	**$17,146**	$1.95	4,512	**$8,798**	$1.95	4,512	**$8,798**	$65.00	722	**$46,925**
Storage Bldg constructed in 1920 - Age of facility would indicate potential of asbestos throughout bldg.	Lexington Meter Dept.	$1.90	15,776	**$29,974**	$1.95	0	**$0**	$1.95	0	**$0**	$65.00	473	**$30,763**
	Lexington Operations Center	$1.90		**$0**			**$0**	$1.95		**$0**			**$0**
Main Bldg - 9,600 Sq. Ft. Transformer Shop constructed in 1911 with potential of asbestos throughout masonry building. Also attached is a 3,600 sq. ft. metal building	Lexington Substation/Relay Dept.	$1.90	9,600	**$18,240**	$1.95	4,800	**$9,360**	$1.95	4,800	**$9,360**	$65.00	768	**$49,920**
Office and Garage Bldg constructed in 1996 (6,200 sq. ft) - Due to age of building asbestos is not suspected	Lexington Substation/Relay Dept.	$1.90		**$0**			**$0**	$1.95		**$0**	$65.00		**$0**
Vacant Brick Bldg (Total 768 Sq. Ft.)	Lexington Substation/Relay Dept.	$1.90		**$0**			**$0**	$1.95		**$0**	$65.00		**$0**
3 Metal Storage Bldgs - Asbestos not suspected	Lexington Substation/Relay Dept.	$1.90		**$0**			**$0**	$1.95		**$0**	$65.00		**$0**
Leased Facility	Livermore Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
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Office was constructed in 1998 (4,700 sq. ft) - Due to age of ~~building asbestos is not suspected~~	~~London~~	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This is a 4,500 sq. ft. storeroom. The office portion was added in 2002 and new metal installed over the 30 yr. old storerooms wood frame. Possible Asbestos in roof.	London Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Bldg constructed in 1956 (875 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct).	Marion Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Bldg constructed in 1960 (3,978 sq. ft.); however, it appears that renovations have been made but possible asbestos in roof.	Maysville	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Bldg constructed in 1960 (2,950 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct). No asbestos suspected	Maysville Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This is a brick masonary two-story building, constructed in 1960 with 8,400 total sq. ft.; however, second floor is leased out. Tile floors, drop ceiling tiles and painted drywall. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Middlesboro	$1.90	8,400	**$15,960**	$1.95	8,400	**$16,380**	$1.95	8,400	**$16,380**	$65.00	672	**$43,680**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
This facility was constructed in 1920 with 12,300 sq. ft. A recent facility analysis suggested vacating this property due to structural integrity and major costs to repair / renovate. Age of this facility would indicate asbestos throughout. (Similar to LG&E 7th & O facility) - Should abandon or demo	Middlesboro Storeroom	$1.90	12,300	**$23,370**	$1.95	0	**$0**	$1.95	0	**$0**	$65.00	369	**$23,985**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Midway (Service Center)	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Bldg constructed in 1970 (total sq. ft. 2400) but customer service area and foyer (sq. ft.) were remodeled 7 years ago. VCT and ceiling tiles in remainder of building suspected to be asbestos.	Morehead	$1.90	1,725	**$3,278**	$1.95	1,725	**$3,364**	$1.95	1,725	**$3,364**	$65.00	192	**$12,480**
Leased Facility	Morehead Storeroom	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
This is a brick masonary two-story building, constructed in 1965 with 7,500 total sq. ft. Asbestos may be present in roof.	Morganfield	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This is a pre-engineered metal building with brick veneer, constructed in 1978 and extended in 1990 (total sq. ft. approx. 4,000). Asbestos not suspected.	Morganfield Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	**Total Cost to Install / Remove Enclosure**	Cost per Sq. Ft	# Sq. Ft.	**Total Cost to Remove Ceiling Tiles**	Cost per Sq. Ft	# Sq. Ft.	**Total Cost to Remove VCT**	Cost per L F.	# L.F.	**Total Cost to Remove Duct & Pipe Insulation**
This is a brick masonary one-story building, constructed in 1972 with ~~3,000 total sq. ft. Suspect asbestos~~ present in roof, floor tiles and possible ceiling tiles.	Mt. Sterling	$1.90	3,000	**$5,700**	$1.95	3,000	**$5,850**	$1.95	3,000	**$5,850**	$65.00		**$0**
This is a 3,400 sq. ft. concrete masonry block facility with concrete floors, ceilings of plywood, walls that are drywall or paneling. Possible asbestos in roof.	Mt. Sterling Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
	Norton	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
	Norton Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
	One Quality General Office												
This is a brick masonary one-story building, constructed around 1980 with 3,795 sq. ft. Suspect asbestos present in roof.	Paris	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This is a 2,783 sq. ft. concrete block facility garage / storeroom with a 10' x 12' office area. It was constructed around 1970. Possible asbestos in roof.	Paris Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
	Pennington Gap	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Leased Facility	Pennington Gap Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
There are several bldgs at this facility - Communications bldg 1,800 sq ft and Trans Dept 2,520 sq. ft. building in 2000-2001; Main Bldg const in 1982 with 32,800 sq. ft. (all of which are metal veneer. Asbestos does not appear to be an issue.	Pineville Stores/Complex; Meter Lab & Substation	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
The original building was constructed in 1970 but an addition was added in early 1980's. It is a one story brick with 5,350 sq. ft. Due to age and photos of the building it appears that VCT / mastic could contain asbestos.	Richmond	$1.90	5,350	**$10,165**	$1.95	0	**$0**	$1.95	5,350	**$10,433**	$65.00		**$0**
This facility was constructed in 1985, is a 2,800 sq. ft. metal structure with metal roof. Asbestos is not suspected.	Richmond Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
	Seventh & Ormsby												
This is a one story brick bldg with 4,500 sq. ft. built in 1955 which has been renovated and asbestos does not appear to be an issue.	Shelbyville	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
There are 2 buildings at this site. One is an older bldg actually dismantled and moved from another site to this location and was constructed in 1972. The other is a pre-engineered metal bldg, constructed in approx 1993. Both bldgs combined have 8,120 sq. ft. (a very small office area). Asbestos possible in roof.	Shelbyville Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
This office was constructed in 1971 with 3,500 sq. ft. It is wood frame with brick veneer. Age of this facility would indicate the potential for asbestos although some renovations have occurred.	Somerset	$1.90	3,500	**$6,650**	$1.95	3,500	**$6,825**	$1.95	3,500	**$6,825**	$65.00	280	**$18,200**
This office was constructed in 1971 with 6,000 sq. ft. It is a metal and concrete structure with metal roof. Age of this facility would indicate the potential for asbestos (tile floors and ceiling in office area).	Somerset Storeroom	$1.90	1,500	**$2,850**	$1.95	1,500	**$2,925**	$1.95	1,500	**$2,925**	$65.00	180	**$11,700**
Roof replaced in 1999	South Service Center	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Bldg constructed in 1985 - Due to age of building asbestos is not suspected	Versailles	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This is a single story brick facility with partial basement and was constructed in 1965 with approx. 3,500 sq. ft. Age of the building would indicate possible asbestos.	Winchester	$1.90	3,500	**$6,650**	$1.95	3,500	**$6,825**	$1.95	3,500	**$6,825**	$65.00	280	**$18,200**
This is a concrete block garage / storeroom with approx. 2,880 sq. ft.. Original construction in 1970 and an addition added in 1982. Asbestos suspected in roof.	Winchester Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
GRAND TOTAL ($000's)				**$166**			**$79**			**$89**			**$310**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
No known asbestos remaining. Renovations have been completed removing known asbestos.	Auburndale Op Ctr			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1965. which has been renovated and there are no signs of asbestos.	Barlow			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
There are 3 wood framed, metal siding and metal roof structures with a combined total of 2,496 sq. ft. Buildings were constructed in 1970; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Barlow Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Facility constructed in 1978 and is a pre-engineered metal building on slab with 3,200 sq. ft. Office area has VCT and drop ceiling which due to age of facility may be asbestos.	Big Stone Gap Substation		0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	0	**$0**
This facility has been renovated throughout and asbestos removed during the process	Broadway Office Complex			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1957. which has been renovated but possible asbestos in roof.	Campbellsville			**$0**			**$0**	$5.00		**$0**	$1.35	2,500	**$3,375**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
There are 3 wood framed, metal siding and metal roof structures with ~~a combined total of 6,450 sq. ft.~~ Buildings were constructed in 1960; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Campbellsville Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
The facility is a one-story metal on concrete slab structure with 555 sq. ft. constructed in 1980. No visible signs of asbestos	Carlise Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
This is a 1-1/2 story brick building with 3,500 sq. ft. constructed in approx. 1970. Shingle roof system installed over original roof (could be asbestos).	Carrollton			**$0**			**$0**	$5.00		**$0**	$1.35	2,956	**$3,991**
One story , 2,644 sq. ft. concrete block building constructed in 1970 with 24' walls and 3 garage doors. Possible asbestos in roof.	Carrollton Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	2,644	**$3,569**
This is a 2 story facility was constructed in 1961 with 3,984 sq. ft.; an addition of 2,200 sq. ft. was added above the drive thru in approx 1980. Due to age of facility asbestos is suspected (excluding roof, which was installed in 2004).	Danville			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
This is a 10,560 sq. ft. pre-engineered metal building on a concrete slab constructed in 1998. Due to the age of the building asbestos is not suspected.	Danville Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
This is a 20,800 sq. ft. pre-engineered metal building on a ~~concrete slab constructed in 1988.~~ Due to the age of the building asbestos is not suspected.	Danville Substation & Meter Dept.			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
The building was constructed between 1975 - 1980 and consists of a wood frame with metal façade and metal roof. Total sq. ft. of 1,900 and is divided into 3 sections - truck parking, office, storage. Heating / Cooling with heat pumps approx 9 yrs. old. Due to the age of the building it may contain asbestos.	Dawson Springs Storeroom		0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	0	**$0**
This facility was constructed in 1970. The office building is a wood frame structure with brick façade with approx. 3,840 sq. ft. Age of the facility indicate potential asbestos.	Earlington		0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	3,840	**$5,184**
This facility has a metal office and storage building with 11,500 sq. ft. constructed in 1990. Due to the age of the building asbestos is not suspected.	Earlington-Parkway Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Bldg constructed in 1995 (approx. 25,000 sq. ft.)- Due to age of building asbestos is not suspected	Earlington-Western Technical Services			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
There is no known asbestos in this facility.	East Oper Ctr			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Possible Asbestos in roof.	Eddyville			**$0**			**$0**	$5.00		**$0**	$1.35	2,400	**$3,240**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
This is a pre-engineered metal building with brick veneer, constructed in 1992 (approx. 3,000 sq. ft.)- Due to age of building asbestos is not suspected	Eddyville Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
	Elizabethtown			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
	Elizabethtown Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
There are 2 buildings at this site. The first bldg was constructed in 1950 with 3,150 sq. ft. The second bldg was constructed in 1980 with 1,280 sq. ft.. Renovations have been made to this facility - but possible asbestos in roof.	Georgetown			**$0**			**$0**	$5.00		**$0**	$1.35	4,364	**$5,891**
Bldg constructed in 1996 - however, roof inspectors noted possible asbestos in roof	Greenville			**$0**			**$0**	$5.00		**$0**	$1.35	7,972	**$10,762**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Greenville Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35		**$0**
Approx. 4,800 sq. ft. storeroom and office area was constructed between late 1960 - early 1970. It is a pre-engineered metal building on a slab. Asbestos does not appear to be present	Harlan Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35		**$0**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Irvine Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	**Total Cost to Remove Boiler & Assoc. Equip**	Cost per Elevator	# Units	**Total Cost to Remove Elevator Brake & Clutch**	Cost per Sq. Ft.	# Sq. Ft.	**Total Cost to Remove Panels or Mastics**	Cost per Sq. Ft.	# Sq. Ft.	**Total Cost to Remove Roofing Materials**
Main Bldg Brick masonary, constructed in 1920 and remodeled in 1970. Tile floors, drop ceiling tiles and painted drywall and block walls. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Lexington Meter Dept.			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Storage Bldg constructed in 1920 - Age of facility would indicate potential of asbestos throughout bldg.	Lexington Meter Dept.			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
	Lexington Operations Center			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Main Bldg - 9,600 Sq. Ft. Transformer Shop constructed in 1911 with potential of asbestos throughout masonry building. Also attached is a 3,600 sq. ft. metal building	Lexington Substation/Relay Dept.			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Office and Garage Bldg constructed in 1996 (6,200 sq. ft) - Due to age of building asbestos is not suspected	Lexington Substation/Relay Dept.			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Vacant Brick Bldg (Total 768 Sq. Ft.)	Lexington Substation/Relay Dept.			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
3 Metal Storage Bldgs - Asbestos not suspected	Lexington Substation/Relay Dept.			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Leased Facility	Livermore Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
Office was constructed in 1998 (4,700 sq. ft) - Due to age of ~~building asbestos is not suspected~~	~~London~~			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
This is a 4,500 sq. ft. storeroom. The office portion was added in 2002 and new metal installed over the 30 yr. old storerooms wood frame. Possible Asbestos in roof.	London Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	4,500	**$6,075**
Bldg constructed in 1956 (875 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct).	Marion Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Bldg constructed in 1960 (3,978 sq. ft.); however, it appears that renovations have been made but possible asbestos in roof.	Maysville			**$0**			**$0**	$5.00		**$0**	$1.35	3,444	**$4,649**
Bldg constructed in 1960 (2,950 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct). No asbestos suspected	Maysville Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
This is a brick masonary two-story building, constructed in 1960 with 8,400 total sq. ft.; however, second floor is leased out. Tile floors, drop ceiling tiles and painted drywall. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Middlesboro			**$0**			**$0**	$5.00		**$0**	$1.35	2,848	**$3,845**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
This facility was constructed in 1920 with 12,300 sq. ft. A recent facility analysis suggested vacating this property due to structural integrity and major costs to repair / renovate. Age of this facility would indicate asbestos throughout. (Similar to LG&E 7th & O facility) - Should abandon or demo	Middlesboro Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	12,300	**$16,605**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Midway (Service Center)			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Bldg constructed in 1970 (total sq. ft. 2400) but customer service area and foyer (sq. ft.) were remodeled 7 years ago. VCT and ceiling tiles in remainder of building suspected to be asbestos.	Morehead			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Leased Facility	Morehead Storeroom			$0			$0	$5.00		$0	$1.35	0	$0
This is a brick masonary two-story building, constructed in 1965 with 7,500 total sq. ft. Asbestos may be present in roof.	Morganfield			**$0**			**$0**	$5.00		**$0**	$1.35	4,106	**$5,543**
This is a pre-engineered metal building with brick veneer, constructed in 1978 and extended in 1990 (total sq. ft. approx. 4,000). Asbestos not suspected.	Morganfield Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
This is a brick masonary one-story building, constructed in 1972 with ~~3,000 total sq. ft. Suspect asbestos~~ present in roof, floor tiles and possible ceiling tiles.	Mt. Sterling			**$0**			**$0**	$5.00		**$0**	$1.35	3,820	**$5,157**
This is a 3,400 sq. ft. concrete masonry block facility with concrete floors, ceilings of plywood, walls that are drywall or paneling. Possible asbestos in roof.	Mt. Sterling Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	3,400	**$4,590**
	Norton			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
	Norton Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
	One Quality General Office							$5.00			$1.35	0	**$0**
This is a brick masonary one-story building, constructed around 1980 with 3,795 sq. ft. Suspect asbestos present in roof.	Paris			**$0**			**$0**	$5.00		**$0**	$1.35	3,795	**$5,123**
This is a 2,783 sq. ft. concrete block facility garage / storeroom with a 10' x 12' office area. It was constructed around 1970. Possible asbestos in roof.	Paris Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	2,783	**$3,757**
	Pennington Gap			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Leased Facility	Pennington Gap Storeroom			**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
There are several bldgs at this facility - Communications bldg 1,800 sq ft and Trans Dept 2,520 sq. ft. building in 2000-2001; Main Bldg const in 1982 with 32,800 sq. ft. (all of which are metal veneer. Asbestos does not appear to be an issue.	Pineville Stores/Complex; Meter Lab & Substation			$0			$0	$5.00		$0	$1.35	0	$0
The original building was constructed in 1970 but an addition was added in early 1980's. It is a one story brick with 5,350 sq. ft. Due to age and photos of the building it appears that VCT / mastic could contain asbestos.	Richmond			$0			$0	$5.00		$0	$1.35	0	$0
This facility was constructed in 1985, is a 2,800 sq. ft. metal structure with metal roof. Asbestos is not suspected.	Richmond Storeroom			$0			$0	$5.00		$0	$1.35	0	$0
	Seventh & Ormsby							$5.00			$1.35		
This is a one story brick bldg with 4,500 sq. ft. built in 1955 which has been renovated and asbestos does not appear to be an issue.	Shelbyville			$0			$0	$5.00		$0	$1.35	0	$0
There are 2 buildings at this site. One is an older bldg actually dismantled and moved from another site to this location and was constructed in 1972. The other is a pre-engineered metal bldg, constructed in approx 1993. Both bldgs combined have 8,120 sq. ft. (a very small office area). Asbestos possible in roof.	Shelbyville Storeroom			$0			$0	$5.00		$0	$1.35	8,120	$10,962

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
This office was constructed in 1971 with 3,500 sq. ft. It is wood frame with brick veneer. Age of this facility would indicate the potential for asbestos although some renovations have occurred.	Somerset		0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	0	**$0**
This office was constructed in 1971 with 6,000 sq. ft. It is a metal and concrete structure with metal roof. Age of this facility would indicate the potential for asbestos (tile floors and ceiling in office area).	Somerset Storeroom		0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	0	**$0**
Roof replaced in 1999	South Service Center		0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	0	**$0**
Bldg constructed in 1985 - Due to age of building asbestos is not suspected	Versailles		0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	0	**$0**
This is a single story brick facility with partial basesment and was constructed in 1965 with approx. 3,500 sq. ft. Age of the building would indicate possible asbestos.	Winchester		0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	3,500	**$4,725**
This is a concrete block garage / storeroom with approx. 2,880 sq. ft.. Original construction in 1970 and an addition added in 1982. Asbestos suspected in roof.	Winchester Storeroom		0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	2,880	**$3,888**
GRAND TOTAL ($000's)				**$0**			**$0**			**$0**	$1.35		**$111**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	**Total Trailer Costs**	Daily Cost per Team of 4	# Days Required	# of Teams	**Total Costs Disposal Suits**	Respirator Mask per Team of 4	# Teams	**Total Costs Type C Respirator Masks**	Cost per Day	# Days Testing	**Total Cost On Job Testing**
No known asbestos remaining. Renovations have been completed removing known asbestos.	Auburndale Op Ctr	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1965. which has been renovated and there are no signs of asbestos.	Barlow	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
There are 3 wood framed, metal siding and metal roof structures with a combined total of 2,496 sq. ft. Buildings were constructed in 1970; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Barlow Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Facility constructed in 1978 and is a pre-engineered metal building on slab with 3,200 sq. ft. Office area has VCT and drop ceiling which due to age of facility may be asbestos.	Big Stone Gap Substation	$98.89	10	**$989**	$162.12	10	1	**$1,621**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
This facility has been renovated throughout and asbestos removed during the process	Broadway Office Complex	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1957. which has been renovated but possible asbestos in roof.	Campbellsville	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
There are 3 wood framed, metal siding and metal roof structures with a combined total of 6,450 sq. ft. Buildings were constructed in 1960; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Campbellsville Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
The facility is a one-story metal on concrete slab structure with 555 sq. ft. constructed in 1980. No visible signs of asbestos	Carlise Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a 1-1/2 story brick building with 3,500 sq. ft. constructed in approx. 1970. Shingle roof system installed over original roof (could be asbestos).	Carrollton	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
One story , 2,644 sq. ft. concrete block building constructed in 1970 with 24' walls and 3 garage doors. Possible asbestos in roof.	Carrollton Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a 2 story facility was constructed in 1961 with 3,984 sq. ft.; an addition of 2,200 sq. ft. was added above the drive thru in approx 1980. Due to age of facility asbestos is suspected (excluding roof, which was installed in 2004).	Danville	$98.89	30	**$2,967**	$162.12	20	3	**$9,727**	$81.04	3	**$243**	$1,384.00	3	**$4,152**
This is a 10,560 sq. ft. pre-engineered metal building on a concrete slab constructed in 1998. Due to the age of the building asbestos is not suspected.	Danville Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
This is a 20,800 sq. ft. pre-engineered metal building on a ~~concrete slab constructed in 1988.~~ Due to the age of the building asbestos is not suspected.	Danville Substation & Meter Dept.	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
The building was constructed between 1975 - 1980 and consists of a wood frame with metal façade and metal roof. Total sq. ft. of 1,900 and is divided into 3 sections - truck parking, office, storage. Heating / Cooling with heat pumps approx 9 yrs. old. Due to the age of the building it may contain asbestos.	Dawson Springs Storeroom	$98.89		**$0**	$162.12	10	1	**$1,621**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
This facility was constructed in 1970. The office building is a wood frame structure with brick façade with approx. 3,840 sq. ft. Age of the facility indicate potential asbestos.	Earlington	$98.89	10	**$989**	$162.12	10	1	**$1,621**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
This facility has a metal office and storage building with 11,500 sq. ft. constructed in 1990. Due to the age of the building asbestos is not suspected.	Earlington-Parkway Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Bldg constructed in 1995 (approx. 25,000 sq. ft.)- Due to age of building asbestos is not suspected	Earlington-Western Technical Services	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
There is no known asbestos in this facility.	East Oper Ctr	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Possible Asbestos in roof.	Eddyville	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
This is a pre-engineered metal building with brick veneer, constructed in 1992 (approx. 3,000 sq. ft.)- Due to age of building asbestos is not suspected	Eddyville Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
	Elizabethtown	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
	Elizabethtown Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
There are 2 buildings at this site. The first bldg was constructed in 1950 with 3,150 sq. ft. The second bldg was constructed in 1980 with 1,280 sq. ft.. Renovations have been made to this facility - but possible asbestos in roof.	Georgetown	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Bldg constructed in 1996 - however, roof inspectors noted possible asbestos in roof	Greenville	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Greenville Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Approx. 4,800 sq. ft. storeroom and office area was constructed between late 1960 - early 1970. It is a pre-engineered metal building on a slab. Asbestos does not appear to be present	Harlan Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Irvine Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	**Total Trailer Costs**	Daily Cost per Team of 4	# Days Required	# of Teams	**Total Costs Disposal Suits**	Respirator Mask per Team of 4	# Teams	**Total Costs Type C Respirator Masks**	Cost per Day	# Days Testing	**Total Cost On Job Testing**
Main Bldg Brick masonary, constructed in 1920 and remodeled in 1970. Tile floors, drop ceiling tiles and painted drywall and block walls. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Lexington Meter Dept.	$98.89	30	**$2,967**	$162.12	20	3	**$9,727**	$81.04	3	**$243**	$1,384.00	3	**$4,152**
Storage Bldg constructed in 1920 - Age of facility would indicate potential of asbestos throughout bldg.	Lexington Meter Dept.	$98.89	30	**$2,967**	$162.12	20	3	**$9,727**	$81.04	3	**$243**	$1,384.00	3	**$4,152**
	Lexington Operations Center	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Main Bldg - 9,600 Sq. Ft. Transformer Shop constructed in 1911 with potential of asbestos throughout masonry building. Also attached is a 3,600 sq. ft. metal building	Lexington Substation/Relay Dept.	$98.89	30	**$2,967**	$162.12	20	3	**$9,727**	$81.04	3	**$243**	$1,384.00	3	**$4,152**
Office and Garage Bldg constructed in 1996 (6,200 sq. ft) - Due to age of building asbestos is not suspected	Lexington Substation/Relay Dept.	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Vacant Brick Bldg (Total 768 Sq. Ft.)	Lexington Substation/Relay Dept.	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
3 Metal Storage Bldgs - Asbestos not suspected	Lexington Substation/Relay Dept.	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Leased Facility	Livermore Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	**Total Trailer Costs**	Daily Cost per Team of 4	# Days Required	# of Teams	**Total Costs Disposal Suits**	Respirator Mask per Team of 4	# Teams	**Total Costs Type C Respirator Masks**	Cost per Day	# Days Testing	**Total Cost On Job Testing**
Office was constructed in 1998 (4,700 sq. ft) - Due to age of ~~building asbestos is not suspected~~	~~London~~	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a 4,500 sq. ft. storeroom. The office portion was added in 2002 and new metal installed over the 30 yr. old storerooms wood frame. Possible Asbestos in roof.	London Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Bldg constructed in 1956 (875 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct).	Marion Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Bldg constructed in 1960 (3,978 sq. ft.); however, it appears that renovations have been made but possible asbestos in roof.	Maysville	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Bldg constructed in 1960 (2,950 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct). No asbestos suspected	Maysville Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a brick masonary two-story building, constructed in 1960 with 8,400 total sq. ft.; however, second floor is leased out. Tile floors, drop ceiling tiles and painted drywall. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Middlesboro	$98.89	30	**$2,967**	$162.12	20	3	**$9,727**	$81.04	3	**$243**	$1,384.00	3	**$4,152**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	**Total Trailer Costs**	Daily Cost per Team of 4	# Days Required	# of Teams	**Total Costs Disposal Suits**	Respirator Mask per Team of 4	# Teams	**Total Costs Type C Respirator Masks**	Cost per Day	# Days Testing	**Total Cost On Job Testing**
This facility was constructed in 1920 with 12,300 sq. ft. A recent facility analysis suggested vacating this property due to structural integrity and major costs to repair / renovate. Age of this facility would indicate asbestos throughout. (Similar to LG&E 7th & O facility) - Should abandon or demo	Middlesboro Storeroom	$98.89	30	**$2,967**	$162.12	20	3	**$9,727**	$81.04	3	**$243**	$1,384.00	3	**$4,152**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Midway (Service Center)	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Bldg constructed in 1970 (total sq. ft. 2400) but customer service area and foyer (sq. ft.) were remodeled 7 years ago. VCT and ceiling tiles in remainder of building suspected to be asbestos.	Morehead	$98.89	10	**$989**	$162.12	10	1	**$1,621**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
Leased Facility	Morehead Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
This is a brick masonary two-story building, constructed in 1965 with 7,500 total sq. ft. Asbestos may be present in roof.	Morganfield	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a pre-engineered metal building with brick veneer, constructed in 1978 and extended in 1990 (total sq. ft. approx. 4,000). Asbestos not suspected.	Morganfield Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

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		Cost per Day	# of Days Required	**Total Trailer Costs**	Daily Cost per Team of 4	# Days Required	# of Teams	**Total Costs Disposal Suits**	Respirator Mask per Team of 4	# Teams	**Total Costs Type C Respirator Masks**	Cost per Day	# Days Testing	**Total Cost On Job Testing**
This is a brick masonary one-story building, constructed in 1972 with ~~3,000 total sq. ft. Suspect asbestos~~ present in roof, floor tiles and possible ceiling tiles.	Mt. Sterling	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a 3,400 sq. ft. concrete masonry block facility with concrete floors, ceilings of plywood, walls that are drywall or paneling. Possible asbestos in roof.	Mt. Sterling Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
	Norton	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
	Norton Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
	One Quality General Office													
This is a brick masonary one-story building, constructed around 1980 with 3,795 sq. ft. Suspect asbestos present in roof.	Paris	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a 2,783 sq. ft. concrete block facility garage / storeroom with a 10' x 12' office area. It was constructed around 1970. Possible asbestos in roof.	Paris Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
	Pennington Gap	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Leased Facility	Pennington Gap Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
There are several bldgs at this facility - Communications bldg 1,800 sq ft and Trans Dept 2,520 sq. ft. ~~building in 2000-2001; Main Bldg~~ const in 1982 with 32,800 sq. ft. (all of which are metal veneer. Asbestos does not appear to be an issue.	Pineville Stores/Complex; Meter Lab & Substation	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
The original building was constructed in 1970 but an addition was added in early 1980's. It is a one story brick with 5,350 sq. ft. Due to age and photos of the building it appears that VCT / mastic could contain asbestos.	Richmond	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
This facility was constructed in 1985, is a 2,800 sq. ft. metal structure with metal roof. Asbestos is not suspected.	Richmond Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
	Seventh & Ormsby													
This is a one story brick bldg with 4,500 sq. ft. built in 1955 which has been renovated and asbestos does not appear to be an issue.	Shelbyville	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
There are 2 buildings at this site. One is an older bldg actually dismantled and moved from another site to this location and was constructed in 1972. The other is a pre-engineered metal bldg, constructed in approx 1993. Both bldgs combined have 8,120 sq. ft. (a very small office area). Asbestos possible in roof.	Shelbyville Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
This office was constructed in 1971 with 3,500 sq. ft. It is wood frame with brick veneer. Age of this facility would indicate the potential for asbestos although some renovations have occurred.	Somerset	$98.89	10	**$989**	$162.12	10	1	**$1,621**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
This office was constructed in 1971 with 6,000 sq. ft. It is a metal and concrete structure with metal roof. Age of this facility would indicate the potential for asbestos (tile floors and ceiling in office area).	Somerset Storeroom	$98.89	10	**$989**	$162.12	10	1	**$1,621**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
Roof replaced in 1999	South Service Center	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Bldg constructed in 1985 - Due to age of building asbestos is not suspected	Versailles	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a single story brick facility with partial basement and was constructed in 1965 with approx. 3,500 sq. ft. Age of the building would indicate possible asbestos.	Winchester	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a concrete block garage / storeroom with approx. 2,880 sq. ft.. Original construction in 1970 and an addition added in 1982. Asbestos suspected in roof.	Winchester Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
GRAND TOTAL ($000's)				**$23**				**$68**			**$2**			**$33**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
No known asbestos remaining. Renovations have been completed removing known asbestos.	Auburndale Op Ctr	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1965. which has been renovated and there are no signs of asbestos.	Barlow	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
There are 3 wood framed, metal siding and metal roof structures with a combined total of 2,496 sq. ft. Buildings were constructed in 1970; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Barlow Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Facility constructed in 1978 and is a pre-engineered metal building on slab with 3,200 sq. ft. Office area has VCT and drop ceiling which due to age of facility may be asbestos.	Big Stone Gap Substation	$606.32	1	**$606**	$775.06	1	**$775**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	4	**$22**
This facility has been renovated throughout and asbestos removed during the process	Broadway Office Complex	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1957. which has been renovated but possible asbestos in roof.	Campbellsville	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
There are 3 wood framed, metal siding and metal roof structures with ~~a combined total of 6,450 sq. ft.~~ Buildings were constructed in 1960; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Campbellsville Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
The facility is a one-story metal on concrete slab structure with 555 sq. ft. constructed in 1980. No visible signs of asbestos	Carlise Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a 1-1/2 story brick building with 3,500 sq. ft. constructed in approx. 1970. Shingle roof system installed over original roof (could be asbestos).	Carrollton	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
One story , 2,644 sq. ft. concrete block building constructed in 1970 with 24' walls and 3 garage doors. Possible asbestos in roof.	Carrollton Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a 2 story facility was constructed in 1961 with 3,984 sq. ft.; an addition of 2,200 sq. ft. was added above the drive thru in approx 1980. Due to age of facility asbestos is suspected (excluding roof, which was installed in 2004).	Danville	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85	3	**$2,124**	$1,773.00	3	**$5,319**	$5.40	20	**$108**
This is a 10,560 sq. ft. pre-engineered metal building on a concrete slab constructed in 1998. Due to the age of the building asbestos is not suspected.	Danville Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
This is a 20,800 sq. ft. pre-engineered metal building on a ~~concrete slab constructed in 1988.~~ Due to the age of the building asbestos is not suspected.	Danville Substation & Meter Dept.	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
The building was constructed between 1975 - 1980 and consists of a wood frame with metal façade and metal roof. Total sq. ft. of 1,900 and is divided into 3 sections - truck parking, office, storage. Heating / Cooling with heat pumps approx 9 yrs. old. Due to the age of the building it may contain asbestos.	Dawson Springs Storeroom	$606.32	1	**$606**	$775.06	1	**$775**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	4	**$22**
This facility was constructed in 1970. The office building is a wood frame structure with brick façade with approx. 3,840 sq. ft. Age of the facility indicate potential asbestos.	Earlington	$606.32	1	**$606**	$775.06	1	**$775**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	4	**$22**
This facility has a metal office and storage building with 11,500 sq. ft. constructed in 1990. Due to the age of the building asbestos is not suspected.	Earlington-Parkway Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Bldg constructed in 1995 (approx. 25,000 sq. ft.)- Due to age of building asbestos is not suspected	Earlington-Western Technical Services	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
There is no known asbestos in this facility.	East Oper Ctr	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Possible Asbestos in roof.	Eddyville	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
This is a pre-engineered metal building with brick veneer, ~~constructed in 1992 (approx. 3,000~~ sq. ft.)- Due to age of building asbestos is not suspected	Eddyville Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
	Elizabethtown	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
	Elizabethtown Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
There are 2 buildings at this site. The first bldg was constructed in 1950 with 3,150 sq. ft. The second bldg was constructed in 1980 with 1,280 sq. ft.. Renovations have been made to this facility - but possible asbestos in roof.	Georgetown	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Bldg constructed in 1996 - however, roof inspectors noted possible asbestos in roof	Greenville	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Greenville Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Approx. 4,800 sq. ft. storeroom and office area was constructed between late 1960 - early 1970. It is a pre-engineered metal building on a slab. Asbestos does not appear to be present	Harlan Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Irvine Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
Main Bldg Brick masonary, constructed in 1920 and remodeled in 1970. Tile floors, drop ceiling tiles and painted drywall and block walls. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Lexington Meter Dept.	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85	3	**$2,124**	$1,773.00	3	**$5,319**	$5.40	20	**$108**
Storage Bldg constructed in 1920 - Age of facility would indicate potential of asbestos throughout bldg.	Lexington Meter Dept.	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85	3	**$2,124**	$1,773.00	3	**$5,319**	$5.40	20	**$108**
	Lexington Operations Center	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Main Bldg - 9,600 Sq. Ft. Transformer Shop constructed in 1911 with potential of asbestos throughout masonry building. Also attached is a 3,600 sq. ft. metal building	Lexington Substation/Relay Dept.	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85	3	**$2,124**	$1,773.00	3	**$5,319**	$5.40	20	**$108**
Office and Garage Bldg constructed in 1996 (6,200 sq. ft) - Due to age of building asbestos is not suspected	Lexington Substation/Relay Dept.	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Vacant Brick Bldg (Total 768 Sq. Ft.)	Lexington Substation/Relay Dept.	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
3 Metal Storage Bldgs - Asbestos not suspected	Lexington Substation/Relay Dept.	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Leased Facility	Livermore Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
Office was constructed in 1998 (4,700 sq. ft) - Due to age of ~~building asbestos is not suspected~~	~~London~~	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a 4,500 sq. ft. storeroom. The office portion was added in 2002 and new metal installed over the 30 yr. old storerooms wood frame. Possible Asbestos in roof.	London Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Bldg constructed in 1956 (875 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct).	Marion Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Bldg constructed in 1960 (3,978 sq. ft.); however, it appears that renovations have been made but possible asbestos in roof.	Maysville	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Bldg constructed in 1960 (2,950 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct). No asbestos suspected	Maysville Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a brick masonary two-story building, constructed in 1960 with 8,400 total sq. ft.; however, second floor is leased out. Tile floors, drop ceiling tiles and painted drywall. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Middlesboro	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85	3	**$2,124**	$1,773.00	3	**$5,319**	$5.40	20	**$108**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
This facility was constructed in 1920 with 12,300 sq. ft. A recent facility analysis suggested vacating this property due to structural integrity and major costs to repair / renovate. Age of this facility would indicate asbestos throughout. (Similar to LG&E 7th & O facility) - Should abandon or demo	Middlesboro Storeroom	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85	3	**$2,124**	$1,773.00	3	**$5,319**	$5.40	20	**$108**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Midway (Service Center)	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Bldg constructed in 1970 (total sq. ft. 2400) but customer service area and foyer (sq. ft.) were remodeled 7 years ago. VCT and ceiling tiles in remainder of building suspected to be asbestos.	Morehead	$606.32	1	**$606**	$775.06	1	**$775**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	4	**$22**
Leased Facility	Morehead Storeroom	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
This is a brick masonary two-story building, constructed in 1965 with 7,500 total sq. ft. Asbestos may be present in roof.	Morganfield	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a pre-engineered metal building with brick veneer, constructed in 1978 and extended in 1990 (total sq. ft. approx. 4,000). Asbestos not suspected.	Morganfield Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
This is a brick masonary one-story building, constructed in 1972 with 3,000 total sq. ft. Suspect asbestos present in roof, floor tiles and possible ceiling tiles.	Mt. Sterling	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a 3,400 sq. ft. concrete masonry block facility with concrete floors, ceilings of plywood, walls that are drywall or paneling. Possible asbestos in roof.	Mt. Sterling Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
	Norton	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
	Norton Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
	One Quality General Office															
This is a brick masonary one-story building, constructed around 1980 with 3,795 sq. ft. Suspect asbestos present in roof.	Paris	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a 2,783 sq. ft. concrete block facility garage / storeroom with a 10' x 12' office area. It was constructed around 1970. Possible asbestos in roof.	Paris Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
	Pennington Gap	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Leased Facility	Pennington Gap Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
There are several bldgs at this facility - Communications bldg 1,800 sq ft and Trans Dept 2,520 sq. ft. building in 2000-2001; Main Bldg - const in 1982 with 32,800 sq. ft. (all of which are metal veneer. Asbestos does not appear to be an issue.	Pineville Stores/Complex; Meter Lab & Substation	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
The original building was constructed in 1970 but an addition was added in early 1980's. It is a one story brick with 5,350 sq. ft. Due to age and photos of the building it appears that VCT / mastic could contain asbestos.	Richmond	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This facility was constructed in 1985, is a 2,800 sq. ft. metal structure with metal roof. Asbestos is not suspected.	Richmond Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
	Seventh & Ormsby															
This is a one story brick bldg with 4,500 sq. ft. built in 1955 which has been renovated and asbestos does not appear to be an issue.	Shelbyville	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
There are 2 buildings at this site. One is an older bldg actually dismantled and moved from another site to this location and was constructed in 1972. The other is a pre-engineered metal bldg, constructed in approx 1993. Both bldgs combined have 8,120 sq. ft. (a very small office area). Asbestos possible in roof.	Shelbyville Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
This office was constructed in 1971 with 3,500 sq. ft. It is wood frame with brick veneer. Age of this facility would indicate the potential for asbestos although some renovations have occurred.	Somerset	$606.32	1	**$606**	$775.06	1	**$775**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	4	**$22**
This office was constructed in 1971 with 6,000 sq. ft. It is a metal and concrete structure with metal roof. Age of this facility would indicate the potential for asbestos (tile floors and ceiling in office area).	Somerset Storeroom	$606.32	1	**$606**	$775.06	1	**$775**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	4	**$22**
Roof replaced in 1999	South Service Center	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Bldg constructed in 1985 - Due to age of building asbestos is not suspected	Versailles	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a single story brick facility with partial basement and was constructed in 1965 with approx. 3,500 sq. ft. Age of the building would indicate possible asbestos.	Winchester	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a concrete block garage / storeroom with approx. 2,880 sq. ft.. Original construction in 1970 and an addition added in 1982. Asbestos suspected in roof.	Winchester Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
GRAND TOTAL ($000's)				**$15**			**$19**			**$17**			**$43**			**$1**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
No known asbestos remaining. Renovations have been completed removing known asbestos.	Auburndale Op Ctr	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1965. which has been renovated and there are no signs of asbestos.	Barlow	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
There are 3 wood framed, metal siding and metal roof structures with a combined total of 2,496 sq. ft. Buildings were constructed in 1970; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Barlow Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Facility constructed in 1978 and is a pre-engineered metal building on slab with 3,200 sq. ft. Office area has VCT and drop ceiling which due to age of facility may be asbestos.	Big Stone Gap Substation	**$34**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$37**
This facility has been renovated throughout and asbestos removed during the process	Broadway Office Complex	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1957. which has been renovated but possible asbestos in roof.	Campbellsville	**$3**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$3**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
There are 3 wood framed, metal siding and metal roof structures with a combined total of 6,450 sq. ft. Buildings were constructed in 1960; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Campbellsville Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
The facility is a one-story metal on concrete slab structure with 555 sq. ft. constructed in 1980. No visible signs of asbestos	Carlise Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
This is a 1-1/2 story brick building with 3,500 sq. ft. constructed in approx. 1970. Shingle roof system installed over original roof (could be asbestos).	Carrollton	**$4**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$7**
One story , 2,644 sq. ft. concrete block building constructed in 1970 with 24' walls and 3 garage doors. Possible asbestos in roof.	Carrollton Storeroom	**$4**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$7**
This is a 2 story facility was constructed in 1961 with 3,984 sq. ft.; an addition of 2,200 sq. ft. was added above the drive thru in approx 1980. Due to age of facility asbestos is suspected (excluding roof, which was installed in 2004).	Danville	**$73**	$673.53	4	2	**$5,388**	$318.89	16	**$5,102**	$167.31	16	**$2,677**	**$13**	**$86**
This is a 10,560 sq. ft. pre-engineered metal building on a concrete slab constructed in 1998. Due to the age of the building asbestos is not suspected.	Danville Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
This is a 20,800 sq. ft. pre-engineered metal building on a concrete slab constructed in 1988. Due to the age of the building asbestos is not suspected.	Danville Substation & Meter Dept.	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
The building was constructed between 1975 - 1980 and consists of a wood frame with metal façade and metal roof. Total sq. ft. of 1,900 and is divided into 3 sections - truck parking, office, storage. Heating / Cooling with heat pumps approx 9 yrs. old. Due to the age of the building it may contain asbestos.	Dawson Springs Storeroom	**$11**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$14**
This facility was constructed in 1970. The office building is a wood frame structure with brick façade with approx. 3,840 sq. ft. Age of the facility indicate potential asbestos.	Earlington	**$48**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$52**
This facility has a metal office and storage building with 11,500 sq. ft. constructed in 1990. Due to the age of the building asbestos is not suspected.	Earlington-Parkway Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Bldg constructed in 1995 (approx. 25,000 sq. ft.)- Due to age of building asbestos is not suspected	Earlington-Western Technical Services	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
There is no known asbestos in this facility.	East Oper Ctr	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Possible Asbestos in roof.	Eddyville	**$3**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$7**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
This is a pre-engineered metal building with brick veneer, ~~constructed in 1992 (approx. 3,000~~ sq. ft.)- Due to age of building asbestos is not suspected	Eddyville Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
	Elizabethtown	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
	Elizabethtown Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
There are 2 buildings at this site. The first bldg was constructed in 1950 with 3,150 sq. ft. The second bldg was constructed in 1980 with 1,280 sq. ft.. Renovations have been made to this facility - but possible asbestos in roof.	Georgetown	$14	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$18
Bldg constructed in 1996 - however, roof inspectors noted possible asbestos in roof	Greenville	$11	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$14
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Greenville Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
Approx. 4,800 sq. ft. storeroom and office area was constructed between late 1960 - early 1970. It is a pre-engineered metal building on a slab. Asbestos does not appear to be present	Harlan Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Irvine Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
Main Bldg Brick masonary, constructed in 1920 and remodeled ~~in 1970. Tile floors, drop ceiling tiles~~ and painted drywall and block walls. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Lexington Meter Dept.	**$110**	$673.53	4	2	**$5,388**	$318.89	16	**$5,102**	$167.31	16	**$2,677**	**$13**	**$124**
Storage Bldg constructed in 1920 - Age of facility would indicate potential of asbestos throughout bldg.	Lexington Meter Dept.	**$90**	$673.53	4	2	**$5,388**	$318.89	16	**$5,102**	$167.31	16	**$2,677**	**$13**	**$103**
	Lexington Operations Center	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Main Bldg - 9,600 Sq. Ft. Transformer Shop constructed in 1911 with potential of asbestos throughout masonry building. Also attached is a 3,600 sq. ft. metal building	Lexington Substation/Relay Dept.	**$116**	$673.53	4	2	**$5,388**	$318.89	16	**$5,102**	$167.31	16	**$2,677**	**$13**	**$129**
Office and Garage Bldg constructed in 1996 (6,200 sq. ft) - Due to age of building asbestos is not suspected	Lexington Substation/Relay Dept.	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Vacant Brick Bldg (Total 768 Sq. Ft.)	Lexington Substation/Relay Dept.	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
3 Metal Storage Bldgs - Asbestos not suspected	Lexington Substation/Relay Dept.	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Leased Facility	Livermore Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
Office was constructed in 1998 (4,700 sq. ft) - Due to age of ~~building asbestos is not suspected~~	~~London~~	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
This is a 4,500 sq. ft. storeroom. The office portion was added in 2002 and new metal installed over the 30 yr. old storerooms wood frame. Possible Asbestos in roof.	London Storeroom	**$6**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$9**
Bldg constructed in 1956 (875 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct).	Marion Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Bldg constructed in 1960 (3,978 sq. ft.); however, it appears that renovations have been made but possible asbestos in roof.	Maysville	**$5**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$8**
Bldg constructed in 1960 (2,950 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct). No asbestos suspected	Maysville Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
This is a brick masonary two-story building, constructed in 1960 with 8,400 total sq. ft.; however, second floor is leased out. Tile floors, drop ceiling tiles and painted drywall. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Middlesboro	**$125**	$673.53	4	2	**$5,388**	$318.89	16	**$5,102**	$167.31	16	**$2,677**	**$13**	**$138**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
This facility was constructed in 1920 with 12,300 sq. ft. A recent facility analysis suggested vacating this property due to structural integrity and major costs to repair / renovate. Age of this facility would indicate asbestos throughout. (Similar to LG&E 7th & O facility) - Should abandon or demo	Middlesboro Storeroom	**$93**	$673.53	4	2	**$5,388**	$318.89	16	**$5,102**	$167.31	16	**$2,677**	**$13**	**$106**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Midway (Service Center)	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Bldg constructed in 1970 (total sq. ft. 2400) but customer service area and foyer (sq. ft.) were remodeled 7 years ago. VCT and ceiling tiles in remainder of building suspected to be asbestos.	Morehead	**$30**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$34**
Leased Facility	Morehead Storeroom	**$0**	$673.53			$0	$318.89		$0	$167.31		$0	**$0**	**$0**
This is a brick masonary two-story building, constructed in 1965 with 7,500 total sq. ft. Asbestos may be present in roof.	Morganfield	**$6**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$9**
This is a pre-engineered metal building with brick veneer, constructed in 1978 and extended in 1990 (total sq. ft. approx. 4,000). Asbestos not suspected.	Morganfield Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	**Total Dumpster Rental Costs**	Pickup / Delivery Costs	# Times Pickup / Delivery	**Total Pick Up/Del Costs**	Asbestos Dump Fee	# of Times Dumped	**Total Asbestos Dump Fee Expense**		
This is a brick masonary one-story building, constructed in 1972 with 3,000 total sq. ft. Suspect asbestos present in roof, floor tiles and possible ceiling tiles.	Mt. Sterling	**$23**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$26**
This is a 3,400 sq. ft. concrete masonry block facility with concrete floors, ceilings of plywood, walls that are drywall or paneling. Possible asbestos in roof.	Mt. Sterling Storeroom	**$5**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$8**
	Norton	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
	Norton Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
	One Quality General Office													
This is a brick masonary one-story building, constructed around 1980 with 3,795 sq. ft. Suspect asbestos present in roof.	Paris	**$5**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$8**
This is a 2,783 sq. ft. concrete block facility garage / storeroom with a 10' x 12' office area. It was constructed around 1970. Possible asbestos in roof.	Paris Storeroom	**$4**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$7**
	Pennington Gap	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Leased Facility	Pennington Gap Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
There are several bldgs at this facility - Communications bldg 1,800 sq ft and Trans Dept 2,520 sq. ft. building in 2000-2001; Main Bldg const in 1982 with 32,800 sq. ft. (all of which are metal veneer. Asbestos does not appear to be an issue.	Pineville Stores/Complex; Meter Lab & Substation	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
The original building was constructed in 1970 but an addition was added in early 1980's. It is a one story brick with 5,350 sq. ft. Due to age and photos of the building it appears that VCT / mastic could contain asbestos.	Richmond	**$21**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$24**
This facility was constructed in 1985, is a 2,800 sq. ft. metal structure with metal roof. Asbestos is not suspected.	Richmond Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
	Seventh & Ormsby													
This is a one story brick bldg with 4,500 sq. ft. built in 1955 which has been renovated and asbestos does not appear to be an issue.	Shelbyville	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
There are 2 buildings at this site. One is an older bldg actually dismantled and moved from another site to this location and was constructed in 1972. The other is a pre-engineered metal bldg, constructed in approx 1993. Both bldgs combined have 8,120 sq. ft. (a very small office area). Asbestos possible in roof.	Shelbyville Storeroom	**$11**	$673.53	4	2	**$5,388**	$318.89	16	**$5,102**	$167.31	16	**$2,677**	**$13**	**$24**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
This office was constructed in 1971 with 3,500 sq. ft. It is wood frame with brick veneer. Age of this facility ~~would indicate the potential for~~ asbestos although some renovations have occurred.	Somerset	$46	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$50
This office was constructed in 1971 with 6,000 sq. ft. It is a metal and concrete structure with metal roof. Age of this facility would indicate the potential for asbestos (tile floors and ceiling in office area).	Somerset Storeroom	$28	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$32
Roof replaced in 1999	South Service Center	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
Bldg constructed in 1985 - Due to age of building asbestos is not suspected	Versailles	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
This is a single story brick facility with partial basement and was constructed in 1965 with approx. 3,500 sq. ft. Age of the building would indicate possible asbestos.	Winchester	$43	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$47
This is a concrete block garage / storeroom with approx. 2,880 sq. ft.. Original construction in 1970 and an addition added in 1982. Asbestos suspected in roof.	Winchester Storeroom	$4	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$7
GRAND TOTAL ($000's)		$974				$66			$63			$33	$161	$1,136

Wiseman, Sara

From:	Miller, Jon
Sent:	Thursday, September 08, 2005 4:50 PM
To:	Riggs, Eric; Wiseman, Sara; Kinder, Debra
Subject:	FW: ARO Info
Follow Up Flag:	Follow up
Flag Status:	Completed
Attachments:	Fin 47 - EWB - TYR - 9-07-05.xls

Property Acct. Folks,

Attached below is the first draft of the FIN 47 information for Brown. As mentioned below, Sam would like to review this further will Mr. Webb (who is out currently due to an illness in the family). Please review and let Sam or I know if any changes should be made.

Jon

From:	Carr, Sam
Sent:	Thursday, September 08, 2005 4:38 PM
To:	Miller, Jon
Cc:	Fraley, Jeffrey; Webb, Robert (KU); Currens, Barry
Subject:	ARO Info

Jon,

Attached is the FIN47 info for Brown and Tyrone. As we discussed today, I would like to have Bobby Webb review the information and make revisions and additions as needed. I will complete this ASAP and advise of any changes.

If there are any concerns at this time, please advise.

Thanks,
Sam Carr
Manager Commercial Operations
E.W. Brown Station
859-748-4424 office
859-265-0583 cell
sam.carr@lgeenergy.com

Fin 47 - EWB - TYR
- 9-07-05.x...

Location BROWN
Asset Retirement Obligations

Asset Description	Location	Legal Requirement	Quantity by year of Installation	($000's) Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement	Comments	Support
Ash Pond	BR ST	Resource Conservation and Recovery Act		$9,506			Not unit specific - Steam units only 1,2,3	$83k/acre for 116 acres Acreage verified by Paul Puckett-Environmental Dept
Radiation Sources - BR3	BR3	The Cabinet for Human Resources - KRS 211.844, regulation 902 KAR Chapter 100		$16			Sources located with the following 10 assets w/UOP 5676: 3-1,3-2,3-3,3-4,&3-5 Feeders Upper & Lower. Also, the assets with UOP 5025: Hoppers A26,A22,A25,A21,A24,A20,A23,A19,B26,B22,B25,B21,B24,B20,B23,B19	Radiation Sources at $870 per 18 sources. Cost based on conversations with vendors (Secoal, contract supplier of radiation sources, 12/02) and physical counts. **Supported by OHMART email**
GSU, transformer oil, lubricating oils, ehc fluid	BR ST	Clean Water Act Toxic Substances Control Act					Not unit specific - include BR 1, 2,3. Transformers only. This oil has no PCBs (non-hazardous). Should be able to sell for reuse. Tie to BR3	Supported by internal email from Shannon Charnas. American Enviro Services will take oil at no cost
GSU, transformer oil, lubricating oils, ehc fluid	BR CT	Clean Water Act Toxic Substances Control Act					Not unit specific - include BR 5, 6, 7, 8, 9, 10,11. Transformers only. This oil has no PCBs (non-hazardous). Should be able to sell for reuse. Tie to BR 7.	Supported by internal email from Shannon Charnas. American Enviro Services will take oil at no cost
Removal of Fuel Oil Tanks - BR Steam units 1, 2, 3	BR ST	Clean Water Act, Comprehensive Emergency Response and Liability Act		$141			Tanks are not unit specific - for BR 1, 2, 3 - flat fee paid to contractor for removal. ESTIMATE	**Supported by email from Somerset Environmental**
Removal of Fuel Oil Tanks - BR CTs	BR CT	Clean Water Act		$281			Tanks are not unit specific - include BR 5, 6, 7, 8, 9, 10, 11 - flat fee paid to contractor for removal. ESTIMATE	**Supported by email from Somerset Environmental**
Remediation of underground fuel oil piping - Steam	BR ST	Clean Water Act, Comprehensive Emergency Response and Liability Act		$17			Estimate - Not unit specific - include BR 1, 2,3.	**Supported by engineering estimate provided by Barry Currens**
Remediation of underground fuel oil piping - CTs	BR CT	Clean Water Act		$32			Not unit specific - include BR 5, 6, 7, 8, 9, 10,11.	**Supported by engineering estimate provided by Barry Currens**
Mercury Removal	BR ST/CT	Resource Conservation and Recovery Act					Due to immaterial costs of $305 no ARO is being established	Per Mike Winkler in Environmental $4.50/lb. **Supported by ENSCO quote. 15 bs per Shannon Charnas email**
Lab Chemical disposal	BR	Resource Conservation and Recovery Act		$18			BR1 - Lab Equipment UOP 5389.	**Supported by estimate from GE Betz Inc.**
Sewage Plant	BR	Clean Water Act		$10			Estimated cost to pump out tank, fill tank with soil, and grade land.	Based on Pineville estimate of $1k for 50 people, assumed $4k for 200 people and additional fee for equipment use. **Supported by BMR invoice**
Coal Yard covering	BR ST	Clean Water Act		$60			Not unit specific - Steam units 1, 2,3.	Based on Pineville estimate - $15k/acre for 4 acres **Acreage verified by Delbert Billiter-Fuels Dept.**
Coal pile retention pond closing	BR ST	Clean Water Act		$185			Estimate - Not unit specific - Steam units 1, 2,3.	**Supported by engineering estimate provided by Barry Currens**

Location BROWN
Asset Retirement Obligations ($000's)

Asset Description	Location	Legal Requirement	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date	Comments	Support
Station Batteries - BR1	BR1	Toxic Substance Control Act	60	$2			BR1 - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Station Batteries - BR2	BR2	Toxic Substance Control Act	60	$2			BR2 - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Station Batteries - BR3	BR2	Toxic Substance Control Act	60	$2			BR3 - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Station Batteries - Dix	Dix	Toxic Substance Control Act	60	$2			Dix - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Batteries - West Cliff	BR ST	Toxic Substance Control Act	60	$2			BR ST - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Batteries - North Sub	BR ST	Toxic Substance Control Act	60	$2			BR ST - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Computer Batteries - BR3	BR3	Toxic Substance Control Act	20	$0.48			BR 3 - Batteries UOP 05049.	Estimate from Bob Webb - $24 per computer battery for removal and disposal.
Computer Batteries - BR1	BR1	Toxic Substance Control Act	10	$0.24			BR1 - Batteries UOP 05049.	Estimate from Bob Webb - $24 per computer battery for removal and disposal.
Computer Batteries - Slurry Room	BR ST	Toxic Substance Control Act	20	$0.48			BR ST - Batteries UOP 05049.	Estimate from Bob Webb - $24 per computer battery for removal and disposal.
Location	**TYRONE**							
Ash Pond	TY	Resource Conservation and Recovery Act		$751			Not unit specific.	$83k/acre at 9 acres based on Pineville estimate Acreage verified by Paul Puckett-Environmental Dept
Demolition Service Water Pump structures	TY	Corps of Engineers		$181			2 structures which have asbestos and lead paint issues - Not unit specific.	Flat fee for contractor removal. **Supported by estimate from Evans Construction Co**
GSU, transformer oil, lubricating oils, ehc fluid	TY	Clean Water Act Toxic Substances Control Act		$0			Not unit specific - Tie to transformer on TY3. This oil has no PCBs (non-hazardous). Should be able to sell for reuse.	8 oil-field transformers at $5,000. Based upon estimate from Somerset Environmental (contractor) received on 12/23/02.
Removal of Fuel Oil Tanks	TY	Clean Water Act, Comprehensive Emergency Response and Liability Act		$101			One underground and one above ground - Not unit specific.	Flat fee for contractor removal. Based upon estimate from Somerset Environmental (contractor) received on 12/23/02.
Remediation of underground fuel oil piping	TY	Clean Water Act, Comprehensive Emergency Response and Liability Act		$14			Not unit specific.	Engineering estimate provided by Barry Currens
Mercury Removal	TY	Resource Conservation and Recovery Act		$3			Not unit specific - allocable among units. UOP 5373 - Instrument or measuring device (instrumentation). Tie to TY3	**Supported by ENSCO quote provided by Mike Winkler**
Sewage Plant	TY	Clean Water Act		$5			Estimated cost to pump out tank, fill tank with soil, and grade land.	Based on Pineville estimate of $1k for 50 people and additional fee for equipment use. **Supported by PMR invoice**
Coal Yard covering	TY	Clean Water Act		$30			Assuming that we would be required to close similar to the ash pond - Not unit specific	2 acres at $15k per acre Pineville estimate **Acreage verified by Delbert Billiter-Fuels Dept.**

Wiseman, Sara

From: Miller, Jon
Sent: Thursday, September 08, 2005 8:41 AM
To: Riggs, Eric
Cc: Wiseman, Sara; Kinder, Debra
Subject: RE: Updated FIN 47 Information

I've received info from Green River, but it needs a couple revisions - I'll forward it on when I receive it. I'm checking on TC, the Brown group (including Lock 7 and Dix) and I check on Ohio Falls.

Jon

From: Riggs, Eric
Sent: Thursday, September 08, 2005 7:43 AM
To: Miller, Jon
Cc: Wiseman, Sara; Kinder, Debra
Subject: RE: Updated FIN 47 Information

Jon,

We are trying to make sure we have covered all the facilities in regards to the FIN 47 issue. We have Ghent and Cane Run (which included Paddy's, Canal, Waterside). Was there something on Mill Creek, Dix Dam, Ohio Falls, Lock 7?

Thanks,
Eric Riggs
2822

From: Miller, Jon
Sent: Friday, September 02, 2005 12:39 PM
To: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Cc: Charnas, Shannon
Subject: FW: Updated FIN 47 Information

Attached is an updated FIN 47 schedule for Ghent.

Jon

<< File: Fin 47 Ghent Station 083005.xls >>

Fred Jackson
Manager Commercial Operations
Ghent Generating Station
Kentucky Utilities Company
Telephone: (502)347-4104
Pager: (502)336-6837

Wiseman, Sara

From: Charnas, Shannon
Sent: Friday, September 09, 2005 11:13 AM
To: Wiseman, Sara
Subject: FW: FIN 47
Attachments: DI 05_5 Asset-Retirement Obligations.pdf

Sara-

I haven't had a chance to look at this yet, but thought you would want it also.

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Gahlen, Christian [mailto:Christian.Gahlen@eon.com]
Sent: Friday, September 02, 2005 9:01 AM
To: Charnas, Shannon
Subject: WG: FIN 47

Shannon,

Brian forwarded your email to me (sorry for delay):

Unfortunately, we do not have any calculation from other areas of the business : We had very few asbestos cases, especially in german companies that operate nuclear plants with asbestos. The corresponding obligations had already been included in the FAS 143-calculations for the decommissioning of power plant components.
There were also some activities to estimate the impact for the removal of asbestos in our former real estate business, but no calculations were done due to E.ON`s expected disposal of that business prior to the transistion date of FIN 47.

I attached KPMG`s Defining Issues on FIN 47 that includes an example on asbestos where the company has insufficient information to estimate fair value of the obligation. In addition, we are currently looking for companies that early adopted FIN 47 to provide some disclosure examples in the near future.

It might be helpful if you could provide further facts and circumstances (such as: type of assets, current treatment under US GAAP (EITF 89-13 or SOP 96-1) etc.) and more details on your difficulties in estimating cost.

Best regards,

Christian

Christian Gahlen

E.ON Group Accounting

Tel: +49 211 4579 - 204

Fax: +49 211 4579 - 1204

-----Ursprüngliche Nachricht-----
Von: Jungwirth, Brian
Gesendet: Mittwoch, 24. August 2005 06:49
An: Brandt, Henning; Gahlen, Christian; Hansal, Uwe
Betreff: WG: FIN 47

-----Ursprüngliche Nachricht-----
Von: Charnas, Shannon [mailto:Shannon.Charnas@lgeenergy.com]
Gesendet: Mittwoch, 27. Juli 2005 13:55
An: Jungwirth, Brian
Betreff: RE: FIN 47

Brian-

I just wanted to touch base with you again to see if you were able to find anything from other areas on FIN 47 asbestos disclosures or calculations.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Charnas, Shannon
Sent: Friday, July 08, 2005 3:33 PM
To: 'Brian.Jungwirth@eon.com'
Subject: FIN 47

Brian-

We are still working through FIN 47 here. We had a discussion with several people within Generation yesterday mainly regarding the asbestos issue. We are going to discuss more, but it appears that in most cases it will be extremely difficult to determine any cost estimate for asbestos abatement and disposal. I wanted to ask if you had gotten any information regarding asbestos from other areas of the business that may be helpful. Any information you could share would be appreciated.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

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Wiseman, Sara

From: Miller, Jon
Sent: Friday, September 16, 2005 11:14 AM
To: Riggs, Eric; Wiseman, Sara; Kinder, Debra
Subject: FW: Fin 47

Follow Up Flag: Follow up
Flag Status: Completed

Attachments: Fin 47 Template - MC revised.xls

Attached is the Fin 47 data for Mill Creek.

Jon

From: Pence, Mark
Sent: Friday, September 16, 2005 10:53 AM
To: Miller, Jon
Cc: Cook, Dave; Kirkland, Mike
Subject: RE: Fin 47

Jon,

Try this one.

Mark

Fin 47 Template - MC revised.x...

Location
Asset Retirement Obligations

Asset Description	Location	Legal Requirement	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date	Comments	Support
Remediation of Underground Fuel Oil Piping	MC3	Comprehensive Emergency Response and Liability Act	1 (1978)	7,000		End of Plant Life	Includes excavation, removal, and disposal (Estimated in 2005 dollars)	2005 Quote from Evans Construction
Remediation of Underground Fuel Oil Piping	MC4	Comprehensive Emergency Response and Liability Act	1 (1982)	7,000		End of Plant Life	Includes excavation, removal, and disposal (Estimated in 2005 dollars)	2005 Quote from Evans Construction
Batteries - Lead Acid (#1 Controls)	Service Building	Toxic Substance Control Act	1 set (1988)	16,000		2008	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Lead Acid (#2 Controls)	Service Building	Toxic Substance Control Act	1 set (2004)	16,000		2024	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Lead Acid (#1 Emergency)	Service Building	Toxic Substance Control Act	1 set (2003)	16,000		2023	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Lead Acid (#2 Emergency)	Service Building	Toxic Substance Control Act	1 set (2002)	16,000		2022	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Dry Cell (UPS #1)	Service Building	Toxic Substance Control Act	1 set (2001)	10,000		2008	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Dry Cell (UPS #2)	Service Building	Toxic Substance Control Act	1 set (2004)	10,000		2011	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Dry Cell (UPS #3)	Service Building	Toxic Substance Control Act	1 set (2003)	10,000		2010	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Dry Cell (UPS #4)	Service Building	Toxic Substance Control Act	1 set (2002)	10,000		2009	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Dry Cell (GPP)	Gypsum Plant	Toxic Substance Control Act	1 set (2002)	10,000		2009	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Dry Cell (138kV Station)	138kV Sw. Sta.	Toxic Substance Control Act	1 set (2002)	10,000		2009	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Dry Cell (Coal Handling Controls)	#3 CH Control House	Toxic Substance Control Act	1 set (1997)	10,000		2007	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Dry Cell (Limestone UPS)	Limestone Building	Toxic Substance Control Act	1 set (1999)	10,000		2007	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Dry Cell (1&2 FGD Controls)	Scrubber Serv Building	Toxic Substance Control Act	1 set (1993)	10,000		2007	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Dry Cell (UPS 1&2 FGD)	Scrubber Serv Building	Toxic Substance Control Act	1 set (2003)	10,000		2010	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05
Batteries - Dry Cell (UPS 3&4 FGD)	Scrubber Serv Building	Toxic Substance Control Act	1 set (2003)	10,000		2010	Includes removal and disposal	Based on Ghent's quote from Alpine Power Systems dated 8/23/05

Assumption: Adjustment factor of 15% per 25MW of additional unit capacity

Mill Creek Unit 1 356 MW

	Base Cost	Multiplier 2.536	Adjustments	Total	
Penthouse	150	380	(380)	0	No Asbestos
External Furnace	750	1,902	(1,902)	0	No Asbestos
Deareator Heater & Storage Tank	0	0	225	225	Full enclosure of vessels. Connecting pipe also requires abatement
Piping, External - Operating Floor up	250	634	(259)	375	High energy, sootblower, heater extraction, downcomers, etc.
Pipe and Equipment, below Operating floor	150	380	220	600	Covers all FW heaters, turbine, service water piping, condenser, etc.
Ductwork, Equipment, Operating floor up	300	761	(461)	300	Expansion joints thoughout ductwork.
Ductwork, under Operating floor	200	507	(307)	200	Expansion joints thoughout ductwork.
Survey, Air Testing, Permits, etc.	100	254	(154)	100	
Contingency	400	1,014	(614)	400	Bunker room pipiing, turbine/boiler room roofs, boiler dead air spaces
Drum and Lower Drum	0	0	300	300	Extensive scaffolding and mult-floor enclosures required.
Plant Wiring and Electrical Devices	0	0	600	600	Approx. 40% of remaining wiring.
HVAC Air Handling Room	0	0	75	75	
Scrubber	0	0	200	200	Various piping systems.
Coal Handling	0	0	180	180	Common system for all units.
Total:	2,300	5,833	(2,278)	3,555	

Mill Creek Unit 2 356 MW

	Base Cost	Multiplier 2.536	Adjustments	Total	
Penthouse	150	380	(380)	0	No Asbestos
External Furnace	750	1,902	(1,902)	0	No Asbestos
Deareator Heater & Storage Tank	0	0	225	225	Full enclosure of vessels. Connecting pipe also requires abatement
Piping, External - Operating Floor up	250	634	(259)	375	High energy, sootblower, heater extraction, downcomers, etc.
Pipe and Equipment, below Operating floor	150	380	220	600	Covers all FW heaters, turbine, service water piping, condenser, etc.
Ductwork, Equipment, Operating floor up	300	761	(461)	300	Expansion joints thoughout ductwork.
Ductwork, under Operating floor	200	507	(307)	200	Expansion joints thoughout ductwork.
Survey, Air Testing, Permits, etc.	100	254	(154)	100	
Contingency	400	1,014	(614)	400	Bunker room pipiing, turbine/boiler room roofs, boiler dead air spaces
Drum and Lower Drum	0	0	300	300	Extensive scaffolding and mult-floor enclosures required.
Plant Wiring and Electrical Devices	0	0	400	400	Approx. 20% of remaining wiring.
Scrubber	0	0	200	200	Various piping systems.
Cooling Tower	0	0	0	0	Already abated.
Coal Handling	0	0	0	0	See unit 1
Total:	2,300	5,833	(2,733)	3,100	

Mill Creek Unit 3 — 463 MW

	Base Cost	Multiplier	Adjustments	Total	
		3.178			
Penthouse	150	477	(477)	0	No Asbestos
External Furnace	750	2,384	(2,384)	0	No Asbestos
Piping, External - Operating Floor up	250	795	(695)	100	Some power house mud will require abatement.
Pipe and Equipment, below Operating floor	150	477	(377)	100	Some power house mud will require abatement.
Ductwork, Equipment, Operating floor up	300	953	(653)	300	Expansion joints thoughout ductwork.
Ductwork, under Operating floor	200	636	(436)	200	Expansion joints thoughout ductwork.
Survey, Air Testing, Permits, etc.	100	318	(218)	100	
Contingency	400	1,271	(821)	450	Bunker room pipiing, turbine/boiler room roofs, boiler dead air spaces
Plant Wiring and Electrical Devices	0	0	300	300	Approx. 10% of remaining wiring.
Cooling Tower	0	0	600	600	Fill and drift eliminators. Estimate from 2005 Mill Creek bids.
Scrubber	0	0	200	200	Various piping systems
Coal Handling	0	0	0	0	See unit 1
Total:	2,300	7,309	(4,959)	2,350	

Mill Creek Unit 4 — 543 MW

	Base Cost	Multiplier	Adjustments	Total	
		3.658			
Penthouse	150	549	(549)	0	No Asbestos
External Furnace	750	2,744	(2,744)	0	No Asbestos
Piping, External - Operating Floor up	250	915	(765)	150	Some power house mud will require abatement.
Pipe and Equipment, below Operating floor	150	549	(399)	150	Some power house mud will require abatement.
Ductwork, Equipment, Operating floor up	300	1,097	(697)	400	Expansion joints thoughout ductwork.
Ductwork, under Operating floor	200	732	(482)	250	Expansion joints thoughout ductwork.
Survey, Air Testing, Permits, etc.	100	366	(266)	100	
Contingency	400	1,463	(1,013)	450	Bunker room pipiing, turbine/boiler room roofs, boiler dead air spaces
Plant Wiring and Electrical Devices	0	0	300	300	Approx. 10% of remaining wiring.
Cooling Tower	0	0	600	600	Fill and drift eliminators. Estimate from 2005 Mill Creek bids.
Scrubber	0	0	200	200	Various piping systems
Coal Handling	0	0	0	0	See unit 1
Total:	2,300	8,413	(5,813)	2,600	

Wiseman, Sara

From: Scott, Valerie
Sent: Tuesday, October 04, 2005 5:51 PM
To: Charnas, Shannon; Wiseman, Sara
Subject: FW: FIN 47 Survey Question

Valerie

-----Original Message-----
From: bounce-244988-175405@ls.eei.org [mailto:bounce-244988-175405@ls.eei.org]
Sent: Tuesday, October 04, 2005 2:54 PM
To: Accounting Standards Committee
Cc: Blake, Chris; Allcorn-Walker, Anita
Subject: RE: FIN 47 Survey Question

The responses from Southern Company are below:

1(a) Yes.
1(b)(i) In conjunction with a third party, developed an estimation methodology for asbestos in structures around the system.
1(b)(ii) Remaining life based on most recent depreciation study
1(c) & (d) All facilities that contain asbestos are known and estimates made based on the Concepts 7 method referenced in SFAS 143 regardless of their status.
2. Yes based on liabilities and net income.
3. Asbestos abatement estimates in depreciation were known and used to compute amounts in accumulated depreciation.

-----Original Message-----
From: bounce-244660-345795@ls.eei.org
[mailto:bounce-244660-345795@ls.eei.org] On Behalf Of Scarpitta, Grace
Sent: Thursday, September 29, 2005 10:33 AM
To: Accounting Standards Committee
Subject: FIN 47 Survey Question

To The EEI Accounting Standards Committee:
I would like to pose the following questions regarding your implementation of FIN 47 as it relates to asbestos removal. Thanks...

> Consolidated Edison Company of New York has over 400 locations that contain asbestos. For a small percentage of locations we have definite plans for asbestos removal. For most of the others, we have no current plans to remove asbestos, renovate, retire or sell the facility. There are no surveys done to determine the amount and condition of existing asbestos. In addition, we also have approximately 280,000 underground system structures with asbestos that are usually retired in place.
>
> Can you please answer the following questions:
> 1. Are you recording an ARO liability in the following circumstances:
> a. There is a current plan for asbestos abatement, sale or retirement.
> b. Asset is known to contain asbestos, but there is no current plan for abatement, sale or retirement. The amount of existing asbestos is not known.
> i. If recording an ARO liability, on what basis are you determining the amount of the future liability and;
> ii. Since there is no plan for abatement, what time period are you using for the estimated retirement date?
> c. Asset containing asbestos has already been retired in place (original cost is no longer on the books) and asbestos abatement may be done sometime in the future, although the timing is not known. The amount of existing

asbestos is also not known.
> d. Underground system structures containing
asbestos that are generally retired in place.
>
> 2. Did you set a materiality threshold for recording ARO> '> s?
What are the factors you considered when determining materiality?
>
> 3. If you are recording an ARO for regulated utility operations,
how are you calculating the asbestos removal cost in the accumulated depreciation reserve?
>
>
>

Grace Scarpitta
Consolidated Edison Company of New York
212-460-6693

You are currently subscribed to asc as: [jjhodnet@southernco.com] To unsubscribe, forward this message to leave-244660-345795M@ls.eei.org

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Wiseman, Sara

From: Cook, Dave
Sent: Tuesday, October 04, 2005 4:22 PM
To: Miller, Jon; Charnas, Shannon; Wiseman, Sara
Cc: Pence, Mark; Cecil, Ray
Subject: FIN47 Data for Mill Creek

Attachments: FIN-47-Mill Creek.xls

Jon,

Attached is the Mill Creek data for FIN 47. Let me know if you need anything else.

Dave

FIN-47-Mill Creek.xls

Wiseman, Sara

From: Carr, Sam
Sent: Wednesday, October 05, 2005 4:06 PM
To: Miller, Jon
Cc: Charnas, Shannon; Wiseman, Sara; Kinder, Debra; Riggs, Eric; Fraley, Jeffrey; Currens, Barry
Subject: Brown FIN 47

Follow Up Flag: Follow up
Flag Status: Completed

Attachments: Fin 47 - EWB - TYR - 10-04-05.xls

Jon,

Attached is the revised FIN 47 spreadsheet for Brown and Tyrone with the asbestos abatement estimates included. As we discussed, I also added a preliminary asbestos abatement estimate for Pineville per your request.

Please advise if there are questions or concerns.

Thanks,
Sam Carr
Manager Commercial Operations
E.W. Brown Station
859-748-4424 office
859-265-0583 cell
sam.carr@lgeenergy.com

Fin 47 - EWB - TYR
- 10-04-05....

Asset Retirement Obligations			($000's)					
Asset Description	Location	Legal Requirement	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremental Cost of Disposal ($'s)	Estimated Retirement	Comments	Support
Location	**BROWN**							
Ash Pond	BR ST	Resource Conservation and Recovery Act		$10,440			Not unit specific - Steam units only 1,2,3	$90k/acre per 2002 FMSM estimate of $83k/acre for 116 acres inflated 3% per year. Closure requires 2 ft. cover soil, monitoring wells, and permitting pond as a landfill per FMSM. Acreage verified by Paul Puckett-Environmental Dept.
Asbestos Abatement - BR1	BR1			$2,056			BR1 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of 15% per each 25 MW increase above 100 MW. Adjustments made for abatement completed on BR1 penthouse and external furnace.
Asbestos Abatement - BR2	BR2			$3,296			BR2 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of 15% per each 25 MW increase above 100 MW. Adjustments made for abatement completed on BR2 penthouse, external furnace, and high energy piping.
Asbestos Abatement - BR3	BR3			$7,435			BR3 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, coal handling equipment, office areas, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of 15% per each 25 MW increase above 100 MW. Adjustments made for abatement completed on BR3 penthouse, external furnace, and high energy piping.
Radiation Sources - BR3	BR3	The Cabinet for Human Resources - KRS 211.844, regulation 902 KAR Chapter 100		$16			Sources located with the following 10 assets w/UOP 5676: 3-1,3-2,3-3,3-4,&3-5 Feeders Upper & Lower. Also, the assets with UOP 5025: Hoppers A26,A22,A25,A21,A24,A20,A23,A19,B26,B22,B25,B21,B24,B20,B23,B19	Radiation Sources at $870 per 18 sources. Cost based on conversations with vendors (Secoal, contract supplier of radiation sources, 12/02) and physical counts. **Supported by OHMART email**
GSU, transformer oil, lubricating oils, ehc fluid	BR ST	Clean Water Act Toxic Substances Control Act					Not unit specific - include BR 1, 2,3. Transformers only. This oil has no PCBs (non-hazardous). Should be able to sell for reuse. Tie to BR3	Supported by internal email from Shannon Charnas. American Enviro Services will take oil at no cost
GSU, transformer oil, lubricating oils, ehc fluid	BR CT	Clean Water Act Toxic Substances Control Act					Not unit specific - include BR 5, 6, 7, 8, 9, 10,11. Transformers only. This oil has no PCBs (non-hazardous). Should be able to sell for reuse. Tie to BR 7.	Supported by internal email from Shannon Charnas. American Enviro Services will take oil at no cost
Removal of Fuel Oil Tanks - BR Steam units 1, 2, 3	BR ST	Clean Water Act, Comprehensive Emergency Response and Liability Act		$141			Tanks are not unit specific - for BR 1, 2, 3 - flat fee paid to contractor for removal. ESTIMATE	**Supported by email from Somerset Environmental**
Removal of Fuel Oil Tanks - BR CTs	BR CT	Clean Water Act		$281			Tanks are not unit specific - include BR 5, 6, 7, 8, 9, 10, 11 - flat fee paid to contractor for removal. ESTIMATE	**Supported by email from Somerset Environmental**
Remediation of underground fuel oil piping - Steam	BR ST	Clean Water Act, Comprehensive Emergency Response and Liability Act		$17			Estimate - Not unit specific - include BR 1, 2,3.	**Supported by engineering estimate provided by Barry Currens**

Asset Retirement Obligations			($000's)					
Asset Description	**Location**	**Legal Requirement**	**Quantity by year of Installation**	**Removal Cost per Asset ($'s)**	**Incremental Cost of Disposal ($'s)**	**Estimated Retirement**	**Comments**	**Support**
Remediation of underground fuel oil piping - CTs	BR CT	Clean Water Act		$32			Not unit specific - include BR 5, 6, 7, 8, 9, 10,11.	**Supported by engineering estimate provided by Barry Currens**
Mercury Removal	BR ST/CT	Resource Conservation and Recovery Act					Due to immaterial costs of $305 no ARO is being established	Per Mike Winkler in Environmental $4.50/lb. **Supported by ENSCO quote. 15 bs per Shannon Charnas email**
Lab Chemical disposal	BR	Resource Conservation and Recovery Act		$18			BR1 - Lab Equipment UOP 5389.	**Supported by estimate from GE Betz Inc.**
Sewage Plant	BR	Clean Water Act		$10			Estimated cost to pump out tank, fill tank with soil, and grade land.	Based on Pineville estimate of $1k for 50 people, assumed $4k for 200 people and additional fee for equipment use. **Supported by BMR invoice**
Coal Yard covering	BR ST	Clean Water Act		$60			Not unit specific - Steam units 1, 2,3.	Based on Pineville estimate - $15k/acre for 4 acres **Acreage verified by Delbert Billiter-Fuels Dept.**
Coal pile retention pond closing	BR ST	Clean Water Act		$185			Estimate - Not unit specific - Steam units 1, 2,3.	**Supported by engineering estimate provided by Barry Currens**
Station Batteries - BR1	BR1	Toxic Substance Control Act	60	$2			BR1 - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Station Batteries - BR2	BR2	Toxic Substance Control Act	60	$2			BR2 - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Station Batteries - BR3	BR2	Toxic Substance Control Act	60	$2			BR3 - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Station Batteries - Dix	Dix	Toxic Substance Control Act	60	$2			Dix - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Batteries - West Cliff	BR ST	Toxic Substance Control Act	60	$2			BR ST - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Batteries - North Sub	BR ST	Toxic Substance Control Act	60	$2			BR ST - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Computer Batteries - BR3	BR3	Toxic Substance Control Act	20	$0.48			BR 3 - Batteries UOP 05049.	Estimate from Bob Webb - $24 per computer battery for removal and disposal.
Computer Batteries - BR1	BR1	Toxic Substance Control Act	10	$0.24			BR1 - Batteries UOP 05049.	Estimate from Bob Webb - $24 per computer battery for removal and disposal.
Computer Batteries - Slurry Room	BR ST	Toxic Substance Control Act	20	$0.48			BR ST - Batteries UOP 05049.	Estimate from Bob Webb - $24 per computer battery for removal and disposal.
Location	**TYRONE**							

Asset Retirement Obligations				**($000's)**				
Asset Description	**Location**	**Legal Requirement**	**Quantity by year of Installation**	**Removal Cost per Asset ($'s)**	**Incremental Cost of Disposal ($'s)**	**Estimated Retirement**	**Comments**	**Support**
Ash Pond	TY	Resource Conservation and Recovery Act		$810			Not unit specific.	$90k/acre per 2002 FMSM estimate of $83k/acre for 9 acres inflated 3% per year. Closure requires 2 ft. cover soil, monitoring wells, and permitting pond as a landfill per FMSM. Acreage verified by Paul Puckett-Environmental Dept.
Demolition Service Water Pump structures	TY	Corps of Engineers		$181			2 structures which have asbestos and lead paint issues - Not unit specific.	Flat fee for contractor removal. **Supported by estimate from Evans Construction Co**
GSU, transformer oil, lubricating oils, ehc fluid	TY	Clean Water Act Toxic Substances Control Act		$0			Not unit specific - Tie to transformer on TY3. This oil has no PCBs (non-hazardous). Should be able to sell for reuse.	8 oil-field transformers at $5,000. Based upon estimate from Somerset Environmental (contractor) received on 12/23/02.
Removal of Fuel Oil Tanks	TY	Clean Water Act, Comprehensive Emergency Response and Liability Act		$101			One underground and one above ground - Not unit specific.	Flat fee for contractor removal. Based upon estimate from Somerset Environmental (contractor) received on 12/23/02.
Remediation of underground fuel oil piping	TY	Clean Water Act, Comprehensive Emergency Response and Liability Act		$14			Not unit specific.	Engineering estimate provided by Barry Currens
Mercury Removal	TY	Resource Conservation and Recovery Act		$3			Not unit specific - allocable among units. UOP 5373 - Instrument or measuring device (instrumentation). Tie to TY3	**Supported by ENSCO quote provided by Mike Winkler**
Sewage Plant	TY	Clean Water Act		$5			Estimated cost to pump out tank, fill tank with soil, and grade land.	Based on Pineville estimate of $1k for 50 people and additional fee for equipment use. **Supported by PMR invoice**
Coal Yard covering	TY	Clean Water Act		$30			Assuming that we would be required to close similar to the ash pond - Not unit specific	2 acres at $15k per acre Pineville estimate **Acreage verified by Delbert Billiter-Fuels Dept.**
Batteries	TY	Toxic Substance Control Act	60	2.7			TY ST - Batteries UOP 05049.	Estimate from Barry Currens - $45 per station battery for removal and disposal.
Batteries	Haefling	Toxic Substance Control Act	60	2.7			Haefling - Batteries UOP 05049.	Estimate from Barry Currens - $45 per station battery for removal and disposal.
Asbestos Abatement - TY1	TY1			$1,459			TY1 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of (15%) per 25 MW reduced unit capacity below 100 MW.
Asbestos Abatement - TY2	TY2			$1,459			TY2 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of (15%) per 25 MW reduced unit capacity below 100 MW.
Asbestos Abatement - TY3	TY3			$2,107			TY3 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of (15%) per 25 MW reduced unit capacity below 100 MW. Adjustment for boiler #5 penthouse internal abatement completed.
Location	**PINEVILLE**							

Asset Retirement Obligations			($000's)					
Asset Description	Location	Legal Requirement	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremental Cost of Disposal ($'s)	Estimated Retirement	Comments	Support
Asbestos Abatement - Pineville Station	Pineville			$1,534			Pineville Unit 1 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of (15%) per 25 MW reduced unit capacity below 100 MW.

Assumption: multiplier factor of 15% per 25MW of increased unit capacity above 100 MW

Brown Unit 1 - 108 MW

108	Base Cost	MW Multiplier	Adjustments	Total	
		1.048			
Penthouse	365	382.52	-17.52	38.3	Abatement completed internally. Roof penetrations remain.
External Furnace	750	786	-36	550.2	Furnace walls abated above Main Floor to penthouse.
Piping, External - Operating Floor up	250	262	-12	262.0	
Pipe and Equipment, below Operating floor	150	157.2	-7.2	157.2	
Ductwork, Equipment, Operating floor up	300	314.4	-14.4	314.4	
Ductwork, under Operating floor	200	209.6	-9.6	209.6	
Survey, Air Testing, Permits, etc.	100	104.8	-4.8	104.8	
Contingency	400	419.2	-19.2	419.2	
Coal Handling	0	0	0	0.0	
Total:	$ 2,515.0	$ 2,635.7	$ (120.7)	2,055.7	

Brown Unit 2 - 178 MW

178	Base Cost	MW Multiplier	Adjustments	Total	
		1.468			
Penthouse	365	535.82	-170.82	267.9	Abatement completed internally. Roof area remains.
External Furnace	750	1101	-351	990.9	Misc. furnace wall areas abated (backpass).
Piping, External - Operating Floor up	250	367	-117	348.7	Partial abatement on high energy piping completed.
Pipe and Equipment, below Operating floor	150	220.2	-70.2	220.2	
Ductwork, Equipment, Operating floor up	300	440.4	-140.4	440.4	
Ductwork, under Operating floor	200	293.6	-93.6	293.6	
Survey, Air Testing, Permits, etc.	100	146.8	-46.8	146.8	
Contingency	400	587.2	-187.2	587.2	
Coal Handling	0	0	0	0.0	
Total:	$ 2,515.0	$ 3,692.0	$ (1,177.0)	3,295.7	

Brown Unit 3 - 454 MW

454	Base Cost (100MW)	MW Multiplier	Adjustments	Total	
		3.124			
Penthouse	365	1140.26	-775.26	$798.2	Abatement completed internally. Wall area remains.
External Furnace	750	2343	-1593	$2,225.9	Misc. furnace wall areas abated.
Piping, External - Operating Floor up	250	781	-531	$742.0	Partial abatement on high energy piping completed.
Pipe and Equipment, below Operating floor	150	468.6	-318.6	$445.2	Partial abatement on high energy piping completed.
Ductwork, Equipment, Operating floor up	300	937.2	-637.2	$937.2	
Ductwork, under Operating floor	200	624.8	-424.8	$624.8	
Survey, Air Testing, Permits, etc.	100	312.4	-212.4	$312.4	
Contingency	400	1249.6	-849.6	$1,249.6	
Coal Handling	0	0	0	$100.0	
Total:	$ 2,515.0	$ 7,856.9	$ (5,341.9)	$7,435.2	

Assumption: multiplier factor of 15% per 25MW of reduced unit capacity below 100 MW

Tyrone Unit 1 - 30 MW

	Base Cost	MW Multiplier	Adjustments	Total
		0.58		
Penthouse	365	211.7	153.3	211.7
External Furnace	750	435	315	435.0
Piping, External - Operating Floor up	250	145	105	145.0
Pipe and Equipment, below Operating floor	150	87	63	87.0
Ductwork, Equipment, Operating floor up	300	174	126	174.0
Ductwork, under Operating floor	200	116	84	116.0
Survey, Air Testing, Permits, etc.	100	58	42	58.0
Contingency	400	232	168	232.0
Coal Handling	0	0	0	0.0
Total:	$ 2,515.0	$ 1,458.7	$ 1,056.3	1458.7

Tyrone Unit 2 - 30 MW

	Base Cost	MW Multiplier	Adjustments	Total
		0.58		
Penthouse	365	211.7	153.3	211.7
External Furnace	750	435	315	435.0
Piping, External - Operating Floor up	250	145	105	145.0
Pipe and Equipment, below Operating floor	150	87	63	87.0
Ductwork, Equipment, Operating floor up	300	174	126	174.0
Ductwork, under Operating floor	200	116	84	116.0
Survey, Air Testing, Permits, etc.	100	58	42	58.0
Contingency	400	232	168	232.0
Coal Handling	0	0	0	0.0
Total:	$ 2,515.0	$ 1,458.7	$ 1,056.3	1458.7

Tyrone Unit 3 - 75 MW

	Base Cost (100MW)	MW Multiplier	Adjustments	Total	
		0.85			
Penthouse	365	310.25	54.75	279.2	Boiler #5 penthouse internals abated.
External Furnace	750	637.5	112.5	637.5	
Piping, External - Operating Floor up	250	212.5	37.5	212.5	
Pipe and Equipment, below Operating floor	150	127.5	22.5	127.5	
Ductwork, Equipment, Operating floor up	300	255	45	255.0	
Ductwork, under Operating floor	200	170	30	170.0	
Survey, Air Testing, Permits, etc.	100	85	15	85.0	
Contingency	400	340	60	340.0	
Coal Handling	0	0	0	0.0	
Total:	$ 2,515.0	$ 2,137.8	$ 377.3	2106.7	

Assumption: multiplier factor of 15% per 25MW of reduced unit capacity below 100 MW

Pineville Unit 1 - 38 MW

35		Base Cost	MW Multiplier	Adjustment:	Total
			0.61		
Penthouse		365	222.65	142.35	222.7
External Furnace		750	457.5	292.5	457.5
Piping, External - Operating Floor up		250	152.5	97.5	152.5
Pipe and Equipment, below Operating floor		150	91.5	58.5	91.5
Ductwork, Equipment, Operating floor up		300	183	117	183.0
Ductwork, under Operating floor		200	122	78	122.0
Survey, Air Testing, Permits, etc.		100	61	39	61.0
Contingency		400	244	156	244.0
Coal Handling		0	0	0	0.0
	Total:	$ 2,515.0	$ 1,534.2	$ 980.9	1534.2

Wiseman, Sara

From: Kapp, Karan
Sent: Wednesday, October 05, 2005 11:18 AM
To: Charnas, Shannon; Wiseman, Sara; Riggs, Eric; Kinder, Debra
Cc: Grant, Jerry
Subject: ASBESTOS REMOVAL EST COSTS FOR FACILITIES

Attachments: ASBESTOS REMOVAL EST COSTS FOR FACILITIES.xls

ASBESTOS
OVAL EST COSTS F(

I think we're finished. You can print out the Summary of Costs Tab of the attached worksheet and if you want to print out the detail used for the estimates print out the Back Up Detail Tab.

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
IM&E OFFICE: It is assumed that this building contains ACM floor tiles which are currently covered by non-ACM tiles. The wall and ceiling insulation is presumed to be ACM.	Muldraugh Station	$1.90	2,500	**$4,750**	$10.00	792	**$7,920**	$10.00	792	**$7,920**	$5.00	126	**$630**
KEWANEE BOILER ROOM: ACM boiler piping insulation still exists from the boiler to where it enters the Compressor Building. The boiler insulation is Presumed ACM.	Muldraugh Station	$1.90	512	**$973**	$1.95	0	**$0**	$1.95	0	**$0**	$65.00	125	**$8,125**
PURIFIER 1: All piping and pressure vessel ACM was replaced in 2001. Transite panels still serve as a wind break. PACM in old control box. PACM on Reboiler and Heat Exchanger gaskets.	Muldraugh Station	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
COMPRESSOR BUILDING: This building was presumed to have originally been constructed in the late 1930's with modifications and additions in the 1950's, 1960's, and 1970's. ACM flange gaskets, valve packing, and various compressor gaskets have been identified and some of it has been abated. ACM caulking has been discovered on the windows.	Muldraugh Station	$1.90	0	**$0**	$1.95	0	**$0**	$1.95	0	**$0**	$7.00	1538	**$10,766**
PURIFIER 2: The regenerator contains ACM vessel insulation although minimal sections have been abated. The boiler insulation is Presumed ACM.	Muldraugh Station	$4.00	2,700	**$10,800**	$1.95		**$0**	$1.95		**$0**	$65.00	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
PURIFIER 3: The boiler insulation is Presumed ACM.	Muldraugh Station	$1.90	608	**$1,155**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
ABANDONED H2S INCINERATOR: This facility contains a transite wind break, ACM valve packing and ACM flange gaskets.	Muldraugh Station	$1.90	0	**$0**	$1.95	0	**$0**	$1.95	0	**$0**	$65.00	0	**$0**
LOCKER ROOM: The facility contains ACM asphalt roofing. It is unknown if any other ACM exists so it was assumed that the insulation and dry wall are PACM.	Muldraugh Station	$1.90	630	**$1,197**	$1.95	200	**$390**	$1.95		**$0**	$65.00	0	**$0**
STATION VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Station	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
STATION PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Station	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00	200	**$13,000**
MULDRAUGH FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Storage Field	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
MULDRAUGH FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Storage Field	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00	200	**$13,000**
DOE RUN FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Field	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
DOE RUN FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Field	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00	400	**$26,000**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
DOE RUN DEEP FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Deep Field	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
DOE RUN DEEP FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals.	Doe Run Deep Field	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00	300	**$19,500**
Excludes in site retirement.													
MULDRAUGH DISTRIBUTION: Miscellaneous disposal of gaskets, valve packing, coal tar pipe and stopbox valve legs. Excludes pipe abandoned in place.	Muldraugh Storage-Distribution Stopbox Valve Legs.	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00	100	**$6,500**
GRAND TOTAL ($000's)				**$14**			**$0**			**$0**			**$97**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
IM&E OFFICE: It is assumed that this building contains ACM floor tiles which are currently covered by non-ACM tiles. The wall and ceiling insulation is presumed to be ACM.	Muldraugh Station		**$0.00**	**$0**			**$0**	**$5.00**	1568	**$7,840**	$1.35	0	**$0**
KEWANEE BOILER ROOM: ACM boiler piping insulation still exists from the boiler to where it enters the Compressor Building. The boiler insulation is Presumed ACM.	Muldraugh Station	$65.00	**$345.00**	**$22,425**			**$0**		0	**$0**	$1.35	0	**$0**
PURIFIER 1: All piping and pressure vessel ACM was replaced in 2001. Transite panels still serve as a wind break. PACM in old control box. PACM on Reboiler and Heat Exchanger gaskets.	Muldraugh Station			**$5,000**			**$0**	**$5.00**	1099	**$5,495**	$1.35	0	**$0**
COMPRESSOR BUILDING: This building was presumed to have originally been constructed in the late 1930's with modifications and additions in the 1950's, 1960's, and 1970's. ACM flange gaskets, valve packing, and various compressor gaskets have been identified and some of it has been abated. ACM caulking has been discovered on the windows.	Muldraugh Station			**$50,000**		0	**$0**	**$1.00**	0	**$0**	$1.35	0	**$0**
PURIFIER 2: The regenerator contains ACM vessel insulation although minimal sections have been abated. The boiler insulation is Presumed ACM.	Muldraugh Station	$65.00	898	**$58,370**			**$0**			**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
PURIFIER 3: The boiler insulation is Presumed ACM.	Muldraugh Station	$65.00	308	**$20,020**			**$0**			**$0**	$1.35	0	**$0**
ABANDONED H2S INCINERATOR: This facility contains a transite wind break, ACM valve packing and ACM flange gaskets.	Muldraugh Station			**$0**			**$0**	**$5.00**	190	**$950**	$1.35	0	**$0**
LOCKER ROOM: The facility contains ACM asphalt roofing. It is unknown if any other ACM exists so it was assumed that the insulation and dry wall are PACM.	Muldraugh Station			**$0**			**$0**			**$0**	$1.35	266	**$359**
STATION VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Station			**$60,000**			**$0**			**$0**	$1.35	0	**$0**
STATION PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Station			**$0**			**$0**			**$0**	$1.35	0	**$0**
MULDRAUGH FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Storage Field			**$50,000**			**$0**			**$0**	$1.35		**$0**
MULDRAUGH FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Storage Field			**$0**			**$0**			**$0**	$1.35		**$0**
DOE RUN FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Field			**$100,000**			**$0**			**$0**	$1.35		**$0**
DOE RUN FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Field			**$0**		**$0.00**	**$0**			**$0**	$1.35		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
DOE RUN DEEP FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Deep Field			**$30,000**		**$0.00**	**$0**			**$0**	$1.35		**$0**
DOE RUN DEEP FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals.	Doe Run Deep Field			**$0**			**$0**			**$0**	$1.35		**$0**
Excludes in site retirement.													
MULDRAUGH DISTRIBUTION: Miscellaneous disposal of gaskets, valve packing, coal tar pipe and stopbox valve legs. Excludes pipe abandoned in place.	Muldraugh Storage-Distribution Stopbox Valve Legs.			**$40,000**			**$0**			**$0**	$1.35		**$0**
GRAND TOTAL ($000's)				**$436**			**$0**			**$6**	$1.35		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	**Total Trailer Costs**	Daily Cost per Team of 4	# Days Required	# of Teams	**Total Costs Disposal Suits**	Respirator Mask per Team of 4	# Teams	**Total Costs Type C Respirator Masks**	Cost per Day	# Days Testing	**Total Cost On Job Testing**
IM&E OFFICE: It is assumed that this building contains ACM floor tiles which are currently covered by non-ACM tiles. The wall and ceiling insulation is presumed to be ACM.	Muldraugh Station	$98.89	5	**$494**	$162.12	5	1	**$811**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
KEWANEE BOILER ROOM: ACM boiler piping insulation still exists from the boiler to where it enters the Compressor Building. The boiler insulation is Presumed ACM.	Muldraugh Station	$98.89	1	**$99**	$162.12	1	1	**$162**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
PURIFIER 1: All piping and pressure vessel ACM was replaced in 2001. Transite panels still serve as a wind break. PACM in old control box. PACM on Reboiler and Heat Exchanger gaskets.	Muldraugh Station	$98.89	0	**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00	1	**$1,384**
COMPRESSOR BUILDING: This building was presumed to have originally been constructed in the late 1930's with modifications and additions in the 1950's, 1960's, and 1970's. ACM flange gaskets, valve packing, and various compressor gaskets have been identified and some of it has been abated. ACM caulking has been discovered on the windows.	Muldraugh Station	$98.89	0	**$0**	$162.12	5	1	**$811**	$81.04	0	**$0**	$1,384.00	1	**$1,384**
PURIFIER 2: The regenerator contains ACM vessel insulation although minimal sections have been abated. The boiler insulation is Presumed ACM.	Muldraugh Station	$98.89	10	**$989**	$162.12	10	1	**$1,621**	$81.04	1	**$81**	$1,384.00	2	**$2,768**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
PURIFIER 3: The boiler insulation is Presumed ACM.	Muldraugh Station	$98.89	3	**$297**	$162.12	3	1	**$486**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
ABANDONED H2S INCINERATOR: This facility contains a transite wind break, ACM valve packing and ACM flange gaskets.	Muldraugh Station	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
LOCKER ROOM: The facility contains ACM asphalt roofing. It is unknown if any other ACM exists so it was assumed that the insulation and dry wall are PACM.	Muldraugh Station	$98.89	5	**$494**	$162.12	5	1	**$811**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
STATION VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Station	$98.89	0	**$0**	$162.12	0	0	**$0**	$81.04	2	**$162**	$1,384.00	1	**$1,384**
STATION PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Station	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
MULDRAUGH FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Storage Field	$98.89		**$0**	$162.12			**$0**	$81.04	2	**$162**	$1,384.00	1	**$1,384**
MULDRAUGH FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Storage Field	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
DOE RUN FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Field	$98.89		**$0**	$162.12			**$0**	$81.04	2	**$162**	$1,384.00	1	**$1,384**
DOE RUN FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Field	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
DOE RUN DEEP FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Deep Field	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
DOE RUN DEEP FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals.	Doe Run Deep Field	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Excludes in site retirement.														
MULDRAUGH DISTRIBUTION: Miscellaneous disposal of gaskets, valve packing, coal tar pipe and stopbox valve legs. Excludes pipe abandoned in place.	Muldraugh Storage-Distribution Stopbox Valve Legs.	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
GRAND TOTAL ($000's)				**$2**				**$4**			**$1**			**$14**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
IM&E OFFICE: It is assumed that this building contains ACM floor tiles which are currently covered by non-ACM tiles. The wall and ceiling insulation is presumed to be ACM.	Muldraugh Station	$606.32	1	**$606**	$775.06	2	**$1,550**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	20	**$108**
KEWANEE BOILER ROOM: ACM boiler piping insulation still exists from the boiler to where it enters the Compressor Building. The boiler insulation is Presumed ACM.	Muldraugh Station	$606.32	1	**$606**	$775.06	1	**$775**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	30	**$162**
PURIFIER 1: All piping and pressure vessel ACM was replaced in 2001. Transite panels still serve as a wind break. PACM in old control box. PACM on Reboiler and Heat Exchanger gaskets.	Muldraugh Station	$606.32	0	**$0**	$775.06	1	**$775**	$707.85	0	**$0**	$1,773.00	0	**$0**	$5.40	10	**$54**
COMPRESSOR BUILDING: This building was presumed to have originally been constructed in the late 1930's with modifications and additions in the 1950's, 1960's, and 1970's. ACM flange gaskets, valve packing, and various compressor gaskets have been identified and some of it has been abated. ACM caulking has been discovered on the windows.	Muldraugh Station	$606.32	1	**$606**	$775.06	2	**$1,550**	$707.85	0	**$0**	$1,773.00	0	**$0**	$5.40	10	**$54**
PURIFIER 2: The regenerator contains ACM vessel insulation although minimal sections have been abated. The boiler insulation is Presumed ACM.	Muldraugh Station	$606.32	2	**$1,213**	$775.06	4	**$3,100**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	200	**$1,080**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
PURIFIER 3: The boiler insulation is Presumed ACM.	Muldraugh Station	$606.32	1	**$606**	$775.06	2	**$1,550**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	50	**$270**
ABANDONED H2S INCINERATOR: This facility contains a transite wind break, ACM valve packing and ACM flange gaskets.	Muldraugh Station	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
LOCKER ROOM: The facility contains ACM asphalt roofing. It is unknown if any other ACM exists so it was assumed that the insulation and dry wall are PACM.	Muldraugh Station	$606.32	1	**$606**	$775.06	2	**$1,550**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	50	**$270**
STATION VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Station	$606.32	0	**$0**	$775.06	1	**$775**	$707.85	0	**$0**	$1,773.00	0	**$0**	$5.40	200	**$1,080**
STATION PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Station	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	50	**$270**
MULDRAUGH FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Storage Field	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	150	**$810**
MULDRAUGH FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Storage Field	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	50	**$270**
DOE RUN FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Field	$606.32		**$0**	$775.06	1	**$775**	$707.85		**$0**	$1,773.00		**$0**	$5.40	300	**$1,620**
DOE RUN FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Field	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	100	**$540**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
DOE RUN DEEP FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Deep Field	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	50	**$270**
DOE RUN DEEP FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals.	Doe Run Deep Field	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	100	**$540**
Excludes in site retirement.																
MULDRAUGH DISTRIBUTION: Miscellaneous disposal of gaskets, valve packing, coal tar pipe and stopbox valve legs. Excludes pipe abandoned in place.	Muldraugh Storage-Distribution Stopbox Valve Legs.	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	100	**$540**
GRAND TOTAL ($000's)				**$4**			**$11**			**$3**			**$7**			**$8**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremental Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
IM&E OFFICE: It is assumed that this building contains ACM floor tiles which are currently covered by non-ACM tiles. The wall and ceiling insulation is presumed to be ACM.	Muldraugh Station	**$37**	$673.53	1	1	**$674**	$318.89	1	**$319**	$167.31	1	**$167**	**$1**	**$38**
KEWANEE BOILER ROOM: ACM boiler piping insulation still exists from the boiler to where it enters the Compressor Building. The boiler insulation is Presumed ACM.	Muldraugh Station	**$15**	$673.53	0.2	1	**$135**	$318.89	0.2	**$64**	$167.31	1	**$167**	**$0**	**$15**
PURIFIER 1: All piping and pressure vessel ACM was replaced in 2001. Transite panels still serve as a wind break. PACM in old control box. PACM on Reboiler and Heat Exchanger gaskets.	Muldraugh Station	**$30**	$673.53	0.2	1	**$135**	$318.89	0.2	**$64**	$167.31	1	**$167**	**$0**	**$30**
COMPRESSOR BUILDING: This building was presumed to have originally been constructed in the late 1930's with modifications and additions in the 1950's, 1960's, and 1970's. ACM flange gaskets, valve packing, and various compressor gaskets have been identified and some of it has been abated. ACM caulking has been discovered on the windows.	Muldraugh Station	**$20**	$673.53	2	0	**$0**	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$20**
PURIFIER 2: The regenerator contains ACM vessel insulation although minimal sections have been abated. The boiler insulation is Presumed ACM.	Muldraugh Station	**$29**	$673.53	3	1	**$2,021**	$318.89	1	**$319**	$167.31	1	**$167**	**$3**	**$32**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremental Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
PURIFIER 3: The boiler insulation is Presumed ACM.	Muldraugh Station	**$58**	$673.53	1	1	**$674**	$318.89	1	**$319**	$167.31	1	**$167**	**$1**	**$59**
ABANDONED H2S INCINERATOR: This facility contains a transite wind break, ACM valve packing and ACM flange gaskets.	Muldraugh Station	**$21**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$21**
LOCKER ROOM: The facility contains ACM asphalt roofing. It is unknown if any other ACM exists so it was assumed that the insulation and dry wall are PACM.	Muldraugh Station	**$10**	$673.53	1	1	**$674**	$318.89	1	**$319**	$167.31	1	**$167**	**$1**	**$11**
STATION VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Station	**$3**	$673.53	0.2	1	**$135**	$318.89	0.5	**$159**	$167.31	0.5	**$84**	**$0**	**$4**
STATION PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Station	**$73**	$673.53	4	1	**$2,694**	$318.89	1	**$319**	$167.31	1	**$167**	**$3**	**$76**
MULDRAUGH FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Storage Field	**$2**	$673.53	0.2	1	**$135**	$318.89	0.5	**$159**	$167.31	0.5	**$84**	**$0**	**$3**
MULDRAUGH FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Storage Field	**$63**	$673.53	5	1	**$3,368**	$318.89	2	**$638**	$167.31	1	**$167**	**$4**	**$67**
DOE RUN FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Field	**$4**	$673.53	0.5	1	**$337**	$318.89	0.5	**$159**	$167.31	1	**$167**	**$1**	**$5**
DOE RUN FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Field	**$127**	$673.53	7	1	**$4,715**	$318.89	4	**$1,276**	$167.31	2	**$335**	**$6**	**$133**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremental Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
DOE RUN DEEP FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Deep Field	**$0**	$673.53	0.5	1	**$337**	$318.89	1	**$319**	$167.31	1	**$167**	**$1**	**$1**
DOE RUN DEEP FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals.	Doe Run Deep Field	**$50**	$673.53	7	1	**$4,715**	$318.89	4	**$1,276**	$167.31	2	**$335**	**$6**	**$56**
Excludes in site retirement.														
MULDRAUGH DISTRIBUTION: Miscellaneous disposal of gaskets, valve packing, coal tar pipe and stopbox valve legs. Excludes pipe abandoned in place.	Muldraugh Storage-Distribution Stopbox Valve Legs.	**$7**	$673.53	5	1	**$3,368**	$318.89	1	**$319**	$167.31	2	**$335**	**$4**	**$11**
GRAND TOTAL ($000's)		**$513**				**$23**			**$6**			**$3**	**$32**	**$545**

<u>FACILITY ASSUMPTIONS</u>

Any Facility constructed before 1985 will have asbestos, unless abatement has been completed

SMALL BUSINESS OFFICES & OPER CTRS- L. F. is calculated based on 8% of total sq. ft. for removal of pipe & ductwork insulation @ $65/LN. FT. or SQ. FT. (Includes removal & air monitoring costs) Costs per Ln. Ftl is based on recent invoicing for work performed by NEC.

STOREROOMS - L. F. is calculated based on 3% of total sq. ft. for pipe and ductwork insulation @ $65/LN.FT. or SQ. FT. (Includes removal and air monitoring costs). Cost per Ln. Ft. is based on recent invoicing for work performed by NEC.

Cost to remove VCT is based on actual invoicing from NEC for work performed at South Service Center in 1994. The same costs were applied to removal of ceiling tiles.

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove VCT (Floor Tile)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
Metal roof.	Ashby	$1.90	384	**$730**	$1.95	336	**$655**	$1.35	0	**$0**
	Bishop	$1.90	400	**$760**	$1.95	400	**$780**	$1.35	0	**$0**
Station built in 1994.	Bluegrass	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Brandenburg	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Brook	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Station built in 1996	Campground	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Carter	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Clarks Lane	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Crestwood	$1.90	384	**$730**	$1.95	400	**$780**	$1.35	0	**$0**
	Crop	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
New roof in 1994.	Dahlia	$1.90	468	**$889**	$1.95	400	**$780**	$1.35	0	**$0**
Metal roof.	Del Park	$1.90	384	**$730**	$1.95	400	**$780**	$1.35	0	**$0**
Metal roof.	Dixie	$1.90	384	**$730**	$1.95	400	**$780**	$1.35	0	**$0**
	Dumesnil	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Eighth Street	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Fairmount	$1.90	400	**$760**	$1.95	400	**$780**	$1.35	0	**$0**
	Falls City	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
New roof in 1995.	Floyd	$1.90	345	**$656**	$1.95	400	**$780**	$1.35	0	**$0**
Station built in 1993.	Ford	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Forty Fourth	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Freys Hill	$1.90	384	**$730**	$1.95	400	**$780**	$1.35	0	**$0**
	Gaulbert	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Gilligan	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Goss	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Station built in 1998.	Grade Lane	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Built up roof unknown date.	Grady	$1.90	672	**$1,277**	$1.95	672	**$1,310**	$1.35	672	**$907**
	Grand	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Hale	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove VCT (Floor Tile)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
Built up roof unknown date.	Harmony Landing	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	468	**$632**
	Herman	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Built up roof unknown date.	Highland	$1.90	1,000	**$1,900**	$1.95	1,000	**$1,950**	$1.35	1,000	**$1,350**
New roof 1993.	Hillcrest	$1.90	1,674	**$3,181**	$1.95	1,674	**$3,264**	$1.35	0	**$0**
New roof 1995.	Hurstbourne	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	0	**$0**
Station built in 1994.	International	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Jeffersontown	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
Metal roof.	Kenwood	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
Built up roof unknown date.	Knob Creek	$1.90	768	**$1,459**	$1.95	768	**$1,498**	$1.35	768	**$1,037**
Built up roof unknown date.	Locust	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	468	**$632**
	Logan	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Louisville Downs	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Lynn	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
New roof in 2000	Magazine	$1.90	3,638	**$6,912**	$1.95	3,638	**$7,094**	$1.35	0	**$0**
New roof 1998.	Manslick	$1.90	1,271	**$2,415**	$1.95	1,271	**$2,478**	$1.35	0	**$0**
	Muldraugh	$1.90	400	**$760**	$1.95	400	**$780**	$1.35	0	**$0**
Metal roof.	Nachand	$1.90	384	$730	$1.95	384	$749	$1.35	0	$0
Station built in 1989.	Okolona	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Ormsby	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Pirtle	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
New roof 1992	Plainview	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	0	**$0**
New roof 1999.	Pleasure Ridge	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	0	**$0**
	Seventh Street	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Shawnee	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Shepherdsville	$1.90	294	**$559**	$1.95	294	**$573**	$1.35	0	**$0**
Metal roof.	Skylight	$1.90	156	**$296**	$1.95	156	**$304**	$1.35	0	**$0**
Metal roof.	Smyrna	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
	Solite	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove VCT (Floor Tile)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
Metal roof.	South Park	$1.90	315	**$599**	$1.95	315	**$614**	$1.35	0	**$0**
New roof 2001.	Southern	$1.90	5,002	**$9,504**	$1.95	5,002	**$9,754**	$1.35	0	**$0**
	Southern Baptist Seminary	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Stewart	$1.90	432	**$821**	$1.95	432	**$842**	$1.35		**$0**
	Trimble Cty Sw. Rm (12 kv)	$1.90	400	**$760**	$1.95	400	**$780**	$1.35	0	**$0**
Metal roof.	Terry	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
	Vermont	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Waterside (D)	$1.90	5,000	**$9,500**	$1.95	5,000	**$9,750**	$1.35	0	**$0**
	Westpoint	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Western	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	WHAS	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
Station built in 2001.	Worthington	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Zorn	$1.90	225	**$428**	$1.95	225	**$439**	$1.35	0	**$0**
LG&E TOTAL ($000's)				**$55**			**$57**	$1.35		**$5**
KU has 478 distribution Substations	KU Dist. Substations	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
KU TOTAL ($000's)										
GRAND TOTAL ($000's)										

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man		
		Cost per Day	# of Days Required	**Total Trailer Costs**	Daily Cost per Team of 4	# Days Required	# of Teams	**Total Costs Disposal Suits**	Respirator Mask per Team of 4	# Teams	**Total Costs Type C Respirator Masks**
Metal roof.	Ashby	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Bishop	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Station built in 1994.	Bluegrass	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Brandenburg	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Brook	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Station built in 1996	Campground	$98.89	0	**$0**	$162.12	0	0	**$0**	$81.04	0	**$0**
	Carter	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Clarks Lane	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Crestwood	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Crop	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
New roof in 1994.	Dahlia	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Del Park	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Dixie	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Dumesnil	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Eighth Street	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Fairmount	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Falls City	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
New roof in 1995.	Floyd	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Station built in 1993.	Ford	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Forty Fourth	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Freys Hill	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Gaulbert	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Gilligan	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Goss	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Station built in 1998.	Grade Lane	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Built up roof unknown date.	Grady	$98.89	3	**$297**	$162.12	3	2	**$973**	$81.04	2	**$162**
	Grand	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Hale	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks
Built up roof unknown date.	Harmony Landing	$98.89	3	**$297**	$162.12	3	2	**$973**	$81.04	2	**$162**
	Herman	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Built up roof unknown date.	Highland	$98.89	5	**$494**	$162.12	5	4	**$3,242**	$81.04	4	**$324**
New roof 1993.	Hillcrest	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
New roof 1995.	Hurstbourne	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Station built in 1994.	International	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Jeffersontown	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Kenwood	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Built up roof unknown date.	Knob Creek	$98.89	4	**$396**	$162.12	4	4	**$2,594**	$81.04	4	**$324**
Built up roof unknown date.	Locust	$98.89	3	**$297**	$162.12	3	2	**$973**	$81.04	2	**$162**
	Logan	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Louisville Downs	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Lynn	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
New roof in 2000	Magazine	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
New roof 1998.	Manslick	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Muldraugh	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Nachand	$98.89	2	$198	$162.12	2	1	$324	$81.04	1	$81
Station built in 1989.	Okolona	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Ormsby	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Pirtle	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
New roof 1992	Plainview	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
New roof 1999.	Pleasure Ridge	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Seventh Street	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Shawnee	$98.89	0	**$0**	$162.12	0	1			1	
Metal roof.	Shepherdsville	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Skylight	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Smyrna	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Solite	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks
Metal roof.	South Park	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
New roof 2001.	Southern	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Southern Baptist Seminary	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Stewart	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Trimble Cty Sw. Rm (12 kv)	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Terry	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Vermont	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Waterside (D)	$98.89	5	**$494**	$162.12	5	1	**$811**	$81.04	1	**$81**
	Westpoint	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Western	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	WHAS	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Station built in 2001.	Worthington	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Zorn	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
LG&E TOTAL ($000's)				**$8**				**$18**			**$6**
KU has 478 distribution Substations	KU Dist. Substations	$98.89	2	**$198**	$162.12	4	1	**$648**	$81.04	1	**$81**
KU TOTAL ($000's)											
GRAND TOTAL ($000's)											

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Air monitoring testing, 12 Tests / Day (On Job Testing/Day)			Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal E Air
		Cost per Day	# Days Testing	Total Cost On Job Testing	Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit
Metal roof.	Ashby	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Bishop	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1994.	Bluegrass	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Brandenburg	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Brook	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1996	Campground	$1,384.00	0	**$0**	$606.32		**$0**	$775.06		**$0**	$707.85
	Carter	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Clarks Lane	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Crestwood	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Crop	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof in 1994.	Dahlia	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
Metal roof.	Del Park	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Dixie	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Dumesnil	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Eighth Street	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Fairmount	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06		**$0**	$707.85
	Falls City	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof in 1995.	Floyd	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1993.	Ford	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Forty Fourth	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Freys Hill	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Gaulbert	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Gilligan	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Goss	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1998.	Grade Lane	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Built up roof unknown date.	Grady	$1,384.00	4	**$5,536**	$606.32	2	**$1,213**	$775.06	2	**$1,550**	$707.85
	Grand	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Hale	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Air monitoring testing, 12 Tests / Day (On Job Testing/Day)			Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal E Air
		Cost per Day	# Days Testing	Total Cost On Job Testing	Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit
Built up roof unknown date.	Harmony Landing	$1,384.00	3	**$4,152**	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85
	Herman	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Built up roof unknown date.	Highland	$1,384.00	4	**$5,536**	$606.32	5	**$3,032**	$775.06	5	**$3,875**	$707.85
New roof 1993.	Hillcrest	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof 1995.	Hurstbourne	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1994.	International	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Jeffersontown	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Kenwood	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Built up roof unknown date.	Knob Creek	$1,384.00	3	**$4,152**	$606.32	4	**$2,425**	$775.06	4	**$3,100**	$707.85
Built up roof unknown date.	Locust	$1,384.00	3	**$4,152**	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85
	Logan	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Louisville Downs	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Lynn	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
New roof in 2000	Magazine	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
New roof 1998.	Manslick	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Muldraugh	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
Metal roof.	Nachand	$1,384.00	2	$2,768	$606.32		$0	$775.06		$0	$707.85
Station built in 1989.	Okolona	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Ormsby	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Pirtle	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof 1992	Plainview	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof 1999.	Pleasure Ridge	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Seventh Street	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Shawnee		2								
Metal roof.	Shepherdsville	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Skylight	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Smyrna	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Solite	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Air monitoring testing, 12 Tests / Day (On Job Testing/Day)			Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal E Air
		Cost per Day	# Days Testing	Total Cost On Job Testing	Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit
Metal roof.	South Park	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof 2001.	Southern	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Southern Baptist Seminary	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Stewart	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Trimble Cty Sw. Rm (12 kv)	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Terry	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Vermont	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Waterside (D)	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Westpoint	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Western	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	WHAS	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 2001.	Worthington	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Zorn	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
LG&E TOTAL ($000's)				**$192**			**$10**			**$13**	
KU has 478 distribution Substations	KU Dist. Substations	$1,384.00	4	**$5,536**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
KU TOTAL ($000's)											
GRAND TOTAL ($000's)											

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	quip Required - Negative Pressure System		Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic			Removal of Circuit Breake	
		# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag	Cost per Unit	# Units
Metal roof.	Ashby		$0	$1,773.00		$0	$5.40		$0		
	Bishop		$0	$1,773.00		$0	$5.40		$0		
Station built in 1994.	Bluegrass		$0	$1,773.00		$0	$5.40		$0		
	Brandenburg	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Brook		$0	$1,773.00		$0	$5.40		$0		
Station built in 1996	Campground		$0	$1,773.00		$0	$5.40		$0		
	Carter		$0	$1,773.00		$0	$5.40		$0		
	Clarks Lane		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Crestwood		$0	$1,773.00		$0	$5.40		$0		
	Crop		$0	$1,773.00		$0	$5.40		$0		
New roof in 1994.	Dahlia	0	$0	$1,773.00	0	$0	$5.40	0	$0		
Metal roof.	Del Park		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Dixie		$0	$1,773.00		$0	$5.40		$0		
	Dumesnil	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Eighth Street	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Fairmount		$0	$1,773.00		$0	$5.40		$0		
	Falls City		$0	$1,773.00		$0	$5.40		$0		
New roof in 1995.	Floyd		$0	$1,773.00		$0	$5.40		$0		
Station built in 1993.	Ford		$0	$1,773.00		$0	$5.40		$0		
	Forty Fourth		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Freys Hill		$0	$1,773.00		$0	$5.40		$0		
	Gaulbert		$0	$1,773.00		$0	$5.40		$0		
	Gilligan		$0	$1,773.00		$0	$5.40		$0		
	Goss		$0	$1,773.00		$0	$5.40		$0		
Station built in 1998.	Grade Lane		$0	$1,773.00		$0	$5.40		$0		
Built up roof unknown date.	Grady	2	$1,416	$1,773.00	8	$14,184	$5.40	50	$270		
	Grand		$0	$1,773.00		$0	$5.40		$0		
	Hale	0	$0	$1,773.00	0	$0	$5.40	0	$0		

Asset Description	Location	quip Required - Negative Pressure System		Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic			Removal of Circuit Breake	
		# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag	Cost per Unit	# Units
Built up roof unknown date.	Harmony Landing	3	**$2,124**	$1,773.00	8	**$14,184**	$5.40	50	**$270**		
	Herman		**$0**	$1,773.00		**$0**	$5.40	0	**$0**		
Built up roof unknown date.	Highland	5	**$3,539**	$1,773.00	16	**$28,368**	$5.40	70	**$378**		
New roof 1993.	Hillcrest		**$0**	$1,773.00		**$0**	$5.40		**$0**		
New roof 1995.	Hurstbourne		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Station built in 1994.	International		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Jeffersontown		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Kenwood		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Built up roof unknown date.	Knob Creek	4	**$2,831**	$1,773.00	16	**$28,368**	$5.40	70	**$378**		
Built up roof unknown date.	Locust	3	**$2,124**	$1,773.00	8	**$14,184**	$5.40	50	**$270**		
	Logan		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Louisville Downs		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Lynn	0	**$0**	$1,773.00	0	**$0**	$5.40	0	**$0**		
New roof in 2000	Magazine	0	**$0**	$1,773.00	0	**$0**	$5.40	0	**$0**		
New roof 1998.	Manslick		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Muldraugh	0	**$0**	$1,773.00	0	**$0**	$5.40	0	**$0**		
Metal roof.	Nachand		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Station built in 1989.	Okolona		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Ormsby		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Pirtle		**$0**	$1,773.00		**$0**	$5.40		**$0**		
New roof 1992	Plainview		**$0**	$1,773.00		**$0**	$5.40		**$0**		
New roof 1999.	Pleasure Ridge		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Seventh Street		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Shawnee								**$0**		
Metal roof.	Shepherdsville		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Skylight		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Smyrna		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Solite		**$0**	$1,773.00		**$0**	$5.40		**$0**		

Asset Description	Location	quip Required - Negative Pressure System		Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic			Removal of Circuit Breaker	
		# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag	Cost per Unit	# Units
Metal roof.	South Park		**$0**	$1,773.00		**$0**	$5.40		**$0**		
New roof 2001.	Southern		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Southern Baptist Seminary		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Stewart	0	**$0**	$1,773.00	0	**$0**	$5.40	0	**$0**		
	Trimble Cty Sw. Rm (12 kv)		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Terry		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Vermont	0	**$0**	$1,773.00	0	**$0**	$5.40	0	**$0**		
	Waterside (D)	0	**$0**	$1,773.00	0	**$0**	$5.40	0	**$0**		
	Westpoint	0	**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Western		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	WHAS		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Station built in 2001.	Worthington		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Zorn		**$0**	$1,773.00		**$0**	$5.40		**$0**		
LG&E TOTAL ($000's)			**$12**			**$99**			**$2**		
KU has 478 distribution Substations	KU Dist. Substations	0	**$0**	$1,773.00	1	**$1,773**	$5.40	5	**$27**		
KU TOTAL ($000's)											
GRAND TOTAL ($000's)											

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Arc Chutes	Removal of Control Wiring			Removal Cost per Asset ($000's)	40 Cu			
		Total Cost	Cost per Unit	# Units	Total Cost		Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs
Metal roof.	Ashby	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
	Bishop	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
Station built in 1994.	Bluegrass	**$0**			**$0**	**$3**	$673.53	0	0	**$0**
	Brandenburg	**$2,500**			**$6,500**	**$12**	$673.53	0	0	**$0**
	Brook	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
Station built in 1996	Campground	**$0**			**$0**	**$0**	$673.53	0	0	**$0**
	Carter	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
	Clarks Lane	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
Metal roof.	Crestwood	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
	Crop	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
New roof in 1994.	Dahlia	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
Metal roof.	Del Park	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
Metal roof.	Dixie	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
	Dumesnil	**$2,500**			**$6,500**	**$12**	$673.53	0	0	**$0**
	Eighth Street	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
	Fairmount	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
	Falls City	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
New roof in 1995.	Floyd	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
Station built in 1993.	Ford	**$0**			**$0**	**$3**	$673.53	1	1	**$674**
	Forty Fourth	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
Metal roof.	Freys Hill	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
	Gaulbert	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
	Gilligan	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
	Goss	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
Station built in 1998.	Grade Lane	**$0**			**$0**	**$3**	$673.53	1	1	**$674**
Built up roof unknown date.	Grady	**$2,500**			**$6,500**	**$38**	$673.53	1	3	**$2,021**
	Grand	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
	Hale	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Arc Chutes	Removal of Control Wiring			Removal Cost per Asset ($000's)				40 Cu
		Total Cost	Cost per Unit	# Units	Total Cost		Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs
Built up roof unknown date.	Harmony Landing	$2,500			$6,500	$38	$673.53	1	3	$2,021
	Herman	$2,500			$2,500	$8	$673.53	0	0	$0
Built up roof unknown date.	Highland	$2,500			$6,500	$63	$673.53	1	3	$2,021
New roof 1993.	Hillcrest	$2,500			$6,500	$19	$673.53	1	1	$674
New roof 1995.	Hurstbourne	$2,500			$6,500	$14	$673.53	1	1	$674
Station built in 1994.	International	$0			$0	$3	$673.53	0	0	$0
Metal roof.	Jeffersontown	$2,500			$6,500	$14	$673.53	1	1	$674
Metal roof.	Kenwood	$2,500			$6,500	$14	$673.53	1	1	$674
Built up roof unknown date.	Knob Creek	$2,500			$6,500	$58	$673.53	1	2	$1,347
Built up roof unknown date.	Locust	$2,500			$6,500	$38	$673.53	1	1	$674
	Logan	$2,500			$2,500	$8	$673.53	0	0	$0
	Louisville Downs	$2,500			$2,500	$8	$673.53	0	0	$0
	Lynn	$2,500			$2,500	$8	$673.53	0	0	$0
New roof in 2000	Magazine	$2,500			$6,500	$26	$673.53	0	0	$0
New roof 1998.	Manslick	$2,500			$6,500	$17	$673.53	1	1	$674
	Muldraugh	$2,500			$6,500	$14	$673.53	0	0	$0
Metal roof.	Nachand	$2,500			$6,500	$14	$673.53	1	1	$674
Station built in 1989.	Okolona	$0			$0	$3	$673.53	0	0	$0
	Ormsby	$2,500			$2,500	$8	$673.53	1	1	$674
	Pirtle	$2,500			$2,500	$8	$673.53	0	0	$0
New roof 1992	Plainview	$2,500			$6,500	$14	$673.53	1	1	$674
New roof 1999.	Pleasure Ridge	$2,500			$6,500	$14	$673.53	1	1	$674
	Seventh Street	$2,500			$2,500	$8	$673.53	0	0	$0
	Shawnee	$2,500			$2,500	$5	$673.53	0	0	$0
Metal roof.	Shepherdsville	$2,500			$6,500	$14	$673.53	1	1	$674
Metal roof.	Skylight	$2,500			$6,500	$13	$673.53	1	1	$674
Metal roof.	Smyrna	$2,500			$6,500	$14	$673.53	1	1	$674
	Solite	$0			$0	$3	$673.53	0	0	$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Arc Chutes	Removal of Control Wiring			Removal Cost per Asset ($000's)	40 Cu			
		Total Cost	Cost per Unit	# Units	Total Cost		Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs
Metal roof.	South Park	$2,500			$6,500	$14	$673.53	1	1	$674
New roof 2001.	Southern	$2,500			$6,500	$32	$673.53	1	5	$3,368
	Southern Baptist Seminary	$2,500			$6,500	$12	$673.53	0	0	$0
Metal roof.	Stewart	$2,500			$6,500	$14	$673.53	1	1	$674
	Trimble Cty Sw. Rm (12 kv)	$2,500			$6,500	$14	$673.53	1	1	$674
Metal roof.	Terry	$2,500			$6,500	$14	$673.53	1	1	$674
	Vermont	$2,500			$6,500	$12	$673.53	0	0	$0
	Waterside (D)	$2,500			$6,500	$32	$673.53	1	2	$1,347
	Westpoint	$2,500			$6,500	$12	$673.53	0	0	$0
	Western	$2,500			$6,500	$12	$673.53	0	0	$0
Metal roof.	WHAS	$2,500			$6,500	$14	$673.53	1	1	$674
Station built in 2001.	Worthington	$0			$0	$3	$673.53	0	0	$0
Metal roof.	Zorn	$2,500			$6,500	$13	$673.53	0	0	$0
LG&E TOTAL ($000's)						$937				$31
KU has 478 distribution Substations	KU Dist. Substations	$0			$3,000	$11	$673.53	1	1	$674
KU TOTAL ($000's)										
GRAND TOTAL ($000's)										

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Yd Asbestos Dumpster Costs Per Unit						Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
		Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
Metal roof.	Ashby	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
	Bishop	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
Station built in 1994.	Bluegrass	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$3**
	Brandenburg	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$12**
	Brook	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
Station built in 1996	Campground	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$0**
	Carter	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Clarks Lane	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
Metal roof.	Crestwood	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
	Crop	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
New roof in 1994.	Dahlia	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
Metal roof.	Del Park	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
Metal roof.	Dixie	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
	Dumesnil	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$12**
	Eighth Street	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Fairmount	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
	Falls City	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
New roof in 1995.	Floyd	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
Station built in 1993.	Ford	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$4**
	Forty Fourth	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
Metal roof.	Freys Hill	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
	Gaulbert	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Gilligan	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Goss	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
Station built in 1998.	Grade Lane	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$4**
Built up roof unknown date.	Grady	$318.89	6	**$1,913**	$167.31	3	**$502**	**$4**	**$43**
	Grand	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$8**
	Hale	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**

Asset Description	Location	Yd Asbestos Dumpster Costs Per Unit						Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
		Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
Built up roof unknown date.	Harmony Landing	$318.89	6	**$1,913**	$167.31	5	**$837**	**$5**	**$43**
	Herman	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$8**
Built up roof unknown date.	Highland	$318.89	6	**$1,913**	$167.31	5	**$837**	**$5**	**$68**
New roof 1993.	Hillcrest	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$20**
New roof 1995.	Hurstbourne	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Station built in 1994.	International	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$3**
Metal roof.	Jeffersontown	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Metal roof.	Kenwood	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Built up roof unknown date.	Knob Creek	$318.89	4	**$1,276**	$167.31	2	**$335**	**$3**	**$61**
Built up roof unknown date.	Locust	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$39**
	Logan	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Louisville Downs	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$8**
	Lynn	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
New roof in 2000	Magazine	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$26**
New roof 1998.	Manslick	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$19**
	Muldraugh	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$14**
Metal roof.	Nachand	$318.89	2	**$638**	$167.31		$0	**$1**	**$15**
Station built in 1989.	Okolona	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$3**
	Ormsby	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$9**
	Pirtle	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
New roof 1992	Plainview	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
New roof 1999.	Pleasure Ridge	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
	Seventh Street	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$8**
	Shawnee	$318.89	0	**$0**					
Metal roof.	Shepherdsville	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
Metal roof.	Skylight	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
Metal roof.	Smyrna	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
	Solite	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$3**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Yd Asbestos Dumpster Costs Per Unit						Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
		Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
Metal roof.	South Park	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
New roof 2001.	Southern	$318.89	10	**$3,189**	$167.31	10	**$1,673**	**$8**	**$40**
	Southern Baptist Seminary	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$12**
Metal roof.	Stewart	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
	Trimble Cty Sw. Rm (12 kv)	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Metal roof.	Terry	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
	Vermont	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$12**
	Waterside (D)	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$36**
	Westpoint	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$12**
	Western	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$12**
Metal roof.	WHAS	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Station built in 2001.	Worthington	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$3**
Metal roof.	Zorn	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$13**
LG&E TOTAL ($000's)				**$29**			**$10**	**$71**	**$1,003**
KU has 478 distribution Substations	KU Dist. Substations	$318.89	2	**$638**	$167.31	1	**$167**	**$1**	**$13**
KU TOTAL ($000's)									**$599**
GRAND TOTAL ($000's)									[redacted]

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Estimated Retirement Date	Comments
Metal roof.	Ashby		
	Bishop		
Station built in 1994.	Bluegrass		
	Brandenburg		
	Brook		
Station built in 1996	Campground		
	Carter		
	Clarks Lane		
Metal roof.	Crestwood		
	Crop		
New roof in 1994.	Dahlia		
Metal roof.	Del Park		
Metal roof.	Dixie		
	Dumesnil		
	Eighth Street		
	Fairmount		
	Falls City		
New roof in 1995.	Floyd		
Station built in 1993.	Ford		
	Forty Fourth		
Metal roof.	Freys Hill		
	Gaulbert		
	Gilligan		
	Goss		
Station built in 1998.	Grade Lane		
Built up roof unknown date.	Grady		
	Grand		
	Hale		

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Estimated Retirement Date	Comments
Built up roof unknown date.	Harmony Landing		
	Herman		
Built up roof unknown date.	Highland		
New roof 1993.	Hillcrest		
New roof 1995.	Hurstbourne		
Station built in 1994.	International		
Metal roof.	Jeffersontown		
Metal roof.	Kenwood		
Built up roof unknown date.	Knob Creek		
Built up roof unknown date.	Locust		
	Logan		
	Louisville Downs		
	Lynn		
New roof in 2000	Magazine		
New roof 1998.	Manslick		
	Muldraugh		
Metal roof.	Nachand		
Station built in 1989.	Okolona		
	Ormsby		
	Pirtle		
New roof 1992	Plainview		
New roof 1999.	Pleasure Ridge		
	Seventh Street		
	Shawnee		
Metal roof.	Shepherdsville		
Metal roof.	Skylight		
Metal roof.	Smyrna		
	Solite		

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Estimated Retirement Date	Comments
Metal roof.	South Park		
New roof 2001.	Southern		
	Southern Baptist Seminary		
Metal roof.	Stewart		
	Trimble Cty Sw. Rm (12 kv)		
Metal roof.	Terry		
	Vermont		
	Waterside (D)		
	Westpoint		
	Western		
Metal roof.	WHAS		
Station built in 2001.	Worthington		
Metal roof.	Zorn		
LG&E TOTAL ($000's)			
KU has 478 distribution Substations	KU Dist. Substations		
KU TOTAL ($000's)			
GRAND TOTAL ($000's)			

Wiseman, Sara

From:	Satkamp, Mark
Sent:	Friday, October 07, 2005 5:04 PM
To:	Kinder, Debra; Wiseman, Sara
Cc:	Lawson, William; Collins, Mike
Subject:	FW: Identifying Asbestos Removal and Disposal Liabilities
Attachments:	ASBESTOS REMOVAL EST COSTS FOR FACILITIES (Gas Control Areas).xls

Sara and Debra,

Attached please find the template provided previously with the cost estimates for removing asbestos wall board at the Preston city gate station and asbestos insulation for the indirect fired heater at the Doe Run city gate station. **The total removal cost is estimated at $31K.** I estimated the total square feet of insulation for the Doe Run heater and used $35.00 per square foot to estimate this cost. From a conversation with Jeff Gilbert, Corporate Health and Safety has a record indicating that wall board samples taken at Preston came back as 30% asbestos, and samples taken at Penile city gate station came back negative. We are fairly certain that the wallboard in the buildings for the newer city gate stations and regulator stations does not contain asbestos. After interviewing some current and former employees, we are fairly certain that all of the shingle type roofs on the buildings at the city gate and regulator stations have been replaced since 1980 and are thus very unlikely to contain asbestos. Many of these roofs were replaced in the early 1990s by the Special Construction Department before they were disbanded. We have an ACE written in 1991 which identifies some of these regulator facilities where the roofs were replaced. Please let me know if you have questions or require any additional information.

Thanks,

Mark Satkamp
Manager, Gas Control
502-627-3135 Office

ASBESTOS
OVAL EST COSTS F(

From:	Satkamp, Mark
Sent:	Wednesday, September 28, 2005 10:42 AM
To:	Kinder, Debra
Cc:	Collins, Mike; Lawson, William
Subject:	RE: Identifying Asbestos Removal and Disposal Liabilities

Debra,

Some of the buildings at our city gate and large regulator stations are believed to have fiberboard inside the buildings which contains asbestos. We are not sure about the roofs. We think we have about 13 interior rooms with this type of fiberboard. We have not abated the walls from these types of buildings before and therefore don't know what the costs would be. A lot of costs would be associated with temporarily relocating all of our equipment from the buildings while the abatement work was being completed, or constructing new buildings and permanently relocating our equipment. I would guess that it could cost $50k or more per room for this type of work to be completed. Also, we have one heater at the Doe Run city gate station with asbestos insulation. I would guess that it might cost $50k to abate the heater insulation, or it might make sense to replace the heater for around $150k. Please note that these numbers would be considered very rough estimates as detailed work scopes to complete this type of work have not been completed.

Thanks,

Mark Satkamp
Manager, Gas Control
502-627-3135 Office

From:	Kinder, Debra
Sent:	Tuesday, September 27, 2005 10:53 AM
To:	Satkamp, Mark; Skaggs, John; Harmeling, Dave
Cc:	Wiseman, Sara; Riggs, Eric; Charnas, Shannon
Subject:	Identifying Asbestos Removal and Disposal Liabilities

All,

It is necessary for us to identify all sources of asbestos and estimate the current value of removal and disposal costs associated with assets containing asbestos in order to comply with FIN 47 (FASB Interpretation No. 47) which encompasses all legal retirement obligations. Do our gas plants or city gates contain asbestos insulation, roofing, siding, or other sources? If so, do you have historical abatement information that could be used to estimate current removal and disposal liabilities of contaminated assets? I would appreciate a quick response regarding your thoughts on this issue as we need to report our findings to E.ON relatively soon. It is becoming apparent that I will need to schedule a meeting this week to facilitate the gathering of needed data. Can any of you suggest other individuals that could contribute to this discussion?

Thanks for your help,
Debbie

Debra A. Kinder
Property Accounting Analyst
Louisville Gas & Electric
(502) 627-3369

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Costs to Remove Duct and/ or Pipe Insulation			Costs to Remove Transite Panels / Mastics (Adhesives)			Trailer (Change Room Cost)			Disposal Suits (4 su w/ a 4	
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required
Meter Building: Wall and ceiling panels may contain asbestos. Building approx. 16' x 16'. (768 sq ft)	Preston City Gate Station	$1.90		**$0**	$65.00		**$0**	$5.00	**768**	**$3,840**	$98.89		**$0**	$162.12	3
Control Building: Wall and ceiling panels may contain asbestos. Building approx. 10' x 16'. (576 sq ft)	Preston City Gate Station	$1.90		**$0**	$65.00		**$0**	$5.00	**576**	**$2,880**	$98.89		**$0**	$162.12	2
Doe Run Indirect Fired Heater: Heater insulation contains asbestos: Heater size approx. 5' diameter and 20' in length. (314 sq ft)	Doe Run City Gate Station	$1.90		**$0**	$35.00	314	**$10,990**	$5.00		**$0**	$98.89		**$0**	$162.12	2
GRAND TOTAL ($000's)				**$0**			**$11**			**$7**			**$0**		

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	its per man / day $40.53) - Man Team		Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
Meter Building: Wall and ceiling panels may contain asbestos. Building approx. 16' x 16'. (768 sq ft)	Preston City Gate Station	1	**$486**	$81.04	1	**$81**	$1,384.00	3	**$4,152**
Control Building: Wall and ceiling panels may contain asbestos. Building approx. 10' x 16'. (576 sq ft)	Preston City Gate Station	1	**$324**	$81.04	1	**$81**	$1,384.00	2	**$2,768**
Doe Run Indirect Fired Heater: Heater insulation contains asbestos: Heater size approx. 5' diameter and 20' in length. (314 sq ft)	Doe Run City Gate Station	1	**$324**	$81.04	1	**$81**	$1,384.00	2	**$2,768**
GRAND TOTAL ($000's)			**$1**			**$0**			**$10**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
Meter Building: Wall and ceiling panels may contain asbestos. Building approx. 16' x 16'. (768 sq ft)	Preston City Gate Station	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	1	**$5**
Control Building: Wall and ceiling panels may contain asbestos. Building approx. 10' x 16'. (576 sq ft)	Preston City Gate Station	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	1	**$5**
Doe Run Indirect Fired Heater: Heater insulation contains asbestos: Heater size approx. 5' diameter and 20' in length. (314 sq ft)	Doe Run City Gate Station	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	1	**$5**
GRAND TOTAL ($000's)				**$0**			**$0**			**$0**			**$0**			**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
Meter Building: Wall and ceiling panels may contain asbestos. Building approx. 16' x 16'. (768 sq ft)	Preston City Gate Station	**$9**	$673.53	0.6	1	**$404**	$318.89	1	**$319**	$167.31	1	**$167**	**$1**	**$9**
Control Building: Wall and ceiling panels may contain asbestos. Building approx. 10' x 16'. (576 sq ft)	Preston City Gate Station	**$6**	$673.53	0.4	1	**$269**	$318.89		**$0**	$167.31	0	**$0**	**$0**	**$6**
Doe Run Indirect Fired Heater: Heater insulation contains asbestos: Heater size approx. 5' diameter and 20' in length. (314 sq ft)	Doe Run City Gate Station	**$14**	$673.53	0.4	1	**$269**	$318.89	1	**$319**	$167.31	1	**$167**	**$1**	**$15**
GRAND TOTAL ($000's)		**$29**				**$1**			**$1**			**$0**	**$2**	**$31**

<u>FACILITY ASSUMPTIONS</u>

Any Facility constructed before 1985 will have asbestos, unless abatement has been completed

SMALL BUSINESS OFFICES & OPER CTRS- L. F. is calculated based on 8% of total sq. ft. for removal of pipe & ductwork insulation @ $65/LN. FT. or SQ. FT. (Includes removal & air monitoring costs) Costs per Ln. Ftl is based on recent invoicing for work performed by NEC.

STOREROOMS - L. F. is calculated based on 3% of total sq. ft. for pipe and ductwork insulation @ $65/LN.FT. or SQ. FT. (Includes removal and air monitoring costs). Cost per Ln. Ft. is based on recent invoicing for work performed by NEC.

Cost to remove VCT is based on actual invoicing from NEC for work performed at South Service Center in 1994. The same costs were applied to removal of ceiling tiles.

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Location
Asset Retirement Obligations

Asset Description	Location		Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation			Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Transite Panels / Mastics (Adhesives)		
			Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics
Magnolia Compressor Station engine room. Q ft building constructed in the 1950's. Transcite paneling and ACM roofing.	Magnolia	(G	$1.95		$0	$65.00		$0			$0	$5.00	6196	$30,980
Magnolia Compressor Station Auxiliary building. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	(G	$1.95	540	$1,053	$65.00		$0			$0	$5.00	2994	$14,970
Magnolia Compressor Station Field Shop. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	(G	$1.95		$0	$65.00		$0			$0	$5.00	1406	$7,030
Magnolia Compressor Station piping insulation	Magnolia	(	$1.95	0	$0	$65.00	100	$6,500		0	$0	$5.00	0	$0
Magnolia Compressor Station - #1 Purifier Reactivator	Magnolia	(	$1.95		$0	$65.00		$0	$61.32	424	$26,000	$5.00		$0
Magnolia Station and Field Valves - valve packing and gaskets	Magnolia, Center and Transmission lines	G	$1.95		$0	$65.00		$0			$40,000			$0
Station piping and Field piping during pipeline removals	Magnolia, Center and Transmission lines	G	$1.95		$0	$65.00	1,000	$65,000			$0			$0
Distribution - Miscellaneous Removal and disposal of gaskets, valve legs and coal tar	Bardstown, Center and Magnolia Distribution	D	$1.95		$0	$65.00	800	$52,000			$0			$0
GRAND TOTAL ($000's)					$1			$124			$66			$53

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Location	
Asset Retirement Obligations	

($000's)

Asset Description	Location	Costs to Remove Roofing Materials			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic			Removal Cost per Asset ($000's)
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials	Cost per Day	# Days Testing	Total Cost On Job Testing	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Glove Bag	
Magnolia Compressor Station engine room. Q ft building constructed in the 1950's. Transcite paneling and ACM roofing.	Magnolia	$1.35	6,900	**$9,315**	$1,384.00		**$0**	$775.06		**$0**	$5.40		**$0**	**$40**
Magnolia Compressor Station Auxiliary building. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	$1.35	1,212	**$1,636**	$1,384.00		**$0**	$775.06		**$0**	$5.40		**$0**	**$18**
Magnolia Compressor Station Field Shop. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	$1.35	1,800	**$2,430**	$1,384.00		**$0**	$775.06		**$0**	$5.40		**$0**	**$9**
Magnolia Compressor Station piping insulation	Magnolia	$1.35	0	**$0**	$1,384.00	0	**$0**	$775.06	0	**$0**	$5.40	4	**$22**	**$7**
Magnolia Compressor Station - #1 Purifier Reactivator	Magnolia	$1.35	0	**$0**	$1,384.00		**$0**	$775.06		**$0**	$5.40		**$0**	**$26**
Magnolia Station and Field Valves - valve packing and gaskets	Magnolia, Center and Transmission lines	$1.35	0	**$0**	$1,384.00	3	**$4,152**	$775.06	1	**$775**	$5.40	200	**$1,080**	**$32**
Station piping and Field piping during pipeline removals	Magnolia, Center and Transmission lines	$1.35	0	**$0**	$1,384.00		**$0**	$775.06		**$0**	$5.40	200	**$1,080**	**$106**
Distribution - Miscellaneous Removal and disposal of gaskets, valve legs and coal tar	Bardstown, Center and Magnolia Distribution	$1.35		**$0**	$1,384.00		**$0**	$775.06		**$0**	$5.40	100	**$540**	**$53**
GRAND TOTAL ($000's)		$1.35		**$13**			**$4**			**$1**			**$3**	**$291**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Location	
Asset Retirement Obligations	

Asset Description	Location	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
		Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
Magnolia Compressor Station engine room. Q ft building constructed in the 1950's. Transcite paneling and ACM roofing.	Magnolia	$673.53			$0	$318.89		$0	$167.31		$0	$0	$40
Magnolia Compressor Station Auxiliary building. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	$673.53			$0	$318.89		$0	$167.31		$0	$0	$18
Magnolia Compressor Station Field Shop. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	$673.53			$0	$318.89		$0	$167.31		$0	$0	$9
Magnolia Compressor Station piping insulation	Magnolia	$673.53	0	0	$0	$318.89	0	$0	$167.31	0	$0	$0	$7
Magnolia Compressor Station - #1 Purifier Reactivator	Magnolia	$673.53			$0	$318.89		$0	$167.31		$0	$0	$26
Magnolia Station and Field Valves - valve packing and gaskets	Magnolia, Center and Transmission lines	$673.53	0	1	$0	$318.89	1	$319	$167.31	1	$167	$0	$33
Station piping and Field piping during pipeline removals	Magnolia, Center and Transmission lines	$673.53	8	1	$5,388	$318.89	2	$638	$167.31	2	$335	$6	$112
Distribution - Miscellaneous Removal and disposal of gaskets, valve legs and coal tar	Bardstown, Center and Magnolia Distribution	$673.53	5	1	$3,368	$318.89	1	$319	$167.31	1	$167	$4	$56
GRAND TOTAL ($000's)					$9			$1			$1	$11	$302

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Location	
Asset Retirement Obligations	

Asset Description	Location	Estimated Retirement Date	Comments
Magnolia Compressor Station engine room. Q ft building constructed in the 1950's. Transcite paneling and ACM roofing.	Magnolia		
Magnolia Compressor Station Auxiliary building. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia		
Magnolia Compressor Station Field Shop. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia		
Magnolia Compressor Station piping insulation	Magnolia		A portion of this is known (app 20-feet). The rest is assuming that there will be a few other lines found or have to be assumed ACM.
Magnolia Compressor Station - #1 Purifier Reactivator	Magnolia		
Magnolia Station and Field Valves - valve packing and gaskets	Magnolia, Center and Transmission lines		General assumptions, a more detailed estimate would require additional time to review maintenance records with field personnel.
Station piping and Field piping during pipeline removals	Magnolia, Center and Transmission lines		General assumptions; additional details required.
Distribution - Miscellaneous Removal and disposal of gaskets, valve legs and coal tar	Bardstown, Center and Magnolia Distribution		General assumptions; additional details required.

GRAND TOTAL ($000's)			

FACILITY ASSUMPTIONS

Any Facility constructed before 1985 will have asbestos, unless abatement has been completed

SMALL BUSINESS OFFICES & OPER CTRS- L. F. is calculated based on 8% of total sq. ft. for removal of pipe & ductwork insulation @ $65/LN. FT. or SQ. FT. (Includes removal & air monitoring costs) Costs per Ln. Ftl is based on recent invoicing for work performed by NEC.

STOREROOMS - L. F. is calculated based on 3% of total sq. ft. for pipe and ductwork insulation @ $65/LN.FT. or SQ. FT. (Includes removal and air monitoring costs). Cost per Ln. Ft. is based on recent invoicing for work performed by NEC.

Cost to remove VCT is based on actual invoicing from NEC for work performed at South Service Center in 1994. The same costs were applied to removal of ceiling tiles.

Wiseman, Sara

From: Riggs, Eric
Sent: Wednesday, October 05, 2005 4:54 PM
To: Sundheimer, Glenn
Cc: Walker, Barry; Wiseman, Sara; Charnas, Shannon; Kinder, Debra
Subject: RE: FIN 47

Glen,

Thanks for the response. We will need for our auditors (PWC), all the backup documentation you have concerning how this number was developed.

Thanks,
Eric Riggs

From: Sundheimer, Glenn
Sent: Wednesday, October 05, 2005 1:33 PM
To: Riggs, Eric
Cc: Walker, Barry
Subject: FW: FIN 47

Eric,

To plug and abandon all of our gas wells would cost about $7,250,000. Let me know if you need anything else.

Glenn

From: McDonald, Pam
Sent: Tuesday, September 27, 2005 8:17 AM
To: Riggs, Eric
Cc: Sundheimer, Glenn
Subject: RE: FIN 47

Eric,

Glenn Sundheimer will contact you directly concerning the Gas Wells.

Pam

Pam McDonald
Energy Delivery Budgeting
Ext. 2850

From: Riggs, Eric
Sent: Monday, September 26, 2005 4:08 PM
To: McDonald, Pam
Cc: Paciorek, Marcelo; Wiseman, Sara; Charnas, Shannon; Kinder, Debra
Subject: RE: FIN 47

Pam,

We need to report our findings to E.ON soon regarding the impact of FIN 47 on the Utility. Do you have any response for the capping and abandonment of Gas Wells? I would like to confirm from the emails below that the information regarding the number of poles and cross arms disposed of in a year is not available.

Thanks,
Eric Riggs

2822

From: McDonald, Pam
Sent: Thursday, September 08, 2005 7:44 AM
To: Riggs, Eric
Cc: Paciorek, Marcelo
Subject: RE: FIN 47

Eric,

I will send these questions out to the parties involved for their response.

Pam

Pam McDonald
Energy Delivery Budgeting
Ext. 2850

From: Riggs, Eric
Sent: Thursday, September 08, 2005 7:36 AM
To: McDonald, Pam
Cc: Wiseman, Sara; Kinder, Debra; Paciorek, Marcelo
Subject: RE: FIN 47

Pam,

Thanks for the information provided on electric distribution assets. We are hopeful that the response well satisfy all of the interested parties.

There are still a couple of big areas of concern. Have you been able to get anything on the capping and abandonment of gas wells? The Legal Department suggests that an ARO be established due to state and federal regulations requiring purging and capping of abandoned gas pipes and plugging of wells.

Also, Asbestos is still being investigated as an ARO. Is there any information of the potential asbestos issue with the service/office centers for the companies?

I have a related request to the poles and cross arms issue. I am in the process of listing the poles and cross arms in the Fixed Asset System so that ARO calculations can be made. Does anyone in Distribution have a number of poles and cross arms physically removed every year, abandoned in place, or otherwise reported to Property Accounting to be retired? Is there a policy on removing poles that are abandoned in place after a period of time? If poles are abandoned in place, are they reported to Property Accounting to be retired?

Thanks,
Eric Riggs

From: Riggs, Eric
Sent: Thursday, August 25, 2005 10:18 AM
To: McDonald, Pam
Cc: Wiseman, Sara; Kinder, Debra; Miller, Jon; Paciorek, Marcelo
Subject: RE: FIN 47

Pam,

Thanks for the reply. Another utility that we are comparing notes with stated that they were considering the costs associated with abandoning gas pipe (Cutting, purging, filling with concrete). Is Gas Operations considering this in their response? Is the capping and abandonment of gas wells being considered? I take it from the email below that asbestos will be considered. In regards to asbestos in company facilities, I have talked to Jerry Grant in the recent past, but never requested a formal response. Would that issue be considered in your review?

Thanks,
Eric

From: McDonald, Pam
Sent: Tuesday, August 23, 2005 2:26 PM
To: Riggs, Eric
Cc: Wiseman, Sara; Kinder, Debra; Miller, Jon; Paciorek, Marcelo
Subject: RE: FIN 47

Eric,

After discussing this with Marcelo, our approach will be to calculate the incremental removal cost associated with disposing of contaminated assets. I have sent spreadsheets to Electric Operations, Substations, and Gas Operations to identify the type of contaminated assets they would have and to provide an estimate of the incremental removal cost associated with disposal. The preliminary feedback that I am receiving from the field is that we have replaced the majority of our assets containing PCB's, and that very little exist. It is our practice to test this equipment when it is removed from service, and it is rare to find one that is contaminated. The incremental removal cost would be immaterial on these assets. Some of our assets such as wood poles, cross arms, and batteries by their nature require special disposal treatment and 100% of these assets would qualify. The removal cost associated with these assets are included in our yearly estimated removal expense.

I will send you our estimated removal cost when I receive it from the field which should be in the next week. The data is not available on the quantity and year installed. This will have to be estimated using property records and an estimated percentage.

Pam

Pam McDonald
Energy Delivery Budgeting
Ext. 2850

From: Riggs, Eric
Sent: Monday, August 22, 2005 3:11 PM
To: McDonald, Pam; Miller, Jon
Cc: Wiseman, Sara; Kinder, Debra
Subject: RE: FIN 47

Pam, Jon,

We are fast closing in on the deadline to provide information to EON on this issue. Do you have anything as of yet? Please let us know where you stand, regardless of where that might be, by Wednesday.

Thanks,
Eric

From: Riggs, Eric
Sent: Friday, August 12, 2005 2:53 PM
To: McDonald, Pam; Miller, Jon
Cc: Wiseman, Sara; Kinder, Debra; Charnas, Shannon
Subject: FIN 47

Pam, Jon,

Would you provide an update on the progress being made in regards to FIN47? I have attached a file listing general requirements that we believe that will be necessary in order for us to make the necessary calculations.

<< File: Data Requirements for FIN 47.doc >>

Thanks,
Eric Riggs

From: McDonald, Pam
Sent: Wednesday, July 27, 2005 12:08 PM
To: Riggs, Eric
Cc: Miller, Jon

Subject: RE: ARO Property

Eric,

After our last meeting, I have read through the documentation and developed an action plan. Most of the people I need to talk to have been on vacation or busy with other priorities. I will try to work on it next week and give you an update. Sorry for the delay.

Pam

Pam McDonald
Energy Delivery Budgeting
Ext. 2850

From: Riggs, Eric
Sent: Wednesday, July 27, 2005 11:15 AM
To: McDonald, Pam
Subject: RE: ARO Property

Pam,

No, He didn't provide any documentation to me. When this first got started last August, he provided the list that I handed out at the last meeting. Where or from whom he got that information I don't know. In the meeting we had today with just Sara, Debbie, myself, and Shannon, we were asked to contact Jon Miller and yourself to see where you stood with the items.

Thanks,
Eric

From: McDonald, Pam
Sent: Wednesday, July 27, 2005 10:49 AM
To: Riggs, Eric
Subject: ARO Property

Eric,

Did Mr. Winkler provide what you needed for this documentation?

Thanks,
Pam

Pam McDonald
Energy Delivery Budgeting
Ext. 2850

Wiseman, Sara

From: Scott, Valerie
Sent: Tuesday, October 05, 2004 7:05 PM
To: Wiseman, Sara
Subject: FW: Review of Exposure Draft - Interpretation FAS 143

Attachments: FAS 143 Interpretation Exposure Draft.doc; FAS 143 Interpretation Exposure Draft Attachment I.doc; FAS 143 Interpretation Exposure Draft Attachment II.xls

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Sara,

This is the e-mail I mentioned this morning about the SFAS 143 interpretation & what we told E.ON so far. They've not asked for numbers yet, but I suspect it will take us a while to calculate them once they do ask.

Valerie

-----Original Message-----
From: Scott, Valerie
Sent: Monday, August 16, 2004 5:09 PM
To: 'Jungwirth, Brian'
Cc: Dalton, LaStacia; Skaggs, Gerald; French, M. Glen; Hudson, Rusty; Strange, Vicki; 'Waldhausen, Nicola'; 'Brandt, Henning'; 'Gahlen, Christian'; Skaggs, Gerald; Riggs, Eric
Subject: RE: Review of Exposure Draft - Interpretation FAS 143

Brian,

Once again, my apologies for the delay. Attached is our documentation for KU and LG&E.

Valerie

-----Original Message-----
From: Jungwirth, Brian [mailto:Brian.Jungwirth@eon.com]
Sent: Monday, August 16, 2004 1:11 AM
To: Scott, Valerie
Cc: Dalton, LaStacia; Skaggs, Gerald; French, M. Glen; Hudson, Rusty; Strange, Vicki; Waldhausen, Nicola; Brandt, Henning; Gahlen, Christian
Subject: AW: Review of Exposure Draft - Interpretation FAS 143

Valerie

Any final word on your assessment of the impact.

Thanks

Brian

-----Ursprüngliche Nachricht-----
Von: Jungwirth, Brian
Gesendet: Sonntag, 25. Juli 2004 12:20
An: 'Scott, Valerie'
Cc: Dalton, LaStacia; Skaggs, Gerald; French, M. Glen; Hudson, Rusty; Strange, Vicki;

Waldhausen, Nicola; Brandt, Henning; Gahlen, Christian
Betreff: AW: Review of Exposure Draft - Interpretation FAS 143

Hello Valerie,

Hope all is well in Kentucky. It has been a long time since we last communicated.

I am mainly interestedin obtaining from each market unit only an understanding if this would be applicable as well as in what ares such as the examples you mentioned below. No dollar amount is expected by August. When we understand the applicability of this in the Group, we will set up a timeline with input from each market unit. This issue will be discussed at our group accounting day which we have finally scheduled for October 4 / 5, 2004.

Thanks again

Brian

-----Ursprüngliche Nachricht-----
Von: Scott, Valerie [mailto:Valerie.Scott@lgeenergy.com]
Gesendet: Samstag, 24. Juli 2004 01:03
An: Jungwirth, Brian
Cc: Dalton, LaStacia; Skaggs, Gerald; French, M. Glen; Hudson, Rusty; Strange, Vicki
Betreff: RE: Review of Exposure Draft - Interpretation FAS 143

Hello Brian,

LaStacia Dalton forwarded your message to me about the Exposure Draft on AROs. I would like some clarification on how much information you would like by August 13. Are you primarily interested in what items owned by the Company would be affected (i.e., asbestos, utility poles, etc.) or are you looking for a dollar impact? We will have a very difficult time trying to quantify a dollar impact by that date, and may not be able to quantify a dollar impact on some items that would be covered by the ED.

Any clarification you can provide would be appreciated.

Regards,

Valerie

-----Original Message-----
From: Dalton, LaStacia
Sent: Thursday, July 22, 2004 10:03 AM
To: Skaggs, Gerald; Scott, Valerie
Subject: FW: Review of Exposure Draft - Interpretation FAS 143

Valerie and Gerald,
Please see the email below from E.ON. Could you please review this, offer a response, and please note the deadline? Thanks.

-----Original Message-----
From: Jungwirth, Brian [mailto:Brian.Jungwirth@eon.com]
Sent: Wednesday, July 21, 2004 3:46 AM
To: peter.mohnen@eon-ruhrgas.com; David.Baumber@eon-uk.com; Christoph.Meyer@eon-energie.com; charlotte.pennander@sydkraft.se; Dalton, LaStacia; French, M. Glen
Cc: EON-FRW1; Wilhelm, Michael; Hansal, Uwe; Haeger, Bernd; Brambosch, Wolfgang
Subject: Review of Exposure Draft - Interpretation FAS 143

Dear all,

On June 17, the FASB issued an Exposure Draft of a proposed Interpretation of FASB Statement No. 143 on the subject of "Accounting for Conditional Asset Retirement Obligations". That document can be downloaded from http://www.fasb.org/draft/ed_prop_interp_aro.pdf. The proposed Interpretation would require the recognition of an ARO liability even if the obligation is conditional on a future event, provided that the fair value of the obligation can be reasonably estimated. If approved, the Interpretation will become effective on January 1, 2006.

For an assessment of the proposed Interpretation's relevance to the E.ON Group, we ask you to discuss the Exposure Draft with subsidiaries' accounting representatives in your respective market units and provide us with a summary of your findings by August 13. If you disagree with the FASB's reasoning and the conclusions made in the Exposure Draft and if you would like us to submit a comment to the FASB, please note that your feedback is required earlier (by July 28) beacuse of the comment deadline.

The Exposure Draft on conditional AROs will be discussed at the E.ON Group Accounting Meeting in October.

Thank you for your support.

Mit freundlichen Grüssen/
Best regards

Brian Jungwirth

E.ON AG
Leiter Konzernrechnungswesen
Corporate Accounting
E.ON-Platz 1
40479 Düsseldorf
Germany

phone +49 211 45 79 833
fax +49 211 45 79 584

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Kentucky Utilities Company
Louisville Gas and Electric Company
Proposed Interpretation of SFAS 143, Accounting for Asset Retirement Obligations
August 16, 2004

On June 17, 2004, the Financial Accounting Standards Board issued an exposure draft for an interpretation of SFAS 143, Accounting for Asset Retirement Obligations. The exposure draft is titled "*Accounting for Conditional Asset Retirement Obligations*".

Summary of Exposure Draft

This exposure draft was issued to address the timing of recognizing liabilities for legal obligations when the retirement activity is dependent on another event (i.e. the date of retirement is currently unknown and based on a future determination or unplanned). The proposed interpretation indicates that asset retirement obligations must be recognized if the fair value of the liability can be reasonably estimated. The exposure draft indicates that "uncertainty surrounding the timing and method of settlement that may be conditional on events occurring in the future should be factored into the measurement of the liability rather than the recognition of the liability".

The expected effective date for this interpretation is fiscal years ended after December 15, 2005, or December 31, 2005 for KU and LG&E. Amounts recorded as a result of this interpretation would be accounted for as a change in accounting principle and would result in a cumulative effect adjustment similar to that recorded when SFAS 143 was initially adopted. The Companies will ask for regulatory asset and regulatory liability treatment upon the adoption of this interpretation from the Kentucky Public Service Commission so that the initial adoption would have no impact on their net incomes.

Contrary to the adoption of SFAS 143, upon adoption of this interpretation, prior years would be restated on a pro forma basis at implementation, consistent with APB Opinion No. 20, *Accounting Changes*. The Companies would not be required to restate prior 2005 quarterly results if the interpretation is adopted in the first or last quarter of 2005.

The Edison Electric Institute, an industry group, in which the Companies are members, commented on the exposure draft. A copy of that comment letter is attached as Attachment I.

Potential Obligations Identified (not included with the adoption of SFAS 143)

After an extensive review by accounting, legal, environmental, operations and senior management personnel, the following potential obligations were not included in the adoption of SFAS 143 at January 1, 2003, but could be included in the adoption of the current exposure draft interpretation:

- LG&E operates its Ohio Falls plant under a 30-year licensing agreement with the U.S. Army Corps of Engineers. This agreement requires the dam to be restored to the Corps' specifications upon abandonment of the plant. The cost of this restoration was estimated at $8 million in 2002. The Company has renewed the licensing agreement with the Corps of Engineers continually since the plants' construction and expects to renew the agreement continually at each expiration date. Because the hydro plant has an indeterminate retirement date no ARO liability was established.

- KU owns two hydro facilities, Dix Dam and Lock 7. Estimated decommissioning costs for these plants in 2002 were $1.3 million and $3.4 million, respectively; however, a legal review the hydro licenses found no specific legal obligation upon the final decommissioning of these plants. It should be noted that the permitting authorities, particularly FERC, have significant inherent discretion in setting conditions to allow a surrender of a permit. These conditions are based upon the specific facts, issues and concerns at the time of decommissioning. In the case of Lock 7, a study determined that it was likely that surrender of the FERC permit would involve both removal of generation equipment and demolition of station down to water line. Because no specific legal liability was identified and the retirement date is indeterminate no ARO liability was established at January 1, 2003.

- Some components of the Companies' Transmission and Distribution business have retirement obligations associated with them due to environmental or other contractual agreements. KU and LG&E have certain electrical equipment containing PCBs, such as transformers and capacitors, which require special disposal. Both Companies undertook a program in the 1980's to replace most of this PCB impaired equipment. Thus the Companies have few remaining obligations related to PCB contamination. The retirements related to these assets were addressed for frequency and materiality in 2002 to determine if the interim retirement would fall within the scope of SFAS 143 as described below.

    - Some substation equipment such as bushings, breakers, etc., may have retirement obligation related to PCB contaminants. If so, this equipment must be disposed of per EPA regulation. However the cost, generally less than $20K per year, is immaterial. In 2002, the Company disposed of four assets at a cost of $17K. Specific assets impacted are not identifiable until failure or replacement. See Attachment II for a listing of these assets.

    - PCB contaminated line transformers must be disposed of per environmental regulation. The company disposes of PCB contaminated line transformers through a third party vendor. LG&E costs were approximately $10K in 2002. KU costs were approximately $42K in 2002. Based on 2002 disposals the cost of this activity on an annual basis is immaterial. In addition, specific assets impacted are not identifiable until failure or replacement.

- LG&E operates wells in its gas storage system that must be plugged if abandoned, per Kentucky mines & minerals law/regulations. Because LG&E intends to operate the wells in perpetuity and the retirement date is indeterminate, no ARO was established as of January 1, 2003. The estimated cost of plugging the 546 wells was $17K per well or $9.2 million in total in 2002.

- LG&E also operates 4 above ground gas compressor stations under perpetual lease agreements. The ground leases for the Muldraugh KY, Cedar Fields IN, and Brandenburg KY (Riggs and Doe Run sites) were reviewed for contractual obligations. A 1946 letter of agreement related to one acre of the 40 acres of the Brandenburg KY (Riggs site) lease requires LG&E to "return it to lessor on the expiration of the lease in approximately the same condition as found at the present time." The estimated cost to dismantle and remove the Brandenburg station was $48K in 2002.

- Kentucky statutes and regulations govern highways and rights-of-way.

  - Kentucky State Highway rules require all encroachments on public highways to be permitted. Upon any expiration or revocation of a permit the state may require removal or relocation of the encroachment at the expense of the permit holder. Given the uncertainty of the state requiring such removal or relocation, the Companies do not believe any retirement obligation exists.

  - The state may order any level railroad crossing closed for public safety and the closure is to occur at the owners' expense. However, no statute or rule states that an abandoned or unused crossing, due solely to its abandonment or non-use and absent other circumstances, is to be considered unsafe or required to be closed. Given the uncertainty of the state requiring closure, the Companies do not believe any retirement obligation exists.

  - For overpasses and bridges air space permit can be issued. One section of air space permitting requires that any structures or attachments must be removed at the permit holder's expense upon expiration or cancellation, while two other sections provided only that the state had the discretion to require removal, relocation or restoration regarding the air space structures. The Companies do not believe any retirement obligations exist and that the obligation as primarily discretionary, rather than obligatory.

- The Department of Transportation regulations require the cutting of pipes, purging of gas and capping for gas transportation pipelines when abandoned. Since these pipelines are expected to be used in perpetuity no ARO liability was established at January 1, 2002.

- The National Electric Safety Code does not differentiate between abandoned (de-energized) or functioning (energized) electric transmission and distribution facilities. Both are to comply with the same safety and serviceability standards. Our current obligations of maintenance and repair would continue after abandonment (de-energizing) and no new or specific obligations on abandonment arise. Since these assets are expected to be used in perpetuity no ARO liability was established at January 1, 2002.

- Personal computer monitors contain metals that require special disposal. The Companies are negotiating a new contract to dispose of used personal computer equipment that will address these potential costs.

- Many buildings built prior to the early 1980's contain some asbestos in the building materials. Asbestos requires special processes to remove, if it is disturbed. The Companies' position has generally been to retire facilities intact and to incur the costs to remove them only if necessary; accordingly, no ARO liability was established at January 1, 2002, but one would be established should plans for a building change.

Attachment I

701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004-2696
Telephone 202-508-5527

EEI EDISON ELECTRIC INSTITUTE

July 30, 2004

Mr. Lawrence Smith
Director – Technical Application & Implementation Activities
Financial Accounting Standards Board
401 Merritt 7
P.O. Box 5116
Norwalk, CT 06856-5116

Subject: File Reference No. 1099-001

Dear Mr. Smith:

The Edison Electric Institute (EEI) appreciates the opportunity to comment on the Financial Accounting Standards Board's (FASB or the Board) Exposure Draft (ED) of a Proposed Interpretation, *Accounting for Conditional Asset Retirement Obligations an interpretation of FASB Statement No. 143* (Statement 143).

EEI is the association of the United States investor-owned electric utilities and industry affiliates and associates worldwide. Its U.S. members serve over 90 percent of all customers served by the investor-owned segment of the industry. They generate approximately three-quarters of all the electricity generated by electric utilities in the country and serve approximately 70 percent of all ultimate customers in the nation. EEI members own a majority of the transmission and generation facilities in the nation.

EEI supports the Board's desire to promote consistent application of Statement 143 and commends the Board for this effort. However, we believe that the proposed Interpretation will result in more diversity in practice in the application of Statement 143 than currently exists today. Although the proposed Interpretation includes examples of various types of conditional asset retirement obligations (AROs), a company's individual facts and circumstances could change the determination of whether a conditional ARO exists. The determination of whether a settlement date is indeterminate could vary from company-to-company and the calculation of how to include a measurement of uncertainty in the calculation of the ARO would likely vary from one company to the next.

EEI believes that the current requirements to record obligations for which a company could be held legally liable will yield a more consistent result. Statement 143, versus the proposed Interpretation, provides a more objective basis on which to determine whether an ARO exists because it is based upon legal requirements. The law will remove much of the subjectivity in determining whether an ARO exists. In connection with the initial adoption of Statement 143, legal counsel was consulted to identify asset retirement obligations. Application of the proposed Interpretation would likely result in the recording of obligations on the financial statements that are not considered obligations from a legal perspective, resulting in internal inconsistencies.

Further, the scope of Statement 143 includes any obligations under the doctrine of promissory estoppel. The current exposure draft intends to expand liability recognition such that any requirement to handle waste appropriately upon the removal of the asset or any component of the asset should fall within the scope of an ARO. Some parties could interpret the recording of these types of liabilities, for which a company is not legally liable, as a promise to perform a future action or event. This would then scope these liabilities, not previously legally required, into the category of legally required liabilities through the doctrine of promissory estoppel, *e.g.,* examples 1 through 3 in the exposure draft or any other similar instances where a legal obligation under Statement 143 does not currently exist. EEI believes that this proposed accounting could expose companies to risk in this respect and is an inappropriate and unintended result.

Issue 1: *The Board concluded that the uncertainty surrounding the timing and method of settlement should not affect whether the fair value of a liability for a conditional asset retirement obligation would be recognized but rather, should be factored into the measurement of the liability. Do you agree with the Board's conclusion? If not, please provide your alternative view and the basis for it.*

EEI agrees, in general, with the Board's re-affirmation in Issue 1 of the ED of the paragraph A17 as found in Statement 143, which defines a conditional ARO. However, EEI fundamentally *disagrees* with the Board's specific *interpretation* of a conditional obligation as stated in the ED. EEI understands that Statement 143 provides that uncertainty regarding the amount and timing of cash flows of a *legal obligation*, does not exempt a company from recognizing a conditional ARO. However, the proposed Interpretation incorrectly scopes an ARO obligation that does not meet the definition of Concepts No. 6 as follows:

1. The entity has a present duty or responsibility to one or more other entities that entails settlement by probable future transfer or use of assets at a specified or determinable date, on occurrence of a specified event, or on demand.

Paragraph B9 states that "if an entity is required by current laws, regulations, or contracts to settle an asset retirement obligation upon retirement of the asset, that requirement imposes a present duty." When a company is constructing or acquiring a facility, the event that imposes the duty to perform certain activities has not yet occurred. In the example of asbestos, the specific event that actually and legally obligates the entity to incur costs is when the asbestos becomes friable, or when that company elects to demolish the facility, at which point the determination that asbestos will be removed has been made. Up to that point, there are no legal obligations that would require the removal of asbestos. A company does not record a liability on the day it acquires or constructs a facility for the costs, excluding asbestos, to demolish or dismantle the facility because, under SFAS 143, there is no legal requirement for this activity to occur. It seems inconsistent that the timing of the obligating event is viewed differently for certain components of the facility (normal demolition cost versus asbestos related costs) solely because of the nature of the costs to be incurred. FASB's proposed Interpretation should not generalize issues to fit every situation. Statement 143 relies on legal review of obligations by attorneys representing a particular company. It appears that FASB may be imposing their own definition of a legal commitment that obligates a company on top of a company's legal analysis.

2. The duty or responsibility obligates a particular entity, leaving it little or no discretion to avoid the future sacrifice.

Paragraph B10 indicates that the Board believes that a company's ability to indefinitely defer settlement of an ARO does not provide the entity discretion to avoid the future sacrifice and that, implicit in this conclusion, is the belief that no tangible asset will last forever. EEI does not agree with the Board's conclusion. A company does have discretion on whether or not it will remove an asset to the extent that there is no legal obligation for the company to remove that facility. While a company may not be able to operate a facility indefinitely, or may determine to discontinue operations early because of performance or economics of the unit, a company may elect to mothball a facility indefinitely and would not elect to incur dismantling/disposal costs unless it was economically feasible to do so or some other event occurred which would trigger a requirement or decision to dismantle the facility.

3. The transaction or other event obligating the entity has already happened.

Paragraph B11 concludes that "Statement 143 states that the obligating event is the acquisition, construction, or development and (or) the normal operation of the long-lived asset. Thus, the obligating event occurs when there is a duty or responsibility and the existence of the condition relating to the duty or responsibility. The obligating event is not the retirement of the asset."

As discussed above, EEI does not believe that the obligating event has occurred until the point in time where a company elects to demolish a facility. The discussion of Statement 143 relating to the existence of a condition relating to the duty or responsibility is still based upon the existence of a legal obligation for the company to incur such costs at a future point in time. If a company has placed a facility in reserve shutdown, or mothballed a facility indefinitely, as long as the unit is not demolished, there would be no law that would require the company to incur these costs. In the example of treated utility poles, a company has no legal liability to remediate the poles when the poles are removed from service unless it elects to dispose of the pole as a solid waste. A company also may decide to donate or sell that pole to another user for use as a treated wood product and would have no liability regarding treatment or disposal of the pole. Because there is no legal requirement for these types of costs, based upon the normal use or operation of the asset, EEI does not believe they would qualify as an ARO under Statement 143.

Issue 2: *Are there instances where law or regulation obligates an entity to perform retirement activities but allows the entity to permanently avoid settling the obligation? If so, please provide specific examples.*

Most environmental regulations of which EEI is aware require an entity to dispose of certain materials in a particular fashion to the extent that the material is considered contaminated. EEI is not aware of specific regulations that allow a company to permanently avoid settling an obligation of this sort, to the extent that an event has occurred, which requires disposal under the appropriate regulations. However as noted above, an item such as a treated utility pole may be settled by removing the pole from service and selling or donating the pole in its current condition to another user (for use in parking lots or some other form of secondary use). EEI's understanding is that any future liability regarding the disposal of the pole would transfer to the party who took possession of the pole and that liability is not triggered until when, and if, the party that owns the pole decides to dispose of it as a solid waste. Additionally utility transformers, which may contain polychlorinated biphenyls (PCBs), are typically taken out of service when one fails or will be replaced for operational reasons. A company may elect to warehouse or store that transformer without removing the PCBs thereby avoiding any obligation as the disposal regulations covering this material are not triggered unless the oil is removed or is spilled, or the electrical device is scrapped or recycled.

Additionally, as also discussed above, a company may permanently avoid settling an obligation such as asbestos to the extent the facility is left intact and no issues arise which require clean up of a spill or release of a material such as friable asbestos.

EEI commends FASB in providing diverse examples in the ED. However, EEI believes that Example 2 should be changed to reflect the indeterminate useful life of wood poles (consistent with Example 4 on oil refineries) and, as covered in these comments, a company may have no liability to remediate the poles when they are finally removed from service.

EEI appreciates the opportunity to respond to the proposed Interpretation. We hope that our comments will be helpful and look forward to working with the Board in the future.

Sincerely,

/ s /

David K. Owens
Executive Vice President, Business Operations

Kentucky Utilities / Louisville Gas and Electric Company
Assets Requiring Special Disposal Treatment

Asset	Legal Requirement - Code of Federal Regulations (1)	Notes
Capacitors - Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. 10% of these units are likely to contain PCBs
Reclosers - Fluid Filled	40 CFR 761	All units older than 1980 must tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Breakers - Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. Fluid is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Bushings - Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. Units are sealed and therefore the fluid is not replaced during maintenance. Approximately 25% of these assets are likely to contain PCB's
Regulators - Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Switches -Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Substation Transformers - Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. Oil is replaced during regular maintenance schedule. Less than 5% of these assets are likely to contain PCB's
Residential Transformers - Fluid Filled	40 CFR 761	All units older than 1980 must be tested when the units are taken off line. Units are operated until they fail. Approximately 10% of these assets are likely to contain PCB's
Batteries	40 CFR 270	These units are sent to a recycle center.
Cable - Oil Filled	40 CFR 761	All oil filled cable older than 1980 must be tested when taken out of service. Less than 5% of these assets are likely to contain PCB's
Wood Poles	40 CFR 240-299	The landfill must be notified that these units contain harmful chemicals. Additional costs are charged by the landfill operators for disposal.
Cross Arms	40 CFR 240-299	The landfill must be notified that these units contain harmful chemicals. Additional costs are charged by the landfill operators for disposal.
Large Diameter Gas Steel Pipe	40 CFR 761	All steel pipe is tested for PCB presence when taken out of service. Historical data indicates very infrequent PCB presence in distribution or storage field piping 4-inches in diameter or more. Less than 5% of pipe is estimated to have PCB contamination.
Residential Gas Pipe	40 CFR 761	All steel pipe is tested for PCB presence when taken out of service. All pipe with less than 4-inch diameter must be disposed of as scrap or in a landfill. Additional costs are charged by landfill operators for disposal. If left in place, pipe is to be grouted or otherwise filled to prohibit reuse.

(1)
Resource Conservation and Recovery Act - 40 CFR Parts 240-299
Toxic Substance Control Act - Parts 40 CFR 761

Wiseman, Sara

From:	Beatty, Stephen
Sent:	Thursday, October 06, 2005 3:22 PM
To:	Beatty, Stephen; Wiseman, Sara
Cc:	Harmeling, Dave; Probus, Dennis (LGE); Walton, Ed; Rieth, Tom
Subject:	RE: Asbestos
Attachments:	Asbestos Removal-Muldraugh.xls

Please use this updated version.

Asbestos
moval-Muldraugh.xl:

From:	Beatty, Stephen
Sent:	Thursday, October 06, 2005 2:10 PM
To:	Wiseman, Sara
Cc:	Harmeling, Dave; Probus, Dennis (LGE); Walton, Ed; Rieth, Tom
Subject:	Asbestos

Sara:

Enclosed is Muldraugh's responsibility. This is the best estimate we can devise under such short notice. Please call me if you have any questions. Some of these costs look low to me. We will attempt to investigate the costs in more detail as time allows.

Steve Beatty

<< File: Asbestos Removal-Muldraugh.xls >>

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
IM&E OFFICE: It is assumed that this building contains ACM floor tiles which are currently covered by non-ACM tiles. The wall and ceiling insulation is presumed to be ACM.	Muldraugh Station	$1.90	2,500	**$4,750**	#####	792	**$7,920**	$10.00	792	**$7,920**	$5.00	126	**$630**
KEWANEE BOILER ROOM: ACM boiler piping insulation still exists from the boiler to where it enters the Compressor Building. The boiler insulation is Presumed ACM.	Muldraugh Station	$1.90	512	**$973**	$1.95	0	**$0**	$1.95	0	**$0**	$65.00	125	**$8,125**
PURIFIER 1: All piping and pressure vessel ACM was replaced in 2001. Transite panels still serve as a wind break. PACM in old control box. PACM on Reboiler and Heat Exchanger gaskets.	Muldraugh Station	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
COMPRESSOR BUILDING: This building was presumed to have originally been constructed in the late 1930's with modifications and additions in the 1950's, 1960's, and 1970's. ACM flange gaskets, valve packing, and various compressor gaskets have been identified and some of it has been abated. ACM caulking has been discovered on the windows.	Muldraugh Station	$1.90	0	**$0**	$1.95	0	**$0**	$1.95	0	**$0**	$7.00	1538	**$10,766**
PURIFIER 2: The regenerator contains ACM vessel insulation although minimal sections have been abated. The boiler insulation is Presumed ACM.	Muldraugh Station	$4.00	2,700	**$10,800**	$1.95		**$0**	$1.95		**$0**	$65.00	0	**$0**
PURIFIER 3: The boiler insulation is Presumed ACM.	Muldraugh Station	$1.90	608	**$1,155**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
ABANDONED H2S INCINERATOR: This facility contains a transite wind break, ACM valve packing and ACM flange gaskets.	Muldraugh Station	$1.90	0	**$0**	$1.95	0	**$0**	$1.95	0	**$0**	$65.00	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
LOCKER ROOM: The facility contains ACM asphalt roofing. It is unknown if any other ACM exists so it was assumed that the insulation and dry wall are PACM.	Muldraugh Station	$1.90	630	**$1,197**	$1.95	200	**$390**	$1.95		**$0**	$65.00	0	**$0**
STATION VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Station	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
STATION PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement. Includes the removal of ACM from Turbine Separators.	Muldraugh Station	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00	200	**$13,000**
MULDRAUGH FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Storage Field	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
MULDRAUGH FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Storage Field	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00	200	**$13,000**
DOE RUN FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Field	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
DOE RUN FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Field	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00	400	**$26,000**
DOE RUN DEEP FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Deep Field	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
DOE RUN DEEP FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Deep Field	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00	300	**$19,500**
MULDRAUGH DISTRIBUTION: Miscellaneous disposal of gaskets, valve packing, coal tar pipe and stopbox valve legs. Excludes pipe abandoned in place.	Muldraugh Storage-Distribution Stopbox Valve Legs.	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00	100	**$6,500**
GRAND TOTAL ($000's)				$14			$0			$0			$97

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
IM&E OFFICE: It is assumed that this building contains ACM floor tiles which are currently covered by non-ACM tiles. The wall and ceiling insulation is presumed to be ACM.	Muldraugh Station		**$0.00**	**$0**			**$0**	**$5.00**	1568	**$7,840**	$1.35	0	**$0**
KEWANEE BOILER ROOM: ACM boiler piping insulation still exists from the boiler to where it enters the Compressor Building. The boiler insulation is Presumed ACM.	Muldraugh Station	$65.00	**$345.00**	**$22,425**			**$0**		0	**$0**	$1.35	0	**$0**
PURIFIER 1: All piping and pressure vessel ACM was replaced in 2001. Transite panels still serve as a wind break. PACM in old control box. PACM on Reboiler and Heat Exchanger gaskets.	Muldraugh Station			**$5,000**			**$0**	**$5.00**	1099	**$5,495**	$1.35	0	**$0**
COMPRESSOR BUILDING: This building was presumed to have originally been constructed in the late 1930's with modifications and additions in the 1950's, 1960's, and 1970's. ACM flange gaskets, valve packing, and various compressor gaskets have been identified and some of it has been abated. ACM caulking has been discovered on the windows.	Muldraugh Station			**$50,000**		0	**$0**	**$1.00**	0	**$0**	$1.35	0	**$0**
PURIFIER 2: The regenerator contains ACM vessel insulation although minimal sections have been abated. The boiler insulation is Presumed ACM.	Muldraugh Station	$65.00	898	**$58,370**			**$0**			**$0**	$1.35	0	**$0**
PURIFIER 3: The boiler insulation is Presumed ACM.	Muldraugh Station	$65.00	308	**$20,020**			**$0**			**$0**	$1.35	0	**$0**
ABANDONED H2S INCINERATOR: This facility contains a transite wind break, ACM valve packing and ACM flange gaskets.	Muldraugh Station			**$0**			**$0**	**$5.00**	190	**$950**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
LOCKER ROOM: The facility contains ACM asphalt roofing. It is unknown if any other ACM exists so it was assumed that the insulation and dry wall are PACM.	Muldraugh Station			**$0**			**$0**			**$0**	$1.35	266	**$359**
STATION VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Station			**$60,000**			**$0**			**$0**	$1.35	0	**$0**
STATION PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement. Includes the removal of ACM from Turbine Separators.	Muldraugh Station			**$3,500**			**$0**			**$0**	$1.35	0	**$0**
MULDRAUGH FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Storage Field			**$50,000**			**$0**			**$0**	$1.35		**$0**
MULDRAUGH FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Storage Field			**$0**			**$0**			**$0**	$1.35		**$0**
DOE RUN FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Field			**$100,000**			**$0**			**$0**	$1.35		**$0**
DOE RUN FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Field			**$0**		**$0.00**	**$0**			**$0**	$1.35		**$0**
DOE RUN DEEP FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Deep Field			**$30,000**		**$0.00**	**$0**			**$0**	$1.35		**$0**
DOE RUN DEEP FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Deep Field			**$0**			**$0**			**$0**	$1.35		**$0**
MULDRAUGH DISTRIBUTION: Miscellaneous disposal of gaskets, valve packing, coal tar pipe and stopbox valve legs. Excludes pipe abandoned in place.	Muldraugh Storage-Distribution Stopbox Valve Legs.			**$40,000**			**$0**			**$0**	$1.35		**$0**
GRAND TOTAL ($000's)				**$439**			**$0**			**$6**	$1.35		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
IM&E OFFICE: It is assumed that this building contains ACM floor tiles which are currently covered by non-ACM tiles. The wall and ceiling insulation is presumed to be ACM.	Muldraugh Station	$98.89	5	**$494**	######	5	1	**$811**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
KEWANEE BOILER ROOM: ACM boiler piping insulation still exists from the boiler to where it enters the Compressor Building. The boiler insulation is Presumed ACM.	Muldraugh Station	$98.89	1	**$99**	######	1	1	**$162**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
PURIFIER 1: All piping and pressure vessel ACM was replaced in 2001. Transite panels still serve as a wind break. PACM in old control box. PACM on Reboiler and Heat Exchanger gaskets.	Muldraugh Station	$98.89	0	**$0**	######			**$0**	$81.04		**$0**	$1,384.00	1	**$1,384**
COMPRESSOR BUILDING: This building was presumed to have originally been constructed in the late 1930's with modifications and additions in the 1950's, 1960's, and 1970's. ACM flange gaskets, valve packing, and various compressor gaskets have been identified and some of it has been abated. ACM caulking has been discovered on the windows.	Muldraugh Station	$98.89	0	**$0**	######	5	1	**$811**	$81.04	0	**$0**	$1,384.00	1	**$1,384**
PURIFIER 2: The regenerator contains ACM vessel insulation although minimal sections have been abated. The boiler insulation is Presumed ACM.	Muldraugh Station	$98.89	10	**$989**	######	10	1	**$1,621**	$81.04	1	**$81**	$1,384.00	2	**$2,768**
PURIFIER 3: The boiler insulation is Presumed ACM.	Muldraugh Station	$98.89	3	**$297**	######	3	1	**$486**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
ABANDONED H2S INCINERATOR: This facility contains a transite wind break, ACM valve packing and ACM flange gaskets.	Muldraugh Station	$98.89		**$0**	######			**$0**	$81.04		**$0**	$1,384.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
LOCKER ROOM: The facility contains ACM asphalt roofing. It is unknown if any other ACM exists so it was assumed that the insulation and dry wall are PACM.	Muldraugh Station	$98.89	5	**$494**	######	5	1	**$811**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
STATION VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Station	$98.89	0	**$0**	######	0	0	**$0**	$81.04	2	**$162**	$1,384.00	1	**$1,384**
STATION PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement. Includes the removal of ACM from Turbine Separators.	Muldraugh Station	$98.89		**$0**	######			**$0**	$81.04		**$0**	$1,384.00		**$0**
MULDRAUGH FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Storage Field	$98.89		**$0**	######			**$0**	$81.04	2	**$162**	$1,384.00	1	**$1,384**
MULDRAUGH FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Storage Field	$98.89		**$0**	######			**$0**	$81.04		**$0**	$1,384.00		**$0**
DOE RUN FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Field	$98.89		**$0**	######			**$0**	$81.04	2	**$162**	$1,384.00	1	**$1,384**
DOE RUN FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Field	$98.89		**$0**	######			**$0**	$81.04		**$0**	$1,384.00		**$0**
DOE RUN DEEP FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Deep Field	$98.89		**$0**	######			**$0**	$81.04		**$0**	$1,384.00		**$0**
DOE RUN DEEP FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Deep Field	$98.89		**$0**	######			**$0**	$81.04		**$0**	$1,384.00		**$0**
MULDRAUGH DISTRIBUTION: Miscellaneous disposal of gaskets, valve packing, coal tar pipe and stopbox valve legs. Excludes pipe abandoned in place.	Muldraugh Storage-Distribution Stopbox Valve Legs.	$98.89		**$0**	######			**$0**	$81.04		**$0**	$1,384.00		**$0**
GRAND TOTAL ($000's)				**$2**				**$4**			**$1**			**$14**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Re bag, 44" x 60" x	
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units
IM&E OFFICE: It is assumed that this building contains ACM floor tiles which are currently covered by non-ACM tiles. The wall and ceiling insulation is presumed to be ACM.	Muldraugh Station	$606.32	1	**$606**	$775.06	2	**$1,550**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	20
KEWANEE BOILER ROOM: ACM boiler piping insulation still exists from the boiler to where it enters the Compressor Building. The boiler insulation is Presumed ACM.	Muldraugh Station	$606.32	1	**$606**	$775.06	1	**$775**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	30
PURIFIER 1: All piping and pressure vessel ACM was replaced in 2001. Transite panels still serve as a wind break. PACM in old control box. PACM on Reboiler and Heat Exchanger gaskets.	Muldraugh Station	$606.32	0	**$0**	$775.06	1	**$775**	$707.85	0	**$0**	$1,773.00	0	**$0**	$5.40	10
COMPRESSOR BUILDING: This building was presumed to have originally been constructed in the late 1930's with modifications and additions in the 1950's, 1960's, and 1970's. ACM flange gaskets, valve packing, and various compressor gaskets have been identified and some of it has been abated. ACM caulking has been discovered on the windows.	Muldraugh Station	$606.32	1	**$606**	$775.06	2	**$1,550**	$707.85	0	**$0**	$1,773.00	0	**$0**	$5.40	10
PURIFIER 2: The regenerator contains ACM vessel insulation although minimal sections have been abated. The boiler insulation is Presumed ACM.	Muldraugh Station	$606.32	2	**$1,213**	$775.06	4	**$3,100**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	200
PURIFIER 3: The boiler insulation is Presumed ACM.	Muldraugh Station	$606.32	1	**$606**	$775.06	2	**$1,550**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	50
ABANDONED H2S INCINERATOR: This facility contains a transite wind break, ACM valve packing and ACM flange gaskets.	Muldraugh Station	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Re bag, 44" x 60" x	
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units
LOCKER ROOM: The facility contains ACM asphalt roofing. It is unknown if any other ACM exists so it was assumed that the insulation and dry wall are PACM.	Muldraugh Station	$606.32	1	**$606**	$775.06	2	**$1,550**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	50
STATION VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Station	$606.32	0	**$0**	$775.06	1	**$775**	$707.85	0	**$0**	$1,773.00	0	**$0**	$5.40	200
STATION PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement. Includes the removal of ACM from Turbine Separators.	Muldraugh Station	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	50
MULDRAUGH FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Storage Field	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	150
MULDRAUGH FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Storage Field	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	50
DOE RUN FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Field	$606.32		**$0**	$775.06	1	**$775**	$707.85		**$0**	$1,773.00		**$0**	$5.40	300
DOE RUN FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Field	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	100
DOE RUN DEEP FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Deep Field	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	50
DOE RUN DEEP FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Deep Field	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	100
MULDRAUGH DISTRIBUTION: Miscellaneous disposal of gaskets, valve packing, coal tar pipe and stopbox valve legs. Excludes pipe abandoned in place.	Muldraugh Storage-Distribution Stopbox Valve Legs.	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	100
GRAND TOTAL ($000's)				**$4**			**$11**			**$3**			**$7**		

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	quired - Glove 6 mil plastic	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit									
		Total Cost Glove Bag		Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense
IM&E OFFICE: It is assumed that this building contains ACM floor tiles which are currently covered by non-ACM tiles. The wall and ceiling insulation is presumed to be ACM.	Muldraugh Station	**$108**	**$37**	$673.53	1	1	**$674**	$318.89	1	**$319**	$167.31	1	**$167**
KEWANEE BOILER ROOM: ACM boiler piping insulation still exists from the boiler to where it enters the Compressor Building. The boiler insulation is Presumed ACM.	Muldraugh Station	**$162**	**$15**	$673.53	0.2	1	**$135**	$318.89	0.2	**$64**	$167.31	1	**$167**
PURIFIER 1: All piping and pressure vessel ACM was replaced in 2001. Transite panels still serve as a wind break. PACM in old control box. PACM on Reboiler and Heat Exchanger gaskets.	Muldraugh Station	**$54**	**$30**	$673.53	0.2	1	**$135**	$318.89	0.2	**$64**	$167.31	1	**$167**
COMPRESSOR BUILDING: This building was presumed to have originally been constructed in the late 1930's with modifications and additions in the 1950's, 1960's, and 1970's. ACM flange gaskets, valve packing, and various compressor gaskets have been identified and some of it has been abated. ACM caulking has been discovered on the windows.	Muldraugh Station	**$54**	**$20**	$673.53	2	0	**$0**	$318.89	0	**$0**	$167.31	0	**$0**
PURIFIER 2: The regenerator contains ACM vessel insulation although minimal sections have been abated. The boiler insulation is Presumed ACM.	Muldraugh Station	**$1,080**	**$29**	$673.53	3	1	**$2,021**	$318.89	1	**$319**	$167.31	1	**$167**
PURIFIER 3: The boiler insulation is Presumed ACM.	Muldraugh Station	**$270**	**$58**	$673.53	1	1	**$674**	$318.89	1	**$319**	$167.31	1	**$167**
ABANDONED H2S INCINERATOR: This facility contains a transite wind break, ACM valve packing and ACM flange gaskets.	Muldraugh Station	**$0**	**$21**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	quired - Glove 6 mil plastic	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit									
		Total Cost Glove Bag		Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense
LOCKER ROOM: The facility contains ACM asphalt roofing. It is unknown if any other ACM exists so it was assumed that the insulation and dry wall are PACM.	Muldraugh Station	**$270**	**$10**	$673.53	1	1	**$674**	$318.89	1	**$319**	$167.31	1	**$167**
STATION VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Station	**$1,080**	**$3**	$673.53	0.2	1	**$135**	$318.89	0.5	**$159**	$167.31	0.5	**$84**
STATION PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement. Includes the removal of ACM from Turbine Separators.	Muldraugh Station	**$270**	**$73**	$673.53	4	1	**$2,694**	$318.89	1	**$319**	$167.31	1	**$167**
MULDRAUGH FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Storage Field	**$810**	**$6**	$673.53	0.2	1	**$135**	$318.89	0.5	**$159**	$167.31	0.5	**$84**
MULDRAUGH FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Storage Field	**$270**	**$63**	$673.53	5	1	**$3,368**	$318.89	2	**$638**	$167.31	1	**$167**
DOE RUN FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Field	**$1,620**	**$4**	$673.53	0.5	1	**$337**	$318.89	0.5	**$159**	$167.31	1	**$167**
DOE RUN FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Field	**$540**	**$127**	$673.53	7	1	**$4,715**	$318.89	4	**$1,276**	$167.31	2	**$335**
DOE RUN DEEP FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Deep Field	**$270**	**$0**	$673.53	0.5	1	**$337**	$318.89	1	**$319**	$167.31	1	**$167**
DOE RUN DEEP FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Deep Field	**$540**	**$50**	$673.53	7	1	**$4,715**	$318.89	4	**$1,276**	$167.31	2	**$335**
MULDRAUGH DISTRIBUTION: Miscellaneous disposal of gaskets, valve packing, coal tar pipe and stopbox valve legs. Excludes pipe abandoned in place.	Muldraugh Storage-Distribution Stopbox Valve Legs.	**$540**	**$7**	$673.53	5	1	**$3,368**	$318.89	1	**$319**	$167.31	2	**$335**
GRAND TOTAL ($000's)		**$8**	**$517**				**$23**			**$6**			**$3**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Total Incremental Cost of Disposal ($000's)	GRAND TOTAL ($000's)
IM&E OFFICE: It is assumed that this building contains ACM floor tiles which are currently covered by non-ACM tiles. The wall and ceiling insulation is presumed to be ACM.	Muldraugh Station	$1	$38
KEWANEE BOILER ROOM: ACM boiler piping insulation still exists from the boiler to where it enters the Compressor Building. The boiler insulation is Presumed ACM.	Muldraugh Station	$0	$15
PURIFIER 1: All piping and pressure vessel ACM was replaced in 2001. Transite panels still serve as a wind break. PACM in old control box. PACM on Reboiler and Heat Exchanger gaskets.	Muldraugh Station	$0	$30
COMPRESSOR BUILDING: This building was presumed to have originally been constructed in the late 1930's with modifications and additions in the 1950's, 1960's, and 1970's. ACM flange gaskets, valve packing, and various compressor gaskets have been identified and some of it has been abated. ACM caulking has been discovered on the windows.	Muldraugh Station	$0	$20
PURIFIER 2: The regenerator contains ACM vessel insulation although minimal sections have been abated. The boiler insulation is Presumed ACM.	Muldraugh Station	$3	$32
PURIFIER 3: The boiler insulation is Presumed ACM.	Muldraugh Station	$1	$59
ABANDONED H2S INCINERATOR: This facility contains a transite wind break, ACM valve packing and ACM flange gaskets.	Muldraugh Station	$0	$21

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Total Incremental Cost of Disposal ($000's)	GRAND TOTAL ($000's)
LOCKER ROOM: The facility contains ACM asphalt roofing. It is unknown if any other ACM exists so it was assumed that the insulation and dry wall are PACM.	Muldraugh Station	**$1**	**$11**
STATION VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Station	**$0**	**$4**
STATION PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement. Includes the removal of ACM from Turbine Separators.	Muldraugh Station	**$3**	**$76**
MULDRAUGH FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Muldraugh Storage Field	**$0**	**$6**
MULDRAUGH FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Muldraugh Storage Field	**$4**	**$67**
DOE RUN FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Field	**$1**	**$5**
DOE RUN FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Field	**$6**	**$133**
DOE RUN DEEP FIELD VALVES: Miscellaneous valves packing and flange gaskets.	Doe Run Deep Field	**$1**	**$1**
DOE RUN DEEP FIELD PIPING: Miscellaneous disposal of coal tar pipe during pipeline removals. Excludes in site retirement.	Doe Run Deep Field	**$6**	**$56**
MULDRAUGH DISTRIBUTION: Miscellaneous disposal of gaskets, valve packing, coal tar pipe and stopbox valve legs. Excludes pipe abandoned in place.	Muldraugh Storage-Distribution Stopbox Valve Legs.	**$4**	**$11**
GRAND TOTAL ($000's)		**$32**	**$549**

Wiseman, Sara

From:	Durbin, Tony
Sent:	Thursday, October 06, 2005 2:58 PM
To:	Wiseman, Sara
Subject:	Asbestos Liability estimate for Distribution Substations
Attachments:	Asbestos Removal _ Distribution Subs.xls

Asbestos Removal
_ Distributio...

Tony Durbin
Electrical Engineer
LG&E SC&M Dept, South Service Center
Ph: (502) 364-8608, Fax: (502) 217-2268

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove VCT (Floor Tile)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
Metal roof.	Ashby	$1.90	384	**$730**	$1.95	336	**$655**	$1.35	0	**$0**
	Bishop	$1.90	400	**$760**	$1.95	400	**$780**	$1.35	0	**$0**
Station built in 1994.	Bluegrass	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Brandenburg	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Brook	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Station built in 1996	Campground	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Carter	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Clarks Lane	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Crestwood	$1.90	384	**$730**	$1.95	400	**$780**	$1.35	0	**$0**
	Crop	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
New roof in 1994.	Dahlia	$1.90	468	**$889**	$1.95	400	**$780**	$1.35	0	**$0**
Metal roof.	Del Park	$1.90	384	**$730**	$1.95	400	**$780**	$1.35	0	**$0**
Metal roof.	Dixie	$1.90	384	**$730**	$1.95	400	**$780**	$1.35	0	**$0**
	Dumesnil	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Eighth Street	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Fairmount	$1.90	400	**$760**	$1.95	400	**$780**	$1.35	0	**$0**
	Falls City	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
New roof in 1995.	Floyd	$1.90	345	**$656**	$1.95	400	**$780**	$1.35	0	**$0**
Station built in 1993.	Ford	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Forty Fourth	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Freys Hill	$1.90	384	**$730**	$1.95	400	**$780**	$1.35	0	**$0**
	Gaulbert	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Gilligan	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Goss	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Station built in 1998.	Grade Lane	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Built up roof unknown date.	Grady	$1.90	672	**$1,277**	$1.95	672	**$1,310**	$1.35	672	**$907**
	Grand	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Hale	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove VCT (Floor Tile)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
Built up roof unknown date.	Harmony Landing	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	468	**$632**
	Herman	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Built up roof unknown date.	Highland	$1.90	1,000	**$1,900**	$1.95	1,000	**$1,950**	$1.35	1,000	**$1,350**
New roof 1993.	Hillcrest	$1.90	1,674	**$3,181**	$1.95	1,674	**$3,264**	$1.35	0	**$0**
New roof 1995.	Hurstbourne	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	0	**$0**
Station built in 1994.	International	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Jeffersontown	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
Metal roof.	Kenwood	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
Built up roof unknown date.	Knob Creek	$1.90	768	**$1,459**	$1.95	768	**$1,498**	$1.35	768	**$1,037**
Built up roof unknown date.	Locust	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	468	**$632**
	Logan	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Louisville Downs	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Lynn	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
New roof in 2000	Magazine	$1.90	3,638	**$6,912**	$1.95	3,638	**$7,094**	$1.35	0	**$0**
New roof 1998.	Manslick	$1.90	1,271	**$2,415**	$1.95	1,271	**$2,478**	$1.35	0	**$0**
	Muldraugh	$1.90	400	**$760**	$1.95	400	**$780**	$1.35	0	**$0**
Metal roof.	Nachand	$1.90	384	$730	$1.95	384	$749	$1.35	0	$0
Station built in 1989.	Okolona	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Ormsby	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Pirtle	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
New roof 1992	Plainview	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	0	**$0**
New roof 1999.	Pleasure Ridge	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	0	**$0**
	Seventh Street	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Shawnee	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Shepherdsville	$1.90	294	**$559**	$1.95	294	**$573**	$1.35	0	**$0**
Metal roof.	Skylight	$1.90	156	**$296**	$1.95	156	**$304**	$1.35	0	**$0**
Metal roof.	Smyrna	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
	Solite	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove VCT (Floor Tile)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
Metal roof.	South Park	$1.90	315	**$599**	$1.95	315	**$614**	$1.35	0	**$0**
New roof 2001.	Southern	$1.90	5,002	**$9,504**	$1.95	5,002	**$9,754**	$1.35	0	**$0**
	Southern Baptist Seminary	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Stewart	$1.90	432	**$821**	$1.95	432	**$842**	$1.35		**$0**
	Trimble Cty Sw. Rm (12 kv)	$1.90	400	**$760**	$1.95	400	**$780**	$1.35	0	**$0**
Metal roof.	Terry	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
	Vermont	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Waterside (D)	$1.90	5,000	**$9,500**	$1.95	5,000	**$9,750**	$1.35	0	**$0**
	Westpoint	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Western	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	WHAS	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
Station built in 2001.	Worthington	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Zorn	$1.90	225	**$428**	$1.95	225	**$439**	$1.35	0	**$0**
LG&E TOTAL ($000's)				**$55**			**$57**	$1.35		**$5**
KU has 478 distribution Substations	KU Dist. Substations	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
KU TOTAL ($000's)										
GRAND TOTAL ($000's)										

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks
Metal roof.	Ashby	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Bishop	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Station built in 1994.	Bluegrass	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Brandenburg	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Brook	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Station built in 1996	Campground	$98.89	0	**$0**	$162.12	0	0	**$0**	$81.04	0	**$0**
	Carter	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Clarks Lane	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Crestwood	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Crop	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
New roof in 1994.	Dahlia	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Del Park	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Dixie	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Dumesnil	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Eighth Street	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Fairmount	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Falls City	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
New roof in 1995.	Floyd	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Station built in 1993.	Ford	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Forty Fourth	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Freys Hill	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Gaulbert	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Gilligan	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Goss	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Station built in 1998.	Grade Lane	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Built up roof unknown date.	Grady	$98.89	3	**$297**	$162.12	3	2	**$973**	$81.04	2	**$162**
	Grand	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Hale	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks
Built up roof unknown date.	Harmony Landing	$98.89	3	**$297**	$162.12	3	2	**$973**	$81.04	2	**$162**
	Herman	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Built up roof unknown date.	Highland	$98.89	5	**$494**	$162.12	5	4	**$3,242**	$81.04	4	**$324**
New roof 1993.	Hillcrest	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
New roof 1995.	Hurstbourne	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Station built in 1994.	International	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Jeffersontown	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Kenwood	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Built up roof unknown date.	Knob Creek	$98.89	4	**$396**	$162.12	4	4	**$2,594**	$81.04	4	**$324**
Built up roof unknown date.	Locust	$98.89	3	**$297**	$162.12	3	2	**$973**	$81.04	2	**$162**
	Logan	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Louisville Downs	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Lynn	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
New roof in 2000	Magazine	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
New roof 1998.	Manslick	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Muldraugh	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Nachand	$98.89	2	$198	$162.12	2	1	$324	$81.04	1	$81
Station built in 1989.	Okolona	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Ormsby	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Pirtle	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
New roof 1992	Plainview	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
New roof 1999.	Pleasure Ridge	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Seventh Street	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Shawnee	$98.89	0	**$0**	$162.12	0	1			1	
Metal roof.	Shepherdsville	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Skylight	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Smyrna	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Solite	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks
Metal roof.	South Park	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
New roof 2001.	Southern	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Southern Baptist Seminary	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Stewart	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Trimble Cty Sw. Rm (12 kv)	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Terry	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Vermont	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Waterside (D)	$98.89	5	**$494**	$162.12	5	1	**$811**	$81.04	1	**$81**
	Westpoint	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Western	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	WHAS	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Station built in 2001.	Worthington	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Zorn	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
LG&E TOTAL ($000's)				**$8**				**$18**			**$6**
KU has 478 distribution Substations	KU Dist. Substations	$98.89	2	**$198**	$162.12	4	1	**$648**	$81.04	1	**$81**
KU TOTAL ($000's)											
GRAND TOTAL ($000's)											

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Air monitoring testing, 12 Tests / Day (On Job Testing/Day)			Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal E Air
		Cost per Day	# Days Testing	Total Cost On Job Testing	Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit
Metal roof.	Ashby	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Bishop	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1994.	Bluegrass	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Brandenburg	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Brook	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1996	Campground	$1,384.00	0	**$0**	$606.32		**$0**	$775.06		**$0**	$707.85
	Carter	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Clarks Lane	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Crestwood	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Crop	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof in 1994.	Dahlia	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
Metal roof.	Del Park	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Dixie	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Dumesnil	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Eighth Street	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Fairmount	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06		**$0**	$707.85
	Falls City	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof in 1995.	Floyd	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1993.	Ford	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Forty Fourth	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Freys Hill	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Gaulbert	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Gilligan	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Goss	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1998.	Grade Lane	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Built up roof unknown date.	Grady	$1,384.00	4	**$5,536**	$606.32	2	**$1,213**	$775.06	2	**$1,550**	$707.85
	Grand	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Hale	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Air monitoring testing, 12 Tests / Day (On Job Testing/Day)			Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal E Air
		Cost per Day	# Days Testing	Total Cost On Job Testing	Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit
Built up roof unknown date.	Harmony Landing	$1,384.00	3	**$4,152**	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85
	Herman	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Built up roof unknown date.	Highland	$1,384.00	4	**$5,536**	$606.32	5	**$3,032**	$775.06	5	**$3,875**	$707.85
New roof 1993.	Hillcrest	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof 1995.	Hurstbourne	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1994.	International	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Jeffersontown	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Kenwood	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Built up roof unknown date.	Knob Creek	$1,384.00	3	**$4,152**	$606.32	4	**$2,425**	$775.06	4	**$3,100**	$707.85
Built up roof unknown date.	Locust	$1,384.00	3	**$4,152**	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85
	Logan	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Louisville Downs	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Lynn	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
New roof in 2000	Magazine	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
New roof 1998.	Manslick	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Muldraugh	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
Metal roof.	Nachand	$1,384.00	2	$2,768	$606.32		$0	$775.06		$0	$707.85
Station built in 1989.	Okolona	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Ormsby	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Pirtle	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof 1992	Plainview	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof 1999.	Pleasure Ridge	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Seventh Street	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Shawnee		2								
Metal roof.	Shepherdsville	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Skylight	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Smyrna	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Solite	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Air monitoring testing, 12 Tests / Day (On Job Testing/Day)			Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal E Air
		Cost per Day	# Days Testing	Total Cost On Job Testing	Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit
Metal roof.	South Park	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof 2001.	Southern	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Southern Baptist Seminary	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Stewart	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Trimble Cty Sw. Rm (12 kv)	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Terry	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Vermont	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Waterside (D)	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Westpoint	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Western	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	WHAS	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 2001.	Worthington	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Zorn	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
LG&E TOTAL ($000's)				**$192**			**$10**			**$13**	
KU has 478 distribution Substations	KU Dist. Substations	$1,384.00	4	**$5,536**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
KU TOTAL ($000's)											
GRAND TOTAL ($000's)											

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	quip Required - Negative Pressure System		Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic			Removal of Circuit Breake	
		# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag	Cost per Unit	# Units
Metal roof.	Ashby		$0	$1,773.00		$0	$5.40		$0		
	Bishop		$0	$1,773.00		$0	$5.40		$0		
Station built in 1994.	Bluegrass		$0	$1,773.00		$0	$5.40		$0		
	Brandenburg	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Brook		$0	$1,773.00		$0	$5.40		$0		
Station built in 1996	Campground		$0	$1,773.00		$0	$5.40		$0		
	Carter		$0	$1,773.00		$0	$5.40		$0		
	Clarks Lane		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Crestwood		$0	$1,773.00		$0	$5.40		$0		
	Crop		$0	$1,773.00		$0	$5.40		$0		
New roof in 1994.	Dahlia	0	$0	$1,773.00	0	$0	$5.40	0	$0		
Metal roof.	Del Park		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Dixie		$0	$1,773.00		$0	$5.40		$0		
	Dumesnil	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Eighth Street	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Fairmount		$0	$1,773.00		$0	$5.40		$0		
	Falls City		$0	$1,773.00		$0	$5.40		$0		
New roof in 1995.	Floyd		$0	$1,773.00		$0	$5.40		$0		
Station built in 1993.	Ford		$0	$1,773.00		$0	$5.40		$0		
	Forty Fourth		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Freys Hill		$0	$1,773.00		$0	$5.40		$0		
	Gaulbert		$0	$1,773.00		$0	$5.40		$0		
	Gilligan		$0	$1,773.00		$0	$5.40		$0		
	Goss		$0	$1,773.00		$0	$5.40		$0		
Station built in 1998.	Grade Lane		$0	$1,773.00		$0	$5.40		$0		
Built up roof unknown date.	Grady	2	$1,416	$1,773.00	8	$14,184	$5.40	50	$270		
	Grand		$0	$1,773.00		$0	$5.40		$0		
	Hale	0	$0	$1,773.00	0	$0	$5.40	0	$0		

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	quip Required - Negative Pressure System		Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic			Removal of Circuit Breaker	
		# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag	Cost per Unit	# Units
Built up roof unknown date.	Harmony Landing	3	**$2,124**	$1,773.00	8	**$14,184**	$5.40	50	**$270**		
	Herman		**$0**	$1,773.00		**$0**	$5.40	0	**$0**		
Built up roof unknown date.	Highland	5	**$3,539**	$1,773.00	16	**$28,368**	$5.40	70	**$378**		
New roof 1993.	Hillcrest		**$0**	$1,773.00		**$0**	$5.40		**$0**		
New roof 1995.	Hurstbourne		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Station built in 1994.	International		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Jeffersontown		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Kenwood		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Built up roof unknown date.	Knob Creek	4	**$2,831**	$1,773.00	16	**$28,368**	$5.40	70	**$378**		
Built up roof unknown date.	Locust	3	**$2,124**	$1,773.00	8	**$14,184**	$5.40	50	**$270**		
	Logan		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Louisville Downs		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Lynn	0	**$0**	$1,773.00	0	**$0**	$5.40	0	**$0**		
New roof in 2000	Magazine	0	**$0**	$1,773.00	0	**$0**	$5.40	0	**$0**		
New roof 1998.	Manslick		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Muldraugh	0	**$0**	$1,773.00	0	**$0**	$5.40	0	**$0**		
Metal roof.	Nachand		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Station built in 1989.	Okolona		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Ormsby		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Pirtle		**$0**	$1,773.00		**$0**	$5.40		**$0**		
New roof 1992	Plainview		**$0**	$1,773.00		**$0**	$5.40		**$0**		
New roof 1999.	Pleasure Ridge		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Seventh Street		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Shawnee								**$0**		
Metal roof.	Shepherdsville		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Skylight		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Smyrna		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Solite		**$0**	$1,773.00		**$0**	$5.40		**$0**		

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	quip Required - Negative Pressure System		Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic			Removal of Circuit Breake	
		# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag	Cost per Unit	# Units
Metal roof.	South Park		$0	$1,773.00		$0	$5.40		$0		
New roof 2001.	Southern		$0	$1,773.00		$0	$5.40		$0		
	Southern Baptist Seminary		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Stewart	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Trimble Cty Sw. Rm (12 kv)		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Terry		$0	$1,773.00		$0	$5.40		$0		
	Vermont	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Waterside (D)	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Westpoint	0	$0	$1,773.00		$0	$5.40		$0		
	Western		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	WHAS		$0	$1,773.00		$0	$5.40		$0		
Station built in 2001.	Worthington		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Zorn		$0	$1,773.00		$0	$5.40		$0		
LG&E TOTAL ($000's)			**$12**			**$99**			**$2**		
KU has 478 distribution Substations	KU Dist. Substations	0	$0	$1,773.00	1	$1,773	$5.40	5	$27		
KU TOTAL ($000's)											
GRAND TOTAL ($000's)											

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Arc Chutes	Removal of Control Wiring			Removal Cost per Asset ($000's)	40 Cu			
		Total Cost	Cost per Unit	# Units	Total Cost		Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs
Metal roof.	Ashby	$2,500			$6,500	$14	$673.53	1	1	$674
	Bishop	$2,500			$6,500	$14	$673.53	1	1	$674
Station built in 1994.	Bluegrass	$0			$0	$3	$673.53	0	0	$0
	Brandenburg	$2,500			$6,500	$12	$673.53	0	0	$0
	Brook	$2,500			$2,500	$8	$673.53	0	0	$0
Station built in 1996	Campground	$0			$0	$0	$673.53	0	0	$0
	Carter	$2,500			$2,500	$8	$673.53	0	0	$0
	Clarks Lane	$2,500			$2,500	$8	$673.53	0	0	$0
Metal roof.	Crestwood	$2,500			$6,500	$14	$673.53	1	1	$674
	Crop	$2,500			$2,500	$8	$673.53	0	0	$0
New roof in 1994.	Dahlia	$2,500			$6,500	$14	$673.53	1	1	$674
Metal roof.	Del Park	$2,500			$6,500	$14	$673.53	1	1	$674
Metal roof.	Dixie	$2,500			$6,500	$14	$673.53	1	1	$674
	Dumesnil	$2,500			$6,500	$12	$673.53	0	0	$0
	Eighth Street	$2,500			$2,500	$8	$673.53	0	0	$0
	Fairmount	$2,500			$6,500	$14	$673.53	1	1	$674
	Falls City	$2,500			$2,500	$8	$673.53	0	0	$0
New roof in 1995.	Floyd	$2,500			$6,500	$14	$673.53	1	1	$674
Station built in 1993.	Ford	$0			$0	$3	$673.53	1	1	$674
	Forty Fourth	$2,500			$2,500	$8	$673.53	0	0	$0
Metal roof.	Freys Hill	$2,500			$6,500	$14	$673.53	1	1	$674
	Gaulbert	$2,500			$2,500	$8	$673.53	0	0	$0
	Gilligan	$2,500			$2,500	$8	$673.53	0	0	$0
	Goss	$2,500			$2,500	$8	$673.53	0	0	$0
Station built in 1998.	Grade Lane	$0			$0	$3	$673.53	1	1	$674
Built up roof unknown date.	Grady	$2,500			$6,500	$38	$673.53	1	3	$2,021
	Grand	$2,500			$2,500	$8	$673.53	0	0	$0
	Hale	$2,500			$2,500	$8	$673.53	0	0	$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Arc Chutes	Removal of Control Wiring			Removal Cost per Asset ($000's)	40 Cu			
		Total Cost	Cost per Unit	# Units	Total Cost		Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs
Built up roof unknown date.	Harmony Landing	**$2,500**			**$6,500**	**$38**	$673.53	1	3	**$2,021**
	Herman	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
Built up roof unknown date.	Highland	**$2,500**			**$6,500**	**$63**	$673.53	1	3	**$2,021**
New roof 1993.	Hillcrest	**$2,500**			**$6,500**	**$19**	$673.53	1	1	**$674**
New roof 1995.	Hurstbourne	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
Station built in 1994.	International	**$0**			**$0**	**$3**	$673.53	0	0	**$0**
Metal roof.	Jeffersontown	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
Metal roof.	Kenwood	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
Built up roof unknown date.	Knob Creek	**$2,500**			**$6,500**	**$58**	$673.53	1	2	**$1,347**
Built up roof unknown date.	Locust	**$2,500**			**$6,500**	**$38**	$673.53	1	1	**$674**
	Logan	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
	Louisville Downs	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
	Lynn	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
New roof in 2000	Magazine	**$2,500**			**$6,500**	**$26**	$673.53	0	0	**$0**
New roof 1998.	Manslick	**$2,500**			**$6,500**	**$17**	$673.53	1	1	**$674**
	Muldraugh	**$2,500**			**$6,500**	**$14**	$673.53	0	0	**$0**
Metal roof.	Nachand	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
Station built in 1989.	Okolona	**$0**			**$0**	**$3**	$673.53	0	0	**$0**
	Ormsby	**$2,500**			**$2,500**	**$8**	$673.53	1	1	**$674**
	Pirtle	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
New roof 1992	Plainview	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
New roof 1999.	Pleasure Ridge	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
	Seventh Street	**$2,500**			**$2,500**	**$8**	$673.53	0	0	**$0**
	Shawnee	**$2,500**			**$2,500**	**$5**	$673.53	0	0	**$0**
Metal roof.	Shepherdsville	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
Metal roof.	Skylight	**$2,500**			**$6,500**	**$13**	$673.53	1	1	**$674**
Metal roof.	Smyrna	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
	Solite	**$0**			**$0**	**$3**	$673.53	0	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Arc Chutes	Removal of Control Wiring			Removal Cost per Asset ($000's)	40 Cu			
		Total Cost	Cost per Unit	# Units	Total Cost		Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs
Metal roof.	South Park	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
New roof 2001.	Southern	**$2,500**			**$6,500**	**$32**	$673.53	1	5	**$3,368**
	Southern Baptist Seminary	**$2,500**			**$6,500**	**$12**	$673.53	0	0	**$0**
Metal roof.	Stewart	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
	Trimble Cty Sw. Rm (12 kv)	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
Metal roof.	Terry	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
	Vermont	**$2,500**			**$6,500**	**$12**	$673.53	0	0	**$0**
	Waterside (D)	**$2,500**			**$6,500**	**$32**	$673.53	1	2	**$1,347**
	Westpoint	**$2,500**			**$6,500**	**$12**	$673.53	0	0	**$0**
	Western	**$2,500**			**$6,500**	**$12**	$673.53	0	0	**$0**
Metal roof.	WHAS	**$2,500**			**$6,500**	**$14**	$673.53	1	1	**$674**
Station built in 2001.	Worthington	**$0**			**$0**	**$3**	$673.53	0	0	**$0**
Metal roof.	Zorn	**$2,500**			**$6,500**	**$13**	$673.53	0	0	**$0**
LG&E TOTAL ($000's)						**$937**				**$31**
KU has 478 distribution Substations	KU Dist. Substations	**$0**			**$3,000**	**$11**	$673.53	1	1	**$674**
KU TOTAL ($000's)										
GRAND TOTAL ($000's)										

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Yd Asbestos Dumpster Costs Per Unit						Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
		Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
Metal roof.	Ashby	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
	Bishop	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
Station built in 1994.	Bluegrass	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$3**
	Brandenburg	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$12**
	Brook	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
Station built in 1996	Campground	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$0**
	Carter	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Clarks Lane	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
Metal roof.	Crestwood	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
	Crop	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
New roof in 1994.	Dahlia	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
Metal roof.	Del Park	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
Metal roof.	Dixie	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
	Dumesnil	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$12**
	Eighth Street	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Fairmount	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
	Falls City	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
New roof in 1995.	Floyd	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
Station built in 1993.	Ford	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$4**
	Forty Fourth	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
Metal roof.	Freys Hill	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
	Gaulbert	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Gilligan	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Goss	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
Station built in 1998.	Grade Lane	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$4**
Built up roof unknown date.	Grady	$318.89	6	**$1,913**	$167.31	3	**$502**	**$4**	**$43**
	Grand	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$8**
	Hale	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Yd Asbestos Dumpster Costs Per Unit						Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
		Pickup / Delivery Costs	# Times Pickup / Delivery	**Total Pick Up/Del Costs**	Asbestos Dump Fee	# of Times Dumped	**Total Asbestos Dump Fee Expense**		
Built up roof unknown date.	Harmony Landing	$318.89	6	**$1,913**	$167.31	5	**$837**	**$5**	**$43**
	Herman	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$8**
Built up roof unknown date.	Highland	$318.89	6	**$1,913**	$167.31	5	**$837**	**$5**	**$68**
New roof 1993.	Hillcrest	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$20**
New roof 1995.	Hurstbourne	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Station built in 1994.	International	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$3**
Metal roof.	Jeffersontown	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Metal roof.	Kenwood	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Built up roof unknown date.	Knob Creek	$318.89	4	**$1,276**	$167.31	2	**$335**	**$3**	**$61**
Built up roof unknown date.	Locust	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$39**
	Logan	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Louisville Downs	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$8**
	Lynn	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
New roof in 2000	Magazine	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$26**
New roof 1998.	Manslick	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$19**
	Muldraugh	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$14**
Metal roof.	Nachand	$318.89	2	**$638**	$167.31		$0	**$1**	**$15**
Station built in 1989.	Okolona	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$3**
	Ormsby	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$9**
	Pirtle	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
New roof 1992	Plainview	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
New roof 1999.	Pleasure Ridge	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
	Seventh Street	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$8**
	Shawnee	$318.89	0	**$0**					
Metal roof.	Shepherdsville	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
Metal roof.	Skylight	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
Metal roof.	Smyrna	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
	Solite	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$3**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Yd Asbestos Dumpster Costs Per Unit						Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
		Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
Metal roof.	South Park	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
New roof 2001.	Southern	$318.89	10	**$3,189**	$167.31	10	**$1,673**	**$8**	**$40**
	Southern Baptist Seminary	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$12**
Metal roof.	Stewart	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
	Trimble Cty Sw. Rm (12 kv)	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Metal roof.	Terry	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
	Vermont	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$12**
	Waterside (D)	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$36**
	Westpoint	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$12**
	Western	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$12**
Metal roof.	WHAS	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Station built in 2001.	Worthington	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$3**
Metal roof.	Zorn	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$13**
LG&E TOTAL ($000's)				**$29**			**$10**	**$71**	**$1,003**
KU has 478 distribution Substations	KU Dist. Substations	$318.89	2	**$638**	$167.31	1	**$167**	**$1**	**$13**
KU TOTAL ($000's)									**$599**
GRAND TOTAL ($000's)									[redacted]

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Estimated Retirement Date	Comments
Metal roof.	Ashby		
	Bishop		
Station built in 1994.	Bluegrass		
	Brandenburg		
	Brook		
Station built in 1996	Campground		
	Carter		
	Clarks Lane		
Metal roof.	Crestwood		
	Crop		
New roof in 1994.	Dahlia		
Metal roof.	Del Park		
Metal roof.	Dixie		
	Dumesnil		
	Eighth Street		
	Fairmount		
	Falls City		
New roof in 1995.	Floyd		
Station built in 1993.	Ford		
	Forty Fourth		
Metal roof.	Freys Hill		
	Gaulbert		
	Gilligan		
	Goss		
Station built in 1998.	Grade Lane		
Built up roof unknown date.	Grady		
	Grand		
	Hale		

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Estimated Retirement Date	Comments
Built up roof unknown date.	Harmony Landing		
	Herman		
Built up roof unknown date.	Highland		
New roof 1993.	Hillcrest		
New roof 1995.	Hurstbourne		
Station built in 1994.	International		
Metal roof.	Jeffersontown		
Metal roof.	Kenwood		
Built up roof unknown date.	Knob Creek		
Built up roof unknown date.	Locust		
	Logan		
	Louisville Downs		
	Lynn		
New roof in 2000	Magazine		
New roof 1998.	Manslick		
	Muldraugh		
Metal roof.	Nachand		
Station built in 1989.	Okolona		
	Ormsby		
	Pirtle		
New roof 1992	Plainview		
New roof 1999.	Pleasure Ridge		
	Seventh Street		
	Shawnee		
Metal roof.	Shepherdsville		
Metal roof.	Skylight		
Metal roof.	Smyrna		
	Solite		

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Estimated Retirement Date	Comments
Metal roof.	South Park		
New roof 2001.	Southern		
	Southern Baptist Seminary		
Metal roof.	Stewart		
	Trimble Cty Sw. Rm (12 kv)		
Metal roof.	Terry		
	Vermont		
	Waterside (D)		
	Westpoint		
	Western		
Metal roof.	WHAS		
Station built in 2001.	Worthington		
Metal roof.	Zorn		
LG&E TOTAL ($000's)			
KU has 478 distribution Substations	KU Dist. Substations		
KU TOTAL ($000's)			
GRAND TOTAL ($000's)			

Wiseman, Sara

From: Charnas, Shannon
Sent: Thursday, October 06, 2005 1:50 PM
To: Wiseman, Sara
Subject: RE: Asbestos meeting-Wednesday-update

Sara-

Thanks very much for the update.

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Wiseman, Sara
Sent: Thursday, October 06, 2005 9:40 AM
To: Charnas, Shannon
Cc: Riggs, Eric; Kinder, Debra
Subject: Asbestos meeting-Wednesday-update

It seems that our distribution folks are on track to complete their asbestos work by Friday or very early next week. Asbestos coating on pipes will not be an ARO, as there are regulations which allow us to leave the pipe buried. We will be receiving support on that from environmental. Jon Miller is pushing on Elaine for Transmission numbers.

Sara Wiseman
Manager-Property Accounting
502.627.3189

Wiseman, Sara

From: Charnas, Shannon
Sent: Thursday, October 06, 2005 7:41 AM
To: Wiseman, Sara
Subject: FW: FIN 47 Survey Question

Sara-

Were you able to provide Valerie with a response? If so, would you please copy me on it.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

-----Original Message-----
From: Scott, Valerie
Sent: Thursday, September 29, 2005 6:25 PM
To: Wiseman, Sara
Cc: Charnas, Shannon
Subject: FW: FIN 47 Survey Question

Sara,

Do we know the answers for these questions yet for ourselves? If so, would you give me our responses so I can forward them on?

Valerie

-----Original Message-----
From: bounce-244660-175405@ls.eei.org [mailto:bounce-244660-175405@ls.eei.org]
Sent: Thursday, September 29, 2005 10:33 AM
To: Accounting Standards Committee
Subject: FIN 47 Survey Question

To The EEI Accounting Standards Committee:
I would like to pose the following questions regarding your implementation of FIN 47 as it relates to asbestos removal. Thanks...

> Consolidated Edison Company of New York has over 400 locations that contain asbestos. For a small percentage of locations we have definite plans for asbestos removal. For most of the others, we have no current plans to remove asbestos, renovate, retire or sell the facility. There are no surveys done to determine the amount and condition of existing asbestos. In addition, we also have approximately 280,000 underground system structures with asbestos that are usually retired in place.
>
> Can you please answer the following questions:
> 1. Are you recording an ARO liability in the following circumstances:
> a. There is a current plan for asbestos abatement, sale or retirement.
> b. Asset is known to contain asbestos, but there is no current plan for abatement, sale or retirement. The amount of existing asbestos is not known.
> i. If recording an ARO liability, on what basis are you determining the amount of the future liability and;
> ii. Since there is no plan for abatement, what time period are you using for the estimated retirement date?
> c. Asset containing asbestos has already been retired in place (original cost is no longer on the books) and asbestos abatement may be done sometime in the future, although the timing is not known. The amount of existing asbestos is also not known.
> d. Underground system structures containing asbestos that are generally

retired in place.
>
> 2. Did you set a materiality threshold for recording ARO> '> s? What are the factors you considered when determining materiality?
>
> 3. If you are recording an ARO for regulated utility operations, how are you calculating the asbestos removal cost in the accumulated depreciation reserve?
>
>
>

Grace Scarpitta
Consolidated Edison Company of New York
212-460-6693

You are currently subscribed to asc as: [valerie.scott@lgeenergy.com] To unsubscribe, forward this message to leave-244660-175405J@ls.eei.org

Wiseman, Sara

From: Miller, Jon
Sent: Friday, October 07, 2005 8:47 AM
To: Wiseman, Sara
Subject: Fin 47 - Haefling

Sara,

I will need to talk to Barry Currens to get the Fin 47 information for Haefling. He is currently in Hawaii and will be for the next week. Realistically, it will probably be two weeks before we can expect to get anything from him.

Jon

Wiseman, Sara

From: Satkamp, Mark
Sent: Friday, October 07, 2005 5:04 PM
To: Kinder, Debra; Wiseman, Sara
Cc: Lawson, William; Collins, Mike
Subject: FW: Identifying Asbestos Removal and Disposal Liabilities

Attachments: ASBESTOS REMOVAL EST COSTS FOR FACILITIES (Gas Control Areas).xls

Sara and Debra,

Attached please find the template provided previously with the cost estimates for removing asbestos wall board at the Preston city gate station and asbestos insulation for the indirect fired heater at the Doe Run city gate station. **The total removal cost is estimated at $31K.** I estimated the total square feet of insulation for the Doe Run heater and used $35.00 per square foot to estimate this cost. From a conversation with Jeff Gilbert, Corporate Health and Safety has a record indicating that wall board samples taken at Preston came back as 30% asbestos, and samples taken at Penile city gate station came back negative. We are fairly certain that the wallboard in the buildings for the newer city gate stations and regulator stations does not contain asbestos. After interviewing some current and former employees, we are fairly certain that all of the shingle type roofs on the buildings at the city gate and regulator stations have been replaced since 1980 and are thus very unlikely to contain asbestos. Many of these roofs were replaced in the early 1990s by the Special Construction Department before they were disbanded. We have an ACE written in 1991 which identifies some of these regulator facilities where the roofs were replaced. Please let me know if you have questions or require any additional information.

Thanks,

Mark Satkamp
Manager, Gas Control
502-627-3135 Office

ASBESTOS
OVAL EST COSTS F(

From: Satkamp, Mark
Sent: Wednesday, September 28, 2005 10:42 AM
To: Kinder, Debra
Cc: Collins, Mike; Lawson, William
Subject: RE: Identifying Asbestos Removal and Disposal Liabilities

Debra,

Some of the buildings at our city gate and large regulator stations are believed to have fiberboard inside the buildings which contains asbestos. We are not sure about the roofs. We think we have about 13 interior rooms with this type of fiberboard. We have not abated the walls from these types of buildings before and therefore don't know what the costs would be. A lot of costs would be associated with temporarily relocating all of our equipment from the buildings while the abatement work was being completed, or constructing new buildings and permanently relocating our equipment. I would guess that it could cost $50k or more per room for this type of work to be completed. Also, we have one heater at the Doe Run city gate station with asbestos insulation. I would guess that it might cost $50k to abate the heater insulation, or it might make sense to replace the heater for around $150k. Please note that these numbers would be considered very rough estimates as detailed work scopes to complete this type of work have not been completed.

Thanks,

Mark Satkamp
Manager, Gas Control
502-627-3135 Office

From: Kinder, Debra
Sent: Tuesday, September 27, 2005 10:53 AM
To: Satkamp, Mark; Skaggs, John; Harmeling, Dave
Cc: Wiseman, Sara; Riggs, Eric; Charnas, Shannon
Subject: Identifying Asbestos Removal and Disposal Liabilities

All,

It is necessary for us to identify all sources of asbestos and estimate the current value of removal and disposal costs associated with assets containing asbestos in order to comply with FIN 47 (FASB Interpretation No. 47) which encompasses all legal retirement obligations. Do our gas plants or city gates contain asbestos insulation, roofing, siding, or other sources? If so, do you have historical abatement information that could be used to estimate current removal and disposal liabilities of contaminated assets? I would appreciate a quick response regarding your thoughts on this issue as we need to report our findings to E.ON relatively soon. It is becoming apparent that I will need to schedule a meeting this week to facilitate the gathering of needed data. Can any of you suggest other individuals that could contribute to this discussion?

Thanks for your help,
Debbie

Debra A. Kinder
Property Accounting Analyst
Louisville Gas & Electric
(502) 627-3369

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Costs to Remove Duct and/ or Pipe Insulation			Costs to Remove Transite Panels / Mastics (Adhesives)			Trailer (Change Room Cost)			Disposal Suits (4 su w/ a 4	
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required
Meter Building: Wall and ceiling panels may contain asbestos. Building approx. 16' x 16'. (768 sq ft)	Preston City Gate Station	$1.90		$0	$65.00		$0	$5.00	768	$3,840	$98.89		$0	$162.12	3
Control Building: Wall and ceiling panels may contain asbestos. Building approx. 10' x 16'. (576 sq ft)	Preston City Gate Station	$1.90		$0	$65.00		$0	$5.00	576	$2,880	$98.89		$0	$162.12	2
Doe Run Indirect Fired Heater: Heater insulation contains asbestos: Heater size approx. 5' diameter and 20' in length. (314 sq ft)	Doe Run City Gate Station	$1.90		$0	$35.00	314	$10,990	$5.00		$0	$98.89		$0	$162.12	2
GRAND TOTAL ($000's)				$0			$11			$7			$0		

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	its per man / day $40.53) - Man Team		Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
Meter Building: Wall and ceiling panels may contain asbestos. Building approx. 16' x 16'. (768 sq ft)	Preston City Gate Station	1	**$486**	$81.04	1	**$81**	$1,384.00	3	**$4,152**
Control Building: Wall and ceiling panels may contain asbestos. Building approx. 10' x 16'. (576 sq ft)	Preston City Gate Station	1	**$324**	$81.04	1	**$81**	$1,384.00	2	**$2,768**
Doe Run Indirect Fired Heater: Heater insulation contains asbestos: Heater size approx. 5' diameter and 20' in length. (314 sq ft)	Doe Run City Gate Station	1	**$324**	$81.04	1	**$81**	$1,384.00	2	**$2,768**
GRAND TOTAL ($000's)			**$1**			**$0**			**$10**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
Meter Building: Wall and ceiling panels may contain asbestos. Building approx. 16' x 16'. (768 sq ft)	Preston City Gate Station	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	1	**$5**
Control Building: Wall and ceiling panels may contain asbestos. Building approx. 10' x 16'. (576 sq ft)	Preston City Gate Station	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	1	**$5**
Doe Run Indirect Fired Heater: Heater insulation contains asbestos: Heater size approx. 5' diameter and 20' in length. (314 sq ft)	Doe Run City Gate Station	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40	1	**$5**
GRAND TOTAL ($000's)				**$0**			**$0**			**$0**			**$0**			**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	**Total Dumpster Rental Costs**	Pickup / Delivery Costs	# Times Pickup / Delivery	**Total Pick Up/Del Costs**	Asbestos Dump Fee	# of Times Dumped	**Total Asbestos Dump Fee Expense**		
Meter Building: Wall and ceiling panels may contain asbestos. Building approx. 16' x 16'. (768 sq ft)	Preston City Gate Station	**$9**	$673.53	0.6	1	**$404**	$318.89	1	**$319**	$167.31	1	**$167**	**$1**	**$9**
Control Building: Wall and ceiling panels may contain asbestos. Building approx. 10' x 16'. (576 sq ft)	Preston City Gate Station	**$6**	$673.53	0.4	1	**$269**	$318.89		**$0**	$167.31	0	**$0**	**$0**	**$6**
Doe Run Indirect Fired Heater: Heater insulation contains asbestos: Heater size approx. 5' diameter and 20' in length. (314 sq ft)	Doe Run City Gate Station	**$14**	$673.53	0.4	1	**$269**	$318.89	1	**$319**	$167.31	1	**$167**	**$1**	**$15**
GRAND TOTAL ($000's)		**$29**				**$1**			**$1**			**$0**	**$2**	**$31**

Wiseman, Sara

From:	Rieth, Tom
Sent:	Friday, October 07, 2005 10:05 AM
To:	Kinder, Debra; Riggs, Eric; Charnas, Shannon; Wiseman, Sara
Cc:	Skaggs, John; Rieth, Tom
Subject:	Magnolia asbestos - Removal and disposal
Attachments:	Magnolia asbestos.xls

Magnolia asbestos.xls

A portion of the pipeline and gasket cost is based on replacement and some is based on what would have to be done if a field was shutdown. Getting a number with more detail will require additional time. These numbers are the ones most likely to change in this area.

Thanks,
Tom

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
Magnolia Compressor Station engine room. Q ft building constructed in the 1950's. Transcite paneling and ACM roofing.	Magnolia	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Magnolia Compressor Station Auxiliary building. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	$1.90		**$0**	$1.95		**$0**	$1.95	540	**$1,053**	$65.00		**$0**
Magnolia Compressor Station Field Shop. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Magnolia Compressor Station piping insulation	Magnolia	$1.90	0	**$0**	$1.95	0	**$0**	$1.95	0	**$0**	$65.00	100	**$6,500**
Magnolia Compressor Station - #1 Purifier Reactivator	Magnolia	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
Magnolia Compressor Station engine room. Q ft building constructed in the 1950's. Transcite paneling and ACM roofing.	Magnolia			**$0**			**$0**	$5.00	**6196**	**$30,980**	$1.35	6,900	**$9,315**
Magnolia Compressor Station Auxiliary building. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia			**$0**			**$0**	$5.00	**2994**	**$14,970**	$1.35	1,212	**$1,636**
Magnolia Compressor Station Field Shop. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia			**$0**			**$0**	$5.00	**1406**	**$7,030**	$1.35	1,800	**$2,430**
Magnolia Compressor Station piping insulation	Magnolia		0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	0	**$0**
Magnolia Compressor Station - #1 Purifier Reactivator	Magnolia	**$61.32**	**424**	**$26,000**			**$0**	$5.00		**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
Magnolia Compressor Station engine room. Q ft building constructed in the 1950's. Transcite paneling and ACM roofing.	Magnolia	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Magnolia Compressor Station Auxiliary building. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Magnolia Compressor Station Field Shop. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Magnolia Compressor Station piping insulation	Magnolia	$98.89	0	$0	$162.12	0	0	$0	$81.04	0	$0	$1,384.00	0	$0
Magnolia Compressor Station - #1 Purifier Reactivator	Magnolia	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
Magnolia Compressor Station engine room. Q ft building constructed in the 1950's. Transcite paneling and ACM roofing.	Magnolia	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Magnolia Compressor Station Auxiliary building. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Magnolia Compressor Station Field Shop. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Magnolia Compressor Station piping insulation	Magnolia	$606.32	0	**$0**	$775.06	0	**$0**	$707.85	0	**$0**	$1,773.00	0	**$0**	$5.40	4	**$22**
Magnolia Compressor Station - #1 Purifier Reactivator	Magnolia	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
Magnolia Compressor Station engine room. Q ft building constructed in the 1950's. Transcite paneling and ACM roofing.	Magnolia	**$40**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$40**
Magnolia Compressor Station Auxiliary building. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	**$18**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$18**
Magnolia Compressor Station Field Shop. Sq ft building constructed in 1950's. Transcite paneling and ACM roofing.	Magnolia	**$9**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$9**
Magnolia Compressor Station piping insulation	Magnolia	**$7**	$673.53	0	0	**$0**	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$7**
Magnolia Compressor Station - #1 Purifier Reactivator	Magnolia	**$26**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$26**

FACILITY ASSUMPTIONS

Any Facility constructed before 1985 will have asbestos, unless abatement has been completed

SMALL BUSINESS OFFICES & OPER CTRS- L. F. is calculated based on 8% of total sq. ft. for removal of pipe & ductwork insulation @ $65/LN. FT. or SQ. FT. (Includes removal & air monitoring costs) Costs per Ln. Ftl is based on recent invoicing for work performed by NEC.

STOREROOMS - L. F. is calculated based on 3% of total sq. ft. for pipe and ductwork insulation @ $65/LN.FT. or SQ. FT. (Includes removal and air monitoring costs). Cost per Ln. Ft. is based on recent invoicing for work performed by NEC.

Cost to remove VCT is based on actual invoicing from NEC for work performed at South Service Center in 1994. The same costs were applied to removal of ceiling tiles.

Wiseman, Sara

From: Rieth, Tom
Sent: Friday, October 07, 2005 2:44 PM
To: Kinder, Debra; Wiseman, Sara; Riggs, Eric; Charnas, Shannon
Subject: Magnolia asbestos - updated

Attachments: Magnolia asbestos.xls

Magnolia asbestos.xls

No change in cost. Did include Flint Hill as a location. This is an abandoned storage field. We still have a couple buildings and some equipment. The only thing I am aware over there that would be asbestos would be some pipe insulation, gaskets, valve packing and possibly some pipeline. We have already decommissioned the field so I do not think there would be much additional pipe removal. Please contact me with any questions.

Thanks,
Tom

Wiseman, Sara

From: Gonzales, Beatriz [BGonzal@pnm.com]

Sent: Monday, October 10, 2005 5:21 PM

To: alina.rocha@pseg.com; andy.krebs@pgnmail.com; avaske@atcllc.com; betty.mincer@conectiv.com; bruce.bollert@pse.com; bruce.friedman@peco-energy.com; bullerja@oge.com; cappiellope@coned.com; Billingsley, Connie; charles.stegner@uinet.com; cindy.perdue@cleco.com; cindy.reed@aquila.com; cmcelwee@sppc.com; cneff@itctransco.com; dane.watson@txu.com; daniel.reardon@northwestern.com; daniel.zielezinski@exeloncorp.com; darren.zurawski@exeloncorp.com; dcoit@empiredistrict.com; demiller@midamerican.com; devavold@otpco.com; dlblaloc@southernco.com; dlkutsunis@midamerican.com; eortlieb@cenhud.com; everett_lawrence@illinoispower.com; fstibor@itctransco.com; Carpenter, Jeff A.; jeff_beasley@wr.com; jehenderson@aep.com; jfrelic@wpsr.com; jhjenson@mge.com; jpnitsche@pplweb.com; jxjackso@southernco.com; kemcdani@southernco.com; kenmenge@alliant-energy.com; laura.rockenberger@aps.com; ldabell@entergy.com; leonard.a.delozier@bge.com; lhancock@epelectric.com; ltuckness@idahopower.com; mdonahue@mnpower.com; mgetz@ameren.com; michelle.koyanagi@heco.com; mpenn@wpsr.com; mrizk@cvps.com; paul.bienek@mdu.com; pgillam@entergy.com; pgrant@blackhillspower.com; plaub@cinergy.com; pmfitzgerald@cmsenergy.com; rawalker@tecoenergy.com; rhansen@otpco.com; rick.baldauf@we-energies.com; rob.pierce@sce.com; robert.pontau@energyeast.com; Wiseman, Sara; skramer@duqlight.com; stackjp@nu.com; sylvia_green@dom.com; throbke@wcnoc.com; tlsimons@cmsenergy.com; tony_cuba@fpl.com; tschad@gpu.com; wftyson@southernco.com; Gonzales, Beatriz; cabymun@southernco.com; daignca@nu.com; david.githae@constellation.com; joseph.freedman@kcpl.com; mary.tenenbaum@bge.com; ssims@tep.com; DStringfellow@eei.org

Cc: Carpenter, Jeff A.; Billingsley, Connie; Barreras, Krystal

Subject: List of potential assets to be considered for FIN47

Attachments: FIN47 List of Assets.doc

Attached is a consolidated list of assets that was put together based on e-mail responses. Some of the assets on the list have been addressed during the implementation of FASB143, some will be considered during FIN47 implementation. The list off assets can very well be unique to each of our companies, and may not be handled the same way. The list should only be used as a working document.

<<FIN47 List of Assets.doc>>

Thank you for all of your previous responses.

Bea Gonzales
Public Service Company of NM
Project Manager
Plant Accounting

Wiseman, Sara

From: Riggs, Eric
Sent: Monday, October 10, 2005 7:45 AM
To: Wiseman, Sara; Kinder, Debra
Subject: FW: Plugging costs

fyi

From: Sundheimer, Glenn
Sent: Monday, October 10, 2005 7:19 AM
To: Riggs, Eric
Subject: RE: Plugging costs

Eric,

We generally plug wells when the casing in the well becomes corroded, either causing a leak or posing the potential for a leak. We have put off plugging wells due to lack of budget funds.

Glenn

From: Riggs, Eric
Sent: Friday, October 07, 2005 4:00 PM
To: Sundheimer, Glenn
Subject: RE: Plugging costs

Glenn,

Would you please tell me the circumstances that causes us to cap/close a well? Do we ever put off closing a well due to lack of budget funds?

Thanks,
Eric

From: Sundheimer, Glenn
Sent: Thursday, October 06, 2005 2:34 PM
To: Riggs, Eric
Subject: Plugging costs

Eric,

Attached is the information you wanted on the wells and the plugging costs.

Thanks.

Glenn

<< File: 05-Est plug wells.xls >> << File: Pluggingcostsfullfield.xls >> << File: Well Summary.xls >>

Kinder, Debra

From: Welsh, Elaine
Sent: Tuesday, October 11, 2005 3:00 PM
To: Kinder, Debra
Subject: RE: ARO Transmission

The 49 is correct because asbestos was not assumed to exist in all 69 stations.

Thanks,
Elaine

From: Kinder, Debra
Sent: Tuesday, October 11, 2005 2:09 PM
To: Welsh, Elaine
Cc: Wiseman, Sara; Riggs, Eric
Subject: RE: ARO Transmission

Elaine,

In the Spreadsheet for Transmission substations you reference a total of 69 substations for KU, but use 49 in the formula to compute the grand total cost. Which is correct?

Thanks,
Debbie

From: Welsh, Elaine
Sent: Friday, October 07, 2005 4:21 PM
To: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: ARO Transmission

<< File: Asbestos Removal _ Transmision Subs.xls >> << File: ARO Poles and Crossarms(Transmission).xls >>

Please let me know if there is anything else I need to do.

Thanks,
Elaine Welsh
LG&E Energy Services Co.
Budget Analyst III - Transmission
elaine.welsh@lgeenergy.com
Phone (502) 627-3578
Fax (502) 627-4716

Kinder, Debra

From: Welsh, Elaine
Sent: Tuesday, October 11, 2005 2:16 PM
To: Kinder, Debra
Subject: RE: Wood Poles, Crossarms

That would be for both companies combined.

Thanks,
Elaine

From: Kinder, Debra
Sent: Tuesday, October 11, 2005 2:15 PM
To: Welsh, Elaine
Cc: Wiseman, Sara; Riggs, Eric
Subject: Wood Poles, Crossarms

Elaine,

Are the removal costs for poles (38000 per yr) and crossarms (10000 per yr) per company or total for both companies ?

Thanks,
Debie

Wiseman, Sara

From: Kinder, Debra
Sent: Tuesday, October 11, 2005 2:09 PM
To: Welsh, Elaine
Cc: Wiseman, Sara; Riggs, Eric
Subject: RE: ARO Transmission

Elaine,

In the Spreadsheet for Transmission substations you reference a total of 69 substations for KU, but use 49 in the formula to compute the grand total cost. Which is correct?

Thanks,
Debbie

From: Welsh, Elaine
Sent: Friday, October 07, 2005 4:21 PM
To: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: ARO Transmission

<< File: Asbestos Removal _ Transmision Subs.xls >> << File: ARO Poles and Crossarms(Transmission).xls >>

Please let me know if there is anything else I need to do.

Thanks,
Elaine Welsh
LG&E Energy Services Co.
Budget Analyst III - Transmission
elaine.welsh@lgeenergy.com
Phone (502) 627-3578
Fax (502) 627-4716

Wiseman, Sara

From: Kinder, Debra
Sent: Tuesday, October 11, 2005 2:15 PM
To: Welsh, Elaine
Cc: Wiseman, Sara; Riggs, Eric
Subject: Wood Poles, Crossarms

Elaine,

Are the removal costs for poles (38000 per yr) and crossarms (10000 per yr) per company or total for both companies ?

Thanks,
Debie

Wiseman, Sara

From: Kinder, Debra
Sent: Tuesday, October 11, 2005 3:39 PM
To: Wiseman, Sara; Riggs, Eric
Subject: Liability Estimates from Field.xls

Attachments: Liability Estimates from Field.xls

Liability Estimates from Field...

Let's discuss this in the morning please.

Deb

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location	Liability Source
General Facilities	Jerry Grant	Big Stone Gap Substation	Asbestos
	Karan Kapp	Campbellsville Concrete Block Bldg	Asbestos
		Carrollton 1-1/2 Story Brick Bldg	Asbestos
		Carrolton Storeroom	Asbestos
		Danville 2 Story Facility	Asbestos
		Dawson Springs Storeroom	Asbestos
		Earlington - Wood Frame Bldg	Asbestos
		Eddyville	Asbestos
		Georgetown - 2 Bldgs	Asbestos
		Greenville	Asbestos
		Lexington Meter Dept.	Asbestos
		Lexington Meter Dept. Storage	Asbestos
		Lexington Substation/Relay Dept.	Asbestos
		London Storeroom	Asbestos
		Maysville	Asbestos
		Middlesboro 2 Story Brick	Asbestos
		Middlesboro Storeroom	Asbestos
		Morehead	Asbestos
		Morganfield 2 Story Brick	Asbestos
		Mt. Sterling - 2 Story Brick	Asbestos
		Mt. Sterling Storeroom	Asbestos
		Paris - 1 Story Brick	Asbestos
		Paris Storeroom	Asbestos
		Richmond	Asbestos
		Seventh and Ormsby	Asbestos
		Shelbyville Storeroom	Asbestos
		Somerset Wood Frame	Asbestos
		Somerset Storeroom	Asbestos
		Stone Rd Main Bldg	Asbestos
		Winchester 1 Story Brick	Asbestos
		Winchester Storeroom	Asbestos

Total Facilities

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location	Liability Source	Field Rem/Disp Estimate
Generation	**Jon Miller**			
	Steve Legler	Waterside	Asbestos	4,000,000
	Steve Legler	Paddy's Run	Asbestos	11,000,000
	Dave Cook	Mill Creek Unit 1 - 356 MW	Asbestos	3,555,000
	Dave Cook	Mill Creek Unit 2 - 356 MW	Asbestos	3,100,000
	Dave Cook	Mill Creek Unit 3 - 463 MW	Asbestos	2,350,000
	Dave Cook	Mill Creek Unit 4 - 543 MW	Asbestos	2,600,000
	Fred Jackson	Ghent Unit 1 - 511 MW	Asbestos	6,517,000
	Fred Jackson	Ghent Unit 2 - 511 MW	Asbestos	8,637,000
	Fred Jackson	Ghent Unit 3 - 511 MW	Asbestos	1,532,000
	Fred Jackson	Ghent Unit 4 - 511 MW	Asbestos	1,532,000
	Steve Legler	Cane Run Unit 1	Asbestos	2,700,000
	Steve Legler	Cane Run Unit 2	Asbestos	2,550,000
	Steve Legler	Cane Run Unit 3	Asbestos	2,700,000
	Steve Legler	Cane Run Unit 4	Asbestos	2,750,000
	Steve Legler	Cane Run Unit 5	Asbestos	2,150,000
	Steve Legler	Cane Run Unit 6	Asbestos	2,500,000
	David Cosby	Trimble	Asbestos	0
		Green River	Asbestos	
	Sam Carr	Brown Unit 1 - 108 MW	Asbestos	2,055,700
	Sam Carr	Brown Unit 2 - 178 MW	Asbestos	3,295,700
	Sam Carr	Brown Unit 3 - 454 MW	Asbestos	7,435,200
		Zorn	Asbestos	
	Steve Legler	Canal	Asbestos	6,000,000
	Sam Carr	Tyronne Unit 1 - 30 MW	Asbestos	1,458,700
	Sam Carr	Tyronne Unit 2 - 30 MW	Asbestos	1,458,700
	Sam Carr	Tyronne Unit 3 - 75 MW	Asbestos	2,106,700
	Sam Carr	Pineville Unit 1 - 38 MW	Asbestos	1,534,200
		Haefling	Asbestos	
		Ohio Falls	Asbestos	
		Dix Dam	Asbestos	
		Lock 7 - Pending Sale	Asbestos	
	Steve Legler	Waterside	Batteries	
	Steve Legler	Paddy's Run - 13 DC - SFC/SES Room	Batteries	3,500
	Steve Legler	Paddy's Run - 12 DC - PR-12 Building	Batteries	3,500
	Steve Legler	Paddy's Run - 11 DC - PR-11 Under Control Room	Batteries	1,000
	Steve Legler	Paddy's Control House DC - Substation	Batteries	3,500
		Mill Creek	Batteries	
	Fred Jackson	Ghent Lead Acid - 4 sets Station Batteries	Batteries	16,000

Fred Jackson	Ghent Lead Acid - Equip Rooms, Scrubber, SCR	Batteries	2,000
Fred Jackson	Ghent Misc. Dry Cell	Batteries	10,000
Steve Legler	Cane Run Unit 1 Basement - Emer. No. 1 (1 & 2)	Batteries	3,500
Steve Legler	Cane Run Unit 3 1st Landing - Emer. No. 2 (3 & 4)	Batteries	3,500
Steve Legler	Cane Run Unit 6 Basement - Emer. No. 3 (6)	Batteries	3,500
Steve Legler	Cane Run No. 1 Breaker House - Station No. 1	Batteries	3,500
Steve Legler	Cane Run Unit 1 Basement - Station No. 2	Batteries	3,500
Steve Legler	Cane Run Unit 3 1st Landing - Station No. 3	Batteries	3,500
Steve Legler	Cane Run Unit 6 Basement - Station No. 4	Batteries	3,500
Steve Legler	Cane Run Unit 4 Turbine Floor - UPS	Batteries	2,000
Steve Legler	Cane Run Unit 5 Turbine Floor - UPS	Batteries	2,000
Steve Legler	Cane Run Unit 6 Turbine Floor - UPS	Batteries	2,000
Steve Legler	Cane Run Old Control House, Rear - Communications	Batteries	2,000
Steve Legler	Cane Run 4 & 5 SPP Elect. Room	Batteries	1,000
Steve Legler	Cane Run Gas Turbine - GT 11	Batteries	3,500
	Trimble	Batteries	
	Green River	Batteries	
Sam Carr	Brown 1 Station Batteries	Batteries	2,000
Sam Carr	Brown 2 Station Batteries	Batteries	2,000
Sam Carr	Brown 3 Station Batteries	Batteries	2,000
Sam Carr	Brown ST - West Cliff	Batteries	2,000
Sam Carr	Brown ST - North Sub	Batteries	2,000
Sam Carr	Brown 3 Computer Batteries	Batteries	480
Sam Carr	Brown 1 Computer Batteries	Batteries	240
Sam Carr	Brown ST Slurry Room	Batteries	480
	Zorn	Batteries	
	Canal	Batteries	
Sam Carr	Tyronne - UOP 05049	Batteries	2,700
	Pineville	Batteries	
Sam Carr	Haefling - UOP 05049	Batteries	2,700
Sam Carr	Dix Station Batteries	Batteries	2,000
	Ohio Falls	Batteries	
	Lock 7 - Pending Sale	Batteries	
Steve Legler	Waterside	PCB (Oil)	5,000
Steve Legler	Paddy's Run	PCB (Oil)	15,000
	Mill Creek	PCB (Oil)	
Fred Jackson	Ghent - Station Oil Reserves	PCB (Oil)	12,000
Steve Legler	Cane Run	PCB (Oil)	10,000
	Trimble	PCB (Oil)	
	Green River	PCB (Oil)	
	Brown	PCB (Oil)	
	Zorn	PCB (Oil)	
Steve Legler	Canal	PCB (Oil)	5,000
	Tyronne	PCB (Oil)	
	Pineville	PCB (Oil)	

Haefling	PCB (Oil)	
Ohio Falls	PCB (Oil)	
Dix Dam	PCB (Oil)	
Lock 7 - Pending Sale	PCB (Oil)	
	Total Generation	**85,660,000**

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location	Liability Source	Field Rem/Disp Estimate
Gas				
	Glenn Sundheimer	Magnolia Deep - 72 Wells	Well Plugging	1,383,000
	Glenn Sundheimer	Magnolia Upper - 91 Wells	Well Plugging	1,948,000
	Glenn Sundheimer	Center - 225 Wells	Well Plugging	3,736,000
	Glenn Sundheimer	Muldraugh - 60 Wells	Well Plugging	967,000
	Glenn Sundheimer	Doe Run - 145 Wells	Well Plugging	2,835,000
	Steve Beatty	Muldraugh - IM&E Office	Asbestos	38,000
	Steve Beatty	Muldraugh - Kewanee Boiler Room	Asbestos	15,000
	Steve Beatty	Muldraugh - Purifier 1	Asbestos	30,000
	Steve Beatty	Muldraugh - Compressor Bldg	Asbestos	20,000
	Steve Beatty	Muldraugh - Purifier 2	Asbestos	32,000
	Steve Beatty	Muldraugh - Purifier 3	Asbestos	59,000
	Steve Beatty	Muldraugh - Abandoned H2S Incinerator	Asbestos	21,000
	Steve Beatty	Muldraugh - Locker Room	Asbestos	11,000
	Steve Beatty	Muldraugh - Station Valves	Asbestos	4,000
	Steve Beatty	Muldraugh - Station Piping	Asbestos	76,000
	Steve Beatty	Muldraugh - Field Valves	Asbestos	6,000
	Steve Beatty	Muldraugh - Field Piping	Asbestos	67,000
	Steve Beatty	Doe Run - Field Valves	Asbestos	5,000
	Steve Beatty	Doe Run - Field Piping	Asbestos	134,000
	Steve Beatty	Doe Run - Deep Field Valves	Asbestos	1,000
	Steve Beatty	Doe Run - Deep Field Piping	Asbestos	56,000
	Steve Beatty	Muldraugh - Distribution	Asbestos	11,000
	Tom Rieth	Magnolia Compressor Station Paneling, Roofing	Asbestos	40,000
	Tom Rieth	Magnolia Compressor Station Auxillary Bldg	Asbestos	18,000
	Tom Rieth	Magnolia compressor Station Field Shop	Asbestos	9,000
	Tom Rieth	Magnolia Compressor Station Piping Insulation	Asbestos	7,000
	Tom Rieth	Magnolia Compressor Station #1 Purifier Reactivator	Asbestos	26,000
	Tom Rieth	Magnolia Station Field Valves	Asbestos	33,000
	Tom Rieth	Magnolia Station and Field Piping	Asbestos	113,000
	Tom Rieth	Misc. Distribution - gaskets, valve legs, coal tar, gaskets	Asbestos	56,000
	Mark Satkamp	City Gate - Preston Station - Meter Bldg	Asbestos	9,000
	Mark Satkamp	City Gate - Preston Station - Contro Bldg	Asbestos	6,000
	Mark Satkamp	City Gate - Doe Run Station	Asbestos	16,000

Bob Ehrler	Gas Pipeline	0
	Total Gas	**11,788,000**

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location	Liability Source	Field Rem/Disp Estimate
Transmission				
	Elaine Welsh	Paddy's Run	Asbestos	14,000
	Elaine Welsh	LGE Substations (approx. 10 substations)	Asbestos	83,000
	Elaine Welsh	KU Substations (69 Substations)	Asbestos	624,000
	Elaine Welsh	Estimated Annual Cost based on past history	Wood Poles	38,000
	Elaine Welsh	Estimated Annual Cost bsed on past history	Cross Arms	10,000
			Total Transmission	**769,000**

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location	Liability Source	Field Rem/Disp Estimate
Distribution Substations	Tony Durbin			
		LGE		
		Ashby	Asbestos	15,000
		Bishop	Asbestos	16,000
		Bluegrass	Asbestos	3,000
		Brandenburg	Asbestos	12,000
		Brook	Asbestos	8,000
		Carter	Asbestos	8,000
		Clarks Lane	Asbestos	16,000
		Crestwood	Asbestos	8,000
		Crop	Asbestos	16,000
		Dahlia	Asbestos	16,000
		Del Park	Asbestos	16,000
		Dixie	Asbestos	12,000
		Dumesnil	Asbestos	8,000
		Eighth Street	Asbestos	16,000
		Fairmont	Asbestos	8,000
		Falls City	Asbestos	15,000
		Floyd	Asbestos	4,000
		Ford	Asbestos	8,000
		Forty Fourth	Asbestos	16,000
		Freys Hill	Asbestos	8,000
		Gaulbert	Asbestos	8,000
		Gilligan	Asbestos	8,000
		Goss	Asbestos	4,000
		Grade Lane	Asbestos	44,000
		Grand	Asbestos	8,000
		Hale	Asbestos	8,000
		Harmony Landing	Asbestos	44,000
		Herman	Asbestos	8,000
		Highland	Asbestos	69,000
		Hillcrest	Asbestos	20,000
		Hurstborne	Asbestos	15,000
		International	Asbestos	3,000
		Jeffersontown	Asbestos	15,000
		Kenwood	Asbestos	15,000
		Knob Creek	Asbestos	61,000
		Locust	Asbestos	39,000
		Logan	Asbestos	8,000
		Louisville Downs	Asbestos	8,000
		Lynn	Asbestos	8,000

Magazine	Asbestos	26,000
Manslick	Asbestos	19,000
Muldraugh	Asbestos	14,000
Nachand	Asbestos	15,000
Okolona	Asbestos	3,000
Ormsby	Asbestos	9,000
Pirtle	Asbestos	8,000
Plainview	Asbestos	16,000
Pleasure Ridge	Asbestos	15,000
Seventh Street	Asbestos	8,000
Sheperdsville	Asbestos	15,000
Skylight	Asbestos	15,000
Smyrna	Asbestos	15,000
Solite	Asbestos	3,000
South Park	Asbestos	15,000
Southern	Asbestos	40,000
Southern Baptist Seminary	Asbestos	12,000
Stewart	Asbestos	15,000
Trimble Cty Sw. Rm (12 kv)	Asbestos	15,000
Terry	Asbestos	15,000
Vermont	Asbestos	12,000
Waterside (D)	Asbestos	36,000
Westpoint	Asbestos	12,000
Western	Asbestos	12,000
WHAS	Asbestos	15,000
Worthington	Asbestos	3,000
Zorn	Asbestos	13,000
KU		
478 Substations 10% or 47 Estimated to have Asbestos Contamination	Asbestos	599,000
Estimated Annual Cost based o	Wood Poles	38,000
Estimated Annual Cost bsed on	Cross Arms	10,000
	Total Distribution	**1,665,000**

Wiseman, Sara

From:	Welsh, Elaine
Sent:	Wednesday, October 12, 2005 10:12 AM
To:	Kinder, Debra; Riggs, Eric; Wiseman, Sara
Subject:	ARO backup

All -

The 10 transmission substations that were assumed to have asbestos are:

Algonquin
Ashbottom
Breckenridge
Canal
Cane Run
Fern Valley
Middletown
Paddy's Run
Northside
Paddy's West

System Operations/System Control was consulted and rendered this list. The costs for asbestos removal were based on the costs submitted by Distribution (Tony Durbin).

System Operations/System Control at Dix Dam was consulted with regard to KU transmission substations and determined that of the 69 substations, 70% of them probably contained asbestos wiring.

Please let me know if I need to supply anything further.

Elaine Welsh
LG&E Energy Services Co.
Budget Analyst III - Transmission
elaine.welsh@lgeenergy.com
Phone (502) 627-3578
Fax (502) 627-4716

Wiseman, Sara

From: Miller, Jon
Sent: Wednesday, October 12, 2005 9:46 AM
To: Wiseman, Sara
Subject: RE: Asbestos

Sara,

Dan expects to have Ohio Falls and Zorn by the end of the week. I'm waiting to hear back from Bryan Baker from Green River.

Jon

From: Wiseman, Sara
Sent: Wednesday, October 12, 2005 9:21 AM
To: Miller, Jon
Subject: RE: Asbestos

Thanks.

Sara Wiseman
Manager-Property Accounting
502.627.3189

From: Miller, Jon
Sent: Wednesday, October 12, 2005 9:20 AM
To: Wiseman, Sara
Subject: RE: Asbestos

I'll follow up and let you know.

From: Wiseman, Sara
Sent: Wednesday, October 12, 2005 9:20 AM
To: Miller, Jon
Cc: Kinder, Debra; Riggs, Eric
Subject: Asbestos

Jon:

What is the status of Green River and Zorn asbestos numbers? We have a meeting with Shannon today to update her on our FIN 47 progress.

Sara Wiseman
Manager-Property Accounting
502.627.3189

Wiseman, Sara

From: Beatty, Stephen
Sent: Thursday, October 13, 2005 2:59 PM
To: Wiseman, Sara
Cc: Kinder, Debra; Riggs, Eric
Subject: RE: Estimate-Riggs Jct.xls

Attachments: Estimate-Riggs Jct (10-13-05).xls

Estimate-Riggs Jct (10-13-05)....

Enclosed is my updated estimate.

From: Wiseman, Sara
Sent: Thursday, October 13, 2005 10:59 AM
To: Beatty, Stephen
Cc: Kinder, Debra; Riggs, Eric
Subject: Estimate-Riggs Jct.xls

<< File: Estimate-Riggs Jct.xls >>

Steve:

I believe we will need to set up an ARO for Riggs Junction. I found this old file from our SFAS 143 work. Would you please update it for us? I hope that it will not cause you too much extra work. Thanks and please give me a call if you have questions.

Sara
Ext. 3189

Tracking:

Recipient
Wiseman, Sara
Kinder, Debra
Riggs, Eric

RETIREMENT AND ABANDONMENT ESTIMATE
RIGGS JUNCTION GAS TRANSMISSION FACILITY

Description:

This estimate is being developed at the request of Property Accounting in compliance with new FERC rules that require the expenses to restore sites after facilities are abandoned be accounted. The lease for the facilities at Riggs Junction requires that LG&E restore the facility to greenspace if the area is ever abandoned.

The Riggs Junction facility contains a valve nest that interconnects two gas transmission pipelines to three Doe Run Upper Storage Field gathering mains and one high-pressure gas distribution main that feeds the City of Brandenburg. The facility also contains two pressure regulating stations; Brandenburg High Pressure Station and Riggs Junction Regulator Assembly. In 1998, a shale recovery compressor, named the Riggs Junction Compressor, was relocated from the site to a new shale recovery site in Laconia, IN. The existing building was demolished, but the building foundation remains. The foundation has not been demolished as it could possibly be used as a foundation for pig traps for the two transmission pipelines.

This estimate is developed solely for the purpose of meeting the new FERC rules. There are no plans to abandon this site to date.

Scope:

1. Demolish existing concrete foundation from Riggs Junction Shale Compressor.
2. Remove existing Brandenburg HP Regulator Station.
3. Remove all of the aboveground piping of the existing valve nest at Riggs Junction. Cap all pipe below grade. The 12" and/or 16" Doe Run Lines, the 3 - 12" Storage Field Gathering Mains, and the 12" Distribution Main will be abandoned in place.
4. The Riggs Junction Regulator Assembly will be removed. The 2" Thin-Mill Steel inlet piping and the 4" PE outlet piping will be capped and abandoned in place.

MATERIALS					
50	lbs, 'Electrodes, Welding, E6010, 5P, 1/8", SFA 5.1	$1.19	$ 59.50		
3	Anode, 9 lb, Magnesium	$25.65	$ 76.95		
70	pkg, Wax Tape	$11.01	$ 770.70		
24	gallons, Wax Tape Primer	$20.22	$ 485.28		
2	Caps, 2" Forged Steel	$4.86	$ 9.72		
1	Caps, 4" PE	$6.30	$ 6.30		
4	Caps, 12", Steel	$56.53	$ 226.12		
2	Caps, 16", Steel	$68.28	$ 136.56		
2	Bags, Seed, 50 lbs	$85.16	$ 170.32		
25	Bails, Straw	$5.67	$ 141.75		
20	yds, Clean backfill	$25.00	$ 500.00		
1	lot, Miscellaneous Materials	$250.00	$ 250.00		
		Subtotal =	$ 2,833.20		
		Consumables =	$ 141.66		
		Miscellaneous =	$ 141.66		
		Subtotal =	$ 3,116.52		
		G & A Overheads =	$ 31.17		
		KY Sales Tax =	$ 186.99		
		Total Materials =		$	3,334.68
COMPANY LABOR					
80	hr, Inspector (Assume PG-12)	$27.23	$ 2,178.40		
4	hr, Records Coordinator	$22.85	$ 91.40		
16	hr, Distribution Mechanic A	$25.17	$ 402.72		
		Unloaded Total Company Labor =	$ 2,672.52		
		96% Co. Labor Loading =	$ 2,576.44		
		Total Company Labor =		$	5,248.96

TRANSPORTATION AND EQUIPMENT

		Transportation and Equipment Costs =	$ 1,049.79		
		Total T & E Expense =		$	1,049.79

CONTRACT LABOR

4	hrs, Supervisor	$49.06	$ 196.24		
40	hrs, Foreman	$38.73	$ 1,549.20		
80	hrs, Welder	$39.01	$ 3,120.80		
80	hrs, Laborer	$21.16	$ 1,692.80		
40	hrs, Equipment Operator	$33.09	$ 1,323.60		
40	hrs, Dump Truck Driver	$24.33	$ 973.20		
80	hrs, Equipment Charge, Welding Truck	$16.97	$ 1,357.60		
80	hrs, Equipment Charge, Backhoe	$18.74	$ 1,499.20		
80	hrs, Equipment Charge, Excavator with hoe ram	$195.05	$ 15,604.00		
80	hrs, Equipment Charge, Compressor	$7.02	$ 561.60		
80	hrs, Equipment Charge, Dump Truck	$40.98	$ 3,278.40		
40	hrs, Equipment Charge, Tractor and Trailer	$40.98	$ 1,639.20		
8	hrs, Equipment Charge, Strawblower	$6.82	$ 54.56		
1	lot, Contractor consumables, safety supplies, misc. materials	$1,000.00	$ 1,000.00		
16	crew hrs, NDT Contractor Expense	$80.00	$ 1,280.00		
500	miles, NDT Contractor Travel Expense	$0.85	$ 425.00		
1	lot, NDT Contractor Material Expense	$280.00	$ 280.00		
		Subtotal =	$ 35,835.40		
		G & A Overheads =	$ 358.35		
		Total Contract Labor =		$	36,193.75

MISCELLANEOUS

6	IBEW 2100 Meal Tickets	$6.00	$ 36.00		
630	mscf, lost gas during blowdowns	$12.00	$ 7,560.00		
1	lot, Construction Debris Disposal	$500.00	$ 500.00		
1	lot, PCB Analysis	$50.00	$ 50.00		
1	lot, Asbestos Pipe Disposal.	$1,200.00	$ 1,200.00		
		Subtotal =	$ 9,346.00		
		G & A Overheads =	$ 93.46		
		Total Miscellaneous =		$	9,439.46
		Subtotal =		$	55,266.65
		8% LOCAL ENGINEERING =		$	4,421.33
		10% CONTINGENCY =		$	5,526.66
		TOTAL PROJECT COSTS =		**$**	**65,214.64**

Assumptions:

1. T&E charges are based upon 20% of Company Labor Charges.
2. Local Engineering will cover LG&E supervision labor and is based upon 8% of the total project subtotal.
3. BU Capital overheads are assumed to be 96.405% of base labor.
4. Assume that disposal is required for asbestos pipe coating.
5. Assume that there are no disposal costs for PCB contamination or any other hazardous materials.
6. The 12" and 16" Doe Run Lines, the 3 - 12" Storage Field Gathering Mains, and the 12" Distribution Main will be abandoned in place. Ignore all customer service requirement issues. Assume service will be provided via another means.
7. Assume there will be no scrap value from the recovered pipe, valves and fittings.

Estimated by S. A. Beatty, 10/13/05

Wiseman, Sara

From:	Miller, Jon
Sent:	Friday, October 14, 2005 11:01 AM
To:	Charnas, Shannon; Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject:	FW: FIN-47
Attachments:	FIN-47 Abatement Methodolgy.doc; Fin 47 Template (2).xls; FIN-47_2.xls

Here is additional information from Dan Kremer for Cane Run and the Jefferson County CTs.

Jon

From:	Kremer, Dan
Sent:	Friday, October 14, 2005 10:57 AM
To:	Miller, Jon
Cc:	Legler, Steve; Turner, Steven
Subject:	FW: FIN-47

Jon, here is the FIN-47 information for CR, OF and CT's. I'll send you the information on OF batteries and Zorn early next week. I believe everything else is complete.

Dan Kremer
Manager Commercial Operations
Cane Run Station
(502) 449-8808
dan.kremer@lgeenergy.com

From: Legler, Steve
Sent: Thursday, September 29, 2005 3:28 PM
To: Kremer, Dan
Cc: Turner, Steven
Subject: RE: FIN-47

Dan,

I have updated Shannon's FIN-47 template with the new numbers. I have also attached the revised abatement methodology Word document and FIN-47_2 spreadsheet to better reflect other plant-wide contingency.

Please review and we can discuss if necessary.

Steve

FIN-47 Abatement Methodolgy.do... Fin 47 Template (2).xls FIN-47_2.xls

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From:	Kremer, Dan
Sent:	Wednesday, September 28, 2005 10:29 AM
To:	Legler, Steve
Cc:	Turner, Steven
Subject:	FW: FIN-47

Steve, here are the files that need to be completed and sent to Shannon by Wednesday October 5th. The first is the original Excel file that you sent. This file is included below in Shannon's e-mail. The others three (FIN_47 Abatement Methodology, PDF file, FIN-47_2) should be sent as back-up for justifying the numbers included in the first file. I would suggest adding a sentence or two at the top of the Word document that explains the 15% adder for every 25MW. Other than that I believe you pretty much have everything you need. You may also want to adjust the numbers upward per our discussion this morning regarding extra contingency for other areas of the plant (offices, SPP, screenhouse, etc.).

Any questions or issues please let me know.

<< File: FIN-47 Abatement Methodolgy.doc >> << File: LG&E KU 100 Meg Budget.pdf >> << File: FIN-47_2.xls >>
Dan Kremer
Manager Commercial Operations
Cane Run Station
(502) 449-8808
dan.kremer@lgeenergy.com

From: Charnas, Shannon
Sent: Wednesday, September 28, 2005 6:38 AM
To: Kremer, Dan
Subject: RE: FIN-47

<< Message: Thursday Asbestos reporting for FIN 47 meeting >>
Dan-

I have attached the original email with the Cane Run spreadsheet, this is how we ultimately want your cost information. The Word document that you have will support this information. If you need to use the spreadsheet that Jon Miller sent out to identify "other" items that would not be included in the NEC or INCORP quotes, it can be used for that. The summary of all the cost information should be in the attached spreadsheet, all other documents would be used for support. If you have any questions, please call.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Kremer, Dan
Sent: Tuesday, September 27, 2005 3:48 PM
To: Charnas, Shannon
Subject: FIN-47

Shannon, sorry but I am confused as to the format that you want us to use for submitting the abatement cost information. Can you send me the file with the format that you want? Also, the deadline for submitting this to you is Wednesday Oct 5?

Dan Kremer
Manager Commercial Operations
Cane Run Station
(502) 449-8808
dan.kremer@lgeenergy.com

FIN-47 ASBESTOS REMOVAL ESTIMATE METHODOLOGY

National Environmental Contracting (NEC) provided an asbestos abatement estimate to remove all asbestos containing material from a typical 100MW coal fired unit. This estimate was based on their familiarization of similar sized units such as CR1 & 2, BR1, and units at Paddy's Run,

I have detailed below how I arrived at the FIN-47 removal numbers for Cane Run. NEC has estimated a cost escalation factor of 15% per 25 mw of additional unit capacity for units larger than the 100MW base. I adjusted the sub-totals to match specific Cane Run equipment configuration and known asbestos location.

Cane Run Unit 1 – 100 MW

- **Penthouse – $150k** - Full enclosure of penthouse. All headers, walls, floor, drum all require abatement.
- **External Furnace - $750k** — Removal of asbestos block from boiler wall. Block located between tube refractory and outer metal casing.
- **Piping, External - Operating Floor up – $250k** - High energy, sootblower, heater extraction, downcomers, etc.
- **Pipe and Equipment, below Operating floor - $400k** – Adder of $250k to cover all FW heaters, turbine, mills, condenser, heater extraction pipe, etc.
- **Ductwork, Equipment, Operating floor up - $300k** – Air heater, side headers, Air/Gas ductwork, windbox, ash hoppers, deaerator heater and storage tank, fans, precipitator.
- **Ductwork, under Operating floor - $200k** – Air Duct, PA Duct.
- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $400k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces, refractory, additional contingency for difficulty of removing boiler furnace block insulation.
- **Coal Handling - $150k** – Transite siding removal $60k, scaffolding to access siding, $90k.

Cane Run Unit 2 – 100 MW

- **Penthouse – $150k** - Full enclosure of penthouse. All headers, walls, floor, drum all require abatement.
- **External Furnace - $750k** — Removal of asbestos block from boiler wall. Block located between tube refractory and outer metal casing.
- **Piping, External - Operating Floor up – $250k** - High energy, sootblower, heater extraction, downcomers, etc.
- **Pipe and Equipment, below Operating floor - $400k** – Adder of $250k to cover all FW heaters, turbine, mills, condenser, heater extraction pipe, etc.
- **Ductwork, Equipment, Operating floor up - $300k** – Air Heater, side headers, Air/Gas ductwork, windbox, ash hoppers, deaerator heater and storage tank, fans, precipitator.
- **Ductwork, under Operating floor - $200k** – Air Duct, PA Duct.
- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $400k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces, refractory, additional contingency for difficulty of removing boiler furnace block insulation.

Cane Run Unit 3 – 125 MW

- **Penthouse – $175k** - Full enclosure of penthouse. All headers, walls, floor, drum all require abatement.
- **External Furnace - $870k** — Removal of asbestos block from boiler wall. Block located between tube refractory and outer metal casing.
- **Piping, External - Operating Floor up – $300k** - High energy, sootblower, heater extraction, downcomers, etc.
- **Pipe and Equipment, below Operating floor - $400k** – Adder of $227k to cover all FW heaters, turbine, mills, heater extraction pipe, condenser, etc.
- **Ductwork, Equipment, Operating floor up - $345k** – Air Heater, side headers, Air/Gas ductwork, windbox, ash hoppers, deaerator heater and storage tank, fans, precipitator.
- **Ductwork, under Operating floor - $230k** – Air Duct, PA Duct.

- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $460k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces, refractory, additional contingency for difficulty of removing boiler furnace block insulation.

Cane Run Unit 4 – 170 MW

- **Penthouse – $150k** – Only walls, floor, and drum require abatement. Headers abated.
- **External Furnace - $1065k** — Removal of asbestos block from boiler wall. Block located between tube refractory and outer metal casing.
- **Piping, External - Operating Floor up – $200k** - Sootblower, heater extraction, downcomers, other. High Energy Piping abated.
- **Pipe and Equipment, below Operating floor - $300k** – Adder of $87k to cover Gas Recirculating Fan, Condenser. FW heaters, mills, turbine, high energy piping abated.
- **Ductwork, Equipment, Operating floor up - $500k** – Air Heater, side headers, Air/Gas ductwork, windbox, ash hoppers, deaerator storage tank. Deaerator heater, steam coils, precipitator, large portions of duct, fans abated.
- **Ductwork, under Operating floor - $350k** – Air Duct, PA Duct.
- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $300k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces, refractory.

Cane Run Unit 5 – 181 MW

- **Penthouse – $150k** – Only floor and drum require abatement. Headers abated.
- **External Furnace - $700k** — Removal of asbestos mud from seams of mineral wool blankets. Large portions of furnace insulation already abated.
- **Piping, External - Operating Floor up – $200k** - Sootblower, heater extraction, downcomers, other. High Energy Piping abated.
- **Pipe and Equipment, below Operating floor - $200k** – Fans, condenser, economizer hoppers, heater extraction pipe. FW heaters, mills, turbine, steam coils abated.
- **Ductwork, Equipment, Operating floor up - $450k** – Air/Gas ductwork, windbox, ash hoppers, deaerator storage tank. Deaerator heater, precipitator, large portions of duct, fans abated.
- **Ductwork, under Operating floor - $300k** – Air/Gas duct.
- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $400k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces.

Cane Run Unit 6 – 260 MW

- **Penthouse – $200k** – Only floor and drum require abatement. Headers abated.
- **External Furnace - $470k** — Removal of asbestos from dead air spaces, mud at backpass transition to duct.
- **Piping, External - Operating Floor up – $350k** - Sootblower, downcomers, other. High Energy Piping abated.
- **Pipe and Equipment, below Operating floor - $300k** – Fans, condenser, duct hoppers, heater extraction pipe. FW heaters, mills, turbine abated.
- **Ductwork, Equipment, Operating floor up - $700k** – Air/Gas ductwork, windbox, ash hoppers, deaerator storage tank.
- **Ductwork, under Operating floor - $400k** – Air/Gas duct.
- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $400k** – Wiring, Bunker room piping, Turbine/Boiler room roofs.

Location						
Asset Retirement Obligations			($000's)			
Asset Description	Location	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date	
Asbestos						
Cane Run						
CR1 Asbestos Abatement	Cane Run Unit 1 Plant		2,700	60		Ductwork, Equip. External, Operating Floor up $300k; Ductwork External, Under Operating Floor $200k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $400k; Penthouse $150k; Furnace External $750k; Air Testing, permits, survey $100k; Boiler misc. $400k; Coal Handling $150k
CR2 Asbestos Abatement	Cane Run Unit 2 Plant		2,550	50		Ductwork, Equip. External, Operating Floor up $300k; Ductwork External, Under Operating Floor $200k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $400k; Penthouse $150k; Furnace External $750k; Air Testing, permits, survey $100k; Boiler misc. $400k
CR3 Asbestos Abatement	Cane Run Unit 3 Plant		2,880	50		Ductwork, Equip. External, Operating Floor up $345k; Ductwork External, Under Operating Floor $230k; Piping External, Opererating Floor up $300k; Pipe and Equip. Under Operating Floor $400k; Penthouse $175k; Furnace External $870k; Air Testing, permits, survey $100k; Boiler misc. $460k
CR4 Asbestos Abatement	Cane Run Unit 4 Plant		3,065	50		Ductwork, Equip. External, Operating Floor up $500k; Ductwork External, Under Operating Floor $350k; Piping External, Opererating Floor up $200k; Pipe and Equip. Under Opererating Floor $300k; Penthouse $150k; Furnace External $1065k; Air Testing, permits, survey $100k; Boiler misc. $400k
CR5 Asbestos Abatement	Cane Run Unit 5 Plant		2,500	40		Ductwork, Equip. External, Operating Floor up $450k; Ductwork External, Under Operating Floor $300k; Piping External, Opererating Floor up $200k; Pipe and Equip. Under Opererating Floor $200k; Penthouse $150k; Furnace External $700k; Air Testing, permits, survey $100k; Boiler misc. $400k
CR6 Asbestos Abatement	Cane Run Unit 6 Plant		2,920	50		Ductwork, Equip. External, Operating Floor up $700k; Ductwork External, Under Operating Floor $400k; Piping External, Opererating Floor up $350k; Pipe and Equip. Under Opererating Floor $300k; Penthouse $200k; Furnace External $470k; Air Testing, permits, survey $100k; Boiler misc. $400k
Paddy's Run						
Plant Asbestos Abatement	Total Plant		11,000	100		Lump Sum price for total removal, cleanup and disposal of asbestos materials from all units including the Service Building and exterior SDRS ductwork. A price quote was received from four vendors in December 1990. The average of the four bides was approximately $7.0 million. This average cost was inflated at 3.0 % per year arriving at $11.0 million.
Canal						
Plant Asbestos Abatement	Total Plant		6,000	75		Estimate prepared using Paddy's Run as basis and adjusted for size of the facility
Waterside						
Plant Asbestos Abatement	Total Plant		4,000	50		Estimate prepared using Paddy's Run as basis and adjusted for size of the facility
Ohio Falls						
Plant Asbestos Abatement	Total Plant		600	20		Estimate based upon actual removal cost of unit 7 performed in 2005 ($60k) plus additional $25k for asbestos contained outside of the unit.
Battery						
Cane Run						
Emergency Battery No. 1 (1&2)	Unit 1 basement	60	3.5	1		
Emergency Battery No. 2 (3&4)	Unit 3 1st landing	60	3.5	1		
Emergency Battery No. 3 (6)	Unit 6 basement	60	3.5	1		
Station Battery No. 1	No. 1 Breaker House	60	3.5	1		
Station Battery No. 2	Unit 1 basement	60	3.5	1		
Station Battery No. 3	Unit 3 1st landing	60	3.5	1		
Station Battery No. 4	Unit 6 basement	60	3.5	1		
Unit 4 UPS Battery	Unit 4 turbine floor	30	2	0.5		
Unit 5 UPS Battery	Unit 6 turbine floor	30	2	0.5		
Unit 6 UPS Battery	Unit 6 turbine floor	30	2	0.5		

Location						
Asset Retirement Obligations			($000's)			
Asset Description	Location	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date	
Communications Battery	Old Control House (rear)	24	2	0.5		
4&5 SPP Batteries	4&5 SPP Elect. Room	10	1	0.5		
Jefferson County Gas Turbines						
Paddy's 13 DC	SFC/SES Room	60	3.5	1		
Paddy's 12 DC	PR-12 Building	60	3.5	1		
Paddy's 11 DC	PR-11 Under Control Rm	14	1	0.5		
Control house DC	Control House	60	3.5	1		
Cane Run GT-11	GT-11 Building	60	3.5	1		
Zorn						
Ohio Falls						
Oil						
Cane Run Station	Plant/GT-11		10	1		Turbine Reservoir/Mill/Fluid Drive/Screenhouse Oil Accumulator, Misc.
Paddy's Run Station	Plant/CT's		15	1		Turbine Reservoir/Mill/Fluid Drive/Screenhouse Oil Accumulator, Misc.
Canal Station	Plant		5	1		Turbine Reservoir/Mill/, Misc.
Waterside	Plant/CT		5	1		Gas Turbine/Misc. Plant Equipment
Ohio Falls	Plant		5	1		Governor Controls, bearing oil & Misc. Equipment

Assumption: Escalation factor of 15% per 25MW of additional unit capacity

Cane Run Unit 1 - 100 MW

	Base Cost	MW Multiplier	Adjustments	Total	
		1	$ 2,300		
Penthouse	150	150	0	150	
External Furnace	750	750	0	750	
Piping, External - Operating Floor up	250	250	0	250	
Pipe and Equipment, below Operating floor	150	150	250	400	FW heaters, heating boiler, condenser, basement lab equipment
Ductwork, Equipment, Operating floor up	300	300	0	300	
Ductwork, under Operating floor	200	200	0	200	
Survey, Air Testing, Permits, etc.	100	100	0	100	
Contingency	400	400	0	400	
Coal Handling	0	0	150	150	Coal Handling - Transite siding, wiring, insulation
Total:	$ 2,300.0	$ 2,300.0	$ 2,700	$ 2,700	

Cane Run Unit 2 - 100 MW

	Base Cost	MW Multiplier	Adjustments	Total	
		1	$ 2,300		
Penthouse	150	150	0	150	
External Furnace	750	750	0	750	
Piping, External - Operating Floor up	250	250	0	250	
Pipe and Equipment, below Operating floor	150	150	250	400	FW Heaters, condenser, basement lab pipe, warehouse areas, tanks
Ductwork, Equipment, Operating floor up	300	300	0	300	
Ductwork, under Operating floor	200	200	0	200	
Survey, Air Testing, Permits, etc.	100	100	0	100	Surveying, testing, permits virtually the same for all units
Contingency	400	400	0	400	
Total:	$ 2,300.0	$ 2,300.0	$ 2,550	2550	

Cane Run Unit 3 - 125 MW

125	Base Cost (100MW)	MW Escalation	Adjustments	Total	
		1.15	$ 2,645		Unit 3 boiler and auxiliaries virtually same size as CR1, 2
Penthouse	150	172.5	2.5	175	
External Furnace	750	862.5	7.5	870	
Piping, External - Operating Floor up	250	287.5	12.5	300	
Pipe and Equipment, below Operating floor	150	172.5	227.5	400	FW Heaters, condenser, turbine, mills, lab equipment
Ductwork, Equipment, Operating floor up	300	345	0	345	
Ductwork, under Operating floor	200	230	0	230	
Survey, Air Testing, Permits, etc.	100	115	-15	100	Surveying, testing, permits virtually the same for all units
Contingency	400	460	0	460	
Total:	$ 2,300.0	$ 2,645.0	$ 2,880	$ 2,880	

Cane Run Unit 4 - 170 MW

170	Base Cost (100MW)	MW Escalation	Adjustments	Total	
		1.42	$ 3,266		
Penthouse	150	213	-63	150	All headers abated
External Furnace	750	1065	0	1065	
Piping, External - Operating Floor up	250	355	-155	200	High energy piping abated
Pipe and Equipment, below Operating floor	150	213	87	300	Add gas recirculating fan, lab equipment
Ductwork, Equipment, Operating floor up	300	426	74	500	Gas Recirc. Duct
Ductwork, under Operating floor	200	284	66	350	Gas Recirc. Duct
Survey, Air Testing, Permits, etc.	100	142	-42	100	Surveying, testing, permits virtually the same for all units
Contingency	400	568	-168	400	Greater awarenes of locations of ACM on operating units
Total:	$ 2,300.0	$ 3,266.0	$ 3,065	$ 3,065	

Cane Run Unit 5 - 181 MW

181	Base Cost (100MW)	MW Escalation	Adjustments	Total	
		1.486	$ 3,418		
Penthouse	150	222.9	-72.9	150	All headers abated. Only crown seals, walls require abatement
External Furnace	750	1114.5	-414.5	700	ACM Mud at seams of wall mineral wool blanket only
Piping, External - Operating Floor up	250	371.5	-171.5	200	High energy piping abated
Pipe and Equipment, below Operating floor	150	222.9	-22.9	200	High energy piping abated
Ductwork, Equipment, Operating floor up	300	445.8	4.2	450	
Ductwork, under Operating floor	200	297.2	2.8	300	
Survey, Air Testing, Permits, etc.	100	148.6	-48.6	100	Surveying, testing, permits virtually the same for all units
Contingency	400	594.4	-194.4	400	Greater awarenes of locations of ACM on operating units
Total:	$ 2,300.0	$ 3,417.8	$ 2,500	$ 2,500	

Cane Run Unit 6 - 260 MW

260	Base Cost (100MW)	MW Escalation	Adjustments		
		1.96	$ 4,508		
Penthouse	150	294	-94	200	All headers abated. Only crown seals, walls require abatement
External Furnace	750	1470	-1000	470	Dead air space and mud at backpass transition to duct only
Piping, External - Operating Floor up	250	490	-140	350	High energy piping abated
Pipe and Equipment, below Operating floor	150	294	6	300	
Ductwork, Equipment, Operating floor up	300	588	112	700	Large areas of windbox/secondary air ducts and hoppers.
Ductwork, under Operating floor	200	392	8	400	
Survey, Air Testing, Permits, etc.	100	196	-96	100	Surveying, testing, permits virtually the same for all units
Contingency	400	784	-384	400	Greater awarenes of locations of ACM on operating units
Total:	$ 2,300.0	$ 4,508.0	$ 2,920	$ 2,920	

Kinder, Debra

From: Mills, Les
Sent: Friday, October 14, 2005 3:20 PM
To: Riggs, Eric; Kinder, Debra
Cc: Cooke, Scott
Subject: Pole Removal Cost

Eric & Debra , here is the best case scenario that I could come up with. The 30yd dumpster that Waste Management supplies us measures 7'W x 5'H x 22'L which comes up to 770 sq.ft. Now to come up with standard pole size is hard. I made it a 40' long pole that would run 1' wide all the way , so that would give you 40 sq.ft. So take the 40' into the 770' and that will give you 19.25 poles per dumpster. Now a basic cross arm is 4" x 4" x 8' and that will be .887 sq.ft. Take the .887 into 770 and that will give you 868.09 cross arms will go into the dumpster. This is not a perfect process and I am sure a math major could better this , but this is the best formula I could come up with. There are so many different poles sizes and even cross arms. I hope this helps , if there is any thing else I may be able to do just let me know.

Les Mills
AOC Distribution Operations
6900 Enterprise Dr.
Louisville, Ky.40214
Off. (502) 364-8436

Wiseman, Sara

From: Cosby, David
Sent: Friday, October 14, 2005 9:48 AM
To: Kinder, Debra
Cc: Wiseman, Sara; Riggs, Eric
Subject: FW: Thursday Asbestos reporting for FIN 47 meeting
Attachments: Fin 47 Template (TC).xls

FYI - Per your email sent today.

David L. Cosby Jr.
Commercial Operations Manager
Trimble County Plant
(502) 627-6203

From: Cosby, David
Sent: Thursday, September 22, 2005 6:19 PM
To: Charnas, Shannon; Miller, Jon; Crutcher, Tom; Rabe, Phil
Subject: RE: Thursday Asbestos reporting for FIN 47 meeting

Good day all! I have attached a sheet for TC in the same format passed around this week for FIN 47. Of course, the fact that Trimble is not really impacted by the asbestos issues lowers the size of this view. The battery information came from a MAXIMO printout. If we need to know actual physical floor locations, I can get with Phil on Monday to add.

I'll be back in the office on Monday. Have a great Friday and weekend!

David L. Cosby Jr.
Commercial Operations Manager
Trimble County Plant
(502) 627-6203

From: Charnas, Shannon
Sent: Tuesday, September 20, 2005 5:59 PM
To: Miller, Jon; Pence, Mark; Turner, Steven; Kremer, Dan; Crutcher, Tom; Jackson, Fred; Carr, Sam; Fraley, Jeffrey; Baker, Bryan; Grant, Jerry
Cc: Riggs, Eric; Kinder, Debra; Wiseman, Sara
Subject: Thursday Asbestos reporting for FIN 47 meeting

This message is to set expectations for the meeting on Thursday. Our time frame for completing FIN 47 work is running short and we need to come to final decisions on our methodology very soon. We need to come away from this meeting with a final plan to provide completed cost estimates for FIN 47 liabilities to Property Accounting by about 9/30.

Our largest remaining issue is asbestos. The first major part of asbestos is generating unit specific abatement work, such as removal from parts of the boiler and generating equipment. I have attached some information that was provided by Cane Run which includes an estimate for asbestos abatement (file "Fin 47 Template (2).xls"). I think this is a good starting point for a consistent methodology to be used across all stations, but much more detail needs to be added. For example, were these numbers based on the NEC estimate provided by Jeff Fraley? Were they adjusted for the size of the unit and any abatement work that had been previously completed on the units? We have estimates from NEC and INCORP (provided by Jeff Fraley), is one better than the other, or should an average of the two be used? The answers to these questions will help us develop a consistent method for determining cost across the business. We definitely need to calculate costs related to the boiler portion of the asbestos abatement liability.

The other asbestos issue is related to the actual buildings, not the equipment, over all the facilities owned by the company. We need to first identify the asbestos that we believe is in the building, such as in the insulation/siding, roof tiles, floor tiles, window caulking, etc.... Some estimate of the quantity should be made. Is there any history on the replacement/removal/abatement of these types of items? Jerry Grant has historical detail on abatements we have done on buildings in the past approx. 10 years and this information will likely be invaluable for helping us with these estimates. Is there a way to get an estimate of the removal/abatement of this type of asbestos from an external vendor similar to what we have on the boiler abatement? We need to consider any other means for attributing costs to these items. We will need to be able to determine a course of action during this meeting on this issue. It is clear from various sources in the industry that we need to make every effort to calculate these costs rather than just disclosing them.

If you have any information or answers to these questions that you would like to distribute to the group in advance of the meeting, that may be helpful. Otherwise, please bring whatever ideas, cost information, documentation that you have to the meeting for final resolution of these issues. Remember that most people will be "attending" the meeting over the phone, so if you have information to share it would be best to email it in advance of th meeting. I'm sure there will be a need for people to go back and determine numbers/costs following this meeting, but the strategy needs to be completed at the meeting.

We may take a few minutes at the end of the meeting to address any leftover remaining FIN 47 issues such as coal docks and hydro facilities. I don't think we have revised FIN 47 information from all the generating stations yet, and we will need to get those also.

Thanks for your assistance. I look forward to a very productive meeting on Thursday!

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

Wiseman, Sara

From: Kinder, Debra
Sent: Friday, October 14, 2005 3:44 PM
To: Mills, Les
Cc: Wiseman, Sara; Riggs, Eric
Subject: RE: Pole Removal Cost

Les,

I just left you a phone message which may be somewhat confusing. Let me try to clarify. How much would waste management charge to empty the same dumpster if it didn't have to go to into a special section of the landfill. In other words if the poles were not contaminated with creosote and could be disposed of with other waste items what would be the cost to empty a dumpster full of non contaminated products. I'm looking for the difference in cost of emptying a contaminated dumpster versus a noncontaminated dumpster.

Thanks,
Debbie

From: Mills, Les
Sent: Friday, October 14, 2005 3:20 PM
To: Riggs, Eric; Kinder, Debra
Cc: Cooke, Scott
Subject: Pole Removal Cost

Eric & Debra , here is the best case scenario that I could come up with. The 30yd dumpster that Waste Management supplies us measures 7'W x 5'H x 22'L which comes up to 770 sq.ft. Now to come up with standard pole size is hard. I made it a 40' long pole that would run 1' wide all the way , so that would give you 40 sq.ft. So take the 40' into the 770' and that will give you 19.25 poles per dumpster. Now a basic cross arm is 4" x 4" x 8' and that will be .887 sq.ft. Take the .887 into 770 and that will give you 868.09 cross arms will go into the dumpster. This is not a perfect process and I am sure a math major could better this , but this is the best formula I could come up with. There are so many different poles sizes and even cross arms. I hope this helps , if there is any thing else I may be able to do just let me know.

Les Mills
AOC Distribution Operations
6900 Enterprise Dr.
Louisville, Ky.40214
Off. (502) 364-8436

Wiseman, Sara

From: Kinder, Debra
Sent: Friday, October 14, 2005 9:43 AM
To: Cosby, David
Cc: Wiseman, Sara; Riggs, Eric
Subject: FIN 47

David,

Regarding our FIN 47 calculations, could you provide us with disposal estimates for batteries and oil at Trimble?

Thanks,
Debbie

Wiseman, Sara

From: Cook, Dave
Sent: Monday, October 17, 2005 9:40 AM
To: Kinder, Debra
Cc: Wiseman, Sara; Miller, Jon
Subject: FW: FIN 47

Attachments: Fin 47

Debra - see below.

From: Pence, Mark
Sent: Monday, October 17, 2005 9:35 AM
To: Cook, Dave
Subject: RE: FIN 47

Dave,

Yes, we provided it to Jon Miller on 9/16. The e-mail is attached for your reference.

Mark

Fin 47

From: Cook, Dave
Sent: Monday, October 17, 2005 9:08 AM
To: Pence, Mark
Subject: FW: FIN 47

Mark - didn't we provide this already? If we haven't, please contact the appropriate people for the estimates.

thanks

From: Kinder, Debra
Sent: Friday, October 14, 2005 9:48 AM
To: Cook, Dave
Cc: Wiseman, Sara; Riggs, Eric
Subject: FIN 47

David,

Regarding our FIN 47 calculations, in addition to the asbestos disposal estimates, we also need to consider the cost to dispose of batteries and oil. Could you provide us with estimates for the two additional items for Mill Creek?

Thanks,
Debbie

Tracking:

Recipient
Kinder, Debra
Wiseman, Sara
Miller, Jon

Wiseman, Sara

From:	Pence, Mark
Sent:	Friday, September 16, 2005 10:16 AM
To:	Miller, Jon
Cc:	Cook, Dave; Kirkland, Mike
Subject:	Fin 47
Attachments:	Fin 47 Template - MC.xls; ARO SFAS 143.xls

Jon,

Attached is the Fin 47 template for MC. Also attached, as a reference, is the SFAS 143 spreadsheet from a couple of years ago. Per our discussion, I have listed items pertaining to batteries and oil on the Fin 47 that were not included previously on the SFAS 143 record. The underground fuel oil piping that is listed was drained back with air blown into it, however, it was not flushed in any other way. If you feel that we don't need to list this then feel free to remove it. The asbestos reporting will be discussed in our meeting next week. Let me know if you need anything else.

Fin 47 Template - MC.xls (23 K...   ARO SFAS 143.xls (135 KB)

Mark A. Pence
Budget Analyst - Mill Creek Station
Phone: 933-6805 Pager: 346-4754

Tracking:

Recipient	Read
Miller, Jon	Read: 9/16/2005 10:12 AM
Cook, Dave	Read: 9/16/2005 12:21 PM
Kirkland, Mike	Read: 9/16/2005 10:53 AM

Location						
Asset Retirement Obligations			($000's)			
Asset Description	Location	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date	
Asbestos						
Cane Run						
CR1 Asbestos Abatement	Cane Run Unit 1 Plant		2,700	60		Ductwork, Equip. External, Operating Floor up $300k; Ductwork External, Under Operating Floor $200k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $400k; Penthouse $150k; Furnace External $750k; Air Testing, permits, survey $100k; Boiler misc. $400k; Coal Handling $150k
CR2 Asbestos Abatement	Cane Run Unit 2 Plant		2,550	50		Ductwork, Equip. External, Operating Floor up $300k; Ductwork External, Under Operating Floor $200k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $400k; Penthouse $150k; Furnace External $750k; Air Testing, permits, survey $100k; Boiler misc. $400k
CR3 Asbestos Abatement	Cane Run Unit 3 Plant		2,880	50		Ductwork, Equip. External, Operating Floor up $345k; Ductwork External, Under Operating Floor $230k; Piping External, Opererating Floor up $300k; Pipe and Equip. Under Operating Floor $400k; Penthouse $175k; Furnace External $870k; Air Testing, permits, survey $100k; Boiler misc. $460k
CR4 Asbestos Abatement	Cane Run Unit 4 Plant		3,065	50		Ductwork, Equip. External, Operating Floor up $500k; Ductwork External, Under Operating Floor $350k; Piping External, Opererating Floor up $200k; Pipe and Equip. Under Opererating Floor $300k; Penthouse $150k; Furnace External $1065k; Air Testing, permits, survey $100k; Boiler misc. $400k
CR5 Asbestos Abatement	Cane Run Unit 5 Plant		2,500	40		Ductwork, Equip. External, Operating Floor up $450k; Ductwork External, Under Operating Floor $300k; Piping External, Opererating Floor up $200k; Pipe and Equip. Under Opererating Floor $200k; Penthouse $150k; Furnace External $700k; Air Testing, permits, survey $100k; Boiler misc. $400k
CR6 Asbestos Abatement	Cane Run Unit 6 Plant		2,920	50		Ductwork, Equip. External, Operating Floor up $700k; Ductwork External, Under Operating Floor $400k; Piping External, Opererating Floor up $350k; Pipe and Equip. Under Opererating Floor $300k; Penthouse $200k; Furnace External $470k; Air Testing, permits, survey $100k; Boiler misc. $400k
Paddy's Run						
Plant Asbestos Abatement	Total Plant		11,000	100		Lump Sum price for total removal, cleanup and disposal of asbestos materials from all units including the Service Building and exterior SDRS ductwork. A price quote was received from four vendors in December 1990. The average of the four bides was approximately $7.0 million. This average cost was inflated at 3.0 % per year arriving at $11.0 million.
Canal						
Plant Asbestos Abatement	Total Plant		6,000	75		Estimate prepared using Paddy's Run as basis and adjusted for size of the facility
Waterside						
Plant Asbestos Abatement	Total Plant		4,000	50		Estimate prepared using Paddy's Run as basis and adjusted for size of the facility
Ohio Falls						
Plant Asbestos Abatement	Total Plant		600	20		Estimate based upon actual removal cost of unit 7 performed in 2005 ($60k) plus additional $25k for asbestos contained outside of the unit.
Zorn						
Plant Asbestos Abatement	Total CT Plant		100	5		CT Exhaust Stack, misc. piping and housing insulation, wiring, gaskets, etc.
Battery						
Cane Run						
Emergency Battery No. 1 (1&2)	Unit 1 basement	60	3.5	1		
Emergency Battery No. 2 (3&4)	Unit 3 1st landing	60	3.5	1		
Emergency Battery No. 3 (6)	Unit 6 basement	60	3.5	1		
Station Battery No. 1	No. 1 Breaker House	60	3.5	1		
Station Battery No. 2	Unit 1 basement	60	3.5	1		
Station Battery No. 3	Unit 3 1st landing	60	3.5	1		

Location						
Asset Retirement Obligations			($000's)			
Asset Description	Location	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date	
Station Battery No. 4	Unit 6 basement	60	3.5	1		
Unit 4 UPS Battery	Unit 4 turbine floor	30	2	0.5		
Unit 5 UPS Battery	Unit 6 turbine floor	30	2	0.5		
Unit 6 UPS Battery	Unit 6 turbine floor	30	2	0.5		
Communications Battery	Old Control House (rear)	24	2	0.5		
4&5 SPP Batteries	4&5 SPP Elect. Room	10	1	0.5		
Jefferson County Gas Turbines						
Paddy's 13 DC	SFC/SES Room	60	3.5	1		
Paddy's 12 DC	PR-12 Building	60	3.5	1		
Paddy's 11 DC	PR-11 Under Control Rm	14	1	0.5		
Control house DC	Control House	60	3.5	1		
Cane Run GT-11	GT-11 Building	60	3.5	1		
Zorn	CT Under Control Rm.	14	1	0.5		
Ohio Falls						
Bank 1 Station Batteries	Unit 1 417 floor	60	3.5	1		
Bank 2 Station Batteries	Unit 1 417 floor	60	3.5	1		
Oil						
Cane Run Station	Plant/GT-11		10	1		Turbine Reservoir/Mill/Fluid Drive/Screenhouse Oil Accumulator, Misc.
Paddy's Run Station	Plant/CT's		15	1		Turbine Reservoir/Mill/Fluid Drive/Screenhouse Oil Accumulator, Misc.
Canal Station	Plant		5	1		Turbine Reservoir/Mill/, Misc.
Waterside	Plant/CT		5	1		Gas Turbine/Misc. Plant Equipment
Ohio Falls	Plant		5	1		Governor Controls, bearing oil & Misc. Equipment
Zorn	CT		3	0.5		Gas Turbine Reservoir

Wiseman, Sara

From: Miller, Jon
Sent: Tuesday, October 18, 2005 10:38 AM
To: Charnas, Shannon; Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FW: Fin 47 Template.xls - Zorn Data

Attachments: Fin 47 Template OF.xls

Fyi - additional data from Dan Kremer for Zorn.

From: Kremer, Dan
Sent: Tuesday, October 18, 2005 9:43 AM
To: Miller, Jon
Cc: Legler, Steve; Turner, Steven
Subject: FW: Fin 47 Template.xls - Zorn Data

Jon, here is the completed template for Fin 47. This now includes the batteries and oil for Zorn and Ohio Falls. This should be everything but if you need something else please let me know.

Dan Kremer
Manager Commercial Operations
Cane Run Station
(502) 449-8808
dan.kremer@lgeenergy.com

Fin 47 Template OF.xls

Location						
Asset Retirement Obligations			($000's)			
Asset Description	Location	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date	
Asbestos						
Cane Run						
CR1 Asbestos Abatement	Cane Run Unit 1 Plant		2,700	60		Ductwork, Equip. External, Operating Floor up $300k; Ductwork External, Under Operating Floor $200k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $400k; Penthouse $150k; Furnace External $750k; Air Testing, permits, survey $100k; Boiler misc. $400k; Coal Handling $150k
CR2 Asbestos Abatement	Cane Run Unit 2 Plant		2,550	50		Ductwork, Equip. External, Operating Floor up $300k; Ductwork External, Under Operating Floor $200k; Piping External, Opererating Floor up $250k; Pipe and Equip. Under Opererating Floor $400k; Penthouse $150k; Furnace External $750k; Air Testing, permits, survey $100k; Boiler misc. $400k
CR3 Asbestos Abatement	Cane Run Unit 3 Plant		2,880	50		Ductwork, Equip. External, Operating Floor up $345k; Ductwork External, Under Operating Floor $230k; Piping External, Opererating Floor up $300k; Pipe and Equip. Under Operating Floor $400k; Penthouse $175k; Furnace External $870k; Air Testing, permits, survey $100k; Boiler misc. $460k
CR4 Asbestos Abatement	Cane Run Unit 4 Plant		3,065	50		Ductwork, Equip. External, Operating Floor up $500k; Ductwork External, Under Operating Floor $350k; Piping External, Opererating Floor up $200k; Pipe and Equip. Under Opererating Floor $300k; Penthouse $150k; Furnace External $1065k; Air Testing, permits, survey $100k; Boiler misc. $400k
CR5 Asbestos Abatement	Cane Run Unit 5 Plant		2,500	40		Ductwork, Equip. External, Operating Floor up $450k; Ductwork External, Under Operating Floor $300k; Piping External, Opererating Floor up $200k; Pipe and Equip. Under Opererating Floor $200k; Penthouse $150k; Furnace External $700k; Air Testing, permits, survey $100k; Boiler misc. $400k
CR6 Asbestos Abatement	Cane Run Unit 6 Plant		2,920	50		Ductwork, Equip. External, Operating Floor up $700k; Ductwork External, Under Operating Floor $400k; Piping External, Opererating Floor up $350k; Pipe and Equip. Under Opererating Floor $300k; Penthouse $200k; Furnace External $470k; Air Testing, permits, survey $100k; Boiler misc. $400k
Paddy's Run						
Plant Asbestos Abatement	Total Plant		11,000	100		Lump Sum price for total removal, cleanup and disposal of asbestos materials from all units including the Service Building and exterior SDRS ductwork. A price quote was received from four vendors in December 1990. The average of the four bides was approximately $7.0 million. This average cost was inflated at 3.0 % per year arriving at $11.0 million.
Canal						
Plant Asbestos Abatement	Total Plant		6,000	75		Estimate prepared using Paddy's Run as basis and adjusted for size of the facility
Waterside						
Plant Asbestos Abatement	Total Plant		4,000	50		Estimate prepared using Paddy's Run as basis and adjusted for size of the facility
Ohio Falls						
Plant Asbestos Abatement	Total Plant		600	20		Estimate based upon actual removal cost of unit 7 performed in 2005 ($60k) plus additional $25k for asbestos contained outside of the unit.
Zorn						
Plant Asbestos Abatement	Total CT Plant		100	5		CT Exhaust Stack, misc. piping and housing insulation, wiring, gaskets, etc.
Battery						
Cane Run						
Emergency Battery No. 1 (1&2)	Unit 1 basement	60	3.5	1		
Emergency Battery No. 2 (3&4)	Unit 3 1st landing	60	3.5	1		
Emergency Battery No. 3 (6)	Unit 6 basement	60	3.5	1		
Station Battery No. 1	No. 1 Breaker House	60	3.5	1		
Station Battery No. 2	Unit 1 basement	60	3.5	1		
Station Battery No. 3	Unit 3 1st landing	60	3.5	1		

Location						
Asset Retirement Obligations		($000's)				
Asset Description	Location	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date	
Station Battery No. 4	Unit 6 basement	60	3.5	1		
Unit 4 UPS Battery	Unit 4 turbine floor	30	2	0.5		
Unit 5 UPS Battery	Unit 6 turbine floor	30	2	0.5		
Unit 6 UPS Battery	Unit 6 turbine floor	30	2	0.5		
Communications Battery	Old Control House (rear)	24	2	0.5		
4&5 SPP Batteries	4&5 SPP Elect. Room	10	1	0.5		
Jefferson County Gas Turbines						
Paddy's 13 DC	SFC/SES Room	60	3.5	1		
Paddy's 12 DC	PR-12 Building	60	3.5	1		
Paddy's 11 DC	PR-11 Under Control Rm	14	1	0.5		
Control house DC	Control House	60	3.5	1		
Cane Run GT-11	GT-11 Building	60	3.5	1		
Zorn	CT Under Control Rm.	14	1	0.5		
Ohio Falls						
Bank 1 Station Batteries	Unit 1 417 floor	60	3.5	1		
Bank 2 Station Batteries	Unit 1 417 floor	60	3.5	1		
Oil						
Cane Run Station	Plant/GT-11		10	1		Turbine Reservoir/Mill/Fluid Drive/Screenhouse Oil Accumulator, Misc.
Paddy's Run Station	Plant/CT's		15	1		Turbine Reservoir/Mill/Fluid Drive/Screenhouse Oil Accumulator, Misc.
Canal Station	Plant		5	1		Turbine Reservoir/Mill/, Misc.
Waterside	Plant/CT		5	1		Gas Turbine/Misc. Plant Equipment
Ohio Falls	Plant		5	1		Governor Controls, bearing oil & Misc. Equipment
Zorn	CT		3	0.5		Gas Turbine Reservoir

Wiseman, Sara

From:	Riggs, Eric
Sent:	Tuesday, October 25, 2005 7:37 AM
To:	Clyde, Peter
Cc:	Kinder, Debra; Wiseman, Sara
Subject:	FW: Retirement Costs
Importance:	High
Attachments:	Gas Pipe Retirement Liability.xls

Pete,

Please let me know that the figures for removal cost used in your calculations are strictly removal/abandonment costs and do not contain any replacement/construction costs. Also, please keep in mind that in going beyond environmental aspects of this accounting pronouncement, is there a legal responsibility on the company to remove/cap the mains/services when abandoned.

Thanks,
Eric Riggs
2822

From:	Clyde, Peter
Sent:	Wednesday, October 19, 2005 11:35 AM
To:	Wiseman, Sara; Riggs, Eric; Kinder, Debra
Cc:	Martin, Cindy; Rieth, Tom
Subject:	Retirement Costs

When LG&E's gas mains and services that are currently active are eventually retired, we can expect costs to run about $68,590,441. That is in 2005 dollars. No inflation factor was taken into consideration. The attached file contains the backup data and calculation used to come up with this figure.

During our phone conference, I thought we were only looking for incremental retirement costs due to environmental issues. That is why my initial reaction was that the costs would not be significant. Once I realized that you were needing all retirement costs regardless of whether they were driven by environmental reasons or not, I pursued gathering the data in the attached file. If you have any questions about this estimate, please let me know.

Pete

Gas Pipe
:etirement Liability...

Gas Main & Service Retirement Costs

Retirement Expenses	$583,639
Main Retirement Footage	204,329
Cost Per Foot	$2.86
Active Main Footage	24,013,149
Future Retirement Costs	$68,590,441

2004 Gas Main Retirement Footage

MAIN NUM	SYSTEM	MAIN SIZE	MAIN MAT'L	MAIN PRES	CUTOUT LENGTH	CUTOUT DATE
12107	D	4	WI	L	1104	3/10/2004
98185	D	8	BS	H	3110	3/12/2004
310051	D	2	CT	H	10	3/12/2004
115194	D	8	CT	H	8	3/12/2004
129032	D	2	CT	H	40	3/12/2004
144185	D	8	CT	H	15	3/12/2004
112944	D	6	CT	E	192	4/1/2004
116793	D	4	CT	E	430	4/1/2004
112945	D	6	CT	E	438	4/1/2004
111107	D	6	CT	E	454	4/1/2004
111118	D	6	CT	E	478	4/1/2004
125984	D	6	CT	E	63	4/1/2004
125983	D	4	CT	E	392	4/1/2004
117653	D	4	CT	E	90	4/1/2004
136057	D	4	CT	E	48	4/1/2004
243702	D	4	CT	E	129	4/1/2004
182457	D	4	CT	L	74	4/6/2004
51398	D	8	BS	L	70	4/6/2004
51773	D	8	BS	L	262	4/6/2004
59154	D	6	BS	L	146	4/6/2004
51397	D	8	BS	L	1009	4/6/2004
57350	D	12	BS	L	2586	4/6/2004
208880	D	4	CT	L	55	4/6/2004
81206	D	8	BS	L	78	4/6/2004
84881	D	4	BS	L	63	4/6/2004
57353	D	8	BS	L	73	4/6/2004
87821	D	12	BS	L	90	4/6/2004
74742	D	6	BS	L	70	4/6/2004
87761	D	12	BS	L	258	4/6/2004
85255	D	12	BS	L	28	4/6/2004
87760	D	12	BS	L	144	4/6/2004
359233	D	6	PL	L	37	4/6/2004
369413	D	2	PL	M	513	8/24/2004
107991	D	8	CT	H	330	9/1/2004
107972	D	8	CT	H	171	9/1/2004
108753	D	4	BS	H	75	9/1/2004
107950	D	8	CT	H	280	9/1/2004
298263	D	4	CT	H	516	7/9/2004
318291	D	4	CT	H	8	7/9/2004
41599	D	2	BS	L	47	6/14/2004
212144	D	8	CT	L	130	9/13/2004
388123	D	8	PL	L	72	9/13/2004
120665	D	4	CT	L	192	9/13/2004
291968	D	8	CT	L	73	9/13/2004
212110	D	8	CT	L	85	9/13/2004
44444	D	4	BS	L	50	9/13/2004
203143	D	2	CT	M	258	4/23/2004
251795	D	4	CT	M	230	5/25/2004
251794	D	4	CT	M	480	5/25/2004

39694	D	4	BS	L	273	6/28/2004
315585	T	12	BS	H	1685	1/8/2004
315682	T	4	BS	H	1075	10/4/2004
315683	T	4	BS	H	120	5/28/2004
315684	T	4	BS	H	178	5/28/2004
315685	T	4	BS	H	346	5/28/2004
315672	T	12	BS	H	588	4/21/2004
315671	T	12	BS	H	2595	4/21/2004
315584	T	16	BS	H	1750	4/21/2004
3874	D	4	WI	L	66	10/26/2004
405690	D	4	PL	M	42	6/29/2004
405689	D	4	PL	M	187	6/29/2004
316838	D	4	CT	H	16	11/10/2004
316839	D	8	CT	M	61	11/10/2004
388120	D	4	PL	L	70	2/16/2004
275277	D	4	CI	L	241	2/16/2004
256176	D	10	CI	L	235	2/16/2004
61008	D	6	BS	E	923	12/11/2004
52205	D	12	CT	H	15	1/19/2004
405242	D	2	PL	M	287	10/15/2004
338860	D	6	PL	M	270	9/16/2004
368437	D	6	PL	M	161	9/16/2004
368436	D	6	PL	M	1143	9/16/2004
327688	D	4	CT	M	7	9/16/2004
327689	D	8	CT	M	1350	9/16/2004
233292	D	8	CT	M	66	9/16/2004
327687	D	8	CT	M	123	9/16/2004
327686	D	8	CT	M	146	9/16/2004
116634	D	4	BS	E	621	1/16/2004
117612	D	4	CT	E	106	1/16/2004
116636	D	4	BS	E	803	1/16/2004
340766	D	4	PL	E	51	1/16/2004
305995	D	4	CT	H	70	9/27/2004
230390	D	4	CT	M	41	9/28/2004
230392	D	2	CT	H	244	9/28/2004
305996	D	2	CT	H	4	9/28/2004
342950	D	4	PL	M	136	11/12/2004
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57348	D	12	BS	L	326	8/26/2004
232490	D	12	CT	L	839	8/26/2004
168910	D	6	CT	L	242	8/26/2004
232287	D	4	CT	L	321	8/26/2004
232492	D	16	CT	L	323	8/26/2004
232491	D	12	CT	L	36	8/26/2004
232489	D	12	CT	L	178	8/26/2004
277490	D	6	CT	L	51	8/26/2004
57077	D	12	BS	L	623	8/26/2004
94402	D	4	BS	L	309	8/26/2004
57417	D	12	BS	L	44	8/26/2004
229209	D	8	CT	L	544	8/26/2004
328509	D	4	CT	L	29	8/26/2004
232289	D	4	CT	L	50	8/26/2004

229208	D	8	CT	L	413	8/26/2004
328516	D	4	CT	L	90	8/26/2004
224940	D	4	CT	L	58	8/26/2004
223788	D	4	CT	L	70	8/26/2004
153459	D	4	CT	L	128	8/26/2004
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89770	D	4	BS	L	21	8/26/2004
94652	D	4	BS	L	82	8/26/2004
101005	D	4	BS	L	160	8/26/2004
114698	D	4	BS	L	85	8/26/2004
121709	D	2	BS	L	46	8/26/2004
136029	D	4	CT	L	165	8/26/2004
136349	D	4	CT	L	62	8/26/2004
140115	D	4	CT	L	279	8/26/2004
209899	D	4	CT	L	305	8/26/2004
209897	D	4	CT	L	675	8/26/2004
209898	D	4	CT	L	681	8/26/2004
144024	D	4	CT	L	801	8/26/2004
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119255	D	4	BS	L	38	8/26/2004
209896	D	4	CT	L	367	8/26/2004
241973	D	4	CT	L	979	8/26/2004
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241971	D	4	CT	L	333	8/26/2004
241972	D	4	CT	L	698	8/26/2004
241975	D	8	CT	L	253	8/26/2004
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126205	D	8	CT	L	666	8/26/2004
255685	D	8	CT	L	998	8/26/2004
134091	D	4	CT	L	36	8/26/2004
132650	D	4	CT	L	680	8/26/2004
118974	D	4	CT	L	21	8/26/2004
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115081	D	8	BS	L	353	8/26/2004
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405569	D	8	PL	L	354	8/26/2004
405571	D	8	PL	L	410	8/26/2004
112043	D	8	BS	L	361	8/26/2004
183592	D	4	CT	L	263	8/26/2004
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310114	D	4	CT	L	210	8/26/2004
112309	D	8	BS	L	953	8/26/2004
124367	D	8	CT	L	309	8/26/2004
214996	D	4	CT	L	708	8/26/2004
165952	D	8	CT	L	550	8/26/2004
233551	D	8	CT	L	599	8/26/2004

233551	D	8	CT	L	171	8/26/2004
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233552	D	8	CT	L	33	8/26/2004
233553	D	8	CT	L	180	8/26/2004
136680	D	8	CT	L	101	8/26/2004
233563	D	4	CT	L	434	8/26/2004
328076	D	6	CT	L	964	8/26/2004
233557	D	6	CT	L	336	8/26/2004
233549	D	4	CT	L	6	8/26/2004
125183	D	8	CT	L	174	8/26/2004
125187	D	4	CT	L	157	8/26/2004
125185	D	4	CT	L	1223	8/26/2004
112378	D	6	BS	L	913	8/26/2004
125186	D	4	CT	L	216	8/26/2004
112382	D	4	BS	L	937	8/26/2004
233562	D	4	CT	L	25	8/26/2004
233564	D	4	CT	L	45	8/26/2004
233565	D	4	CT	L	79	8/26/2004
233554	D	8	CT	L	166	8/26/2004
112381	D	8	BS	L	823	8/26/2004
328077	D	8	CT	L	181	8/26/2004
328077	D	8	CT	L	10	8/26/2004
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113080	D	4	BS	L	602	8/26/2004
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233560	D	8	CT	L	126	8/26/2004
233559	D	8	CT	L	338	8/26/2004
113079	D	8	BS	L	215	8/26/2004
169295	D	8	CT	L	445	8/26/2004
233558	D	6	CT	L	32	8/26/2004
182345	D	4	CT	L	676	8/26/2004
202821	D	6	CT	L	90	8/26/2004
334057	D	8	CT	L	1341	8/26/2004
334056	D	6	CT	L	8	8/26/2004
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405570	D	8	TM	L	110	8/26/2004
120189	D	12	CT	L	98	8/26/2004
123683	D	6	CT	L	11	8/26/2004
115095	D	8	BS	L	1016	8/26/2004
119103	D	4	BS	L	72	8/26/2004
212629	D	8	CT	L	168	8/26/2004
117090	D	4	BS	L	117	8/26/2004
124646	D	4	CT	L	239	8/26/2004
178195	D	4	CT	L	183	8/26/2004
334055	D	4	CT	L	30	8/26/2004
182684	D	4	CT	L	377	8/26/2004
200531	D	4	CT	L	956	8/26/2004
200554	D	4	CT	L	325	8/26/2004
200553	D	4	CT	L	732	8/26/2004
89998	D	8	BS	L	1712	8/26/2004
91514	D	8	BS	L	924	8/26/2004
97706	D	8	BS	L	440	8/26/2004

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334058	D	8	CT	L	8	8/26/2004
283471	D	8	CT	L	398	8/26/2004
282200	D	8	CT	L	322	8/26/2004
332897	D	8	CT	L	482	8/26/2004
332897	D	8	CT	L	20	8/26/2004
112311	D	4	BS	L	170	8/26/2004
118209	D	4	BS	L	322	8/26/2004
118889	D	4	CT	L	570	8/26/2004
118887	D	4	CT	L	131	8/26/2004
118888	D	4	CT	L	129	8/26/2004
118208	D	4	BS	L	557	8/26/2004
283472	D	4	CT	L	79	8/26/2004
112312	D	4	BS	L	183	8/26/2004
118210	D	4	BS	L	323	8/26/2004
120868	D	4	CT	L	202	8/26/2004
147734	D	4	CT	L	621	8/26/2004
151716	D	4	CT	L	647	8/26/2004
151715	D	4	CT	L	266	8/26/2004
151718	D	4	CT	L	60	8/26/2004
151717	D	4	CT	L	61	8/26/2004
112089	D	6	BS	L	1269	8/26/2004
112087	D	4	BS	L	1120	8/26/2004
112086	D	4	BS	L	300	8/26/2004
112088	D	6	BS	L	176	8/26/2004
111062	D	8	BS	L	297	8/26/2004
74581	D	6	BS	L	67	8/26/2004
66467	D	6	BS	L	105	8/26/2004
100407	D	16	CI	L	492	8/26/2004
52265	D	6	BS	L	331	8/26/2004
86668	D	4	BS	L	564	8/26/2004
82692	D	4	BS	L	118	8/26/2004
83333	D	10	BS	L	956	8/26/2004
72373	D	10	BS	L	37	8/26/2004
74247	D	6	BS	L	71	8/26/2004
74248	D	6	BS	L	372	8/26/2004
67514	D	6	BS	L	39	8/26/2004
70362	D	6	BS	L	101	8/26/2004
69119	D	6	BS	L	95	8/26/2004
67453	D	4	BS	L	923	8/26/2004
67452	D	4	BS	L	22	8/26/2004
67515	D	4	BS	L	38	8/26/2004
270845	D	6	CT	L	1383	8/26/2004
48389	D	4	BS	L	218	8/26/2004
138697	D	6	BS	L	88	8/26/2004
63205	D	6	BS	L	290	8/26/2004
138764	D	6	BS	L	16	8/26/2004
328300	D	8	CT	L	545	8/26/2004
328299	D	4	CT	L	697	8/26/2004
328298	D	4	CT	L	14	8/26/2004
133846	D	4	CT	L	118	8/26/2004
48350	D	8	BS	L	102	8/26/2004

48388	D	8	BS	L		1241	8/26/2004
43212	D	6	BS	L		154	8/26/2004
51968	D	1.5	BS	L		66	8/26/2004
25473	D	1.25	BS	L		17	8/26/2004
314200	D	4	CI	L		920	8/26/2004
13050	D	4	WI	L		921	8/26/2004
137221	D	4	CT	L		261	8/26/2004
80081	D	4	BS	L		154	8/26/2004
88151	D	4	BS	L		291	8/26/2004
79926	D	1.5	BS	L		33	8/26/2004
79928	D	2	BS	L		66	8/26/2004
100205	D	4	CI	L		1340	8/26/2004
211715	D	4	BS	L		159	8/26/2004
211716	D	4	CT	L		400	8/26/2004
286193	D	4	CI	L		1032	8/26/2004
61283	D	6	BS	L		542	8/26/2004
31574	D	2	BS	L		38	8/26/2004
327809	D	6	CT	L		312	8/26/2004
327808	D	6	CT	L		841	8/26/2004
347909	D	4	PL	L		11	8/26/2004
81049	D	4	BS	L		42	8/26/2004
83743	D	4	BS	L		373	8/26/2004
85579	D	4	BS	L		194	8/26/2004
70129	D	4	BS	L		38	8/26/2004
219422	D	8	CT	L		311	8/26/2004
70127	D	4	BS	L		29	8/26/2004
70128	D	4	BS	L		57	8/26/2004
48190	D	10	BS	L		312	8/26/2004
100198	D	4	CI	L		1670	8/26/2004
100193	D	4	CI	L		1610	8/26/2004
100194	D	4	CI	L		1560	8/26/2004
124863	D	4	CT	L		54	8/26/2004
100314	D	4	CI	L		1140	8/26/2004
329029	D	4	CT	L		289	8/26/2004
100319	D	6	CI	L		765	8/26/2004
319423	D	6	CI	L		521	8/26/2004
100335	D	16	CI	L		2525	8/26/2004
100337	D	4	CI	L		1650	8/26/2004
25495	D	8	WI	L		39	8/26/2004
100339	D	4	CI	L		240	8/26/2004
147025	D	4	CT	L		592	8/26/2004
26997	D	4	BS	L		657	8/26/2004
44058	D	4	BS	L		318	8/26/2004
159585	D	4	CT	L		197	8/26/2004
61060	D	2	BS	L		35	8/26/2004
27923	D	4	BS	L		274	8/26/2004
44160	D	4	BS	L		116	8/26/2004
49111	D	4	BS	L		121	8/26/2004
49112	D	4	BS	L		37	8/26/2004
49113	D	4	BS	L		33	8/26/2004
31728	D	4	BS	L		133	8/26/2004
30608	D	4	BS	L		141	8/26/2004

323229	D	4	CT	L	54	8/26/2004
103775	D	4	BS	L	125	8/26/2004
130073	D	4	CT	L	336	8/26/2004
100313	D	4	CI	L	775	8/26/2004
31642	D	4	BS	L	520	8/26/2004
127915	D	4	CT	L	422	8/26/2004
127938	D	4	CT	L	18	8/26/2004
268646	D	10	CI	L	1680	8/26/2004
27839	D	4	BS	L	240	8/26/2004
265864	D	10	CI	L	1186	8/26/2004
252606	D	10	CT	L	2	8/26/2004
100192	D	4	CI	L	69	8/26/2004
100121	D	4	CI	L	77	8/26/2004
12958	D	4	WI	L	60	8/26/2004
263100	D	10	CI	L	1890	8/26/2004
172184	D	6	CT	L	113	8/26/2004
228391	D	6	CT	L	110	8/26/2004
147851	D	4	CT	L	7	8/26/2004
13224	D	4	WI	L	10	8/26/2004
268063	D	4	CI	L	1400	8/26/2004
118296	D	4	CI	L	102	8/26/2004
62700	D	4	BS	L	55	8/26/2004
270865	D	4	BS	L	36	8/26/2004
270865	D	4	CI	L	890	8/26/2004
15118	D	2	WI	L	55	8/26/2004
100126	D	4	CI	L	45	8/26/2004
100127	D	1.5	CI	L	40	8/26/2004
127520	D	2	CT	L	2	8/26/2004
15228	D	2	WI	L	83	8/26/2004
118205	D	4	CI	L	398	8/26/2004
22086	D	2	WI	L	530	8/26/2004
118204	D	4	BS	L	2	8/26/2004
111117	D	4	BS	L	97	8/26/2004
49104	D	4	BS	L	13	8/26/2004
22095	D	4	WI	L	84	8/26/2004
118263	D	4	CI	L	700	8/26/2004
24410	D	4	WI	L	536	8/26/2004
62658	D	6	BS	L	1444	8/26/2004
55755	D	6	BS	L	75	8/26/2004
388821	D	4	PL	L	140	8/26/2004
295331	D	4	CT	L	489	8/26/2004
62753	D	4	BS	L	69	8/26/2004
39095	D	4	BS	L	687	8/26/2004
22088	D	2	BS	L	5	8/26/2004
243819	D	4	CT	L	344	8/26/2004
118948	D	4	CT	L	53	8/26/2004
120935	D	4	CT	L	445	8/26/2004
126615	D	4	CT	L	130	8/26/2004
142014	D	4	CT	L	162	8/26/2004
75418	D	6	BS	L	236	8/26/2004
39139	D	4	BS	L	143	8/26/2004
255683	D	6	CT	L	62	8/26/2004

243818	D	4	CT	L	427	8/26/2004
243817	D	4	CT	L	432	8/26/2004
112683	D	6	BS	L	788	8/26/2004
141321	D	4	CT	L	863	8/26/2004
297117	D	6	CT	L	771	8/26/2004
297118	D	6	CT	L	60	8/26/2004
298736	D	4	CT	L	452	8/26/2004
209412	D	6	CT	L	223	8/26/2004
243271	D	4	CT	L	506	8/26/2004
244178	D	4	CT	L	315	8/26/2004
26282	D	2	WI	L	14	8/26/2004
209880	D	4	CT	L	367	8/26/2004
48605	D	4	BS	L	156	8/26/2004
99761	D	6	BS	L	121	8/26/2004
62754	D	4	BS	L	86	8/26/2004
62755	D	6	BS	L	34	8/26/2004
63117	D	4	BS	L	194	8/26/2004
308507	D	4	CT	L	23	8/26/2004
97134	D	6	BS	L	256	8/26/2004
308505	D	4	CT	L	772	8/26/2004
26848	D	4	WI	L	419	8/26/2004
23704	D	4	WI	L	210	8/26/2004
308506	D	4	CT	L	7	8/26/2004
308508	D	4	CT	L	37	8/26/2004
322890	D	6	CT	L	928	8/26/2004
72328	D	12	BS	L	70	8/26/2004
95251	D	12	BS	L	101	8/26/2004
107034	D	12	BS	L	848	8/26/2004
315103	D	4	CT	L	62	8/26/2004
99317	D	6	BS	L	745	8/26/2004
111063	D	6	BS	L	35	8/26/2004
115327	D	4	BS	L	85	8/26/2004
99319	D	4	BS	L	57	8/26/2004
93235	D	4	BS	L	756	8/26/2004
91821	D	4	BS	L	725	8/26/2004
99318	D	4	BS	L	805	8/26/2004
91802	D	4	BS	L	729	8/26/2004
91803	D	4	BS	L	213	8/26/2004
93234	D	4	BS	L	330	8/26/2004
99686	D	4	BS	L	880	8/26/2004
70205	D	6	BS	L	44	8/26/2004
81408	D	6	BS	L	421	8/26/2004
102752	D	12	BS	L	200	8/26/2004
103697	D	4	BS	L	428	8/26/2004
72371	D	10	BS	L	22	8/26/2004
76768	D	10	BS	L	19	8/26/2004
91262	D	10	BS	L	107	8/26/2004
89912	D	10	BS	L	104	8/26/2004
48274	D	10	BS	L	241	8/26/2004
48701	D	10	BS	L	322	8/26/2004
48704	D	8	BS	L	458	8/26/2004
48702	D	10	BS	L	335	8/26/2004

48703	D	10	BS	L	333	8/26/2004
100215	D	4	CI	L	1950	8/26/2004
317506	D	4	CT	L	552	8/26/2004
182849	D	4	CT	L	216	8/26/2004
85487	D	4	BS	L	237	8/26/2004
79932	D	2	BS	L	165	8/26/2004
79931	D	4	BS	L	48	8/26/2004
83539	D	4	BS	L	52	8/26/2004
82979	D	4	BS	L	65	8/26/2004
80415	D	4	BS	L	153	8/26/2004
79929	D	2	BS	L	33	8/26/2004
85336	D	4	BS	L	149	8/26/2004
86880	D	4	BS	L	75	8/26/2004
79927	D	4	BS	L	48	8/26/2004
319530	D	4	CT	L	405	8/26/2004
319529	D	4	CT	L	273	8/26/2004
319532	D	6	CT	L	453	8/26/2004
81552	D	4	BS	L	154	8/26/2004
319533	D	8	CT	L	58	8/26/2004
108391	D	4	BS	L	200	8/26/2004
98137	D	4	BS	L	340	8/26/2004
36074	D	4	BS	L	44	8/26/2004
27149	D	4	BS	L	600	8/26/2004
100327	D	6	CI	L	1950	8/26/2004
100328	D	4	CI	L	560	8/26/2004
81594	D	6	BS	L	44	8/26/2004
80667	D	6	BS	L	129	8/26/2004
268626	D	6	CI	L	1050	8/26/2004
33725	D	4	CI	L	1120	8/26/2004
267981	D	4	CI	L	1550	8/26/2004
27315	D	4	BS	L	258	8/26/2004
33726	D	4	BS	L	8	8/26/2004
56450	D	4	BS	L	16	8/26/2004
115177	D	4	BS	L	615	8/26/2004
214761	D	8	CT	L	378	8/26/2004
214762	D	8	CT	L	318	8/26/2004
57753	D	4	BS	L	45	8/26/2004
68671	D	4	BS	L	23	8/26/2004
77286	D	4	BS	L	14	8/26/2004
71252	D	4	BS	L	88	8/26/2004
70479	D	4	BS	L	85	8/26/2004
57752	D	4	BS	L	41	8/26/2004
99267	D	4	BS	L	576	8/26/2004
100343	D	4	CI	L	815	8/26/2004
30228	D	4	BS	L	112	8/26/2004
30229	D	4	BS	L	11	8/26/2004
250038	D	8	CT	L	244	8/26/2004
81595	D	6	BS	L	371	8/26/2004
36179	D	4	BS	L	613	8/26/2004
36176	D	2	BS	L	41	8/26/2004
36177	D	2	BS	L	41	8/26/2004
40578	D	4	BS	L	42	8/26/2004

26877	D	4	BS	L		318	8/26/2004
27889	D	4	BS	L		342	8/26/2004
52264	D	6	BS	L		170	8/26/2004
42827	D	6	BS	L		347	8/26/2004
176843	D	4	CT	L		58	8/26/2004
77418	D	4	BS	L		46	8/26/2004
64534	D	4	BS	L		58	8/26/2004
43470	D	4	BS	L		41	8/26/2004
40270	D	4	BS	L		186	8/26/2004
101047	D	4	CI	L		81	8/26/2004
124837	D	4	BS	L		138	8/26/2004
100340	D	6	CI	L		780	8/26/2004
81572	D	6	BS	L		346	8/26/2004
100342	D	6	CI	L		180	8/26/2004
100341	D	6	CI	L		685	8/26/2004
330288	D	4	CT	L		715	8/26/2004
314997	D	4	CT	L		723	8/26/2004
221554	D	6	CI	L		1150	8/26/2004
48230	D	4	BS	L		121	8/26/2004
30482	D	4	BS	L		118	8/26/2004
156846	D	4	BS	L		18	8/26/2004
144525	D	6	BS	L		47	8/26/2004
100209	D	4	CI	L		2120	8/26/2004
48273	D	4	BS	L		65	8/26/2004
32679	D	2	BS	L		36	8/26/2004
32669	D	4	BS	L		785	8/26/2004
270086	D	4	CT	L		200	8/26/2004
73234	D	4	BS	L		120	8/26/2004
68080	D	2	BS	L		36	8/26/2004
27887	D	2	BS	L		52	8/26/2004
27885	D	2	BS	L		78	8/26/2004
33412	D	2	BS	L		44	8/26/2004
50790	D	4	BS	L		76	8/26/2004
27888	D	2	BS	L		48	8/26/2004
100218	D	6	CI	L		1150	8/26/2004
308514	D	4	CT	L		296	8/26/2004
323259	D	4	CT	L		288	8/26/2004
323258	D	4	CT	L		721	8/26/2004
323262	D	4	CT	L		4	8/26/2004
111145	D	4	BS	L		97	8/26/2004
101502	D	4	BS	L		376	8/26/2004
156801	D	4	CT	L		18	8/26/2004
148144	D	4	CT	L		322	8/26/2004
101510	D	4	BS	L		409	8/26/2004
103696	D	4	BS	L		143	8/26/2004
103695	D	4	BS	L		480	8/26/2004
323260	D	4	CT	L		4	8/26/2004
92791	D	4	BS	L		595	8/26/2004
101511	D	4	BS	L		499	8/26/2004
32670	D	2	BS	L		36	8/26/2004
169347	D	4	CT	H		459	2/12/2004
114974	D	4	CT	L		114	2/12/2004

342297	D	4	PL	L	33	9/17/2004
59338	D	6	BS	L	209	9/17/2004
59338	D	6	BS	L	239	9/23/2004
100946	D	4	CI	L	343	9/27/2004
185642	D	6	CT	L	562	9/27/2004
405679	D	2	PL	M	64	10/28/2004
405682	D	4	PL	M	145	10/28/2004
416866	D	2	PL	M	25	10/28/2004
100466	D	4	CI	L	57	12/6/2004
90184	D	4	BS	L	26	4/16/2004
315631	T	12	CT	H	54	7/13/2004
51296	D	12	BS	L	2558	6/11/2004
79874	D	4	BS	L	59	6/11/2004
106122	D	6	BS	L	37	6/11/2004
100687	D	4	BS	L	40	6/11/2004
53722	D	6	BS	L	42	6/11/2004
79875	D	4	BS	L	59	6/11/2004
99027	D	4	BS	L	272	6/11/2004
104682	D	4	BS	L	128	6/11/2004
107979	D	4	BS	L	571	6/11/2004
104630	D	6	BS	L	166	6/11/2004
330522	D	4	CT	L	11	6/11/2004
93314	D	6	BS	L	38	6/11/2004
92315	D	6	BS	L	42	6/11/2004
91599	D	6	BS	L	808	6/11/2004
369045	D	6	PL	M	115	6/4/2004
83784	D	4	BS	E	1354	2/20/2004
83363	D	4	BS	E	863	2/20/2004
83334	D	4	BS	E	519	2/20/2004
118325	D	4	BS	E	199	2/20/2004
99163	D	4	BS	E	77	2/20/2004
83730	D	4	BS	E	365	2/20/2004
268926	D	2	CT	M	150	3/24/2004
68542	D	6	BS	E	1049	6/11/2004
78433	D	6	BS	E	70	6/11/2004
86924	D	8	BS	E	859	1/21/2004
369912	D	8	TM	E	34	1/21/2004
94226	D	6	BS	E	61	1/21/2004
94359	D	6	BS	E	46	1/21/2004
95200	D	6	BS	L	64	1/21/2004
86923	D	6	BS	E	641	1/21/2004
102920	D	6	BS	E	1263	1/21/2004
86883	D	4	BS	E	35	1/19/2004
87112	D	4	BS	E	38	1/19/2004
87025	D	8	BS	E	1558	2/4/2004
97514	D	4	BS	E	10	2/3/2004
95252	D	8	BS	E	12	1/29/2004
95201	D	4	BS	E	28	2/3/2004
87111	D	4	BS	E	36	1/20/2004
120317	D	4	CT	E	33	1/20/2004
29067	D	4	BS	L	147	8/26/2004
267578	D	4	CI	L	1750	8/26/2004

72671	D	4	BS	L	74	8/26/2004
21124	D	4	WI	L	581	8/26/2004
320185	D	4	CT	L	2	8/26/2004
90884	D	4	BS	L	460	10/9/2004
93290	D	4	BS	L	55	10/9/2004
50524	D	6	BS	L	841	10/9/2004
48072	D	1.5	BS	L	44	10/9/2004
48070	D	1.5	BS	L	44	10/9/2004
48064	D	1.5	BS	L	46	10/9/2004
48063	D	1.5	BS	L	47	10/9/2004
48067	D	1.5	BS	L	46	10/9/2004
48065	D	1.5	BS	L	47	10/9/2004
48066	D	1.5	BS	L	44	10/9/2004
48071	D	1.5	BS	L	43	10/9/2004
48069	D	1.5	BS	L	42	10/9/2004
48068	D	1.5	BS	L	50	10/9/2004
394597	D	4	TM	H	728	7/14/2004
394598	D	4	TM	H	281	7/14/2004
340164	D	2	PL	L	234	2/25/2004
394239	D	4	PL	M	36	7/20/2004
394238	D	4	PL	M	36	7/21/2004
380802	D	4	PL	M	108	10/14/2004
345805	D	4	PL	M	82	10/11/2004
					204,329	

2004 Gas Facility Retirement Expenses

Company:LUTL

Acct Type:CAPITAL AND RETIREMENT

Org	Project	Act (YTD)
004060-GAS DIST. CONTRACT CONSTRUCTION	GME406 GAS MAIN EXT 406	1,945
	PBWK406G PUB WORKS GAS 406	50,755
	RCST406G Customer requested - Gas	(1,649)
004140-GAS DIST. ENGINEERING	LSMR414 Large Scale Main Replacements	24,985
	PMR414 Priority Main Replacement	118,225
004190-GAS DIST OPRS-REPAIR AND MAINTAIN	NBGCS419 NEW BUS CONNECT SERV 419	242
	NBGS419 NEW BUS GAS SERV 419	30
	RRCS419G REP CO GAS SERV 419	389,105
004200-AUBURNDALE GAS DIST. REPAIR AND MAINTAIN	101175 Gas Main Hwy Relocations-ASC	0
		583,639

Wiseman, Sara

From: Winkler, Michael
Sent: Monday, October 31, 2005 9:40 AM
To: Riggs, Eric
Cc: Wiseman, Sara; Kinder, Debra
Subject: RE: Kentucky poles

I'll check with our rep at the landfill and make sure of the costs and then get back with you.

Wink

From: Riggs, Eric
Sent: Monday, October 31, 2005 8:37 AM
To: Winkler, Michael
Cc: Wiseman, Sara; Kinder, Debra
Subject: RE: Kentucky poles

Mike,

Thanks for talking with me this morning. Would you please read the emails from the bottom up and give us information in writing on disposing of wood poles?

Thanks,
Eric

From: Charnas, Shannon
Sent: Saturday, October 29, 2005 11:57 AM
To: Riggs, Eric
Cc: Wiseman, Sara; Kinder, Debra
Subject: RE: Kentucky poles

Eric-

This is good, thanks. I know you discussed this with me last week, but I couldn't quite remember all the details as to where the incremental costs came from.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Riggs, Eric
Sent: Saturday, October 29, 2005 10:09 AM
To: Charnas, Shannon
Cc: Wiseman, Sara; Kinder, Debra

Subject: RE: Kentucky poles

Shannon,

The incremental cost of disposing poles was determined by subtracting the current price to dispose of a 30yd dumpster filled with contaminated poles - $600, from the cost to dispose of a 30yd dumpster that did not contain contaminated trash - $400. The $600 per dumpster figure comes from Les Mills who works in Electric Distribution Operations and handles the disposal process. The $400 figure comes from the Waste Management Corporation who quoted this price as the fee for handing the same size container filled with non-contaminated trash.

In the beginning of the FIN 47 process the Environmental Dept (Mike Winkler) indicated an increase cost in disposing of contaminated poles. The statement made was "The landfill must be notified that these units contain harmful chemicals. Additional costs are charged by landfill operators for disposal." Conversations with Les Mills indicated that the Waste Management Corporation takes these poles to a special area of the landfill for disposal.

The white paper issued by EEI/AGA, used incremental costs for the disposal of wood poles in an example of establishing the ARO.

Please let me know if you have additional questions that we need to address with this issue.

Thanks,
Eric Riggs

From: Charnas, Shannon
Sent: Friday, October 28, 2005 5:39 PM
To: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FW: Kentucky poles

I was talking to Tom Mitchell from AEP yesterday regarding our estimates for the disposal of poles. They have not found that there is an incremental cost to disposing of treated poles. Would you please provide more details as to how the incremental cost of disposing of treated poles was determined. Please just respond to me for now.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: temitchell@aep.com [mailto:temitchell@aep.com]
Sent: Friday, October 28, 2005 5:29 PM
To: Charnas, Shannon
Cc: tewebb@aep.com; smhannis@aep.com
Subject: Kentucky poles

With respect to the project on determining possible asset retirement obligations, I would like to follow up on our brief conversation yesterday relating to treated poles in the Bluegrass State.

We are told that the following types of treated wood can be discarded as non-hazardous waste and therefore can be easily put into ordinary trash containers, not requiring any special incremental cost:

1. arsenic based treated wood
2. pentachlorophenol treated wood
3. creosote treated wood
4. copper napthenate

Could you give us some direction on how you are looking at this ?

Thanks very much,

Tom

Wiseman, Sara

From: Winkler, Michael
Sent: Monday, October 31, 2005 9:40 AM
To: Riggs, Eric
Cc: Wiseman, Sara; Kinder, Debra
Subject: RE: Kentucky poles

I'll check with our rep at the landfill and make sure of the costs and then get back with you.

Wink

From: Riggs, Eric
Sent: Monday, October 31, 2005 8:37 AM
To: Winkler, Michael
Cc: Wiseman, Sara; Kinder, Debra
Subject: RE: Kentucky poles

Mike,

Thanks for talking with me this morning. Would you please read the emails from the bottom up and give us information in writing on disposing of wood poles?

Thanks,
Eric

From: Charnas, Shannon
Sent: Saturday, October 29, 2005 11:57 AM
To: Riggs, Eric
Cc: Wiseman, Sara; Kinder, Debra
Subject: RE: Kentucky poles

Eric-

This is good, thanks. I know you discussed this with me last week, but I couldn't quite remember all the details as to where the incremental costs came from.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Riggs, Eric
Sent: Saturday, October 29, 2005 10:09 AM
To: Charnas, Shannon
Cc: Wiseman, Sara; Kinder, Debra

Subject: RE: Kentucky poles

Shannon,

The incremental cost of disposing poles was determined by subtracting the current price to dispose of a 30yd dumpster filled with contaminated poles - $600, from the cost to dispose of a 30yd dumpster that did not contain contaminated trash - $400. The $600 per dumpster figure comes from Les Mills who works in Electric Distribution Operations and handles the disposal process. The $400 figure comes from the Waste Management Corporation who quoted this price as the fee for handing the same size container filled with non-contaminated trash.

In the beginning of the FIN 47 process the Environmental Dept (Mike Winkler) indicated an increase cost in disposing of contaminated poles. The statement made was "The landfill must be notified that these units contain harmful chemicals. Additional costs are charged by landfill operators for disposal." Conversations with Les Mills indicated that the Waste Management Corporation takes these poles to a special area of the landfill for disposal.

The white paper issued by EEI/AGA, used incremental costs for the disposal of wood poles in an example of establishing the ARO.

Please let me know if you have additional questions that we need to address with this issue.

Thanks,
Eric Riggs

From: Charnas, Shannon
Sent: Friday, October 28, 2005 5:39 PM
To: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FW: Kentucky poles

I was talking to Tom Mitchell from AEP yesterday regarding our estimates for the disposal of poles. They have not found that there is an incremental cost to disposing of treated poles. Would you please provide more details as to how the incremental cost of disposing of treated poles was determined. Please just respond to me for now.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: temitchell@aep.com [mailto:temitchell@aep.com]
Sent: Friday, October 28, 2005 5:29 PM
To: Charnas, Shannon
Cc: tewebb@aep.com; smhannis@aep.com
Subject: Kentucky poles

With respect to the project on determining possible asset retirement obligations, I would like to follow up on our brief conversation yesterday relating to treated poles in the Bluegrass State.

We are told that the following types of treated wood can be discarded as non-hazardous waste and therefore can be easily put into ordinary trash containers, not requiring any special incremental cost:

1. arsenic based treated wood
2. pentachlorophenol treated wood
3. creosote treated wood
4. copper napthenate

Could you give us some direction on how you are looking at this ?

Thanks very much,

Tom

Wiseman, Sara

From: Charnas, Shannon
Sent: Monday, October 31, 2005 9:51 AM
To: Riggs, Eric; Kinder, Debra; Wiseman, Sara
Subject: FW: Creosote treated poles

I got this message from Scott Cooke, which is contradictory to the information received from Les Mills. Please follow up with Les to make sure we can come to an agreement as to what the disposal costs for poles should be. I haven't gotten a response from Mike Winkler yet, but we should make sure he is in agreement also.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Cooke, Scott
Sent: Monday, October 31, 2005 8:41 AM
To: Charnas, Shannon
Cc: Luckett, John; Mills, Les
Subject: FW: Creosote treated poles

Shannon, we do not pay any more to dispose of creosote poles compared to newly treated/non-creosote poles.

From: Luckett, John
Sent: Monday, October 31, 2005 6:42 AM
To: Charnas, Shannon
Cc: Cooke, Scott
Subject: RE: Creosote treated poles

I have no idea what Les had going on here, but I'm forwarding this to Scott Cooke, he maybe able to help.

From: Charnas, Shannon
Sent: Saturday, October 29, 2005 12:07 PM
To: Luckett, John
Subject: FW: Creosote treated poles

John-

I received an out of office notification from Les. I was wondering if you might be able to help with this information. I believe Les had discussed this with Eric Riggs recently to provide him some numbers which I am looking to verify based on conversations I had with others.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Charnas, Shannon
Sent: Saturday, October 29, 2005 12:04 PM
To: Mills, Les; Winkler, Michael
Subject: Creosote treated poles

Les & Mike-

I was talking with someone from AEP in Ohio this week regarding the disposal costs of creosote treated wood poles. He indicated that they have been told that creosote treated wood can be discarded as non-hazardous waste and thus does not require any incremental cost of disposal above any ordinary trash. Could you please verify if we in KY do need to treat these differently and pay more to dispose of them? If so, please let me know the source of this information.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

Wiseman, Sara

From: Ryan, Joe
Sent: Tuesday, November 01, 2005 5:22 PM
To: Clyde, Peter; Martin, Cindy; Beatty, Stephen; Skaggs, John
Cc: Riggs, Eric; Wiseman, Sara; Kinder, Debra
Subject: RE: Gas Main and Service Abandonments

Peter,

I am going off memory here. I believe that the federal environmental PCB regulations require utilities to perform wipe samples for PCB's prior to piping abandonment. The level of PCB's present dictate the type of abandonment. For example, elevated levels of PCB's present would require a pipeline to be filled with a foam or grout to 50% of the pipeline volume. The cost associated with this would not be known until the test results were obtained. We recently found three gallons of PCB oil in the Mt. Washington pipeline while performing work. No one expected to find liquids in this pipeline. It cost an extra $10,000 to handle the PCB's and associated issues. Please call me and we can discuss.

Regards,
Joe

From: Clyde, Peter
Sent: Friday, October 28, 2005 2:23 PM
To: Ryan, Joe; Martin, Cindy; Beatty, Stephen; Skaggs, John
Cc: Riggs, Eric; Wiseman, Sara; Kinder, Debra
Subject: Gas Main and Service Abandonments

As some of you may be aware, a regulation has been passed that requires companies to show liabilities on their financial statements for any retirement costs they are obligated to incur in the future based on contractual, environmental or legal obligations. I was asked to provide an estimate to abandon our gas mains and services based on the scenario that we decided to shut down shop one day.

Below is the e-mail I plan to send to Eric Riggs, Sara Wiseman, and Debra Kinder. However, I wanted to get input from you guys. Each of you either has responsibility for some of these facilities or could potentially be in a situation where you are asked to update this estimate in future years. I want to make sure we have a methodology that is acceptable to each of us so we do not have to change it in the future. Changing it after starting with this methodology would likely raise a number of questions.

Please pay particular attention to the method associated with services. We may choose to spend more money to physically separate the company and customer service, but I thought the approach outlined below would meet the legal obligations. I would like your thoughts on this. I chose to use the scenario where mains were cut out in large segments rather than just shutting off the regulator stations because I did not feel we could meet the purging requirements otherwise.

If folks feel we need to tweak the methodology, I may schedule a phone conference to discuss the matter. Please try to get back to me by Tuesday. Call if you have questions. Thanks.

Pete

Below is the section of the code of federal register (192.727) that dictates requirements of abandoning natural gas facilities. This is the document that spells out our legal requirements associated with abandoning our facilities. These regulations are issued by the US Department of Transportation Pipeline and Hazardous Materials Safety Administration and are enforced locally by the Kentucky Public Service Commission. I have highlighted the key applicable sections that would drive the cost for us to abandon all of our gas mains and services.

The cost of disconnecting our pipelines from the supply source, purging the lines, and sealing the ends and abandoning associated vaults can be estimated based on data from historic large-scale main replacement projects. In 2004, we spent $24,985 to retire 33.6 miles of gas main. This included the steps listed in the beginning of this paragraph. This is equal to

$743 per mile. Applying this cost to our 4,548 miles of gas mains results in a cost of $3,381,898.

In addition, requirements must be met for each service line as described in 192.727(d). In accordance with the options presented in 192.727(d)(1) and (2), the valve on each meter set could be closed and a lock placed on it. This could be done when the meter reader takes his last reading. The incremental cost would be the cost of the locks for our approximately 320,000 gas meters. A mass purchase of locks would likely allow a unit cost of $1 per lock to be obtained. Therefore the incremental cost of the service line shut offs would be $320,000. This brings the total cost of abandoning our gas mains and services to $3,701,898.

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(c) Except for service lines, each inactive pipeline that is not being maintained under this part must be disconnected from all sources and supplies of gas; purged of gas; in the case of offshore pipelines, filled with water or inert materials; and sealed at the ends. However, the pipeline need not be purged when the volume of gas is so small that there is no potential hazard.

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(f) Each abandoned vault must be filled with a suitable compacted material.

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Wiseman, Sara

From: Clyde, Peter
Sent: Tuesday, November 01, 2005 3:50 PM
To: Beatty, Stephen
Cc: Riggs, Eric; Wiseman, Sara; Kinder, Debra; Ryan, Joe; Skaggs, John; Martin, Cindy
Subject: RE: Gas Main and Service Abandonments

Steve,
The estimate should cover costs associated with asbestos coatings on mains and asbestos valve legs, but this is not just an asbestos issue. We are suppose to submit the cost of abandonments of our assets where the costs are required due to legal obligations. This could be environmental, contractual, or regulatory obligations. Since the DOT has requirements about how we abandon our gas mains and services at the end of their useful life, the abandonment costs fell into the legal obligation category. That is why I estimated the cost of abandoning all of our mains and services, not just coated mains. I had Asset Information give the main footage from ENOM. I assumed the storage fields are mapped. If not, let me know how many additional feet need to be factored in. Thanks.

Pete

From: Beatty, Stephen
Sent: Tuesday, November 01, 2005 8:33 AM
To: Clyde, Peter
Cc: Riggs, Eric; Wiseman, Sara; Kinder, Debra; Ryan, Joe; Skaggs, John; Martin, Cindy
Subject: RE: Gas Main and Service Abandonments

Peter:

Your methodology seems valid. I assume that this process involves the asbestos issue. If so, since you are including the costs for all mains and services, I will need to remove the costs that I included in my asbestos cost submittal. Your method is more exact than my guess.

Thank you for the information.

Steve

From: Clyde, Peter
Sent: Friday, October 28, 2005 2:23 PM
To: Ryan, Joe; Martin, Cindy; Beatty, Stephen; Skaggs, John
Cc: Riggs, Eric; Wiseman, Sara; Kinder, Debra
Subject: Gas Main and Service Abandonments

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Pete

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Standards. In addition to the NPMS-required attributes, operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws. Refer to the NPMS Standards for details in preparing your data for submission. The NPMS Standards also include details of how to submit data. Alternatively, operators may submit reports by mail, fax or e-mail to the Information Officer, ~~Research and Special Programs Administration~~ Pipeline and Hazardous Materials Safety Administration, Department of Transportation, Room 7128, 400 Seventh Street, SW, Washington DC 20590; fax (202) 366-4566; e-mail, roger.little@~~rspa.~~dot.gov. The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws.

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[Part 192 - Org., Aug. 19, 1970, as amended by Amdt. 192-8, 37 FR 20694, Oct. 3, 1972, Amdt. 192-27, 41 FR 34598, Aug. 16, 1976; Amdt. 192-71, 59 FR 6575, Feb. 11, 1994; Amdt. 192-89, 65 FR 54440, Sept. 8, 2000; Amdt. 192-89A, 65 FR 57861, Sept. 26, 2000; Amdt. 192-100, 70 FR 11135, Mar. 8, 2005]

Leenerts, Patricia

From: Charnas, Shannon
Sent: Monday, November 07, 2005 10:15 AM
To: Kinder, Debra
Cc: Leenerts, Patricia; Wiseman, Sara; Riggs, Eric
Subject: RE: Poles and cross arms

Debbie-

Yes, I agree, let's remove them. Every little bit helps! Hopefully this will make a big difference by eliminating one asset that would be very difficult to track going forward.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Kinder, Debra
Sent: Monday, November 07, 2005 9:46 AM
To: Charnas, Shannon
Cc: Leenerts, Patricia; Wiseman, Sara; Riggs, Eric
Subject: FW: Poles and cross arms

Shannon,

Based upon Mikes response, we do not believe that poles and crossarms should be set up as AROs. Do you agree?

Debbie

From: Winkler, Michael
Sent: Monday, November 07, 2005 9:33 AM
To: Wiseman, Sara
Cc: Riggs, Eric; Kinder, Debra
Subject: RE: Poles and cross arms

I talked to the landfill last week and was told that the cost for disposal of regular trash is calculated on a per ton basis. The cost for disposal of poles and cross arms is calculated on a per cubic yard basis (because the poles don't compact like regular trash does in the landfill). There is no cost difference for any of the poles or cross arms, regardless of the wood preservative type ... they are all non-hazardous and cost the same for disposal.

Hope this answers all your questions. If not, you know where to find me !!

Wink

From: Riggs, Eric
Sent: Monday, November 07, 2005 9:13 AM
To: Winkler, Michael
Cc: Wiseman, Sara; Kinder, Debra
Subject: Poles and cross arms

Mike,

Would you please give us an update on what you have found out concerning the poles/cross arms issue. I will let you know that we heard that Bob Erhler is saying that there is no additional cost to dispose of poles. We need your input in order to determine if we need to establish an Asset Retirement Obligation for poles/cross arms.

Thanks,
Eric Riggs
2822

Wiseman, Sara

From: Charnas, Shannon
Sent: Monday, November 07, 2005 4:39 PM
To: Wiseman, Sara
Subject: FW: ARO assets.

Sara,

Can we give Robert and Kent an estimated amount or at least a range of amounts that we are talking about? That may help with the determination.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Charnas, Shannon
Sent: Sunday, November 06, 2005 6:38 PM
To: Conroy, Robert; Wiseman, Sara
Cc: Blake, Kent; Scott, Valerie; Williams, Scott; Leichty, Doug
Subject: RE: ARO assets.

Do you think there is potentially any negative to sending them a letter in advance explaining the increase in the scope of SFAS No. 143 through the creation of FIN 47? If not, I might lean toward that to be conservative, but those in Rates & Regulatory have more experience with these matters.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Conroy, Robert
Sent: Friday, November 04, 2005 3:18 PM
To: Wiseman, Sara
Cc: Blake, Kent; Scott, Valerie; Charnas, Shannon; Williams, Scott; Leichty, Doug
Subject: ARO assets.

Sarah,

You indicated that we are required to record additional ARO assets and liabilities in December 2005 and wanted to know whether we need to file for approval with the PSC or whether an informational letter would be sufficient. In looking at the Commission's order in Case No. 2003-00426 and Case No. 2003-00427 (where we asked for approval of the accounting for the adoption of SFAS No. 143) the Commission approved the establishment of the regulatory asset and liability accounts associated with the adoption of SFAS No. 143 and did not limit the approval to a specific dollar amount to those accounts. Therefore, it does not appear necessary to seek Commission approval if all we are doing is recording additional amounts to those accounts previously approved.

Concerning informing the Commission of the additional amounts to be recorded in December 2005, we have two choices. Either send a separate letter prior to recording the ARO assets and liabilities or inform them in the letter that is sent when we file the financial statements that contain the additional ARO assets and liabilities. I believe the latter would be sufficient but welcome other's thoughts.

Thanks

Robert M. Conroy
Manager, Rates
(502) 627-3324 (phone)
(502) 627-3213 (fax)
(502) 741-4322 (mobile)

Tracking:

Recipient
Wiseman, Sara

Wiseman, Sara

From:	Clyde, Peter
Sent:	Monday, November 07, 2005 11:01 AM
To:	Wiseman, Sara; Riggs, Eric; Kinder, Debra
Subject:	Gas Main and Service Abandonments

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Wiseman, Sara

From: Miller, Jon
Sent: Monday, November 07, 2005 11:11 AM
To: Leenerts, Patricia
Cc: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: RE: Missing Generation items.

Sorry, I misread your initial email.

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 11:10 AM
To: Miller, Jon
Cc: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: RE: Missing Generation items.

I sent them out prior to contacting you. I will copy you as well in the future.

From: Miller, Jon
Sent: Monday, November 07, 2005 11:08 AM
To: Leenerts, Patricia
Subject: RE: Missing Generation items.

Pat,

I would suggest you go ahead and send those emails. You have the correct contact people included. Please copy me as well.

Jon

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 11:06 AM
To: Miller, Jon
Subject: Missing Generation items.

I have sent the following emails regarding other missing items from various locations.

<< Message: FIN 47 Request - Batteries >> << Message: FIN 47 Request - Batteries >> << Message: FIN 47 Request - Asbestos >> << Message: FIN 47 Request - Batteries >>

Pat

Leenerts, Patricia

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 10:41 AM
To: Legler, Steve
Cc: Kinder, Debra; Wiseman, Sara; Riggs, Eric
Subject: FIN 47 Request - Batteries

Steve, I am a new employee with LGE and will (eventually) be the point person for the FIN 47 project. I show you as the contact for the Waterside and Canal locations. Do you have the disposal estimate, according to FIN 47, for Batteries at Waterside and Batteries at Canal?

Thanks

Pat
Ext 3811

Leenerts, Patricia

From: Miller, Jon
Sent: Monday, November 07, 2005 11:04 AM
To: Leenerts, Patricia
Subject: RE: FIN 47 Contact for Dix Dam - Asbestos

Patrica,

Do you know if there are other items you are missing for Generation?

Jon

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 11:03 AM
To: Miller, Jon
Subject: RE: FIN 47 Contact for Dix Dam - Asbestos

Thanks

From: Miller, Jon
Sent: Monday, November 07, 2005 10:59 AM
To: Leenerts, Patricia
Cc: Kinder, Debra; Wiseman, Sara; Riggs, Eric; Carr, Sam
Subject: RE: FIN 47 Contact for Dix Dam - Asbestos

Patricia,

Welcome aboard. Sam Carr would be the best person to contact regarding Dix Dam.

Jon

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 10:56 AM
To: Miller, Jon
Cc: Kinder, Debra; Wiseman, Sara; Riggs, Eric
Subject: FIN 47 Contact for Dix Dam - Asbestos

Jon, I am a new employee with LGE and will (eventually) be the point person for the FIN 47 project. I was told that you may be able to provide me with a contact name for Dix Dam. The contact person will need to provide to me the disposal estimate, according to FIN 47, for Asbestos at Dix Dam?

Pat
Ext 3811

Leenerts, Patricia

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 11:10 AM
To: Carr, Sam
Cc: Miller, Jon; Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FIN 47 Request - Asbestos

Sam, Jon Miller, informed me that you are also the contact for Dix Dam. Do you have the disposal estimate, according to FIN 47, for Asbestos at Dix Dam?

Thanks

Pat
Ext 3811

Leenerts, Patricia

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 11:25 AM
To: Carr, Sam
Cc: Miller, Jon; Fraley, Jeffrey; Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: RE: FIN 47 Request - Batteries

I will need the disposal estimates by close of business on Wednesday, Nov 9th. Today's request, from me, is a follow-up to prior requests from the Property Accounting Department. We are preparing for an external auditor's meeting during which these and other FIN 47 items will be discussed.

Thanks for your help.

Pat

From: Carr, Sam
Sent: Monday, November 07, 2005 11:16 AM
To: Leenerts, Patricia
Cc: Miller, Jon; Fraley, Jeffrey
Subject: RE: FIN 47 Request - Batteries

Pat,

In response to your questions about FIN 47 info for Pineville, Jeff Fraley, General Manager at the Brown Station, was just recently given responsibility for some of the support work for the Pineville Station. This facility has essentially been closed, except for grounds maintenance activities that are managed by the Brown staff.

At this time because the Pineville facility is extremely remote to our location, I am not familiar with the scope and cost for battery disposal. Therefore, I will need to investigate further to get you an answer. Per your request to Jon Miller, I will also need to investigate the scope and cost for any asbestos removal that would be needed at Dix.

What is your time frame for needing this information?

Sam Carr
Manager Commercial Operations
E.W. Brown Station
859-748-4424 office
859-265-0583 cell
sam.carr@lgeenergy.com

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 10:42 AM
To: Carr, Sam
Subject: FIN 47 Request - Batteries

Sam, I am a new employee with LGE and will (eventually) be the point person for the FIN 47 project. I show you as the contact for the Pineville location. Do you have the disposal estimate, according to FIN 47, for Batteries at Pineville?

Pat
Ext 3811

Leenerts, Patricia

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 11:26 AM
To: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FIN 47 Requests - Additional items

I sent 3 emails without copying ya'll. Here's the meat of the emails:

Sam, I am a new employee with LGE and will (eventually) be the point person for the FIN 47 project. I show you as the contact for the Pineville location. Do you have the disposal estimate, according to FIN 47, for Batteries at Pineville?

Russell, I am ... location. Do you have the disposal estimate, according to FIN 47, for Batteries at Green River?

Barry, I am ... location. Do you have the disposal estimate, according to FIN 47, for Asbestos at Haefling?

Pat

Leenerts, Patricia

From: Fraley, Jeffrey
Sent: Monday, November 07, 2005 1:01 PM
To: Currens, Barry; Carr, Sam
Cc: Charnas, Shannon; Leenerts, Patricia
Subject: RE: FIN 47 Request - Asbestos

Barry and Sam,
If these folks need this by Wednesday, let's go ahead and put some estimates together on our own and keep working on getting the back-up information to follow.

Jeff

From: Currens, Barry
Sent: Monday, November 07, 2005 12:57 PM
To: Leenerts, Patricia
Cc: Fraley, Jeffrey
Subject: RE: FIN 47 Request - Asbestos

We are in contact with a contractor to give us viable estimates for asbestos abatement at Haefling. I will send them when we have them. It should be in the next few weeks.

Barry B. Currens
Manager Tyrone Operations
Office (859) 879-3501
Mobile (859) 265-4498

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 10:41 AM
To: Currens, Barry
Subject: FIN 47 Request - Asbestos

Barry, I am a new employee with LGE and will (eventually) be the point person for the FIN 47 project. I show you as the contact for the Haefling location. Do you have the disposal estimate, according to FIN 47, for Asbestos at Haefling?

Pat
Ext 3811

Leenerts, Patricia

From: Currens, Barry
Sent: Tuesday, November 08, 2005 9:19 AM
To: Leenerts, Patricia
Cc: Fraley, Jeffrey; Eubank, Barry; Lanphierd, Steve
Subject: RE: FIN 47 Request - Asbestos

I have found out that previous tests conducted at Haefling have determined that there is no asbestos on this site. There will be no retirement costs for Haefling.

Barry B. Currens
Manager Tyrone Operations
Office (859) 879-3501
Mobile (859) 265-4498

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 10:41 AM
To: Currens, Barry
Subject: FIN 47 Request - Asbestos

Barry, I am a new employee with LGE and will (eventually) be the point person for the FIN 47 project. I show you as the contact for the Haefling location. Do you have the disposal estimate, according to FIN 47, for Asbestos at Haefling?

Pat
Ext 3811

Leenerts, Patricia

From: Leenerts, Patricia
Sent: Tuesday, November 08, 2005 9:33 AM
To: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FW: FIN 47 Request - Asbestos

From: Currens, Barry
Sent: Tuesday, November 08, 2005 9:19 AM
To: Leenerts, Patricia
Cc: Fraley, Jeffrey; Eubank, Barry; Lanphierd, Steve
Subject: RE: FIN 47 Request - Asbestos

I have found out that previous tests conducted at Haefling have determined that there is no asbestos on this site. There will be no retirement costs for Haefling.

Barry B. Currens
Manager Tyrone Operations
Office (859) 879-3501
Mobile (859) 265-4498

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 10:41 AM
To: Currens, Barry
Subject: FIN 47 Request - Asbestos

Barry, I am a new employee with LGE and will (eventually) be the point person for the FIN 47 project. I show you as the contact for the Haefling location. Do you have the disposal estimate, according to FIN 47, for Asbestos at Haefling?

Pat
Ext 3811

Leenerts, Patricia

From:	Baker, Bryan
Sent:	Tuesday, November 08, 2005 10:22 AM
To:	Leenerts, Patricia
Subject:	RE: FIN 47 Request - Batteries

Patricia,

Hello, this is Bryan Baker. I am the contact for Green River in relation to FIN 47 questions/concerns. Russell and I are both supervisors, with "Baker" as our last name, so we get mixed up a lot!

As for the battery disposal estimate. Are you looking for more information than is present in the FIN 47?

From:	Baker, Russell
Sent:	Monday, November 07, 2005 10:49 AM
To:	Baker, Bryan
Subject:	FW: FIN 47 Request - Batteries

I think this was probably suppose to go to you.

From:	Leenerts, Patricia
Sent:	Monday, November 07, 2005 9:42 AM
To:	Baker, Russell
Subject:	FIN 47 Request - Batteries

Russell, I am a new employee with LGE and will (eventually) be the point person for the FIN 47 project. I show you as the contact for the Green River location. Do you have the disposal estimate, according to FIN 47, for Batteries at Green River?

Pat
Ext 3811

Leenerts, Patricia

From: Baker, Bryan
Sent: Tuesday, November 08, 2005 2:03 PM
To: Leenerts, Patricia
Subject: RE: FIN 47 Request - Batteries

Attachments: Fin 47 - GR.xls

Rows 8 & 9? Or are you looking for something else?

Fin 47 - GR.xls

From: Leenerts, Patricia
Sent: Tuesday, November 08, 2005 9:44 AM
To: Baker, Bryan
Cc: Wiseman, Sara; Kinder, Debra; Riggs, Eric; Miller, Jon
Subject: RE: FIN 47 Request - Batteries

Hey Bryan. Thanks for straightening me out.
I am missing the dollar value estimate for battery disposal, according to FIN 47.

Pat
Ext 3811

From: Baker, Bryan
Sent: Tuesday, November 08, 2005 10:22 AM
To: Leenerts, Patricia
Subject: RE: FIN 47 Request - Batteries

Patricia,

Hello, this is Bryan Baker. I am the contact for Green River in relation to FIN 47 questions/concerns. Russell and I are both supervisors, with "Baker" as our last name, so we get mixed up a lot!

As for the battery disposal estimate. Are you looking for more information than is present in the FIN 47?

From: Baker, Russell
Sent: Monday, November 07, 2005 10:49 AM
To: Baker, Bryan
Subject: FW: FIN 47 Request - Batteries

I think this was probably suppose to go to you.

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 9:42 AM
To: Baker, Russell
Subject: FIN 47 Request - Batteries

Russell, I am a new employee with LGE and will (eventually) be the point person for the FIN 47 project. I show you as the contact for the Green River location. Do you have the disposal estimate, according to FIN 47, for Batteries at Green River?

Pat
Ext 3811

Location
Asset Retirement Obligations

Asset Description	Location	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date
#2 ash pond	GR Property	27 acres	$270,000	-	2014
#3 ash pond	GR Property	3 acres	$30,000	-	2014
SO2 Pond	GR Property	10 acres	$10,000	-	2014
Scrap metal	Outside Mech Maint Shop	50 ton	$0	$0	2014
Plant Batteries	Battery rooms in the basement	120	$8,000	$2,000	2014
Plant Batteries - Misc Dry Cell	Throughout the plant	50	$2,000	$1,000	2014
Lube oil in plant equipment	Throughout the plant	5,000 gal	$0	$3,000	2014
Oil in in-plant X-frmrs	Throughout the plant	25,000 gal	$0		2014
Acid	Demineralizer Building	6,000 gal	0**	$0	2014
Caustic	Demineralizer Building	5,000 gal	0**	$0	2014
Other lab chemicals	Lab/Demin	100 gals	0**	$0	2014
Water treatment Chemicals	Basement	1,000 gals	0**	$0	2014
Dry chemicals	Basement	2,000 lbs	0**	$0	2014
Paint	Whse/Paint locker	50 gal at any one time	$1,000	$1,000	2014
Fuel oil for burners	New fuel oil tanks	50,000 gal	0*		2014
Fuel oil for mobile equipment	Fuel Depot	2,000 gal	0*		2014
Gasoline for mobile equipment	Fuel Depot	300 gal	0*		2014
GR1 Asbestos Abatement	Green River Unit 1 Plant		$1,775,000	$75,000	2014
GR2 Asbestos Abatement	Green River Unit 2 Plant		$1,575,000	$75,000	2014
GR3 Asbestos Abatement	Green River Unit 3 Plant		$1,780,000	$75,000	2014
GR4 Asbestos Abatement	Green River Unit 4 Plant		$2,100,000	$75,000	2014
			$7,551,000	$307,000	

0* = Estimated 0 cost for removal of asset that can be used at another plant or recycled at no cost
0** = Estimated removal 0 cost. Asset can be diluted and sent to waste stream off of the property

Leenerts, Patricia

From: Leenerts, Patricia
Sent: Wednesday, November 09, 2005 11:50 AM
To: Baker, Bryan
Subject: RE: FIN 47 Request - Batteries

I appreciate you getting back so quickly.

Pat

From: Baker, Bryan
Sent: Wednesday, November 09, 2005 11:50 AM
To: Leenerts, Patricia
Subject: RE: FIN 47 Request - Batteries

Sorry, I'm kinda swamped here.

These are the final sheets you should be working off of. Two are from what Russell sent to you, and one is our total plant spreadsheet.
<< File: FIN-47_abatement-GR.xls >> << File: FIN-47 Abatement Methodolgy - GR.doc >> << File: Fin 47 - GR.xls >>

Question #1 on the batteries, the TOTAL COST OF RETIREMENT should be $13,000 for all batteries. We read "Removal Cost per Asset" as just that, the cost to remove the asset (ie, all the batteries). The "Incremental Cost of Disposal" would be the cost to dispose of the asset, ie disposing of the batteries that we removed. So, $13,000.

On the Unit #2, the $1,625,000 # is correct. I had a fat finger on that one, good catch. As for the disposal cost, add it to the removal cost.

From: Leenerts, Patricia
Sent: Wednesday, November 09, 2005 10:29 AM
To: Baker, Bryan
Subject: FW: FIN 47 Request - Batteries

Do you have a chance to answer my questions below? Try to get to it today if you could. I need time tomorrow to finalize for an 8 am meeting on Friday with the auditors.

Thanks

From: Leenerts, Patricia
Sent: Tuesday, November 08, 2005 3:49 PM
To: Baker, Bryan
Cc: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FW: FIN 47 Request - Batteries

This is what I'm looking for, thanks. I do have a few questions. According to the attached my calculation would be: 120 units times $8000 + 50 units times $2000 = $960000 + 100000 = $1,060,000 to be the removal costs for the batteries? Should I be using the incremental cost of disposal column too **or instead of?**

Your spreadsheet is similar to a document that was received from Russell Baker on Oct 17, 2005, regarding Green River. I reviewed the GR1-GR4 Asbestos Abatement removal cost numbers that Russell provided and the unit 2 does not match. I will send you the email that Russell sent. ***Please review both documents and let me know which asbestos numbers are correct.*** Again, I have the same question as above: Should I be using the incremental cost of disposal column too **or instead of?**

Thanks for your help

Pat
Ext 3811

From: Baker, Bryan
Sent: Tuesday, November 08, 2005 2:03 PM
To: Leenerts, Patricia
Subject: RE: FIN 47 Request - Batteries

Rows 8 & 9? Or are you looking for something else?

<< File: Fin 47 - GR.xls >>

From: Leenerts, Patricia
Sent: Tuesday, November 08, 2005 9:44 AM
To: Baker, Bryan
Cc: Wiseman, Sara; Kinder, Debra; Riggs, Eric; Miller, Jon
Subject: RE: FIN 47 Request - Batteries

Hey Bryan. Thanks for straightening me out.
I am missing the dollar value estimate for battery disposal, according to FIN 47.

Pat
Ext 3811

From: Baker, Bryan
Sent: Tuesday, November 08, 2005 10:22 AM
To: Leenerts, Patricia
Subject: RE: FIN 47 Request - Batteries

Patricia,

Hello, this is Bryan Baker. I am the contact for Green River in relation to FIN 47 questions/concerns. Russell and I are both supervisors, with "Baker" as our last name, so we get mixed up a lot!

As for the battery disposal estimate. Are you looking for more information than is present in the FIN 47?

From: Baker, Russell
Sent: Monday, November 07, 2005 10:49 AM
To: Baker, Bryan
Subject: FW: FIN 47 Request - Batteries

I think this was probably suppose to go to you.

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 9:42 AM
To: Baker, Russell
Subject: FIN 47 Request - Batteries

Russell, I am a new employee with LGE and will (eventually) be the point person for the FIN 47 project. I show you as the contact for the Green River location. Do you have the disposal estimate, according to FIN 47, for Batteries at Green River?

Pat
Ext 3811

Leenerts, Patricia

From: Leenerts, Patricia
Sent: Wednesday, November 09, 2005 4:50 PM
To: Carr, Sam
Cc: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FW: FIN 47 Request - Batteries

Attachments: Fin 47 - EWB - TYR - 11-09-05.xls

Sam,

I do have a question. Your spreadsheet tab "Fin 47 Brown CT Tyr" has a column headed Removal Cost by Asset. The Dix-Batteries shows $800 and the Pineville-Batteries shows $1000. I want to verify that these are the full extended costs and are not by Asset as the column heading suggests.

Let me know. Thanks for your response and help.

Pat
X 3811

From: Carr, Sam
Sent: Wednesday, November 09, 2005 2:48 PM
To: Leenerts, Patricia
Cc: Miller, Jon
Subject: RE: FIN 47 Request - Batteries

Fin 47 - EWB - TYR
- 11-09-05....

Pat,

Revised FIN 47 info is attached per your request. Included on the revised spreadsheet is the information for Pineville batteries and Dix batteries and asbestos.

If you have questions, please advise.

Thanks,
Sam Carr
Manager Commercial Operations
E.W. Brown Station
859-748-4424 office
859-265-0583 cell
sam.carr@lgeenergy.com

Asset Retirement Obligations				($000's)				
Asset Description	Location	Legal Requirement	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremental Cost of Disposal ($'s)	Estimated Retirement	Comments	Support
Location	BROWN							
Ash Pond	BR ST	Resource Conservation and Recovery Act		$10,440			Not unit specific - Steam units only 1,2,3	$90k/acre per 2002 FMSM estimate of $83k/acre for 116 acres inflated 3% per year. Closure requires 2 ft. cover soil, monitoring wells, and permitting pond as a landfill per FMSM. Acreage verified by Paul Puckett-Environmental Dept.
Asbestos Abatement - BR1	BR1			$2,056			BR1 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of 15% per each 25 MW increase above 100 MW. Adjustments made for abatement completed on BR1 penthouse and external furnace.
Asbestos Abatement - BR2	BR2			$3,296			BR2 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of 15% per each 25 MW increase above 100 MW. Adjustments made for abatement completed on BR2 penthouse, external furnace, and high energy piping.
Asbestos Abatement - BR3	BR3			$7,435			BR3 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, coal handling equipment, office areas, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of 15% per each 25 MW increase above 100 MW. Adjustments made for abatement completed on BR3 penthouse, external furnace, and high energy piping.
Radiation Sources - BR3	BR3	The Cabinet for Human Resources KRS 211.844, regulation 902 KAR Chapter 100		$16			Sources located with the following 10 assets w/UOP 5676: 3-1,3-2,3-3,3-4,&3-5 Feeders Upper & Lower. Also, the assets with UOP 5025: Hoppers A26,A22,A25,A21,A24,A20,A23,A19,B26,B22,B25,B21,B24,B20,B23,B19	Radiation Sources at $870 per 18 sources. Cost based on conversations with vendors (Secoal, contract supplier of radiation sources, 12/02) and physical counts. **Supported by OHMART email**
GSU, transformer oil, lubricating oils, ehc fluid	BR ST	Clean Water Act Toxic Substances Control Act					Not unit specific - include BR 1, 2,3. Transformers only. This oil has no PCBs (non-hazardous). Should be able to sell for reuse. Tie to BR3	Supported by internal email from Shannon Charnas. American Enviro Services will take oil at no cost
GSU, transformer oil, lubricating oils, ehc fluid	BR CT	Clean Water Act Toxic Substances Control Act					Not unit specific - include BR 5, 6, 7, 8, 9, 10,11. Transformers only. This oil has no PCBs (non-hazardous). Should be able to sell for reuse. Tie to BR 7.	Supported by internal email from Shannon Charnas. American Enviro Services will take oil at no cost
Removal of Fuel Oil Tanks - BR Steam units 1, 2, 3	BR ST	Clean Water Act, Comprehensive Emergency Response and Liability Act		$141			Tanks are not unit specific - for BR 1, 2, 3 - flat fee paid to contractor for removal. ESTIMATE	**Supported by email from Somerset Environmental**
Removal of Fuel Oil Tanks - BR CTs	BR CT	Clean Water Act		$281			Tanks are not unit specific - include BR 5, 6, 7, 8, 9, 10, 11 - flat fee paid to contractor for removal. ESTIMATE	**Supported by email from Somerset Environmental**
Remediation of underground fuel oil piping - Steam	BR ST	Clean Water Act, Comprehensive Emergency Response and Liability Act		$17			Estimate - Not unit specific - include BR 1, 2,3.	**Supported by engineering estimate provided by Barry Currens**
Remediation of underground fuel oil piping - CTs	BR CT	Clean Water Act		$32			Not unit specific - include BR 5, 6, 7, 8, 9, 10,11.	**Supported by engineering estimate provided by Barry Currens**
Mercury Removal	BR ST/CT	Resource Conservation and Recovery Act					Due to immaterial costs of $305 no ARO is being established	Per Mike Winkler in Environmental $4.50/lb. **Supported by ENSCO quote. 15 bs per Shannon Charnas email**

Asset Retirement Obligations				($000's)				
Asset Description	Location	Legal Requirement	Quantity by year of installation	Removal Cost per Asset ($'s)	Incremental Cost of Disposal ($'s)	Estimated Retirement	Comments	Support
Lab Chemical disposal	BR	Resource Conservation and Recovery Act		$18			BR1 - Lab Equipment UOP 5389.	**Supported by estimate from GE Betz Inc.**
Sewage Plant	BR	Clean Water Act		$10			Estimated cost to pump out tank, fill tank with soil, and grade land.	Based on Pineville estimate of $1k for 50 people, assumed $4k for 200 people and additional fee for equipment use. **Supported by BMR invoice**
Coal Yard covering	BR ST	Clean Water Act		$60			Not unit specific - Steam units 1, 2,3.	Based on Pineville estimate - $15k/acre for 4 acres **Acreage verified by Delbert Billiter-Fuels Dept.**
Coal pile retention pond closing	BR ST	Clean Water Act		$185			Estimate - Not unit specific - Steam units 1, 2,3.	**Supported by engineering estimate provided by Barry Currens**
Station Batteries - BR1	BR1	Toxic Substance Control Act	60	$2			BR1 - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Station Batteries - BR2	BR2	Toxic Substance Control Act	60	$2			BR2 - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Station Batteries - BR3	BR2	Toxic Substance Control Act	60	$2			BR3 - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Station Batteries - Dix	Dix	Toxic Substance Control Act	60	$2			Dix - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Batteries - West Cliff	BR ST	Toxic Substance Control Act	60	$2			BR ST - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Batteries - North Sub	BR ST	Toxic Substance Control Act	60	$2			BR ST - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Computer Batteries - BR3	BR3	Toxic Substance Control Act	20	$0.48			BR 3 - Batteries UOP 05049.	Estimate from Bob Webb - $24 per computer battery for removal and disposal.
Computer Batteries - BR1	BR1	Toxic Substance Control Act	10	$0.24			BR1 - Batteries UOP 05049.	Estimate from Bob Webb - $24 per computer battery for removal and disposal.
Computer Batteries - Slurry Room	BR ST	Toxic Substance Control Act	20	$0.48			BR ST - Batteries UOP 05049.	Estimate from Bob Webb - $24 per computer battery for removal and disposal.
Location	**TYRONE**							
Ash Pond	TY	Resource Conservation and Recovery Act		$810			Not unit specific.	$90k/acre per 2002 FMSM estimate of $83k/acre for 9 acres inflated 3% per year. Closure requires 2 ft. cover soil, monitoring wells, and permitting pond as a landfill per FMSM. Acreage verified by Paul Puckett-Environmental Dept.
Demolition Service Water Pump structures	TY	Corps of Engineers		$181			2 structures which have asbestos and lead paint issues - Not unit specific.	Flat fee for contractor removal. **Supported by estimate from Evans Construction Co**
GSU, transformer oil, lubricating oils, ehc fluid	TY	Clean Water Act Toxic Substances Control Act		$0			Not unit specific - Tie to transformer on TY3. This oil has no PCBs (non-hazardous). Should be able to sell for reuse.	8 oil-field transformers at $5,000. Based upon estimate from Somerset Environmental (contractor) received on 12/23/02.

Asset Retirement Obligations				($000's)				
Asset Description	Location	Legal Requirement	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremental Cost of Disposal ($'s)	Estimated Retirement	Comments	Support
Removal of Fuel Oil Tanks	TY	Clean Water Act, Comprehensive Emergency Response and Liability Act		$101			One underground and one above ground - Not unit specific.	Flat fee for contractor removal. Based upon estimate from Somerset Environmental (contractor) received on 12/23/02.
Remediation of underground fuel oil piping	TY	Clean Water Act, Comprehensive Emergency Response and Liability Act		$14			Not unit specific.	Engineering estimate provided by Barry Currens
Mercury Removal	TY	Resource Conservation and Recovery Act		$3			Not unit specific - allocable among units. UOP 5373 - Instrument or measuring device (instrumentation). Tie to TY3	**Supported by ENSCO quote provided by Mike Winkler**
Sewage Plant	TY	Clean Water Act		$5			Estimated cost to pump out tank, fill tank with soil, and grade land.	Based on Pineville estimate of $1k for 50 people and additional fee for equipment use. **Supported by PMR invoice**
Coal Yard covering	TY	Clean Water Act		$30			Assuming that we would be required to close similar to the ash pond - Not unit specific	2 acres at $15k per acre Pineville estimate **Acreage verified by Delbert Billiter-Fuels Dept.**
Batteries	TY	Toxic Substance Control Act	60	2.7			TY ST - Batteries UOP 05049.	Estimate from Barry Currens - $45 per station battery for removal and disposal.
Batteries	Haefling	Toxic Substance Control Act	60	2.7			Haefling - Batteries UOP 05049.	Estimate from Barry Currens - $45 per station battery for removal and disposal.
Asbestos Abatement - TY1	TY1			$1,459			TY1 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of (15%) per 25 MW reduced unit capacity below 100 MW.
Asbestos Abatement - TY2	TY2			$1,459			TY2 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of (15%) per 25 MW reduced unit capacity below 100 MW.
Asbestos Abatement - TY3	TY3			$2,107			TY3 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of (15%) per 25 MW reduced unit capacity below 100 MW. Adjustment for boiler #5 penthouse internal abatement completed.
Location	**PINEVILLE**							
Asbestos Abatement - Pineville Station	Pineville			$1,534			Pineville Unit 1 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of (15%) per 25 MW reduced unit capacity below 100 MW.
Station Batteries - Pineville Station	Pineville	Toxic Substance Control Act	30	$1			Pineville - Batteries UOP 05049.	$45 per station battery for removal and disposal.
Location	**DIX**							
Asbestos Abatement	Dix			$345			3 Windings, ductwork lot, ceiling tiles lot, and 3 wickette gate packing.	Cost estimater and scope of work provided by Dave Beck 11/09/05.
Batteries	Dix	Toxic Substance Control Act	20	$0.8			Dix - Batteries UOP 05049.	Estimate from Dave Beck - $40per station battery for removal and disposal.
Lead Paint	Dix			$629			Turbine shutoff valves, machines, wickette gates, oil pumps, tanks, window frames, and hand rails.	Estimate from Dave Beck 11/09/05.

Assumption: multiplier factor of 15% per 25MW of increased unit capacity above 100 MW

Brown Unit 1 - 108 MW

108	Base Cost	MW Multiplier	Adjustments	Total	
		1.048			
Penthouse	365	382.52	-17.52	38.3	Abatement completed internally. Roof penetrations remain.
External Furnace	750	786	-36	550.2	Furnace walls abated above Main Floor to penthouse.
Piping, External - Operating Floor up	250	262	-12	262.0	
Pipe and Equipment, below Operating floor	150	157.2	-7.2	157.2	
Ductwork, Equipment, Operating floor up	300	314.4	-14.4	314.4	
Ductwork, under Operating floor	200	209.6	-9.6	209.6	
Survey, Air Testing, Permits, etc.	100	104.8	-4.8	104.8	
Contingency	400	419.2	-19.2	419.2	
Coal Handling	0	0	0	0.0	
Total:	$ 2,515.0	$ 2,635.7	$ (120.7)	2,055.7	

Brown Unit 2 - 178 MW

178	Base Cost	MW Multiplier	Adjustments	Total	
		1.468			
Penthouse	365	535.82	-170.82	267.9	Abatement completed internally. Roof area remains.
External Furnace	750	1101	-351	990.9	Misc. furnace wall areas abated (backpass).
Piping, External - Operating Floor up	250	367	-117	348.7	Partial abatement on high energy piping completed.
Pipe and Equipment, below Operating floor	150	220.2	-70.2	220.2	
Ductwork, Equipment, Operating floor up	300	440.4	-140.4	440.4	
Ductwork, under Operating floor	200	293.6	-93.6	293.6	
Survey, Air Testing, Permits, etc.	100	146.8	-46.8	146.8	
Contingency	400	587.2	-187.2	587.2	
Coal Handling	0	0	0	0.0	
Total:	$ 2,515.0	$ 3,692.0	$ (1,177.0)	3,295.7	

Brown Unit 3 - 454 MW

454	Base Cost (100MW)	MW Multiplier	Adjustments	Total	
		3.124			
Penthouse	365	1140.26	-775.26	$798.2	Abatement completed internally. Wall area remains.
External Furnace	750	2343	-1593	$2,225.9	Misc. furnace wall areas abated.
Piping, External - Operating Floor up	250	781	-531	$742.0	Partial abatement on high energy piping completed.
Pipe and Equipment, below Operating floor	150	468.6	-318.6	$445.2	Partial abatement on high energy piping completed.
Ductwork, Equipment, Operating floor up	300	937.2	-637.2	$937.2	
Ductwork, under Operating floor	200	624.8	-424.8	$624.8	
Survey, Air Testing, Permits, etc.	100	312.4	-212.4	$312.4	
Contingency	400	1249.6	-849.6	$1,249.6	
Coal Handling	0	0	0	$100.0	
Total:	$ 2,515.0	$ 7,856.9	$ (5,341.9)	$7,435.2	

Assumption: multiplier factor of 15% per 25MW of reduced unit capacity below 100 MW

Tyrone Unit 1 - 30 MW

	Base Cost	MW Multiplier	Adjustments	Total
		0.58		
Penthouse	365	211.7	153.3	211.7
External Furnace	750	435	315	435.0
Piping, External - Operating Floor up	250	145	105	145.0
Pipe and Equipment, below Operating floor	150	87	63	87.0
Ductwork, Equipment, Operating floor up	300	174	126	174.0
Ductwork, under Operating floor	200	116	84	116.0
Survey, Air Testing, Permits, etc.	100	58	42	58.0
Contingency	400	232	168	232.0
Coal Handling	0	0	0	0.0
Total:	$ 2,515.0	$ 1,458.7	$ 1,056.3	1458.7

Tyrone Unit 2 - 30 MW

	Base Cost	MW Multiplier	Adjustments	Total
		0.58		
Penthouse	365	211.7	153.3	211.7
External Furnace	750	435	315	435.0
Piping, External - Operating Floor up	250	145	105	145.0
Pipe and Equipment, below Operating floor	150	87	63	87.0
Ductwork, Equipment, Operating floor up	300	174	126	174.0
Ductwork, under Operating floor	200	116	84	116.0
Survey, Air Testing, Permits, etc.	100	58	42	58.0
Contingency	400	232	168	232.0
Coal Handling	0	0	0	0.0
Total:	$ 2,515.0	$ 1,458.7	$ 1,056.3	1458.7

Tyrone Unit 3 - 75 MW

	Base Cost (100MW)	MW Multiplier	Adjustments	Total	
		0.85			
Penthouse	365	310.25	54.75	279.2	Boiler #5 penthouse internals abated.
External Furnace	750	637.5	112.5	637.5	
Piping, External - Operating Floor up	250	212.5	37.5	212.5	
Pipe and Equipment, below Operating floor	150	127.5	22.5	127.5	
Ductwork, Equipment, Operating floor up	300	255	45	255.0	
Ductwork, under Operating floor	200	170	30	170.0	
Survey, Air Testing, Permits, etc.	100	85	15	85.0	
Contingency	400	340	60	340.0	
Coal Handling	0	0	0	0.0	
Total:	$ 2,515.0	$ 2,137.8	$ 377.3	2106.7	

Assumption: multiplier factor of 15% per 25MW of reduced unit capacity below 100 MW

Pineville Unit 1 - 38 MW

35

	Base Cost	MW Multiplier	Adjustments	Total
		0.61		
Penthouse	365	222.65	142.35	222.7
External Furnace	750	457.5	292.5	457.5
Piping, External - Operating Floor up	250	152.5	97.5	152.5
Pipe and Equipment, below Operating floor	150	91.5	58.5	91.5
Ductwork, Equipment, Operating floor up	300	183	117	183.0
Ductwork, under Operating floor	200	122	78	122.0
Survey, Air Testing, Permits, etc.	100	61	39	61.0
Contingency	400	244	156	244.0
Coal Handling	0	0	0	0.0
Total:	$ 2,515.0	$ 1,534.2	$ 980.9	1534.2

Dix Dam

Lead Paint Abatement	**$/Each**	**Quantity**	**Total**	
Turbine Shut Off Valve(s)	$25,000	2	$50,000	
Machines	$50,000	3	$150,000	
Wicket Gates	$17,000	3	$51,000	
Oil Pumps	$10,000	2	$20,000	
Tanks	$7,500	3	$22,500	
Bldg Window Frames	$300,000	1 Lot	$300,000	
Hand Rails	$35,000	1 Lot	$35,000	
				$628,500
Asbestos Abatement				
Windings	$80,000	3	$240,000	
Duck Work	$25,000	1 Lot	$25,000	
Ceiling Tiles	$50,000	1 Lot	$50,000	
Wickette Gate Packing	$10,000	3	$30,000	
				$345,000
Batteries	40	20	$800	
				$800
			$974,300	

Ref. - Dave Beck 11/9/05

Comments
One Valve Completed in 10/2005
Main and Generator Floors

Leenerts, Patricia

From: Charnas, Shannon
Sent: Wednesday, November 09, 2005 1:08 PM
To: Riggs, Eric
Cc: Wiseman, Sara; Leenerts, Patricia; Kinder, Debra
Subject: RE: KU LGE Tires.xls

Eric-

Thanks for the analysis. I do think this would be a bigger pain to track that is worth the effort. I would like to know if we have any other items that alone may be immaterial, but we have included in our FIN 47 numbers. If so, this could cause a problem with consistency, so we may need to reevaluate.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Riggs, Eric
Sent: Wednesday, November 09, 2005 10:53 AM
To: Charnas, Shannon
Cc: Wiseman, Sara; Leenerts, Patricia; Kinder, Debra
Subject: FW: KU LGE Tires.xls

Shannon,

Attached is a file calculating the disposal costs of tires at LG&E and KU. This information was put together with the assistance of Steve Ramser in the Transportation Department. The total cost per utility is approximately $17 thousand. We believe that this amount is not material and therefore we would not set up an ARO. Do you agree?

<< File: KU LGE Tires.xls >>

Thanks,
Eric

From: Ramser, Steve
Sent: Tuesday, November 08, 2005 8:25 AM
To: Riggs, Eric
Cc: Wiseman, Sara; Kinder, Debra; Leenerts, Patricia; Doggett, William
Subject: RE: KU LGE Tires.xls

Eric,

Looks perfect.

Steve Ramser
LG&E/KU Transportation
502-627-3827

From: Riggs, Eric
Sent: Monday, November 07, 2005 4:45 PM
To: Ramser, Steve
Cc: Wiseman, Sara; Kinder, Debra; Leenerts, Patricia
Subject: KU LGE Tires.xls

<< File: KU LGE Tires.xls >>

Steve,

Please check my logic using your two emails regarding tires. Does the total disposal cost look reasonable to you? Together we are looking at $33K for disposal costs for tires.

Thanks,
Eric

Leenerts, Patricia

From: Carr, Sam
Sent: Wednesday, November 09, 2005 2:48 PM
To: Leenerts, Patricia
Cc: Miller, Jon
Subject: RE: FIN 47 Request - Batteries

Attachments: Fin 47 - EWB - TYR - 11-09-05.xls

Fin 47 - EWB - TYR - 11-09-05....

Pat,

Revised FIN 47 info is attached per your request. Included on the revised spreadsheet is the information for Pineville batteries and Dix batteries and asbestos.

If you have questions, please advise.

Thanks,
Sam Carr
Manager Commercial Operations
E.W. Brown Station
859-748-4424 office
859-265-0583 cell
sam.carr@lgeenergy.com

Asset Retirement Obligations			($000's)					
Asset Description	Location	Legal Requirement	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremental Cost of Disposal ($'s)	Estimated Retirement	Comments	Support
Location	BROWN							
Ash Pond	BR ST	Resource Conservation and Recovery Act		$10,440			Not unit specific - Steam units only 1,2,3	$90k/acre per 2002 FMSM estimate of $83k/acre for 116 acres inflated 3% per year. Closure requires 2 ft. cover soil, monitoring wells, and permitting pond as a landfill per FMSM. Acreage verified by Paul Puckett-Environmental Dept.
Asbestos Abatement - BR1	BR1			$2,056			BR1 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of 15% per each 25 MW increase above 100 MW. Adjustments made for abatement completed on BR1 penthouse and external furnace.
Asbestos Abatement - BR2	BR2			$3,296			BR2 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of 15% per each 25 MW increase above 100 MW. Adjustments made for abatement completed on BR2 penthouse, external furnace, and high energy piping.
Asbestos Abatement - BR3	BR3			$7,435			BR3 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, coal handling equipment, office areas, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of 15% per each 25 MW increase above 100 MW. Adjustments made for abatement completed on BR3 penthouse, external furnace, and high energy piping.
Radiation Sources - BR3	BR3	The Cabinet for Human Resources KRS 211.844, regulation 902 KAR Chapter 100		$16			Sources located with the following 10 assets w/UOP 5676: 3-1,3-2,3-3,3-4,&3-5 Feeders Upper & Lower. Also, the assets with UOP 5025: Hoppers A26,A22,A25,A21,A24,A20,A23,A19,B26,B22,B25,B21,B24,B20,B23,B19	Radiation Sources at $870 per 18 sources. Cost based on conversations with vendors (Secoal, contract supplier of radiation sources, 12/02) and physical counts. **Supported by OHMART email**
GSU, transformer oil, lubricating oils, ehc fluid	BR ST	Clean Water Act Toxic Substances Control Act					Not unit specific - include BR 1, 2,3. Transformers only. This oil has no PCBs (non-hazardous). Should be able to sell for reuse. Tie to BR3	Supported by internal email from Shannon Charnas. American Enviro Services will take oil at no cost
GSU, transformer oil, lubricating oils, ehc fluid	BR CT	Clean Water Act Toxic Substances Control Act					Not unit specific - include BR 5, 6, 7, 8, 9, 10,11. Transformers only. This oil has no PCBs (non-hazardous). Should be able to sell for reuse. Tie to BR 7.	Supported by internal email from Shannon Charnas. American Enviro Services will take oil at no cost
Removal of Fuel Oil Tanks - BR Steam units 1, 2, 3	BR ST	Clean Water Act, Comprehensive Emergency Response and Liability Act		$141			Tanks are not unit specific - for BR 1, 2, 3 - flat fee paid to contractor for removal. ESTIMATE	**Supported by email from Somerset Environmental**
Removal of Fuel Oil Tanks - BR CTs	BR CT	Clean Water Act		$281			Tanks are not unit specific - include BR 5, 6, 7, 8, 9, 10, 11 - flat fee paid to contractor for removal. ESTIMATE	**Supported by email from Somerset Environmental**
Remediation of underground fuel oil piping - Steam	BR ST	Clean Water Act, Comprehensive Emergency Response and Liability Act		$17			Estimate - Not unit specific - include BR 1, 2,3.	**Supported by engineering estimate provided by Barry Currens**
Remediation of underground fuel oil piping - CTs	BR CT	Clean Water Act		$32			Not unit specific - include BR 5, 6, 7, 8, 9, 10,11.	**Supported by engineering estimate provided by Barry Currens**
Mercury Removal	BR ST/CT	Resource Conservation and Recovery Act					Due to immaterial costs of $305 no ARO is being established	Per Mike Winkler in Environmental $4.50/lb. **Supported by ENSCO quote.** 15 bs per Shannon Charnas email

Asset Retirement Obligations				($000's)				
Asset Description	Location	Legal Requirement	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremental Cost of Disposal ($'s)	Estimated Retirement	Comments	Support
Lab Chemical disposal	BR	Resource Conservation and Recovery Act		$18			BR1 - Lab Equipment UOP 5389.	**Supported by estimate from GE Betz Inc.**
Sewage Plant	BR	Clean Water Act		$10			Estimated cost to pump out tank, fill tank with soil, and grade land.	Based on Pineville estimate of $1k for 50 people, assumed $4k for 200 people and additional fee for equipment use. **Supported by BMR invoice**
Coal Yard covering	BR ST	Clean Water Act		$60			Not unit specific - Steam units 1, 2,3.	Based on Pineville estimate - $15k/acre for 4 acres **Acreage verified by Delbert Billiter-Fuels Dept.**
Coal pile retention pond closing	BR ST	Clean Water Act		$185			Estimate - Not unit specific - Steam units 1, 2,3.	**Supported by engineering estimate provided by Barry Currens**
Station Batteries - BR1	BR1	Toxic Substance Control Act	60	$2			BR1 - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Station Batteries - BR2	BR2	Toxic Substance Control Act	60	$2			BR2 - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Station Batteries - BR3	BR2	Toxic Substance Control Act	60	$2			BR3 - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Station Batteries - Dix	Dix	Toxic Substance Control Act	60	$2			Dix - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Batteries - West Cliff	BR ST	Toxic Substance Control Act	60	$2			BR ST - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Batteries - North Sub	BR ST	Toxic Substance Control Act	60	$2			BR ST - Batteries UOP 05049.	Estimate from Bob Webb - $40 per station battery for removal and disposal.
Computer Batteries - BR3	BR3	Toxic Substance Control Act	20	$0.48			BR 3 - Batteries UOP 05049.	Estimate from Bob Webb - $24 per computer battery for removal and disposal.
Computer Batteries - BR1	BR1	Toxic Substance Control Act	10	$0.24			BR1 - Batteries UOP 05049.	Estimate from Bob Webb - $24 per computer battery for removal and disposal.
Computer Batteries - Slurry Room	BR ST	Toxic Substance Control Act	20	$0.48			BR ST - Batteries UOP 05049.	Estimate from Bob Webb - $24 per computer battery for removal and disposal.
Location	**TYRONE**							
Ash Pond	TY	Resource Conservation and Recovery Act		$810			Not unit specific.	$90k/acre per 2002 FMSM estimate of $83k/acre for 9 acres inflated 3% per year. Closure requires 2 ft. cover soil, monitoring wells, and permitting pond as a landfill per FMSM. Acreage verified by Paul Puckett-Environmental Dept.
Demolition Service Water Pump structures	TY	Corps of Engineers		$181			2 structures which have asbestos and lead paint issues - Not unit specific.	Flat fee for contractor removal. **Supported by estimate from Evans Construction Co.**
GSU, transformer oil, lubricating oils, ehc fluid	TY	Clean Water Act Toxic Substances Control Act		$0			Not unit specific - Tie to transformer on TY3. This oil has no PCBs (non-hazardous). Should be able to sell for reuse.	8 oil-field transformers at $5,000. Based upon estimate from Somerset Environmental (contractor) received on 12/23/02.

Asset Retirement Obligations				($000's)				
Asset Description	Location	Legal Requirement	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremental Cost of Disposal ($'s)	Estimated Retirement	Comments	Support
Removal of Fuel Oil Tanks	TY	Clean Water Act, Comprehensive Emergency Response and Liability Act		$101			One underground and one above ground - Not unit specific.	Flat fee for contractor removal. Based upon estimate from Somerset Environmental (contractor) received on 12/23/02.
Remediation of underground fuel oil piping	TY	Clean Water Act, Comprehensive Emergency Response and Liability Act		$14			Not unit specific.	Engineering estimate provided by Barry Currens
Mercury Removal	TY	Resource Conservation and Recovery Act		$3			Not unit specific - allocable among units. UOP 5373 - Instrument or measuring device (instrumentation). Tie to TY3	**Supported by ENSCO quote provided by Mike Winkler**
Sewage Plant	TY	Clean Water Act		$5			Estimated cost to pump out tank, fill tank with soil, and grade land.	Based on Pineville estimate of $1k for 50 people and additional fee for equipment use. **Supported by PMR invoice**
Coal Yard covering	TY	Clean Water Act		$30			Assuming that we would be required to close similar to the ash pond - Not unit specific	2 acres at $15k per acre Pineville estimate **Acreage verified by Delbert Billiter-Fuels Dept.**
Batteries	TY	Toxic Substance Control Act	60	2.7			TY ST - Batteries UOP 05049.	Estimate from Barry Currens - $45 per station battery for removal and disposal.
Batteries	Haefling	Toxic Substance Control Act	60	2.7			Haefling - Batteries UOP 05049.	Estimate from Barry Currens - $45 per station battery for removal and disposal.
Asbestos Abatement - TY1	TY1			$1,459			TY1 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of (15%) per 25 MW reduced unit capacity below 100 MW.
Asbestos Abatement - TY2	TY2			$1,459			TY2 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of (15%) per 25 MW reduced unit capacity below 100 MW.
Asbestos Abatement - TY3	TY3			$2,107			TY3 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of (15%) per 25 MW reduced unit capacity below 100 MW. Adjustment for boiler #5 penthouse internal abatement completed.
Location	**PINEVILLE**							
Asbestos Abatement - Pineville Station	Pineville			$1,534			Pineville Unit 1 penthouse, external furnace, high energy piping, misc. piping and equipment, ductwork, testing, air monitoring, permits, and contingency.	Cost estimate provided by NEC for 100 MW unit. Assumed multiplier of (15%) per 25 MW reduced unit capacity below 100 MW.
Station Batteries - Pineville Station	Pineville	Toxic Substance Control Act	30	$1			Pineville - Batteries UOP 05049.	$45 per station battery for removal and disposal.
Location	**DIX**							
Asbestos Abatement	Dix			$345			3 Windings, ductwork lot, ceiling tiles lot, and 3 wickette gate packing.	Cost estimater and scope of work provided by Dave Beck 11/09/05.
Batteries	Dix	Toxic Substance Control Act	20	$0.8			Dix - Batteries UOP 05049.	Estimate from Dave Beck - $40per station battery for removal and disposal.
Lead Paint	Dix			$629			Turbine shutoff valves, machines, wickette gates, oil pumps, tanks, window frames, and hand rails.	Estimate from Dave Beck 11/09/05.

Assumption: multiplier factor of 15% per 25MW of increased unit capacity above 100 MW

Brown Unit 1 - 108 MW

108	Base Cost	MW Multiplier	Adjustments	Total	
		1.048			
Penthouse	365	382.52	-17.52	38.3	Abatement completed internally. Roof penetrations remain.
External Furnace	750	786	-36	550.2	Furnace walls abated above Main Floor to penthouse.
Piping, External - Operating Floor up	250	262	-12	262.0	
Pipe and Equipment, below Operating floor	150	157.2	-7.2	157.2	
Ductwork, Equipment, Operating floor up	300	314.4	-14.4	314.4	
Ductwork, under Operating floor	200	209.6	-9.6	209.6	
Survey, Air Testing, Permits, etc.	100	104.8	-4.8	104.8	
Contingency	400	419.2	-19.2	419.2	
Coal Handling	0	0	0	0.0	
Total:	$ 2,515.0	$ 2,635.7	$ (120.7)	2,055.7	

Brown Unit 2 - 178 MW

178	Base Cost	MW Multiplier	Adjustments	Total	
		1.468			
Penthouse	365	535.82	-170.82	267.9	Abatement completed internally. Roof area remains.
External Furnace	750	1101	-351	990.9	Misc. furnace wall areas abated (backpass).
Piping, External - Operating Floor up	250	367	-117	348.7	Partial abatement on high energy piping completed.
Pipe and Equipment, below Operating floor	150	220.2	-70.2	220.2	
Ductwork, Equipment, Operating floor up	300	440.4	-140.4	440.4	
Ductwork, under Operating floor	200	293.6	-93.6	293.6	
Survey, Air Testing, Permits, etc.	100	146.8	-46.8	146.8	
Contingency	400	587.2	-187.2	587.2	
Coal Handling	0	0	0	0.0	
Total:	$ 2,515.0	$ 3,692.0	$ (1,177.0)	3,295.7	

Brown Unit 3 - 454 MW

454	Base Cost (100MW)	MW Multiplier	Adjustments	Total	
		3.124			
Penthouse	365	1140.26	-775.26	$798.2	Abatement completed internally. Wall area remains.
External Furnace	750	2343	-1593	$2,225.9	Misc. furnace wall areas abated.
Piping, External - Operating Floor up	250	781	-531	$742.0	Partial abatement on high energy piping completed.
Pipe and Equipment, below Operating floor	150	468.6	-318.6	$445.2	Partial abatement on high energy piping completed.
Ductwork, Equipment, Operating floor up	300	937.2	-637.2	$937.2	
Ductwork, under Operating floor	200	624.8	-424.8	$624.8	
Survey, Air Testing, Permits, etc	100	312.4	-212.4	$312.4	
Contingency	400	1249.6	-849.6	$1,249.6	
Coal Handling	0	0	0	$100.0	
Total:	$ 2,515.0	$ 7,856.9	$ (5,341.9)	$7,435.2	

Assumption: multiplier factor of 15% per 25MW of reduced unit capacity below 100 MW

Tyrone Unit 1 - 30 MW

	Base Cost	MW Multiplier	Adjustments	Total
		0.58		
Penthouse	365	211.7	153.3	211.7
External Furnace	750	435	315	435.0
Piping, External - Operating Floor up	250	145	105	145.0
Pipe and Equipment, below Operating floor	150	87	63	87.0
Ductwork, Equipment, Operating floor up	300	174	126	174.0
Ductwork, under Operating floor	200	116	84	116.0
Survey, Air Testing, Permits, etc.	100	58	42	58.0
Contingency	400	232	168	232.0
Coal Handling	0	0	0	0.0
Total:	$ 2,515.0	$ 1,458.7	$ 1,056.3	1458.7

Tyrone Unit 2 - 30 MW

	Base Cost	MW Multiplier	Adjustments	Total
		0.58		
Penthouse	365	211.7	153.3	211.7
External Furnace	750	435	315	435.0
Piping, External - Operating Floor up	250	145	105	145.0
Pipe and Equipment, below Operating floor	150	87	63	87.0
Ductwork, Equipment, Operating floor up	300	174	126	174.0
Ductwork, under Operating floor	200	116	84	116.0
Survey, Air Testing, Permits, etc.	100	58	42	58.0
Contingency	400	232	168	232.0
Coal Handling	0	0	0	0.0
Total:	$ 2,515.0	$ 1,458.7	$ 1,056.3	1458.7

Tyrone Unit 3 - 75 MW

	Base Cost (100MW)	MW Multiplier	Adjustments	Total	
		0.85			
Penthouse	365	310.25	54.75	279.2	Boiler #5 penthouse internals abated.
External Furnace	750	637.5	112.5	637.5	
Piping, External - Operating Floor up	250	212.5	37.5	212.5	
Pipe and Equipment, below Operating floor	150	127.5	22.5	127.5	
Ductwork, Equipment, Operating floor up	300	255	45	255.0	
Ductwork, under Operating floor	200	170	30	170.0	
Survey, Air Testing, Permits, etc.	100	85	15	85.0	
Contingency	400	340	60	340.0	
Coal Handling	0	0	0	0.0	
Total:	$ 2,515.0	$ 2,137.8	$ 377.3	2106.7	

Assumption: multiplier factor of 15% per 25MW of reduced unit capacity below 100 MW

Pineville Unit 1 - 38 MW

35	Base Cost	MW Multiplier	Adjustments	Total
		0.61		
Penthouse	365	222.65	142.35	222.7
External Furnace	750	457.5	292.5	457.5
Piping, External - Operating Floor up	250	152.5	97.5	152.5
Pipe and Equipment, below Operating floor	150	91.5	58.5	91.5
Ductwork, Equipment, Operating floor up	300	183	117	183.0
Ductwork, under Operating floor	200	122	78	122.0
Survey, Air Testing, Permits, etc.	100	61	39	61.0
Contingency	400	244	156	244.0
Coal Handling	0	0	0	0.0
Total:	$ 2,515.0	$ 1,534.2	$ 980.9	1534.2

Dix Dam

Lead Paint Abatement	**$/Each**	**Quantity**	**Total**	
Turbine Shut Off Valve(s)	$25,000	2	$50,000	
Machines	$50,000	3	$150,000	
Wicket Gates	$17,000	3	$51,000	
Oil Pumps	$10,000	2	$20,000	
Tanks	$7,500	3	$22,500	
Bldg Window Frames	$300,000	1 Lot	$300,000	
Hand Rails	$35,000	1 Lot	$35,000	
				$628,500
Asbestos Abatement				
Windings	$80,000	3	$240,000	
Duck Work	$25,000	1 Lot	$25,000	
Ceiling Tiles	$50,000	1 Lot	$50,000	
Wickette Gate Packing	$10,000	3	$30,000	
				$345,000
Batteries	40	20	$800	
				$800
			$974,300	

Ref. - Dave Beck 11/9/05

Comments

One Valve Completed in 10/2005
Main and Generator Floors

Leenerts, Patricia

From: Leenerts, Patricia
Sent: Wednesday, November 09, 2005 6:31 PM
To: Wiseman, Sara
Cc: Kinder, Debra; Riggs, Eric
Subject: Adjustment to FIN 47 values on Calc Templates

Importance: High

Attachments: FIN-47_abatement-GR.xls; FIN-47 Abatement Methodolgy - GR.doc; Fin 47 - GR.xls

I have found that several of the supporting docs are using the 2 columns, Removal Cost per Asset and Incremental Cost of Disposal. Per Bryan's email below, see the xxxxxx below, the 2 costs should be added together. So the ARO current costs we have in our calc templates need to be updated to include the Incremental Cost of Disposal column. Do you want me to continue preparing for the Friday PWC meeting with the current data and revise it after the meeting? Or do I need to try to get it done tomorrow? I would not be able to get started having the copies made until the reprint of the calc templates is complete.

Let me know

Pat
(The FireStarter)

From: Leenerts, Patricia
Sent: Wednesday, November 09, 2005 4:33 PM
To: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FW: FIN 47 Request - Batteries AND ADDITIONAL QUESTION

Bryan's total of Battery disposal adds $13000 to my previous KU number of $2800. Still immaterial.

I had to raise the current cost of disposal of each GR unit by $75000. The FIN 47 - GR file attached has 2 numbers that need to be added together. Bryan/Russell had cost of removal and cost of disposal which must be added together to get the number we need for FIN 47.

Do you think that happened on any other file?

Pat

From: Baker, Bryan
Sent: Wednesday, November 09, 2005 11:50 AM
To: Leenerts, Patricia
Subject: RE: FIN 47 Request - Batteries

Sorry, I'm kinda swamped here.

These are the final sheets you should be working off of. Two are from what Russell sent to you, and one is our total plant spreadsheet.

FIN-47_abatement-GR.xls FIN-47 Abatement Methodolgy - ... Fin 47 - GR.xls

Question #1 on the batteries, the TOTAL COST OF RETIREMENT should be $13,000 for all batteries. We read "Removal Cost per Asset" as just that, the cost to remove the asset (ie, all the batteries). The "Incremental Cost of Disposal" would be the cost to dispose of the asset, ie disposing of the batteries that we removed. So, $13,000.

On the Unit #2, the $1,625,000 # is correct. I had a fat finger on that one, good catch. As for the disposal cost, add it to the removal cost.

From: Leenerts, Patricia
Sent: Wednesday, November 09, 2005 10:29 AM
To: Baker, Bryan
Subject: FW: FIN 47 Request - Batteries

Do you have a chance to answer my questions below? Try to get to it today if you could. I need time tomorrow to finalize for an 8 am meeting on Friday with the auditors.

Thanks

From: Leenerts, Patricia
Sent: Tuesday, November 08, 2005 3:49 PM
To: Baker, Bryan
Cc: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FW: FIN 47 Request - Batteries

This is what I'm looking for, thanks. I do have a few questions. According to the attached my calculation would be: 120 units times $8000 + 50 units times $2000 = $960000 + 100000 = $1,060,000 to be the removal costs for the batteries? Should I be using the incremental cost of disposal column too **or instead of?**

Your spreadsheet is similar to a document that was received from Russell Baker on Oct 17, 2005, regarding Green River. I reviewed the GR1-GR4 Asbestos Abatement removal cost numbers that Russell provided and the unit 2 does not match. I will send you the email that Russell sent. ***Please review both documents and let me know which asbestos numbers are correct.*** Again, I have the same question as above: Should I be using the incremental cost of disposal column too **or instead of?**

Thanks for your help

Pat
Ext 3811

From: Baker, Bryan
Sent: Tuesday, November 08, 2005 2:03 PM
To: Leenerts, Patricia
Subject: RE: FIN 47 Request - Batteries

Rows 8 & 9? Or are you looking for something else?

<< File: Fin 47 - GR.xls >>

From: Leenerts, Patricia
Sent: Tuesday, November 08, 2005 9:44 AM
To: Baker, Bryan
Cc: Wiseman, Sara; Kinder, Debra; Riggs, Eric; Miller, Jon
Subject: RE: FIN 47 Request - Batteries

Hey Bryan. Thanks for straightening me out.
I am missing the dollar value estimate for battery disposal, according to FIN 47.

Pat
Ext 3811

From: Baker, Bryan
Sent: Tuesday, November 08, 2005 10:22 AM
To: Leenerts, Patricia
Subject: RE: FIN 47 Request - Batteries

Patricia,

Hello, this is Bryan Baker. I am the contact for Green River in relation to FIN 47 questions/concerns. Russell and I are both supervisors, with "Baker" as our last name, so we get mixed up a lot!

As for the battery disposal estimate. Are you looking for more information than is present in the FIN 47?

From: Baker, Russell
Sent: Monday, November 07, 2005 10:49 AM
To: Baker, Bryan
Subject: FW: FIN 47 Request - Batteries

I think this was probably suppose to go to you.

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 9:42 AM
To: Baker, Russell
Subject: FIN 47 Request - Batteries

Russell, I am a new employee with LGE and will (eventually) be the point person for the FIN 47 project. I show you as the contact for the Green River location. Do you have the disposal estimate, according to FIN 47, for Batteries at Green River?

Pat
Ext 3811

Green River Unit 1 - 30 MW

	Base Cost	Adjustments	Total	
Penthouse	45	5	50	
External Furnace	225	100	325	Block between refrac and metal casing
Piping, External - Operating Floor up	75	25	100	High energy piping, extractions, downcomers, etc.
Pipe and Equipment, below Operating floor	45	155	200	FW Heaters, condenser, turbine, mills, high energy piping
Ductwork, Equipment, Operating floor up	90	60	150	
Ductwork, under Operating floor	60	40	100	
Survey, Air Testing, Permits, etc.	100	0	100	Surveying, testing, permits virtually the same for all units
Contingency	400	0	400	
Coal Handling	0	150	150	Coal Handling - Transite siding, wiring, insulation
Building	200	0	200	Coal Handling - Transite siding, wiring, insulation
Total:	$ 1,240	$ 535	$ 1,775	

Green River Unit 2 - 30 MW

	Base Cost	Adjustments	Total	
Penthouse	45	5	50	
External Furnace	225	100	325	Block between refrac and metal casing
Piping, External - Operating Floor up	75	25	100	High energy piping, extractions, downcomers, etc.
Pipe and Equipment, below Operating floor	45	155	200	FW Heaters, condenser, turbine, mills, high energy piping
Ductwork, Equipment, Operating floor up	90	60	150	
Ductwork, under Operating floor	60	40	100	
Survey, Air Testing, Permits, etc.	100	0	100	Surveying, testing, permits virtually the same for all units
Contingency	400	0	400	
Building	200	0	200	Transite siding removal
Total:	$ 1,240	$ 385	$ 1,625	

Green River Unit 3 - 60 MW

	Base Cost	Adjustments	Total	
Penthouse	0	0	0	Penthouse abated
External Furnace	100	0	100	Most of Furnace abated
Piping, External - Operating Floor up	150	25	175	FW heaters, high energy piping
Pipe and Equipment, below Operating floor	175	150	325	FW Heaters, condenser, turbine, mills, high energy piping
Ductwork, Equipment, Operating floor up	180	0	180	
Ductwork, under Operating floor	120	30	150	
Survey, Air Testing, Permits, etc.	100	0	100	Surveying, testing, permits virtually the same for all units
Contingency	240	160	400	Greater awarenes of locations of ACM on operating units
Building	350	0	350	Transite siding removal
Total:	$ 1,415	$ 365	$ 1,780	

Green River Unit 4 - 100 MW

	Base Cost	Adjustments	Total	
Penthouse	0	0	0	Penthouse abated
External Furnace	0	0	0	Furnace abated
Piping, External - Operating Floor up	250	50	300	
Pipe and Equipment, below Operating floor	300	100	400	Add gas recirculating fan, FW heaters, mills, high energy piping
Ductwork, Equipment, Operating floor up	300	0	300	DA tank & heater, I.D. fans, etc.
Ductwork, under Operating floor	200	0	200	Air duct, PA duct
Survey, Air Testing, Permits, etc.	100	0	100	Surveying, testing, permits virtually the same for all units
Contingency	400	0	400	Greater awarenes of locations of ACM on operating units
Building	400	0	400	Transite siding removal
Total:	$ 1,950	$ 150	$ 2,100	

FIN-47 ASBESTOS REMOVAL ESTIMATE METHODOLOGY

NEC provided an asbestos abatement estimate to remove all asbestos containing material from a typical 100MW coal fired unit. This estimate was based on their familiarization of similar sized units such as BR1.

I have detailed below how I arrived at the FIN-47 removal numbers for Green River. Using NEC's estimate as a base, I adjusted the sub-totals to match specific Green River unit size, equipment configuration, and known asbestos location.

Green River Unit 1 – 30 MW

- **Penthouse – $50k** - Full enclosure of penthouse. All headers, walls, floor, drum all require abatement.
- **External Furnace - $325k** — Removal of asbestos block from boiler wall. Block located between tube refractory and outer metal casing.
- **Piping, External - Operating Floor up – $100k** - High energy, heater extraction, downcomers, etc.
- **Pipe and Equipment, below Operating floor - $200k** – Adder of $100k to cover all FW heaters, turbine, mills, condenser, heater extraction pipe, etc.
- **Ductwork, Equipment, Operating floor up - $150k** – Air heater, side headers, Air/Gas ductwork, windbox, ash hoppers, deaerator heater and storage tank, fans.
- **Ductwork, under Operating floor - $100k** – Air Duct, PA Duct.
- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $400k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces, refractory, additional contingency for difficulty of removing boiler furnace block insulation.
- **Coal Handling - $150k** – Transite siding removal $60k, scaffolding to access siding, $90k.
- **Building – $200k** – Transite siding removal

Green River Unit 2 – 30 MW

- **Penthouse – $50k** - Full enclosure of penthouse. All headers, walls, floor, drum all require abatement.
- **External Furnace - $325k** — Removal of asbestos block from boiler wall. Block located between tube refractory and outer metal casing.
- **Piping, External - Operating Floor up – $100k** - High energy, heater extraction, downcomers, etc.
- **Pipe and Equipment, below Operating floor - $200k** – Adder of $100k to cover all FW heaters, turbine, mills, condenser, heater extraction pipe, etc.
- **Ductwork, Equipment, Operating floor up - $150k** – Air Heater, side headers, Air/Gas ductwork, windbox, ash hoppers, deaerator heater and storage tank, fans.
- **Ductwork, under Operating floor - $100k** – Air Duct, PA Duct.
- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $400k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces, refractory, additional contingency for difficulty of removing boiler furnace block insulation.
- **Building – $200k** – Transite siding removal

Green River Unit 3 – 60 MW

- **External Furnace - $100k** — Removal of asbestos block from boiler wall.
- **Piping, External - Operating Floor up – $175k** - High energy, sootblower, heater extraction, downcomers, etc.
- **Pipe and Equipment, below Operating floor - $325k** – Adder of $150k to cover all FW heaters, turbine, mills, heater extraction pipe, condenser, etc.
- **Ductwork, Equipment, Operating floor up - $180k** –Air/Gas ductwork, windbox, fans, precipitator.
- **Ductwork, under Operating floor - $150k** – Air Duct, PA Duct.
- **Survey, Air Testing, Permits, etc. - $100k**

- **Contingency - $400k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces, refractory.
- **Building – $350k** – Transite siding removal

Green River Unit 4 – 100 MW

- **Piping, External - Operating Floor up – $300k** – High Energy piping, Sootblower, heater extraction, downcomers, other.
- **Pipe and Equipment, below Operating floor - $400k** – Adder of $100k to cover Gas Recirculating Fan, Condenser. FW heaters, mills, high energy piping.
- **Ductwork, Equipment, Operating floor up - $300k** – deaerator storage tank. Deaerator heater, I.D. fans, Air Heater, Air/Gas Ductwork.
- **Ductwork, under Operating floor - $200k** – Air Duct, PA Duct.
- **Survey, Air Testing, Permits, etc. - $100k**
- **Contingency - $400k** – Wiring, Bunker room piping, Turbine/Boiler room roofs, boiler dead air spaces, refractory.
- **Building – $400k** – Transite siding removal

Location
Asset Retirement Obligations

Asset Description	Location	Quantity by year of Installation	Removal Cost per Asset ($'s)	Incremantal Cost of Disposal ($'s)	Estimated Retirement Date
#2 ash pond	GR Property	27 acres	$270,000	-	2014
#3 ash pond	GR Property	3 acres	$30,000	-	2014
SO2 Pond	GR Property	10 acres	$10,000	-	2014
Scrap metal	Outside Mech Maint Shop	50 ton	$0	$0	2014
Plant Batteries	Battery rooms in the basement	120	$8,000	$2,000	2014
Plant Batteries - Misc Dry Cell	Throughout the plant	50	$2,000	$1,000	2014
Lube oil in plant equipment	Throughout the plant	5,000 gal	$0	$3,000	2014
Oil in in-plant X-frmrs	Throughout the plant	25,000 gal	$0		2014
Acid	Demineralizer Building	6,000 gal	0**	$0	2014
Caustic	Demineralizer Building	5,000 gal	0**	$0	2014
Other lab chemicals	Lab/Demin	100 gals	0**	$0	2014
Water treatment Chemicals	Basement	1,000 gals	0**	$0	2014
Dry chemicals	Basement	2,000 lbs	0**	$0	2014
Paint	Whse/Paint locker	50 gal at any one time	$1,000	$1,000	2014
Fuel oil for burners	New fuel oil tanks	50,000 gal	0*		2014
Fuel oil for mobile equipment	Fuel Depot	2,000 gal	0*		2014
Gasoline for mobile equipment	Fuel Depot	300 gal	0*		2014
GR1 Asbestos Abatement	Green River Unit 1 Plant		$1,775,000	$75,000	2014
GR2 Asbestos Abatement	Green River Unit 2 Plant		$1,625,000	$75,000	2014
GR3 Asbestos Abatement	Green River Unit 3 Plant		$1,780,000	$75,000	2014
GR4 Asbestos Abatement	Green River Unit 4 Plant		$2,100,000	$75,000	2014
			$7,601,000	$307,000	

0* = Estimated 0 cost for removal of asset that can be used at another plant or recycled at no cost
0** = Estimated removal 0 cost. Asset can be diluted and sent to waste stream off of the property

Leenerts, Patricia

From:	Leenerts, Patricia
Sent:	Wednesday, November 09, 2005 6:39 PM
To:	Wiseman, Sara
Cc:	Kinder, Debra; Riggs, Eric
Subject:	Financial Statement Disclosure for acknowledged ARO liability's that are not set up on books

The above subject may not be new to y'all, but I had not realized that this was needed. I found the information in the KPMG Defining Issues found in the FIN 47 binder.

Is this something that Henning may need to be aware and isn't?

Pat

Leenerts, Patricia

From: Leenerts, Patricia
Sent: Thursday, November 10, 2005 10:21 AM
To: Grant, Jerry
Cc: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: Fin 47 issue - Lead Paint & Lead Pipes

Jerry, it was nice speaking with you this morning. I am new in the Property Accounting Department and have been assigned FIN 47 responsibilities. As I mentioned to you on the phone when responding to some questions on Dix Dam, Sam Carr provided estimates for disposal of lead paint.

This raised questions that we hoped that you could answer. You already told me that lead paint does need to be handled similar to asbestos. Is the lead attached to the same thing that the asbestos is attached too, so that a single process handles both hazards? If so, would we really need to identify additional costs for lead abatement separately or is it already included? You mentioned that if the lead paint had been painted over that the environmental hazard might be different. Could you please follow-up on that question if the asbestos angle doesn't cover all the costs?

You mentioned a study from 7th & Ormsby. If you could easily let me know what the lead abatement costs and the unit of measure, I would appreciate it. If this is not an easy request, don't worry about it for now.

What about potential liability regarding lead pipes? Do we have them, is disposal different than regular pipes, etc?

Please let me know if you can think of any other environmental or legal issues that we need to set up an ARO liability.

Thanks

Pat
X 3811

Leenerts, Patricia

From: Leenerts, Patricia
Sent: Thursday, November 10, 2005 1:52 PM
To: Grant, Jerry
Cc: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: Lead Paint

Jerry,

Sara spoke with Steve Legler and determined that lead paint was not an ARO item. It is not considered an asset on our books, as asbestos is. The liability is dependent on the method of demolition. Since we are not planning on demolition, to guestimate the method of demolition would be pointless. We will not be setting up an ARO liability for lead paint.

I appreciate your helpfulness.

Pat
X 3811

Leenerts, Patricia

From: Carr, Sam
Sent: Thursday, November 10, 2005 7:30 AM
To: Leenerts, Patricia
Subject: RE: FIN 47 Request - Batteries

That is the full extended cost for all batteries being removed per facility.

Sam

From: Leenerts, Patricia
Sent: Wednesday, November 09, 2005 4:50 PM
To: Carr, Sam
Cc: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FW: FIN 47 Request - Batteries

Sam,

I do have a question. Your spreadsheet tab "Fin 47 Brown CT Tyr" has a column headed Removal Cost by Asset. The Dix-Batteries shows $800 and the Pineville-Batteries shows $1000. I want to verify that these are the full extended costs and are not by Asset as the column heading suggests.

Let me know. Thanks for your response and help.

Pat
X 3811

From: Carr, Sam
Sent: Wednesday, November 09, 2005 2:48 PM
To: Leenerts, Patricia
Cc: Miller, Jon
Subject: RE: FIN 47 Request - Batteries

<< File: Fin 47 - EWB - TYR - 11-09-05.xls >>

Pat,

Revised FIN 47 info is attached per your request. Included on the revised spreadsheet is the information for Pineville batteries and Dix batteries and asbestos.

If you have questions, please advise.

Thanks,
Sam Carr
Manager Commercial Operations
E.W. Brown Station
859-748-4424 office
859-265-0583 cell
sam.carr@lgeenergy.com

Leenerts, Patricia

From: Legler, Steve
Sent: Thursday, November 10, 2005 11:10 AM
To: Leenerts, Patricia
Subject: RE: FIN 47 Request - Batteries

Hi Pat,

There are no remaining batteries (that we can find) at the Canal site. At Waterside, there are a few batteries that are associated with the buildings backup generator. Estimated costs of removal is $1,000 with disposal costs of $500.

Let me know if this information is sufficient.

Steve

From: Leenerts, Patricia
Sent: Monday, November 07, 2005 10:41 AM
To: Legler, Steve
Cc: Kinder, Debra; Wiseman, Sara; Riggs, Eric
Subject: FIN 47 Request - Batteries

Steve, I am a new employee with LGE and will (eventually) be the point person for the FIN 47 project. I show you as the contact for the Waterside and Canal locations. Do you have the disposal estimate, according to FIN 47, for Batteries at Waterside and Batteries at Canal?

Thanks

Pat
Ext 3811

Leenerts, Patricia

From: Charnas, Shannon
Sent: Thursday, November 10, 2005 8:56 PM
To: Leenerts, Patricia
Cc: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: RE: Batteries immaterial FIN 47 item

Sorry for the delayed response. I did talk briefly with Sara around 5:00 tonight. I am fine with taking out the batteries and the tires. We'll have to wait and see what comes about with the manholes.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Leenerts, Patricia
Sent: Wednesday, November 09, 2005 1:36 PM
To: Charnas, Shannon
Cc: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: Batteries immaterial FIN 47 item

Shannon,

The only other item that should be considered immaterial is Batteries. The KU batteries are $2800 and the LGE batteries are $20000. We believe that these amounts are immaterial and difficult to track for their dollar value. Therefore we would not set up an ARO. Do you agree?

FYI: In compliance with Fin 43, AROs will be set up for Asbestos, Gas Well Plugging and Gas Main Abandonment. Eric is following up on the outstanding issue regarding manholes, which may be another asbestos issue.

Thanks,

Pat
X 3811

<< File: Combined Batteries.xls >>

From: Charnas, Shannon
Sent: Wednesday, November 09, 2005 1:08 PM
To: Riggs, Eric
Cc: Wiseman, Sara; Leenerts, Patricia; Kinder, Debra
Subject: RE: KU LGE Tires.xls

Eric-

Thanks for the analysis. I do think this would be a bigger pain to track that is worth the effort. I would like to know if we have any other items that alone may be immaterial, but we have included in our FIN 47 numbers. If so, this could cause a problem with consistency, so we may need to reevaluate.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: Riggs, Eric
Sent: Wednesday, November 09, 2005 10:53 AM
To: Charnas, Shannon
Cc: Wiseman, Sara; Leenerts, Patricia; Kinder, Debra
Subject: FW: KU LGE Tires.xls

Shannon,

Attached is a file calculating the disposal costs of tires at LG&E and KU. This information was put together with the assistance of Steve Ramser in the Transportation Department. The total cost per utility is approximately $17 thousand. We believe that this amount is not material and therefore we would not set up an ARO. Do you agree?

<< File: KU LGE Tires.xls >>

Thanks,
Eric

From: Ramser, Steve
Sent: Tuesday, November 08, 2005 8:25 AM
To: Riggs, Eric
Cc: Wiseman, Sara; Kinder, Debra; Leenerts, Patricia; Doggett, William
Subject: RE: KU LGE Tires.xls

Eric,

Looks perfect.

Steve Ramser
LG&E/KU Transportation
502-627-3827

From: Riggs, Eric
Sent: Monday, November 07, 2005 4:45 PM
To: Ramser, Steve
Cc: Wiseman, Sara; Kinder, Debra; Leenerts, Patricia
Subject: KU LGE Tires.xls

<< File: KU LGE Tires.xls >>

Steve,

Please check my logic using your two emails regarding tires. Does the total disposal cost look reasonable to you? Together we are looking at $33K for disposal costs for tires.

Thanks,
Eric

Leenerts, Patricia

From: Kinder, Debra
Sent: Monday, November 14, 2005 2:25 PM
To: Leenerts, Patricia
Subject: gas wells.xls

Attachments: gas wells.xls

gas wells.xls

Gas Facilities

Wells:

Name	Facility Number	Number of Wells	Estimated Current Plugging Costs	Underlying Asset Cost
Doe Run	714	145	2,835,000.00	1,965,395.00
Center	716	225	3,736,000.00	815,252.00
Magnolia	721	163	3,331,000.00	2,508,129.00
Muldraugh	723	60	967,000.00	902,811.00
Total Wells		**593**	**10,869,000.00**	**6,191,587.00**

Leenerts, Patricia

From:	Kinder, Debra
Sent:	Monday, November 14, 2005 2:25 PM
To:	Leenerts, Patricia
Subject:	Pluggingcostsfullfield.xls
Attachments:	Pluggingcostsfullfield.xls

Pluggingcostsfullfiel
d.xls

PLUGGING COSTS FOR FIELD ABANDONMENT

CASE	ITEM	CASING SIZE	COST
1	Well w/acid line and using retainer	4.5 or 5.5"	$27,060
2	Well w/acid line and using retainer	7"	$27,715
3	Well w/no acid line and using retainer	4.5 or 5.5"	$16,053
4	Well w/no acid line and using retainer	7"	$16,709
5	Well w/no acid line and not using retainer	all	$7,971

CASE	FIELD	NUMBER OF WELLS	COST	
1	Magnolia Deep	36	$974,160	
3	Magnolia Deep	14	$224,742	
4	Magnolia Deep	1	$16,709	
5	Magnolia Deep	21	$167,391	
	MAGNOLIA DEEP TOTAL		$1,383,002	
1	Magnolia Upper	17	$460,020	
2	Magnolia Upper	31	$859,165	
3	Magnolia Upper	17	$272,901	
4	Magnolia Upper	17	$284,053	
5	Magnolia Upper	9	$71,739	
	MAGNOLIA UPPER TOTAL		$1,947,878	
1	Center	95	$2,570,700	
2	Center			
3	Center	16	$256,848	
4	Center			
5	Center	114	$908,694	
	CENTER TOTAL		$3,736,242	
1	Muldraugh			
2	Muldraugh			
3	Muldraugh	27	$433,431	
4	Muldraugh	31	$517,979	
5	Muldraugh	2	$15,942	
	MULDRAUGH TOTAL		$967,352	
1	Doe Run	59	$1,596,540	
2	Doe Run	2	$55,430	
3	Doe Run	57	$915,021	
4	Doe Run	6	$100,254	
5	Doe Run	21	$167,391	
	DOE RUN TOTAL		$2,834,636	
	GRAND TOTAL		$7,132,868	$10,869,110

Note: Doe Run totals include Deep wells and assume all will need retainers and 1/2 have acid lines.

Leenerts, Patricia

From: Kinder, Debra
Sent: Monday, November 14, 2005 2:32 PM
To: Leenerts, Patricia
Subject: Asbestos Removal _ Distribution Subs.xls

Attachments: Asbestos Removal _ Distribution Subs.xls

Asbestos Removal
_ Distributio...

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove VCT (Floor Tile)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
Metal roof.	Ashby	$1.90	384	**$730**	$1.95	336	**$655**	$1.35	0	**$0**
	Bishop	$1.90	400	**$760**	$1.95	400	**$780**	$1.35	0	**$0**
Station built in 1994.	Bluegrass	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Brandenburg	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Brook	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Station built in 1996	Campground	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Carter	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Clarks Lane	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Crestwood	$1.90	384	**$730**	$1.95	400	**$780**	$1.35	0	**$0**
	Crop	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
New roof in 1994.	Dahlia	$1.90	468	**$889**	$1.95	400	**$780**	$1.35	0	**$0**
Metal roof.	Del Park	$1.90	384	**$730**	$1.95	400	**$780**	$1.35	0	**$0**
Metal roof.	Dixie	$1.90	384	**$730**	$1.95	400	**$780**	$1.35	0	**$0**
	Dumesnil	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Eighth Street	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Fairmount	$1.90	400	**$760**	$1.95	400	**$780**	$1.35	0	**$0**
	Falls City	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
New roof in 1995.	Floyd	$1.90	345	**$656**	$1.95	400	**$780**	$1.35	0	**$0**
Station built in 1993.	Ford	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Forty Fourth	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Freys Hill	$1.90	384	**$730**	$1.95	400	**$780**	$1.35	0	**$0**
	Gaulbert	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Gilligan	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Goss	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Station built in 1998.	Grade Lane	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Built up roof unknown date.	Grady	$1.90	672	**$1,277**	$1.95	672	**$1,310**	$1.35	672	**$907**
	Grand	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Hale	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove VCT (Floor Tile)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
Built up roof unknown date.	Harmony Landing	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	468	**$632**
	Herman	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Built up roof unknown date.	Highland	$1.90	1,000	**$1,900**	$1.95	1,000	**$1,950**	$1.35	1,000	**$1,350**
New roof 1993.	Hillcrest	$1.90	1,674	**$3,181**	$1.95	1,674	**$3,264**	$1.35	0	**$0**
New roof 1995.	Hurstbourne	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	0	**$0**
Station built in 1994.	International	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Jeffersontown	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
Metal roof.	Kenwood	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
Built up roof unknown date.	Knob Creek	$1.90	768	**$1,459**	$1.95	768	**$1,498**	$1.35	768	**$1,037**
Built up roof unknown date.	Locust	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	468	**$632**
	Logan	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Louisville Downs	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Lynn	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
New roof in 2000	Magazine	$1.90	3,638	**$6,912**	$1.95	3,638	**$7,094**	$1.35	0	**$0**
New roof 1998.	Manslick	$1.90	1,271	**$2,415**	$1.95	1,271	**$2,478**	$1.35	0	**$0**
	Muldraugh	$1.90	400	**$760**	$1.95	400	**$780**	$1.35	0	**$0**
Metal roof.	Nachand	$1.90	384	$730	$1.95	384	$749	$1.35	0	$0
Station built in 1989.	Okolona	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Ormsby	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Pirtle	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
New roof 1992	Plainview	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	0	**$0**
New roof 1999.	Pleasure Ridge	$1.90	468	**$889**	$1.95	468	**$913**	$1.35	0	**$0**
	Seventh Street	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Shawnee	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Shepherdsville	$1.90	294	**$559**	$1.95	294	**$573**	$1.35	0	**$0**
Metal roof.	Skylight	$1.90	156	**$296**	$1.95	156	**$304**	$1.35	0	**$0**
Metal roof.	Smyrna	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
	Solite	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove VCT (Floor Tile)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
Metal roof.	South Park	$1.90	315	**$599**	$1.95	315	**$614**	$1.35	0	**$0**
New roof 2001.	Southern	$1.90	5,002	**$9,504**	$1.95	5,002	**$9,754**	$1.35	0	**$0**
	Southern Baptist Seminary	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Stewart	$1.90	432	**$821**	$1.95	432	**$842**	$1.35		**$0**
	Trimble Cty Sw. Rm (12 kv)	$1.90	400	**$760**	$1.95	400	**$780**	$1.35	0	**$0**
Metal roof.	Terry	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
	Vermont	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Waterside (D)	$1.90	5,000	**$9,500**	$1.95	5,000	**$9,750**	$1.35	0	**$0**
	Westpoint	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
	Western	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	WHAS	$1.90	384	**$730**	$1.95	384	**$749**	$1.35	0	**$0**
Station built in 2001.	Worthington	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
Metal roof.	Zorn	$1.90	225	**$428**	$1.95	225	**$439**	$1.35	0	**$0**
LG&E TOTAL ($000's)				**$55**			**$57**	$1.35		**$5**
KU has 478 distribution Substations	KU Dist. Substations	$1.90	0	**$0**	$1.95	0	**$0**	$1.35	0	**$0**
KU TOTAL ($000's)										
GRAND TOTAL ($000's)										

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks
Metal roof.	Ashby	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Bishop	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Station built in 1994.	Bluegrass	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Brandenburg	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Brook	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Station built in 1996	Campground	$98.89	0	**$0**	$162.12	0	0	**$0**	$81.04	0	**$0**
	Carter	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Clarks Lane	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Crestwood	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Crop	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
New roof in 1994.	Dahlia	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Del Park	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Dixie	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Dumesnil	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Eighth Street	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Fairmount	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Falls City	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
New roof in 1995.	Floyd	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Station built in 1993.	Ford	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Forty Fourth	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Freys Hill	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Gaulbert	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Gilligan	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Goss	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Station built in 1998.	Grade Lane	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Built up roof unknown date.	Grady	$98.89	3	**$297**	$162.12	3	2	**$973**	$81.04	2	**$162**
	Grand	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Hale	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks
Built up roof unknown date.	Harmony Landing	$98.89	3	**$297**	$162.12	3	2	**$973**	$81.04	2	**$162**
	Herman	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Built up roof unknown date.	Highland	$98.89	5	**$494**	$162.12	5	4	**$3,242**	$81.04	4	**$324**
New roof 1993.	Hillcrest	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
New roof 1995.	Hurstbourne	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Station built in 1994.	International	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Jeffersontown	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Kenwood	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Built up roof unknown date.	Knob Creek	$98.89	4	**$396**	$162.12	4	4	**$2,594**	$81.04	4	**$324**
Built up roof unknown date.	Locust	$98.89	3	**$297**	$162.12	3	2	**$973**	$81.04	2	**$162**
	Logan	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Louisville Downs	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Lynn	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
New roof in 2000	Magazine	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
New roof 1998.	Manslick	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Muldraugh	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Nachand	$98.89	2	$198	$162.12	2	1	$324	$81.04	1	$81
Station built in 1989.	Okolona	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Ormsby	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Pirtle	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
New roof 1992	Plainview	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
New roof 1999.	Pleasure Ridge	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Seventh Street	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Shawnee	$98.89	0	**$0**	$162.12	0	1			1	
Metal roof.	Shepherdsville	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Skylight	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Smyrna	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Solite	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks
Metal roof.	South Park	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
New roof 2001.	Southern	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Southern Baptist Seminary	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Stewart	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Trimble Cty Sw. Rm (12 kv)	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Metal roof.	Terry	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
	Vermont	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Waterside (D)	$98.89	5	**$494**	$162.12	5	1	**$811**	$81.04	1	**$81**
	Westpoint	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
	Western	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	WHAS	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
Station built in 2001.	Worthington	$98.89	0	**$0**	$162.12	0	1	**$0**	$81.04	1	**$81**
Metal roof.	Zorn	$98.89	2	**$198**	$162.12	2	1	**$324**	$81.04	1	**$81**
LG&E TOTAL ($000's)				**$8**				**$18**			**$6**
KU has 478 distribution Substations	KU Dist. Substations	$98.89	2	**$198**	$162.12	4	1	**$648**	$81.04	1	**$81**
KU TOTAL ($000's)											
GRAND TOTAL ($000's)											

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Air monitoring testing, 12 Tests / Day (On Job Testing/Day)			Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal E Air
		Cost per Day	# Days Testing	Total Cost On Job Testing	Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit
Metal roof.	Ashby	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Bishop	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1994.	Bluegrass	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Brandenburg	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Brook	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1996	Campground	$1,384.00	0	**$0**	$606.32		**$0**	$775.06		**$0**	$707.85
	Carter	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Clarks Lane	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Crestwood	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Crop	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof in 1994.	Dahlia	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
Metal roof.	Del Park	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Dixie	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Dumesnil	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Eighth Street	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Fairmount	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06		**$0**	$707.85
	Falls City	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof in 1995.	Floyd	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1993.	Ford	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Forty Fourth	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Freys Hill	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Gaulbert	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Gilligan	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Goss	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1998.	Grade Lane	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Built up roof unknown date.	Grady	$1,384.00	4	**$5,536**	$606.32	2	**$1,213**	$775.06	2	**$1,550**	$707.85
	Grand	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Hale	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Air monitoring testing, 12 Tests / Day (On Job Testing/Day)			Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal E Air
		Cost per Day	# Days Testing	Total Cost On Job Testing	Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit
Built up roof unknown date.	Harmony Landing	$1,384.00	3	**$4,152**	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85
	Herman	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Built up roof unknown date.	Highland	$1,384.00	4	**$5,536**	$606.32	5	**$3,032**	$775.06	5	**$3,875**	$707.85
New roof 1993.	Hillcrest	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof 1995.	Hurstbourne	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 1994.	International	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Jeffersontown	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Kenwood	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Built up roof unknown date.	Knob Creek	$1,384.00	3	**$4,152**	$606.32	4	**$2,425**	$775.06	4	**$3,100**	$707.85
Built up roof unknown date.	Locust	$1,384.00	3	**$4,152**	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85
	Logan	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Louisville Downs	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Lynn	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
New roof in 2000	Magazine	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
New roof 1998.	Manslick	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Muldraugh	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
Metal roof.	Nachand	$1,384.00	2	$2,768	$606.32		$0	$775.06		$0	$707.85
Station built in 1989.	Okolona	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Ormsby	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Pirtle	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof 1992	Plainview	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof 1999.	Pleasure Ridge	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Seventh Street	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Shawnee		2								
Metal roof.	Shepherdsville	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Skylight	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Smyrna	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Solite	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Air monitoring testing, 12 Tests / Day (On Job Testing/Day)			Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal E Air
		Cost per Day	# Days Testing	Total Cost On Job Testing	Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit
Metal roof.	South Park	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
New roof 2001.	Southern	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Southern Baptist Seminary	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Stewart	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Trimble Cty Sw. Rm (12 kv)	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Terry	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Vermont	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Waterside (D)	$1,384.00	2	**$2,768**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
	Westpoint	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
	Western	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	WHAS	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Station built in 2001.	Worthington	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
Metal roof.	Zorn	$1,384.00	2	**$2,768**	$606.32		**$0**	$775.06		**$0**	$707.85
LG&E TOTAL ($000's)				**$192**			**$10**			**$13**	
KU has 478 distribution Substations	KU Dist. Substations	$1,384.00	4	**$5,536**	$606.32	0	**$0**	$775.06	0	**$0**	$707.85
KU TOTAL ($000's)											
GRAND TOTAL ($000's)											

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	quip Required - Negative Pressure System		Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic			Removal of Circuit Breake	
		# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag	Cost per Unit	# Units
Metal roof.	Ashby		$0	$1,773.00		$0	$5.40		$0		
	Bishop		$0	$1,773.00		$0	$5.40		$0		
Station built in 1994.	Bluegrass		$0	$1,773.00		$0	$5.40		$0		
	Brandenburg	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Brook		$0	$1,773.00		$0	$5.40		$0		
Station built in 1996	Campground		$0	$1,773.00		$0	$5.40		$0		
	Carter		$0	$1,773.00		$0	$5.40		$0		
	Clarks Lane		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Crestwood		$0	$1,773.00		$0	$5.40		$0		
	Crop		$0	$1,773.00		$0	$5.40		$0		
New roof in 1994.	Dahlia	0	$0	$1,773.00	0	$0	$5.40	0	$0		
Metal roof.	Del Park		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Dixie		$0	$1,773.00		$0	$5.40		$0		
	Dumesnil	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Eighth Street	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Fairmount		$0	$1,773.00		$0	$5.40		$0		
	Falls City		$0	$1,773.00		$0	$5.40		$0		
New roof in 1995.	Floyd		$0	$1,773.00		$0	$5.40		$0		
Station built in 1993.	Ford		$0	$1,773.00		$0	$5.40		$0		
	Forty Fourth		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Freys Hill		$0	$1,773.00		$0	$5.40		$0		
	Gaulbert		$0	$1,773.00		$0	$5.40		$0		
	Gilligan		$0	$1,773.00		$0	$5.40		$0		
	Goss		$0	$1,773.00		$0	$5.40		$0		
Station built in 1998.	Grade Lane		$0	$1,773.00		$0	$5.40		$0		
Built up roof unknown date.	Grady	2	$1,416	$1,773.00	8	$14,184	$5.40	50	$270		
	Grand		$0	$1,773.00		$0	$5.40		$0		
	Hale	0	$0	$1,773.00	0	$0	$5.40	0	$0		

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	quip Required - Negative Pressure System		Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic			Removal of Circuit Breake	
		# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag	Cost per Unit	# Units
Built up roof unknown date.	Harmony Landing	3	**$2,124**	$1,773.00	8	**$14,184**	$5.40	50	**$270**		
	Herman		**$0**	$1,773.00		**$0**	$5.40	0	**$0**		
Built up roof unknown date.	Highland	5	**$3,539**	$1,773.00	16	**$28,368**	$5.40	70	**$378**		
New roof 1993.	Hillcrest		**$0**	$1,773.00		**$0**	$5.40		**$0**		
New roof 1995.	Hurstbourne		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Station built in 1994.	International		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Jeffersontown		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Kenwood		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Built up roof unknown date.	Knob Creek	4	**$2,831**	$1,773.00	16	**$28,368**	$5.40	70	**$378**		
Built up roof unknown date.	Locust	3	**$2,124**	$1,773.00	8	**$14,184**	$5.40	50	**$270**		
	Logan		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Louisville Downs		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Lynn	0	**$0**	$1,773.00	0	**$0**	$5.40	0	**$0**		
New roof in 2000	Magazine	0	**$0**	$1,773.00	0	**$0**	$5.40	0	**$0**		
New roof 1998.	Manslick		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Muldraugh	0	**$0**	$1,773.00	0	**$0**	$5.40	0	**$0**		
Metal roof.	Nachand		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Station built in 1989.	Okolona		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Ormsby		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Pirtle		**$0**	$1,773.00		**$0**	$5.40		**$0**		
New roof 1992	Plainview		**$0**	$1,773.00		**$0**	$5.40		**$0**		
New roof 1999.	Pleasure Ridge		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Seventh Street		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Shawnee								**$0**		
Metal roof.	Shepherdsville		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Skylight		**$0**	$1,773.00		**$0**	$5.40		**$0**		
Metal roof.	Smyrna		**$0**	$1,773.00		**$0**	$5.40		**$0**		
	Solite		**$0**	$1,773.00		**$0**	$5.40		**$0**		

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	quip Required - Negative Pressure System		Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic			Removal of Circuit Breaker	
		# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag	Cost per Unit	# Units
Metal roof.	South Park		$0	$1,773.00		$0	$5.40		$0		
New roof 2001.	Southern		$0	$1,773.00		$0	$5.40		$0		
	Southern Baptist Seminary		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Stewart	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Trimble Cty Sw. Rm (12 kv)		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Terry		$0	$1,773.00		$0	$5.40		$0		
	Vermont	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Waterside (D)	0	$0	$1,773.00	0	$0	$5.40	0	$0		
	Westpoint	0	$0	$1,773.00		$0	$5.40		$0		
	Western		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	WHAS		$0	$1,773.00		$0	$5.40		$0		
Station built in 2001.	Worthington		$0	$1,773.00		$0	$5.40		$0		
Metal roof.	Zorn		$0	$1,773.00		$0	$5.40		$0		
LG&E TOTAL ($000's)			**$12**			**$99**			**$2**		
KU has 478 distribution Substations	KU Dist. Substations	0	**$0**	$1,773.00	1	**$1,773**	$5.40	5	**$27**		
KU TOTAL ($000's)											
GRAND TOTAL ($000's)											

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Arc Chutes	Removal of Control Wiring			Removal Cost per Asset ($000's)	40 Cu			
		Total Cost	Cost per Unit	# Units	Total Cost		Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs
Metal roof.	Ashby	$2,500			$6,500	$14	$673.53	1	1	$674
	Bishop	$2,500			$6,500	$14	$673.53	1	1	$674
Station built in 1994.	Bluegrass	$0			$0	$3	$673.53	0	0	$0
	Brandenburg	$2,500			$6,500	$12	$673.53	0	0	$0
	Brook	$2,500			$2,500	$8	$673.53	0	0	$0
Station built in 1996	Campground	$0			$0	$0	$673.53	0	0	$0
	Carter	$2,500			$2,500	$8	$673.53	0	0	$0
	Clarks Lane	$2,500			$2,500	$8	$673.53	0	0	$0
Metal roof.	Crestwood	$2,500			$6,500	$14	$673.53	1	1	$674
	Crop	$2,500			$2,500	$8	$673.53	0	0	$0
New roof in 1994.	Dahlia	$2,500			$6,500	$14	$673.53	1	1	$674
Metal roof.	Del Park	$2,500			$6,500	$14	$673.53	1	1	$674
Metal roof.	Dixie	$2,500			$6,500	$14	$673.53	1	1	$674
	Dumesnil	$2,500			$6,500	$12	$673.53	0	0	$0
	Eighth Street	$2,500			$2,500	$8	$673.53	0	0	$0
	Fairmount	$2,500			$6,500	$14	$673.53	1	1	$674
	Falls City	$2,500			$2,500	$8	$673.53	0	0	$0
New roof in 1995.	Floyd	$2,500			$6,500	$14	$673.53	1	1	$674
Station built in 1993.	Ford	$0			$0	$3	$673.53	1	1	$674
	Forty Fourth	$2,500			$2,500	$8	$673.53	0	0	$0
Metal roof.	Freys Hill	$2,500			$6,500	$14	$673.53	1	1	$674
	Gaulbert	$2,500			$2,500	$8	$673.53	0	0	$0
	Gilligan	$2,500			$2,500	$8	$673.53	0	0	$0
	Goss	$2,500			$2,500	$8	$673.53	0	0	$0
Station built in 1998.	Grade Lane	$0			$0	$3	$673.53	1	1	$674
Built up roof unknown date.	Grady	$2,500			$6,500	$38	$673.53	1	3	$2,021
	Grand	$2,500			$2,500	$8	$673.53	0	0	$0
	Hale	$2,500			$2,500	$8	$673.53	0	0	$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Arc Chutes	Removal of Control Wiring			Removal Cost per Asset ($000's)	40 Cu			
		Total Cost	Cost per Unit	# Units	Total Cost		Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs
Built up roof unknown date.	Harmony Landing	$2,500			$6,500	$38	$673.53	1	3	$2,021
	Herman	$2,500			$2,500	$8	$673.53	0	0	$0
Built up roof unknown date.	Highland	$2,500			$6,500	$63	$673.53	1	3	$2,021
New roof 1993.	Hillcrest	$2,500			$6,500	$19	$673.53	1	1	$674
New roof 1995.	Hurstbourne	$2,500			$6,500	$14	$673.53	1	1	$674
Station built in 1994.	International	$0			$0	$3	$673.53	0	0	$0
Metal roof.	Jeffersontown	$2,500			$6,500	$14	$673.53	1	1	$674
Metal roof.	Kenwood	$2,500			$6,500	$14	$673.53	1	1	$674
Built up roof unknown date.	Knob Creek	$2,500			$6,500	$58	$673.53	1	2	$1,347
Built up roof unknown date.	Locust	$2,500			$6,500	$38	$673.53	1	1	$674
	Logan	$2,500			$2,500	$8	$673.53	0	0	$0
	Louisville Downs	$2,500			$2,500	$8	$673.53	0	0	$0
	Lynn	$2,500			$2,500	$8	$673.53	0	0	$0
New roof in 2000	Magazine	$2,500			$6,500	$26	$673.53	0	0	$0
New roof 1998.	Manslick	$2,500			$6,500	$17	$673.53	1	1	$674
	Muldraugh	$2,500			$6,500	$14	$673.53	0	0	$0
Metal roof.	Nachand	$2,500			$6,500	$14	$673.53	1	1	$674
Station built in 1989.	Okolona	$0			$0	$3	$673.53	0	0	$0
	Ormsby	$2,500			$2,500	$8	$673.53	1	1	$674
	Pirtle	$2,500			$2,500	$8	$673.53	0	0	$0
New roof 1992	Plainview	$2,500			$6,500	$14	$673.53	1	1	$674
New roof 1999.	Pleasure Ridge	$2,500			$6,500	$14	$673.53	1	1	$674
	Seventh Street	$2,500			$2,500	$8	$673.53	0	0	$0
	Shawnee	$2,500			$2,500	$5	$673.53	0	0	$0
Metal roof.	Shepherdsville	$2,500			$6,500	$14	$673.53	1	1	$674
Metal roof.	Skylight	$2,500			$6,500	$13	$673.53	1	1	$674
Metal roof.	Smyrna	$2,500			$6,500	$14	$673.53	1	1	$674
	Solite	$0			$0	$3	$673.53	0	0	$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Arc Chutes	Removal of Control Wiring			Removal Cost per Asset ($000's)	40 Cu			
		Total Cost	Cost per Unit	# Units	Total Cost		Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs
Metal roof.	South Park	$2,500			$6,500	$14	$673.53	1	1	$674
New roof 2001.	Southern	$2,500			$6,500	$32	$673.53	1	5	$3,368
	Southern Baptist Seminary	$2,500			$6,500	$12	$673.53	0	0	$0
Metal roof.	Stewart	$2,500			$6,500	$14	$673.53	1	1	$674
	Trimble Cty Sw. Rm (12 kv)	$2,500			$6,500	$14	$673.53	1	1	$674
Metal roof.	Terry	$2,500			$6,500	$14	$673.53	1	1	$674
	Vermont	$2,500			$6,500	$12	$673.53	0	0	$0
	Waterside (D)	$2,500			$6,500	$32	$673.53	1	2	$1,347
	Westpoint	$2,500			$6,500	$12	$673.53	0	0	$0
	Western	$2,500			$6,500	$12	$673.53	0	0	$0
Metal roof.	WHAS	$2,500			$6,500	$14	$673.53	1	1	$674
Station built in 2001.	Worthington	$0			$0	$3	$673.53	0	0	$0
Metal roof.	Zorn	$2,500			$6,500	$13	$673.53	0	0	$0
LG&E TOTAL ($000's)						$937				$31
KU has 478 distribution Substations	KU Dist. Substations	$0			$3,000	$11	$673.53	1	1	$674
KU TOTAL ($000's)										
GRAND TOTAL ($000's)										

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Yd Asbestos Dumpster Costs Per Unit						Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
		Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
Metal roof.	Ashby	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
	Bishop	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
Station built in 1994.	Bluegrass	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$3**
	Brandenburg	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$12**
	Brook	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
Station built in 1996	Campground	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$0**
	Carter	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Clarks Lane	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
Metal roof.	Crestwood	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
	Crop	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
New roof in 1994.	Dahlia	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
Metal roof.	Del Park	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
Metal roof.	Dixie	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
	Dumesnil	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$12**
	Eighth Street	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Fairmount	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
	Falls City	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
New roof in 1995.	Floyd	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
Station built in 1993.	Ford	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$4**
	Forty Fourth	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
Metal roof.	Freys Hill	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
	Gaulbert	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Gilligan	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Goss	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
Station built in 1998.	Grade Lane	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$4**
Built up roof unknown date.	Grady	$318.89	6	**$1,913**	$167.31	3	**$502**	**$4**	**$43**
	Grand	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$8**
	Hale	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Yd Asbestos Dumpster Costs Per Unit						Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
		Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
Built up roof unknown date.	Harmony Landing	$318.89	6	**$1,913**	$167.31	5	**$837**	**$5**	**$43**
	Herman	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$8**
Built up roof unknown date.	Highland	$318.89	6	**$1,913**	$167.31	5	**$837**	**$5**	**$68**
New roof 1993.	Hillcrest	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$20**
New roof 1995.	Hurstbourne	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Station built in 1994.	International	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$3**
Metal roof.	Jeffersontown	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Metal roof.	Kenwood	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Built up roof unknown date.	Knob Creek	$318.89	4	**$1,276**	$167.31	2	**$335**	**$3**	**$61**
Built up roof unknown date.	Locust	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$39**
	Logan	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
	Louisville Downs	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$8**
	Lynn	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
New roof in 2000	Magazine	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$26**
New roof 1998.	Manslick	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$19**
	Muldraugh	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$14**
Metal roof.	Nachand	$318.89	2	**$638**	$167.31		$0	**$1**	**$15**
Station built in 1989.	Okolona	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$3**
	Ormsby	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$9**
	Pirtle	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$8**
New roof 1992	Plainview	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$16**
New roof 1999.	Pleasure Ridge	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
	Seventh Street	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$8**
	Shawnee	$318.89	0	**$0**					
Metal roof.	Shepherdsville	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
Metal roof.	Skylight	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
Metal roof.	Smyrna	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
	Solite	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$3**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Yd Asbestos Dumpster Costs Per Unit						Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
		Pickup / Delivery Costs	# Times Pickup / Delivery	**Total Pick Up/Del Costs**	Asbestos Dump Fee	# of Times Dumped	**Total Asbestos Dump Fee Expense**		
Metal roof.	South Park	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
New roof 2001.	Southern	$318.89	10	**$3,189**	$167.31	10	**$1,673**	**$8**	**$40**
	Southern Baptist Seminary	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$12**
Metal roof.	Stewart	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
	Trimble Cty Sw. Rm (12 kv)	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Metal roof.	Terry	$318.89	2	**$638**	$167.31	2	**$335**	**$2**	**$15**
	Vermont	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$12**
	Waterside (D)	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$36**
	Westpoint	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$12**
	Western	$318.89	0	**$0**	$167.31		**$0**	**$0**	**$12**
Metal roof.	WHAS	$318.89	2	**$638**	$167.31		**$0**	**$1**	**$15**
Station built in 2001.	Worthington	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$3**
Metal roof.	Zorn	$318.89	0	**$0**	$167.31	0	**$0**	**$0**	**$13**
LG&E TOTAL ($000's)				**$29**			**$10**	**$71**	**$1,018**
KU has 478 distribution Substations	KU Dist. Substations	$318.89	2	**$638**	$167.31	1	**$167**	**$1**	**$13**
KU TOTAL ($000's)									**$599**
GRAND TOTAL ($000's)									[redacted]

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Estimated Retirement Date	Comments
Metal roof.	Ashby		
	Bishop		
Station built in 1994.	Bluegrass		
	Brandenburg		
	Brook		
Station built in 1996	Campground		
	Carter		
	Clarks Lane		
Metal roof.	Crestwood		
	Crop		
New roof in 1994.	Dahlia		
Metal roof.	Del Park		
Metal roof.	Dixie		
	Dumesnil		
	Eighth Street		
	Fairmount		
	Falls City		
New roof in 1995.	Floyd		
Station built in 1993.	Ford		
	Forty Fourth		
Metal roof.	Freys Hill		
	Gaulbert		
	Gilligan		
	Goss		
Station built in 1998.	Grade Lane		
Built up roof unknown date.	Grady		
	Grand		
	Hale		

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Estimated Retirement Date	Comments
Built up roof unknown date.	Harmony Landing		
	Herman		
Built up roof unknown date.	Highland		
New roof 1993.	Hillcrest		
New roof 1995.	Hurstbourne		
Station built in 1994.	International		
Metal roof.	Jeffersontown		
Metal roof.	Kenwood		
Built up roof unknown date.	Knob Creek		
Built up roof unknown date.	Locust		
	Logan		
	Louisville Downs		
	Lynn		
New roof in 2000	Magazine		
New roof 1998.	Manslick		
	Muldraugh		
Metal roof.	Nachand		
Station built in 1989.	Okolona		
	Ormsby		
	Pirtle		
New roof 1992	Plainview		
New roof 1999.	Pleasure Ridge		
	Seventh Street		
	Shawnee		
Metal roof.	Shepherdsville		
Metal roof.	Skylight		
Metal roof.	Smyrna		
	Solite		

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Estimated Retirement Date	Comments
Metal roof.	South Park		
New roof 2001.	Southern		
	Southern Baptist Seminary		
Metal roof.	Stewart		
	Trimble Cty Sw. Rm (12 kv)		
Metal roof.	Terry		
	Vermont		
	Waterside (D)		
	Westpoint		
	Western		
Metal roof.	WHAS		
Station built in 2001.	Worthington		
Metal roof.	Zorn		
LG&E TOTAL ($000's)			
KU has 478 distribution Substations	KU Dist. Substations		
KU TOTAL ($000's)			
GRAND TOTAL ($000's)			

FACILITY ASSUMPTIONS

Any Facility constructed before 1985 will have asbestos, unless abatement has been completed

SMALL BUSINESS OFFICES & OPER CTRS- L. F. is calculated based on 8% of total sq. ft. for removal of pipe & ductwork insulation @ $65/LN. FT. or SQ. FT. (Includes removal & air monitoring costs) Costs per Ln. Ftl is based on recent invoicing for work performed by NEC.

STOREROOMS - L. F. is calculated based on 3% of total sq. ft. for pipe and ductwork insulation @ $65/LN.FT. or SQ. FT. (Includes removal and air monitoring costs). Cost per Ln. Ft. is based on recent invoicing for work performed by NEC.

Cost to remove VCT is based on actual invoicing from NEC for work performed at South Service Center in 1994. The same costs were applied to removal of ceiling tiles.

Leenerts, Patricia

From:	Kinder, Debra
Sent:	Monday, November 14, 2005 2:35 PM
To:	Leenerts, Patricia
Subject:	Liability Estimates from Field.xls
Attachments:	Liability Estimates from Field.xls

Liability Estimates
from Field...

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES SUMMARY

BUSINESS AREA	ESTIMATED REMOVAL COSTS - FIN 47
GENERAL FACILITIES	1,450,000
GENERATION	93,842,900
GAS	15,555,900
TRANSMISSION	721,000
DISTRIBUTION	1,617,000
Grand Total	113,186,800

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Bus. Area	Contacts	Co	Location	ARO Asset Number	Liability Source	Disposal Estimate	Location	Plant Acct.	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
General Facilities	Jerry Grant	110	Big Stone Gap Substation	FAC361AROC	Asbestos	29,000	D301	136100	1.89	0.26	53	38	1946	2037	91
	Karan Kapp	110	Campbellsville Concrete Block Bldg		Asbestos	3,000	A040	139010							
		110	Carrollton 1-1/2 Story Brick Bldg		Asbestos	7,000	A060	139010							
		110	Carrolton Storeroom		Asbestos	7,000	A062	139010							
		110	Danville 2 Story Facility		Asbestos	76,000	A140	139010							
		110	Dawson Springs Storeroom		Asbestos	14,000	A162	139010							
		110	Earlington - Wood Frame Bldg		Asbestos	44,000	A170	139010							
		110	Eddyville		Asbestos	7,000	A181	139010							
		110	Georgetown - 2 Bldgs		Asbestos	18,000	A260	139010							
		110	Greenville		Asbestos	14,000	A280	139010							
		110	Lexington Meter Dept.		Asbestos	102,000	A383	139010							
		110	Lexington Meter Dept. Storage		Asbestos	88,000	A382	139010							
		110	Lexington Substation/Relay Dept.		Asbestos	106,000	A389	139010							
		110	London Storeroom		Asbestos	9,000	A413	139010							
		110	Maysville		Asbestos	8,000	A440	139010							
		110	Middlesboro 2 Story Brick		Asbestos	118,000	A450	139010							
		110	Middlesboro Storeroom		Asbestos	95,000	A451	139010							
		110	Morehead		Asbestos	28,000	A470	139010							
		110	Morganfield 2 Story Brick		Asbestos	9,000	A480	139010							
		110	Mt. Sterling - 2 Story Brick		Asbestos	26,000	A490	139010							
		110	Mt. Sterling Storeroom		Asbestos	8,000	A491	139010							
		110	Paris - 1 Story Brick		Asbestos	8,000	A530	139010							
		110	Paris Storeroom		Asbestos	7,000	A531	139010							
		110	Richmond		Asbestos	24,000	A571	139010							
		110	Shelbyville Storeroom		Asbestos	24,000	A590	139010							
		110	Somerset Wood Frame		Asbestos	41,000	A600	139010							
		110	Somerset Storeroom		Asbestos	26,000	A602	139010							
		110	Stone Rd Main Bldg		Asbestos	34,000	A384	139010							
		110	Winchester 1 Story Brick		Asbestos	38,000	A690	139010							
		110	Winchester Storeroom		Asbestos	7,000	A691	139010							
		110	Total 139010	FAC390AROC		996,000		139010	1.76	0	50	38	1949	2037	88
		100	Seventh and Ormsby	FAC390AROC	Asbestos	425,000	0806	339020	2.14	0.22	50	45	1949	2044	95
					Total Facilities	**1,450,000**									

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Co	Contacts	Location	Liability Source		Field Rem/Disp Estimate	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
Generation		Jon Miller											
	100	Steve Legler	Waterside	Asbestos		4,000,000	1.30	0.00	41	11	1958	2010	52
		Steve Legler	Paddy's Run	Asbestos		11,000,000	2.10	0.00	44	24	1955	2023	68
	100	Dave Cook	Mill Creek Unit 1 - 356 MW	Asbestos		3,555,000	2.39	0.37	36	20	1963	2019	56
	100	Dave Cook	Mill Creek Unit 2 - 356 MW	Asbestos		3,100,000	2.29	0.35	37	21	1962	2020	58
	100	Dave Cook	Mill Creek Unit 3 - 463 MW	Asbestos		2,350,000	3.03	0.22	37	25	1962	2024	62
	100	Dave Cook	Mill Creek Unit 4 - 543 MW	Asbestos		2,600,000	2.82	0.21	33	30	1966	2029	63
	100	Fred Jackson	Ghent Unit 1 - 511 MW	Asbestos		6,517,000	3.12	0.30	39	21	1960	2020	60
	100	Fred Jackson	Ghent Unit 2 - 511 MW	Asbestos		8,637,000	1.84	0.35	39	25	1960	2024	64
	100	Fred Jackson	Ghent Unit 3 - 511 MW	Asbestos		1,532,000	2.22	0.27	36	29	1963	2028	65
	100	Fred Jackson	Ghent Unit 4 - 511 MW	Asbestos		1,532,000	2.16	0.23	34	32	1965	2031	66
	100	Steve Legler	Cane Run Unit 1	Asbestos		2,700,000	3.06	0.51	32	19	1967	2018	51
	100	Steve Legler	Cane Run Unit 2	Asbestos		2,550,000	3.06	0.51	32	19	1967	2018	51
	100	Steve Legler	Cane Run Unit 3	Asbestos		2,700,000	3.06	0.51	32	19	1967	2018	51
	100	Steve Legler	Cane Run Unit 4	Asbestos		2,750,000	2.94	0.52	31	19	1968	2018	50
	100	Steve Legler	Cane Run Unit 5	Asbestos		2,150,000	2.87	0.51	32	19	1967	2018	51
	100	Steve Legler	Cane Run Unit 6	Asbestos		2,500,000	3.06	0.51	32	19	1967	2018	51
	100	David Cosby	Trimble	Asbestos		0	2.40	0.08	38	34	1961	2033	72
		Russell Baker	Green River Unit 1 - 30 MW	Asbestos		1,775,000	1.71	0.82	46	18	1953	2017	64
		Russell Baker	Green River Unit 2 - 30 MW	Asbestos		1,625,000	1.71	0.82	46	18	1953	2017	64
		Russell Baker	Green River Unit 3 - 60 MW	Asbestos		1,780,000	1.94	0.76	47	18	1952	2017	65
		Russell Baker	Green River Unit 4 - 100 MW	Asbestos		2,100,000	3.10	0.78	32	19	1967	2018	51
		Sam Carr	Brown Unit 1 - 108 MW	Asbestos		2,055,700	2.90	0.65	33	20	1966	2019	53
		Sam Carr	Brown Unit 2 - 178 MW	Asbestos		3,295,700	2.88	0.50	33	19	1966	2018	52
		Sam Carr	Brown Unit 3 - 454 MW	Asbestos		7,435,200	3.91	0.52	33	20	1966	2019	53
	100		Zorn	Asbestos		100,000	2.10	0.00	44	24	1955	2023	68
		Steve Legler	Canal	Asbestos		6,000,000	2.10	0.00	44	24	1955	2023	68
		Sam Carr	Tyronne Unit 1 - 30 MW	Asbestos		1,458,700	2.13	1.10	44	18	1955	2017	62
		Sam Carr	Tyronne Unit 2 - 30 MW	Asbestos		1,458,700	2.13	1.10	44	18	1955	2017	62
		Sam Carr	Tyronne Unit 3 - 75 MW	Asbestos		2,106,700	2.13	1.10	44	18	1955	2017	62
		Sam Carr	Pineville Unit 1 - 38 MW	Asbestos		1,534,200	2.28	0.73	43	18	1956	2017	61
			Ohio Falls	Asbestos		600,000	1.34	0.00	44	24	1955	2023	68
			Dix Dam	Asbestos		345,000	1.59	0.40	61	23	1938	2022	84
			Lock 7 - Sale pending	Asbestos		0	2.46	1.33	49	23	1950	2022	72

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Co	Contacts	Location	Liability Source		Field Rem/Disp Estimate	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
				Total Generation		93,842,900							

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Bus. Area	Contacts	Location	ARO Asset Number	Liability Source	Disposal Estimate	Location	Plant Acct.	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
Gas														
	Glenn Sundheimer	Magnolia - 163 Wells	WELLMAGAROC	Well Plugging	3,331,000	721	235202	2.35	0.89	38	23	1961	2022	61
	Glenn Sundheimer	Center - 225 Wells	WELLCENAROC	Well Plugging	3,736,000	716	235202	2.35	0.89	38	23	1961	2022	61
	Glenn Sundheimer	Muldraugh - 60 Wells	WELLMULAROC	Well Plugging	967,000	723	235202	2.35	0.89	38	23	1961	2022	61
	Glenn Sundheimer	Doe Run - 145 Wells	WELLDOEAROC	Well Plugging	2,835,000	714	235202	2.35	0.89	38	23	1961	2022	61
	Steve Beatty	Muldraugh - IM&E Office		Asbestos	38,000	723	235120							
	Steve Beatty	Muldraugh - Kewanee Boiler Room		Asbestos	15,000	723	235120							
	Steve Beatty	Muldraugh - Compressor Bldg		Asbestos	20,000	723	235120							
	Steve Beatty	Muldraugh - Abandoned H2S Incinerator		Asbestos	21,000	723	235120							
	Steve Beatty	Muldraugh - Locker Room		Asbestos	11,000	723	235120							
		BUILDING AND STRUCTURES MULDRAUGH	BSMULAROC	Asbestos	105,000		235120	2.45	0.46	35	22	1964	2021	57
	Steve Beatty	Muldraugh - Purifier 1		Asbestos	30,000	723	235600							
	Steve Beatty	Muldraugh - Purifier 2		Asbestos	32,000	723	235600							
	Steve Beatty	Muldraugh - Purifier 3		Asbestos	59,000	723	235600							
		PURIFICATION EQUIPMENT MULDRAUGH	PURMULAROC	Asbestos	121,000		235600	3.50	0.89	30	22	1969	2021	52
	Steve Beatty	Muldraugh - Station Valves		Asbestos	4,000	723	235300							
	Steve Beatty	Muldraugh - Station Piping		Asbestos	76,000	723	235300							
	Steve Beatty	Muldraugh - Field Valves		Asbestos	6,000	723	235300							
	Steve Beatty	Muldraugh - Field Piping		Asbestos	67,000	723	235300							
		UG STORAGE LINES MULDRAUGH	UGSMULAROC	Asbestos	153,000	723	235300	2.53	0.34	28	15	1971	2014	43
	Steve Beatty	Doe Run - Field Valves		Asbestos	5,000	714	235300							
	Steve Beatty	Doe Run - Field Piping		Asbestos	134,000	714	235300							
	Steve Beatty	Doe Run - Deep Field Valves		Asbestos	1,000	714	235300							
	Steve Beatty	Doe Run - Deep Field Piping		Asbestos	56,000	714	235300							
		UG STORAGE LINES DOE RUN	UGSDOEAROC	Asbestos	196,000	714	235300	2.53	0.34	28	15	1971	2014	43
	Steve Beatty	DISTRIBUTION MULDRAUGH	DPMULAROC	Asbestos	11,000	723	237510	3.59	1.55	38	10	1961	2009	48
	Tom Rieth	Magnolia Compressor Station Paneling, Roofing		Asbestos	40,000	721	235120							
	Tom Rieth	Magnolia Compressor Station Auxillary Bldg		Asbestos	18,000	721	235120							
	Tom Rieth	Magnolia compressor Station Field Shop		Asbestos	9,000	721	235120							
	Tom Rieth	Magnolia Compressor Station Piping Insulation		Asbestos	7,000	721	235120							
		BUILDING AND STRUCTURES MAGNOLIA	BSMAGAROC	Asbestos	74,000	721	235120	2.45	0.46	35	22	1964	2021	57
	Tom Rieth	PURIFICATION EQUIPMENT MAGNOLIA	PURMAGAROC	Asbestos	26,000	721	235600	3.50	0.89	30	22	1969	2021	52

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Bus. Area	Contacts	Location	ARO Asset Number	Liability Source	Disposal Estimate	Location	Plant Acct.	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
	Tom Rieth	Magnolia Station Field Valves		Asbestos	33,000	721	235300							
	Tom Rieth	Magnolia Station and Field Piping		Asbestos	113,000	721	235300							
	Tom Rieth	Misc. Distribution - gaskets, valve legs, coal tar, gaskets		Asbestos	56,000	721	235300							
		UG STORAGE LINES MAGNOLIA	UGSMAGAROC	Asbestos	202,000	721	235300	2.53	0.34	28	15	1971	2014	43
	Mark Satkamp	City Gate - Preston Station - Meter Bldg		Asbestos	9,000	2485	237900							
	Mark Satkamp	City Gate - Preston Station - Contro Bldg		Asbestos	6,000	2485	237900							
		CITY GATE BUILDING AND STRUCTURES - PRESTON	CGPRESAROC	Asbestos	15,000	2485	237900	3.14	0.00	33	21	1966	2020	54
	Mark Satkamp	CITY GATE BUILDING AND STRUCTURES - DOE RUN	CGDOEAROC	Asbestos	16,000	2376	237900	3.14	0.00	33	21	1966	2020	54
	Steve Beatty	Riggs Junction - Compressor Station	RIGGSJUNAROC	Green Space	66,000	2327	235120	2.45	0.46	35	22	1964	2021	57
	Bob Ehrler			Gas Pipeline	3,701,900		237600	2.23	0.00	55	42	1944	2041	97
				Total Gas	**15,555,900**									

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location	Liability Source	Field Rem/Disp Estimate		Plant Acct.	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
Transmission	Elaine Welsh	KU Substations (69)	Asbestos	624,000		1352	2.65	1.2	55	37	1944	2036	92
		LGE Substations (11)	Asbestos	97,000		135210	2.02	0.37	50	27	1949	2026	77
		Total Transmission		**721,000**									

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location	Liability Source	Field Rem/Disp Estimate		Plant Acct.	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
Distribution	Tony Durbin	KU Substations (47)	Asbestos	599,000		1361	1.89	0.26	53	38	1946	2037	91
		LGE Substations (66)	Asbestos	1,018,000		136110	2.21	0.4	48	25	1951	2024	73
		Total Distribution		**1,617,000**									

Leenerts, Patricia

From: Riggs, Eric
Sent: Monday, November 14, 2005 7:36 AM
To: Leenerts, Patricia; Kinder, Debra; Wiseman, Sara
Subject: FW: Cost to Remove Asbestos in Vaults

FYI

From: Harshfield, Eddie
Sent: Monday, November 14, 2005 7:26 AM
To: Riggs, Eric
Subject: FW: Cost to Remove Asbestos in Vaults

Here is Scott's assumption.

From: Cooke, Scott
Sent: Friday, November 11, 2005 2:33 PM
To: Harshfield, Eddie
Cc: Gaynor, Mark
Subject: Cost to Remove Asbestos in Vaults

WR 475774: $18,112.35 (typical 2-unit vault)
WR 475987: $24,168.97 (typical 4-unit vault)

Average = $21,140.66 (assuming equal number of 2-unit and 4-unit vaults)

Total Cost = $3,593,912 ($21,140.66/vault)*(170 vaults)

Leenerts, Patricia

From: Kinder, Debra
Sent: Tuesday, November 15, 2005 10:56 AM
To: Leenerts, Patricia
Subject: RE: Liability Estimates from Field.xls

Facilities and Gas

From: Leenerts, Patricia
Sent: Monday, November 14, 2005 4:45 PM
To: Kinder, Debra
Subject: FW: Liability Estimates from Field.xls

Debbie, which question is this answering?

Pat

From: Kinder, Debra
Sent: Monday, November 14, 2005 2:35 PM
To: Leenerts, Patricia
Subject: Liability Estimates from Field.xls

<< File: Liability Estimates from Field.xls >>

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES SUMMARY

BUSINESS AREA	ESTIMATED REMOVAL COSTS - FIN 47
GENERAL FACILITIES	1,450,000
GENERATION	93,842,900
GAS	15,555,900
TRANSMISSION	721,000
DISTRIBUTION	1,617,000
Grand Total	113,186,800

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Bus. Area	Contacts	Co	Location	ARO Asset Number	Liability Source	Disposal Estimate	Location	Plant Acct.	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
General Facilities	Jerry Grant	110	Big Stone Gap Substation	FAC361AROC	Asbestos	29,000	D301	136100	1.89	0.26	53	38	1946	2037	91
	Karan Kapp	110	Campbellsville Concrete Block Bldg		Asbestos	3,000	A040	139010							
		110	Carrollton 1-1/2 Story Brick Bldg		Asbestos	7,000	A060	139010							
		110	Carrolton Storeroom		Asbestos	7,000	A062	139010							
		110	Danville 2 Story Facility		Asbestos	76,000	A140	139010							
		110	Dawson Springs Storeroom		Asbestos	14,000	A162	139010							
		110	Earlington - Wood Frame Bldg		Asbestos	44,000	A170	139010							
		110	Eddyville		Asbestos	7,000	A181	139010							
		110	Georgetown - 2 Bldgs		Asbestos	18,000	A260	139010							
		110	Greenville		Asbestos	14,000	A280	139010							
		110	Lexington Meter Dept.		Asbestos	102,000	A383	139010							
		110	Lexington Meter Dept. Storage		Asbestos	88,000	A382	139010							
		110	Lexington Substation/Relay Dept.		Asbestos	106,000	A389	139010							
		110	London Storeroom		Asbestos	9,000	A413	139010							
		110	Maysville		Asbestos	8,000	A440	139010							
		110	Middlesboro 2 Story Brick		Asbestos	118,000	A450	139010							
		110	Middlesboro Storeroom		Asbestos	95,000	A451	139010							
		110	Morehead		Asbestos	28,000	A470	139010							
		110	Morganfield 2 Story Brick		Asbestos	9,000	A480	139010							
		110	Mt. Sterling - 2 Story Brick		Asbestos	26,000	A490	139010							
		110	Mt. Sterling Storeroom		Asbestos	8,000	A491	139010							
		110	Paris - 1 Story Brick		Asbestos	8,000	A530	139010							
		110	Paris Storeroom		Asbestos	7,000	A531	139010							
		110	Richmond		Asbestos	24,000	A571	139010							
		110	Shelbyville Storeroom		Asbestos	24,000	A590	139010							
		110	Somerset Wood Frame		Asbestos	41,000	A600	139010							
		110	Somerset Storeroom		Asbestos	26,000	A602	139010							
		110	Stone Rd Main Bldg		Asbestos	34,000	A384	139010							
		110	Winchester 1 Story Brick		Asbestos	38,000	A690	139010							
		110	Winchester Storeroom		Asbestos	7,000	A691	139010							
		110	Total 139010	FAC390AROC		996,000		139010	1.76	0	50	38	1949	2037	88
		100	Seventh and Ormsby	FAC390AROC	Asbestos	425,000	0806	339020	2.14	0.22	50	45	1949	2044	95
					Total Facilities	**1,450,000**									

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Co	Contacts	Location	Liability Source		Field Rem/Disp Estimate	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
Generation		**Jon Miller**											
	100	Steve Legler	Waterside	Asbestos		4,000,000	1.30	0.00	41	11	1958	2010	52
		Steve Legler	Paddy's Run	Asbestos		11,000,000	2.10	0.00	44	24	1955	2023	68
	100	Dave Cook	Mill Creek Unit 1 - 356 MW	Asbestos		3,555,000	2.39	0.37	36	20	1963	2019	56
	100	Dave Cook	Mill Creek Unit 2 - 356 MW	Asbestos		3,100,000	2.29	0.35	37	21	1962	2020	58
	100	Dave Cook	Mill Creek Unit 3 - 463 MW	Asbestos		2,350,000	3.03	0.22	37	25	1962	2024	62
	100	Dave Cook	Mill Creek Unit 4 - 543 MW	Asbestos		2,600,000	2.82	0.21	33	30	1966	2029	63
	100	Fred Jackson	Ghent Unit 1 - 511 MW	Asbestos		6,517,000	3.12	0.30	39	21	1960	2020	60
	100	Fred Jackson	Ghent Unit 2 - 511 MW	Asbestos		8,637,000	1.84	0.35	39	25	1960	2024	64
	100	Fred Jackson	Ghent Unit 3 - 511 MW	Asbestos		1,532,000	2.22	0.27	36	29	1963	2028	65
	100	Fred Jackson	Ghent Unit 4 - 511 MW	Asbestos		1,532,000	2.16	0.23	34	32	1965	2031	66
	100	Steve Legler	Cane Run Unit 1	Asbestos		2,700,000	3.06	0.51	32	19	1967	2018	51
	100	Steve Legler	Cane Run Unit 2	Asbestos		2,550,000	3.06	0.51	32	19	1967	2018	51
	100	Steve Legler	Cane Run Unit 3	Asbestos		2,700,000	3.06	0.51	32	19	1967	2018	51
	100	Steve Legler	Cane Run Unit 4	Asbestos		2,750,000	2.94	0.52	31	19	1968	2018	50
	100	Steve Legler	Cane Run Unit 5	Asbestos		2,150,000	2.87	0.51	32	19	1967	2018	51
	100	Steve Legler	Cane Run Unit 6	Asbestos		2,500,000	3.06	0.51	32	19	1967	2018	51
	100	David Cosby	Trimble	Asbestos		0	2.40	0.08	38	34	1961	2033	72
		Russell Baker	Green River Unit 1 - 30 MW	Asbestos		1,775,000	1.71	0.82	46	18	1953	2017	64
		Russell Baker	Green River Unit 2 - 30 MW	Asbestos		1,625,000	1.71	0.82	46	18	1953	2017	64
		Russell Baker	Green River Unit 3 - 60 MW	Asbestos		1,780,000	1.94	0.76	47	18	1952	2017	65
		Russell Baker	Green River Unit 4 - 100 MW	Asbestos		2,100,000	3.10	0.78	32	19	1967	2018	51
		Sam Carr	Brown Unit 1 - 108 MW	Asbestos		2,055,700	2.90	0.65	33	20	1966	2019	53
		Sam Carr	Brown Unit 2 - 178 MW	Asbestos		3,295,700	2.88	0.50	33	19	1966	2018	52
		Sam Carr	Brown Unit 3 - 454 MW	Asbestos		7,435,200	3.91	0.52	33	20	1966	2019	53
	100		Zorn	Asbestos		100,000	2.10	0.00	44	24	1955	2023	68
		Steve Legler	Canal	Asbestos		6,000,000	2.10	0.00	44	24	1955	2023	68
		Sam Carr	Tyronne Unit 1 - 30 MW	Asbestos		1,458,700	2.13	1.10	44	18	1955	2017	62
		Sam Carr	Tyronne Unit 2 - 30 MW	Asbestos		1,458,700	2.13	1.10	44	18	1955	2017	62
		Sam Carr	Tyronne Unit 3 - 75 MW	Asbestos		2,106,700	2.13	1.10	44	18	1955	2017	62
		Sam Carr	Pineville Unit 1 - 38 MW	Asbestos		1,534,200	2.28	0.73	43	18	1956	2017	61
			Ohio Falls	Asbestos		600,000	1.34	0.00	44	24	1955	2023	68
			Dix Dam	Asbestos		345,000	1.59	0.40	61	23	1938	2022	84
			Lock 7 - Sale pending	Asbestos		0	2.46	1.33	49	23	1950	2022	72

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Co	Contacts	Location	Liability Source		Field Rem/Disp Estimate	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
				Total Generation		93,842,900							

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Gas														
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	Glenn Sundheimer	Center - 225 Wells	WELLCENAROC	Well Plugging	3,736,000	716	235202	2.35	0.89	38	23	1961	2022	61
	Glenn Sundheimer	Muldraugh - 60 Wells	WELLMULAROC	Well Plugging	967,000	723	235202	2.35	0.89	38	23	1961	2022	61
	Glenn Sundheimer	Doe Run - 145 Wells	WELLDOEAROC	Well Plugging	2,835,000	714	235202	2.35	0.89	38	23	1961	2022	61
	Steve Beatty	Muldraugh - IM&E Office		Asbestos	38,000	723	235120							
	Steve Beatty	Muldraugh - Kewanee Boiler Room		Asbestos	15,000	723	235120							
	Steve Beatty	Muldraugh - Compressor Bldg		Asbestos	20,000	723	235120							
	Steve Beatty	Muldraugh - Abandoned H2S Incinerator		Asbestos	21,000	723	235120							
	Steve Beatty	Muldraugh - Locker Room		Asbestos	11,000	723	235120							
		BUILDING AND STRUCTURES MULDRAUGH	BSMULAROC	Asbestos	105,000		235120	2.45	0.46	35	22	1964	2021	57
	Steve Beatty	Muldraugh - Purifier 1		Asbestos	30,000	723	235600							
	Steve Beatty	Muldraugh - Purifier 2		Asbestos	32,000	723	235600							
	Steve Beatty	Muldraugh - Purifier 3		Asbestos	59,000	723	235600							
		PURIFICATION EQUIPMENT MULDRAUGH	PURMULAROC	Asbestos	121,000		235600	3.50	0.89	30	22	1969	2021	52
	Steve Beatty	Muldraugh - Station Valves		Asbestos	4,000	723	235300							
	Steve Beatty	Muldraugh - Station Piping		Asbestos	76,000	723	235300							
	Steve Beatty	Muldraugh - Field Valves		Asbestos	6,000	723	235300							
	Steve Beatty	Muldraugh - Field Piping		Asbestos	67,000	723	235300							
		UG STORAGE LINES MULDRAUGH	UGSMULAROC	Asbestos	153,000	723	235300	2.53	0.34	28	15	1971	2014	43
	Steve Beatty	Doe Run - Field Valves		Asbestos	5,000	714	235300							
	Steve Beatty	Doe Run - Field Piping		Asbestos	134,000	714	235300							
	Steve Beatty	Doe Run - Deep Field Valves		Asbestos	1,000	714	235300							
	Steve Beatty	Doe Run - Deep Field Piping		Asbestos	56,000	714	235300							
		UG STORAGE LINES DOE RUN	UGSDOEAROC	Asbestos	196,000	714	235300	2.53	0.34	28	15	1971	2014	43
	Steve Beatty	DISTRIBUTION MULDRAUGH	DPMULAROC	Asbestos	11,000	723	237510	3.59	1.55	38	10	1961	2009	48
	Tom Rieth	Magnolia Compressor Station Paneling, Roofing		Asbestos	40,000	721	235120							
	Tom Rieth	Magnolia Compressor Station Auxillary Bldg		Asbestos	18,000	721	235120							
	Tom Rieth	Magnolia compressor Station Field Shop		Asbestos	9,000	721	235120							
	Tom Rieth	Magnolia Compressor Station Piping Insulation		Asbestos	7,000	721	235120							
		BUILDING AND STRUCTURES MAGNOLIA	BSMAGAROC	Asbestos	74,000	721	235120	2.45	0.46	35	22	1964	2021	57
	Tom Rieth	PURIFICATION EQUIPMENT MAGNOLIA	PURMAGAROC	Asbestos	26,000	721	235600	3.50	0.89	30	22	1969	2021	52

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

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	Tom Rieth	Magnolia Station and Field Piping		Asbestos	113,000	721	235300							
	Tom Rieth	Misc. Distribution - gaskets, valve legs, coal tar, gaskets		Asbestos	56,000	721	235300							
		UG STORAGE LINES MAGNOLIA	UGSMAGAROC	Asbestos	202,000	721	235300	2.53	0.34	28	15	1971	2014	43
	Mark Satkamp	City Gate - Preston Station - Meter Bldg		Asbestos	9,000	2485	237900							
	Mark Satkamp	City Gate - Preston Station - Contro Bldg		Asbestos	6,000	2485	237900							
		CITY GATE BUILDING AND STRUCTURES - PRESTON	CGPRESAROC	Asbestos	15,000	2485	237900	3.14	0.00	33	21	1966	2020	54
	Mark Satkamp	CITY GATE BUILDING AND STRUCTURES - DOE RUN	CGDOEAROC	Asbestos	16,000	2376	237900	3.14	0.00	33	21	1966	2020	54
	Steve Beatty	Riggs Junction - Compressor Station	RIGGSJUNAROC	Green Space	66,000	2327	235120	2.45	0.46	35	22	1964	2021	57
	Bob Ehrler			Gas Pipeline	3,701,900		237600	2.23	0.00	55	42	1944	2041	97
				Total Gas	**15,555,900**									

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location	Liability Source	Field Rem/Disp Estimate		Plant Acct.	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
Transmission	Elaine Welsh	KU Substations (69)	Asbestos	624,000		1352	2.65	1.2	55	37	1944	2036	92
		LGE Substations (11)	Asbestos	97,000		135210	2.02	0.37	50	27	1949	2026	77
		Total Transmission		**721,000**									

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location	Liability Source	Field Rem/Disp Estimate		Plant Acct.	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
Distribution	Tony Durbin	KU Substations (47)	Asbestos	599,000		1361	1.89	0.26	53	38	1946	2037	91
		LGE Substations (66)	Asbestos	1,018,000		136110	2.21	0.4	48	25	1951	2024	73
		Total Distribution		**1,617,000**									

Wiseman, Sara

From: Hennekes, Lisa
Sent: Wednesday, November 16, 2005 11:07 AM
To: Wiseman, Sara
Subject: RE: FIN 47

Okay, I need to respond to E.ON today so I will call you on our next break which should be around noon. If you aren't going to be around, please let me know so that I can figure out another time to talk to you today.

From: Wiseman, Sara
Sent: Wednesday, November 16, 2005 11:06 AM
To: Hennekes, Lisa
Subject: RE: FIN 47

I think it might be easier if we talk.

Sara Wiseman
Manager-Property Accounting
502.627.3189

From: Hennekes, Lisa
Sent: Wednesday, November 16, 2005 10:51 AM
To: Wiseman, Sara
Subject: FW: FIN 47

Sara,

Do you have an answer for me on this? E.ON is asking me again. I am in CORE training today, so if you could email me something I'd appreciate it. If we need to talk about it, I can try to call you on one of our breaks. Let me know please.

Lisa

From: Hennekes, Lisa
Sent: Friday, November 11, 2005 11:26 AM
To: Wiseman, Sara
Subject: FW: FIN 47

Sara,

Could you please let me know what you know about this so that I can answer E.ON from a budget perspective? Also, can you give me a little background on what FIN47 relates to? Thanks.

From: Schmidt, Heike (C/CP3) [mailto:Heike.Schmidt2@eon.com]

Sent: Friday, November 11, 2005 10:51 AM
To: Hennekes, Lisa
Cc: Wouters, Joep
Subject: FIN 47

Lisa,

Our Accounting deparment was mentioning the accounting principle FIN 47 and that they heard from you that there is a potential adjustment coming in 4Q.

Could you please let me know if you have reflected this effect in the MTPor if this is not calculatable .

Many thanks.

Regards
Heike

E.ON AG
Corporate Planning and Controlling
Energy Nordic, UK & US
E.ON-Platz 1
40479 Düsseldorf
Tel: +49(0)211-4579-415
Fax: +49(0)211-4579-597
E-Mail: heike.schmidt2@eon.com

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Leenerts, Patricia

From: Leenerts, Patricia
Sent: Wednesday, November 16, 2005 9:25 AM
To: Kinder, Debra
Subject: FW: Liability Estimates from Field.xls

Attachments: Liability Estimates from Field.xls

Debbie, you said to use this file to backup Facilities and Gas, but I thought these were the summary sheets you made. If it isn't the original, can you find what came from the field?

From: Kinder, Debra
Sent: Monday, November 14, 2005 2:35 PM
To: Leenerts, Patricia
Subject: Liability Estimates from Field.xls

Liability Estimates from Field...

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES SUMMARY

BUSINESS AREA	ESTIMATED REMOVAL COSTS - FIN 47
GENERAL FACILITIES	1,450,000
GENERATION	93,842,900
GAS	15,555,900
TRANSMISSION	721,000
DISTRIBUTION	1,617,000
Grand Total	113,186,800

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Bus. Area	Contacts	Co	Location	ARO Asset Number	Liability Source	Disposal Estimate	Location	Plant Acct.	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
General Facilities	Jerry Grant	110	Big Stone Gap Substation	FAC361AROC	Asbestos	29,000	D301	136100	1.89	0.26	53	38	1946	2037	91
	Karan Kapp	110	Campbellsville Concrete Block Bldg		Asbestos	3,000	A040	139010							
		110	Carrollton 1-1/2 Story Brick Bldg		Asbestos	7,000	A060	139010							
		110	Carrolton Storeroom		Asbestos	7,000	A062	139010							
		110	Danville 2 Story Facility		Asbestos	76,000	A140	139010							
		110	Dawson Springs Storeroom		Asbestos	14,000	A162	139010							
		110	Earlington - Wood Frame Bldg		Asbestos	44,000	A170	139010							
		110	Eddyville		Asbestos	7,000	A181	139010							
		110	Georgetown - 2 Bldgs		Asbestos	18,000	A260	139010							
		110	Greenville		Asbestos	14,000	A280	139010							
		110	Lexington Meter Dept.		Asbestos	102,000	A383	139010							
		110	Lexington Meter Dept. Storage		Asbestos	88,000	A382	139010							
		110	Lexington Substation/Relay Dept.		Asbestos	106,000	A389	139010							
		110	London Storeroom		Asbestos	9,000	A413	139010							
		110	Maysville		Asbestos	8,000	A440	139010							
		110	Middlesboro 2 Story Brick		Asbestos	118,000	A450	139010							
		110	Middlesboro Storeroom		Asbestos	95,000	A451	139010							
		110	Morehead		Asbestos	28,000	A470	139010							
		110	Morganfield 2 Story Brick		Asbestos	9,000	A480	139010							
		110	Mt. Sterling - 2 Story Brick		Asbestos	26,000	A490	139010							
		110	Mt. Sterling Storeroom		Asbestos	8,000	A491	139010							
		110	Paris - 1 Story Brick		Asbestos	8,000	A530	139010							
		110	Paris Storeroom		Asbestos	7,000	A531	139010							
		110	Richmond		Asbestos	24,000	A571	139010							
		110	Shelbyville Storeroom		Asbestos	24,000	A590	139010							
		110	Somerset Wood Frame		Asbestos	41,000	A600	139010							
		110	Somerset Storeroom		Asbestos	26,000	A602	139010							
		110	Stone Rd Main Bldg		Asbestos	34,000	A384	139010							
		110	Winchester 1 Story Brick		Asbestos	38,000	A690	139010							
		110	Winchester Storeroom		Asbestos	7,000	A691	139010							
		110	Total 139010	FAC390AROC		996,000		139010	1.76	0	50	38	1949	2037	88
		100	Seventh and Ormsby	FAC390AROC	Asbestos	425,000	0806	339020	2.14	0.22	50	45	1949	2044	95
					Total Facilities	**1,450,000**									

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Co	Contacts	Location	Liability Source	Field Rem/Disp Estimate	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
Generation		**Jon Miller**										
	100	Steve Legler	Waterside	Asbestos	4,000,000	1.30	0.00	41	11	1958	2010	52
		Steve Legler	Paddy's Run	Asbestos	11,000,000	2.10	0.00	44	24	1955	2023	68
	100	Dave Cook	Mill Creek Unit 1 - 356 MW	Asbestos	3,555,000	2.39	0.37	36	20	1963	2019	56
	100	Dave Cook	Mill Creek Unit 2 - 356 MW	Asbestos	3,100,000	2.29	0.35	37	21	1962	2020	58
	100	Dave Cook	Mill Creek Unit 3 - 463 MW	Asbestos	2,350,000	3.03	0.22	37	25	1962	2024	62
	100	Dave Cook	Mill Creek Unit 4 - 543 MW	Asbestos	2,600,000	2.82	0.21	33	30	1966	2029	63
	100	Fred Jackson	Ghent Unit 1 - 511 MW	Asbestos	6,517,000	3.12	0.30	39	21	1960	2020	60
	100	Fred Jackson	Ghent Unit 2 - 511 MW	Asbestos	8,637,000	1.84	0.35	39	25	1960	2024	64
	100	Fred Jackson	Ghent Unit 3 - 511 MW	Asbestos	1,532,000	2.22	0.27	36	29	1963	2028	65
	100	Fred Jackson	Ghent Unit 4 - 511 MW	Asbestos	1,532,000	2.16	0.23	34	32	1965	2031	66
	100	Steve Legler	Cane Run Unit 1	Asbestos	2,700,000	3.06	0.51	32	19	1967	2018	51
	100	Steve Legler	Cane Run Unit 2	Asbestos	2,550,000	3.06	0.51	32	19	1967	2018	51
	100	Steve Legler	Cane Run Unit 3	Asbestos	2,700,000	3.06	0.51	32	19	1967	2018	51
	100	Steve Legler	Cane Run Unit 4	Asbestos	2,750,000	2.94	0.52	31	19	1968	2018	50
	100	Steve Legler	Cane Run Unit 5	Asbestos	2,150,000	2.87	0.51	32	19	1967	2018	51
	100	Steve Legler	Cane Run Unit 6	Asbestos	2,500,000	3.06	0.51	32	19	1967	2018	51
	100	David Cosby	Trimble	Asbestos	0	2.40	0.08	38	34	1961	2033	72
		Russell Baker	Green River Unit 1 - 30 MW	Asbestos	1,775,000	1.71	0.82	46	18	1953	2017	64
		Russell Baker	Green River Unit 2 - 30 MW	Asbestos	1,625,000	1.71	0.82	46	18	1953	2017	64
		Russell Baker	Green River Unit 3 - 60 MW	Asbestos	1,780,000	1.94	0.76	47	18	1952	2017	65
		Russell Baker	Green River Unit 4 - 100 MW	Asbestos	2,100,000	3.10	0.78	32	19	1967	2018	51
		Sam Carr	Brown Unit 1 - 108 MW	Asbestos	2,055,700	2.90	0.65	33	20	1966	2019	53
		Sam Carr	Brown Unit 2 - 178 MW	Asbestos	3,295,700	2.88	0.50	33	19	1966	2018	52
		Sam Carr	Brown Unit 3 - 454 MW	Asbestos	7,435,200	3.91	0.52	33	20	1966	2019	53
	100		Zorn	Asbestos	100,000	2.10	0.00	44	24	1955	2023	68
		Steve Legler	Canal	Asbestos	6,000,000	2.10	0.00	44	24	1955	2023	68
		Sam Carr	Tyronne Unit 1 - 30 MW	Asbestos	1,458,700	2.13	1.10	44	18	1955	2017	62
		Sam Carr	Tyronne Unit 2 - 30 MW	Asbestos	1,458,700	2.13	1.10	44	18	1955	2017	62
		Sam Carr	Tyronne Unit 3 - 75 MW	Asbestos	2,106,700	2.13	1.10	44	18	1955	2017	62
		Sam Carr	Pineville Unit 1 - 38 MW	Asbestos	1,534,200	2.28	0.73	43	18	1956	2017	61
			Ohio Falls	Asbestos	600,000	1.34	0.00	44	24	1955	2023	68
			Dix Dam	Asbestos	345,000	1.59	0.40	61	23	1938	2022	84
			Lock 7 - Sale pending	Asbestos	0	2.46	1.33	49	23	1950	2022	72

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Co	Contacts	Location	Liability Source		Field Rem/Disp Estimate	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
				Total Generation		93,842,900							

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Bus. Area	Contacts	Location	ARO Asset Number	Liability Source	Disposal Estimate	Location	Plant Acct.	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
Gas														
	Glenn Sundheimer	Magnolia - 163 Wells	WELLMAGAROC	Well Plugging	3,331,000	721	235202	2.35	0.89	38	23	1961	2022	61
	Glenn Sundheimer	Center - 225 Wells	WELLCENAROC	Well Plugging	3,736,000	716	235202	2.35	0.89	38	23	1961	2022	61
	Glenn Sundheimer	Muldraugh - 60 Wells	WELLMULAROC	Well Plugging	967,000	723	235202	2.35	0.89	38	23	1961	2022	61
	Glenn Sundheimer	Doe Run - 145 Wells	WELLDOEAROC	Well Plugging	2,835,000	714	235202	2.35	0.89	38	23	1961	2022	61
	Steve Beatty	Muldraugh - IM&E Office		Asbestos	38,000	723	235120							
	Steve Beatty	Muldraugh - Kewanee Boiler Room		Asbestos	15,000	723	235120							
	Steve Beatty	Muldraugh - Compressor Bldg		Asbestos	20,000	723	235120							
	Steve Beatty	Muldraugh - Abandoned H2S Incinerator		Asbestos	21,000	723	235120							
	Steve Beatty	Muldraugh - Locker Room		Asbestos	11,000	723	235120							
		BUILDING AND STRUCTURES MULDRAUGH	BSMULAROC	Asbestos	105,000		235120	2.45	0.46	35	22	1964	2021	57
	Steve Beatty	Muldraugh - Purifier 1		Asbestos	30,000	723	235600							
	Steve Beatty	Muldraugh - Purifier 2		Asbestos	32,000	723	235600							
	Steve Beatty	Muldraugh - Purifier 3		Asbestos	59,000	723	235600							
		PURIFICATION EQUIPMENT MULDRAUGH	PURMULAROC	Asbestos	121,000		235600	3.50	0.89	30	22	1969	2021	52
	Steve Beatty	Muldraugh - Station Valves		Asbestos	4,000	723	235300							
	Steve Beatty	Muldraugh - Station Piping		Asbestos	76,000	723	235300							
	Steve Beatty	Muldraugh - Field Valves		Asbestos	6,000	723	235300							
	Steve Beatty	Muldraugh - Field Piping		Asbestos	67,000	723	235300							
		UG STORAGE LINES MULDRAUGH	UGSMULAROC	Asbestos	153,000	723	235300	2.53	0.34	28	15	1971	2014	43
	Steve Beatty	Doe Run - Field Valves		Asbestos	5,000	714	235300							
	Steve Beatty	Doe Run - Field Piping		Asbestos	134,000	714	235300							
	Steve Beatty	Doe Run - Deep Field Valves		Asbestos	1,000	714	235300							
	Steve Beatty	Doe Run - Deep Field Piping		Asbestos	56,000	714	235300							
		UG STORAGE LINES DOE RUN	UGSDOEAROC	Asbestos	196,000	714	235300	2.53	0.34	28	15	1971	2014	43
	Steve Beatty	DISTRIBUTION MULDRAUGH	DPMULAROC	Asbestos	11,000	723	237510	3.59	1.55	38	10	1961	2009	48
	Tom Rieth	Magnolia Compressor Station Paneling, Roofing		Asbestos	40,000	721	235120							
	Tom Rieth	Magnolia Compressor Station Auxillary Bldg		Asbestos	18,000	721	235120							
	Tom Rieth	Magnolia compressor Station Field Shop		Asbestos	9,000	721	235120							
	Tom Rieth	Magnolia Compressor Station Piping Insulation		Asbestos	7,000	721	235120							
		BUILDING AND STRUCTURES MAGNOLIA	BSMAGAROC	Asbestos	74,000	721	235120	2.45	0.46	35	22	1964	2021	57
	Tom Rieth	PURIFICATION EQUIPMENT MAGNOLIA	PURMAGAROC	Asbestos	26,000	721	235600	3.50	0.89	30	22	1969	2021	52

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Bus. Area	Contacts	Location	ARO Asset Number	Liability Source	Disposal Estimate	Location	Plant Acct.	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
	Tom Rieth	Magnolia Station Field Valves		Asbestos	33,000	721	235300							
	Tom Rieth	Magnolia Station and Field Piping		Asbestos	113,000	721	235300							
	Tom Rieth	Misc. Distribution - gaskets, valve legs, coal tar, gaskets		Asbestos	56,000	721	235300							
		UG STORAGE LINES MAGNOLIA	UGSMAGAROC	Asbestos	202,000	721	235300	2.53	0.34	28	15	1971	2014	43
	Mark Satkamp	City Gate - Preston Station - Meter Bldg		Asbestos	9,000	2485	237900							
	Mark Satkamp	City Gate - Preston Station - Contro Bldg		Asbestos	6,000	2485	237900							
		CITY GATE BUILDING AND STRUCTURES - PRESTON	CGPRESAROC	Asbestos	15,000	2485	237900	3.14	0.00	33	21	1966	2020	54
	Mark Satkamp	CITY GATE BUILDING AND STRUCTURES - DOE RUN	CGDOEAROC	Asbestos	16,000	2376	237900	3.14	0.00	33	21	1966	2020	54
	Steve Beatty	Riggs Junction - Compressor Station	RIGGSJUNAROC	Green Space	66,000	2327	235120	2.45	0.46	35	22	1964	2021	57
	Bob Ehrler			Gas Pipeline	3,701,900		237600	2.23	0.00	55	42	1944	2041	97
				Total Gas	**15,555,900**									

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location	Liability Source	Field Rem/Disp Estimate		Plant Acct.	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
Transmission	Elaine Welsh	KU Substations (69)	Asbestos	624,000		1352	2.65	1.2	55	37	1944	2036	92
		LGE Substations (11)	Asbestos	97,000		135210	2.02	0.37	50	27	1949	2026	77
		Total Transmission		**721,000**									

FIN 47 - ASSET RETIREMENT OBLIGATION ANALYSIS
FIELD ESTIMATES

Business Area	Contacts	Location	Liability Source	Field Rem/Disp Estimate		Plant Acct.	Accrual Rate	Net Salv Rate	Depr Study Avg Svc Life	Depr Study Est Rem Life	In Svc. Year	Est Retire Date	Est Life (yrs)
Distribution	Tony Durbin	KU Substations (47)	Asbestos	599,000		1361	1.89	0.26	53	38	1946	2037	91
		LGE Substations (66)	Asbestos	1,018,000		136110	2.21	0.4	48	25	1951	2024	73
		Total Distribution		**1,617,000**									

Leenerts, Patricia

From: Charnas, Shannon
Sent: Friday, November 18, 2005 7:15 AM
To: Wiseman, Sara
Cc: Kinder, Debra; Leenerts, Patricia; Riggs, Eric
Subject: ARO

Sara-

I had a meeting yesterday regarding the transfer of Lock 7. Everyone is still hoping that the transfer is completed by year end, but there is a potential hold up with the PSC or FERC. To cover our bases on this regarding AROs, I asked Tom Moore to send estimates of asbestos removal to us in case the transfer doesn't happen this year. He said he should have it in a few days. If you don't hear from him, please follow up so we can make that calculation.

I did talk to John Voyles yesterday regarding some different assumptions on retirement dates to use on generation facilities. Please set up a short meeting (around your IFRS commitments) with the group by Tuesday (I will be out on Wednesday) so we can discuss other calculations to make.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

Leenerts, Patricia

From:	Kinder, Debra
Sent:	Wednesday, November 23, 2005 2:42 PM
To:	Leenerts, Patricia
Subject:	AROC asset list.xls
Attachments:	AROC asset list.xls

AROC asset list.xls

Asset Number	Asset Description	Plant Account	Cost	Corporate Book
CHAZGRAROC	AROC - HAZARDOUS MATERIAL TANK	131700	200.00	FA_KU_BOOK
CLABBRAROC	AROC - LAB	131700	1,190.00	FA_KU_BOOK
CNUCGRAROC	AROC - NUCLEAR SOURCE	131700	30.00	FA_KU_BOOK
CPIPBRAROC	AROC - STATION FUEL OIL PIPING	131700	1,120.00	FA_KU_BOOK
CPIPTYAROC	AROC - STATION FUEL OIL PIPING	131700	330.00	FA_KU_BOOK
CRADBRAROC	AROC - RADIATION SOURCES	131700	1,060.00	FA_KU_BOOK
CRADGHAROC	AROC - RADIATION	131700	16,600.00	FA_KU_BOOK
C045084AROC	AROC - GR3 GSU TRANSFORMER	135910	160.00	FA_KU_BOOK
C045085AROC	AROC - GSU SPARE TRANSFORMER	135910	150.00	FA_KU_BOOK
C045207AROC	AROC - G1-2 GSU TRANSFORMER	135910	120.00	FA_KU_BOOK
C045281AROC	AROC - GR4 GSU TRANSFORMER	135910	1,250.00	FA_KU_BOOK
C063991AROC	AROC - GH4 GSU TRANSFORMER	135910	220.00	FA_KU_BOOK
C064114AROC	AROC - GH1 GSU TRANSFORMER	135910	210.00	FA_KU_BOOK
C064115AROC	AROC - GH2 GSU TRANSFORMER	135910	200.00	FA_KU_BOOK
C100858AROC	AROC - FUEL OIL TANKS UNIT 1	131700	880.00	FA_KU_BOOK
C101197AROC	AROC - COAL STORAGE	131700	520.00	FA_KU_BOOK
C101251AROC	AROC - SEWAGE TREATMENT PLANT	131700	430.00	FA_KU_BOOK
C101281AROC	AROC - ASH POND	131700	82,770.00	FA_KU_BOOK
C101358AROC	AROC - SVC WATER PUMP STATION	131700	4,580.00	FA_KU_BOOK
C101524AROC	AROC - BR 1 COAL STORAGE	131700	1,510.00	FA_KU_BOOK
C102462AROC	AROC - BR 3 FUEL OIL TANKS	131700	9,910.00	FA_KU_BOOK
C102983AROC	AROC - ASH POND	131700	946,440.00	FA_KU_BOOK
C103022AROC	AROC - COAL STORAGE	131700	8,730.00	FA_KU_BOOK
C103234AROC	AROC - LIMESTONE SILO	131700	580.00	FA_KU_BOOK
C103939AROC	AROC - OIL STORAGE TANKS	131700	1,130.00	FA_KU_BOOK
C104329AROC	AROC - COAL STORAGE	131700	186,610.00	FA_KU_BOOK
C104352AROC	AROC - SEWAGE TREATMENT PLANT	131700	770.00	FA_KU_BOOK
C104400AROC	AROC - UG TANK COAL	131700	990.00	FA_KU_BOOK
C104973AROC	AROC - STATION FUEL OIL PIPING	131700	310.00	FA_KU_BOOK
C105544AROC	AROC - CHEMICAL TANKS GH4	131700	1,170.00	FA_KU_BOOK
C114355AROC	AROC - CT9 FUEL OIL TANKS	134700	69,360.00	FA_KU_BOOK
C114424AROC	AROC - ASH POND	131700	3,041,280.00	FA_KU_BOOK
C122567AROC	AROC - FUEL OIL TANKS	131700	18,590.00	FA_KU_BOOK
C132623AROC	AROC - SEWAGE TREATMENT PLANT	131700	1,900.00	FA_KU_BOOK
C132682AROC	AROC - BR3 SEWAGE TREATMENT PLANT	131700	3,480.00	FA_KU_BOOK
C133299AROC	AROC - GYPSUM STACK	131700	250,280.00	FA_KU_BOOK
C133391AROC	AROC - ASH POND GH4	131700	3,938,990.00	FA_KU_BOOK
CCOALBRAROC	AROC - COAL PILE RETENTION POND	131700	4,670.00	FA_KU_BOOK
CMERCGRAROC	AROC - MERCURY SOURCES	131700	70.00	FA_KU_BOOK
CMERCTYAROC	AROC - MERCURY SOURCES	131700	70.00	FA_KU_BOOK

CPIP2BRAROC	AROC - CT FUEL OIL PIPING	134700	1,630.00	FA_KU_BOOK
C1706389AROC	AROC - UNDERGROUND TANKS 1& 2	131700	6,250.00	FA_KU_BOOK
C1732720AROC	AROC - GH SPARE GSU TRANSFORMER	135910	600.00	FA_KU_BOOK
C1732740AROC	AROC - GH3 GSU TRANSFORMER	135910	690.00	FA_KU_BOOK
	Total KU		8,608,030.00	
CHAZMCAROC	AROC - HAZARDOUS MATERIAL STORAGE	131700	2,710.00	FA_LGE_BOOK
CHAZTCAROC	AROC - HAZARDOUS MATERIAL	131700	150.00	FA_LGE_BOOK
CLABMCAROC	AROC - LAB	131700	270.00	FA_LGE_BOOK
CNUCCRAROC	AROC - NUCLEAR SOURCES	131700	2,780.00	FA_LGE_BOOK
CNUCTCAROC	AROC - NUCLEAR	131700	2,110.00	FA_LGE_BOOK
CRADMCAROC	AROC - RADIATION	131700	2,170.00	FA_LGE_BOOK
CMERCCRAROC	AROC - MERCURY SOURCES	131700	320.00	FA_LGE_BOOK
C1108207AROC	AROC - CR4 GSU	135910	140.00	FA_LGE_BOOK
C1108314AROC	AROC - CR5 GSU	135910	170.00	FA_LGE_BOOK
C1121129AROC	AROC - MC1 GSU	135910	250.00	FA_LGE_BOOK
C1121561AROC	AROC - MC2 GSU	135910	260.00	FA_LGE_BOOK
C1122727AROC	AROC - MC3 GSU	135910	340.00	FA_LGE_BOOK
C1123008AROC	AROC - MC4 GSU	135910	310.00	FA_LGE_BOOK
C1126696AROC	AROC - STORAGE PILE	131700	14,160.00	FA_LGE_BOOK
C1127093AROC	AROC - CHEMICAL TANKS	131700	990.00	FA_LGE_BOOK
C1127657AROC	AROC - ASH POND	131700	505,150.00	FA_LGE_BOOK
C1127837AROC	AROC - STORAGE TANKS	131700	1,910.00	FA_LGE_BOOK
C1130206AROC	AROC - COAL STORAGE	131700	30,880.00	FA_LGE_BOOK
C1130302AROC	AROC - ASH POND	131700	892,370.00	FA_LGE_BOOK
C1131509AROC	AROC - COAL PILE	131700	6,610.00	FA_LGE_BOOK
C1132257AROC	AROC - SEWAGE PLANT	131700	500.00	FA_LGE_BOOK
C1132399AROC	AROC - SEWAGE TREATMENT PLANT	131700	530.00	FA_LGE_BOOK
C1134814AROC	AROC - LAND FILL	131700	331,940.00	FA_LGE_BOOK
C1135331AROC	AROC - SPARE GSU	135910	170.00	FA_LGE_BOOK
C1136412AROC	AROC - ASH POND	131700	293,090.00	FA_LGE_BOOK
C1142644AROC	AROC - SPARE GSU	135910	1,070.00	FA_LGE_BOOK
C1755793AROC	AROC - LANDFILL	131700	2,492,370.00	FA_LGE_BOOK
C1850199AROC	AROC - CR6 GSU	135910	1,290.00	FA_LGE_BOOK
	Total LGE		4,585,010.00	
	Grand Total		13,193,040.00	

Leenerts, Patricia

From:	Leenerts, Patricia
Sent:	Friday, December 09, 2005 5:05 PM
To:	Charnas, Shannon
Cc:	Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject:	Generation Life's

I have added the weighted average life's (+13 years for currently retired & +38 years for those still active) as was determined through your conversation with Jim Moore regarding generation assets. Would you please forward supporting documentation for that decision.

In addition, was a decision made that I should also change the life of the generation assets to be the life of the transmission substation equipment for the active units? If so, please forward supporting documentation for this also.

Please let me know (or remind me) as to what decision was made.

Thanks

Leenerts, Patricia

From:	Charnas, Shannon
Sent:	Monday, December 12, 2005 6:48 AM
To:	Leenerts, Patricia
Cc:	Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject:	RE: Generation Life's

Pat-

I do not have any specific supporting documentation to send you, I thought that the discussion we had would be documented to support the decision. The changes were based on recommendations from PwC that we don't have to be as conservative as we were originally, but the numbers were developed from discussions with John Voyles, and verified with Jerry Grant for other assets. Regarding the lives of the active generation assets compared to the transmission assets on those sites, I thought the information was going to be pulled so we could review and see if it made sense to change it. We are running out of time to do this as we will need to revisit with PwC and meet with Brad this week or early next to get him up to speed and ensure he has no issues with the methodology. Sara, please let me know when you think we can get together with Brad to discuss, as usual, his calendar is filling up quickly.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From:	Leenerts, Patricia
Sent:	Friday, December 09, 2005 5:05 PM
To:	Charnas, Shannon
Cc:	Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject:	Generation Life's

I have added the weighted average life's (+13 years for currently retired & +38 years for those still active) as was determined through your conversation with Jim Moore regarding generation assets. Would you please forward supporting documentation for that decision.

In addition, was a decision made that I should also change the life of the generation assets to be the life of the transmission substation equipment for the active units? If so, please forward supporting documentation for this also.

Please let me know (or remind me) as to what decision was made.

Thanks

Wiseman, Sara

From: Hennekes, Lisa
Sent: Thursday, December 15, 2005 1:40 PM
To: Dalton, LaStacia; Erskine, Greg; Moore, Timothy; Marshall, Steve
Cc: Wiseman, Sara; Strange, Vicki
Subject: FW: FAS143 / FIN47

FYI - Vicki and I met with Sara today to understand the accounting for the implementation of FIN47 which will be recorded in Dec 2005's closing.

Based on what we discussed, this is what Sara said will happen in the Dec 2005 entries when FIN47 is implemented.

1.	DR Asset	CR ARO liability
2.	CR Cumulative Effect (I/S account)	CR Accum Depr
3.	DR Cumulative Effect (I/S account)	CR ARO Liability (for the accretion)
4.	DR Reg Asset	CR Regulatory Credits (I/S account) - sum of 2 and 3

Based on this information and the fact that there is no income statement impact due to the regulatory accounting treatment, all of the income statement items should be reported in cumulative effect. Sara will be setting up some new accounts in Oracle to deal with FIN47 and she'll make sure that for consolidated accounting purposes the accounts set up for the implementation entry all role into cumulative effect on the income statement. This is similar to how it was ultimately handled with the implementation of FAS143. Therefore the net cumulative effect in Dec 2005 will be zero.

On a go forward basis, similar to FAS143 the transactions on the income statement side all net out into depreciation expense.

Just wanted to let you all know what we discussed so that if you see any issued with it we can discuss them.

Thanks.

Lisa

From: Hennekes, Lisa
Sent: Thursday, December 15, 2005 11:24 AM
To: Wiseman, Sara
Cc: Strange, Vicki
Subject: FAS143 / FIN47

Sara,

I couldn't find any specific notes on the topic, but based on looking at the various files the final outcome definitely was what we thought - that all of the transactions recorded initially roll into cumulative effect on the income statement, so any accounts would need to be mapped to the cumulative effect line item for consolidated reporting (based on my opinion). Thanks.

Lisa Hennekes
Manager, Corporate Financial Planning
Phone (502) 627-4903
Fax (502) 627-3820
lisa.hennekes@eon-us.com

Wiseman, Sara

From: Conroy, Robert
Sent: Thursday, December 15, 2005 4:39 PM
To: Blake, Kent; Charnas, Shannon; Wiseman, Sara
Subject: ARO Case.

Attachments: ARO Application KU Exhibits.pdf; ARO Application LG&E Exhibits.pdf; ARO Case Data Response.pdf; Transition JE's 6.6 %.xls

As discussed in the meeting yesterday, attached are some of the journal entry exhibits to the ARO cases and the rate case.

Exhibits contained in the Application for Case 2003-00426 and Case 2003-00427.

ARO Application KU Exhibits.pd...   ARO Application LG&E Exhibits....

Data response to PSC question 4 showing T-Accounts.

ARO Case Data Response.pdf

Journal entry in response to AG 1st data request question 140 in the KU rate case. There were a lot more attachments to the data response, but I didn't feel it was necessary to attach. If you want to see them and don't have a copy, let me know.

Transition JE's 6.6 %.xls

For the rate cases the following is a listing of the questions that dealt in some manner with SFAS 143.

KU
- PSC 1-56
- AG 1-139
- AG 1-140
- AG 1-141
- PSC 2-55

LG&E
- PSC 1-56
- AG 1-196
- AG 1-197
- AG 1-198
- KIUC 1-100
- PSC 2-1
- PSC 2-65

Robert M. Conroy
Manager, Rates
(502) 627-3324 (phone)
(502) 627-3213 (fax)
(502) 741-4322 (mobile)

Exhibit 1

Kentucky Utilities Company
ARO Journal Entries Required at Implementation
($000's)

DESCRIPTION	DEBIT	CREDIT
Long Lived Assets - ARO - *(New Account)*	8,608	
COR Liability Accrued to Date	2,388	
Regulatory Asset	9,926	
Cumulative Effect	9,926	
Regulatory Credits		9,926
Regulatory Liability - *(New Account)*		910
Accumulated Depreciation of ARO Asset - *(New Account)*		1,536
ARO Liability - *(New Account)*		18,477
	30,849	30,849
To record the implementation of SFAS No.143 (detailed entries shown below)		

DESCRIPTION	DEBIT	CREDIT
Long Lived Assets - ARO - BS Account 317	8,608	
ARO Liability - BS Account 230		8,608

To record the initial present value of ARO liability

Upon implementation of SFAS No. 143, the ARO liability (in current dollars) must be future valued at the anticipated inflation rate. The ARO liability must then be present valued back to when the liability was incurred using risk free rate plus risk premium at the time the liability was incurred.
The ARO asset is valued at the present value of the liability at the time the liability is incurred.

DESCRIPTION	DEBIT	CREDIT
Cumulative Effect Adjustment - IS Account 435	1,536	
Accumulated Depreciation of ARO Asset - BS Account 108		1,536

To record accumulated depreciation on ARO assets

Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.
The cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407) and a debit to Regulatory Assets (Account 182.3)

DESCRIPTION	DEBIT	CREDIT
Cumulative Effect Adjustment - IS Account 435	9,869	
ARO Liability - BS Account 230		9,869

To record accumulated accretion on ARO liability

The total accretion expense that would have been incurred if the liability was accreted from the time the liability was incurred to date.
The cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407) and a debit to Regulatory Assets (Account 182.3)

DESCRIPTION	DEBIT	CREDIT
Accumulated Deprecation- BS Account 108	2,388	
Regulatory Liability - BS Account 254		910
Cumulative Effect Adjustment - IS Account 435		1,478

To reclassify existing Cost of Removal

The COR liability currently reflected on the Balance Sheet must be fully reversed from the reserve.
The cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407) and a debit to Regulatory Assets (Account 182.3)

DESCRIPTION	DEBIT	CREDIT
Regulatory Assets - BS Account 182.3	9,926	
Regulatory Credits - IS Account 407		9,926

Because ARO costs qualify for SFAS No. 71 treatment the cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407) and a debit to Regulatory Assets (Account 182.3)

Exhibit 2

Kentucky Utilities Company
ARO Journal Entries Subsequent to Implementation
($000's)

DESCRIPTION	Annual Amounts DEBIT	Annual Amounts CREDIT
Depreciation Expense - IS Account 403.1	176	
Accumulated Depreciation of ARO Asset - BS Account 108.1		176
To record monthly depreciation expense		
Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.		
Regulatory Asset Account- BS Account 182.3	176	
Regulatory Credits - IS Account 407		176
To reverse monthly depreciation to regulatory asset/liability (Utility is I/S Neutral)		
The monthly depreciation expense must be reflected against a Regulatory Asset so that all effects of SFAS No. 143 are Income Statement neutral.		
Accretion Expense - IS Account 411.1	1,221	
ARO Liability - BS Account 230		1,221
To record monthly accretion expense on ARO liability		
The liability at implementation must be accreted to the anticipated cash outlay.		
Regulatory Asset Account- BS Account 182.3	1,221	
Regulatory Credits - IS Account 407		1,221
To reverse monthly accretion expense to regulatory asset/liability (Utility is I/S neutral)		
The monthly depreciation expense must be reflected against a Regulatory Asset so that all effects of SFAS No. 143 are Income Statement neutral.		
Depreciation Expense	xxxx	
Accumulated Depreciation		xxxx
To record monthly depreciation expense on underlying asset to which ARO related		
The underlying asset to which the ARO is attached is already in G/L systems and is shown for illustrative purposes. The original asset must somehow be linked to the ARO asset, the ARO Liability and the Regulatory Asset/Liability.		

Exhibit 1

Louisville Gas and Electric Company
ARO Journal Entries Required at Implementation
($000's)

DESCRIPTION	DEBIT	CREDIT
Long Lived Assets - ARO - *(New Account)*	4,585	
COR Liability Accrued to Date	458	
Regulatory Asset	5,281	
Cumulative Effect	5,281	
Regulatory Credits		5,281
Regulatory Liability - *(New Account)*		59
Accumulated Depreciation of ARO Asset - *(New Account)*		934
ARO Liability - *(New Account)*		9,331
	15,605	15,605
Summary entry to record the implementation of SFAS No. 143 (detailed entries shown below)		

Long Lived Assets - ARO - BS Account 317	4,585	
ARO Liability - BS Account 230		4,585

To record the initial present value of ARO liability

Upon implementation of SFAS No. 143, the ARO liability (in current dollars) must be future valued at the anticipated inflation rate. The ARO liability must then be present valued back to when the liability was incurred using risk free rate plus risk premium at the time the liability was incurred.
The ARO asset is valued at the present value of the liability at the time the liability is incurred.

Cumulative Effect Adjustment - IS Account 435	934	
Accumulated Depreciation of ARO Asset - BS Account 108		934

To record accumulated depreciation on ARO assets

Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.
The cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407) and a debit to Regulatory Assets (Account 182.3)

Cumulative Effect Adjustment - IS Account 435	4,745	
ARO Liability - BS Account 230		4,745

To record accumulated accretion on ARO liability

The total accretion expense that would have been incurred if the liability was accreted from the time the liability was incurred to date.
The cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407) and a debit to Regulatory Assets (Account 182.3)

Accumulated Deprecation- BS Account 108	458	
Regulatory Liability - BS Account 254		59
Cumulative Effect Adjustment - IS Account 435		398

To reclassify existing Cost of Removal

The COR liability currently reflected on the Balance Sheet must be fully reversed from the reserve.
The cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407) and a debit to Regulatory Assets (Account 182.3)

Regulatory Assets - BS Account 182.3	5,281	
Regulatory Credits - IS Account 407		5,281

Because ARO costs qualify for SFAS 71 treatment the cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407) and a debit to Regulatory Assets (Account 182.3)

Exhibit 2

Louisville Gas and Electric Company
ARO Journal Entries Subsequent to Implementation
($000's)

DESCRIPTION	Annual Amounts DEBIT	CREDIT
Depreciation Expense - IS Account 403.1	117.45	
Accumulated Depreciation of ARO Asset - BS Account 108.1		117.45
To record monthly depreciation expense		
Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.		
Regulatory Asset Account- BS Account 182.3	117.45	
Regulatory Credits - IS Account 407		117.45
To reverse monthly depreciation to regulatory asset/liability (Utility is I/S Neutral)		
The monthly depreciation expense must be reflected against a Regulatory Asset so that all effects of SFAS No. 143 are Income Statement neutral.		
Accretion Expense - IS Account 411.1	616.75	
ARO Liability - BS Account 230		616.75
To record monthly accretion expense on ARO liability		
The liability at implementation must be accreted to the anticipated cash outlay.		
Regulatory Asset Account- BS Account 182.3	616.75	
Regulatory Credits - IS Account 407		616.75
To reverse monthly accretion expense to regulatory asset/liability (Utility is I/S neutral)		
The monthly depreciation expense must be reflected against a Regulatory Asset so that all effects of SFAS No. 143 are Income Statement neutral.		
Depreciation Expense	xxxx	
Accumulated Depreciation		xxxx
To record monthly depreciation expense on underlying asset to which ARO related		
The underlying asset to which the ARO is attached is already in General Ledger systems and is shown for illustrative purposes. The original asset must somehow be linked to the ARO asset, the ARO Liability and the Regulatory Asset/Liability.		

LOUISVILLE GAS AND ELECTRIC COMPANY
AND
KENTUCKY UTILITIES COMPANY

CASE NOS. 2003-00426 and 2003-00427

Response to First Data Request of Commission Staff Dated December 4, 2003

Question No. 4

Responding Witness: Valerie L. Scott

Q-4. Refer to Exhibit 1 of the Applications.

a. Indicate when LG&E and KU recorded the entries shown in Application Exhibit 1 on their books.

b. For each utility, prepare a series of "T-Accounts" that reflect all the entries required at the implementation of SFAS No. 143. Include a separate "T-Account" for each account number shown in the entries and explanatory notes in Application Exhibit 1.

A-4.

a. LG&E and KU were required to adopt SFAS 143 effective January 1, 2003 and recorded the entries shown in Application Exhibit 1 on their books in the first quarter of 2003. FERC Order 631 was not issued in final format until April 9, 2003.

b. See attached Exhibit 4-b Schedules 1 and 2.

Exhibit 4-b
Schedule 1

Kentucky Utilities Company
ARO Journal Entries Required at Implementation
($000's)

Balance Sheet Accounts

Accts. 317, 347 & 359.1 ARO Assets

8,608 [1]	
8,608	

Act 230 ARO Liability

	8,608 [1]
	9,869 [3]
	18,477

Act 108 Acc. Reserve

	1,536 [2]
2,388 [4]	
852	

Act 254 Reg. Liability

	910 [4]
	910

Act 182.3 Reg. Assets

9,926 [5]	
9,926	

Income Statement Accounts

Acct 435 Cumulative Effect Adjustment

1,536 [2]	
9,869 [3]	
	1,478 [4]
9,927	

Acct 407 Reg Credits

	9,926 [5]
	9,926

[1] ***To record the initial present value of ARO liability***

Upon implementation of SFAS No. 143, the ARO liability (in current dollars) must be future valued at the anticipated inflation rate. The ARO liability must then be present valued back to when the liability was incurred using risk free rate plus risk premium at the time the liability was incurred.
The ARO asset is valued at the present value of the liability at the time the liability is incurred.

[2] ***To record accumulated depreciation on ARO assets***

Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.
The cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407)
and a debit to Regulatory Assets (Account 182.3)

[3] ***To record accumulated accretion on ARO liability***

The total accretion expense that would have been incurred if the liability was accreted from the time the liability was incurred to date.
The cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407)
and a debit to Regulatory Assets (Account 182.3)

[4] ***To reclassify existing Cost of Removal***

The COR liability currently reflected on the Balance Sheet must be fully reversed from the reserve.
The cumulative affect adjustment is offset by a debit to Other Regulatory Credits (Account 407)
and a credit to Regulatory Assets (Account 182.3)

[5] ***Because ARO costs qualify for SFAS 71 treatment the cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407) and a debit to Regulatory Assets (Account 182.3)***

The offsets described above for entries 2-4 are summarized below to equal the amount reflected in entry 5.

	DR/(CR)	
Entry	Acct. 182.3	Acct. 407
2	$ 1,536	$ (1,536)
3	9,869	(9,869)
4	(1,478)	1,478
	$ 9,927	$ (9,927)

Exhibit 4-b
Schedule 2

Louisville Gas and Electric Company
ARO Journal Entries Required at Implementation
($000's)

Balance Sheet Accounts

Accts. 317 & 359.1 ARO Assets	
4,585 [1]	
4,585	

Act 230 ARO Liability	
	4,585 [1]
	4,745 [3]
	9,330

Act 108 Acc. Reserve	
	934 [2]
458 [4]	
	476

Act 254 Reg. Liability	
	59 [4]
	59

Act 182.3 Reg. Assets	
5,281 [5]	
5,281	

Income Statement Accounts

Acct 435 Cumulative Effect Adjustment	
934 [2]	
4,745 [3]	
	398 [4]
5,281	

Acct 407 Reg Credits	
	5,281 [5]
	5,281

[1] ***To record the initial present value of ARO liability***

Upon implementation of SFAS No. 143, the ARO liability (in current dollars) must be future valued at the anticipated inflation rate. The ARO liability must then be present valued back to when the liability was incurred using risk free rate plus risk premium at the time the liability was incurred.
The ARO asset is valued at the present value of the liability at the time the liability is incurred.

[2] ***To record accumulated depreciation on ARO assets***

Assumes the ARO Asset is depreciated over the same life and method as the asset for which the ARO is attached.
The cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407) and a debit to Regulatory Assets (Account 182.3)

[3] ***To record accumulated accretion on ARO liability***

The total accretion expense that would have been incurred if the liability was accreted from the time the liability was incurred to date.
The cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407) and a debit to Regulatory Assets (Account 182.3)

[4] ***To reclassify existing Cost of Removal***

The COR liability currently reflected on the Balance Sheet must be fully reversed from the reserve.
The cumulative affect adjustment is offset by a debit to Other Regulatory Credits (Account 407) and a credit to Regulatory Assets (Account 182.3)

[5] ***Because ARO costs qualify for SFAS 71 treatment the cumulative affect adjustment is offset by a credit to Other Regulatory Credits (Account 407) and a debit to Regulatory Assets (Account 182.3)***

The offsets described above for entries 2-4 are summarized below to equal the amount reflected in entry 5.

	DR/(CR)	
Entry	Acct. 182.3	Acct. 407
2	$ 934	$ (934)
3	4,745	(4,745)
4	(398)	398
	$ 5,281	$ (5,281)

Leenerts, Patricia

From:	Leenerts, Patricia
Sent:	Monday, December 19, 2005 2:59 PM
To:	Ruckriegel, Tony
Subject:	Disposition of Personal Computers

Hey Tony, I'm new with E.On in Property Accounting. My main responsibility is FIN 47. Sara Wiseman had a note that a contract was being negotiated regarding disposition of PCs which might keep us from setting up an ARO (Asset Retirement Obligation) for the PCs. Can you give me the information? I would like to know disposition schedule, contract price (per unit maybe?), length of contract and anything else that may seem relevant.

I know that the year-end and vacations are upon us, but I would appreciate a quick response if possible. I will need time to move forward with calculations, if necessary.

Thanks and Merry Christmas

Pat

Leenerts, Patricia

From: Lyons, Susan
Sent: Monday, December 19, 2005 4:39 PM
To: Leenerts, Patricia
Subject: Asset Disposal Contract

Attachments: TEKsystems - FINAL v.15 101904 SL.doc; CPA 10363 TEKsystems Amendment 1 021005SL.doc; CPA 10363 TEKsystems Amendment 2 031005SL.doc

Pat,

Attached, please find our current contract for asset (PCs, Monitors, etc.) disposal.

As I mentioned by phone, Bruce Flannery, Manager - Desktop Operations, may be able to assist you with the actual numbers of assets disposed.

Here is the contract, and the amendments extending the agreement.

If you have any other questions, please let me know.

Thank you,

Susan Lyons
Corporate Supply Chain
E.ON U.S. Services Inc.
820 W. Broadway
Louisville, Kentucky 40202
(502) 627-3681 Office
(502) 217-2340 Fax
susan.lyons@eon-us.com

ΓEKsystems - FINAL v.15 10190... | CPA 10363 :systems Amendme | CPA 10363 :systems Amendme

CONTRACT #10363

This Contract is entered into, effective as of October 19, 2004, between LG&E Energy Services, Incorporated (hereinafter referred to as "LG&E"), whose address is 820 West Broadway, Louisville, Kentucky 40202, and

TEKsystems, Inc.
(hereinafter referred to as "Contractor")

ADDRESS: 7437 Race Road
Hanover, MD 21076

The parties hereto agree as follows:

1.0 GENERAL

Contractor shall perform the following: **Pilot program for the pick-up and disposal of used computers and associated electronic equipment; including monitors, CPUs, printers, etc. (hereinafter referred to as "Assets"),** as more specifically described in Article 2.0, hereof (hereinafter referred to as the Work) and LG&E shall compensate Contractor under all the terms and conditions hereof.

2.0 DESCRIPTION OF WORK

2.1 Except as otherwise expressly provided herein, Contractor shall supply all labor, materials, supervision, transportation, and shall pay all expenses, necessary or appropriate in the performance of Work.

2.2 The Work shall include, but not be limited to the following:

2.2.1 Contractor shall, upon LG&E's request, pick-up computers and associated electronic equipment (including monitors, CPU's, printers, etc) at designated sites and transport to Contractor's facility located at 1610 East Highwood Drive, Pontiac, MI.

2.2.1.1 LG&E shall notify Contractor when a shipment is ready for pick-up. Contractor shall subcontract Tantara Transportation Group to facilitate pick-up and transportation of Assets.

2.2.1.2 Pick-up and transportation services are included in the charges as described below in Article 7.0, and include:

- All necessary packaging and shipping materials
- Labor for palletizing and shrink wrapping Assets
- Loading of Assets onto truck
- Creation of any necessary shipping documentation
- Complete transport of all Assets to Contractor's facility
- Final Transport of all Assets between Contractor's facility and United Recycling Industries

2.2.1.3 LG&E agrees that:

- Assets will be ready for pick-up upon arrival of the freight carrier
- For each site that has a pick-up, there will be a minimum of 75 assets at that location. Not all sites will have a pick-up each time, however, the total pick-up will be a minimum of 150 assets.
- Equipment will be located within 100 ft. of a loading dock
- Facilities are tractor-trailer accessible
- Facilities do not have restrictions with the use of pallet jacks
- Facilities do not require protective covering for floors, walls or elevators.

2.2.2 Contractor will transport all Assets to United Recycling Industries where assets will be bar-coded and scanned for tracking purposes. After auditing, URI will demanufacture as outlined in the attached Flow-Chart (Exhibit A). United Recycling Industries shall assign each shipment an order number which is used to track the Assets throughout the demanufacturing process.

2.2.3 Assets will be received at United Recycling Industries in whole units and will be demanufactured and segregated into various materials such as plastic, iron, aluminum, glass, boards, etc. No components will be removed and resold. Batteries will be removed and sent for recycling as detailed in attached Exhibit A. All other product will be shredded.

2.2.4 LG&E assets will ONLY be sent to United Recycling Industries for recycling at ONLY the disposal sites listed in Exhibit A. Use of any other disposal facilities will require a written dually executed amendment to this agreement.

2.2.5 Contractor shall provide to LG&E a Certificate of Destruction/Recycling for each shipment of Assets taken from LG&E's facilities. Certificate will reference an attached detailed spreadsheet of all Assets for each shipment. These certificates will be presented to LG&E at time of invoicing.

2.2.6 Contractor shall be required to pick-up assets at LG&E's designated point of pick-up within 10 business days following the pick-up request.

2.2.7 LG&E may request pick-up services from any of the following locations:

2.2.7.1 LG&E Energy Services, Inc.
Broadway Office Complex
820 W. Broadway
Louisville, Kentucky 40202

2.2.7.2 LG&E Energy Services, Inc.
Corporate Offices
220 West Main Street
Louisville, Kentucky 40202

2.2.7.3 Kentucky Utilities
One Quality Street
Lexington, Kentucky 40507

2.2.8 At time of asset pick-up, Contractor shall sign an LG&E generated Disposal Detail Report verifying the count of all assets removed from LG&E's premises.

2.2.9 Title shall pass to Contractor at the point of pick-up.

2.2.10 Contractor shall dispose of all assets in accordance with applicable EPA Standards, state, and municipal laws. Contractor shall submit a Certificate of Disposal with an attached excel spreadsheet listing disposed units by serial number

2.2.11 LG&E shall have the right, at its own expense, to inspect the disposal operations conducted by Contractor, or its subcontractor at any tier in the performance of this Work. Such inspections shall not operate to relieve Contractor of its responsibility or liability under this Contract.

3.0 TERM

This Contract shall become effective on October 19, 2004 and continue through November 30, 2004. LG&E makes no promise or guarantee as to the amount of Work to be performed under this Contract, nor does it convey an exclusive right to the Contractor, to perform Work of the type or nature set forth in this Contract.

4.0 TERMS AND CONDITIONS

LG&E's Professional Service Agreement Terms and Conditions are as agreed to during the LG&E Vendor Certification process and thereby made a part of this contract.

5.0 EXHIBITS

Exhibit A   Listing of Final Disposal Sites for Recycled Materials

6.0 PRECEDENCE

6.1 In cases of express conflict between parts of the Contract, requirements, specifications, the order of precedence shall be as follows:

6.1.1 Contract
6.1.2 Professional Services Agreement
6.1.3 Attachments or Exhibits

6.2 In the event of an express conflict between the documents listed in Section 5.1, or between any other documents which are a part of the Contract, Buyer shall notify LG&E immediately and shall comply with LG&E's resolution of the conflict.

7.0 REPORTING REQUIRMENTS

7.1 Contractor shall be required to sign LG&E generated disposal report – verifying the number of pieces taken from LG&E's facilities.

7.2 Contractor shall provide a Certificate of Disposal for each pick-up of assets from an LG&E facility. The Certificate of Disposal will have an attached spreadsheet listing all assets by serial number that were disposed

8.0 COMPENSATION

8.1 Full compensation to Contractor for full and complete performance by Contractor of the Work, compliance with all terms and conditions of this Contract, and for Contractor's payment of all obligations incurred in, or applicable to, performance of the Work (hereinafter referred to as the "Contract Price") shall be as set forth below. These fees shall contain all charges associated with disposing of the asset including, but not limited to; labor, supervision, materials, transportation, disposal and handling. Fees will be invoiced within sixty days of the date assets are picked-up from LG&E's facilities.

CPU	$ 23 per unit
Monitor	$ 23 per unit
Server	$ 23 per unit
Printer (small)	$ 23 per unit
Printer (large)	$ 23 per unit
UPS	$ 23 per unit (plus $0.80 per lb. for battery recycling)
Docking Station	$ 23 per unit
Misc. Products	$ 23 per box (CPU sized box)

8.2 The fee for equipment not listed above (large servers, cabinets, server racks, and mainframe and midrange equipment) will be \$12.00 per Asset. Additional packaging, handling, and freight charges will be negotiated prior to pick-up on a case-by-case basis.

8.3 In no event shall the Work performed under this contract exceed ten-thousand dollars (\$10,000).

8.4 Invoicing Instructions

8.4.1 See the Article entitled " Invoices and Effect of Payments" in the Professional Services Agreement.

8.4.2 Contractor shall submit one complete invoice for each pick-up from LG&E's facilities. Each invoice must be accompanied by a Certificate of Disposal and an attached detailed spreadsheet by serial number. All invoices shall be submitted by Contractor within sixty (60) days of the date of pick-up. No subsequent partial invoices will be accepted.

8.4.3 Invoices shall include Contract Number 10363 and shall be submitted as follows:

Original: LG&E Energy Services, Inc.
Mr. Bruce Flannery
Manager, Desktop Operations
Broadway Office Complex
820 W. Broadway
Louisville, Kentucky 40202
bruce.flannery@lgeenergy.com

9.0 ENTIRE AGREEMENT

This Contract, including the attachments, constitutes the entire agreement between the parties relating to the Work and supersedes all prior or contemporaneous oral or written agreements, negotiations, understandings and statements pertaining to the Work or this Contract.

The parties hereto have executed this Contract on the dates written below, but it is effective as of the date first written above.

LG&E ENERGY SERVICES INC.

BY: ______________________________

TITLE: ______________________________

DATE: ______________________________

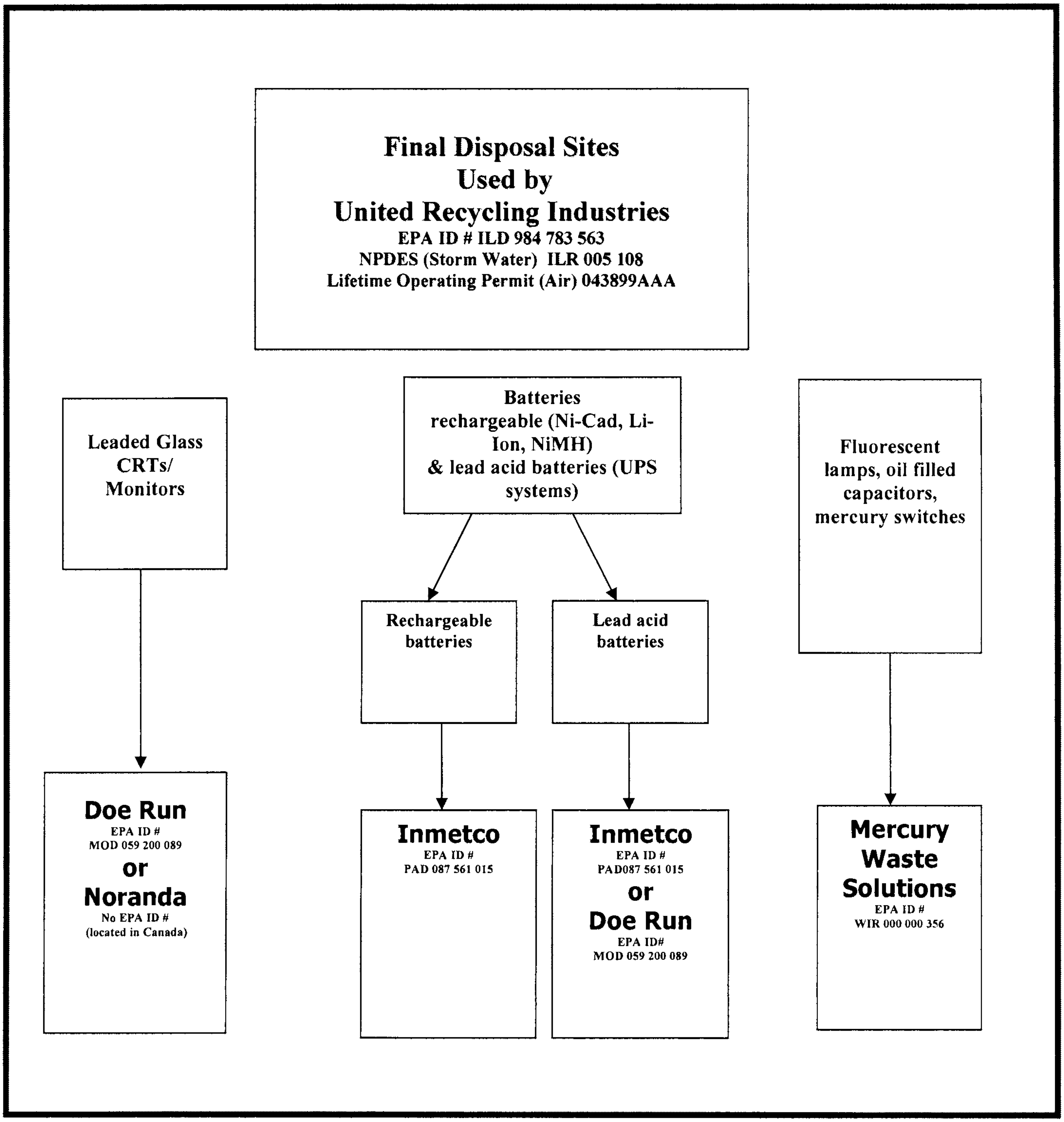
TEKsystems, Inc.

BY: ______________________________

TITLE: ______________________________

DATE: ______________________________

Exhibit A Contract # 10363



Amendment One (1) to Contract (CPA) Number 10363

THIS AMENDMENT IS entered into, effective as of February 10, 2005, by and between LG&E Energy Services Incorporated and affiliates (hereinafter referred to as "LG&E"), whose address is: 820 W. Broadway, Louisville, Kentucky 40232 and TEKsystems, Inc. (herein referred to as "Contractor"), whose address is: 1610 E. Highwood Drive, Pontiac, MI 48340. In consideration of the agreements herein contained, the parties hereto agree as follows:

1.0 AMENDMENTS

Section 3.0 TERM of the Contract heretofore entered into by the parties, dated effective October 19, 2004 and identified by the Contract Number **10363**, (hereinafter referred to as "Contract"), is hereby amended in it's entirety as follows:

> This Contract shall become effective on October 19, 2004 and continue through February 28, 2005. LG&E makes no promise or guarantee as to the amount of Work to be performed under this Contract, nor does it convey an exclusive right to the Contractor, to perform Work of the type or nature set forth in this Contract.

2.0 STATUS OF CONTRACT

As amended herein, the Contract shall continue in full force and effect.

IN WITNESS WHEREOF, the parties hereto have executed this Amendment on the day and year below written, but effective as of the day and year first set forth above.

LG&E Energy Services Incorporated	**TEKsystems, Inc.**
By____________________ William K. Woodard	By____________________
Title Manager, Corporate Purchasing	Name (print) ________________
Date February 10, 2005	Title____________________
	Date____________________

Amendment Two (2) to Contract (CPA) Number 10363

THIS AMENDMENT IS entered into, effective as of March 1, 2005, by and between LG&E Energy Services Incorporated and affiliates (hereinafter referred to as "LG&E"), whose address is: 820 W. Broadway, Louisville, Kentucky 40232 and TEKsystems, Inc. (herein referred to as "Contractor"), whose address is: 1610 E. Highwood Drive, Pontiac, MI 48340. In consideration of the agreements herein contained, the parties hereto agree as follows:

1.0 **AMENDMENTS**

1.1 Section 3.0 TERM of the Contract heretofore entered into by the parties, dated effective October 19, 2004 and identified by the Contract Number **10363**, (hereinafter referred to as "Contract"), is hereby amended in it's entirety as follows:

This Contract shall become effective on October 19, 2004 and continue through **October 18, 2007.** LG&E makes no promise or guarantee as to the amount of Work to be performed under this Contract, nor does it convey an exclusive right to the Contractor, to perform Work of the type or nature set forth in this Contract.

1.2 Section 2.2.1.2 of the Contract heretofore entered into by the parties, dated effective October 19, 2004 and identified by the Contract Number **10363**, (hereinafter referred to as "Contract"), is hereby amended in it's entirety as follows:

Pick-up and transportation services are included in the charges as described below in Article 7.0, and include:

- All necessary packaging and shipping materials
- Labor for palletizing and shrink wrapping Assets
- Loading of Assets onto a truck
- **Maximum length of truck (cab and trailer combined) used for Asset pick-up must not exceed 80 feet.**
- Creation of any necessary shipping documentation
- Complete transport of all Assets to Contractor's facility
- Final Transport of all Assets between Contractor's facility and United Recycling Industries

1.3 Section 8.3 of the Contract heretofore entered into by the parties, dated effective October 19, 2004 and identified by the Contract Number **10363**, (hereinafter referred to as "Contract"), is hereby amended in it's entirety as follows:

In no event shall the Work performed under this contract exceed one hundred thirty-five thousand dollars ($135,000).

2.0 STATUS OF CONTRACT

As amended herein, the Contract shall continue in full force and effect.

IN WITNESS WHEREOF, the parties hereto have executed this Amendment on the day and year below written, but effective as of the day and year first set forth above.

LG&E Energy Services Incorporated	**TEKsystems, Inc.**
By________________________________ William K. Woodard	By________________________________
Title Manager, Corporate Purchasing	Name (print) ______________________
Date March 10, 2005	Title____________________________
	Date____________________________

Leenerts, Patricia

From:	Scott, Valerie
Sent:	Wednesday, December 21, 2005 5:43 PM
To:	Leenerts, Patricia
Cc:	Charnas, Shannon; Wiseman, Sara
Subject:	RE: FIN 47 dollars by category

Pat,

If the summary below is correct, would you send this to Brad in addition to your original e-mail? I doubt he will want to go through the spreadsheets, but I think what he really wanted was the total AROs by facility type.

Thanks.

In summary the AROs at 12/31/05 for KU are:

Distribution Substation	$ 92,884.62
Office,Service Facilities	$ 158,943.51
Generation Facilities	$8,794,416.17
Transmission Facilities	$ 99,372.02
Total	$9,145,616.32

The AROs at 12/31/05 for LG&E are:

Office,Service Facilities	$ 54,696.11
Generation Facilities	$14,041,714.15
Transmission Facilities	$ 20,159.85
Gas Distribution Substations	$ 223,150.47
Gas City Gate & Storage Facilities	$ 246,189.82
Distribution Manhole Vaults	$ 876,345.04
Wells plugging	$ 6,911,863.45
Gas Main & Service Abandonments	$ 1,419,430.92
Riggs Station	$ 15,670.74
Total	$23,809,220.55

Valerie

From:	Leenerts, Patricia
Sent:	Wednesday, December 21, 2005 5:06 PM
To:	Rives, Brad
Cc:	Scott, Valerie; Charnas, Shannon; Wiseman, Sara
Subject:	FIN 47 dollars by category

Per your request, I have consolidated the various categories for your review. You will find the summary journal entry for each category as well as a summary by company.

I can be reached at X 3811 if you should have any questions or comments.

Pat

<< File: FIN 47 Combined LGE-exact dollars extended life.xls >> << File: FIN 47 Combined KU-exact dollars extended

life.xls >>

Leenerts, Patricia

From: Scott, Valerie
Sent: Thursday, December 22, 2005 11:03 AM
To: Leenerts, Patricia
Subject: RE: FIN 47 dollars by category

Thanks Pat.

Valerie

From: Leenerts, Patricia
Sent: Thursday, December 22, 2005 10:17 AM
To: Rives, Brad
Cc: Scott, Valerie; Charnas, Shannon; Wiseman, Sara
Subject: FW: FIN 47 dollars by category

Valerie suggested a more summarized format for your review. I have attached a summary in an excel file for ease of printing.

Please let me know if you have any questions or comments.

Merry Christmas

Pat
X 3811

<< File: ARO Items Summary.xls >>

From: Scott, Valerie
Sent: Wednesday, December 21, 2005 5:43 PM
To: Leenerts, Patricia
Cc: Charnas, Shannon; Wiseman, Sara
Subject: RE: FIN 47 dollars by category

Pat,

If the summary below is correct, would you send this to Brad in addition to your original e-mail? I doubt he will want to go through the spreadsheets, but I think what he really wanted was the total AROs by facility type.

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Generation Facilities	$14,041,714.15
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Gas City Gate & Storage Facilities	$	246,189.82
Distribution Manhole Vaults	$	876,345.04
Wells plugging	$	6,911,863.45
Gas Main & Service Abandonments	$	1,419,430.92
Riggs Station	$	15,670.74
Total		$23,809,220.55

Valerie

From: Leenerts, Patricia
Sent: Wednesday, December 21, 2005 5:06 PM
To: Rives, Brad
Cc: Scott, Valerie; Charnas, Shannon; Wiseman, Sara
Subject: FIN 47 dollars by category

Per your request, I have consolidated the various categories for your review. You will find the summary journal entry for each category as well as a summary by company.

I can be reached at X 3811 if you should have any questions or comments.

Pat

<< File: FIN 47 Combined LGE-exact dollars extended life.xls >> << File: FIN 47 Combined KU-exact dollars extended life.xls >>

Leenerts, Patricia

From: Kinder, Debra
Sent: Thursday, December 22, 2005 1:12 PM
To: Leenerts, Patricia
Subject: LGE KU 100 Meg Budget.pdf

Attachments: LGE KU 100 Meg Budget.pdf

LGE KU 100 Meg Budget.pdf

National Environmental Contracting, Inc.
2660 Technology Drive • Louisville, KY 40299-6424

Office: 502.261.0800
800.650.8893 • Fax: 502.261.0828

Estimate Cost for Asbestos Abatement of a Typical 100 MW Coal Fired Unit

Penthouse	300 ManDays @ $500.00 Per Day	$150,000.00
External Furnace (incl. Reheat Sect.)	1500 ManDays @ $500.00 Per Day	$750,000.00
External Piping (Oper. Floor Up)	500 ManDays @ $500.00 Per Day	$250,000.00
External Ductwork (Oper. Floor Up)	400 ManDays @ $500.00 Per Day	$200,000.00
Pipe & Equipment Under Oper. Floor	600 ManDays @ $500.00 Per Day	$300,000.00
Pipe & Equipment Under Oper. Floor	300 ManDays @ $500.00 Per Day	$150,000.00
Survey, Air Testing, Permits, etc.		$100,000.00
Contingency (Boiler Internals, Refractory, Unforseen)		$400,000.00
ESTIMATED TOTAL COST (in 2005 $$)		**$2,300,000.00**

Leenerts, Patricia

From:	Kinder, Debra
Sent:	Thursday, December 22, 2005 1:30 PM
To:	Leenerts, Patricia
Subject:	ASBESTOS REMOVAL EST COSTS FOR FACILITIES (2).xls
Attachments:	ASBESTOS REMOVAL EST COSTS FOR FACILITIES (2).xls

ASBESTOS
OVAL EST COSTS F(

SUMMARY OF ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES DEPT

		($000's)			
Asset Description	Location	Removal Cost per Asset ($000's)	Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)	Estimated Retirement Date
No known asbestos remaining. Renovations have been completed removing known asbestos.	Auburndale Op Ctr	$0	$0	$0	
One story , 2,500 sq. ft. concrete block building constructed in 1965. which has been renovated and there are no signs of asbestos.	Barlow	$0	$0	$0	
There are 3 wood framed, metal siding and metal roof structures with a combined total of 2,496 sq. ft. Buildings were constructed in 1970; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Barlow Storeroom	$0	$0	$0	
Facility constructed in 1978 and is a pre-engineered metal building on slab with 3,200 sq. ft. Office area has VCT and drop ceiling which due to age of facility may be asbestos.	Big Stone Gap Substation	$26	$3	$29	
This facility has been renovated throughout and asbestos removed during the process	Broadway Office Complex	$0	$0	$0	
One story , 2,500 sq. ft. concrete block building constructed in 1957. which has been renovated but possible asbestos in roof.	Campbellsville	$3	$0	$3	
There are 3 wood framed, metal siding and metal roof structures with a combined total of 6,450 sq. ft. Buildings were constructed in 1960; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Campbellsville Storeroom	$0	$0	$0	
The facility is a one-story metal on concrete slab structure with 555 sq. ft. constructed in 1980. No visible signs of asbestos	Carlise Storeroom	$0	$0	$0	
This is a 1-1/2 story brick building with 3,500 sq. ft. constructed in approx. 1970. Shingle roof system installed over original roof (could be asbestos).	Carrollton	$4	$3	$7	
One story , 2,644 sq. ft. concrete block building constructed in 1970 with 24' walls and 3 garage doors. Possible asbestos in roof.	Carrollton Storeroom	$4	$3	$7	
This is a 2 story facility was constructed in 1961 with 3,984 sq. ft.; an addition of 2,200 sq. ft. was added above the drive thru in approx 1980. Due to age of facility asbestos is suspected (excluding roof, which was installed in 2004).	Danville	$63	$13	$76	
This is a 10,560 sq. ft. pre-engineered metal building on a concrete slab constructed in 1998. Due to the age of the building asbestos is not suspected.	Danville Storeroom	$0	$0	$0	
This is a 20,800 sq. ft. pre-engineered metal building on a concrete slab constructed in 1988. Due to the age of the building asbestos is not suspected.	Danville Substation & Meter Dept.	$0	$0	$0	
The building was constructed between 1975 - 1980 and consists of a wood frame with metal façade and metal roof. Total sq. ft. of 1,900 and is divided into 3 sections - truck parking, office, storage. Heating / Cooling with heat pumps approx 9 yrs. old. Due to the age of the building it may contain asbestos.	Dawson Springs Storeroom	$11	$3	$14	

SUMMARY OF ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES DEPT

	($000's)				
Asset Description	Location	Removal Cost per Asset ($000's)	Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)	Estimated Retirement Date
This facility was constructed in 1970. The office building is a wood frame structure with brick façade with approx. 3,840 sq. ft. Age of the facility indicate potential asbestos.	Earlington	$41	$3	$44	
This facility has a metal office and storage building with 11,500 sq. ft. constructed in 1990. Due to the age of the building asbestos is not suspected.	Earlington-Parkway Storeroom	$0	$0	$0	
Bldg constructed in 1995 (approx. 25,000 sq. ft.)- Due to age of building asbestos is not suspected	Earlington-Western Technical Services	$0	$0	$0	
There is no known asbestos in this facility.	East Oper Ctr	$0	$0	$0	
Possible Asbestos in roof.	Eddyville	$3	$3	$7	
This is a pre-engineered metal building with brick veneer, constructed in 1992 (approx. 3,000 sq. ft.)- Due to age of building asbestos is not suspected	Eddyville Storeroom	$0	$0	$0	
	Elizabethtown	$0	$0	$0	
	Elizabethtown Storeroom	$0	$0	$0	
There are 2 buildings at this site. The first bldg was constructed in 1950 with 3,150 sq. ft. The second bldg was constructed in 1980 with 1,280 sq. ft.. Renovations have been made to this facility - but possible asbestos in roof.	Georgetown	$14	$3	$18	
Bldg constructed in 1996 - however, roof inspectors noted possible asbestos in roof	Greenville	$11	$3	$14	
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Greenville Storeroom	$0	$0	$0	
Approx. 4,800 sq. ft. storeroom and office area was constructed between late 1960 - early 1970. It is a pre-engineered metal building on a slab. Asbestos does not appear to be present	Harlan Storeroom	$0	$0	$0	
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Irvine Storeroom	$0	$0	$0	
Main Bldg Brick masonary, constructed in 1920 and remodeled in 1970. Tile floors, drop ceiling tiles and painted drywall and block walls. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Lexington Meter Dept.	$89	$13	$102	
Storage Bldg constructed in 1920 - Age of facility would indicate potential of asbestos throughout bldg.	Lexington Meter Dept.	$75	$13	$88	
	Lexington Operations Center	$0	$0	$0	
Main Bldg - 9,600 Sq. Ft. Transformer Shop constructed in 1911 with potential of asbestos throughout masonry building. Also attached is a 3,600 sq. ft. metal building	Lexington Substation/Relay Dept.	$93	$13	$106	
Office and Garage Bldg constructed in 1996 (6,200 sq. ft) - Due to age of building asbestos is not suspected	Lexington Substation/Relay Dept.	$0	$0	$0	

SUMMARY OF ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES DEPT

		($000's)			
Asset Description	Location	Removal Cost per Asset ($000's)	Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)	Estimated Retirement Date
Vacant Brick Bldg (Total 768 Sq. Ft.)	Lexington Substation/Relay Dept.	$0	$0	$0	
3 Metal Storage Bldgs - Asbestos not suspected	Lexington Substation/Relay Dept.	$0	$0	$0	
Leased Facility	Livermore Storeroom	$0	$0	$0	
Office was constructed in 1998 (4,700 sq. ft) - Due to age of building asbestos is not suspected	London	$0	$0	$0	
This is a 4,500 sq. ft. storeroom. The office portion was added in 2002 and new metal installed over the 30 yr. old storerooms wood frame. Possible Asbestos in roof.	London Storeroom	$6	$3	$9	
Bldg constructed in 1956 (875 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct).	Marion Storeroom	$0	$0	$0	
Bldg constructed in 1960 (3,978 sq. ft.); however, it appears that renovations have been made but possible asbestos in roof.	Maysville	$5	$3	$8	
Bldg constructed in 1960 (2,950 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct). No asbestos suspected	Maysville Storeroom	$0	$0	$0	
This is a brick masonary two-story building, constructed in 1960 with 8,400 total sq. ft.; however, second floor is leased out. Tile floors, drop ceiling tiles and painted drywall. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Middlesboro	$105	$13	$118	
This facility was constructed in 1920 with 12,300 sq. ft. A recent facility analysis suggested vacating this property due to structural integrity and major costs to repair / renovate. Age of this facility would indicate asbestos throughout. (Similar to LG&E 7th & O facility) - Should abandon or demo	Middlesboro Storeroom	$82	$13	$95	
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Midway (Service Center)	$0	$0	$0	
Bldg constructed in 1970 (total sq. ft. 2400) but customer service area and foyer (sq. ft.) were remodeled 7 years ago. VCT and ceiling tiles in remainder of building suspected to be asbestos.	Morehead	$25	$3	$28	
Leased Facility	Morehead Storeroom	$0	$0	$0	
This is a brick masonary two-story building, constructed in 1965 with 7,500 total sq. ft. Asbestos may be present in roof.	Morganfield	$6	$3	$9	
This is a pre-engineered metal building with brick veneer, constructed in 1978 and extended in 1990 (total sq. ft. approx. 4,000). Asbestos not suspected.	Morganfield Storeroom	$0	$0	$0	
This is a brick masonary one-story building, constructed in 1972 with 3,000 total sq. ft. Suspect asbestos present in roof, floor tiles and possible ceiling tiles.	Mt. Sterling	$23	$3	$26	

SUMMARY OF ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES DEPT

		($000's)			
Asset Description	Location	Removal Cost per Asset ($000's)	Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)	Estimated Retirement Date
This is a 3,400 sq. ft. concrete masonry block facility with concrete floors, ceilings of plywood, walls that are drywall or paneling. Possible asbestos in roof.	Mt. Sterling Storeroom	$5	$3	$8	
	Norton	$0	$0	$0	
	Norton Storeroom	$0	$0	$0	
Asbestos not suspected	One Quality General Office				
This is a brick masonary one-story building, constructed around 1980 with 3,795 sq. ft. Suspect asbestos present in roof.	Paris	$5	$3	$8	
This is a 2,783 sq. ft. concrete block facility garage / storeroom with a 10' x 12' office area. It was constructed around 1970. Possible asbestos in roof.	Paris Storeroom	$4	$3	$7	
	Pennington Gap	$0	$0	$0	
Leased Facility	Pennington Gap Storeroom	$0	$0	$0	
There are several bldgs at this facility - Communications bldg 1,800 sq ft and Trans Dept 2,520 sq. ft. building in 2000-2001; Main Bldg const in 1982 with 32,800 sq. ft. (all of which are metal veneer. Asbestos does not appear to be an issue.	Pineville Stores/Complex; Meter Lab & Substation	$0	$0	$0	
The original building was constructed in 1970 but an addition was added in early 1980's. It is a one story brick with 5,350 sq. ft. Due to age and photos of the building it appears that VCT / mastic could contain asbestos.	Richmond	$21	$3	$24	
This facility was constructed in 1985, is a 2,800 sq. ft. metal structure with metal roof. Asbestos is not suspected.	Richmond Storeroom	$0	$0	$0	
This facility is a 3 story building with a total of 109,386 sq. ft. and was formerly used as an operation center with warehouse and offices. Age of this facility suggests asbestos throughout.	Seventh & Ormsby	$372	$53	$425	
This is a one story brick bldg with 4,500 sq. ft. built in 1955 which has been renovated and asbestos does not appear to be an issue.	Shelbyville	$0	$0	$0	
There are 2 buildings at this site. One is an older bldg actually dismantled and moved from another site to this location and was constructed in 1972. The other is a pre-engineered metal bldg, constructed in approx 1993. Both bldgs combined have 8,120 sq. ft. (a very small office area). Asbestos possible in roof.	Shelbyville Storeroom	$11	$13	$24	
This office was constructed in 1971 with 3,500 sq. ft. It is wood frame with brick veneer. Age of this facility would indicate the potential for asbestos although some renovations have occurred.	Somerset	$38	$3	$41	

SUMMARY OF ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES DEPT

	($000's)				
Asset Description	**Location**	**Removal Cost per Asset ($000's)**	**Total Incremantal Cost of Disposal ($000's)**	**GRAND TOTAL ($000's)**	**Estimated Retirement Date**
This office was constructed in 1971 with 6,000 sq. ft. It is a metal and concrete structure with metal roof. Age of this facility would indicate the potential for asbestos (tile floors and ceiling in office area).	Somerset Storeroom	$23	$3	$26	
Abatement of tile performed in 2004. Roofs have been replaced. Asbestos not suspected.	South Service Center	$0	$0	$0	
The main building was constructed in early 1970's and an additional section added around 1985. This is a 2 story concrete block with brick veneer front structure. Gross sq. ft. 10,179. Some updates have been completed however, VCT suspected asbestos.	Stone Road	$31	$3	$34	
Bldg constructed in 1985 - Due to age of building asbestos is not suspected	Versailles	$0	$0	$0	
This is a single story brick facility with partial basement and was constructed in 1965 with approx. 3,500 sq. ft. Age of the building would indicate possible asbestos.	Winchester	$35	$3	$38	
This is a concrete block garage / storeroom with approx. 2,880 sq. ft.. Original construction in 1970 and an addition added in 1982. Asbestos suspected in roof.	Winchester Storeroom	$4	$3	$7	
GRAND TOTAL ($000's)		**$1,234**	**$217**	**$1,452**	

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation (If <100 Ln.Ft. Cost = $64, otherwise $35/Ln.Ft.)		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
No known asbestos remaining. Renovations have been completed removing known asbestos.	Auburndale Op Ctr	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1965. which has been renovated and there are no signs of asbestos.	Barlow	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
There are 3 wood framed, metal siding and metal roof structures with a combined total of 2,496 sq. ft. Buildings were constructed in 1970; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Barlow Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Facility constructed in 1978 and is a pre-engineered metal building on slab with 3,200 sq. ft. Office area has VCT and drop ceiling which due to age of facility may be asbestos.	Big Stone Gap Substation	$1.90	1,600	**$3,040**	$1.95	1,600	**$3,120**	$1.95	1,600	**$3,120**	$35.00	256	**$8,960**
This facility has been renovated throughout and asbestos removed during the process	Broadway Office Complex	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1957. which has been renovated but possible asbestos in roof.	Campbellsville	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
There are 3 wood framed, metal siding and metal roof structures with a combined total of 6,450 sq. ft. Buildings were constructed in 1960; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Campbellsville Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation (If <100 Ln.Ft. Cost = $64, otherwise $35/Ln.Ft.)		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
The facility is a one-story metal on concrete slab structure with 555 sq. ft. constructed in 1980. No visible signs of asbestos	Carlise Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This is a 1-1/2 story brick building with 3,500 sq. ft. constructed in approx. 1970. Shingle roof system installed over original roof (could be asbestos).	Carrollton	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
One story , 2,644 sq. ft. concrete block building constructed in 1970 with 24' walls and 3 garage doors. Possible asbestos in roof.	Carrollton Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This is a 2 story facility was constructed in 1961 with 3,984 sq. ft.; an addition of 2,200 sq. ft. was added above the drive thru in approx 1980. Due to age of facility asbestos is suspected (excluding roof, which was installed in 2004).	Danville	$1.90	3,984	**$7,570**	$1.95	3,984	**$7,769**	$1.95	3,984	**$7,769**	$35.00	318.72	**$11,155**
This is a 10,560 sq. ft. pre-engineered metal building on a concrete slab constructed in 1998. Due to the age of the building asbestos is not suspected.	Danville Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This is a 20,800 sq. ft. pre-engineered metal building on a concrete slab constructed in 1988. Due to the age of the building asbestos is not suspected.	Danville Substation & Meter Dept.	$1.90		$0	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
The building was constructed between 1975 - 1980 and consists of a wood frame with metal façade and metal roof. Total sq. ft. of 1,900 and is divided into 3 sections - truck parking, office, storage. Heating / Cooling with heat pumps approx 9 yrs. old. Due to the age of the building it may contain asbestos.	Dawson Springs Storeroom	$1.90	627	**$1,191**	$1.95	627	**$1,223**	$1.95	627	**$1,223**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation (If <100 Ln.Ft. Cost = $64, otherwise $35/Ln.Ft.)		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
This facility was constructed in 1970. The office building is a wood frame structure with brick façade with approx. 3,840 sq. ft. Age of the facility indicate potential asbestos.	Earlington	$1.90	3,200	**$6,080**	$1.95	3,200	**$6,240**	$1.95	3,200	**$6,240**	$35.00	256	**$8,960**
This facility has a metal office and storage building with 11,500 sq. ft. constructed in 1990. Due to the age of the building asbestos is not suspected.	Earlington-Parkway Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Bldg constructed in 1995 (approx. 25,000 sq. ft.)- Due to age of building asbestos is not suspected	Earlington-Western Technical Services	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
There is no known asbestos in this facility.	East Oper Ctr	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Possible Asbestos in roof.	Eddyville	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This is a pre-engineered metal building with brick veneer, constructed in 1992 (approx. 3,000 sq. ft.)- Due to age of building asbestos is not suspected	Eddyville Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
	Elizabethtown	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
	Elizabethtown Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
There are 2 buildings at this site. The first bldg was constructed in 1950 with 3,150 sq. ft. The second bldg was constructed in 1980 with 1,280 sq. ft.. Renovations have been made to this facility - but possible asbestos in roof.	Georgetown	$1.90	4,430	**$8,417**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Bldg constructed in 1996 - however, roof inspectors noted possible asbestos in roof	Greenville	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Greenville Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation (If <100 Ln.Ft. Cost = $64, otherwise $35/Ln.Ft.)		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
Approx. 4,800 sq. ft. storeroom and office area was constructed between late 1960 - early 1970. It is a pre-engineered metal building on a slab. Asbestos does not appear to be present	Harlan Storeroom	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Irvine Storeroom	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
Main Bldg Brick masonary, constructed in 1920 and remodeled in 1970. Tile floors, drop ceiling tiles and painted drywall and block walls. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Lexington Meter Dept.	$1.90	9,024	$17,146	$1.95	4,512	$8,798	$1.95	4,512	$8,798	$35.00	722	$25,267
Storage Bldg constructed in 1920 - Age of facility would indicate potential of asbestos throughout bldg.	Lexington Meter Dept.	$1.90	15,776	$29,974	$1.95	0	$0	$1.95	0	$0	$35.00	473	$16,565
	Lexington Operations Center	$1.90		$0			$0	$1.95		$0	$65.00		$0
Main Bldg - 9,600 Sq. Ft. Transformer Shop constructed in 1911 with potential of asbestos throughout masonry building. Also attached is a 3,600 sq. ft. metal building	Lexington Substation/Relay Dept.	$1.90	9,600	$18,240	$1.95	4,800	$9,360	$1.95	4,800	$9,360	$35.00	768	$26,880
Office and Garage Bldg constructed in 1996 (6,200 sq. ft) - Due to age of building asbestos is not suspected	Lexington Substation/Relay Dept.	$1.90		$0			$0	$1.95		$0	$65.00		$0
Vacant Brick Bldg (Total 768 Sq. Ft.)	Lexington Substation/Relay Dept.	$1.90		$0			$0	$1.95		$0	$65.00		$0
3 Metal Storage Bldgs - Asbestos not suspected	Lexington Substation/Relay Dept.	$1.90		$0			$0	$1.95		$0	$65.00		$0
Leased Facility	Livermore Storeroom	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
Office was constructed in 1998 (4,700 sq. ft) - Due to age of building asbestos is not suspected	London	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation (If <100 Ln.Ft. Cost = $64, otherwise $35/Ln.Ft.)		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
This is a 4,500 sq. ft. storeroom. The office portion was added in 2002 and new metal installed over the 30 yr. old storerooms wood frame. Possible Asbestos in roof.	London Storeroom	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
Bldg constructed in 1956 (875 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct).	Marion Storeroom	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
Bldg constructed in 1960 (3,978 sq. ft.); however, it appears that renovations have been made but possible asbestos in roof.	Maysville	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
Bldg constructed in 1960 (2,950 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct). No asbestos suspected	Maysville Storeroom	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
This is a brick masonary two-story building, constructed in 1960 with 8,400 total sq. ft.; however, second floor is leased out. Tile floors, drop ceiling tiles and painted drywall. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Middlesboro	$1.90	8,400	$15,960	$1.95	8,400	$16,380	$1.95	8,400	$16,380	$35.00	672	$23,520
This facility was constructed in 1920 with 12,300 sq. ft. A recent facility analysis suggested vacating this property due to structural integrity and major costs to repair / renovate. Age of this facility would indicate asbestos throughout. (Similar to LG&E 7th & O facility) - Should abandon or demo	Middlesboro Storeroom	$1.90	12,300	$23,370	$1.95	0	$0	$1.95	0	$0	$35.00	369	$12,915
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Midway (Service Center)	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation (If <100 Ln.Ft. Cost = $64, otherwise $35/Ln.Ft.)		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
Bldg constructed in 1970 (total sq. ft. 2400) but customer service area and foyer (sq. ft.) were remodeled 7 years ago. VCT and ceiling tiles in remainder of building suspected to be asbestos.	Morehead	$1.90	1,725	**$3,278**	$1.95	1,725	**$3,364**	$1.95	1,725	**$3,364**	$35.00	192	**$6,720**
Leased Facility	Morehead Storeroom	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
This is a brick masonary two-story building, constructed in 1965 with 7,500 total sq. ft. Asbestos may be present in roof.	Morganfield	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This is a pre-engineered metal building with brick veneer, constructed in 1978 and extended in 1990 (total sq. ft. approx. 4,000). Asbestos not suspected.	Morganfield Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This is a brick masonary one-story building, constructed in 1972 with 3,000 total sq. ft. Suspect asbestos present in roof, floor tiles and possible ceiling tiles.	Mt. Sterling	$1.90	3,000	**$5,700**	$1.95	3,000	**$5,850**	$1.95	3,000	**$5,850**	$65.00		**$0**
This is a 3,400 sq. ft. concrete masonry block facility with concrete floors, ceilings of plywood, walls that are drywall or paneling. Possible asbestos in roof.	Mt. Sterling Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
	Norton	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
	Norton Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
Asbestos not suspected	One Quality General Office										$65.00		
This is a brick masonary one-story building, constructed around 1980 with 3,795 sq. ft. Suspect asbestos present in roof.	Paris	$1.90		$0	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation (If <100 Ln.Ft. Cost = $64, otherwise $35/Ln.Ft.)		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
This is a 2,783 sq. ft. concrete block facility garage / storeroom with a 10' x 12' office area. It was constructed around 1970. Possible asbestos in roof.	Paris Storeroom	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
	Pennington Gap	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
Leased Facility	Pennington Gap Storeroom	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
There are several bldgs at this facility - Communications bldg 1,800 sq ft and Trans Dept 2,520 sq. ft. building in 2000-2001; Main Bldg const in 1982 with 32,800 sq. ft. (all of which are metal veneer. Asbestos does not appear to be an issue.	Pineville Stores/Complex; Meter Lab & Substation	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
The original building was constructed in 1970 but an addition was added in early 1980's. It is a one story brick with 5,350 sq. ft. Due to age and photos of the building it appears that VCT / mastic could contain asbestos.	Richmond	$1.90	5,350	$10,165	$1.95	0	$0	$1.95	5,350	$10,433	$65.00		$0
This facility was constructed in 1985, is a 2,800 sq. ft. metal structure with metal roof. Asbestos is not suspected.	Richmond Storeroom	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0
This facility is a 3 story building with a total of 109,386 sq. ft. and was formerly used as an operation center with warehouse and offices. Age of this facility suggests asbestos throughout.	Seventh & Ormsby				$1.95	3,000	$5,850	$1.95	3,000	$5,850	$35.00	960	$33,600
This is a one story brick bldg with 4,500 sq. ft. built in 1955 which has been renovated and asbestos does not appear to be an issue.	Shelbyville	$1.90		$0	$1.95		$0	$1.95		$0	$65.00		$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation (If <100 Ln.Ft. Cost = $64, otherwise $35/Ln.Ft.)		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
There are 2 buildings at this site. One is an older bldg actually dismantled and moved from another site to this location and was constructed in 1972. The other is a pre-engineered metal bldg, constructed in approx 1993. Both bldgs combined have 8,120 sq. ft. (a very small office area). Asbestos possible in roof.	Shelbyville Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
This office was constructed in 1971 with 3,500 sq. ft. It is wood frame with brick veneer. Age of this facility would indicate the potential for asbestos although some renovations have occurred.	Somerset	$1.90	3,500	**$6,650**	$1.95	3,500	**$6,825**	$1.95	3,500	**$6,825**	$35.00	280	**$9,800**
This office was constructed in 1971 with 6,000 sq. ft. It is a metal and concrete structure with metal roof. Age of this facility would indicate the potential for asbestos (tile floors and ceiling in office area).	Somerset Storeroom	$1.90	1,500	**$2,850**	$1.95	1,500	**$2,925**	$1.95	1,500	**$2,925**	$35.00	180	**$6,300**
Abatement of tile performed in 2004. Roofs have been replaced. Asbestos not suspected.	South Service Center	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
The main building was constructed in early 1970's and an additional section added around 1985. This is a 2 story concrete block with brick veneer front structure. Gross sq. ft. 10,179. Some updates have been completed however, VCT suspected asbestos.	Stone Road	$1.90	8,000	**$15,200**	$1.95		**$0**	$1.95	8,000	**$15,600**	$65.00		**$0**
Bldg constructed in 1985 - Due to age of building asbestos is not suspected	Versailles	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Enclosure using wood studs & poly, install & removal			Cost to Remove Ceiling Tiles			Cost to Remove VCT (Floor Tile)			Costs to Remove Duct and/ or Pipe Insulation (If <100 Ln.Ft. Cost = $64, otherwise $35/Ln.Ft.)		
		Cost per Sq. Ft	# Sq. Ft.	Total Cost to Install / Remove Enclosure	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove Ceiling Tiles	Cost per Sq. Ft	# Sq. Ft.	Total Cost to Remove VCT	Cost per L F.	# L.F.	Total Cost to Remove Duct & Pipe Insulation
This is a single story brick facility with partial basesment and was constructed in 1965 with approx. 3,500 sq. ft. Age of the building would indicate possible asbestos.	Winchester	$1.90	3,500	**$6,650**	$1.95	3,500	**$6,825**	$1.95	3,500	**$6,825**	$35.00	280	**$9,800**
This is a concrete block garage / storeroom with approx. 2,880 sq. ft.. Original construction in 1970 and an addition added in 1982. Asbestos suspected in roof.	Winchester Storeroom	$1.90		**$0**	$1.95		**$0**	$1.95		**$0**	$65.00		**$0**
GRAND TOTAL ($000's)				**$181**			**$85**			**$111**			**$200**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
No known asbestos remaining. Renovations have been completed removing known asbestos.	Auburndale Op Ctr	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
One story , 2,500 sq. ft. concrete block building constructed in 1965. which has been renovated and there are no signs of asbestos.	Barlow	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
There are 3 wood framed, metal siding and metal roof structures with a combined total of 2,496 sq. ft. Buildings were constructed in 1970; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Barlow Storeroom	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
Facility constructed in 1978 and is a pre-engineered metal building on slab with 3,200 sq. ft. Office area has VCT and drop ceiling which due to age of facility may be asbestos.	Big Stone Gap Substation	$65.00	0	$0		0	$0	$5.00	0	$0	$1.35	0	$0
This facility has been renovated throughout and asbestos removed during the process	Broadway Office Complex	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
One story , 2,500 sq. ft. concrete block building constructed in 1957. which has been renovated but possible asbestos in roof.	Campbellsville	$65.00		$0			$0	$5.00		$0	$1.35	2,500	$3,375
There are 3 wood framed, metal siding and metal roof structures with a combined total of 6,450 sq. ft. Buildings were constructed in 1960; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Campbellsville Storeroom	$65.00		$0			$0	$5.00		$0	$1.35	0	$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	**Total Cost to Remove Boiler & Assoc. Equip**	Cost per Elevator	# Units	**Total Cost to Remove Elevator Brake & Clutch**	Cost per Sq. Ft.	# Sq. Ft.	**Total Cost to Remove Panels or Mastics**	Cost per Sq. Ft.	# Sq. Ft.	**Total Cost to Remove Roofing Materials**
The facility is a one-story metal on concrete slab structure with 555 sq. ft. constructed in 1980. No visible signs of asbestos	Carlise Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
This is a 1-1/2 story brick building with 3,500 sq. ft. constructed in approx. 1970. Shingle roof system installed over original roof (could be asbestos).	Carrollton	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	2,956	**$3,991**
One story , 2,644 sq. ft. concrete block building constructed in 1970 with 24' walls and 3 garage doors. Possible asbestos in roof.	Carrollton Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	2,644	**$3,569**
This is a 2 story facility was constructed in 1961 with 3,984 sq. ft.; an addition of 2,200 sq. ft. was added above the drive thru in approx 1980. Due to age of facility asbestos is suspected (excluding roof, which was installed in 2004).	Danville	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
This is a 10,560 sq. ft. pre-engineered metal building on a concrete slab constructed in 1998. Due to the age of the building asbestos is not suspected.	Danville Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
This is a 20,800 sq. ft. pre-engineered metal building on a concrete slab constructed in 1988. Due to the age of the building asbestos is not suspected.	Danville Substation & Meter Dept.	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
The building was constructed between 1975 - 1980 and consists of a wood frame with metal façade and metal roof. Total sq. ft. of 1,900 and is divided into 3 sections - truck parking, office, storage. Heating / Cooling with heat pumps approx 9 yrs. old. Due to the age of the building it may contain asbestos.	Dawson Springs Storeroom	$65.00	0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	**Total Cost to Remove Boiler & Assoc. Equip**	Cost per Elevator	# Units	**Total Cost to Remove Elevator Brake & Clutch**	Cost per Sq. Ft.	# Sq. Ft.	**Total Cost to Remove Panels or Mastics**	Cost per Sq. Ft.	# Sq. Ft.	**Total Cost to Remove Roofing Materials**
This facility was constructed in 1970. The office building is a wood frame structure with brick façade with approx. 3,840 sq. ft. Age of the facility indicate potential asbestos.	Earlington	$65.00	0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	3,840	**$5,184**
This facility has a metal office and storage building with 11,500 sq. ft. constructed in 1990. Due to the age of the building asbestos is not suspected.	Earlington-Parkway Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Bldg constructed in 1995 (approx. 25,000 sq. ft.)- Due to age of building asbestos is not suspected	Earlington-Western Technical Services	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
There is no known asbestos in this facility.	East Oper Ctr	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Possible Asbestos in roof.	Eddyville	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	2,400	**$3,240**
This is a pre-engineered metal building with brick veneer, constructed in 1992 (approx. 3,000 sq. ft.)- Due to age of building asbestos is not suspected	Eddyville Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
	Elizabethtown	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
	Elizabethtown Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
There are 2 buildings at this site. The first bldg was constructed in 1950 with 3,150 sq. ft. The second bldg was constructed in 1980 with 1,280 sq. ft.. Renovations have been made to this facility - but possible asbestos in roof.	Georgetown	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	4,364	**$5,891**
Bldg constructed in 1996 - however, roof inspectors noted possible asbestos in roof	Greenville	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	7,972	**$10,762**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Greenville Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
Approx. 4,800 sq. ft. storeroom and office area was constructed between late 1960 - early 1970. It is a pre-engineered metal building on a slab. Asbestos does not appear to be present	Harlan Storeroom	$65.00		$0			$0	$5.00		$0	$1.35		$0
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Irvine Storeroom	$65.00		$0			$0	$5.00		$0	$1.35		$0
Main Bldg Brick masonary, constructed in 1920 and remodeled in 1970. Tile floors, drop ceiling tiles and painted drywall and block walls. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Lexington Meter Dept.	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
Storage Bldg constructed in 1920 - Age of facility would indicate potential of asbestos throughout bldg.	Lexington Meter Dept.	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
	Lexington Operations Center	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
Main Bldg - 9,600 Sq. Ft. Transformer Shop constructed in 1911 with potential of asbestos throughout masonry building. Also attached is a 3,600 sq. ft. metal building	Lexington Substation/Relay Dept.	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
Office and Garage Bldg constructed in 1996 (6,200 sq. ft) - Due to age of building asbestos is not suspected	Lexington Substation/Relay Dept.	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
Vacant Brick Bldg (Total 768 Sq. Ft.)	Lexington Substation/Relay Dept.	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
3 Metal Storage Bldgs - Asbestos not suspected	Lexington Substation/Relay Dept.	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
Leased Facility	Livermore Storeroom	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
Office was constructed in 1998 (4,700 sq. ft) - Due to age of building asbestos is not suspected	London	$65.00		$0			$0	$5.00		$0	$1.35	0	$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
This is a 4,500 sq. ft. storeroom. The office portion was added in 2002 and new metal installed over the 30 yr. old storerooms wood frame. Possible Asbestos in roof.	London Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	4,500	**$6,075**
Bldg constructed in 1956 (875 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct).	Marion Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Bldg constructed in 1960 (3,978 sq. ft.); however, it appears that renovations have been made but possible asbestos in roof.	Maysville	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	3,444	**$4,649**
Bldg constructed in 1960 (2,950 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct). No asbestos suspected	Maysville Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
This is a brick masonary two-story building, constructed in 1960 with 8,400 total sq. ft.; however, second floor is leased out. Tile floors, drop ceiling tiles and painted drywall. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Middlesboro	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	2,848	**$3,845**
This facility was constructed in 1920 with 12,300 sq. ft. A recent facility analysis suggested vacating this property due to structural integrity and major costs to repair / renovate. Age of this facility would indicate asbestos throughout. (Similar to LG&E 7th & O facility) - Should abandon or demo	Middlesboro Storeroom	$65.00		**$0**			**$0**	$5.00		$0	$1.35	12,300	**$16,605**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Midway (Service Center)	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
Bldg constructed in 1970 (total sq. ft. 2400) but customer service area and foyer (sq. ft.) were remodeled 7 years ago. VCT and ceiling tiles in remainder of building suspected to be asbestos.	Morehead	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
Leased Facility	Morehead Storeroom	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
This is a brick masonary two-story building, constructed in 1965 with 7,500 total sq. ft. Asbestos may be present in roof.	Morganfield	$65.00		$0			$0	$5.00		$0	$1.35	4,106	$5,543
This is a pre-engineered metal building with brick veneer, constructed in 1978 and extended in 1990 (total sq. ft. approx. 4,000). Asbestos not suspected.	Morganfield Storeroom	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
This is a brick masonary one-story building, constructed in 1972 with 3,000 total sq. ft. Suspect asbestos present in roof, floor tiles and possible ceiling tiles.	Mt. Sterling	$65.00		$0			$0	$5.00		$0	$1.35	3,820	$5,157
This is a 3,400 sq. ft. concrete masonry block facility with concrete floors, ceilings of plywood, walls that are drywall or paneling. Possible asbestos in roof.	Mt. Sterling Storeroom	$65.00		$0			$0	$5.00		$0	$1.35	3,400	$4,590
	Norton	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
	Norton Storeroom	$65.00		$0			$0	$5.00		$0	$1.35	0	$0
Asbestos not suspected	One Quality General Office	$65.00						$5.00			$1.35	0	$0
This is a brick masonary one-story building, constructed around 1980 with 3,795 sq. ft. Suspect asbestos present in roof.	Paris	$65.00		$0			$0	$5.00		$0	$1.35	3,795	$5,123

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
This is a 2,783 sq. ft. concrete block facility garage / storeroom with a 10' x 12' office area. It was constructed around 1970. Possible asbestos in roof.	Paris Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	2,783	**$3,757**
	Pennington Gap	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
Leased Facility	Pennington Gap Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
There are several bldgs at this facility - Communications bldg 1,800 sq ft and Trans Dept 2,520 sq. ft. building in 2000-2001; Main Bldg const in 1982 with 32,800 sq. ft. (all of which are metal veneer. Asbestos does not appear to be an issue.	Pineville Stores/Complex; Meter Lab & Substation	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
The original building was constructed in 1970 but an addition was added in early 1980's. It is a one story brick with 5,350 sq. ft. Due to age and photos of the building it appears that VCT / mastic could contain asbestos.	Richmond	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
This facility was constructed in 1985, is a 2,800 sq. ft. metal structure with metal roof. Asbestos is not suspected.	Richmond Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**
This facility is a 3 story building with a total of 109,386 sq. ft. and was formerly used as an operation center with warehouse and offices. Age of this facility suggests asbestos throughout.	Seventh & Ormsby	$65.00	780	**$50,700**	$10,000	$2	**$20,000**	$5.00	50,000	**$250,000**	$1.35		**$0**
This is a one story brick bldg with 4,500 sq. ft. built in 1955 which has been renovated and asbestos does not appear to be an issue.	Shelbyville	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	**Total Cost to Remove Boiler & Assoc. Equip**	Cost per Elevator	# Units	**Total Cost to Remove Elevator Brake & Clutch**	Cost per Sq. Ft.	# Sq. Ft.	**Total Cost to Remove Panels or Mastics**	Cost per Sq. Ft.	# Sq. Ft.	**Total Cost to Remove Roofing Materials**
There are 2 buildings at this site. One is an older bldg actually dismantled and moved from another site to this location and was constructed in 1972. The other is a pre-engineered metal bldg, constructed in approx 1993. Both bldgs combined have 8,120 sq. ft. (a very small office area). Asbestos possible in roof.	Shelbyville Storeroom	$65.00		**$0**			**$0**	$5.00		**$0**	$1.35	8,120	**$10,962**
This office was constructed in 1971 with 3,500 sq. ft. It is wood frame with brick veneer. Age of this facility would indicate the potential for asbestos although some renovations have occurred.	Somerset	$65.00	0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	0	**$0**
This office was constructed in 1971 with 6,000 sq. ft. It is a metal and concrete structure with metal roof. Age of this facility would indicate the potential for asbestos (tile floors and ceiling in office area).	Somerset Storeroom	$65.00	0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	0	**$0**
Abatement of tile performed in 2004. Roofs have been replaced. Asbestos not suspected.	South Service Center	$65.00	0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	0	**$0**
The main building was constructed in early 1970's and an additional section added around 1985. This is a 2 story concrete block with brick veneer front structure. Gross sq. ft. 10,179. Some updates have been completed however, VCT suspected asbestos.	Stone Road	$65.00	0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	0	$0
Bldg constructed in 1985 - Due to age of building asbestos is not suspected	Versailles	$65.00	0	**$0**		0	**$0**	$5.00	0	**$0**	$1.35	0	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Costs to Remove Boilers and Assoc. Equip (Thermal Seals, Gaskets, etc.)			Costs to Remove Elevator Brake and Clutch Assemblies			Costs to Remove Transite Panels / Mastics (Adhesives)			Costs to Remove Roofing Materials		
		Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Boiler & Assoc. Equip	Cost per Elevator	# Units	Total Cost to Remove Elevator Brake & Clutch	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Panels or Mastics	Cost per Sq. Ft.	# Sq. Ft.	Total Cost to Remove Roofing Materials
This is a single story brick facility with partial basement and was constructed in 1965 with approx. 3,500 sq. ft. Age of the building would indicate possible asbestos.	Winchester	$65.00	0	$0		0	$0	$5.00	0	$0	$1.35	3,500	$4,725
This is a concrete block garage / storeroom with approx. 2,880 sq. ft.. Original construction in 1970 and an addition added in 1982. Asbestos suspected in roof.	Winchester Storeroom	$65.00	0	$0		0	$0	$5.00	0	$0	$1.35	2,880	$3,888
GRAND TOTAL ($000's)				$51			$20			$250			$111

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	**Total Trailer Costs**	Daily Cost per Team of 4	# Days Required	# of Teams	**Total Costs Disposal Suits**	Respirator Mask per Team of 4	# Teams	**Total Costs Type C Respirator Masks**	Cost per Day	# Days Testing	**Total Cost On Job Testing**
No known asbestos remaining. Renovations have been completed removing known asbestos.	Auburndale Op Ctr	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1965. which has been renovated and there are no signs of asbestos.	Barlow	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
There are 3 wood framed, metal siding and metal roof structures with a combined total of 2,496 sq. ft. Buildings were constructed in 1970; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Barlow Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Facility constructed in 1978 and is a pre-engineered metal building on slab with 3,200 sq. ft. Office area has VCT and drop ceiling which due to age of facility may be asbestos.	Big Stone Gap Substation	$98.89	10	**$989**	$162.12	10	1	**$1,621**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
This facility has been renovated throughout and asbestos removed during the process	Broadway Office Complex	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1957. which has been renovated but possible asbestos in roof.	Campbellsville	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
There are 3 wood framed, metal siding and metal roof structures with a combined total of 6,450 sq. ft. Buildings were constructed in 1960; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Campbellsville Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
The facility is a one-story metal on concrete slab structure with 555 sq. ft. constructed in 1980. No visible signs of asbestos	Carlise Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
This is a 1-1/2 story brick building with 3,500 sq. ft. constructed in approx. 1970. Shingle roof system installed over original roof (could be asbestos).	Carrollton	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
One story , 2,644 sq. ft. concrete block building constructed in 1970 with 24' walls and 3 garage doors. Possible asbestos in roof.	Carrollton Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
This is a 2 story facility was constructed in 1961 with 3,984 sq. ft.; an addition of 2,200 sq. ft. was added above the drive thru in approx 1980. Due to age of facility asbestos is suspected (excluding roof, which was installed in 2004).	Danville	$98.89	30	$2,967	$162.12	20	3	$9,727	$81.04	3	$243	$1,384.00	3	$4,152
This is a 10,560 sq. ft. pre-engineered metal building on a concrete slab constructed in 1998. Due to the age of the building asbestos is not suspected.	Danville Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
This is a 20,800 sq. ft. pre-engineered metal building on a concrete slab constructed in 1988. Due to the age of the building asbestos is not suspected.	Danville Substation & Meter Dept.	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
The building was constructed between 1975 - 1980 and consists of a wood frame with metal façade and metal roof. Total sq. ft. of 1,900 and is divided into 3 sections - truck parking, office, storage. Heating / Cooling with heat pumps approx 9 yrs. old. Due to the age of the building it may contain asbestos.	Dawson Springs Storeroom	$98.89		$0	$162.12	10	1	$1,621	$81.04	1	$81	$1,384.00	1	$1,384

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	**Total Trailer Costs**	Daily Cost per Team of 4	# Days Required	# of Teams	**Total Costs Disposal Suits**	Respirator Mask per Team of 4	# Teams	**Total Costs Type C Respirator Masks**	Cost per Day	# Days Testing	**Total Cost On Job Testing**
This facility was constructed in 1970. The office building is a wood frame structure with brick façade with approx. 3,840 sq. ft. Age of the facility indicate potential asbestos.	Earlington	$98.89	10	**$989**	$162.12	10	1	**$1,621**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
This facility has a metal office and storage building with 11,500 sq. ft. constructed in 1990. Due to the age of the building asbestos is not suspected.	Earlington-Parkway Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Bldg constructed in 1995 (approx. 25,000 sq. ft.)- Due to age of building asbestos is not suspected	Earlington-Western Technical Services	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
There is no known asbestos in this facility.	East Oper Ctr	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Possible Asbestos in roof.	Eddyville	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a pre-engineered metal building with brick veneer, constructed in 1992 (approx. 3,000 sq. ft.)- Due to age of building asbestos is not suspected	Eddyville Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
	Elizabethtown	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
	Elizabethtown Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
There are 2 buildings at this site. The first bldg was constructed in 1950 with 3,150 sq. ft. The second bldg was constructed in 1980 with 1,280 sq. ft.. Renovations have been made to this facility - but possible asbestos in roof.	Georgetown	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Bldg constructed in 1996 - however, roof inspectors noted possible asbestos in roof	Greenville	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Greenville Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
Approx. 4,800 sq. ft. storeroom and office area was constructed between late 1960 - early 1970. It is a pre-engineered metal building on a slab. Asbestos does not appear to be present	Harlan Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Irvine Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Main Bldg Brick masonary, constructed in 1920 and remodeled in 1970. Tile floors, drop ceiling tiles and painted drywall and block walls. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Lexington Meter Dept.	$98.89	30	$2,967	$162.12	20	3	$9,727	$81.04	3	$243	$1,384.00	3	$4,152
Storage Bldg constructed in 1920 - Age of facility would indicate potential of asbestos throughout bldg.	Lexington Meter Dept.	$98.89	30	$2,967	$162.12	20	3	$9,727	$81.04	3	$243	$1,384.00	3	$4,152
	Lexington Operations Center	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Main Bldg - 9,600 Sq. Ft. Transformer Shop constructed in 1911 with potential of asbestos throughout masonry building. Also attached is a 3,600 sq. ft. metal building	Lexington Substation/Relay Dept.	$98.89	30	$2,967	$162.12	20	3	$9,727	$81.04	3	$243	$1,384.00	3	$4,152
Office and Garage Bldg constructed in 1996 (6,200 sq. ft) - Due to age of building asbestos is not suspected	Lexington Substation/Relay Dept.	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Vacant Brick Bldg (Total 768 Sq. Ft.)	Lexington Substation/Relay Dept.	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
3 Metal Storage Bldgs - Asbestos not suspected	Lexington Substation/Relay Dept.	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Leased Facility	Livermore Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Office was constructed in 1998 (4,700 sq. ft) - Due to age of building asbestos is not suspected	London	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
This is a 4,500 sq. ft. storeroom. The office portion was added in 2002 and new metal installed over the 30 yr. old storerooms wood frame. Possible Asbestos in roof.	London Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Bldg constructed in 1956 (875 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct).	Marion Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Bldg constructed in 1960 (3,978 sq. ft.); however, it appears that renovations have been made but possible asbestos in roof.	Maysville	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Bldg constructed in 1960 (2,950 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct). No asbestos suspected	Maysville Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a brick masonary two-story building, constructed in 1960 with 8,400 total sq. ft.; however, second floor is leased out. Tile floors, drop ceiling tiles and painted drywall. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Middlesboro	$98.89	30	**$2,967**	$162.12	20	3	**$9,727**	$81.04	3	**$243**	$1,384.00	3	**$4,152**
This facility was constructed in 1920 with 12,300 sq. ft. A recent facility analysis suggested vacating this property due to structural integrity and major costs to repair / renovate. Age of this facility would indicate asbestos throughout. (Similar to LG&E 7th & O facility) - Should abandon or demo	Middlesboro Storeroom	$98.89	30	**$2,967**	$162.12	20	3	**$9,727**	$81.04	3	**$243**	$1,384.00	3	**$4,152**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Midway (Service Center)	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
Bldg constructed in 1970 (total sq. ft. 2400) but customer service area and foyer (sq. ft.) were remodeled 7 years ago. VCT and ceiling tiles in remainder of building suspected to be asbestos.	Morehead	$98.89	10	**$989**	$162.12	10	1	**$1,621**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
Leased Facility	Morehead Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
This is a brick masonary two-story building, constructed in 1965 with 7,500 total sq. ft. Asbestos may be present in roof.	Morganfield	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a pre-engineered metal building with brick veneer, constructed in 1978 and extended in 1990 (total sq. ft. approx. 4,000). Asbestos not suspected.	Morganfield Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a brick masonary one-story building, constructed in 1972 with 3,000 total sq. ft. Suspect asbestos present in roof, floor tiles and possible ceiling tiles.	Mt. Sterling	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This is a 3,400 sq. ft. concrete masonry block facility with concrete floors, ceilings of plywood, walls that are drywall or paneling. Possible asbestos in roof.	Mt. Sterling Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
	Norton	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
	Norton Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Asbestos not suspected	One Quality General Office													
This is a brick masonary one-story building, constructed around 1980 with 3,795 sq. ft. Suspect asbestos present in roof.	Paris	$98.89		**$0**	$162.12			$0	$81.04		**$0**	$1,384.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
This is a 2,783 sq. ft. concrete block facility garage / storeroom with a 10' x 12' office area. It was constructed around 1970. Possible asbestos in roof.	Paris Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
	Pennington Gap	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
Leased Facility	Pennington Gap Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
There are several bldgs at this facility - Communications bldg 1,800 sq ft and Trans Dept 2,520 sq. ft. building in 2000-2001; Main Bldg const in 1982 with 32,800 sq. ft. (all of which are metal veneer. Asbestos does not appear to be an issue.	Pineville Stores/Complex; Meter Lab & Substation	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
The original building was constructed in 1970 but an addition was added in early 1980's. It is a one story brick with 5,350 sq. ft. Due to age and photos of the building it appears that VCT / mastic could contain asbestos.	Richmond	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
This facility was constructed in 1985, is a 2,800 sq. ft. metal structure with metal roof. Asbestos is not suspected.	Richmond Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
This facility is a 3 story building with a total of 109,386 sq. ft. and was formerly used as an operation center with warehouse and offices. Age of this facility suggests asbestos throughout.	Seventh & Ormsby	$98.89	60	$5,933	$162.12	40	6	$38,909	$81.04	6	$486	$1,384.00	6	$8,304
This is a one story brick bldg with 4,500 sq. ft. built in 1955 which has been renovated and asbestos does not appear to be an issue.	Shelbyville	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	**Total Trailer Costs**	Daily Cost per Team of 4	# Days Required	# of Teams	**Total Costs Disposal Suits**	Respirator Mask per Team of 4	# Teams	**Total Costs Type C Respirator Masks**	Cost per Day	# Days Testing	**Total Cost On Job Testing**
There are 2 buildings at this site. One is an older bldg actually dismantled and moved from another site to this location and was constructed in 1972. The other is a pre-engineered metal bldg, constructed in approx 1993. Both bldgs combined have 8,120 sq. ft. (a very small office area). Asbestos possible in roof.	Shelbyville Storeroom	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
This office was constructed in 1971 with 3,500 sq. ft. It is wood frame with brick veneer. Age of this facility would indicate the potential for asbestos although some renovations have occurred.	Somerset	$98.89	10	**$989**	$162.12	10	1	**$1,621**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
This office was constructed in 1971 with 6,000 sq. ft. It is a metal and concrete structure with metal roof. Age of this facility would indicate the potential for asbestos (tile floors and ceiling in office area).	Somerset Storeroom	$98.89	10	**$989**	$162.12	10	1	**$1,621**	$81.04	1	**$81**	$1,384.00	1	**$1,384**
Abatement of tile performed in 2004. Roofs have been replaced. Asbestos not suspected.	South Service Center	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
The main building was constructed in early 1970's and an additional section added around 1985. This is a 2 story concrete block with brick veneer front structure. Gross sq. ft. 10,179. Some updates have been completed however, VCT suspected asbestos.	Stone Road	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**
Bldg constructed in 1985 - Due to age of building asbestos is not suspected	Versailles	$98.89		**$0**	$162.12			**$0**	$81.04		**$0**	$1,384.00		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Trailer (Change Room Cost)			Disposal Suits (4 suits per man / day $40.53) - w/ a 4 Man Team				Type C Respirator mask (incl hose & filters) per man			Air monitoring testing, 12 Tests / Day (On Job Testing/Day)		
		Cost per Day	# of Days Required	Total Trailer Costs	Daily Cost per Team of 4	# Days Required	# of Teams	Total Costs Disposal Suits	Respirator Mask per Team of 4	# Teams	Total Costs Type C Respirator Masks	Cost per Day	# Days Testing	Total Cost On Job Testing
This is a single story brick facility with partial basesment and was constructed in 1965 with approx. 3,500 sq. ft. Age of the building would indicate possible asbestos.	Winchester	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
This is a concrete block garage / storeroom with approx. 2,880 sq. ft.. Original construction in 1970 and an addition added in 1982. Asbestos suspected in roof.	Winchester Storeroom	$98.89		$0	$162.12			$0	$81.04		$0	$1,384.00		$0
GRAND TOTAL ($000's)				$29				$107			$2			$42

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
No known asbestos remaining. Renovations have been completed removing known asbestos.	Auburndale Op Ctr	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1965. which has been renovated and there are no signs of asbestos.	Barlow	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
There are 3 wood framed, metal siding and metal roof structures with a combined total of 2,496 sq. ft. Buildings were constructed in 1970; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Barlow Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Facility constructed in 1978 and is a pre-engineered metal building on slab with 3,200 sq. ft. Office area has VCT and drop ceiling which due to age of facility may be asbestos.	Big Stone Gap Substation	$606.32	1	**$606**	$775.06	1	**$775**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	4	**$22**
This facility has been renovated throughout and asbestos removed during the process	Broadway Office Complex	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
One story , 2,500 sq. ft. concrete block building constructed in 1957. which has been renovated but possible asbestos in roof.	Campbellsville	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
There are 3 wood framed, metal siding and metal roof structures with a combined total of 6,450 sq. ft. Buildings were constructed in 1960; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Campbellsville Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
The facility is a one-story metal on concrete slab structure with 555 sq. ft. constructed in 1980. No visible signs of asbestos	Carlise Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a 1-1/2 story brick building with 3,500 sq. ft. constructed in approx. 1970. Shingle roof system installed over original roof (could be asbestos).	Carrollton	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
One story , 2,644 sq. ft. concrete block building constructed in 1970 with 24' walls and 3 garage doors. Possible asbestos in roof.	Carrollton Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a 2 story facility was constructed in 1961 with 3,984 sq. ft.; an addition of 2,200 sq. ft. was added above the drive thru in approx 1980. Due to age of facility asbestos is suspected (excluding roof, which was installed in 2004).	Danville	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85	3	**$2,124**	$1,773.00	3	**$5,319**	$5.40	20	**$108**
This is a 10,560 sq. ft. pre-engineered metal building on a concrete slab constructed in 1998. Due to the age of the building asbestos is not suspected.	Danville Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a 20,800 sq. ft. pre-engineered metal building on a concrete slab constructed in 1988. Due to the age of the building asbestos is not suspected.	Danville Substation & Meter Dept.	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
The building was constructed between 1975 - 1980 and consists of a wood frame with metal façade and metal roof. Total sq. ft. of 1,900 and is divided into 3 sections - truck parking, office, storage. Heating / Cooling with heat pumps approx 9 yrs. old. Due to the age of the building it may contain asbestos.	Dawson Springs Storeroom	$606.32	1	**$606**	$775.06	1	**$775**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	4	**$22**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
This facility was constructed in 1970. The office building is a wood frame structure with brick façade with approx. 3,840 sq. ft. Age of the facility indicate potential asbestos.	Earlington	$606.32	1	$606	$775.06	1	$775	$707.85	1	$708	$1,773.00	1	$1,773	$5.40	4	$22
This facility has a metal office and storage building with 11,500 sq. ft. constructed in 1990. Due to the age of the building asbestos is not suspected.	Earlington-Parkway Storeroom	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
Bldg constructed in 1995 (approx. 25,000 sq. ft.)- Due to age of building asbestos is not suspected	Earlington-Western Technical Services	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
There is no known asbestos in this facility.	East Oper Ctr	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
Possible Asbestos in roof.	Eddyville	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
This is a pre-engineered metal building with brick veneer, constructed in 1992 (approx. 3,000 sq. ft.)- Due to age of building asbestos is not suspected	Eddyville Storeroom	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
	Elizabethtown	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
	Elizabethtown Storeroom	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
There are 2 buildings at this site. The first bldg was constructed in 1950 with 3,150 sq. ft. The second bldg was constructed in 1980 with 1,280 sq. ft.. Renovations have been made to this facility - but possible asbestos in roof.	Georgetown	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
Bldg constructed in 1996 - however, roof inspectors noted possible asbestos in roof	Greenville	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Greenville Storeroom	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
Approx. 4,800 sq. ft. storeroom and office area was constructed between late 1960 - early 1970. It is a pre-engineered metal building on a slab. Asbestos does not appear to be present	Harlan Storeroom	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Irvine Storeroom	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
Main Bldg Brick masonary, constructed in 1920 and remodeled in 1970. Tile floors, drop ceiling tiles and painted drywall and block walls. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Lexington Meter Dept.	$606.32	3	$1,819	$775.06	3	$2,325	$707.85	3	$2,124	$1,773.00	3	$5,319	$5.40	20	$108
Storage Bldg constructed in 1920 - Age of facility would indicate potential of asbestos throughout bldg.	Lexington Meter Dept.	$606.32	3	$1,819	$775.06	3	$2,325	$707.85	3	$2,124	$1,773.00	3	$5,319	$5.40	20	$108
	Lexington Operations Center	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
Main Bldg - 9,600 Sq. Ft. Transformer Shop constructed in 1911 with potential of asbestos throughout masonry building. Also attached is a 3,600 sq. ft. metal building	Lexington Substation/Relay Dept.	$606.32	3	$1,819	$775.06	3	$2,325	$707.85	3	$2,124	$1,773.00	3	$5,319	$5.40	20	$108
Office and Garage Bldg constructed in 1996 (6,200 sq. ft) - Due to age of building asbestos is not suspected	Lexington Substation/Relay Dept.	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
Vacant Brick Bldg (Total 768 Sq. Ft.)	Lexington Substation/Relay Dept.	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
3 Metal Storage Bldgs - Asbestos not suspected	Lexington Substation/Relay Dept.	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
Leased Facility	Livermore Storeroom	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
Office was constructed in 1998 (4,700 sq. ft) - Due to age of building asbestos is not suspected	London	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
This is a 4,500 sq. ft. storeroom. The office portion was added in 2002 and new metal installed over the 30 yr. old storerooms wood frame. Possible Asbestos in roof.	London Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Bldg constructed in 1956 (875 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct).	Marion Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Bldg constructed in 1960 (3,978 sq. ft.); however, it appears that renovations have been made but possible asbestos in roof.	Maysville	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Bldg constructed in 1960 (2,950 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct). No asbestos suspected	Maysville Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a brick masonary two-story building, constructed in 1960 with 8,400 total sq. ft.; however, second floor is leased out. Tile floors, drop ceiling tiles and painted drywall. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Middlesboro	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85	3	**$2,124**	$1,773.00	3	**$5,319**	$5.40	20	**$108**
This facility was constructed in 1920 with 12,300 sq. ft. A recent facility analysis suggested vacating this property due to structural integrity and major costs to repair / renovate. Age of this facility would indicate asbestos throughout. (Similar to LG&E 7th & O facility) - Should abandon or demo	Middlesboro Storeroom	$606.32	3	**$1,819**	$775.06	3	**$2,325**	$707.85	3	**$2,124**	$1,773.00	3	**$5,319**	$5.40	20	**$108**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Midway (Service Center)	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		$0	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	**Total Cost Asbestos Vacuum w/Attachmt**	Cost per Unit	# Units	**Total Cost Hydraspray Piston Pump**	Cost per Unit	# Units	**Total Cost Air Pressure Systems**	Cost per Unit	# Units	**Total Cost Grade D Breathing Equip**	Cost per Unit	# Units	**Total Cost Glove Bag**
Bldg constructed in 1970 (total sq. ft. 2400) but customer service area and foyer (sq. ft.) were remodeled 7 years ago. VCT and ceiling tiles in remainder of building suspected to be asbestos.	Morehead	$606.32	1	**$606**	$775.06	1	**$775**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	4	**$22**
Leased Facility	Morehead Storeroom	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
This is a brick masonary two-story building, constructed in 1965 with 7,500 total sq. ft. Asbestos may be present in roof.	Morganfield	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a pre-engineered metal building with brick veneer, constructed in 1978 and extended in 1990 (total sq. ft. approx. 4,000). Asbestos not suspected.	Morganfield Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a brick masonary one-story building, constructed in 1972 with 3,000 total sq. ft. Suspect asbestos present in roof, floor tiles and possible ceiling tiles.	Mt. Sterling	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This is a 3,400 sq. ft. concrete masonry block facility with concrete floors, ceilings of plywood, walls that are drywall or paneling. Possible asbestos in roof.	Mt. Sterling Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
	Norton	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
	Norton Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Asbestos not suspected	One Quality General Office															
This is a brick masonary one-story building, constructed around 1980 with 3,795 sq. ft. Suspect asbestos present in roof.	Paris	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
This is a 2,783 sq. ft. concrete block facility garage / storeroom with a 10' x 12' office area. It was constructed around 1970. Possible asbestos in roof.	Paris Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
	Pennington Gap	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Leased Facility	Pennington Gap Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
There are several bldgs at this facility - Communications bldg 1,800 sq ft and Trans Dept 2,520 sq. ft. building in 2000-2001; Main Bldg const in 1982 with 32,800 sq. ft. (all of which are metal veneer. Asbestos does not appear to be an issue.	Pineville Stores/Complex; Meter Lab & Substation	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
The original building was constructed in 1970 but an addition was added in early 1980's. It is a one story brick with 5,350 sq. ft. Due to age and photos of the building it appears that VCT / mastic could contain asbestos.	Richmond	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This facility was constructed in 1985, is a 2,800 sq. ft. metal structure with metal roof. Asbestos is not suspected.	Richmond Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This facility is a 3 story building with a total of 109,386 sq. ft. and was formerly used as an operation center with warehouse and offices. Age of this facility suggests asbestos throughout.	Seventh & Ormsby	$606.32	6	**$3,638**	$775.06	6	**$4,650**	$707.85	6	**$4,247**	$1,773.00	6	**$10,638**	$5.40	40	**$216**
This is a one story brick bldg with 4,500 sq. ft. built in 1955 which has been renovated and asbestos does not appear to be an issue.	Shelbyville	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
There are 2 buildings at this site. One is an older bldg actually dismantled and moved from another site to this location and was constructed in 1972. The other is a pre-engineered metal bldg, constructed in approx 1993. Both bldgs combined have 8,120 sq. ft. (a very small office area). Asbestos possible in roof.	Shelbyville Storeroom	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
This office was constructed in 1971 with 3,500 sq. ft. It is wood frame with brick veneer. Age of this facility would indicate the potential for asbestos although some renovations have occurred.	Somerset	$606.32	1	**$606**	$775.06	1	**$775**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	4	**$22**
This office was constructed in 1971 with 6,000 sq. ft. It is a metal and concrete structure with metal roof. Age of this facility would indicate the potential for asbestos (tile floors and ceiling in office area).	Somerset Storeroom	$606.32	1	**$606**	$775.06	1	**$775**	$707.85	1	**$708**	$1,773.00	1	**$1,773**	$5.40	4	**$22**
Abatement of tile performed in 2004. Roofs have been replaced. Asbestos not suspected.	South Service Center	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
The main building was constructed in early 1970's and an additional section added around 1985. This is a 2 story concrete block with brick veneer front structure. Gross sq. ft. 10,179. Some updates have been completed however, VCT suspected asbestos.	Stone Road	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**
Bldg constructed in 1985 - Due to age of building asbestos is not suspected	Versailles	$606.32		**$0**	$775.06		**$0**	$707.85		**$0**	$1,773.00		**$0**	$5.40		**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Equip Required - Asbestos vacuum w/attachments			Removal Equip Required - Hydraspray piston pump			Removal Equip Required - Negative Air Pressure System			Removal Equip Required - Grade D breathing air equipment			Removal Equip Required - Glove bag, 44" x 60" x 6 mil plastic		
		Cost per Unit	# Units	Total Cost Asbestos Vacuum w/Attachmt	Cost per Unit	# Units	Total Cost Hydraspray Piston Pump	Cost per Unit	# Units	Total Cost Air Pressure Systems	Cost per Unit	# Units	Total Cost Grade D Breathing Equip	Cost per Unit	# Units	Total Cost Glove Bag
This is a single story brick facility with partial basement and was constructed in 1965 with approx. 3,500 sq. ft. Age of the building would indicate possible asbestos.	Winchester	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
This is a concrete block garage / storeroom with approx. 2,880 sq. ft.. Original construction in 1970 and an addition added in 1982. Asbestos suspected in roof.	Winchester Storeroom	$606.32		$0	$775.06		$0	$707.85		$0	$1,773.00		$0	$5.40		$0
GRAND TOTAL ($000's)				$18			$23			$21			$53			$1

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
No known asbestos remaining. Renovations have been completed removing known asbestos.	Auburndale Op Ctr	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
One story , 2,500 sq. ft. concrete block building constructed in 1965. which has been renovated and there are no signs of asbestos.	Barlow	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
There are 3 wood framed, metal siding and metal roof structures with a combined total of 2,496 sq. ft. Buildings were constructed in 1970; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Barlow Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
Facility constructed in 1978 and is a pre-engineered metal building on slab with 3,200 sq. ft. Office area has VCT and drop ceiling which due to age of facility may be asbestos.	Big Stone Gap Substation	$26	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$29
This facility has been renovated throughout and asbestos removed during the process	Broadway Office Complex	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
One story , 2,500 sq. ft. concrete block building constructed in 1957. which has been renovated but possible asbestos in roof.	Campbellsville	$3	$673.53			$0	$318.89		$0	$167.31		$0	$0	$3
There are 3 wood framed, metal siding and metal roof structures with a combined total of 6,450 sq. ft. Buildings were constructed in 1960; however, they are concrete slab with exception of tile in restrooms. No visible signs of asbestos.	Campbellsville Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	**Total Dumpster Rental Costs**	Pickup / Delivery Costs	# Times Pickup / Delivery	**Total Pick Up/Del Costs**	Asbestos Dump Fee	# of Times Dumped	**Total Asbestos Dump Fee Expense**		
The facility is a one-story metal on concrete slab structure with 555 sq. ft. constructed in 1980. No visible signs of asbestos	Carlise Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
This is a 1-1/2 story brick building with 3,500 sq. ft. constructed in approx. 1970. Shingle roof system installed over original roof (could be asbestos).	Carrollton	**$4**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$7**
One story , 2,644 sq. ft. concrete block building constructed in 1970 with 24' walls and 3 garage doors. Possible asbestos in roof.	Carrollton Storeroom	**$4**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$7**
This is a 2 story facility was constructed in 1961 with 3,984 sq. ft.; an addition of 2,200 sq. ft. was added above the drive thru in approx 1980. Due to age of facility asbestos is suspected (excluding roof, which was installed in 2004).	Danville	**$63**	$673.53	4	2	**$5,388**	$318.89	16	**$5,102**	$167.31	16	**$2,677**	**$13**	**$76**
This is a 10,560 sq. ft. pre-engineered metal building on a concrete slab constructed in 1998. Due to the age of the building asbestos is not suspected.	Danville Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
This is a 20,800 sq. ft. pre-engineered metal building on a concrete slab constructed in 1988. Due to the age of the building asbestos is not suspected.	Danville Substation & Meter Dept.	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
The building was constructed between 1975 - 1980 and consists of a wood frame with metal façade and metal roof. Total sq. ft. of 1,900 and is divided into 3 sections - truck parking, office, storage. Heating / Cooling with heat pumps approx 9 yrs. old. Due to the age of the building it may contain asbestos.	Dawson Springs Storeroom	**$11**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$14**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
This facility was constructed in 1970. The office building is a wood frame structure with brick façade with approx. 3,840 sq. ft. Age of the facility indicate potential asbestos.	Earlington	$41	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$44
This facility has a metal office and storage building with 11,500 sq. ft. constructed in 1990. Due to the age of the building asbestos is not suspected.	Earlington-Parkway Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
Bldg constructed in 1995 (approx. 25,000 sq. ft.)- Due to age of building asbestos is not suspected	Earlington-Western Technical Services	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
There is no known asbestos in this facility.	East Oper Ctr	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
Possible Asbestos in roof.	Eddyville	$3	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$7
This is a pre-engineered metal building with brick veneer, constructed in 1992 (approx. 3,000 sq. ft.)- Due to age of building asbestos is not suspected	Eddyville Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
	Elizabethtown	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
	Elizabethtown Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
There are 2 buildings at this site. The first bldg was constructed in 1950 with 3,150 sq. ft. The second bldg was constructed in 1980 with 1,280 sq. ft.. Renovations have been made to this facility - but possible asbestos in roof.	Georgetown	$14	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$18
Bldg constructed in 1996 - however, roof inspectors noted possible asbestos in roof	Greenville	$11	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$14
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Greenville Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
Approx. 4,800 sq. ft. storeroom and office area was constructed between late 1960 - early 1970. It is a pre-engineered metal building on a slab. Asbestos does not appear to be present	Harlan Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Irvine Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Main Bldg Brick masonary, constructed in 1920 and remodeled in 1970. Tile floors, drop ceiling tiles and painted drywall and block walls. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Lexington Meter Dept.	**$89**	$673.53	4	2	**$5,388**	$318.89	16	**$5,102**	$167.31	16	**$2,677**	**$13**	**$102**
Storage Bldg constructed in 1920 - Age of facility would indicate potential of asbestos throughout bldg.	Lexington Meter Dept.	**$75**	$673.53	4	2	**$5,388**	$318.89	16	**$5,102**	$167.31	16	**$2,677**	**$13**	**$88**
	Lexington Operations Center	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Main Bldg - 9,600 Sq. Ft. Transformer Shop constructed in 1911 with potential of asbestos throughout masonry building. Also attached is a 3,600 sq. ft. metal building	Lexington Substation/Relay Dept.	**$93**	$673.53	4	2	**$5,388**	$318.89	16	**$5,102**	$167.31	16	**$2,677**	**$13**	**$106**
Office and Garage Bldg constructed in 1996 (6,200 sq. ft) - Due to age of building asbestos is not suspected	Lexington Substation/Relay Dept.	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Vacant Brick Bldg (Total 768 Sq. Ft.)	Lexington Substation/Relay Dept.	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
3 Metal Storage Bldgs - Asbestos not suspected	Lexington Substation/Relay Dept.	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Leased Facility	Livermore Storeroom	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
Office was constructed in 1998 (4,700 sq. ft) - Due to age of building asbestos is not suspected	London	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
This is a 4,500 sq. ft. storeroom. The office portion was added in 2002 and new metal installed over the 30 yr. old storerooms wood frame. Possible Asbestos in roof.	London Storeroom	$6	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$9
Bldg constructed in 1956 (875 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct).	Marion Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
Bldg constructed in 1960 (3,978 sq. ft.); however, it appears that renovations have been made but possible asbestos in roof.	Maysville	$5	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$8
Bldg constructed in 1960 (2,950 sq. ft.); however, it is a pre-engineered metal building (without ceiling or vct). No asbestos suspected	Maysville Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
This is a brick masonary two-story building, constructed in 1960 with 8,400 total sq. ft.; however, second floor is leased out. Tile floors, drop ceiling tiles and painted drywall. Age of the facility and date of remodel indicate potential asbestos throughout bldg.	Middlesboro	$105	$673.53	4	2	$5,388	$318.89	16	$5,102	$167.31	16	$2,677	$13	$118
This facility was constructed in 1920 with 12,300 sq. ft. A recent facility analysis suggested vacating this property due to structural integrity and major costs to repair / renovate. Age of this facility would indicate asbestos throughout. (Similar to LG&E 7th & O facility) - Should abandon or demo	Middlesboro Storeroom	$82	$673.53	4	2	$5,388	$318.89	16	$5,102	$167.31	16	$2,677	$13	$95
Bldg constructed in 1995 - Due to age of building asbestos is not suspected	Midway (Service Center)	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit: Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense	Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
Bldg constructed in 1970 (total sq. ft. 2400) but customer service area and foyer (sq. ft.) were remodeled 7 years ago. VCT and ceiling tiles in remainder of building suspected to be asbestos.	Morehead	$25	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$28
Leased Facility	Morehead Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
This is a brick masonary two-story building, constructed in 1965 with 7,500 total sq. ft. Asbestos may be present in roof.	Morganfield	$6	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$9
This is a pre-engineered metal building with brick veneer, constructed in 1978 and extended in 1990 (total sq. ft. approx. 4,000). Asbestos not suspected.	Morganfield Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
This is a brick masonary one-story building, constructed in 1972 with 3,000 total sq. ft. Suspect asbestos present in roof, floor tiles and possible ceiling tiles.	Mt. Sterling	$23	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$26
This is a 3,400 sq. ft. concrete masonry block facility with concrete floors, ceilings of plywood, walls that are drywall or paneling. Possible asbestos in roof.	Mt. Sterling Storeroom	$5	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$8
	Norton	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
	Norton Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
Asbestos not suspected	One Quality General Office													
This is a brick masonary one-story building, constructed around 1980 with 3,795 sq. ft. Suspect asbestos present in roof.	Paris	$5	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$8

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
This is a 2,783 sq. ft. concrete block facility garage / storeroom with a 10' x 12' office area. It was constructed around 1970. Possible asbestos in roof.	Paris Storeroom	$4	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$7
	Pennington Gap	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
Leased Facility	Pennington Gap Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
There are several bldgs at this facility - Communications bldg 1,800 sq ft and Trans Dept 2,520 sq. ft. building in 2000-2001; Main Bldg const in 1982 with 32,800 sq. ft. (all of which are metal veneer. Asbestos does not appear to be an issue.	Pineville Stores/Complex; Meter Lab & Substation	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
The original building was constructed in 1970 but an addition was added in early 1980's. It is a one story brick with 5,350 sq. ft. Due to age and photos of the building it appears that VCT / mastic could contain asbestos.	Richmond	$21	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$24
This facility was constructed in 1985, is a 2,800 sq. ft. metal structure with metal roof. Asbestos is not suspected.	Richmond Storeroom	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0
This facility is a 3 story building with a total of 109,386 sq. ft. and was formerly used as an operation center with warehouse and offices. Age of this facility suggests asbestos throughout.	Seventh & Ormsby	$372	$673.53	8	4	$21,553	$318.89	64	$20,409	$167.31	64	$10,708	$53	$425
This is a one story brick bldg with 4,500 sq. ft. built in 1955 which has been renovated and asbestos does not appear to be an issue.	Shelbyville	$0	$673.53			$0	$318.89		$0	$167.31		$0	$0	$0

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit											Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	**Total Dumpster Rental Costs**	Pickup / Delivery Costs	# Times Pickup / Delivery	**Total Pick Up/Del Costs**	Asbestos Dump Fee	# of Times Dumped	**Total Asbestos Dump Fee Expense**			
There are 2 buildings at this site. One is an older bldg actually dismantled and moved from another site to this location and was constructed in 1972. The other is a pre-engineered metal bldg, constructed in approx 1993. Both bldgs combined have 8,120 sq. ft. (a very small office area). Asbestos possible in roof.	Shelbyville Storeroom	**$11**	$673.53	4	2	**$5,388**	$318.89	16	**$5,102**	$167.31	16	**$2,677**	**$13**	**$24**
This office was constructed in 1971 with 3,500 sq. ft. It is wood frame with brick veneer. Age of this facility would indicate the potential for asbestos although some renovations have occurred.	Somerset	**$38**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$41**
This office was constructed in 1971 with 6,000 sq. ft. It is a metal and concrete structure with metal roof. Age of this facility would indicate the potential for asbestos (tile floors and ceiling in office area).	Somerset Storeroom	**$23**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$26**
Abatement of tile performed in 2004. Roofs have been replaced. Asbestos not suspected.	South Service Center	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**
The main building was constructed in early 1970's and an additional section added around 1985. This is a 2 story concrete block with brick veneer front structure. Gross sq. ft. 10,179. Some updates have been completed however, VCT suspected asbestos.	Stone Road	**$31**	$673.53	2	1	**$1,347**	$318.89	4	**$1,276**	$167.31	4	**$669**	**$3**	**$34**
Bldg constructed in 1985 - Due to age of building asbestos is not suspected	Versailles	**$0**	$673.53			**$0**	$318.89		**$0**	$167.31		**$0**	**$0**	**$0**

ASBESTOS REMOVAL ESTIMATES
FACILITY SERVICES

Asset Description	Location	Removal Cost per Asset ($000's)	40 Cu Yd Asbestos Dumpster Costs Per Unit										Total Incremantal Cost of Disposal ($000's)	GRAND TOTAL ($000's)
			Weekly Rental Fees	# Weeks Required	# Units	Total Dumpster Rental Costs	Pickup / Delivery Costs	# Times Pickup / Delivery	Total Pick Up/Del Costs	Asbestos Dump Fee	# of Times Dumped	Total Asbestos Dump Fee Expense		
This is a single story brick facility with partial basesment and was constructed in 1965 with approx. 3,500 sq. ft. Age of the building would indicate possible asbestos.	Winchester	$35	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$38
This is a concrete block garage / storeroom with approx. 2,880 sq. ft.. Original construction in 1970 and an addition added in 1982. Asbestos suspected in roof.	Winchester Storeroom	$4	$673.53	2	1	$1,347	$318.89	4	$1,276	$167.31	4	$669	$3	$7
GRAND TOTAL ($000's)		$1,234				$89			$84			$44	$217	$1,452

FACILITY ASSUMPTIONS

Any Facility constructed before 1985 will have asbestos, unless abatement has been completed

SMALL BUSINESS OFFICES & OPER CTRS- L. F. is calculated based on 8% of total sq. ft. for removal of pipe & ductwork insulation @ $65/LN. FT. or SQ. FT. (Includes removal & air monitoring costs) Costs per Ln. Ftl is based on recent invoicing for work performed by NEC.

STOREROOMS - L. F. is calculated based on 3% of total sq. ft. for pipe and ductwork insulation @ $65/LN.FT. or SQ. FT. if total LN. FT. totals 100, if > 100 cost is $35/LN. FT. (Includes removal and air monitoring costs). Cost per Ln. Ft. is based on recent invoicing for work performed by NEC.

Cost to remove VCT is based on actual invoicing from NEC for work performed at South Service Center in 1994. The same costs were applied to removal of ceiling tiles.

Costs to remove roofing materials is based on actual sq. ft. costs for the removal of Bldg 1 & Bldg 2 Roof at the Auburndale facility (to be completed in 3 phases between 2003 and 2006)

Costs to remove Elevator Brakes / Clutches are based on 50% of actual labor invoiced in 2004 for BOC Freight Elevator System

Leenerts, Patricia

From: Kinder, Debra
Sent: Tuesday, December 27, 2005 8:53 AM
To: Leenerts, Patricia
Subject: FW: Interest Rates

From: Wiseman, Sara
Sent: Tuesday, December 06, 2005 7:56 AM
To: Kinder, Debra
Subject: FW: Interest Rates

Sara Wiseman
Manager-Property Accounting
502.627.3189

From: Arbough, Dan
Sent: Monday, December 05, 2005 6:08 PM
To: Wiseman, Sara
Subject: Interest Rates

http://www.federalreserve.gov/releases/h15/data/Monthly/H15_AAA_NA.txt

Sara,

The above link has monthly corporate bond pricing for AAA rated entities while the link below is for Baa rated entities. E.ON US entities have historically been in between these two credit ratings, but this is the best source I have found that goes back several years. It is published by the Federal Reserve so it should be credible. I would suggest that our corporate rates would be closer to the AAA rates than the Baa rates when we are talking about the utilities, but you may also want to take the average of the two.

Dan

http://www.federalreserve.gov/releases/h15/data/Monthly/H15_BAA_NA.txt

Leenerts, Patricia

From: Kapp, Karan
Sent: Tuesday, December 27, 2005 10:06 AM
To: Leenerts, Patricia
Cc: 'lisa.m.dean@us.pwc.com'
Subject: RE: ASBESTOS REMOVAL EST COSTS FOR FACILITIES (2).xls

I actually prepared the estimates on all of the facilities listed in the attached spreadsheet.

From: Leenerts, Patricia
Sent: Thursday, December 22, 2005 2:46 PM
To: Kapp, Karan
Cc: 'lisa.m.dean@us.pwc.com'
Subject: FW: ASBESTOS REMOVAL EST COSTS FOR FACILITIES (2).xls

Hi Karan...I don't remember if we have met or not. I am taking the ARO responsibilities from Debra Kinder. I have been with the company a couple of months.

I sent the PWC auditor, Lisa Dean, the file attached.

Lisa replied as follows: "In looking at the executive summary, it looks like the assets in the different functional groups were evaluated by a specific individual within that function. Do you know if they all used the model developed by Karan as a tool to come up with their estimate, or if they used different methods of estimating the liability?"

Can you answer her question? Please make sure that you copy me on your answer.

Thanks

From: Leenerts, Patricia
Sent: Thursday, December 22, 2005 1:42 PM
To: 'lisa.m.dean@us.pwc.com'
Subject: FW: ASBESTOS REMOVAL EST COSTS FOR FACILITIES (2).xls

Here is the second file that you requested.

From: Kinder, Debra
Sent: Thursday, December 22, 2005 1:30 PM
To: Leenerts, Patricia
Subject: ASBESTOS REMOVAL EST COSTS FOR FACILITIES (2).xls

<< File: ASBESTOS REMOVAL EST COSTS FOR FACILITIES (2).xls >>

Leenerts, Patricia

From: Leenerts, Patricia
Sent: Tuesday, December 27, 2005 10:08 AM
To: Kapp, Karan
Subject: RE: ASBESTOS REMOVAL EST COSTS FOR FACILITIES (2).xls

Thanks. Lisa is out this week but is responding to emails. Thanks for getting back so quickly!

From: Kapp, Karan
Sent: Tuesday, December 27, 2005 10:06 AM
To: Leenerts, Patricia
Cc: 'lisa.m.dean@us.pwc.com'
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From: Kinder, Debra
Sent: Thursday, December 22, 2005 1:30 PM
To: Leenerts, Patricia
Subject: ASBESTOS REMOVAL EST COSTS FOR FACILITIES (2).xls

<< File: ASBESTOS REMOVAL EST COSTS FOR FACILITIES (2).xls >>

Leenerts, Patricia

From: Wiseman, Sara
Sent: Tuesday, January 03, 2006 4:56 PM
To: Riggs, Eric; Leenerts, Patricia
Subject: FW: Asbestos - Date of Legal Obligation

Sara Wiseman
Manager-Property Accounting
502.627.3189

-----Original Message-----
From: Scott, Valerie
Sent: Tuesday, January 03, 2006 4:50 PM
To: Wiseman, Sara
Cc: Charnas, Shannon
Subject: FW: Asbestos - Date of Legal Obligation

This question has arisen from the EEI Accounting Standards Committee... What date are we using?

Valerie

-----Original Message-----
From: bounce-251608-175405@ls.eei.org [mailto:bounce-251608-175405@ls.eei.org] On Behalf Of Keller.Kim
Sent: Tuesday, January 03, 2006 4:36 PM
To: Accounting Standards Committee
Subject: RE: Asbestos - Date of Legal Obligation

We are using 1990

-----Original Message-----
From: bounce-251600-70323@ls.eei.org
[mailto:bounce-251600-70323@ls.eei.org] On Behalf Of Scarpitta, Grace
Sent: Tuesday, January 03, 2006 3:02 PM
To: Accounting Standards Committee
Subject: Asbestos - Date of Legal Obligation

To the Accounting Standards Committee:

Con Edison would like to know the date you will be using as the legal obligation date for the removal of asbestos for the implementation of FIN 47. There have been several laws passed at various dates including 1973, 1979, 1984 and 1990.

Thanks...
Grace Scarpitta
Con Edison
212-460-6693

You are currently subscribed to asc as: [kim.keller@we-energies.com] To unsubscribe, forward this message to leave-251600-70323J@ls.eei.org

---
You are currently subscribed to asc as: [valerie.scott@eon-us.com] To unsubscribe, forward this message to leave-251608-175405J@ls.eei.org

Leenerts, Patricia

From: Wiseman, Sara
Sent: Tuesday, January 03, 2006 5:34 PM
To: Scott, Valerie
Cc: Charnas, Shannon; Kinder, Debra; Riggs, Eric; Leenerts, Patricia
Subject: RE: Asbestos - Date of Legal Obligation

We used the average in-service date of the asset group per the depreciation study in effect. This is consistent with the SFAS 143 implementation where we used the average in-service date instead of the date the law was enacted which gave rise to the liability.

Sara Wiseman
Manager-Property Accounting
502.627.3189

-----Original Message-----
From: Scott, Valerie
Sent: Tuesday, January 03, 2006 4:50 PM
To: Wiseman, Sara
Cc: Charnas, Shannon
Subject: FW: Asbestos - Date of Legal Obligation

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Grace Scarpitta
Con Edison
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You are currently subscribed to asc as: [kim.keller@we-energies.com] To unsubscribe, forward this message to leave-251600-70323J@ls.eei.org

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You are currently subscribed to asc as: [valerie.scott@eon-us.com] To unsubscribe, forward this message to leave-251608-175405J@ls.eei.org

Leenerts, Patricia

From: Scott, Valerie
Sent: Tuesday, January 03, 2006 5:42 PM
To: Wiseman, Sara
Cc: Charnas, Shannon; Kinder, Debra; Riggs, Eric; Leenerts, Patricia
Subject: RE: Asbestos - Date of Legal Obligation

Attachments: RE: Asbestos - Date of Legal Obligation; RE: Asbestos - Date of Legal Obligation; Re: Asbestos - Date of Legal Obligation; Re: Asbestos - Date of Legal Obligation; Re: Asbestos - Date of Legal Obligation; RE: Asbestos - Date of Legal Obligation; RE: Asbestos - Date of Legal Obligation

RE: Asbestos - Date of Legal O... RE: Asbestos - Date of Legal O... Re: Asbestos - Date of Legal O... Re: Asbestos - Date of Legal O... Re: Asbestos - Date of Legal O... RE: Asbestos - Date of Legal O... RE: Asbestos - Date of Legal O...

From the e-mails I've been getting it sounds like many companies are using 1990, which I assume was the date the laws on asbestos were enacted. I don't know if this difference will create an issue for PwC, but it's something we may want to think about.

Attached are the other e-mails.

Valerie

-----Original Message-----
From: Wiseman, Sara
Sent: Tuesday, January 03, 2006 5:34 PM
To: Scott, Valerie
Cc: Charnas, Shannon; Kinder, Debra; Riggs, Eric; Leenerts, Patricia
Subject: RE: Asbestos - Date of Legal Obligation

We used the average in-service date of the asset group per the depreciation study in effect. This is consistent with the SFAS 143 implementation where we used the average in-service date instead of the date the law was enacted which gave rise to the liability.

Sara Wiseman
Manager-Property Accounting
502.627.3189

-----Original Message-----
From: Scott, Valerie
Sent: Tuesday, January 03, 2006 4:50 PM
To: Wiseman, Sara
Cc: Charnas, Shannon
Subject: FW: Asbestos - Date of Legal Obligation

This question has arisen from the EEI Accounting Standards Committee... What date are we using?

Valerie

-----Original Message-----
From: bounce-251608-175405@ls.eei.org [mailto:bounce-251608-175405@ls.eei.org] On Behalf Of Keller.Kim
Sent: Tuesday, January 03, 2006 4:36 PM
To: Accounting Standards Committee
Subject: RE: Asbestos - Date of Legal Obligation

We are using 1990

-----Original Message-----
From: bounce-251600-70323@ls.eei.org
[mailto:bounce-251600-70323@ls.eei.org] On Behalf Of Scarpitta, Grace
Sent: Tuesday, January 03, 2006 3:02 PM
To: Accounting Standards Committee
Subject: Asbestos - Date of Legal Obligation

To the Accounting Standards Committee:

Con Edison would like to know the date you will be using as the legal obligation date for the removal of asbestos for the implementation of FIN 47. There have been several laws passed at various dates including 1973, 1979, 1984 and 1990.

Thanks...
Grace Scarpitta
Con Edison
212-460-6693

You are currently subscribed to asc as: [kim.keller@we-energies.com] To unsubscribe, forward this message to leave-251600-70323J@ls.eei.org

---
You are currently subscribed to asc as: [valerie.scott@eon-us.com] To unsubscribe, forward this message to leave-251608-175405J@ls.eei.org

Leenerts, Patricia

From: bounce-251627-175405@ls.eei.org on behalf of STEIN, HERBERT E [HSTEIN@entergy.com]
Sent: Tuesday, January 03, 2006 5:06 PM
To: Accounting Standards Committee
Subject: RE: Asbestos - Date of Legal Obligation

Tom,

What's the significance of this - is 1990 the date that the ARC asset is discounted back to and the accumulated depreciation begins? Thanks.

Herb

-----Original Message-----
From: bounce-251612-27442@ls.eei.org [mailto:bounce-251612-27442@ls.eei.org] **On Behalf Of** temitchell@aep.com
Sent: Tuesday, January 03, 2006 3:46 PM
To: Accounting Standards Committee
Subject: Re: Asbestos - Date of Legal Obligation

AEP is using 1990

"Scarpitta, Grace" <SCARPITTAG@coned.com>
Sent by: bounce-251600-27400@ls.eei.org

01/03/2006 04:02 PM

Please respond to
"Accounting Standards Committee" <asc@ls.eei.org>

To "Accounting Standards Committee" <asc@ls.eei.org>
cc
Subject Asbestos - Date of Legal Obligation

To the Accounting Standards Committee:

Con Edison would like to know the date you will be using as the legal obligation date for the removal of asbestos for the implementation of FIN 47. There have been several laws passed at various dates including 1973, 1979, 1984 and 1990.

Thanks...
Grace Scarpitta
Con Edison
212-460-6693

You are currently subscribed to asc as: [temitchell@aep.com]
To unsubscribe, forward this message to leave-251600-27400X@ls.eei.org

--- You are currently subscribed to asc as: [hstein@entergy.com] To unsubscribe, forward this message to leave-251612-27442Y@ls.eei.org

---

You are currently subscribed to asc as: [valerie.scott@eon-us.com]
To unsubscribe, forward this message to leave-251627-175405J@ls.eei.org

Leenerts, Patricia

From: bounce-251623-175405@ls.eei.org on behalf of kevinj.waden@exeloncorp.com
Sent: Tuesday, January 03, 2006 4:47 PM
To: Accounting Standards Committee
Cc: joseph.trpik@exeloncorp.com; kevinj.waden@exeloncorp.com
Subject: RE: Asbestos - Date of Legal Obligation

Exelon is using 1973.

-----Original Message-----
From: bounce-251600-960516@ls.eei.org
[mailto:bounce-251600-960516@ls.eei.org]On Behalf Of Scarpitta, Grace
Sent: Tuesday, January 03, 2006 3:02 PM
To: Accounting Standards Committee
Subject: Asbestos - Date of Legal Obligation

To the Accounting Standards Committee:

Con Edison would like to know the date you will be using as the legal obligation date for the removal of asbestos for the implementation of FIN 47. There have been several laws passed at various dates including 1973, 1979, 1984 and 1990.

Thanks...
Grace Scarpitta
Con Edison
212-460-6693

You are currently subscribed to asc as: [kevinj.waden@exeloncorp.com] To unsubscribe, forward this message to leave-251600-960516P@ls.eei.org

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****

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Leenerts, Patricia

From:	bounce-251621-175405@ls.eei.org on behalf of Keli_Morrison@dom.com
Sent:	Tuesday, January 03, 2006 4:58 PM
To:	Accounting Standards Committee
Subject:	Re: Asbestos - Date of Legal Obligation

Dominion is using 1990.

"Scarpitta, Grace" <SCARPITTAG@coned.com>
Sent by: bounce-251600-631327@ls.eei.org

01/03/2006 04:02 PM

Please respond to "Accounting Standards Committee" <asc@ls.eei.org>

To
"Accounting Standards Committee" <asc@ls.eei.org>

cc

Subject
Asbestos - Date of Legal Obligation

To the Accounting Standards Committee:

Con Edison would like to know the date you will be using as the legal obligation date for the removal of asbestos for the implementation of FIN 47. There have been several laws passed at various dates including 1973, 1979, 1984 and 1990.

Thanks...
Grace Scarpitta
Con Edison
212-460-6693

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Leenerts, Patricia

From: bounce-251615-175405@ls.eei.org on behalf of dmckee@firstenergycorp.com
Sent: Tuesday, January 03, 2006 4:49 PM
To: Accounting Standards Committee
Cc: tietzr@firstenergycorp.com; rlevans@firstenergycorp.com; tschad@gpu.com
Subject: Re: Asbestos - Date of Legal Obligation

FirstEnergy is using 1984.

Regards,
Dena

Dena R. McKee
Accounting Research Manager
FirstEnergy Corp.
76 South Main St.
Akron, Ohio 44308
Phone: 330-384-5495
Fax: 330-384-5299

"Scarpitta, Grace" <SCARPITTAG@coned.com>
Sent by: bounce-251600-1006604@ls.eei.org

01/03/2006 04:02 PM

Please respond to "Accounting Standards Committee" <asc@ls.eei.org>

To
"Accounting Standards Committee" <asc@ls.eei.org>

cc

Subject
Asbestos - Date of Legal Obligation

To the Accounting Standards Committee:

Con Edison would like to know the date you will be using as the legal obligation date for the removal of asbestos for the implementation of FIN 47. There have been several laws passed at various dates including 1973, 1979, 1984 and 1990.

Thanks...
Grace Scarpitta
Con Edison
212-460-6693

You are currently subscribed to asc as: [dmckee@firstenergycorp.com] To unsubscribe, forward this message to leave-251600-1006604C@ls.eei.org

Leenerts, Patricia

From: bounce-251612-175405@ls.eei.org on behalf of temitchell@aep.com
Sent: Tuesday, January 03, 2006 4:46 PM
To: Accounting Standards Committee
Subject: Re: Asbestos - Date of Legal Obligation

AEP is using 1990

"Scarpitta, Grace" <SCARPITTAG@coned.com>
Sent by: bounce-251600-27400@ls.eei.org

01/03/2006 04:02 PM

Please respond to
"Accounting Standards Committee" <asc@ls.eei.org>

To "Accounting Standards Committee" <asc@ls.eei.org>
cc
Subject Asbestos - Date of Legal Obligation

To the Accounting Standards Committee:

Con Edison would like to know the date you will be using as the legal obligation date for the removal of asbestos for the implementation of FIN 47. There have been several laws passed at various dates including 1973, 1979, 1984 and 1990.

Thanks...
Grace Scarpitta
Con Edison
212-460-6693

You are currently subscribed to asc as: [temitchell@aep.com]
To unsubscribe, forward this message to leave-251600-27400X@ls.eei.org

--- You are currently subscribed to asc as: [valerie.scott@eon-us.com] To unsubscribe, forward this message to leave-251612-175405J@ls.eei.org

Leenerts, Patricia

From: bounce-251608-175405@ls.eei.org on behalf of Keller.Kim [kim.keller@we-energies.com]
Sent: Tuesday, January 03, 2006 4:36 PM
To: Accounting Standards Committee
Subject: RE: Asbestos - Date of Legal Obligation

We are using 1990

-----Original Message-----
From: bounce-251600-70323@ls.eei.org
[mailto:bounce-251600-70323@ls.eei.org] On Behalf Of Scarpitta, Grace
Sent: Tuesday, January 03, 2006 3:02 PM
To: Accounting Standards Committee
Subject: Asbestos - Date of Legal Obligation

To the Accounting Standards Committee:

Con Edison would like to know the date you will be using as the legal obligation date for the removal of asbestos for the implementation of FIN 47. There have been several laws passed at various dates including 1973, 1979, 1984 and 1990.

Thanks...
Grace Scarpitta
Con Edison
212-460-6693

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You are currently subscribed to asc as: [valerie.scott@eon-us.com] To unsubscribe, forward this message to leave-251608-175405J@ls.eei.org

Leenerts, Patricia

From:	bounce-251606-175405@ls.eei.org on behalf of Sheppard, Amy [Amy.Sheppard@Cinergy.COM]
Sent:	Tuesday, January 03, 2006 4:33 PM
To:	Accounting Standards Committee
Subject:	RE: Asbestos - Date of Legal Obligation

Cinergy is using 1990 as our date of legal obligation.

-----Original Message-----
From: bounce-251600-848720@ls.eei.org
[mailto:bounce-251600-848720@ls.eei.org] On Behalf Of Scarpitta, Grace
Sent: Tuesday, January 03, 2006 4:02 PM
To: Accounting Standards Committee
Subject: Asbestos - Date of Legal Obligation

To the Accounting Standards Committee:

Con Edison would like to know the date you will be using as the legal obligation date for the removal of asbestos for the implementation of FIN 47. There have been several laws passed at various dates including 1973, 1979, 1984 and 1990.

Thanks...
Grace Scarpitta
Con Edison
212-460-6693

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You are currently subscribed to asc as: [valerie.scott@eon-us.com] To unsubscribe, forward this message to leave-251606-175405J@ls.eei.org

Leenerts, Patricia

From:	Scott, Valerie
Sent:	Wednesday, January 04, 2006 8:48 AM
To:	Wiseman, Sara; Kinder, Debra; Leenerts, Patricia
Cc:	Charnas, Shannon
Subject:	More EEI Asbestos Survey Results
Attachments:	RE: Asbestos - Date of Legal Obligation; RE: Asbestos - Date of Legal Obligation; RE: Asbestos - Date of Legal Obligation; RE: Asbestos - Date of Legal Obligation

RE: Asbestos - Date of Legal O... RE: Asbestos - Date of Legal O... RE: Asbestos - Date of Legal O... RE: Asbestos - Date of Legal O...

Looks like 1973 is leading the way here!

Valerie

Leenerts, Patricia

From: bounce-251690-175405@ls.eei.org on behalf of Stranik, Mike [mike.stranik@pse.com]
Sent: Tuesday, January 03, 2006 8:10 PM
To: Accounting Standards Committee
Subject: RE: Asbestos - Date of Legal Obligation

PSE is using April 6, 1973 (EPA promulgated the 1st asbestos NESCHAP - regulation).

Mike Stranik
Assistant Corporate Secretary and
Assistant Controller
Puget Sound Energy
Ph: (425) 462-3202
Fax (425) 462-3515
E-mail address: mike.stranik@pse.com

-----Original Message-----
From: bounce-251600-33407@ls.eei.org
[mailto:bounce-251600-33407@ls.eei.org]On Behalf Of Scarpitta, Grace
Sent: Tuesday, January 03, 2006 1:02 PM
To: Accounting Standards Committee
Subject: Asbestos - Date of Legal Obligation

To the Accounting Standards Committee:

Con Edison would like to know the date you will be using as the legal obligation date for the removal of asbestos for the implementation of FIN 47. There have been several laws passed at various dates including 1973, 1979, 1984 and 1990.

Thanks...
Grace Scarpitta
Con Edison
212-460-6693

You are currently subscribed to asc as: [mike.stranik@pse.com] To unsubscribe, forward this message to leave-251600-33407B@ls.eei.org

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You are currently subscribed to asc as: [valerie.scott@eon-us.com] To unsubscribe, forward this message to leave-251690-175405J@ls.eei.org

Leenerts, Patricia

From: bounce-251688-175405@ls.eei.org on behalf of Abrams, Camille L [camille.l.abrams@xcelenergy.com]
Sent: Tuesday, January 03, 2006 5:33 PM
To: Accounting Standards Committee
Subject: RE: Asbestos - Date of Legal Obligation

Xcel is using 1973. We could not determine the amount of asbestos that was friable (airborne upon removal, typically around a boiler, 1973) versus non-friable (not airborne on removal, roof shingles, 1990) in our estimates and chose the earlier date.

-----Original Message-----
From: bounce-251600-1052688@ls.eei.org
[mailto:bounce-251600-1052688@ls.eei.org]On Behalf Of Scarpitta, Grace
Sent: Tuesday, January 03, 2006 3:02 PM
To: Accounting Standards Committee
Subject: Asbestos - Date of Legal Obligation

To the Accounting Standards Committee:

Con Edison would like to know the date you will be using as the legal obligation date for the removal of asbestos for the implementation of FIN 47. There have been several laws passed at various dates including 1973, 1979, 1984 and 1990.

Thanks...
Grace Scarpitta
Con Edison
212-460-6693

You are currently subscribed to asc as: [camille.l.abrams@xcelenergy.com] To unsubscribe, forward this message to leave-251600-1052688C@ls.eei.org

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You are currently subscribed to asc as: [valerie.scott@eon-us.com] To unsubscribe, forward this message to leave-251688-175405J@ls.eei.org

Leenerts, Patricia

From: bounce-251686-175405@ls.eei.org on behalf of Schmit, Donette [donette.schmit@mdu.com]
Sent: Tuesday, January 03, 2006 5:13 PM
To: Accounting Standards Committee
Subject: RE: Asbestos - Date of Legal Obligation

We are using 1973

-----Original Message-----
From: bounce-251600-27415@ls.eei.org
[mailto:bounce-251600-27415@ls.eei.org] On Behalf Of Scarpitta, Grace
Sent: Tuesday, January 03, 2006 3:02 PM
To: Accounting Standards Committee
Subject: Asbestos - Date of Legal Obligation

To the Accounting Standards Committee:

Con Edison would like to know the date you will be using as the legal obligation date for the removal of asbestos for the implementation of FIN 47. There have been several laws passed at various dates including 1973, 1979, 1984 and 1990.

Thanks...
Grace Scarpitta
Con Edison
212-460-6693

You are currently subscribed to asc as: [donette.schmit@mdu.com]
To unsubscribe, forward this message to leave-251600-27415C@ls.eei.org

---
You are currently subscribed to asc as: [valerie.scott@eon-us.com]
To unsubscribe, forward this message to leave-251686-175405J@ls.eei.org

Leenerts, Patricia

From: bounce-251684-175405@ls.eei.org on behalf of Moreira, John [John_Moreira@nstaronline.com]
Sent: Tuesday, January 03, 2006 5:08 PM
To: Accounting Standards Committee
Subject: RE: Asbestos - Date of Legal Obligation

Grace, NSTAR is using 1973.

John

-----Original Message-----
From: bounce-251600-31972@ls.eei.org [mailto:bounce-251600-31972@ls.eei.org]
On Behalf Of Scarpitta, Grace
Sent: Tuesday, January 03, 2006 4:02 PM
To: Accounting Standards Committee
Subject: Asbestos - Date of Legal Obligation

To the Accounting Standards Committee:

Con Edison would like to know the date you will be using as the legal obligation date for the removal of asbestos for the implementation of FIN 47. There have been several laws passed at various dates including 1973, 1979, 1984 and 1990.

Thanks...
Grace Scarpitta
Con Edison
212-460-6693

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Leenerts, Patricia

From: Charnas, Shannon
Sent: Wednesday, January 04, 2006 12:31 PM
To: Wiseman, Sara; Leenerts, Patricia
Subject: FW: FIN 47 asbestos

Tracking:

Recipient	Message Status
Wiseman, Sara	
Leenerts, Patricia	

Sara & Pat-

Here is some additional information from Exelon regarding legal requirement dates for assets other than in-service dates. Asbestos is the largest one. I don't think we had a lot in terms of PCB related expenses, I think it was all tied up with oil or transformer disposal, but if I remember correctly that was not one of the larger items from SFAS 143. Bob Ehrler may have additional information or thoughts, but for now I would suggest using 1973 for asbestos.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

From: kevinj.waden@exeloncorp.com [mailto:kevinj.waden@exeloncorp.com]
Sent: Wednesday, January 04, 2006 12:09 PM
To: Charnas, Shannon
Subject: RE: FIN 47 asbestos

Shannon- Thanks for the message, hope you holidays were good.

In terms of your question, for the following items we are using the more current of the inservice dates or the legal requirement that we were able to identify which are as follows:

Asbestos 1973
PCB 1978
Underground Storage Tanks 1989 (not big dollars)
Aboveground Storage Tanks 1984 (again not big dollars)

Hope this helps.

Kevin J. Waden
EED Director of Financial Reporting
and Accounting Research
630-437-2337

Click to add my contact info to your organizer:
http://my.infotriever.com/ex7tp6ug

>

-----Original Message-----
From: Charnas, Shannon [mailto:Shannon.Charnas@eon-us.com]
Sent: Wednesday, January 04, 2006 10:15 AM
To: Waden, Kevin J.
Subject: FIN 47 asbestos

Kevin-

I have seen the emails going around regarding the legal obligation date being used for FIN 47 asbestos related assets. Exelon seems to be using 1973. I was wondering if the asbestos assets are the only assets you are using a date other than the in-service date. If you could let me know I would really appreciate it.

Thanks,

Shannon Charnas
Director, Utility Accounting and Reporting
(502) 627-4978

****
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****

Leenerts, Patricia

From:	Wiseman, Sara
Sent:	Wednesday, January 04, 2006 5:56 PM
To:	Leenerts, Patricia; Wyatt, Larissa; Griffin, Sharon
Cc:	Kinder, Debra; Riggs, Eric
Subject:	New account numbers.xls
Attachments:	New account numbers.xls

New account numbers.xls

I am attempting to add the new accounts listed on the "all" tab on this spreadsheet for FIN 47. We expect to book the FIN47 entry no later than Saturday. Please remember this will affect your plant report and reconciliations as this will be an entry to GL only, FA will not be impacted until at least January, possibly February.

Change:
101107 PLANT IN SERVICE - ARO ASSET RETIREMENT COST
chg to---- Plant In Service- Electric ARO Asset Retirement Cost-Equipment
Add:
101125 Plant In Service- Electric ARO Asset Retirement Cost-Land/Building
101207 Plant In Service- Gas ARO Asset Retirement Cost-Equipment
101225 Plant In Service- Gas ARO Asset Retirement Cost-Land/Building
101307 Plant In Service- Common ARO Asset Retirement Cost-Equipment
101325 Plant In Service- Common ARO Asset Retirement Cost-Land/Building

Change:
108107 ACCUM. DEPR. - ARO ASSET RETIREMENT COST
chg to---- ACCUM. DEPR. - ELECTRIC ARO ASSET RETIREMENT COST-EQUIPMENT
Add:
108125 ACCUM. DEPR. - ELECTRIC ARO ASSET RETIREMENT COST-LAND/BUILDING
108207 ACCUM. DEPR. - GAS ARO ASSET RETIREMENT COST-EQUIPMENT
108225 ACCUM. DEPR. - GAS ARO ASSET RETIREMENT COST-LAND/BUILDING
108307 ACCUM. DEPR. - COMMON ARO ASSET RETIREMENT COST-EQUIPMENT
108325 ACCUM. DEPR. - COMMON ARO ASSET RETIREMENT COST-LAND/BUILDING

Change:
182317 OTHER REGULATORY ASSETS ARO - STEAM
chg to---- OTHER REGULATORY ASSETS ARO - GENERATION
Add:
182325 OTHER REGULATORY ASSETS ARO - DISTRIBUTION
182326 OTHER REGULATORY ASSETS ARO - GAS
182327 OTHER REGULATORY ASSETS ARO - COMMON

Change:
230002 ASSET RETIREMENT OBLIGATIONS - STEAM
chg to---- ASSET RETIREMENT OBLIGATIONS - GENERATION
Add:
230005 ASSET RETIREMENT OBLIGATIONS - DISTRIBUTION
230006 ASSET RETIREMENT OBLIGATIONS - GAS
230007 ASSET RETIREMENT OBLIGATIONS - COMMON

Change:
254014 REGULATORY LIABILITY ARO - STEAM
chg to---- REGULATORY LIABILITY ARO - GENERATION
Add:
254016 REGULATORY LIABILITY ARO - GAS

Change:
407401 REGULATORY CREDITS - STEAM
chg to---- REGULATORY CREDITS - GENERATION
Add:
407405 REGULATORY CREDITS - DISTRIBUTION
407406 REGULATORY CREDITS - GAS
407407 REGULATORY CREDITS - COMMON

Add:
407411 CUMM EFF-REGULATORY CREDITS - GENERATION
407412 CUMM EFF-REGULATORY CREDITS - TRANSMISSION
407415 CUMM EFF-REGULATORY CREDITS - DISTRIBUTION
407416 CUMM EFF-REGULATORY CREDITS - GAS
407417 CUMM EFF-REGULATORY CREDITS - COMMON

Change:
411150 ACCRETION EXPENSE - STEAM
chg to---- ACCRETION EXPENSE - GENERATION
Add:
411155 ACCRETION EXPENSE - DISTRIBUTION
411156 ACCRETION EXPENSE - GAS
411157 ACCRETION EXPENSE - COMMON

Change:
435002 EXTRAORDINARY DEDUCTIONS - STEAM
chg to---- CUMM EFFECT OF ACCT CHANGE-ARO-GENERATION
435003 EXTRAORDINARY DEDUCTIONS - TRANSMISSION
chg to---- CUMM EFFECT OF ACCT CHANGE-ARO-TRANSMISSION
Add:
435005 CUMM EFFECT OF ACCT CHANGE-ARO-DISTRIBUTION
435006 CUMM EFFECT OF ACCT CHANGE-ARO-GAS
435007 CUMM EFFECT OF ACCT CHANGE-ARO-COMMON

Change:
101107 PLANT IN SERVICE - ARO ASSET RETIREMENT COST
chg to---- Plant In Service- Electric ARO Asset Retirement Cost-Equipment

Change:
108107 ACCUM. DEPR. - ARO ASSET RETIREMENT COST
chg to---- ACCUM. DEPR. - ELECTRIC ARO ASSET RETIREMENT COST-EQUIPMENT

Change:
182317 OTHER REGULATORY ASSETS ARO - STEAM
chg to---- OTHER REGULATORY ASSETS ARO - GENERATION

Change:
230002 ASSET RETIREMENT OBLIGATIONS - STEAM
chg to---- ASSET RETIREMENT OBLIGATIONS - GENERATION

Change:
254014 REGULATORY LIABILITY ARO - STEAM
chg to---- REGULATORY LIABILITY ARO - GENERATION

Change:
407401 REGULATORY CREDITS - STEAM
chg to---- REGULATORY CREDITS - GENERATION

Change:
411150 ACCRETION EXPENSE - STEAM
chg to---- ACCRETION EXPENSE - GENERATION

Change:
435002 EXTRAORDINARY DEDUCTIONS - STEAM
chg to---- CUMM EFFECT OF ACCT CHANGE-ARO-GENERATION
435003 EXTRAORDINARY DEDUCTIONS - TRANSMISSION
chg to---- CUMM EFFECT OF ACCT CHANGE-ARO-TRANSMISSION

Leenerts, Patricia

From: Arbough, Dan
Sent: Thursday, January 05, 2006 9:02 AM
To: Leenerts, Patricia
Cc: Wiseman, Sara
Subject: RE: Update: SFAS 143 Rates for Year End 2005 - final

Pat,

We should be using "E.ON US Yield p.a." rather than the "E.ON Yield p.a." column. The note about "off-the-run" rates does not apply in this case. It is dealing with issuing bonds. The abbreviations s.a. and p.a. are semi-annual and per annum.

Dan

-----Original Message-----
From: Leenerts, Patricia
Sent: Thursday, January 05, 2006 8:54 AM
To: Arbough, Dan
Cc: Wiseman, Sara
Subject: FW: Update: SFAS 143 Rates for Year End 2005 - final

Attached are the final rates that I will be using for FIN 47. Sara understood that we are to use the "E.ON Yield p.a." column. I have a couple of questions. Is the note relevant to us about the "off-the-run" rates? Also, what do s.a. and p.a. mean?

Thanks for your help.

Pat

X 3811

-----Original Message-----
From: Wiseman, Sara
Sent: Thursday, January 05, 2006 7:26 AM
To: Leenerts, Patricia
Subject: FW: Update: SFAS 143 Rates for Year End 2005 - final

Sara Wiseman
Manager-Property Accounting
502.627.3189

-----Original Message-----
From: Gahlen, Christian [mailto:Christian.Gahlen@eon.com]
Sent: Thursday, January 05, 2006 5:03 AM
To: Christoph.Meyer@eon-energie.com; Berthold.Peter@eon-energie.com; Charlotte.Pennander@eon.se; Magnus.Wennersten@eon.se; Simon.Cosson@eon-uk.com; Nutter, Mark T (Corp); Dalton, LaStacia; Scott, Valerie; Wiseman, Sara; britta.starck@eon-ruhrgas.com; matthias.wibelitz@eon-ruhrgas.com
Cc: EON-FRW1; josef.lehr@degussa.com; Rolf.Schneider@RAG.de; Brambosch, Wolfgang; Wilhelm, Michael; Hansal, Uwe; Haeger, Bernhard; Mertens, Karl; Hoffmann, Marc; Barr, Christian; Witt, Manuela; Hartel, Michael; Senczek, Melanie; Granderath, Lutz (PWC); Langen, Almut (PwC); Kammlott, Claudia (PWC); Heyden, Sandra
Subject: Update: SFAS 143 Rates for Year End 2005 - final

Dear all,

please find enclosed our update on FAS 143 interest rates as per 31.12.2005 as announced in our year end timetable and instructions:

Due to the fact that there was only a minor movement in interest rates during the 2nd half of December, we agreed upon using the interest rates we provided on December 15, 2005 (please see below).

If you have any further questions, please do not hesitate to contact me.

Kind regards

Christian Gahlen

E.ON AG
Konzernrechnungswesen
Corporate Accounting
E.ON-Platz 1
40479 Düsseldorf
Germany

phone +49 211 45 79 204
fax +49 211 45 79 1204

> -----Ursprüngliche Nachricht-----
> Von: Gahlen, Christian
> Gesendet: Donnerstag, 15. Dezember 2005 19:41
> An: 'Christoph.Meyer@eon-energie.com'; 'Charlotte.Pennander@eon.se'; 'Magnus.Wennersten@eon.se'; 'Simon.Cosson@eon-uk.com'; 'Nutter, Mark T (Corp)'; 'LaStacia.Dalton@lgeenergy.com'; 'Valerie.Scott@lgeenergy.com'; 'britta.starck@eon-ruhrgas.com'; 'matthias.wibelitz@eon-ruhrgas.com'
> Cc: EON-FRW1; 'josef.lehr@degussa.com'; 'Rolf.Schneider@RAG.de'; Brambosch, Wolfgang; Wilhelm, Michael; Hansal, Uwe; Haeger, Bernhard; Mertens, Karl; Hoffmann, Marc; Barr, Christian; Witt, Manuela; Hartel, Michael; Senczek, Melanie; Granderath, Lutz (PWC); 'Josef-Thomas.Sepp@eon-energie.com'; Kammlott, Claudia (PWC); Heyden, Sandra
> Betreff: Subject: SFAS 143 Rates (preliminary)
>
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>
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> These rates will be reviewed as of December 31, 2005, and the final interest rates reviewed by the auditor will be sent out on January 5, 2006.
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> If you have any further questions, please do not hesitate to contact us.
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> Mit freundlichen Grüssen/
> Best regards
>

> Brian Jungwirth	Christian Gahlen
> E.ON AG	E.ON AG
> Leiter Konzernrechnungswesen	Konzernrechnungswesen
> Corporate Accounting	Corporate Accounting
> E.ON-Platz 1	E.ON-Platz 1
> 40479 Düsseldorf	40479 Düsseldorf
> Germany	Germany
> phone +49 211 45 79 833	+49 211 45 79 204
> fax +49 211 45 79 584	+49 211 45 79 1204

>
<<E ON Zinskurve 2005 15122005.XLS>> << Datei: E ON Zinskurve 2005 15122005.XLS >>

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Leenerts, Patricia

From: Leenerts, Patricia
Sent: Thursday, January 05, 2006 9:09 AM
To: Arbough, Dan
Cc: Wiseman, Sara
Subject: RE: Update: SFAS 143 Rates for Year End 2005 - final

Thank you. The one you said is the one Sara thought, I picked up the wrong column name.

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Sara Wiseman
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Witt, Manuela; Hartel, Michael; Senczek, Melanie; Granderath, Lutz (PWC); Langen, Almut (PwC); Kammlott, Claudia (PWC); Heyden, Sandra
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Kind regards

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> Gesendet: Donnerstag, 15. Dezember 2005 19:41
> An: 'Christoph.Meyer@eon-energie.com'; 'Charlotte.Pennander@eon.se'; 'Magnus.Wennersten@eon.se'; 'Simon.Cosson@eon-uk.com'; 'Nutter, Mark T (Corp)'; 'LaStacia.Dalton@lgeenergy.com'; 'Valerie.Scott@lgeenergy.com'; 'britta.starck@eon-ruhrgas.com'; 'matthias.wibelitz@eon-ruhrgas.com'
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Leenerts, Patricia

From: Leenerts, Patricia
Sent: Thursday, January 05, 2006 5:07 PM
To: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: FW: In-service date of Asbestos - FIN 47

PWC agreed that we should use 1973 for the asbestos related AROs for FIN 47.

From: rene.m.newsome@us.pwc.com [mailto:rene.m.newsome@us.pwc.com]
Sent: Thursday, January 05, 2006 4:49 PM
To: Leenerts, Patricia
Cc: lisa.m.dean@us.pwc.com; james.king.moore@us.pwc.com; melanie.r.lockard@us.pwc.com
Subject: Fw: In-service date of Asbestos - FIN 47

Pat,

Attached is the response received today re: your inquiry.

Thanks,
Rene'

Rene' Newsome | PricewaterhouseCoopers LLP

Assurance and Business Advisory Services | 500 W. Main Street, Suite 1800, Louisville, KY 40202 | phone: 502.585.7726 | cell: 813.857.9664 | fax: 813.375.8139

----- Forwarded by Rene M Newsome/US/ABAS/PwC on 01/05/2006 04:47 PM -----

James Moore/US/ABAS/PwC

01/05/2006 03:33 PM
(502) 585 7819
Louisville
US

To Rene M Newsome/US/ABAS/PwC@Americas-US
cc Melanie R. Lockard/US/ABAS/PwC@Americas-US
Subject Re: Fw: In-service date of Asbestos - FIN 47Link

I agree - they should be using the date the obligation to remove the asbestos became effective.

Jim Moore | PricewaterhouseCoopers LLP

500 W. Main Street, Suite 1800, Louisville, KY 40202 | phone: 502.585.7819 | cell: 502.649.8240 | fax: 813.741.6648

----- Forwarded by Rene M Newsome/US/ABAS/PwC on 01/05/2006 01:48 PM -----

"Leenerts, Patricia" <Patricia.Leenerts@eon-us.com>

01/04/2006 03:52 PM

To James Moore/US/ABAS/PwC@Americas-US, Rene M Newsome/US/ABAS/PwC@Americas-US, Melanie R. Lockard/US/ABAS/PwC@Americas-US

cc Lisa M Dean/US/TLS/PwC@Americas-US, "Wiseman, Sara" <Sara.Wiseman@eon-us.com>, "Kinder, Debra" <Debra.Kinder@eon-us.com>, "Riggs, Eric" <Eric.Riggs@eon-us.com>

Subject In-service date of Asbestos - FIN 47

When we set-up the asbestos AROs for FIN 47, we used the calculated in-service date based on the depreciation study Average Service Life as of 1999. This calculated date was prior to 1973 in all cases. We are about to change the in-service year to 1973 for all asbestos related AROs to conform with an agreed date of legal obligation to be 1973. The remaining life, per the 1999 Depreciation Study adjusted to 2005, would remain unchanged. PSE, Xcel, Con Edison and NSTAR are examples of other companies that are using the 1973 in-service date for asbestos related assets.

This issue was just raised, so please let me know by noon on 01/05/2006 if it is felt that we should not change our in-service date for Asbestos related AROs to be 1973.

Thank you for your time.

Pat Leenerts
X 3811

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Leenerts, Patricia

From: rene.m.newsome@us.pwc.com
Sent: Thursday, January 05, 2006 4:49 PM
To: Leenerts, Patricia
Cc: lisa.m.dean@us.pwc.com; james.king.moore@us.pwc.com; melanie.r.lockard@us.pwc.com
Subject: Fw: In-service date of Asbestos - FIN 47

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cc Lisa M Dean/US/TLS/PwC@Americas-US, "Wiseman, Sara" <Sara.Wiseman@eon-us.com>, "Kinder, Debra" <Debra.Kinder@eon-us.com>, "Riggs, Eric" <Eric.Riggs@eon-us.com>
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Leenerts, Patricia

From: Riggs, Eric
Sent: Friday, January 13, 2006 3:23 PM
To: Leenerts, Patricia
Subject: RE: ASSUMPTIONS for FIN 47-Revised 01132006

I have no changes to suggest. Looks good to me.

From: Leenerts, Patricia
Sent: Friday, January 13, 2006 2:10 PM
To: Wiseman, Sara; Kinder, Debra; Riggs, Eric
Subject: ASSUMPTIONS for FIN 47-Revised 01132006

Please take a few moments to review and critique the attached revision. PWC is requesting that our documents be finalized.

I have highlighted the most recent changes/additions in blue. (I didn't think about using the tracking changes tool.)

Let me know your comments so that I can get this to PWCs Lisa Dean...I was hoping for today, but I don't know all your deadlines.

Thanks

Pat
<< File: ASSUMPTIONS for FIN 47-Revised 011306.doc >>

Leenerts, Patricia

From: james.king.moore@us.pwc.com
Sent: Tuesday, January 31, 2006 9:06 PM
To: Leenerts, Patricia
Cc: Wiseman, Sara
Subject: Re: Revised Exec Memo
Attachments: Executive Summary FIN 47-revised 01242006.doc; ARO example.xls; ATT966095.txt

Patricia,

Sorry for the late follow up, but one thing which would be helpful for us would be a summary which includes the amounts and types of ARO's recognized for both 143 and FIN 47, for example coal piles, ash pones, asbestos, pcb, etc. I have included a template attached. If at all possible to get this in a day two would be appreciated as we are trying to wrap up our procedures. Call me and we can discuss if you wish.

Jim Moore

Jim Moore | PricewaterhouseCoopers LLP

500 W. Main Street, Suite 1800, Louisville, KY 40202 | phone: 502.585.7819 | cell: 502.649.8240 | fax: 813.741.6648

"Leenerts, Patricia" <Patricia.Leenerts@eon-us.com>

01/24/2006 02:52 PM

To James Moore/US/ABAS/PwC@Americas-US
cc
Subject Revised Exec Memo

Here is my pass at revising per the suggestions that you have made. Let me know any additional comments.

Thanks,

Pat
X 3811

<<Executive Summary FIN 47-revised 01242006.doc>>

Leenerts, Patricia

From: Leenerts, Patricia
Sent: Wednesday, February 01, 2006 11:07 AM
To: james.king.moore@us.pwc.com
Cc: Wiseman, Sara
Subject: FW: Revised Exec Memo
Attachments: Executive Summary FIN 47-revised 01242006.doc; ARO example.xls; ATT966095.txt

I do have a few questions/verifications.

1. On your ARO example you show a date of 10/1/2005 on the FIN 47 implementation. I believe that this date should be 12/31/2005.
2. I will provide to you the ARO Liab, ARC Asset and FV ARO as of implementation, 01/01/2003 - FASB 143 and 12/31/2005 - FIN 47.
3. I don't see any changes, by you, to the Exec Sum, was that your intent?

I will be able to complete your request for the summary, but it will not be real quick response. Our FASB 143 records are in Excel files by each location, each file then has the type of ARO broken down within it. I also need to work your request in with my closing duties for Jan06. I expect to be able to get this to you on Friday or Monday.

Patricia Leenerts
E.ON U.S.
Property Accounting
Accounting Analyst III
phone: 502.627-3811
fax: 502.627.3820

From: james.king.moore@us.pwc.com [mailto:james.king.moore@us.pwc.com]
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Cc: Wiseman, Sara
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"Leenerts, Patricia" <Patricia.Leenerts@eon-us.com>

01/24/2006 02:52 PM

To James Moore/US/ABAS/PwC@Americas-US
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Thanks,

Pat
X 3811

<<Executive Summary FIN 47-revised 01242006.doc>>

MEMORANDUM

TO: Gerald Skaggs
Val Scott
Shannon Charnas

FROM: John Fendig
LG&E Energy Law Dept.

DATE: March 18, 2003

RE: FAS 143 – Legal Reviews

This is to summarize work done by the LG&E Energy Corp. Law Dept. during recent months regarding analysis of the "legal obligation" component of certain FAS 143 issue areas.

<u>The analysis and conclusions hereunder are provided solely for the purposes of FAS 143 and related uses, should not be deemed binding or conclusive for any other purpose and are not intended to constitute a waiver of rights or admission against interest in any other proceeding</u>.

ELECTRIC GENERATION ASSETS

No specific legal obligation to remove electric generating plants or restore the land when a generating plant is decommissioned was found in the course of this review. However, certain legal obligations associated with the retirement of component assets when a plant is decommissioned were documented. These obligations arise primarily from environmental regulation and have been documented in the supporting papers for SFAS 143.

In addition to the environmental obligations described above, activities associated with the final retirement of generating plants not required by environmental regulation were reviewed to determine whether they arose from a specific legal obligation as discussed below.

COAL DOCKS

<u>**Energy "Sebree" Dock**</u> - Beth Cocanougher and Stacey Skillman analyzed this matter, including discussions with Mike McElwain of WKE.

<u>Contractual Obligation</u> -- A legal obligation exists upon termination. WKE leases the property from Powell Holdings pursuant to a lease agreement. Section 20 of this agreement establishes post-termination reclamation obligations of WKE. These include (a) removing the coal base, (b) filling the tunnel openings, (c) covering and seeding the property, (d) removing any buildings (if

not retained at the option of the Powell's) and (e) removing the dock structure, including the work barge and metal dolphins.

Permit Obligations -- A legal obligation exists upon release of the permits. The dock is covered by permits from the state Division of Water, the Coast Guard and the Army Corps of Engineers. Aggregate remediation obligations under the DoW permit will be met by steps (a) and (c) above and under the CG and ACoE by completion of step (e) above.

Estimate -- Mike McElwain estimated the cost of these reclamation steps would be between \$60,000 and \$70,000 including equipment salvage values or approx. \$175,000 without salvage.

Regulated docks - No determinable legal obligations presently. Documents, particularly historic waterway permits (if any) for the regulated docks were not available for review. In the absence of such permits, it cannot be determined that a legal obligation conclusively exists. (Although it is possible that, in some cases, similar obligations, such as removing structures in navigable waterways, could exist.) Further, these docks sit on land owned by the company, so no contractual obligations upon abandonment or non-use would arise. .

BRIDGES AND TUNNELS

John Fendig and Stacey Skillman analyzed this matter, including discussions with Randy Magollan of LG&E. A list of material tunnels, railroad crossings and bridges owned or associated with company sites was provided by the Accounting Dept. The Law Dept. then requested copies any applicable permits and easements relating thereto from the Rights of Way Dept. The Law Dept. further reviewed the Kentucky statutes and regulations governing highways and rights-of-way. In particular, specific information was available regarding the following structures:

Mill Creek Railroad Tunnel under US 31W
Ghent Pipe Tunnel under US 42
Ghent Pipe and Slurry Bridge over US 42

The following general analysis is suggested for all similar bridges, tunnels and crossings:

Permit Obligations -- No affirmative obligation upon termination. In each case, analysis of the statutes, rules and permits indicates that they are either (a) potential perpetual assets or (b) remediation obligations are discretionary, but not mandatory, by the state. (However, if tunnels relate to natural gas pipes, an obligation to fill the empty vault may exist under Dept. of Transportation rules. See Gas Transportation and Distribution below.)

Highway rules require all encroachments on public highways to be permitted under KRS 177.106 and 603 KAR 5:150. However, the terms of the statutes, regulations and the permits do not contain an affirmative requirement to remove or remediate upon abandonment or retirement. Rather they provide that, upon any expiration or revocation of the permit (the state may do the latter if reasonable necessary) the state MAY require removal or relocation of the encroachment at the expense of the permit holder. Thus, the permits have no time limit and the state may, but is not necessarily required, to insist on removal of encroachments.

Pursuant to KRS 177.120, the state may order any level railroad crossing closed for public safety and the closure is to occur at the owner's expense. However, no statute or rule states that an abandoned or unused crossing, due solely to its abandonment or non-use and absent other circumstances, is to be considered unsafe or required to be closed. Thus it cannot be said that a definite requirement exists to close or remediate.

For overpasses and bridges specifically, a similar situation , albeit with some conflicting language, exists. In these cases requirements for an airspace permit can exist pursuant to 23 CFR Section 713, Subpart B. An airspace permit of this sort reviewed had a one-year term with automatic successive one-year extensions until terminated by notice. Abandonment or non-use also constitutes termination. However, the permit contained conflicting provisions regarding requirements upon termination or revocation. One section required that any structures or attachments must be removed at the permitee's expense upon expiration or cancellation, while two other sections provided only that the state had the discretion to require removal, relocation or restoration regarding the airspace structures. While perhaps not fully clear, it is not unreasonable to view the restoration obligation as primarily discretionary, rather than obligatory.

<u>Estimates</u> -- Estimates of costs of remediation, if any, were not received.

HYDRO FACILITIES

Researched by Jim Dimas. Review included analysis of real estate documents, FERC, Coast Guard, Army Corps of Engineer and other permits applicable to these facilities. Significant analysis by outside counsel and consultants had been done in the case of Lock 7 in connection with the potential surrender of its license during 2001.

<u>Permit Obligations</u> -- Formal legal obligations not currently present. Under the existing regulatory framework, removal obligations are determined in the discretion of permitting authority as part of an application to surrender the permit. however, analysis of the permits and licenses indicates that they do not themselves contain specific obligations upon surrender. Advice of outside counsel and consultants indicates that permit authorities, particularly the FERC, retain significant authority in determining what they may require in order to surrender a hydro license. In large part, it appears that the specific requirements are driven by the case-by-case concerns of the agency which would take control of the hydro facility after abandonment.

In the case of Lock 7 analysis, it was determined that the FERC may require remediation steps including removal of all generation equipment and demolition of the station down to the waterline. It may be reasonable to infer the same or similar requirements in the case of Ohio Falls or Dix Dam. (Although Dix Dam is not regulated by the FERC.)

<u>Estimates</u>: The 2001 Lock 7 study estimated costs of $1,274,000 for removal of generation equipment and $3,417,000 for demolition of the station to the waterline. Estimates were not available for other the other hydro sites, but it is anticipated that they could be significantly

higher, due to the much larger size and complexity of Ohio Falls and Dix Dam as compared to Lock 7.

On this basis, no license or contract legal obligations upon abandonment were found and no obligation is established until required by specific direction of the permitting authority.

WATER PUMP STRUCTURES – EW BROWN

Researched by John Fendig. Analysis was done of the real estate and permit issues, if any, attendant to the water pump structures at the E.W. Brown facility. It was indicated that these pump structures rest in an enclosed lake which is on property owned by the company.

Permit or Contractual Obligations. No legal obligations were found. The lake does not constitute a navigable waterway and no Army Corps of Engineers or Coast Guard permits were applicable. The lake is entirely on company-owned, not leased, lands. On this basis, no license or contract legal obligations upon abandonment were found or anticipated.

GAS STORAGE FIELDS – WELLS AND PIPES

Reviewed by Jim Dimas, John Fendig and Gerina White, including discussions with Glenn Sundheimer, Barry Walker and others. Review was made of a sample of our form gas storage lease with landowners. Review was also made of the federal and state statutes applicable to mines and minerals and natural gas.

The following general analysis is suggested for all similar gas storage wells and pipes matters.

Statutory and Permit Obligations -- Legal obligations upon abandonment exist. Under Kentucky oil and gas law at KRS 353.550 and 805 KAR 1:080, the general rule is that abandoned wells at gas storage sites must be capped and receive certificates to that effect. Abandoned wells and their certificates are periodically inspected. Under federal Dept. of Transportation rules at 49 CFR 192.727, operators of abandoned or inactive gas pipelines are required to (a) disconnect the pipe from all sources of gas, (b) purge the pipe of any significant volumes of gas and (c) sealed at the ends.

Contractual Obligations -- No legal obligations. Our standard form gas storage lease does not contain any obligations upon abandonment, particularly no obligation to remove wells or return land to its prior state. The contract permits the company to surrender the lease upon payment of one dollar, along with payment of any prior amounts due, and be released from all further obligations or covenants thereunder. (Nonetheless, the presence of statutory obligations above will be controlling.)

Estimate -- Glen Sundheimer offered an estimate of approximately $15,000 for plugging a well, plus an additional $2,000 for land restoration. Costs of cutting and capping pipes were said to be non-material. Per Glen, the well counts are 154 wells in the Muldraugh area (Muldraugh and Doe Run fields) and 392 wells in the Magnolia area (Magnolia Upper, Deep and Central fields.)

GAS STORAGE FIELDS -- COMPRESSOR STATIONS

Reviewed by John Fendig, including discussions with Randy Magollan. Review was made of the leases with land owners of the sites where major above ground buildings or facilities were located. In particular, specific information for the following sites was

Ft. Knox Compressor Site -- Muldraugh
Indiana Compressor Site -- Cedar Farms
Brandenburg Compressor Site -- Doe Run
Brandenburg Compressor Site -- Riggs Lease

The following general analysis is suggested for all facilities :

Contractual Obligations -- No definitive affirmative legal obligation exists. Regarding the Ft. Knox site, the 30 November 1992 agreement between LG&E and the USA was reviewed. Section 9 of the 1992 agreement provides that (a) upon termination by LG&E, the company may remove all equipment upon termination of the agreement and that any surface facilities left after termination becomes property of the USA and (b) upon termination by the USA, the company has up to 2 years to remove facilities. Thus, the contract provides LG&E the option, but not the requirement, to remove facilities. (Prior 1928 leases governing the compressor site were also reviewed, which were our standard form of gas storage lease as elsewhere described herein.)

Regarding the remaining sites, all three are initially governed by LG&E's standard form of gas storage lease which does not contain any obligations upon abandonment, particularly no obligation to remove facilities or return land to its prior state. These contract permits the company to surrender the lease upon payment of one dollar, along with payment of any prior amounts due, and be released from all further obligations or covenants thereunder.

However, the Brandenburg-Riggs Field form lease is supplemented by letters or agreements dated 27 April 1946 and 21 March 1979. The 1979 document authorizes erection and operation of a compressor station on land covered by the earlier form lease. The 1946 letter states that, regarding one certain additional acre of the overall lease area, "[LG&E] agrees to fence the said acre and to return it to lessor on the expiration of this lease in approximately the same condition as found at the present time." However, it cannot be determined that (or whether) the compressor station resides on the specific acre which includes these remediation obligations or on the remaining 40 acres constituting the Riggs property which do not include a remediation obligation.

Estimate -- Although no demonstrated obligation to remove buildings is found, the following background estimates on compressor site removals was given by Steve Beatty: $2 million of the Ft. Knox site and $100,000 each for the remaining sites (including the uncertain Riggs site).

GAS TRANSPORT AND DISTRIBUTION ASSETS

Reviewed by Gerina White, including discussions with Butch Cockrell. Analysis was made of the federal Dept. of Transportation codes

Code Analysis -- Routine legal obligations exist. As discussed above, upon abandonment of gas transportation pipelines, Dept. of Transportation regulations require cutting of pipes, purging gas and capping. These costs were not stated to be material by operations individuals.

ELECTRIC TRANSMISSION AND DISTRIBUTION ASSETS

Reviewed by Gerina White, including discussions with Mike Leake. Review was made of the National Electric Safety Code. Review was also made of our predominant forms of right-of-way or easement agreements used with land owners and applicable to these assets.

<u>Code Obligations</u> -- No legal obligation exists. The National Electric Safety Code does not differentiate between abandoned (de-energized) or functioning (energized) facilities. Both are to comply with the same safety and serviceability standards. Thus, our current obligations of maintenance and repair would continue after abandonment (de-energizing) and no new or specific obligations on abandonment arise.

<u>Contract Obligations</u> -- No legal obligations were found. Forms analyzed in our sample study did not generally have specific expiration dates or have termination clauses tied to abandonment nor remediation obligations upon such abandonment other than routine maintenance and upkeep tasks similar to those already applicable to assets in use.

<u>Estimate</u> -- No estimates were obtained.

be shown above or below the line based upon whether customers or stockholders bear the expense or receive the benefits of the transaction. Instead, the nature of the transaction determines whether it is shown as utility operating income (above-the-line) or as other income and deductions (below-the-line). With enactment of the CAAA, allowance transactions are expected to become an integral part of utility operations, especially if the market for allowance trading develops as intended. The above-the-line classification required herein does not dictate how gains and losses on dispositions of allowances should be apportioned between ratepayer and stockholders, but merely reflects the fact that allowance transactions are a part of utility operations.

G. Regulatory Assets and Liabilities

The Commission proposed in the NOPR to provide accounting for regulatory assets and liabilities, i.e., assets and liabilities created through the ratemaking actions of regulatory agencies and not specifically provided for in other accounts. The NOPR proposed to create four new accounts for regulatory assets and liabilities: Account 182.3, Other Regulatory Assets; Account 244, Other Regulatory Liabilities; Account 407.3, Regulatory Debits; and Account 407.4, Regulatory Credits. The first two are balance sheet accounts; the latter two are income accounts.

As proposed, Account 182.3 would include costs incurred and charged to expense which have been, or are soon expected to be, authorized for recovery through rates and which are not specifically provided for in other accounts. Regulatory assets would be recorded by charges to Account 182.3 and credits to Account 407.4. Amounts in Account 182.3 would be amortized to Account 407.3 over the appropriate rate recognition period.

Account 244 would include liabilities imposed by the ratemaking actions of regulatory agencies and not specifically provided for in other accounts. Included in Account 244 would be revenues or gains realized and credited to income that the company is required, or is expected to be required, to use to reduce future rates. Regulatory liabilities would be established by credits to Account 244 and debits to Account 407.3. Amounts included in Account 244 would be amortized to Account 407.4 over the appropriate rate recognition period.

Support for the NOPR. National Fuel Gas, the Florida Commission and the Ohio Staff support the proposed rule. The Ohio Staff states that the proposed treatment will provide uniformity in the way utilities report the economic effects of regulatory actions and will facilitate review of regulatory assets and liabilities.

Support for the Status Quo. Virginia Power and PSI Energy oppose any change in current accounting practices for regulatory assets and liabilities. Virginia Power argues that the accounting practices used over the years have worked well and should be considered GAAP for regulated entities. PSI Energy argues that the USofA already provides sufficient guidance and accounts for regulatory assets and liabilities and that financial reporting rules ensure the itemization in financial statements of significant regulatory assets or liabilities.

Procedural Objections. A large number of commenters urge deletion of this issue from this proceeding and initiation of a separate rulemaking on regulatory assets and liabilities. 81/ Many of these commenters assert that the issue of regulatory assets and liabilities is too important and complex to be included in a rulemaking on accounting for allowances.

Pennsylvania Power & Light and Wisconsin Electric argue that this proceeding should address only those regulatory assets and liabilities related to allowances and that other regulatory assets and liabilities should be considered in a separate rulemaking.

AICPA, Arthur Andersen and Deloitte & Touche argue that the following issues should be exempted from the final rule pending further study: whether FASB instructs regulated enterprises to account for certain effects on income taxes only on the balance sheet, not on the income statement; whether deferred returns from phase-in plans and other similar deferrals should be reported below-the-line; and whether some items are classified in a way unique to the regulatory process and are not accounted for as proposed in the NOPR.

81/ AICPA, Arthur Andersen, Coopers & Lybrand, Deloitte & Touche, EEI, Central & South West, Commonwealth Edison, Con Edison, Detroit Edison, Duke Power, Gulf States, Kansas City Power & Light, Kentucky Utilities, PJM, Potomac Electric, PSE&G and Wisconsin Public Service.

General Substantive Objections. AEP argues that, according to FASB, regulatory assets and related deferred income taxes should be reflected only on the balance sheet. PSI Energy argues that the income statement presentation of phase-in plans should be specifically excluded from the final rule.

AEP also argues that, if a utility is deferring significant costs, e.g., through a phase-in plan, and is accruing a return on the unrecovered balances, the NOPR may wrongly move the credit for the deferred return from below-the-line to above-the-line. AEP argues that this result would distort both operating and non-operating income and is contrary to the regulatory intent to provide the credit as compensation to investors, not as a reduction of the cost of service.

Centerior argues that a new account is needed for the deferral of return through a carrying charge because crediting such amounts to Account 407.4, an above-the-line account, would be inconsistent with past Commission practice. Centerior argues that the Commission has consistently required the carrying charge to be credited to Account 421, Miscellaneous Nonoperating Income, a below-the-line account.

EEI argues that the Commission should allow certain regulatory assets and liabilities, such as the gross-up of portions of previously-recorded AFUDC, to be classified with the plant accounts. EEI also argues that certain costs should be presented separately from other regulatory assets and liabilities. EEI states, for example, that the net phase-in costs capitalized in each period or the net amount of previously allowable phase-in costs recovered during each period should be reported as a separate item of other income or expense in the income statement.

Applicability of Accounts 407.3 and 407.4. EEI argues that utilities should be allowed to use accounts other than 407.3 and 407.4 if state regulators have previously allowed such use. EEI argues that if state regulators have allowed the use of other accounts, the requirement to use Accounts 407.3 and 407.4 should apply only prospectively. Allegheny Power and Kansas City Power & Light assert that use of the new accounts should not be required if the commission with primary ratemaking jurisdiction requires the use of other accounts.

Southern Company argues that the new accounts should apply only to new regulatory assets and liabilities. Southern Company asserts that the new accounts could lead to cost recovery problems under existing contracts and joint ownership agreements under which costs previously deferred are now being amortized to an account reflected in formulary billings. Southern Company argues that a change in account classification would jeopardize cost recovery and could require costly renegotiation of contracts and agreements.

AEP argues that, if Accounts 407.3 and 407.4 are adopted, these accounts should not apply to deferred income taxes. AEP argues that the needed information is not always available for individual book/tax timing differences, especially those involving plant-in-service. AEP argues that identifying the proper accounts in which deferred taxes should be recorded can be difficult or impossible.

Several commenters argue that regulatory assets and liabilities should be recorded in income statement accounts reflecting the nature of the underlying transactions, regardless of when the transactions are recognized. 82/ The American Gas Association, for example, asserts that financial statement readers are more interested in the nature of a company's transactions than in the differences between GAAP for non-regulated and regulated businesses. The Association asserts that, when necessary, utilities and regulators can determine the effect of regulation for ratemaking purposes and that these differences should not be the focus of the statements.

Effect on Coverage Ratios. EEI, AEP, Gulf States and Virginia Power assert that using new Accounts 407.3 and 407.4 will distort the computation of coverage ratios under SEC rules. They assert that, under the standard coverage formula, the adjustments to income taxes would be added back to determine earnings for coverage purposes, but the related adjustments to the regulatory asset and liability income statement accounts would not be added back.

Defining Regulatory Assets and Liabilities. A number of commenters argue that regulatory assets and liabilities should be

82/ American Gas Association, Baltimore Gas & Electric, Columbia Gas, Con Edison, Virginia Power and Wisconsin Public Service.

defined more consistently with FASB Statement No. 71. 83/ They argue, for example, that the USofA should allow recognition of regulatory assets and liabilities only when rate recovery is probable, i.e., likely to occur, not just reasonably expected. Otherwise, they argue, utilities might have to report the same transactions under two sets of accounting principles.

NARUC notes that Account 182.3 includes regulatory assets related to the amortization or normalization of certain costs, and suggests that the account be clarified to include only those regulatory assets "related to the amortization of specific and significant non-recurring or infrequent operating or maintenance expense items . . . ." In support, NARUC states that the word "normalization" is ambiguous. The North Carolina Staff similarly argues that, in any ratemaking decision, regulators may adopt several adjustments to set rates at an average, or "normal" level, but not to provide for recovery of a specific cost in a period other than the one in which it would be recognized for accounting purposes. The North Carolina Staff argues that, contrary to the implication in the NOPR, it would be inappropriate to record a regulatory asset or liability for such adjustments.

Inconsistent Classification. Many commenters note that proposed Account 182.3, Other Regulatory Assets, is classified as

83/ AEP, AICPA, Arthur Andersen, EEI, Centerior, Commonwealth Edison, Consumers Power, the Georgia Commission, NARUC, the North Carolina Staff, Price Waterhouse, PSI Energy and Virginia Power.

a deferred asset while proposed Account 244, Other Regulatory Liabilities, is classified as a current liability. A number of commenters argue that regulatory assets and liabilities should both be classified in deferred accounts. 84/ Others propose the establishment of both current and deferred accounts for both regulatory assets and liabilities. 85/ Still others find either of these two approaches acceptable. 86/ The American Gas Association and Con Edison argue that the classification of a regulatory asset or liability as current or deferred should be determined by GAAP.

Commission Response. The Commission now believes that, although separate accounts for regulatory assets and liabilities should still be established in this rulemaking, the two-step process described in the NOPR is not generally necessary and in some instances may contribute to inappropriate results. Based upon the comments received, the Commission will make certain changes in the accounting required for regulatory assets and liabilities.

For consistency in the balance sheet presentation of regulatory assets and liabilities, the Commission will renumber

84/ AEP, Baltimore Gas & Electric, Centerior, Delmarva Power, PacifiCorp, PJM, Ohio Edison, Penn Power and Wisconsin Electric.

85/ Allegheny Power, Central & South West, PG&E, Virginia Power, Price Waterhouse and Potomac Electric.

86/ EEI, Cincinnati Gas & Electric, Commonwealth Edison, Gulf States, IES Industries, NYSE&G, PSI Energy and Wisconsin Public Service.

proposed Account 244, Other Regulatory Liabilities, to Account 254. Account 254 will be in the deferred credits section of the balance sheet, thus paralleling the placement of Account 182.3, Other Regulatory Assets, in the deferred debits section of the balance sheet.

The Commission will require that deferred returns and/or carrying charges accrued on regulatory assets and liabilities be credited to Account 421, Miscellaneous Nonoperating Income, or charged to Account 431, Other Interest Expense, as appropriate. Both of these accounts are below-the-line. This change, recommended by several commenters, is needed to conform the required accounting treatment to the accounting used in recording deferred returns and/or carrying charges in other circumstances.

The Commission will also redefine regulatory assets and liabilities to use terms more similar to those used in FASB Statement No. 71, in order to avoid unnecessary differences between financial statements issued for regulatory purposes and general purpose financial statements. The term "probable," as used in the definition adopted herein for regulatory assets and liabilities, refers to that which can reasonably be expected or believed on the basis of available evidence or logic but is neither certain nor proved. 87/

87/ Webster's New World Dictionary of the American Language, 2d college ed. [New York: Simon and Schuster, 1982] at 1132. This is the meaning referred to in FASB Concepts Statement No. 6, Elements of Financial Statements, 25 n.18 and 35 n.21, (1985) (superseding FASB Concepts Statement No. 3), in Accounting Statements - Original Pronouncements (1991).

Finally, to reduce other possible conflicts with current practices, the Commission will modify the proposed text of the accounts for regulatory assets and liabilities. Under the originally-proposed accounting for regulatory assets and liabilities, all entries to Accounts 182.3 and 244 (now 254) would have been through charges or credits to Accounts 407.3 and 407.4. Also, the proposed accounting would have required current expense (revenue) recognition consistent with the USofA requirements as determined without regard to the creation of regulatory assets and liabilities; whereas, the current practice is generally not to recognize the expense (revenue) but to capitalize the cost (or recognize a liability). The proposed accounting would therefore have affected income statement accounts even though net income was not affected (i.e., a liability would be recorded along with an equal regulatory asset or an asset would be recorded along with an equal regulatory liability). Although net income would not have been affected, the NOPR's proposed accounting could have distorted various financial ratios, such as pre-tax interest coverage calculations. Thus, the Commission will adopt Accounts 407.3 and 407.4, as modified, to provide for separate income and expense recognition only in appropriate situations, such as for the net amount capitalized for phase-in plans in each period and the net amount of previously capitalized allowable costs recovered during each period.

Definitions

* * * * *

31. Regulatory Assets and Liabilities are assets and liabilities that result from rate actions of regulatory agencies. Regulatory assets and liabilities arise from specific revenues, expenses, gains, or losses that would have been included in net income determinations in one period under the general requirements of the Uniform System of Accounts but for it being probable: 1) that such items will be included in a different period(s) for purposes of developing the rates the utility is authorized to charge for its utility services; or 2) in the case of regulatory liabilities, that refunds to customers, not provided for in other accounts, will be required.

9. In Part 201, Balance Sheet Accounts, Accounts 182.3 and 254 are added to read as follows:

Balance Sheet Accounts

* * * * *

182.3 Other regulatory assets.

A. This account shall include the amounts of regulatory-created assets, not includible in other accounts, resulting from the ratemaking actions of regulatory agencies. (See Definition No. 31.)

B. The amounts included in this account are to be established by those charges which would have been included in net income determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that such items will be included in a different period(s) for purposes of developing the rates that the utility is authorized to charge for its utility services. Where specific identification of the particular source of the regulatory asset cannot be made, such as in plant phase-ins, rate moderation plans, or rate levelization plans, Account 407.4, Regulatory Credits, shall be credited. The amounts recorded in this account are generally to be charged, concurrently with the recovery of the amounts in rates, to the same account that would have been charged if included in income when incurred, except all regulatory assets established through the use of Account 407.4 shall be charged to Account 407.3, Regulatory Debits, concurrent with the recovery of the amounts in rates.

C. If rate recovery of all or part of an amount included in this account is disallowed, the disallowed amount shall be charged to Account 426.5, Other Deductions, or Account 435, Extraordinary Deductions, in the year of the disallowance.

D. The records supporting the entries to this account shall be kept so that the utility can furnish full information as to the nature and amount of each regulatory asset included in this account, including justification for inclusion of such amounts in this account.

* * * * *

254 Other regulatory liabilities.

A. This account shall include the amounts of regulatory liabilities, not includible in other accounts, imposed on the utility by the ratemaking actions of regulatory agencies. (See Definition No. 30.)

B. The amounts included in this account are to be established by those credits which would have been included in net income determinations in the current period under the general requirements of the Uniform System of Accounts but for it being probable that: 1) such items will be included in a different period(s) for purposes of developing the rates that the utility is authorized to charge for its utility services; or 2) refunds to customers, not provided for in other accounts, will be required. When specific identification of the particular source of the regulatory liability cannot be made or when the liability arises from revenues collected pursuant to tariffs on file at a regulatory agency, Account 407.3, Regulatory Debits, shall be debited. The amounts recorded in this account generally are to be credited to the same account that would have been credited if included in income when earned except: 1) all regulatory liabilities established through the use of Account 407.3 shall be credited to Account 407.4, Regulatory Credits; and 2) in the case of refunds, a cash account or other appropriate account should be credited when the obligation is satisfied.

C. If it is later determined that the amounts recorded in this account will not be returned to customers through rates or refunds, such amounts shall be credited to Account 421, Miscellaneous Nonoperating Income, or Account 434, Extraordinary Income, as appropriate, in the year such determination is made.

D. The records supporting the entries to this account shall be so kept that the utility can furnish full information as to the nature and amount of each regulatory liability included in this account, including justification for inclusion of such amounts in this account.

10. In Part 201, Income Accounts, Accounts 407.3 and 407.4 are added to read as follows:

Income Accounts

* * * * *

407.3 Regulatory debits.

This account shall be debited, when appropriate, with the amounts credited to Account 254, Other Regulatory Liabilities, to record regulatory liabilities imposed on the utility by the ratemaking actions of regulatory agencies. This account shall also be debited, when appropriate, with the amounts credited to Account 182.3, Other Regulatory Assets, concurrent with the recovery of such amounts in rates.

407.4 Regulatory credits.

This account shall be credited, when appropriate, with the amounts debited to Account 182.3, Other Regulatory Assets, to establish regulatory assets. This account shall also be credited, when appropriate, with the amounts debited to Account 254, Other Regulatory Liabilities, concurrent with the return of such amounts to customers through rates.

NOTE: This appendix will not be published in the Code of Federal Regulations.

Appendix A

PRICEWATERHOUSECOOPERS

Questions and Answers*

Interpretations for the Utility Industry

Accounting for Property, Plant and Equipment, Asset Retirement Obligations and Depreciation

*connectedthinking

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Introduction

Accounting for property, plant and equipment and the related retirement obligations has been a fundamental element of financial reporting by utilities for many years. However, deregulation of generation assets in some jurisdictions and the issuance of FASB 143, *Accounting for Asset Retirement Obligations*, have challenged industry members to rethink previous accounting and reporting methods. FIN 47, *Conditional Asset Retirement Obligations*, effective in the fourth quarter of 2005 for most utilities, will provide new challenges.

This Questions and Answers paper was written to provide practical guidance and to assist utility companies with the challenges of implementing FIN 47. As always, the people of PricewaterhouseCoopers are available to assist you with any questions you may have regarding this publication.

I would like to acknowledge the PwC contributors and editors to this publication for a job well done.

Warmest Regards,

Paul

Paul M. Keglevic
PricewaterhouseCoopers U.S. Utilities Leader

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Background

Utilities often apply the mass-asset convention of accounting[1] (also known as the "group" method) to certain fixed assets such as utility poles and other components of their transmission and distribution systems which are too numerous to practically track on an individual basis given the small relative value of each individual asset. Similarly, many utility companies utilize the composite convention of accounting for component parts of larger assets such as electric generating stations which also contain numerous components and parts which are impractical to separately track. As opposed to the unitary convention of accounting for fixed assets, generally neither the group or composite convention of accounting result in the recognition of a gain or loss upon the retirement of an asset. Rather, any difference between the net book value of the assets and the value realized at retirement (salvage proceeds less removal and disposal costs) are embedded in accumulated depreciation and considered in the determination of prospective depreciation rates.

In addition to the longstanding acceptance of the group and composite accounting conventions as Generally Accepted Accounting Principles ("GAAP"), regulatory guidance and industry practice[2] specifically address the appropriate convention of accounting for retirements of utility plant. The Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts ("USoA") General Instructions specify that retirements should be recorded as: (i) a credit to the plant account; and (ii) a debit to the accumulated provision for depreciation. The cost of removal and the proceeds from salvage are also charged against the accumulated depreciation accounts when they are incurred. As a result, generally gains or losses are not recorded in the retirement of utility plant.

In order to demonstrate an example of this accounting convention, assume a utility installs an asset with an estimated useful life of 19 years incurring a total cost upon purchase and installation of $20,000. At the time of installation, the expected net salvage value of the asset (expected salvage less the expected cost of removal and disposal) is $1,000 resulting in a depreciable base of $19,000. Assume that at the end of 15 years of service the asset is replaced at a removal cost of $500 and salvage proceeds of $1,250, resulting in net salvage of $750. Pursuant to industry accounting described above, the resulting journal entries for the removal would be:

Dr. Cash (proceeds from net salvage)	$ 750	
Dr. Accumulated Depreciation	*19,250	
Cr. Property		($20,000)

** Calculated as $15,000 accumulated depreciation plus the $4,250 calculated loss [net salvage of $750 less the cost of the asset ($20,000 – $15,000)]*

Another layer of complexity to retirement accounting results from the common rate-making convention of including a provision for cost-of-removal in depreciation rates, thereby increasing depreciation expense over the life of an asset. If we were to assume a 10% removal cost for an asset for which no salvage proceeds are expected to be received, the depreciation over the life of the asset would be 110% of the cost of the asset. Under cost-of-service ratemaking, depreciation expense is recovered from customers over the life of the asset providing the utility with the revenues over the life of the asset to fund the eventual removal cost of the asset.

Prior to the implementation of Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* ("FAS 143"), GAAP considered this "excess depreciation" expense or "negative salvage" embedded in utilities accumulated depreciation accounts to be "regulatory liabilities" representing cash previously collected to fund anticipated future expenditures.[3] Since industry

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[1] As defined in the American Institute of Certified Public Accountants ("AICPA") Draft Statement of Position, *Accounting For Certain Costs and Activities Related to Property, Plant and Equipment*, the mass-asset convention of accounting applies to the accounting for large numbers of homogeneous assets in situations in which the accounting for individual assets is not practical. Under this convention, homogeneous assets are aggregated and depreciated by applying a rate based on the average expected useful life of the assets.

[2] As defined by the Uniform System of Accounts of the Federal Energy Regulatory Commission, ("USoA"), specifically 18 CFR chapter 1, General Instruction 10, *Additions and Retirements of Electric Plant*.

[3] See Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation*, paragraph 11. b. and FAS 143, paragraph 20.

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fixed asset accounting conventions resulted in these cost of removal expenditures eventually being debited to accumulated depreciation, the industry saw no benefit in grossing-up balance sheets to provide for the separate accounting of these amounts. However, concurrent with the implementation of FAS 143, the Staff of the Securities and Exchange Commission ("SEC") provided informal guidance to the Big Four Accounting Firms and to the Edison Electric Institute that these embedded regulatory liabilities should be reclassified out of accumulated depreciation to the liability section of the balance sheet. Accordingly, utilities collecting cost of removal in their depreciation rates estimated and reclassified previously collected but unspent recoveries for removal costs to a regulatory liability.[4]

While FAS 143 required the accrual of an asset retirement obligation ("ARO") liability for legally required removal costs, prior to the release of FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an interpretation of FASB Statement No. 143* ("FIN 47"), AROs were not recorded for legally required disposal costs related to assets which themselves were never legally required to be retired (pursuant to previous interpretations of FAS 143 paragraphs A15 and A17). Therefore, even though a legal requirement may have existed to dispose of items such as treated utility poles once the utility pole was removed from service, no ARO had been recorded because there was no legal requirement to ever remove the pole from service. FIN 47 has provided interpretative guidance around this issue which will result in the establishment of AROs for these "conditional" obligations based on the premise that eventually the treated pole will be removed from service as a result of its eventual deterioration. Accordingly, we expect that many utility companies will record AROs for these conditional disposal obligations when they implement FIN 47, thereby establishing a liability for the portion of the costs that are attributable to the legal obligation. Of course, to the extent such disposal costs have previously been included in a company's estimated removal cost included in its regulatory depreciation rates, a regulatory liability already exists for the portion of the disposal costs.

In considering these two further layers of complexity to our simple example above would result in the following assumptions and balances as of December 31st of year 15, the day of the implementation of FIN 47:

Original asset cost	$20,000
Salvage value:	
Cost of removal (no legal obligation)	(450)
Cost of disposal (legal obligation)	(50)
Salvage value	1,500
Net salvage value	1,000
Net depreciable value	$19,000
Estimated depreciable life	19 yrs

Upon adoption of FIN 47, it is assumed that the Company has reclassified the cost of removal and disposal to a regulatory liability. In addition, an asset retirement cost and obligation of $30 were recorded. For simplicity, the cumulative effect was not considered. As of year 15, the Company has already recognized approximately $40 ($50/19 yrs*15) in removal cost through accumulated depreciation. As such, these costs have been reclassified out of the regulatory liability. Resulting balances at the end of year 15 assuming the implementation of FIN No. 47 has been completed:

Dr. Adjusted asset cost	$20,030	
Cr. ARO @ 12/31/05 (assumed)		($ 30)
Cr. Accrued regulatory liability for cost of removal and disposal [(450+50)/19*15]-ARO of 30		(365)
Cr. Accumulated depreciation [(20,000-1,500)/19*15]		(14,600)

[4] Generally, removal costs remain embedded in as accumulated depreciation for regulatory reporting as outlined in paragraph 37 of FERC Order 631.

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Finally, assume the asset is disposed of January 1st of year 16 with an actual cost of disposal of $100, cost of removal of $200 and proceeds from salvage of $6,300. If the asset was accounted for under unit convention of accounting, the following entry would be recorded:

Dr. ARO	$ 30	
Dr. Accrued regulatory liability	365	
Dr. Cash	6,000	
Dr. Accumulated depreciation	14,600	
Cr. Property		($20,030)
Cr. Gain on Sale		(965)

Depending upon the regulatory mechanism, the difference between the actual disposal and removal costs of $300 and the accrued balance of $395 (accrued regulatory liability plus ARO) may remain as a regulatory liability and flowed back to the customer in future years.

Under the composite convention of accounting, no gain or loss would be recorded as follows:

Dr. ARO	$ 30	
Dr. Accrued regulatory liability	365	
Dr. Cash	6,000	
Dr. Accumulated depreciation	*13,635	
Cr. Property		($20,030)

*The accumulated depreciation balance includes the following:

Accumulated depreciation of the asset	$14,600
Gain on salvage - $6,300 less $5,430	(870)
Gain on removal costs - $200 less $365	(165)
Loss on ARO settlement - $100 less $30	70
Total impact to accumulated deprecation	$13,635

In this circumstance, depending upon the regulatory mechanism, the embedded gains and losses are flowed back through the customer through depreciation rates adjusted periodically going forward.

While tracking this detail is not difficult for one asset as demonstrated above, utilities typically have tens or hundreds of thousands of these assets which have accumulated over many years. For instance, as disclosed in the property section of their Form 10-K, a single small integrated electric utility company with a market capitalization of approximately $1.1 billion has approximately 10 generating units, 300 transmission and distribution substations, and 12,000 miles of transmission and distribution lines.

As a result of the complexities detailed above, the following Q&A has been designed to address some of the common questions regarding mass unit accounting conventions and the impact on asset retirement obligations.

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Q. 1. *Many owners of previously regulated generation assets continued the use of the composite convention of accounting for their generating assets after deregulation. Is it appropriate for these companies to continue to apply the composite or group convention of accounting to these unregulated generating stations?*

A.1. The composite convention of accounting is an acceptable convention regardless of whether an entity is subject to cost-of-service regulation. As noted above, the composite or group convention was established as a means of simplifying the process of tracking a large asset system with many small components with small relative values compared to the larger composite group. As discussed in the following excerpts from Chapter 11 of Kieso, Weygandt, and Warfield's Intermediate Accounting Text (11th Edition), both of these conventions of accounting are considered acceptable conventions pursuant to GAAP.

> Two methods of depreciating multiple-asset accounts are employed: the group method and the composite method. The term "group" refers to a collection of assets that are similar in nature. "Composite" refers to a collection of assets that are dissimilar in nature. The group method is frequently used when the assets are fairly homogeneous and have approximately the same useful lives. The composite approach is used when the assets are heterogeneous and have different lives. The group method more closely approximates a single-unit cost procedure because the dispersion from the average is not as great. The method of computation for group or composite is essentially the same: find an average and depreciate on that basis.
>
> The differences between the group or composite method and the single-unit depreciation method become accentuated when we look at asset retirements. If an asset is retired before, or after, the average service life of the group is reached, the resulting gain or loss is buried in the Accumulated Depreciation account. This practice is justified because some assets will be retired before the average service life and others after the average life. For this reason, the debit to Accumulated Depreciation is the difference between original cost and cash received. No gain or loss on disposition is recorded.
>
> The group or composite method simplifies the bookkeeping process and tends to average out errors caused by over-or under depreciation. As a result, periodic income is not distorted by gains or losses on disposals of assets.

It also may be suitable for an entity to use both unit and group depreciation conventions on different groups of assets based on the type of assets and ease of application. As outlined in the AICPA Audit Guide *Audits of Airlines* section 3.104, unit depreciation could be used for other fixed assets which have large units cost and are comparatively few in number.

However, we believe it would generally not be appropriate for a company to switch to composite or group depreciation convention from the unitary convention of depreciation based on preferability as established by Accounting Principles Board ("APB") Opinion No. 20, *Accounting Changes* or FASB Statement of Financial Accounting Standards No 154, *Accounting Changes and Error Corrections -- a replacement of APB No. 20 and FAS No. 3*. The selection of the composite or group depreciation is an acceptable convention of accounting when entities have not maintained detail records to support the unitary convention. One would assume that those companies who have historically used the unitary bases of depreciation should have the capability to continue the use of this convention of depreciation. Those who have historically used group or composite depreciation have not maintained detail records to their mass asset accounts and may not have the information available to establish a single unit convention of accounting.

We also believe that those businesses using the composite or group deprecation convention should regularly obtain updated depreciation studies (perhaps every 3 – 5 years), which is consistent with FERC regulations. The periodic update of depreciation rates is necessary to level actual incurred disposition gains or losses and is part of the underlying basis for the acceptability of these group accounting conventions.

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Q.2. *How do the composite and group depreciation conventions impact the recognition of gains and losses in the case of "abnormal" or "extraordinary" retirement of assets?*

A.2. To the extent that a company may choose to depreciate assets on a group or composite basis, the policy for recognizing gains or losses on its retirement of assets should be consistent. The AICPA Audit Guide, *Audit of Airlines*, in its glossary defines group depreciation as follows:

> "A plan under which (1) depreciation is based on the application of a single depreciation rate to the total book cost of all property included in a given depreciable property and equipment account or class, despite differences in service life of individual items of property and equipment, (2) the full original cost, less any salvage realized, of a retired item of depreciable property or equipment is charged to the allowance for depreciation regardless of the age of the item, and (3) no gain or loss is recognized on the retirement of individual items."

As noted above, in the case of normal retirement, no gain or loss would be recognized. As such, gains or losses which would be recognized if one used the unitary convention of accounting are simply included in the entity's net property balance and are depreciated over future years. However, although not specifically addressed in the audit guide, we believe a gain or loss should be considered in cases where abnormal or extraordinary retirements have occurred. We believe that the occurrence of an abnormal or extraordinary retirement would be rare.[5]

As mentioned in A.1., above, businesses using the composite or group deprecation convention should obtain updated depreciation studies periodically (every 3 – 5 years), which is consistent with FERC regulations. However, in a circumstance where an entity experiences a significant and unplanned level of retirements we recommend that an updated depreciation study be obtained more immediately. It is likely that as a result of the significant and unplanned level of retirements that the characteristics (i.e. average age of the assets, average remaining life if the assets, etc.) of the entity's property may have changed so significantly that the previous depreciation rates may no longer be a reasonable estimate of the assets' remaining depreciable life.

[5] This topic is also addressed by the USoA, specifically 18 CFR chapter 1, General Instruction 10, *Additions and Retirements of Electric Plant* paragraphs 5F and 10F. Paragraph 5F discusses the retirement of an entire system or operating unit which requires the recognition of the entire gain or loss in income rather than as an adjustment to accumulated depreciation. Paragraph 10F discusses that the early retirement of material property units, referred to as "extraordinary retirements," can lead to separate deferred amortization of unrecovered plant costs, but usually requires specific regulatory approval.

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Q. 3. *What is the appropriate accounting for differences between estimated accrued ARO liabilities and the actual cost of extinguishing those liabilities under composite or group convention of accounting?*

A. 3. While not addressed in the body of FAS 143, the accounting for the extinguishment of AROs was alluded to in paragraph B41 of Appendix B: Background Information and Basis for Conclusions. As further described in PwC's DataLine 2001-22: *FASB Statement No. 143, Accounting for Obligations Associated with the Retirement of Long-Lived Assets* paragraph 4, "The Board acknowledges that if the cost actually incurred to settle an ARO is less than the obligation accrued by the company based on fair value, **the company will have a gain on retirement**. The fair value measurement convention of FAS 143 was one of the most controversial of its provisions during the exposure period. The FASB published an article entitled *Understanding the Issues: The Case for Initially Measuring Liabilities at Fair Value* to explain and defend its conclusions on measurement of AROs. Consequently, we have concluded that the accounting for the extinguishment of AROs would be consistent with the accounting for the extinguishment of any other non-financial liability: any difference between the accrued and actual cost should be recognized when the liability is fully satisfied." (Emphasis added) However, we believe that the accounting for AROs is a sub-set of an entity's fixed asset accounting policies and, therefore, to the extent that an entity has elected to use the group or composite convention of accounting for depreciation, the entity should follow the group or composite accounting as described below for their accounting of AROs.

Referencing the simple example above, the recognition of a loss on retirement of $70 (the release of the $30 ARO liability as compared to the cash expenditure of $100 assumed in the example) is straight-forward, and to the extent that AROs are established on a unitary basis and actual retirement costs incurred can be matched to an individual asset and ARO, this accounting is appropriate. However, many (if not substantially all) of the AROs recorded by utilities (at least those not related to nuclear plant decommissioning costs) relate to assets which are accounted for under either the group or composite conventions of accounting. Therefore the assets for which these AROs have been established are not tracked separately. These AROs have been estimated using methodologies similar to those used to establish the average or composite depreciable life of the assets: developing averages for the estimated remaining life of the assets, the period remaining until the obligations will be incurred, and the fair value of the obligations. Therefore, for the same reasons that utilities would have difficulties determining the specific gain or loss resulting from the retirement of a specific asset as a result of not maintaining detailed records of their mass asset accounts, it will also be difficult for utilities to determine the difference between the accrued ARO for an asset's retirement and the actual cost incurred for the retirement of the obligation. Entities that utilize the group or composite conventions of accounting for their property, plant and equipment do not have detailed records to track the asset and ARO information for literally thousands of group and component assets.

We believe that given: (i) the accepted convention of the group and composite accounting to embed gains and losses on the retirement of assets in the accumulated depreciation account[6]; and (ii) the FERC USoA's accounting instructions to account for gains, losses, salvage and cost of removal as charges to accumulated depreciation[7]; a modified group and composite accounting convention for AROs is acceptable. Such a method might include the following conventions:

1. The continued real-time accounting for actual costs incurred for the cost of removal of assets (including those amounts for which an ARO has been accrued) as charges to accumulated depreciation;

2. Recording accretion expense for the ARO during the current year based on the prior year's balance;

[6] See excerpt from Chapter 11 of Kieso, Weygandt, and Warfield's Intermediate Accounting Text (11th Edition) above.
[7] See footnote 2 above.

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3. A periodic (at least annually, however more frequently if there have been significant amounts of property additions or retirements) revision of the estimated ARO and regulatory liability (amounts already collected in rates) for removal and disposal costs based on a current statistical analysis of updated fixed assets considering the impact on current year additions, retirements, and other changes to the asset average age, ARO fair value, or other relevant assumptions (i.e. similar to an updated depreciation study) and costed and discounted using current year assumptions.

Any adjustment required as a result of the analyses would result in a charge to accumulated depreciation. It is noted that some consideration was given to charging this entry to the ARC and adjusting depreciation of the ARC accordingly. However, the impact of recording the adjustment against the ARC does not result in different income treatments and adjusting accumulated depreciation preserves consistency with current accounting conventions of group depreciation. Consistent with the application of group and composite accounting theory, adjustments to accumulated depreciation will be reflected in future depreciation expense based on the utility's updated depreciation studies.

In order to provide a practical example of the three-step approach above, assume a utility has 1,000 of the assets in the previous example accounted for under the composite method. The balances as of the end of year 15 are assumed to be as follows:

Original asset cost	$ 20,000,000
Asset Retirement Costs (ARC)	30,000
Assumed ARO @ 12/31/05	(30,000)
Accrued regulatory liability for cost of removal and disposal [(450,000+50,000)/19*15]-ARO of 30	(365,000)
Accumulated depreciation [(20,000,000-1,500,000)/19*15]	(14,600,000)

The following journal entries would be recorded if ten of the 1,000 assets were removed and disposed at a cost of $4,000 and $250, respectively. The total salvage value of the assets was $14,000.

Step 1 – Real time accounting for the cost of removal:

Dr. Cash – Earned in salvage	$ 14,000	
Dr. Accumulated depreciation	190,550	
Cr. Cash – Cost of removal and disposal		($ 4,250)
Cr. Utility Plant		(200,300)

The balance charged to accumulated depreciation represents the adjustment to the accumulated depreciation of the assets sold as well as the gains and losses related to the difference between the estimated removal costs, disposal costs, and salvage value as of the date of the disposal.

Step 2 – Record accretion expense based on the liability as of the beginning of the year (assuming 7% * 30,000):

Dr. Accretion expense	$2,100	
Cr. ARO		($2,100)

By recording the accretion expense based upon prior liability, one assumes that there have been no significant changes in total ARO during the year (i.e. there are some new additions to offset the disposals.)

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Step 3 – Annual revision of the estimated ARO assuming an increase in overall estimate of costs of disposal for remaining assets to $35,000 based on an updated ARO cost study:

Dr. Accumulated depreciation	$2,900	
Cr. ARO		($2,900)*

*The adjustment to the ARO is equal to the following:

Beginning ARO	$30,000
Accretion expense	2,100
Less: Required ARO	35,000
Total adjustment recorded	$ 2,900

It is noted that step 2 and 3 above do not contemplate potential impacts of regulatory recovery of removal and disposal costs. Certain regulatory recovery mechanisms will also require periodic adjustment to regulatory asset or liabilities based on the timing differences between collection, recognition and payment of removal and disposal costs. In addition, accretion expense may qualify as a deferred cost.

We also note that companies that follow the full cost rules in accordance with the SEC's Article 4-10 of Regulation S-X, which prescribes financial accounting and reporting standards for public companies engaged in the production of crude oil or natural gas in the United States, account for gains and losses resulting from the settlement of AROs in a manner similar to companies that follow the group or composite conventions of accounting for property, plant and equipment. Upon the issuance of FAS 143, the SEC Staff addressed a number of accounting issues for companies that utilize the full cost rules in Staff Accounting Bulletin No. 106, *Topic 12 D (4) Interaction of Statement 143 and the Full Cost Rules* ("SAB 106"). One issue that was not specifically addressed in SAB 106 was the accounting for gains or losses resulting from the settlement of AROs. However, the SEC did provide informal guidance to companies utilizing the full cost method that allowed those companies to preclude the recognition of gains or losses from the settlement of AROs. Instead, those companies were to record any gains or losses as adjustments to accumulated depreciation of the full cost pool, which is consistent with the overall theoretical basis of full cost accounting. This SEC guidance provides a useful analogy to the accounting concepts described above.

(Note: entities that have selected the unitary convention of accounting for fixed assets would not follow the guidance above but would recognize the difference between the estimated ARO and actual cost in earnings upon settlement of the ARO)

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Q. 4. *How frequently should cost studies supporting the computation of AROs for the decommissioning of nuclear plants be updated?*

A. 4. FAS 143, paragraph 13, states that "an entity shall recognize period-to-period changes in the liability for an asset retirement obligation resulting from (a) the passage of time and (b) revisions to either the timing or the original estimate of undiscounted cash flows." However, the standard does not provide specific guidance on the frequency that updates to the original estimate of undiscounted cash flows should be performed.

The estimate of an ARO for nuclear decommissioning is generally calculated using expected-cash flow technique as described in FASB Concepts Statement 7, *Using Cash Flow Information and Present Value in Accounting Measurements* ("CON 7") and is subject to significant variability from even slight changes to key assumptions or inputs into the cash-flow model. Estimates of nuclear decommissioning costs involve a number of assumptions and cost estimates including: a) decommissioning costs for many discrete components; b) cost escalation factors; c) decommission approach/scenario regarding timing and methodologies; and d) choice of credit-adjusted risk free rates. Changes and revisions to these key assumptions may occur for various reasons including changes in technology and/or management's approach to decommissioning.

The Nuclear Regulatory Commission ("NRC") is responsible for overseeing the decommissioning of all nuclear plants in the United States. NRC regulation Section 50.75, *Reporting and Record Keeping for Decommissioning Planning*, establishes the requirements for how nuclear plant owners (known as licensees) are to provide the NRC reasonable assurance that the appropriate level of funds will be available for the decommissioning process. As part of the reporting process to the NRC, all licensees are required to provide a site specific cost study for the decommissioning of each nuclear unit owned every five years. These cost studies are used by the NRC to verify the licensee will have adequate funds available for the ultimate decommissioning of the unit. The preparation of these studies is generally performed by a third-party engineering firm and is an extremely expensive and time consuming process, sometimes requiring over a year to complete. Cost estimates are developed by the individual task or project required to decommission the unit. Also, the original design and subsequent modifications make each nuclear unit unique. As a result, cost estimates are specific to each nuclear unit.

The NRC provides for three alternative time choices to decommission a nuclear facility, DECON, SAFSTOR (or Delayed DECON) and ENTOMB. The DECON alternative involves the more immediate removal or decontamination of the equipment, structures and portions of the facility that contain radioactive containments so that the property can be released and the NRC license can be terminated. The SAFSTOR or Delayed DECON allows for the nuclear facility to be maintained in a condition that allows sufficient time for the radioactivity to decay; and afterwards, it is dismantled. Under ENTOMB, radioactive contaminants are encased in a structurally sound material such as concrete and appropriately maintained and monitored until the radioactivity decays to a level permitting release of the property. These time periods would generally be substantial, i.e., measured in decades rather than years.

Cost studies are typically prepared by an independent third-party consultant for each nuclear unit. The cost studies may reflect the cost to decommission a nuclear facility under a single approach or under different scenarios using a probability determination to calculate the cost estimate. The site specific cost estimate for each decommissioning scenario is prepared using the present day costs that are then escalated to the year that the decommissioning is planned for the unit. Each nuclear unit has its own specific timeline for completion, cost estimate and management's assessment of the likelihood of which decommissioning strategy will be followed that is incorporated into the expected cash flow model used to calculate the cost estimate.

The escalation factors used to determine the future cost of labor, materials and equipment, energy, burial and other decommissioning activities at the planned time of decommissioning are typically based on an assessment of the consumer price index, employment cost index, producer price index and other indices.

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Considerations

Of course, ARO should be updated when cost studies are completed at least every five years as required by the NRC. However, if circumstances warrant a change to management's approach to decommissioning a nuclear unit prior to the completion of an updated cost study, then the ARO calculation should be adjusted accordingly in the period the change is made. It may also be possible to annually obtain independent third-party verification, or an internal representation from qualified engineers, that there have been no material changes to the previously completed cost studies to further support the reasonableness of the estimated ARO. Additionally when decommissioning activities begin, the update of the applicable cost estimates should become more frequent to ensure the accuracy of the ARO.

From an accounting perspective, it is good practice to obtain all site-specific cost estimates within the same reporting period. However, for entities that own multiple nuclear units, this may not be feasible from an operational perspective. If cost estimates for different plants are updated in different periods, management should document its consideration of the feasibility of extrapolating cost study updates from one nuclear unit to other nuclear units for which updated cost estimates have not been obtained during a period.

Changes in escalation factors can have a significant impact to the ARO estimate. The underlying indices of the escalation factors' change are based on current and expected future economic conditions. As such, the rates used to escalate the costs as determined by the site-specific cost estimates should be evaluated by management at least annually and preferably within the same reporting period (i.e. quarter) for consistency between years. Additionally, for entities with multiple nuclear units, the escalation factors for all units should be updated within the same reporting period during the year. Management may obtain updates to its escalation factors from its third-party provider that was utilized to provide cost study updates or from internal sources; however, management should be consistent with its sources when determining changes to escalation factors.

The probability weightings assigned to the decommissioning scenarios incorporated into the expected cash flow model used to calculate the ARO should be updated when site-specific cost estimates are prepared. In addition, management should consider whether any events have occurred that would impact the previous probability weightings used in the calculation. Such events could include a new nuclear management team, a change in the strategic direction of the company related to the operation of their nuclear facilities, or advances in the technology and methods of decommissioning nuclear facilities.

Accounting Recognition

Pursuant to FAS 143, changes resulting from revisions in the timing or amount of estimated cash flows should be recognized as an increase or decrease in the carrying amount of the ARO and the associated capitalized ARC. Increases in the ARO as a result of upward revisions in undiscounted cash flow estimates should be considered a new obligation and initially measured using a current credit-adjusted risk-free interest rate. Any decreases in the ARO as a result of downward revisions in cash flow estimates should be treated as a modification of an existing ARO, and should be measured at the historical interest rate used to measure the initial ARO.

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Q.5. *How should one account for an asset retirement obligation when a previously inestimable ARO becomes estimable?*

A.5. Paragraph 4 of FIN 47 states that an ARO would be reasonably estimable if one of the following conditions were met: (a) It is evident that the fair value of the obligation is embodied in the acquisition price of the asset; (b) An active market exists for the transfer of the obligation; (c) Sufficient information exists to apply an expected present value technique.

Additional clarity around the ability to estimate and the subsequent accounting has been outlined under example 4 of Appendix A of the Interpretation which demonstrates that an obligation may be recognized at a date subsequent to the date that the obligation was incurred. Paragraphs A26 and A27 of FAS 143 provide guidance for the revisions of asset retirement obligations and the impact on the asset retirement cost as follows:

> A26. Revisions to a previously recorded asset retirement obligation will result from changes in the assumptions used to estimate the cash flows required to settle the asset retirement obligation, including changes in estimated probabilities, amounts, and timing of the settlement of the asset retirement obligation, as well as changes in the legal requirements of an obligation. Any changes that result in upward revisions to the undiscounted estimated cash flows shall be treated as a new liability and discounted at the current rate. Any downward revisions to the undiscounted estimated cash flows will result in a reduction of the asset retirement obligation. For downward revisions, the amount of the liability to be removed from the existing accrual shall be discounted at the rate that was used at the time the obligation to which the downward revision relates was originally recorded (or the historical weighted-average rate if the year(s) to which the downward revision applies cannot be determined).
>
> A27. Revisions to the asset retirement obligation result in adjustments of capitalized asset retirement costs and will affect subsequent depreciation of the related asset. Such adjustments are depreciated on a prospective basis.

The preceding excerpt provides implied guidance on how to account for the recognition of an asset retirement obligation which was previously inestimable at the date it was incurred or upon the implementation of FAS 143 and FIN 47. In summary, the asset retirement obligation is recorded at fair value with an equal and offsetting asset retirement cost resulting in no income statement impact. The asset retirement cost is amortized over the remaining life of the asset, mimicking the prospective approach to change in estimate[8].

[8] See paragraph 31 of APB 20 and paragraph 19 of FAS 154.

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Principal Authors:

Michael (Casey) Herman
U.S Utilities Technical Accounting and Auditing Leader

David (Michael) Eberhardt
Partner

Jim Nowoswiat
Senior Manager

Andrea Larsen
Manager

Caroline Fulginiti
Manager

Editorial Team and Contributions:

Paul Keglevic
U.S. Utilities Leader

Tom McGuiness
Partner

Mike Elpers
Partner

Alan Felsenthal
Managing Director

PricewaterhouseCoopers' Utilities Practice For more information, please contact:

Paul Keglevic
U.S. Utilities Leader
Email: paul.keglevic@us.pwc.com
Telephone: 213.356.6309

Michael (Casey) Herman
U.S Utilities Technical Accounting and Auditing Leader
Email: michael.a.herman@us.pwc.com
Telephone: 312.298.4462

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Clean Water Act

1. National Pollutant Discharge Elimination System
   ash treatment basins
   coal pile runoff basins (limestone) (gypsum) (any material storage pile)
   sewage treatment plants

KYDOW 401 KAR Chapter 5
USEPA 40 CFR Part 122, 123, 124, 125, 129 & 423

2. Best Management Practices Plan
   hazardous chemical storage (aboveground)

KYDOW 401 KAR Chapter 5
USEPA 40 CFR Part 125 Subpart K

3. Spill Prevention Control and Countermeasures Plan and Facility Response Plan
   petroleum product storage (aboveground)

KYDOW 401 KAR Chapter 5
USEPA 40 CFR Part 112 Part 151

must properly close all wastewater treatment facilities under KPDES permit program

must remove all material storage piles (coal, limestone, gypsum, etc.) to eliminate the potential for "contaminated" stormwater runoff from the site

must drain/remove all hazardous chemicals/petroleum products from aboveground storage tanks/reservoirs and recycle/reuse or disposed of properly

FASB 143
Asset Retirement Obligations

Clean Air Act

1. Title III – Hazardous Air Pollutants

    asbestos – only a concern if there is a "release" to the environment of 1 lb. or more – typically, asbestos can be left in place as long as it is in a non-friable state (i.e., encapsulated, covered with lagging, etc.)

USEPA asbestos NESHAPS = 40 CFR Part 63
KYDAQ asbestos = 401 KAR Chapter 58

2. Title VI – Stratospheric Ozone Protection

    refrigerants – must be removed at the end of the useful life of a piece of refrigerant equipment – must be recycled or disposed of properly

USEPA refrigerant rule = 40 CFR Part 82

Resource Conservation and Recovery Act

1. Hazardous Wastes: toxic, ignitable, corrosive

KYDWM 401 KAR Chapter 31 & 32
USEPA 40 CFR Part 260, 261, 262, 263, 270 & 271

must be removed from the site and disposed of properly
LQ hazardous wastes, mercury, laboratory chemicals, boiler water chemicals

2. Special Wastes: coal, ash, (bottom and fly), scrubber sludge

KYDWM 401 KAR Chapter 45
USEPA 40 CFR Part 261

coal combustion by-product storage disposal facilities must be properly closed and monitored
ash treatment basins
scrubber sludge landfills

Toxic Substances Control Act

1. PCBs
USEPA 40 CFR Part 761

must be removed from <u>electrical</u> equipment (transmission and distribution substations GSUs) at the end of its useful life and disposed of properly

removed gas pipeline – wipe for PCBs and disposed of properly

Comprehensive Emergency Response and Liability Act

1. Underground Storage Tank Program

KYDWM 401 KAR Chapter 42
USEPA 40 CFR Part 280 & 281

must properly "close" all USTs

Corps of Engineers

barge mooring facilities / intake and discharge structures

Federal Aviation Administration

striping (painted red/white stripes)
chimneys → lighting requirements on stacks of a certain height and/or distance from airports

LG&E ENERGY

Gerald —
Here is a marked up ARO list for you — I have put the statute containing the requirement after each description.

Caryl

Caryl M. Pfeiffer
Director, Environmental Affairs
502-627-2774
502-627-2930 FAX

Utility
Asset Retirement Obligations
Underlying Asset Inventory

Asset Retirement Obligation Summary		
Location	**Description**	**Legal/Regulatory Requirement**
MC4	River cell, work barge, and bridge removal	**Corps of Engineers?**
MC3	Ash Pond & Landfill	**Resource Conservation and Recovery Act**
MC3		
MC1	Storage Pile Remediation	**Clean Water Act**
MC3	Drain all oil storage tanks	**Clean Water Act**
MC	Empty & Remediate above ground haz mat storage	**Clean Water Act**
MC	Mercury Switch Removal	**Resource Conservation and Recovery Act**
MC	Drain transformers	**Clean Water Act** **Toxic Substances Control Act**
	Mill Creek 1	
	Mill Creek 2	
	Mill Creek 3	
	Mill Creek 4	
	Mill Creek Spare	
MC	Lab Chemical disposal	**Resource Conservation and Recovery Act**
MC	Fill Underground Tunnel under 31W	Legal reviewing
MC4so2	Chemical Tank clean up	**Clean Water Act**
MC	Radiation Sources	**The Cabinet for Human Resources - KRS 211.844, regulation 902 KAR Chapter 100**

CAA = Clean Air Act
CWA = Clean Water Act
RCRA = Resource Conservation & Recovery Act

CERCLA - Comprehensive Environmental Response Compensation & Liability Act

FE FER

Asset Retirement Obligation Summary

TOSCA = Toxic Substances Control Act

Location	Description	Cost ($000s)	Comment
CR	Ash Pond Closure RCRA (moves from CWA)	$ 700	70 acres @ $10k per acre - based on Pineville - not unit specific
CR	Landfill Closure RCRA	$ 1,000	110 acres - based on 65 acre closure bond estimate
CR	Coal Pile CWA	$ 100	100k for closure
CR	Mecury Removal RCRA	$ 5	Based on Pineville estimate - allocate evenly across 3 units
CR	Nuclear Source Removal	$ 50	50 cesium sources - allocate evenly across 3 units
CR	Station Oil Reservoirs CWA	$ 500	420,000 gallons - allocate evenly across 3 units
CR	Sewage Treatment Plant CWA	$ 50	Based on Pineville estimate
CR	Refrigerant Removal CAA	$ 50	
OF	Total Cost	$ 8,000	Developed from work done in conjunction with rehabilitation analyses - This assumes we would walk away from our FERC license and close the facility.
MC	Refrigerant Removal CAA	$ 50	Not unit specific
MC	River cell, work barge, and bridge removal (CORPS)	$ 800	Not unit specific
MC	Ash Pond & Landfill RCRA	$ 5,000	Status of landfill unknown - need to hire consultant - not unit specific - Range of $4M - $6M was provided. An average was used.
MC	Storage Pile Remediation CWA	$ 2,000	Assumes maximum fuel utilization (zero tons of usable coal) - not unit specific
MC	Drain Boiler Water	$ 120	Allocate evenly across units
MC	Drain all oil storage tanks CWA	$ 200	16 tanks - Allocate evenly across units
MC	Empty & Remediate above ground haz mat storage CWA	$ 30	Asbestos, mercury, used oil, chemicals - Allocate evenly across units. This is a building which contains waste material that has already been removed for disposal. This is not associated with an asset. Only the material must go, not the building. The cost is for disposal of the material.
MC	Mercury Switch Removal RCRA	$ 60	All encapsulated - Allocate evenly across units
MC	Drain transformers & wrap in nitrogen blanket CWA TOSCA	$ 1,650	Including OCB (oil current breaker) - 28 transformers - Allocate evenly across units
MC2	Demo Unit 2 Cooling Tower	$ 150	
MC3	Asbestos Fill in Unit 3 Cooling towers CAA	$ 600	
MC4	Asbestos Fill in Unit 4 Cooling towers CAA	$ 600	
MC	Lab Chemical disposal RCRA	$ 10	Not unit specific
MC	Fill Underground Tunnel under 31W	$ 25	Not unit specific
MC	Chemical Tank clean up CWA	$ 150	Not unit specific
MC	Radiation Sources	$ 50	Allocate evenly across units
TC1	Ash Pond Closure RCRA	$ 1,000	$10k/acre at 100 acres
TC1	Coal storage area CWA	$ 225	$5k/acre at 45 acres
TC1	Mercury Removal - Level Instrumentation RCRA	$ 2	Quote - 1 barrel - Located throughout the plant. Small 4" cube box. Used wherever level indication is needed. These are potentially used wherever there is water in the system that needs to be measured. - Tie to boiler asset on TC1.
TC1	Nuclear Source Removal - Coal Flow indicators	$ 40	Cesium source removal - $1,600 per 25 sources - 25 boxes attached to outside of ductwork and above coal feeders. Tie to conveyors on TC1.
TC1	Sewage Treatment Plant CWA	$ 10	

Asset Retirement Obligation Summary

Location	Description	Cost ($000s)	Comment
GH	Ash Pond ATB I & II RCRA	$ 1,950	Closure at $10k per acre - 195 acres - $1M for ATB 1 and $1.5M for ATB II
GH	Gypsum Stack CWA	$ 400	Closure at $10k per acre - 40 acres
GH	Radiation Sources	$ 140	Cesium Sources - 154 - Cesium sources - 154. Unit 1 - 15%; Unit 2 - 24%; Unit 3 - 16%; Unit 4 - 19%; Scrubber - 9%; Coal Yard - 17%
GH	Radiation Sources	$ 300	Radium Sources - 42 - Redium Sources - 42; Unit 1 - 6; Unit 2 - 12; Unit 3 - 12; Unit 4 - 12
GH	GSU, transformer oil, lubricating oils, ehc fluid CWA, TOSCA	$ 600	Estimate - need to validate
GH	Demolition of Cooling Towers	$ 500	$125K per unit
GH	Close ~~Removal of~~ 10,000 Gallon underground tank CERCLA	$ 30	Common to the plant in the Coal Yard
GH	Remediation of underground fuel oil piping CERCLA	$ 75	Common to the plant or divide equally among the 4 units
GH	Remove railroad crossing from highway 42	$ 50	Common to the plant
GH	Mercury Removal RCRA	$ 50	12.5 per unit
GH	Lab Chemical disposal RCRA	$ 10	Common to the plant
GH	Remove pipe bridge over highway 42	$ 50	Unit 1 specific today - will ultimately serve unit 2 if it is a limestone FGD
GH	Fill underground tunnel for piping under highway 42	$ 25	Common to the entire plant
GH	Chemical Tank clean up CWA	$ 250	Common to the plant - divide equally among the units
GH	Sewage Plant CWA	$ 50	Pineville Estimate
GH	Refrigeration gases CAA	$ 50	Estimate - need to validate
GH	Coal Yard covering CWA	$ 500	Assuming that we would be required to close in similar to the ash pond - Not unit specific
BR ST	Ash Pond RCRA	$ 5,000	Closure at $100,000 per acre - need to validate acreage - Not unit specific - Steam units only 1,2,3
BR3	Radiation Sources - BR3	$ 135	Radiation Sources at $7,500 per source (18) - Sources located with the following 10 assets with UOP 5676: 3-1 Feeder Upper; 3-1 Feeder Lower; 3-2 Feeder Upper; 3-2 Feeder Lower; 3-3 Feeder Upper; 3-3 Feeder Lower; 3-4 Feeder Upper; 3-4 Feeder Lower; 3-5 Feeder Upper; 3-5 Feeder Lower. Also, the following assets with UOP 5025: Hoppers A26 & A22; Hoppers A25 & A21; Hoppers A24 & A20; Hoppers A23 & A19; Hoppers B26 & B22; Hoppers B25 & B21; Hoppers B24 & B20; Hoppers B23 & B19
BR1	Demolition Service Water Pump structures - BR1	$ 50	Estimate - need to validate
BR2	Demolition Service Water Pump structures - BR2	$ 50	Estimate - need to validate
BR3	Demolition Service Water Pump structures - BR3	$ 100	Estimate - need to validate
BR ST	GSU, transformer oil, lubricating oils, ehc fluid CWA, TOSCA	$ 450	3 Units at $150,000 each - Not unit specific - include BR 1, 2,3 Transformers only. Tie to BR3
BR CT	GSU, transformer oil, lubricating oils, ehc fluid CWA, TOSCA	$ 1,050	7 Units at $150,000 each - Not unit specific - include BR 5, 6, 7, 8, 9, 10,11 Transformers only. Tie to BR 7.
BR1	Demolition of Cooling Towers - Unit 1	$ 250	Estimate - need to validate 1 tower at $250k
BR2	Demolition of Cooling Towers - Unit 2	$ 250	Estimate - need to validate 1 tower at $250k
BR3	Demolition of Cooling Towers - Unit 3	$ 500	Estimate - need to validate 2 towers at $250k each

Asset Retirement Obligation Summary

Location	Description	Cost ($000s)	Comment
BR ST	Close ~~Removal of~~ Fuel Oil Tanks - BR Steam units 1, 2, 3 CWA, CERCLA	$ 600	Estimate - need to validate 3 tanks at $200,000 each - Tanks are not unit specific - for BR 1, 2, 3
BR CT	Close ~~Removal of~~ Fuel Oil Tanks - BR CTs CWA	$ 400	Estimate - need to validate 2 tanks at $200,000 each - Tanks are not unit specific - include BR 5, 6, 7, 8, 9, 10, 11
BR ST	Remediation of underground fuel oil piping - Steam CWA, CERCLA	$ 40	Estimate - need to validate - Not unit specific - include BR 1, 2,3
BR CT	Remediation of underground fuel oil piping - CTs CWA	$ 35	Estimate - need to validate - Not unit specific - include BR 5, 6, 7, 8, 9, 10,11
BR	Remove railroad crossing from highway 395	$ 10	Estimate - need to validate - not unit specific
BR ST	Mercury Removal RCRA	$ 15	Estimate - need to validate - Not unit specific - includes BR 1,2,3 - Tie to BR3 - UOP 5373 - Instrument or measuring device (instrumentation)
BR CT	Mercury Removal RCRA	$ 35	Estimate - need to validate - Not unit specific - includes BR 5, 6,7 ,8,9,10,11Not unit specific - Tie to BR7 - UOP 5373 - Instrument or measuring device (instrumentation)
BR	Lab Chemical disposal RCRA	$ 10	Estimate - need to validate - BR1 - Lab Equipment UOP 5389
BR ST	Chemical Tank clean up CWA	$ 250	Estimate - need to validate - Steam units only - not unit specific
BR	Sewage Plant CWA	$ 50	Pineville Estimate - Not unit specific
BR ST	Refrigeration gases CAA	$ 15	Estimate - need to validate - Not unit specific - includes BR 1,2,3 - Tie to BR3 - 5008 UOP Air Conditioner, central install
BR CT	Refrigeration gases CAA	$ 35	Estimate - need to validate - Not unit specific - includes BR 5,6,7,8,9,10,11- Tie to BR7 - 5008 UOP Air Conditioner, central install
BR ST	Coal Yard covering CWA	$ 500	Assuming that we would be required to close similar to the ash pond - Not unit specific - Steam units 1, 2,3
BR ST	Coal pile retention pond closing CWA	$ 100	Estimate - Not unit specific - Steam units 1, 2,3
BR CT	Gas pipeline remediation	$ 250	Estimate - For CT units only BR 5,6,7,8,9,10,11
Dix Dam			
Lock 7			
TY	Ash Pond RCRA	$ 500	Closure at $50,000 per acre - need to validate acreage - Not unit specific
TY	Radiation Sources	$ -	none
TY	Demolition Service Water Pump structures CORPS	$ 200	2 structures which have asbestos and lead paint issues - Not unit specific
TY	GSU, transformer oil, lubricating oils, ehc fluid CWA, TOSCA	$ 1,200	8 Units at $150,000 - Not unit specific - Tie to transformer on TY3
TY	Demolition of Cooling Towers	$ -	none
TY	Closure ~~Removal of~~ Fuel Oil Tanks CWA, CERCLA	$ 100	one underground and one above ground - Not unit specific
TY	Remediation of underground fuel oil piping CWA, CERCLA	$ 75	could be less if no problems are found - Not unit specific
TY	Mercury Removal RCRA	$ 100	Estimate - need to validate - Not unit specific - allocable among units. UOP 5373 - Instrument or measuring device (instrumentation). Tie to TY3
TY	Lab Chemical disposal RCRA	$ 1	very small amounts - Not unit specific - Lab Equipment UOP 5389. Tie to TY1/2
TY	Chemical Tank clean up CWA	$ 20	2 tanks $10,000 each - Not unit specific
TY	Sewage Plant CWA	$ 50	Pineville Estimate - Not unit specific
TY	Refrigeration gases CAA	$ 5	8 separate units - Not unit specific - Tie to TY3 - 5008 UOP Air Conditioner, central install

Asset Retirement Obligation Summary

Location	Description	Cost ($000s)	Comment
TY	Coal Yard covering CWA	$ 500	Assuming that we would be required to close similar to the ash pond - Not unit specific
TY	Coal pile retention pond closing CWA	$ 100	Estimate 2 ponds - Not unit specific
TY	Gas pipeline remediation	$ -	none
GR	Holding Pond Remediation CWA	$ 200	Not unit specific
GR	Coal Storage Pile Remediation CWA	$ 150	Not unit specific
GR	Oil Storage Tanks CWA	$ 50	Not unit specific
GR	Underground Storage Tanks CERCLA	$ 50	Not unit specific
GR 1/2	Mercury Switches - Units 1/2 RCRA	$ 5	
GR3	Mercury Switches - Unit 3 RCRA	$ 5	
GR4	Mercury Switches - Unit 4 RCRA	$ 15	
GR 1/2	Generator Transformers - Units 1/2 CWA, TOSCA	$ 40	
GR3	Generator Transformers - Unit 3 CWA, TOSCA	$ 35	
GR4	Generator Transformers - Unit 4 CWA, TOSCA	$ 25	
GR	Sewage Treatment Plant CWA	$ 50	Not unit specific
	Total	$ 41,913	

Table 1a - KY

Kentucky Utilities
Electric Division
Kentucky
Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon
Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		DEPRECIABLE PLANT					
		STEAM PLANT					
		KU Generation-Common					
311.00	5591	Structures and Improvements	805,715.82	373,841.85		337,926.85	35,915.00
316.00	5591	Misc. Power Plant Equipment	1,330,284.07	244,560.51		215,132.51	29,428.00
		Total KU Gen.-Common	2,135,999.89	618,402.36	0.00	553,059.36	65,343.00
		Tyrone Unit 3					
311.60	5603	Structures and Improvements	5,293,882.85	5,722,687.36		4,929,429.36	793,258.00
312.00	5603	Boiler Plant Equipment	8,663,220.42	8,867,763.82		7,824,472.82	1,043,291.00
312.00	5603	Mandated NOX Proj.-2004 Closing	1,502,053.00			0.00	0.00
314.00	5603	Turbogenerator Units	2,649,841.16	3,039,367.81		2,653,065.81	386,302.00
315.00	5603	Accessory Electric Equipment	570,736.22	635,229.41		548,104.41	87,125.00
316.00	5603	Misc. Power Plant Equipment	403,549.14	245,719.29		214,760.29	30,959.00
		Total Tyrone Unit 3	19,083,282.79	18,510,767.69	0.00	16,169,832.69	2,340,935.00
		Tyrone Units 1 & 2					
311.60	5604	Structures and Improvements	589,405.14	676,047.70		566,941.70	109,106.00
312.00	5604	Boiler Plant Equipment	3,549,368.50	4,048,571.36		3,306,109.36	742,462.00
314.00	5604	Turbogenerator Units	1,592,029.04	1,813,795.27		1,478,911.27	334,884.00
315.00	5604	Accessory Electric Equipment	828,016.44	881,009.49		707,589.49	173,420.00
316.00	5604	Misc. Power Plant Equipment	47,552.54	49,787.51		39,804.51	9,983.00
		Total Tyrone Units 1 & 2	6,606,371.66	7,469,211.32	0.00	6,099,356.32	1,369,855.00
		Green River Unit 3					
311.40	5613	Structures and Improvements	2,809,804.71	3,228,465.61		2,945,216.61	283,249.00
312.00	5613	Boiler Plant Equipment	9,061,059.76	8,870,130.27		8,096,688.27	773,442.00
312.00	5613	Mandated NOX Proj.-2004 Closing	1,731,984.00			0.00	0.00
314.00	5613	Turbogenerator Units	2,651,645.58	3,041,437.48		2,755,705.48	285,732.00
315.00	5613	Accessory Electric Equipment	696,352.89	761,113.71		697,346.71	63,767.00
316.00	5613	Misc. Power Plant Equipment	70,833.53	53,321.13		48,341.13	4,980.00
		Total Green River Unit 3	17,021,680.47	15,954,468.20	0.00	14,543,298.20	1,411,170.00
		Green River Unit 4					
311.40	5614	Structures and Improvements	4,099,390.94	3,630,655.71		3,381,760.71	248,895.00
312.00	5614	Boiler Plant Equipment	18,776,499.07	14,845,967.78		13,624,266.78	1,221,701.00
314.00	5614	Turbogenerator Units	8,323,622.30	6,365,139.77		5,843,012.77	522,127.00
315.00	5614	Accessory Electric Equipment	809,269.35	907,190.94		834,325.94	72,865.00
316.00	5614	Misc. Power Plant Equipment	1,961,965.76	1,134,997.25		1,034,887.25	100,110.00
		Total Green River Unit 4	33,970,747.42	26,883,951.46	0.00	24,718,253.46	2,165,698.00
		Green River Units 1&2					
311.40	5615	Structures and Improvements	3,797,160.20	4,226,239.30		3,682,695.30	543,544.00
312.00	5615	Boiler Plant Equipment	12,249,873.99	11,761,983.55		10,164,249.55	1,597,734.00
314.00	5615	Turbogenerator Units	2,762,747.30	2,769,226.60		2,390,366.60	378,860.00
315.00	5615	Accessory Electric Equipment	584,072.29	649,488.39		564,622.39	84,866.00
316.00	5615	Misc. Power Plant Equipment	190,224.48	180,211.55		153,691.55	26,520.00
		Total Green River Units 1&2	19,584,078.26	19,587,149.39	0.00	16,955,625.39	2,631,524.00
		Brown Unit 1					
311.10	5621	Structures and Improvements	4,088,137.49	4,518,000.24		4,179,478.24	338,522.00
312.00	5621	Boiler Plant Equipment	32,815,581.55	19,517,750.44		17,766,421.44	1,751,329.00
312.00	5621	Mandated NOX Proj.-2004 Closing	221,421.00			0.00	0.00
314.00	5621	Turbogenerator Units	4,694,847.01	4,801,992.34		4,372,650.34	429,342.00
315.00	5621	Accessory Electric Equipment	2,663,640.09	2,136,179.18		1,960,528.18	175,651.00
316.00	5621	Misc. Power Plant Equipment	293,859.48	201,466.86		181,882.86	19,584.00
		Total Brown Unit 1	44,777,486.62	31,175,389.07	0.00	28,460,961.07	2,714,428.00

Table 1a - KY

Kentucky Utilities
Electric Division
Kentucky
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Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		Brown Unit 2					
311.10	5622	Structures and Improvements	1,452,821.22	1,685,381.25		1,550,088.25	135,293.00
312.00	5622	Boiler Plant Equipment	26,010,201.59	16,848,811.36		15,229,650.36	1,619,161.00
312.00	5622	Mandated NOX Proj.-2004 Closing	2,237,589.00			0.00	0.00
314.00	5622	Turbogenerator Units	8,729,916.37	6,056,772.92		5,476,396.92	580,376.00
315.00	5622	Accessory Electric Equipment	970,596.10	912,287.58		832,032.58	80,255.00
316.00	5622	Misc. Power Plant Equipment	85,647.82	69,823.47		62,557.47	7,266.00
		Total Brown Unit 2	39,486,772.10	25,573,076.58	0.00	23,150,725.58	2,422,351.00
		Brown Unit 3					
311.10	5623	Structures and Improvements	12,078,731.61	11,558,765.60		10,589,507.60	969,258.00
312.00	5623	Boiler Plant Equipment	71,536,455.78	49,316,382.34		44,368,891.34	4,947,491.00
312.00	5623	Mandated NOX Proj.-2004 Closing	1,305,198.00			0.00	0.00
312.00	5623	Mandated NOX Proj.-2005 Closing	4,004,000.00			0.00	0.00
314.00	5623	Turbogenerator Units	22,985,210.48	13,723,542.56		12,349,015.56	1,374,527.00
315.00	5623	Accessory Electric Equipment	5,076,639.52	4,577,463.36		4,156,038.36	421,425.00
316.00	5623	Misc. Power Plant Equipment	3,695,436.94	1,904,428.84		1,699,247.84	205,181.00
		Total Brown Unit 3	120,681,672.33	81,080,582.70	0.00	73,162,700.70	7,917,882.00
		Pineville Unit 3					
311.50	5643	Structures and Improvements	0.00	0.00		0.00	0.00
312.00	5643	Boiler Plant Equipment	226,832.50	1,782,011.42		1,750,876.42	31,135.00
314.00	5643	Turbogenerator Units	0.00	0.00		0.00	0.00
315.00	5643	Accessory Electric Equipment	0.00	0.00		0.00	0.00
316.00	5643	Misc. Power Plant Equipment	0.00	0.00		0.00	0.00
		Total Pineville Unit 3	226,832.50	1,782,011.42	0.00	1,750,876.42	31,135.00
		Pineville Units 1 & 2					
311.50	5644	Structures and Improvements	0.00	0.00		0.00	0.00
312.00	5644	Boiler Plant Equipment	0.00	254,230.51		254,230.51	0.00
314.00	5644	Turbogenerator Units	0.00	0.00		0.00	0.00
315.00	5644	Accessory Electric Equipment	0.00	0.00		0.00	0.00
316.00	5644	Misc. Power Plant Equipment	0.00	0.00		0.00	0.00
		Total Pineville Units 1 & 2	0.00	254,230.51	0.00	254,230.51	0.00
		Ghent 1 Pollution Control Equip					
311.30	5650	Structures and Improvements	24,352,142.19	10,966,983.04		10,274,287.04	692,696.00
312.00	5650	Boiler Plant Equipment	86,308,756.05	34,816,239.80		32,375,570.80	2,440,669.00
315.00	5650	Turbogenerator Units	3,016,784.27	1,319,776.32		1,234,173.32	85,603.00
316.00	5650	Accessory Electric Equipment	985,410.01	371,392.72		343,404.72	27,988.00
		Total Ghent 1 Pollution Control Equip	114,663,092.52	47,474,391.89	0.00	44,227,435.89	3,246,956.00
		Ghent Unit 1					
311.20	5651	Structures and Improvements	16,838,431.28	16,551,200.35		15,670,282.35	880,918.00
312.00	5651	Boiler Plant Equipment	88,268,090.96	58,633,236.77		54,906,380.77	3,726,856.00
312.00	5623	Mandated NOX Proj.-2004 Closing	38,235,757.00			0.00	0.00
312.00	5623	Mandated NOX Proj.-2005 Closing	38,980,000.00			0.00	0.00
314.00	5651	Turbogenerator Units	22,672,666.15	17,547,331.79		16,436,757.79	1,110,574.00
315.00	5651	Accessory Electric Equipment	7,456,587.14	6,385,744.31		6,385,744.31	0.00
316.00	5651	Misc. Power Plant Equipment	1,683,635.89	1,107,233.96		1,031,489.96	75,744.00
		Total Ghent Unit 1		100,224,747.18	0.00	94,430,655.18	5,794,092.00

Table 1a - KY

Kentucky Utilities
Electric Division
Kentucky
Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		Ghent Unit 2					
311.20	5652	Structures and Improvements	16,012,536.37	14,520,990.15		13,763,216.15	757,774.00
312.00	5652	Boiler Plant Equipment	86,733,989.30	58,712,497.52		55,065,177.52	3,647,320.00
312.00	5652	Mandated NOX Proj.-2004 Closing	4,735.00			0.00	0.00
312.00	5652	Mandated NOX Proj.-2005 Closing	3,016,000.00			0.00	0.00
314.00	5652	Turbogenerator Units	28,358,360.55	18,546,227.18		17,401,567.18	1,144,660.00
315.00	5652	Accessory Electric Equipment	10,785,959.50	8,840,614.25		8,840,614.25	0.00
316.00	5652	Misc. Power Plant Equipment	1,478,017.69	1,038,436.36		969,123.36	69,313.00
		Total Ghent Unit 2	146,389,598.41	101,658,765.45	0.00	96,039,698.45	5,619,067.00
		Ghent Unit 3					
311.20	5653	Structures and Improvements	40,539,913.20	29,396,596.88		27,779,408.88	1,617,188.00
312.00	5653	Boiler Plant Equipment	169,648,430.42	102,664,063.36		95,978,667.36	6,685,396.00
312.00	5653	Mandated NOX Proj.-2004 Closing	73,887,596.00			0.00	0.00
312.00	5653	Mandated NOX Proj.-2005 Closing	1,976,000.00			0.00	0.00
314.00	5653	Turbogenerator Units	38,111,389.85	23,633,415.76		22,109,025.76	1,524,390.00
315.00	5653	Accessory Electric Equipment	25,961,221.84	17,808,728.79		17,808,728.79	0.00
316.00	5653	Misc. Power Plant Equipment	3,135,971.64	1,849,696.44		1,720,838.44	128,858.00
		Total Ghent Unit 3	353,260,522.95	175,352,501.24	0.00	165,396,669.24	9,955,832.00
		Ghent Unit 4					
311.20	5654	Structures and Improvements	21,953,259.20	12,923,736.93		12,202,326.93	721,410.00
312.00	5654	Boiler Plant Equipment	168,701,912.41	83,355,028.86		77,875,705.86	5,479,323.00
312.00	5654	Mandated NOX Proj.-2004 Closing	52,148,251.00			0.00	0.00
312.00	5654	Mandated NOX Proj.-2005 Closing	15,424,000.00			0.00	0.00
314.00	5654	Turbogenerator Units	48,190,569.27	26,306,716.71		24,595,210.71	1,711,506.00
315.00	5654	Accessory Electric Equipment	21,869,238.82	12,749,802.99		12,749,802.99	0.00
316.00	5654	Misc. Power Plant Equipment	5,356,692.15	1,998,833.97		1,859,015.97	139,818.00
		Total Ghent Unit 4	333,643,922.85	137,334,119.46	0.00	129,282,062.46	8,052,057.00
		Ghent 4 Rail Cars					
312.20	5659	Boiler Plant Equipment	7,647,232.19	3,920,826.86		3,722,898.86	197,928.00
		Total Ghent 4 Rail Cars	7,647,232.19	3,920,826.86	0.00	3,722,898.86	197,928.00
		Total Steam Production *	1,333,494,917.96	794,854,592.77	0.00	738,918,339.77	55,936,253.00
		HYDRAULIC PLANT					
		Dix Dam					
330.10	5691	Land Rights	879,311.47	879,311.47		879,311.47	0.00
331.10	5691	Structures and Improvements	429,524.71	328,160.22		301,863.22	26,297.00
332.10	5691	Reservoirs, Dams and Waterways	7,818,030.36	5,639,672.93		5,129,939.93	509,733.00
333.10	5691	Waterwheel, Turbines and Generators	418,543.74	526,528.02		496,732.02	29,796.00
334.10	5691	Accessory Electric Equipment	85,383.13	69,663.35		63,571.35	6,092.00
335.10	5691	Misc. Power Plant Equipment	97,031.59	50,788.41		46,453.41	4,335.00
336.10	5691	Roads, Railroads and Bridges	46,976.12	41,111.69		37,545.69	3,566.00
		Total Dix Dam	9,774,801.12	7,535,236.10	0.00	6,955,417.10	579,819.00
		Lock #7					
330.10	5692	Land Rights	0.00			0.00	0.00
331.20	5692	Structures and Improvements	67,902.49	69,837.66		49,951.66	19,886.00
332.20	5692	Reservoirs, Dams and Waterways	324,145.88	288,220.44		195,327.44	92,893.00
333.20	5692	Waterwheel, Turbines and Generators	114,085.49	126,064.47		92,780.47	33,284.00
334.20	5692	Accessory Electric Equipment	264,485.91	245,974.54		172,287.54	73,687.00
335.20	5692	Misc. Power Plant Equipment	66,094.89	57,509.70		39,348.70	18,161.00
336.20	5692	Roads, Railroads and Bridges	1,169.79	1,061.33		718.33	343.00
		Total Lock #7	837,884.45	788,668.13	0.00	550,414.13	238,254.00
		Total Hydraulic Plant	10,612,685.57	8,323,904.23	0.00	7,505,831.23	818,073.00

Table 1a - KY

Kentucky Utilities
Electric Division
Kentucky
Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		OTHER PRODUCTION PLANT					
		Paddy's Run GT 13					
341.00	0432	Structures and Improvements	1,910,327.76	92,928.55		92,928.55	0.00
342.00	0432	Fuel Holders, Producers and Access.	1,975,977.95	111,401.17		111,401.17	0.00
343.00	0432	Prime Movers	17,355,293.47	808,034.94		808,034.94	0.00
344.00	0432	Generators	5,185,636.11	307,414.14		307,414.14	0.00
345.00	0432	Accessory Electric Equipment	2,456,320.01	125,405.92		125,405.92	0.00
346.00	0432	Misc. Power Plant Equipment	1,089,550.03	53,681.91		53,681.91	0.00
		Total Paddy's Run GT 13	29,973,105.33	1,498,866.63	0.00	1,498,866.63	0.00
		Trimble Co 5					
341.00	0470	Structures and Improvements	3,566,217.06	56,544.29		56,544.29	0.00
342.00	0470	Fuel Holders, Producers and Access.	237,747.79	4,376.02		4,376.02	0.00
343.00	0470	Prime Movers	29,842,502.10	452,882.82		452,882.82	0.00
344.00	0470	Generators	3,734,423.83	72,278.13		72,278.13	0.00
345.00	0470	Accessory Electric Equipment	1,664,234.64	27,740.69		27,740.69	0.00
		Total Trimble Co 5	39,045,125.42	613,821.94	0.00	613,821.94	0.00
		Trimble Co 6					
341.00	0471	Structures and Improvements	3,564,353.91	56,515.17		56,515.17	0.00
342.00	0471	Fuel Holders, Producers and Access.	237,623.60	4,373.11		4,373.11	0.00
343.00	0471	Prime Movers	29,826,880.91	452,646.01		452,646.01	0.00
344.00	0471	Generators	3,732,468.71	72,240.28		42,240.28	30,000.00
345.00	0471	Accessory Electric Equipment	1,663,365.15	27,726.13		27,726.13	0.00
		Total Trimble Co 6	39,024,692.28	613,500.69	0.00	583,500.69	30,000.00
		Trimble Co Pipeline					
342.00	0473	Trimble Co Pipeline	4,474,853.28	95,855.07		95,855.07	0.00
		Trimble Co Pipeline	4,474,853.28	95,855.07	0.00	95,855.07	0.00
		Brown 5					
341.00	5635	Structures and Improvements	755,148.65	37,043.69		37,043.69	0.00
342.00	5635	Fuel Holders, Producers and Access.	727,929.28	41,384.06		41,384.06	0.00
343.00	5635	Prime Movers	12,440,942.32	584,099.27		584,099.27	0.00
344.00	5635	Generators	2,831,528.33	169,269.40		169,269.40	0.00
345.00	5635	Accessory Electric Equipment	2,265,166.84	116,618.79		116,618.79	0.00
346.00	5635	Misc. Power Plant Equipment	2,085,163.17	103,598.68		103,598.68	0.00
		Total Brown 5	21,105,878.59	1,052,013.88	0.00	1,052,013.88	0.00
		Brown 6					
341.00	5636	Structures and Improvements	133,678.33	15,683.87		15,683.87	0.00
342.00	5636	Fuel Holders, Producers and Access.	146,514.66	19,731.26		19,731.26	0.00
343.00	5636	Prime Movers	31,591,711.55	3,471,602.03		3,471,602.03	0.00
344.00	5636	Generators	3,712,619.52	526,458.34		526,458.34	0.00
345.00	5636	Accessory Electric Equipment	1,354,816.11	165,517.84		165,517.84	0.00
346.00	5636	Misc. Power Plant Equipment	18,003.82	1,852.51		1,852.51	0.00
		Total Brown 6	36,957,343.99	4,200,845.85	0.00	4,200,845.85	0.00
		Brown 7					
341.00	5637	Structures and Improvements	488,353.77	54,782.80		54,782.80	0.00
342.00	5637	Fuel Holders, Producers and Access.	145,745.15	18,790.39		18,790.39	0.00
343.00	5637	Prime Movers	39,071,447.54	3,762,389.64		3,762,389.64	0.00
344.00	5637	Generators	3,722,788.46	506,168.50		506,168.50	0.00
345.00	5637	Accessory Electric Equipment	1,347,700.35	157,809.63		157,809.63	0.00
346.00	5637	Misc. Power Plant Equipment	15,776.54	1,774.61		1,774.61	0.00
		Total Brown 7	44,791,811.81	4,501,715.56	0.00	4,501,715.56	0.00

Table 1a - KY

Kentucky Utilities
Electric Division
Kentucky
Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		Brown 8					
341.00	5638	Structures and Improvements	2,012,654.95	551,147.81		551,147.81	0.00
342.00	5638	Fuel Holders, Producers and Access.	19,612.88	6,197.13		6,197.13	0.00
343.00	5638	Prime Movers	18,625,319.58	4,649,763.68		4,649,763.68	0.00
344.00	5638	Generators	4,953,960.72	1,657,115.05		1,657,115.05	0.00
345.00	5638	Accessory Electric Equipment	1,797,053.82	516,223.20		516,223.20	0.00
346.00	5638	Misc. Power Plant Equipment	230,068.72	63,080.90		63,080.90	0.00
		Total Brown 8	27,638,670.67	7,443,527.78	0.00	7,443,527.78	0.00
		Brown 9					
341.00	5639	Structures and Improvements	4,641,054.86	1,283,383.52		1,283,383.52	0.00
342.00	5639	Fuel Holders, Producers and Access.	1,943,454.44	587,787.17		587,787.17	0.00
343.00	5639	Prime Movers	20,674,801.66	5,251,127.97		5,251,127.97	0.00
344.00	5639	Generators	5,452,040.97	1,849,282.53		1,849,282.53	0.00
345.00	5639	Accessory Electric Equipment	3,226,186.26	926,881.86		926,881.86	0.00
346.00	5639	Misc. Power Plant Equipment	760,255.37	208,250.52		208,250.52	0.00
		Total Brown 9	36,697,793.56	10,106,713.57	0.00	10,106,713.57	0.00
		Brown 10					
341.00	5640	Structures and Improvements	1,865,718.20	450,116.53		450,116.53	0.00
342.00	5640	Fuel Holders, Producers and Access.	31,737.96	8,861.24		8,861.24	0.00
343.00	5640	Prime Movers	18,800,096.69	4,229,904.20		4,229,904.20	0.00
344.00	5640	Generators	4,944,422.71	1,447,725.28		1,447,725.28	0.00
345.00	5640	Accessory Electric Equipment	1,804,419.47	455,008.19		455,008.19	0.00
346.00	5640	Misc. Power Plant Equipment	241,523.31	54,067.02		54,067.02	0.00
		Total Brown 10	27,687,918.34	6,645,682.47	0.00	6,645,682.47	0.00
		Brown 11					
341.00	5641	Structures and Improvements	1,802,595.65	381,497.12		381,497.12	0.00
342.00	5641	Fuel Holders, Producers and Access.	52,429.84	12,597.47		12,597.47	0.00
343.00	5641	Prime Movers	33,050,028.28	5,018,851.36		5,018,851.36	0.00
344.00	5641	Generators	5,187,040.30	1,365,544.57		1,365,544.57	0.00
345.00	5641	Accessory Electric Equipment	916,326.28	207,761.39		207,761.39	0.00
346.00	5641	Misc. Power Plant Equipment	204,854.53	39,269.61		39,269.61	0.00
		Total Brown 11	41,213,274.88	7,025,521.52	0.00	7,025,521.52	0.00
		Brown 9 Pipeline					
340.10	5645	Land Rights	176,409.31	49,181.12		49,181.12	0.00
342.00	5645	Fuel Holders, Producers and Access.	8,151,131.81	2,181,651.65		2,181,651.65	0.00
		Total Brown 9 Pipeline	8,327,541.12	2,230,832.77	0.00	2,230,832.77	0.00
		Hafeling					
341.00	5696	Structures and Improvements	434,853.46	109,355.00		109,355.00	0.00
342.00	5696	Fuel Holders, Producers and Access.	181,132.61	160,069.45		160,069.45	0.00
344.00	5696	Generators	4,023,002.37	3,495,007.49		3,495,007.49	0.00
345.00	5696	Accessory Electric Equipment	621,206.80	492,390.44		492,390.44	0.00
346.00	5696	Misc. Power Plant Equipment	35,805.20	27,184.63		27,184.63	0.00
		Total Hafeling	23,432,497.79	4,284,007.02	0.00	4,284,007.02	0.00
		Total Other Production Plant	380,370,507.06	50,312,904.75	0.00	50,282,904.75	30,000.00
		Total Production Plant	1,724,478,110.59	853,491,401.75	0.00	796,707,075.75	56,784,326.00
		TRANSMISSION PLANT					
350.10		Land Rights	22,991,433.46	11,658,723.90		11,658,723.90	0.00
		Structures and Improvements					
352.10		Struct. and Improve. - Non Sys. Control/Com.	6,426,546.76	2,832,052.15		1,983,470.72	848,581.43
352.20		Struct. and Improve. - Sys. Control/Com.	1,166,434.25	711,936.94	17,975.03	586,774.60	107,187.31
		Total Account 352	7,592,981.01		17,975.03	2,570,245.32	955,768.74

Table 1a - KY

Kentucky Utilities
Electric Division
Kentucky
Calculation of Cost of Removal In Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		Station Equipment					
353.10		Station Equipment - Non Sys. Control/Com.	146,527,337.37	50,453,773.27		45,266,416.75	5,187,356.52
353.20		Station Equip - Sys.Control/Com. (Microwave)	14,284,914.20	8,038,391.66		7,295,042.92	743,348.74
		Total Account 353	160,812,251.57		0.00	52,561,459.67	5,930,705.26
354.00		Towers and Fixtures	60,533,459.11	35,842,997.16		11,870,207.08	23,972,790.08
355.00		Poles and Fixtures	74,915,940.37	39,080,978.14		17,254,044.30	21,826,933.84
356.00		Overhead Conductors and Devices	122,030,093.52	80,292,060.35		50,843,072.07	29,448,988.28
357.00		Underground Conduit	435,926.80	87,891.34		79,267.50	8,623.84
358.00		Underground Conductors and Devices	1,114,761.90	610,385.26		585,756.22	24,629.04
		Total Transmission Plant	588,247,665.85	229,609,190.17	17,975.03	147,422,776.06	82,168,439.08
		DISTRIBUTION PLANT					
360.10		Land Rights	1,423,182.13	871,665.37		871,665.37	0.00
361.00		Structures and Improvements	3,798,329.41	1,297,363.29		1,100,515.13	196,848.16
362.00		Station Equipment	92,514,069.32	26,913,724.72		21,992,348.35	4,921,376.37
364.00		Poles, Towers and Fixtures	167,558,546.62	71,525,016.94		47,259,930.85	24,265,086.09
365.00		Overhead Conductors and Devices	160,511,631.53	79,079,691.18		42,030,013.30	37,049,677.88
366.00		Underground Conduit	1,551,966.69	790,660.29		730,114.37	60,545.92
367.00		Underground Conductors and Devices	49,804,065.26	11,589,403.43		10,870,627.02	718,776.41
368.00		Line Transformers	209,705,230.76	66,818,337.52		55,671,009.35	11,147,328.17
369.00		Services	81,680,930.54	46,743,901.54		34,607,411.07	12,136,490.47
370.00		Meters	61,133,035.49	17,892,318.35	1,456,792.77	13,832,427.00	2,603,098.58
371.00		Installations on customers' Premises	18,270,303.32	6,925,709.76		6,925,709.76	0.00
373.00		Street Lighting and Signal Systems	45,406,623.49	13,863,494.93		10,782,787.90	3,080,707.03
		Total Distribution Plant	893,357,914.56	344,311,287.31	1,456,792.77	246,674,559.46	96,179,935.08
		GENERAL PLANT					
		Structures and Improvements					
390.10		Struct. And Improve. To Owned Property	28,987,368.24	10,718,145.14		10,718,145.14	0.00
390.20		Improvements to Leased Property	694,489.17	427,336.62		427,336.62	0.00
		Total Account 390	29,681,857.41		0.00	11,145,481.77	0.00
		Office Furniture and Equipment					
391.10		Office Equipment	6,168,471.98	2,154,796.89		2,154,796.89	0.00
391.30		Cash Processing Equipment	369,383.94	250,365.99		250,365.99	0.00
		Total Account 391	6,537,855.92		0.00	2,405,162.88	0.00
393.00		Stores Equipment	571,858.05	347,614.14		347,614.14	0.00
394.00		Tools, Shop and Garage Equipment	3,700,720.83	1,499,979.76		1,499,979.76	0.00
395.00		Laboratory Equipment	3,306,885.77	1,752,921.21		1,752,921.21	0.00
396.00		Power Operated Equipment	200,677.14	126,436.76		126,436.76	0.00
		Communication Equipment					
397.10		Carrier Communication Equipment	3,093,194.70	1,276,444.53		1,276,444.53	0.00
397.20		Remote Control Communication Equipment	3,889,910.58	1,237,153.86		1,237,153.86	0.00
397.30		Mobile Communication Equipment	4,579,895.62	1,132,687.81		1,132,687.81	0.00
		Total Account 397	11,563,000.90		0.00	3,646,286.21	0.00
398.00		Miscellaneous Equipment	457,348.94	213,335.55		213,335.55	0.00
		Total General Plant	56,020,204.96	47,579,179.53	0.00	21,137,218.27	0.00
		Sub-Total Depreciable Plant	3,262,103,895.96	1,474,991,058.76	1,474,767.80	1,211,941,629.54	235,132,700.16
		Other Plant (Not Studied)					
391.20		Non PC Computer Equipment	9,611,731.44	3,963,686.38		3,963,686.38	0.00
391.40		Personal Computers	9,814,322.00	8,735,674.86		8,735,674.86	0.00
392.00		Transportation Equipment - Cars & Trucks	23,749,238.51	13,742,600.02		13,742,600.02	0.00
		Total Other Plant (Not Studied)	43,175,291.95	0.00	0.00	26,441,961.26	
		Total Depreciable Plant	3,305,279,187.91	1,474,991,058.76	1,474,767.80	1,238,383,590.80	235,132,700.16

Table 1a - KY

Kentucky Utilities
Electric Division
Kentucky
Calculation of Cost of Removal In Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Loc. Code	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
		NON-DEPRECIABLE PLANT					
		INTANGIBLE PLANT					
301.00		Organization	44,455.58	0.00		0.00	
302.00		Franchises and Consents	81,350.32	0.00		0.00	
303.00		Miscellaneous Intangible Plant	17,297,387.08	0.00		0.00	
		Total Intangible Plant	17,423,192.98	0.00	0.00	0.00	
		LAND & LAND RIGHTS					
310.20		Production Land	10,478,524.55	0.00		0.00	
330.20		Hydraulic Plant	13,479.47	0.00		0.00	
340.20		Other Production Land	98,602.74	0.00		0.00	
350.20		Transmission Land	1,162,528.04	0.00		0.00	
360.20		Distribution Land	1,584,825.82	0.00		0.00	
389.20		Land	2,826,347.43	0.00		0.00	
		Total Land	16,164,308.05	0.00	0.00	0.00	
		Total Non-Depreciable Plant	33,587,501.03	0.00	0.00	0.00	
		Total Electric Plant In Service	3,338,866,688.94	1,474,991,058.76	1,474,767.80	1,238,383,590.80	

(1) Life Span Method Utilized. Interim Retirement Rate. Service Lives Vary.

Summary		% of Adj'd Resv Depr Reserve
Total Book Depr Reserve 12-31-02	$1,474,991,058.76	
Adjustment for Omitted Retirements	1,474,767.80	
Adjusted Book Depr Reserve 12-31-02	1,473,516,290.96	
Plant & Gross Salvage Depr Reserve 12-31-02	1,238,383,590.80	84.0%
Cost of Removal Depr Reserve 12-31-02	235,132,700.16	16.0%

Table 1a - VA

Kentucky Utilities
Electric Division
Virginia
Calculation of Cost of Removal In Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (g)	Plant Depr Reserve 12/31/02	Cost of Removal Depr Reserve 12/31/02
	DEPRECIABLE PLANT				
	TRANSMISSION PLANT				
350.10	Land Rights	1,782,030.88	1,282,804.80	1,282,804.80	0.00
	Structures and Improvements				
352.10	Struct. and Improve. - Non Sys. Control/Com.	1,050,280.78	501,590.05	360,507.47	141,082.58
352.20	Struct. and Improve. - Sys. Control/Com.	0.00	0.00	0.00	0.00
	Total Account 352	1,050,280.78		360,507.47	141,082.58
	Station Equipment				
353.10	Station Equipment - Non Sys. Control/Com.	13,943,172.45	4,808,386.94	4,346,731.70	461,655.24
353.20	Station Equip - Sys.Control/Com. (Microwave)	0.00	0.00	0.00	0.00
	Total Account 353	13,943,172.45		4,346,731.70	461,655.24
354.00	Towers and Fixtures	6,739,096.01	3,343,877.02	1,244,469.45	2,099,407.57
355.00	Poles and Fixtures	5,246,663.42	2,671,893.76	1,266,261.97	1,405,631.79
356.00	Overhead Conductors and Devices	11,605,472.16	7,164,742.76	4,681,186.31	2,483,556.45
357.00	Underground Conduit	0.00	0.00	0.00	0.00
358.00	Underground Conductors and Devices	0.00	0.00	0.00	0.00
	Total Transmission Plant	40,366,715.70	19,773,295.33	13,181,961.70	6,591,333.63
	DISTRIBUTION PLANT				
360.10	Land Rights	83,580.13	49,087.98	49,087.98	0.00
361.00	Structures and Improvements	367,467.51	138,922.33	120,242.43	18,679.90
362.00	Station Equipment	6,294,362.38	1,857,713.58	1,556,161.58	301,552.00
364.00	Poles, Towers and Fixtures	12,133,206.90	6,062,010.91	4,236,660.23	1,825,350.68
365.00	Overhead Conductors and Devices	12,306,434.76	6,905,462.62	4,037,289.81	2,868,172.81
366.00	Underground Conduit	0.00	0.00	0.00	0.00
367.00	Underground Conductors and Devices	519,618.44	161,218.31	152,286.52	8,931.79
368.00	Line Transformers	12,035,778.33	5,011,031.05	4,268,982.75	742,048.30
369.00	Services	4,905,735.94	3,410,040.37	2,622,607.31	787,433.06
370.00	Meters	3,616,919.29	1,389,229.45	1,209,680.65	179,548.80
371.00	Installations on customers' Premises	867,302.80	- 437,931.20	437,931.20	0.00
373.00	Street Lighting and Signal Systems	1,229,044.76	489,084.71	392,844.17	96,240.54
	Total Distribution Plant	54,359,451.24	25,911,732.50	19,083,774.62	6,827,957.88
	GENERAL PLANT				
	Structures and Improvements				
390.10	Struct. And Improve. To Owned Property	643,848.85	381,131.81	381,131.81	0.00
390.20	Improvements to Leased Property	75,980.87	65,901.46	65,901.46	0.00
	Total Account 390	719,829.72		447,033.26	0.00
	Office Furniture and Equipment				
391.10	Office Equipment	39,094.49	31,967.61	31,967.61	0.00
391.30	Cash Processing Equipment	0.00	0.00	0.00	0.00
	Total Account 391	39,094.49		31,967.61	0.00

Table 1a - VA

Kentucky Utilities
Electric Division
Virginia
Calculation of Cost of Removal In Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (g)	Plant Depr Reserve 12/31/02	Cost of Removal Depr Reserve 12/31/02
393.00	Stores Equipment	8,103.30	5,283.48	5,283.48	0.00
394.00	Tools, Shop and Garage Equipment	275,731.08	69,256.48	69,256.48	0.00
395.00	Laboratory Equipment	37,683.18	27,624.58	27,624.58	0.00
396.00	Power Operated Equipment	0.00	0.00	0.00	0.00
	Communication Equipment				
397.10	Carrier Communication Equipment	153,447.99	150,248.86	150,248.86	0.00
397.20	Remote Control Communication Equipment	160,272.74	72,452.57	72,452.57	0.00
397.30	Mobile Communication Equipment	240,853.23	58,275.04	58,275.04	0.00
	Total Account 397	554,573.96		280,976.47	0.00
398.00	Miscellaneous Equipment	16,363.42	11,025.57	11,025.57	0.00
	Total General Plant	1,651,379.15	1,752,006.96	873,167.45	0.00
	Sub-Total Depreciable Plant	96,377,546.09	47,437,034.79	33,138,903.77	13,419,291.51
	Other Plant (Not Studied)				
391.20	Non PC Computer Equipment	0.00	0.00	0.00	
391.40	Personal Computers	0.00	0.00	0.00	
392.00	Transportation Equipment - Cars & Trucks	1,315,837.37	878,839.51	878,839.51	
	Total Other Plant (Not Studied)	1,315,837.37	0.00	878,839.51	0.00
	Total Depreciable Plant	97,693,383.46	47,437,034.79	34,017,743.28	13,419,291.51
	NON-DEPRECIABLE PLANT				
	INTANGIBLE PLANT				
301.00	Organization	5,338.69	0.00		
302.00	Franchises and Consents	0.00	0.00		
303.00	Miscellaneous Intangible Plant	0.00	0.00		
	Total Intangible Plant	5,338.69	0.00	0.00	0.00
	LAND & LAND RIGHTS				
310.20	Production Land	0.00	0.00		
330.20	Hydraulic Plant	0.00	0.00		
340.20	Other Production Land	0.00	0.00		
350.20	Transmission Land	68,167.96	0.00		
360.20	Distribution Land	96,439.08	0.00		
389.20	Land	91,571.48	0.00		
	Total Land	256,178.52	0.00	0.00	0.00
	Total Non-Depreciable Plant	261,517.21	0.00	0.00	0.00
	Total Electric Plant in Service	97,954,900.67	47,437,034.79	34,017,743.28	13,419,291.51

Table 1a - VA

Kentucky Utilities
Electric Division
Virginia
Calculation of Cost of Removal In Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (b)	Original Cost 12/31/02 (c)	Total Book Depr Reserve 12/31/02 (g)	Plant Depr Reserve 12/31/02	Cost of Removal Depr Reserve 12/31/02
	Summary		**% of Adj'd Resv Depr Reserve**		
	Total Book Depr Reserve 12-31-02	$47,437,034.79			
	Adjustment for Omitted Retirements	0.00			
	Adjusted Book Depr Reserve 12-31-02	47,437,034.79			
	Plant & Gross Salvage Depr Reserve 12-31-02	34,017,743.28	71.7%		
	Cost of Removal Depr Reserve 12-31-02	13,419,291.51	28.3%		

Louisville Gas and Electric
Electric Division

Calculation of Cost of Removal In Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (j)	Cost of Removal Depr Reserve 12/31/02	Adjusted Book Reserve-w/o COR 12/31/2002
	DEPRECIABLE PLANT				
	STEAM PRODUCTION PLANT				
	Cane Run Locomotive & Rail Cars				
312.00	Boiler Plant Equipment	51,549.42	49,217.02	3,348.00	
312.00	Boiler Plant Equipment	1,501,772.81	767,268.58	49,375.00	
	Total Cane Run Locomotive & Rail Cars	1,553,322.23	816,485.60	52,723.00	763,762.60
	Cane Run Unit 1				
311.00	Structures and Improvements	4,182,197.33	5,007,364.88	307,040.00	
312.00	Boiler Plant Equipment	1,053,742.53	1,212,428.34	75,031.00	
314.00	Turbogenerator Units	106,008.55	135,990.09	7,959.00	
315.00	Accessory Electric Equipment	1,891,012.53	2,361,744.12	141,923.00	
316.00	Misc. Power Plant Equipment	151,638.76	183,908.16	8,962.00	
	Total Cane Run Unit 1	7,384,599.70	8,901,435.58	540,915.00	8,360,520.58
	Cane Run Unit 2				
311.00	Structures and Improvements	2,102,941.66	2,104,456.36	152,621.00	
312.00	Boiler Plant Equipment	132,836.82	133,304.91	9,770.00	
314.00	Turbogenerator Units	19,998.97	20,838.93	1,493.00	
315.00	Accessory Electric Equipment	1,277,223.20	1,340,996.08	95,322.00	
	Total Cane Run Unit 2	3,533,000.65	3,599,596.28	259,206.00	3,340,390.28
	Cane Run Unit 3				
311.00	Structures and Improvements	3,532,140.77	5,863,328.73	252,855.00	
312.00	Boiler Plant Equipment	716,616.30	1,119,078.61	48,495.00	
314.00	Turbogenerator Units	581,177.52	1,030,902.17	42,526.00	
315.00	Accessory Electric Equipment	767,324.52	1,326,714.57	56,033.00	
316.00	Misc. Power Plant Equipment	11,664.48	20,567.80	738.00	
	Total Cane Run Unit 3	5,608,923.59	9,360,591.88	400,647.00	8,959,944.88
	Cane Run Unit 4				
311.00	Structures and Improvements	3,547,227.06	3,145,648.04	230,175.00	
312.00	Boiler Plant Equipment	25,980,016.48	14,936,101.51	1,059,047.00	
312.00	Mandated NOX Proj.-2004 Closing	2,442,926.00		0.00	
314.00	Turbogenerator Units	8,432,342.78	6,415,903.06	449,834.00	
315.00	Accessory Electric Equipment	5,490,677.18	2,589,321.48	182,569.00	
316.00	Misc. Power Plant Equipment	54,253.32	17,147.80	1,110.00	
	Total Cane Run Unit 4	45,947,442.82	27,104,121.89	1,922,735.00	25,181,386.89
	Cane Run Unit 4 Scrubber				
311.00	Structures and Improvements	760,360.00	1,142,221.25	40,775.00	
312.00	Boiler Plant Equipment	16,701,761.03	19,987,932.17	710,292.00	
315.00	Accessory Electric Equipment	987,949.29	1,066,985.23	55,200.00	
316.00	Misc. Power Plant Equipment	6,464.30	6,464.30	375.00	
	Total Cane Run Unit 4 Scrubber	18,456,534.62	22,203,602.95	806,642.00	21,396,960.95
	Cane Run Unit 5				
311.00	Structures and Improvements	5,416,846.93	4,223,751.15	319,923.00	
312.00	Boiler Plant Equipment	21,717,140.89	11,680,384.07	862,365.00	
312.00	Mandated NOX Proj.-2004 Closing	2,318,975.00		0.00	
314.00	Turbogenerator Units	6,985,593.95	5,632,062.00	409,643.00	
315.00	Accessory Electric Equipment	6,846,848.21	3,094,934.16	225,458.00	
316.00	Misc. Power Plant Equipment	42,867.49	7,894.99	537.00	
	Total Cane Run Unit 5	43,328,272.47	24,639,026.36	1,817,926.00	22,821,100.36
	Cane Run Unit 5 Scrubber				
311.00	Structures and Improvements	1,696,435.28	1,705,086.49	85,459.00	
312.00	Boiler Plant Equipment	27,928,602.90	25,440,779.02	1,246,622.00	
315.00	Accessory Electric Equipment	2,173,037.73	2,390,465.99	115,499.00	

Louisville Gas and Electric
Electric Division

Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (j)	Cost of Removal Depr Reserve 12/31/02	Adjusted Book Reserve-w/o COR 12/31/2002
316.00	Misc. Power Plant Equipment	47,299.47	60,158.06	2,590.00	
	Total Cane Run Unit 5 Scrubber	31,845,375.38	29,596,489.56	1,450,170.00	28,146,319.56
	Cane Run Unit 6				
311.00	Structures and Improvements	18,149,961.41	11,310,161.61	915,740.00	
312.00	Boiler Plant Equipment	35,613,831.67	18,613,062.65	1,474,838.00	
312.00	Mandated NOX Proj.-2004 Closing	384,664.00		0.00	
314.00	Turbogenerator Units	11,274,211.57	8,027,114.38	626,983.00	
315.00	Accessory Electric Equipment	8,173,345.07	3,909,387.88	306,596.00	
316.00	Misc. Power Plant Equipment	1,806,951.04	915,533.28	64,548.00	
	Total Cane Run Unit 6	75,402,964.76	42,775,259.80	3,388,705.00	39,386,554.80
	Cane Run Unit 6 Scrubber				
311.00	Structures and Improvements	1,859,591.50	1,559,237.99	85,926.00	
312.00	Boiler Plant Equipment	30,524,761.84	22,372,713.66	1,198,527.00	
315.00	Accessory Electric Equipment	2,124,667.29	2,144,382.93	113,141.00	
316.00	Misc. Power Plant Equipment	31,568.91	38,278.10	1,785.00	
	Total Cane Run Unit 6 Scrubber	34,540,589.54	26,114,612.68	1,399,379.00	24,715,233.68
	Mill Creek Locomotive & Rails Cars				
312.00	Boiler Plant Equipment	613,424.43	558,573.13	30,205.00	
312.00	Boiler Plant Equipment	3,631,645.61	1,862,746.59	93,830.00	
	Total Mill Creek Locomotive & Rails Cars	4,245,070.04	2,421,319.72	124,035.00	2,297,284.72
	Mill Creek Unit 1				
311.00	Structures and Improvements	18,350,957.82	15,111,640.28	937,617.00	
312.00	Boiler Plant Equipment	40,579,264.08	25,156,522.44	1,544,604.00	
312.00	Mandated NOX Proj.-2004 Closing	298,528.00		0.00	
312.00	Mandated NOX Proj.-2005 Closing	250,000.00		0.00	
314.00	Turbogenerator Units	13,449,713.81	10,984,999.07	653,059.00	
315.00	Accessory Electric Equipment	14,520,069.59	6,128,517.94	368,445.00	
316.00	Misc. Power Plant Equipment	654,992.48	458,697.92	23,744.00	
	Total Mill Creek Unit 1	88,103,525.78	57,840,377.64	3,527,469.00	54,312,908.64
	Mill Creek Unit 1 Scrubber				
311.00	Structures and Improvements	1,697,743.03	1,217,072.74	64,460.00	
312.00	Boiler Plant Equipment	33,874,404.57	21,426,853.04	1,107,154.00	
315.00	Accessory Electric Equipment	5,541,694.53	4,273,045.26	218,367.00	
	Total Mill Creek Unit 1 Scrubber	41,113,842.13	26,916,971.04	1,389,981.00	25,526,990.04
	Mill Creek Unit 2				
311.00	Structures and Improvements	10,703,506.13	8,178,641.31	494,660.00	
312.00	Boiler Plant Equipment	33,397,635.49	17,698,958.31	1,054,317.00	
312.00	Mandated NOX Proj.-2004 Closing	243,288.00		0.00	
312.00	Mandated NOX Proj.-2005 Closing	250.00		0.00	
314.00	Turbogenerator Units	14,801,053.25	10,895,295.62	631,471.00	
315.00	Accessory Electric Equipment	7,420,343.06	4,450,450.07	261,234.00	
316.00	Misc. Power Plant Equipment	105,299.47	82,497.03	4,145.00	
	Total Mill Creek Unit 2	66,671,375.40	41,305,842.35	2,445,827.00	38,860,015.35
	Mill Creek Unit 2 Scrubber				
311.00	Structures and Improvements	1,393,403.67	947,196.37	49,691.00	
312.00	Boiler Plant Equipment	34,412,558.24	17,978,498.46	910,681.00	
315.00	Accessory Electric Equipment	4,451,153.72	3,467,639.40	173,336.00	
	Total Mill Creek Unit 2 Scrubber	40,257,115.63	22,393,336.23	1,133,708.00	21,259,628.23
	Mill Creek Unit 3				
311.00	Structures and Improvements	24,487,440.44	15,892,174.24	880,176.00	
312.00	Boiler Plant Equipment	65,259,053.22	41,186,363.84	2,209,150.00	
312.00	Mandated NOX Proj.-2004 Closing	65,597,028.00		0.00	
312.00	Mandated NOX Proj.-2005 Closing	3,198,000.00		0.00	

Louisville Gas and Electric
Electric Division

Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (j)	Cost of Removal Depr Reserve 12/31/02	Adjusted Book Reserve-w/o COR 12/31/2002
314.00	Turbogenerator Units	26,232,206.52	17,259,343.05	899,415.00	
315.00	Accessory Electric Equipment	13,482,711.35	9,003,881.35	476,383.00	
316.00	Misc. Power Plant Equipment	318,625.29	274,298.72	11,945.00	
	Total Mill Creek Unit 3	198,575,064.82	83,616,061.20	4,477,069.00	79,138,992.20
	Mill Creek Unit 3 Scrubber				
311.00	Structures and Improvements	362,866.58	230,008.75	12,763.00	
312.00	Boiler Plant Equipment	52,369,621.74	21,983,261.31	1,180,426.00	
315.00	Accessory Electric Equipment	2,531,772.82	1,845,000.66	95,297.00	
	Total Mill Creek Unit 3 Scrubber	55,264,261.14	24,058,270.72	1,288,486.00	22,769,784.72
	Mill Creek Unit 4				
311.00	Structures and Improvements	56,594,172.78	26,766,630.73	1,650,939.00	
312.00	Boiler Plant Equipment	154,787,100.00	62,421,714.83	3,674,173.00	
312.00	Mandated NOX Proj.-2004 Closing	63,382,718.00		0.00	
312.00	Mandated NOX Proj.-2005 Closing	1,402,000.00	-	0.00	
312.00	Mandated NOX Proj.-2006 Closing	3,000,000.00		0.00	
314.00	Turbogenerator Units	40,475,497.49	20,964,672.43	1,197,214.00	
315.00	Accessory Electric Equipment	21,428,489.73	11,328,525.97	659,167.00	
316.00	Misc. Power Plant Equipment	3,926,266.27	1,564,750.41	75,580.00	
	Total Mill Creek Unit 4	344,996,244.27	123,046,294.36	7,257,073.00	115,789,221.36
	Mill Creek Unit 4 Scrubber				
311.00	Structures and Improvements	5,079,085.65	2,164,530.50	157,301.00	
312.00	Boiler Plant Equipment	105,450,790.06	31,729,807.81	2,150,481.00	
315.00	Accessory Electric Equipment	5,811,079.36	3,142,825.39	205,013.00	
316.00	Misc. Power Plant Equipment	41,441.04	26,572.02	1,486.00	
	Total Mill Creek Unit 4 Scrubber	116,382,396.11	37,063,735.72	2,514,281.00	34,549,454.72
	Trimble County Unit 1				
311.00	Structures and Improvements	161,248,919.71	47,758,039.32	1,424,072.00	
312.00	Boiler Plant Equipment	235,442,385.84	62,456,671.60	1,737,965.00	
312.00	Mandated NOX Proj.-2004 Closing	2,832,801.00		0.00	
314.00	Turbogenerator Units	66,236,375.14	21,515,114.70	587,435.00	
315.00	Accessory Electric Equipment	56,332,123.79	18,070,820.41	500,288.00	
316.00	Misc. Power Plant Equipment	2,332,701.72	831,971.41	18,544.00	
	Total Trimble County Unit 1	524,425,307.20	150,632,617.44	4,268,304.00	146,364,313.44
	Total Trimble County Unit 1 Scrubber				
311.00	Structures and Improvements	450,053.78	199,877.35	4,369.00	
312.00	Boiler Plant Equipment	54,528,851.05	30,321,313.03	578,706.00	
315.00	Accessory Electric Equipment	2,736,920.21	1,557,453.07	29,683.00	
	Total Trimble County Unit 1 Scrubber	57,715,825.04	32,078,643.45	612,758.00	31,465,885.45
	Total Steam Production Plant	1,805,351,053.32	796,484,692.45	41,078,039.00	755,406,653.45
	HYDRAULIC PLANT Project 289				
	Ohio Falls Plant - Project 289				
331.10	Structures and Improvements	4,995,148.82	4,989,034.51	341,482.00	
332.10	Reservoirs, Dams and Waterways	303,530.35	237,807.60	55,773.00	
333.10	Waterwheel, Turbines and Generators	2,316,031.31	2,528,445.62	214,972.00	
334.10	Accessory Electric Equipment	1,304,908.02	1,052,232.67	129,905.00	
335.10	Miscellaneous Power Plant Equipment	151,460.96	173,144.02	27,979.00	
336.10	Roads, Railroads and Bridges	178,846.99	169,665.39	0.00	
	Total Ohio Falls Plant - Project 289	9,249,926.45	9,150,329.81	770,111.00	8,380,218.81

Other Than Project 289

Ohio Falls Plant - Non Project 289

Louisville Gas and Electric
Electric Division

Calculation of Cost of Removal In Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (i)	Cost of Removal Depr Reserve 12/31/02	Adjusted Book Reserve-w/o COR 12/31/2002
331.00	Structures and Improvements	65,796.14	26,465.65	1,596.00	
335.00	Miscellaneous Power Plant Equipment	7,813.67	6,014.78	1,338.00	
336.00	Roads, Railroads and Bridges	1,133.98	592.79	0.00	
	Total Ohio Falls Plant - Non Project 289	74,743.79	33,073.22	2,934.00	30,139.22
	Total Hydraulic Plant	9,324,670.24	9,183,403.03	773,045.00	8,410,358.03
	OTHER PRODUCTION PLANT				
	Cane Run CT's				
341.00	Structures and Improvements	68,931.71	59,101.41	4,340.00	
342.00	Fuel Holders, Producers and Accessory	123,338.90	84,856.13	7,458.00	
344.00	Generators	2,492,496.42	1,590,838.99	120,701.00	
345.00	Accessory Electric Equipment	113,683.82	98,154.10	3,180.00	
	Cane Run CT's	2,798,450.85	1,832,950.64	135,679.00	1,697,271.64
	Zorn CT's				
341.00	Structures and Improvements	8,241.14	8,360.08	552.00	
342.00	Fuel Holders, Producers and Accessory	12,801.77	13,202.27	1,044.00	
344.00	Generators	1,827,580.88	1,688,469.30	115,203.00	
345.00	Accessory Electric Equipment	40,936.08	39,733.30	1,158.00	
	Zorn CT's	1,889,559.87	1,749,764.95	117,957.00	1,631,807.95
	Waterside CT's				
341.00	Structures and Improvements	411,977.94	392,074.27	28,279.00	
342.00	Fuel Holders, Producers and Accessory	124,163.26	115,527.66	9,974.00	
343.00	Prime Movers	2,671,305.84	2,140,319.74	62,459.00	
344.00	Generators	451,117.33	432,486.53	32,232.00	
345.00	Accessory Electric Equipment	342,628.38	167,133.97	5,319.00	
346.00	Misc. Power Plant Equipment	24,766.29	22,894.93	708.00	
	Waterside CT's	4,025,959.04	3,270,437.09	138,971.00	3,131,466.09
	Paddys 11 CT				
342.00	Fuel Holders, Producers and Accessory	9,237.57	9,613.48	753.00	
344.00	Generators	1,523,115.56	1,415,850.36	95,729.00	
345.00	Accessory Electric Equipment	68,109.35	56,264.89	1,625.00	
	Paddys 12 CT	1,600,462.48	1,481,728.73	98,107.00	1,383,621.73
	Paddys 12 CT				
341.00	Structures and Improvements	42,864.53	45,293.55	2,871.00	
342.00	Fuel Holders, Producers and Accessory	12,197.11	12,814.41	972.00	
344.00	Generators	2,991,745.77	2,898,337.55	189,838.00	
345.00	Accessory Electric Equipment	114,337.63	98,654.90	2,759.00	
346.00	Accessory Electric Equipment	1,140.74	1,155.82	31.00	
	Paddys 12 CT	3,162,285.78	3,056,256.24	196,471.00	2,859,785.24
	Paddys 13 CT				
341.00	Structures and Improvements	2,158,698.12	111,886.17	9,087.00	
342.00	Fuel Holders, Producers and Accessory	2,233,773.85	117,701.76	11,443.00	
343.00	Prime Movers	19,627,845.35	969,405.90	31,854.00	
344.00	Generators	5,859,857.93	304,558.38	25,558.00	
345.00	Accessory Electric Equipment	2,778,992.60	141,142.47	5,058.00	
346.00	Misc. Power Plant Equipment	1,260,054.85	66,713.68	2,324.00	
	Paddys 13 CT	33,919,222.70	1,711,408.36	85,324.00	1,626,084.36
	Brown 5 CT				
341.00	Structures and Improvements	858,538.64	44,387.35	3,614.00	
342.00	Fuel Holders, Producers and Accessory	822,580.92	43,235.24	4,214.00	
343.00	Prime Movers	14,126,417.74	695,947.72	22,926.00	
344.00	Generators	3,219,205.40	166,895.19	14,041.00	

Louisville Gas and Electric
Electric Division

Calculation of Cost of Removal In Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (j)	Cost of Removal Depr Reserve 12/31/02	Adjusted Book Reserve-w/o COR 12/31/2002
345.00	Accessory Electric Equipment	2,575,301.42	130,470.02	4,688.00	
346.00	Misc. Power Plant Equipment	2,370,656.38	125,200.80	4,374.00	
	Brown 5 CT	23,972,700.50	1,206,136.32	53,857.00	1,152,279.32
	Brown 6 CT				
341.00	Structures and Improvements	69,733.40	5,427.49	522.00	
342.00	Fuel Holders, Producers and Accessory	363,762.04	28,779.79	3,313.00	
343.00	Prime Movers	19,890,998.18	1,475,064.65	57,398.00	
344.00	Generators	2,417,994.54	188,695.05	18,752.00	
345.00	Accessory Electric Equipment	942,589.47	71,661.01	3,041.00	
346.00	Misc. Power Plant Equipment	11,034.25	866.20	36.00	
	Brown 6 CT	23,696,111.88	1,770,494.18	83,062.00	1,687,432.18
	Brown 7 CT				
341.00	Structures and Improvements	105,588.33	18,897.37	764.00	
342.00	Fuel Holders, Producers and Accessory	102,065.03	18,571.39	899.00	
343.00	Prime Movers	20,023,957.45	3,414,831.32	55,870.00	
344.00	Generators	2,421,079.26	434,489.81	18,155.00	
345.00	Accessory Electric Equipment	943,792.03	165,275.71	2,949.00	
346.00	Misc. Power Plant Equipment	11,048.30	2,008.95	35.00	
	Brown 7 CT	23,607,530.40	4,054,074.55	78,672.00	3,975,402.55
	Trimble County CT5				
341.00	Structures and Improvements	1,458,614.33	23,800.76	2,051.00	
342.00	Fuel Holders, Producers and Accessory	97,240.96	1,613.28	166.00	
343.00	Prime Movers	12,205,907.18	189,785.32	6,617.00	
344.00	Generators	1,527,420.57	24,992.49	2,225.00	
345.00	Accessory Electric Equipment	680,686.68	10,867.85	413.00	
	Trimble County CT5	15,969,869.72	251,059.70	11,472.00	239,587.70
	Trimble County CT6				
341.00	Structures and Improvements	1,457,842.69	23,804.36	2,050.00	
342.00	Fuel Holders, Producers and Accessory	97,189.52	1,612.27	166.00	
343.00	Prime Movers	12,199,437.94	189,670.95	6,613.00	
344.00	Generators	1,526,610.88	24,977.32	2,224.00	
345.00	Accessory Electric Equipment	680,326.59	10,861.72	413.00	
	Trimble County CT6	15,961,407.62	250,926.61	11,466.00	239,460.61
	Trimble County Pipeline				
342.00	Fuel Holders, Producers and Accessory	1,835,164.93	39,264.86	2,954.00	
	Trimble County Pipeline	1,835,164.93	39,264.86	2,954.00	36,310.86
	Total Other Production Plant	152,438,725.77	20,674,502.23	1,013,992.00	19,660,510.23
	Total Production Plant	1,967,114,449.33	826,342,597.71	42,865,076.00	783,477,521.71
	TRANSMISSION PLANT				
	Project 289				
353.10	Station Equipment - Non Sys. Control/Com.	0.00	0.00	0.00	
356.10	Overhead Conductors and Devices	0.00	0.00	0.00	
	Total Project 289	0.00			
	Other Than Project 289				
350.10	Land Rights	2,592,773.81	1,862,138.53	0.00	
352.10	Struct. and Improve. - Non Sys. Control/Com.	2,907,082.83	1,319,755.12	101,723.53	
353.10	Station Equipment - Non Sys. Control/Com.	116,591,836.76	58,783,885.97	0.00	
354.00	Towers and Fixtures	23,879,707.58	21,296,311.23	5,507,834.14	
355.00	Poles and Fixtures	26,398,367.92	13,173,697.14	3,046,488.45	
356.00	Overhead Conductors and Devices	33,372,312.49	15,162,638.38	5,302,734.30	
357.00	Underground Conduit	1,868,318.57	273,390.24	0.00	
358.00	Underground Conductors and Devices	5,312,495.53	1,675,296.39	0.00	
	Total Other Than Project 289	212,922,895.49		13,958,780.42	
	Total Transmission Plant	212,922,895.49	113,547,113.00	13,958,780.42	99,588,332.58

Louisville Gas and Electric
Electric Division

Calculation of Cost of Removal In Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (j)	Cost of Removal Depr Reserve 12/31/02	Adjusted Book Reserve-w/o COR 12/31/2002
	DISTRIBUTION PLANT				
361.00	Structures and Improvements	5,969,141.37	2,810,349.10	263,364.37	
362.00	Station Equipment	77,088,050.08	25,191,883.20	2,707,221.30	
364.00	Poles, Towers and Fixtures	92,365,173.96	52,705,237.56	51,574,413.02	
365.00	Overhead Conductors and Devices	141,726,406.02	67,131,787.38	33,232,448.85	
366.00	Underground Conduit	52,616,554.86	9,688,016.23	1,442,689.56	
367.00	Underground Conductors and Devices	77,051,441.80	38,273,266.16	8,847,369.95	
	Line Transformers				
368.10	Line Transformers	86,278,030.41	30,721,515.99	2,712,659.47	
368.20	Line Transformers Installations	8,778,300.38	2,574,339.21	227,309.93	
	Total Account 368	95,056,330.79		2,939,969.40	
	Services				
369.10	Underground Services	2,342,286.94	1,563,578.81	112,301.01	
369.20	Overhead Services	20,427,859.34	12,732,459.31	7,605,077.07	
	Total Account 369	22,770,146.28		7,717,378.08	
	Meters & Installations				
370.10	Meters	25,219,577.02	12,282,632.27	925,469.15	
370.20	Meter Installations	8,352,742.98	3,425,757.97	258,237.30	
	Total Account 370	33,572,320.00		1,183,706.45	
	Street Lighting				
373.10	Overhead Street Lighting	22,600,470.37	10,854,699.83	1,858,955.61	
373.20	Underground Street Lighting	32,156,589.32	11,484,555.55	1,545,162.17	
373.40	Street Lighting Trannsformers	87,546.43	63,128.93	0.00	
	Total Account 373	54,844,606.12		3,404,117.78	
	Total Distribution Plant	653,060,171.28	281,503,207.50	113,312,678.76	168,190,528.74
	GENERAL PLANT				
392.20	Transportation Equipment - Trailers	590,217.25	289,107.58	0.00	
394.00	Tools, Shop and Garage Equipment	2,687,990.96	1,172,580.84	0.00	
395.00	Laboratory Equipment	1,548,796.71	914,919.83	0.00	
396.20	Power Operated Equipment - Other	145,466.83	145,466.83	0.00	
	Total General Plant	4,972,471.75	14,464,912.06	0.00	14,464,912.06
	Sub-Total Depreciable Plant	2,838,069,987.85	1,235,857,830.27	170,136,535.18	1,065,721,295.09
	Other Plant (Not Studied)				
392.10	Transportation Equipment - Cars & Trucks	12,069,086.02	9,473,237.14	0.00	
396.10	Power Operated Equipment - Hourly Rated	2,337,037.87	2,469,599.85	0.00	
	Total Other Plant (Not Studied)	14,406,123.89	0.00	0.00	
	Total Depreciable Plant	2,852,476,111.74	1,235,857,830.27	170,136,535.18	1,065,721,295.09
	NON-DEPRECIABLE PLANT				
	INTANGIBLE PLANT				
301.00	Organization	2,240.29	0.00		
302.00	Franchises and Consents	100.00	100.00		
	Total Intangible Plant	2,340.29	100.00	0.00	100.00
	LAND				
310.20	Production Land	5,053,819.49	-30,023.89	0.00	
330.20	Hydraulic Plant	13.00	0.00	0.00	
340.20	Other Production Land	41,125.94	0.00	0.00	
350.20	Transmission Land	888,237.78	0.00	0.00	
360.20	Distribution Land	2,629,414.76	-126,985.13	0.00	
	Total Land	8,612,610.97	-157,009.02	0.00	(157,009.02)
	Total Non-Depreciable Plant	8,614,951.26	-156,909.02	0.00	-156,909.02

Louisville Gas and Electric
Electric Division

Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (f)	Cost of Removal Depr Reserve 12/31/02	Adjusted Book Reserve-w/o COR 12/31/2002
	Total Utility Plant in Service	**2,861,091,063.00**	**1,235,700,921.25**	**170,136,535.18**	**1,065,564,386.07**
	Plant Held for Future Use				
360.20	Substation Land	685,389.54			
362.00	Substation Equipment	11,382.12			
	Total Plant Held for Future Use	696,771.66	0.00		
	Total Electric Plant in Service	**2,861,787,834.66**	**1,235,700,921.25**		

(1) Life Span Method Utiized. Interim Retirement Rate. Service Lives Vary.

Table 1a

Louisville Gas and Electric
Gas Division

Calculation of Cost of Removal In Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Original Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
	DEPRECIABLE PLANT					
	NATURAL GAS STORAGE PLANT					
350.20	Rights of Ways	63,678.14	9,691.16		9,691.16	0.00
	Structures					
351.20	Compressor Station Structures	1,011,754.95	481,954.58		443,937.90	38,016.68
351.30	Measuring and Regulating Station Structures	10,879.61	9,783.40		8,943.57	839.83
351.40	Other Structures	1,148,713.70	627,983.27		579,166.76	48,816.51
	Total Account 351	2,171,348.26		0.00	1,032,048.23	87,673.02
	Wells					
352.20	Reservoirs	400,511.40	420,536.97		420,536.97	0.00
352.30	Nonrecoverable Natural Gas	9,648,855.00	6,989,872.90		6,989,872.90	0.00
352.40	Well Drilling	2,549,654.96	2,360,349.18		2,104,890.64	255,458.54
352.50	Well Equipment	5,037,990.48	2,872,807.26		2,506,210.96	366,596.30
	Total Account 352	17,637,011.84		0.00	12,021,511.47	622,054.84
353.00	Lines	10,349,000.14	6,095,915.63	32,116.18	5,547,182.74	516,616.71
354.00	Compressor Station Equipment	13,404,078.82	6,689,546.37		6,689,546.37	0.00
355.00	Measuring and Regulating Equipment	370,320.90	164,482.43		164,482.43	0.00
356.00	Purification Equipment	9,314,575.58	3,420,245.60		3,000,445.28	419,800.32
357.00	Other Equipment	961,279.76	214,121.80		214,121.80	0.00
	Total Natural Gas Storage Plant	54,271,293.44	30,357,290.55	32,116.18	28,679,029.48	1,646,144.89
	TRANSMISSION PLANT					
365.20	Rights of Way	220,659.05	203,173.96		203,173.96	0.00
367.00	Mains	12,193,974.86	10,763,203.94		8,497,366.02	2,265,837.92
	Total Transmission Plant	12,414,633.91	10,966,377.90	0.00	8,700,539.98	2,265,837.92
	DISTRIBUTION PLANT					
374.22	Other Distribution Land Rights	74,018.23	41,329.75		41,329.75	0.00
	Structures and Improvements					
375.10	City Gate Check Station Struct. and Improve.	133,639.45	68,371.51		56,081.25	12,290.26
375.20	Other Distribution Struct. and Improve.	788,487.48	259,447.97		232,118.15	27,329.82
	Total Account 375	922,126.93		0.00	288,199.40	39,620.08
376.00	Mains	213,002,709.24	60,821,356.04		47,638,638.35	13,182,717.69
378.00	Measuring and Regulating Station Equip. - Gen.	4,590,719.10	1,143,819.63		912,694.45	231,125.18
379.00	Measuring and Reg. Station Eq. - City Gate	2,947,888.13	497,944.10	83,859.07	414,085.03	0.00
380.00	Services	103,680,138.72	42,281,968.92		23,448,692.49	18,833,276.43
381.00	Meters	18,573,635.12	5,672,639.18	1,019,847.12	4,257,616.39	395,175.67
382.00	Meter Installations	7,218,670.36	1,574,182.49	271,757.58	1,128,796.02	173,628.89
383.00	House Regulators	3,106,054.85	1,252,849.08	39,100.59	1,090,958.63	122,789.86
384.00	House Regulator Installations	970,849.46	307,336.05	35,789.97	271,546.08	0.00
385.00	Industrial Measuring and Reg. Station Equip.	142,801.65	61,409.10		61,409.10	0.00
387.00	Other Equipment	65,051.59	12,672.24		12,672.24	0.00
	Total Distribution Plant	355,294,663.38	113,995,326.07	1,450,354.33	79,566,637.94	32,978,333.80
	GENERAL PLANT					
392.20	Transportation Equipment - Trailers	354,261.36	105,520.57		105,520.57	0.00
394.00	Tools, shop and Garage Equipment	2,896,361.96	936,258.93		936,258.93	0.00
395.00	Laboratory Equipment	435,068.27	251,764.70		251,764.70	0.00
	Power Operated Equipment					
396.20	Power Operated Equipment - Other	58,118.72	36,688.40		36,688.40	0.00
	Total Account 396	58,118.72		0.00	36,688.40	
	Total General Plant	3,743,810.31	5,031,608.83	0.00	1,330,232.60	0.00
	Sub-Total Depreciable Plant	425,724,401.04	160,350,603.35	1,482,470.51	118,276,440.00	36,890,316.61

Table 1a

Louisville Gas and Electric
Gas Division

Calculation of Cost of Removal in Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Original Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
	Other Plant (Not Studied)					
392.10	Transportation Equipment - Cars & Trucks	3,209,727.45	2,192,655.87		2,192,655.87	0.00
396.10	Power Operated Equipment - Hourly Rated	2,029,908.51	1,508,720.36		1,508,720.36	0.00
	Total Other Plant (Not Studied)	5,239,635.96	0.00	0.00	3,701,376.23	0.00
	Total Depreciable Plant	430,964,037.00	160,350,603.35	1,482,470.51	121,977,816.23	36,890,316.61
	NON-DEPRECIABLE PLANT					
	INTANGIBLE PLANT					
302.00	Franchises and Consents	1,187.49	800.00		800.00	
352.10	Storage Leaseholds and Rights	552,045.10	573,393.92		573,393.92	
	Total Intangible Plant	553,232.59	574,193.92	0.00	574,193.92	
	LAND					
350.10	Land	32,864.07	3,154.64		3,154.64	
374.11	City Gate Check Station Land	0.00	0.00		0.00	
374.12	Other Distribution Land	62,043.73	-586.44		-586.44	
	Total Land	94,907.80	2,568.20	0.00	2,568.20	
	Total Non-Depreciable Plant	648,140.39	576,762.12	0.00	576,762.12	
	Total Gas Plant in Service	431,612,177.39	160,927,365.47	1,482,470.51	122,554,578.35	

(1) Life Span Method Utilized. Interim Retirement Rate. Service Lives Vary.

Summary		**% of Adj'd Resv Depr Reserve**
Total Book Depr Reserve 12-31-02	**$160,350,603.35**	
Adjustment for Omitted Retirements	**1,482,470.51**	
Adjusted Book Depr Reserve 12-31-02	**158,868,132.84**	
Plant & Gross Salvage Depr Reserve 12-31-02	**121,977,816.23**	**76.8%**
Cost of Removal Depr Reserve 12-31-02	**36,890,316.61**	**23.2%**

Table 1a

Louisville Gas and Electric
Common Plant

Calculation of Cost of Removal In Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
	DEPRECIABLE PLANT					
	GENERAL PLANT					
389.20	Land Rights	202,094.94	59,152.70		59,152.70	0.00
	Structures and Improvements					
390.10	Structures & Improvements - G.O.	44,852,641.93	12,331,415.90	3,428.37	11,779,055.21	548,932.32
390.20	Structures & Improvements - Trans.	1,803,773.44	429,010.82		405,676.80	23,334.02
390.30	Structures & Improvements - Stores	10,918,534.46	3,921,748.91		3,705,442.11	216,306.80
390.40	Structures & Improvements - Shops	379,370.51	148,753.01		140,073.97	8,679.04
390.60	Structures & Improvements - Micro	694,996.39	91,039.63		87,167.80	3,871.83
	Total Account 390	58,649,316.73	16,921,968.26	3,428.37	16,117,415.88	801,124.01
391.00	Office Furniture & Equipment	16,068,584.97	10,448,071.99		10,448,071.99	0.00
392.20	Transportation Equipment - Trailers	63,404.28	10,771.79	3,112.35	7,659.44	0.00
393.00	Stores Equipment	1,229,701.73	272,869.12		272,869.12	0.00
394.00	Tools, Shop and Garage Equipment	1,928,936.72	558,696.04		558,696.04	0.00
395.00	Laboratory Equipment	22,281.50	11,531.93		11,531.93	0.00
	Power Operated Equipment					
396.20	Power Operated Equipment - Other	14,147.08	6,555.71		6,555.71	0.00
	Total Account 396	14,147.08	6,555.71	0.00	6,555.71	
	Communication Equipment					
397.00	Communication Equipment	29,922,166.57	9,915,062.42		9,915,062.42	0.00
397.10	Communication Equipment - Computer	5,189,546.51	1,514,083.95		1,514,083.95	0.00
	Total Account 397	35,111,713.08	11,429,146.37	0.00	11,429,146.37	0.00
398.00	Miscellaneous Equipment	1,012,231.71	244,741.40		244,741.40	0.00
	TOTAL General Plant	114,302,412.74	55,289,741.92	6,540.72	39,155,840.58	801,124.01
	Sub-Total Depreciable Plant	114,302,412.74	55,289,741.92	6,540.72	39,155,840.58	801,124.01
	Other Plant (Not Studied)					
390.11	Struct & Improv.-G.O. (LG&E Bldg & Actors)	2,409,305.82	1,455,764.48		1,431,945.38	23,819.10
391.30	Computer Equipment	16,385,046.53	8,277,681.43		8,277,681.43	0.00
391.31	Personal Computers	9,794,521.46	5,300,087.10		5,300,087.10	0.00
392.10	Transportation Equipment - Cars & Trucks	223,351.84	121,852.82		121,852.82	0.00
396.10	Power Operated Equipment - Hourly Rated	261,447.33	170,850.79		170,850.79	0.00
	Total Other Plant (Not Studied)	29,073,672.98	0.00		15,302,417.51	23,819.10
	Total Depreciable Plant	143,376,085.72	55,289,741.92	6,540.72	54,458,258.09	824,943.11

Table 1a

Louisville Gas and Electric
Common Plant

Calculation of Cost of Removal In Book Depreciation Reserve as of December 31, 2002 Based Upon Theoretical Depreciation Reserves (By Location and Account) Using Existing Depreciation Parameters

Account No. (a)	Description (d)	Cost 12/31/02 (e)	Total Book Depr Reserve 12/31/02 (j)	Adjustment For Omitted Retirements (k)	Plant Depr Reserve 12/31/02 (l)	Cost of Removal Depr Reserve 12/31/02
	NON-DEPRECIABLE PLANT					
	INTANGIBLE PLANT					
301.00	Organization	83,782.29	0.00	0.00	0.00	
302.00	Franchises and Consents	4,200.00	4,700.00		4,700.00	
303.00	Miscellaneous Intangible Plant - Soft	24,365,948.39	18,018,454.53		18,018,454.53	
303.20	Miscellaneous Intangible Plant - Law	78,799.60	78,799.60		78,799.60	
	TOTAL Intangible Plant	24,532,730.28	18,101,954.13	0.00	18,101,954.13	
	LAND					
389.10	General Land	1,661,503.17	0.00		0.00	
	TOTAL Land	1,661,503.17	0.00	0.00	0.00	
	TOTAL Non-Depreciable Plant	26,194,233.45	18,101,954.13	0.00	18,101,954.13	
	TOTAL Common Utility Plant in Service	169,570,319.17	73,391,696.05	6,540.72	72,560,212.22	

(1) Life Span Method Utiized. Interim Retirement Rate. Service Lives Vary.

Summary		% of Adj'd Resv Depr Reserve
Total Book Depr Reserve 12-31-02	$55,289,741.92	
Adjustment for Omitted Retirements	6,540.72	
Adjusted Book Depr Reserve 12-31-02	55,283,201.20	
Plant & Gross Salvage Depr Reserve 12-31-02	54,458,258.09	98.5%
Cost of Removal Depr Reserve 12-31-02	824,943.11	1.5%

Louisville Gas and Electric Company
Estimated Removal Cost in Reserve
at December 2002

Property Group	Reserve Balance 12-31-02	Salv/Dep Ratio	Estimated Net Salvage	% of Reserve
LG&E				
Total Steam Production Plant	796,484,692.45	-	81,279,833.36	10%
Ohio Falls Hydraulic Production Plant	9,183,403.03	-	-	0%
Total Other Production Plant	20,674,502.23	-	-	0%
Total Transmission Plant	113,547,113.18	-	20,025,125.45	18%
Total Distribution Plant	281,376,222.37	-	66,721,682.50	24%
Total General Plant	14,464,912.06	-	(2,532,915.75)	-18%
TOTAL ELECTRIC	1,235,730,845.32		165,493,725.56	13%
TOTAL GAS *	158,773,492.53	-	41,317,003.31	26%
TOTAL COMMON	73,242,363.78	-	1,963,218.31	3%
TOTAL LG&E	1,467,746,701.63		208,773,947.17	14%
KU				
Total Steam Production Plant	794,854,592.78	-	81,279,833.36	10%
Ohio Falls Hydraulic Production Plant	8,323,904.23	-	-	0%
Total Other Production Plant	50,312,904.75	-	-	0%
Total Transmission Plant	249,396,208.57	-	20,025,125.45	8%
Total Distribution Plant	371,679,811.83	-	66,721,682.50	18%
Total General Plant	49,485,369.49	-	(2,532,915.75)	-5%
TOTAL KU	1,235,730,845.32		165,493,725.56	13%
TOTAL UTILITY	2,703,477,546.95		374,267,672.73	14%

Louisville Gas and Electric Company
Estimated Removal Cost in Reserve
at December 2002

Property Group	Reserve Balance 12-31-02	Salv/Dep Ratio	Estimated Removal Cost
Intangible Plant			
302 Franchises and Consents	100	0%	-
303 Misc Intangible Plant	-		
Total Intangible Plant	100		-
Steam Production Plant			
Cane Run 1	9,717,921	0%	-
Cane Run 2	3,599,596	0%	-
Cane Run 3	9,360,592	0%	-
Cane Run 4	27,104,122	18%	4,878,741.94
Cane Run 5	24,639,026	18%	4,435,024.74
Cane Run 6	42,775,260	17%	7,271,794.17
Cane Run 4 FGD	22,203,603	0%	-
Cane Run 5 FGD	29,596,490	43%	12,726,490.51
Cane Run 6 FGD	26,114,613	35%	9,140,114.44
Mill Creek 1	60,261,697	15%	9,039,254.60
Mill Creek 2	41,305,842	15%	6,195,876.35
Mill Creek 3	83,616,061	7%	5,853,124.28
Mill Creek 4	123,046,294	7%	8,613,240.61
Mill Creek 1 FGD	26,916,971	14%	3,768,375.95
Mill Creek 2 FGD	22,393,336	14%	3,135,067.07
Mill Creek 3 FGD	24,058,271	12%	2,886,992.49
Mill Creek 4 FGD	37,063,736	9%	3,335,736.21
Trimble County 1	150,632,617	3%	4,518,978.52
Trimble County 1 FGD	32,078,643	5%	1,603,932.17
Total Steam Production Plant	796,484,692		81,279,833
Ohio Falls Hydraulic Production Plant	9,183,403	0%	-
Other Production Plant			
Cane Run 11	1,832,951	0%	-
Zorn	1,749,765	0%	-
Waterside	3,270,437	0%	-
Paddys 11	1,481,729	0%	-
Paddys 12	3,056,256	0%	-
Paddys 13	1,711,408	0%	-
Brown 5	1,206,136	0%	-
Brown 6	1,770,494	0%	-
Brown 7	4,054,075	0%	-
Trimble County 5	251,060	0%	-
Trimble County 6	250,927	0%	-
TC Pipeline	39,265	0%	-
Total Other Production Plant	20,674,502		-
Transmission Plant			
350.1 Land Rights	1,328,614	0%	-
352 Structures and Improvements	1,552,050	18%	279,369.07
353.1 Station Equipment	65,044,509	0%	-

354 Towers & Fixtures	17,988,442	56%	10,073,527.73	
355 Poles & Fixtures	10,493,122	26%	2,728,211.62	
356 Overhead Conductors and Devices	15,781,857	44%	6,944,017.02	
357 Underground Conduit	296,505	0%	-	
358 Underground Conductors & Devices	1,062,014	0%	-	
Total Transmission Plant	113,547,113		20,025,125	
Distribution Plant				
360.1 Land Rights	(126,985)	0	-	
361 Structures and Improvements	4,271,725	0.18	768,910.43	
362 Station Equipment	38,785,067	0.07	2,714,954.67	
364 Poles Towers & Fixtures	45,059,307	0.48	21,628,467.18	
365 Overhead Conductors and Devices	58,580,199	0.32	18,745,663.78	
366 Underground Conduit	18,971,047	0.06	1,138,262.82	
367 Underground Conductors & Devices	29,087,262	0.14	4,072,216.74	
368 Line Transformers	41,798,461	0.13	5,433,799.98	
369 Services	12,741,426	0.62	7,899,684.10	
370 Meters	13,259,006	0.14	1,856,260.77	
373 Street Lighting & Signal Systems	18,949,708	0.13	2,463,462.02	
Total Distribution Plant	281,376,222		66,721,682	
General Plant				
392.0 Transportation Equipment	10,924,780	-17%	(1,857,213)	
394 Tool, Shop & Garage Equipment	665,248	0%	-	
395 Laboratory Equipment	680,339	-9%	(61,230)	
396 Power Operated Equipment	2,194,545	-28%	(614,473)	
Total General Plant	14,464,912		(2,532,916)	
Total Electric Reserve	1,235,730,945		165,493,726	13%

Louisville Gas and Electric Company
Estimated Removal Cost in Reserve
at December 2002

Property Group	Reserve Balance 12-31-02	Salv/Dep Ratio	Estimated Removal Cost
GAS PLANT			
INTANGIBLE PLANT	574,194	0%	-
UNDERGROUND STORAGE			
350.10 LAND	2,657	0%	-
350.20 RIGHTS OF WAY	17,227	0%	-
351.20 COMPRESSOR STATION STRUCTURES	612,216	19%	113,919.54
351.30 MEAS. & REG. STATION STRUCTS.	14,190	0%	-
351.40 OTHER STRUCTURES	702,549	36%	255,063.41
352.20 RESERVOIRS	435,216	0%	(4.04)
352.30 NONRECOVERABLE NATURAL GAS	6,498,004	0%	2.79
352.40 WELL DRILLING	2,284,122	54%	1,234,368.43
352.50 WELL EQUIPMENT	2,490,213	38%	939,950.73
353.00 LINES	5,303,771	13%	713,679.40
354.00 COMPRESSOR STATION EQUIPMENT	6,416,288	0%	12.78
355.00 MEAS. & REG. EQUIPMENT	241,547	0%	22.90
356.00 PURIFICATION EQUIPMENT	3,000,444	26%	765,652.11
357.00 OTHER EQUIPMENT	188,129	0%	2.64
TOTAL UNDERGROUND	28,206,572		4,022,671
TRANSMISSION PLANT			
365.20 RIGHTS OF WAY	184,549	0%	-
367.00 MAINS	10,781,829	49%	5,238,918.44
	10,966,378		5,238,918.44
DISTRIBUTION PLANT			
374.00 Land Rights	63,454	0%	-
375.10 CITY GATE CHECK STATION STRUCTS.	84,620	43%	36,456.99
375.20 OTHER DISTRIBUTION STRUCTURES	278,034	16%	44,944.73
376.00 MAINS	72,244,897	22%	15,616,723.17
378.00 MEAS. & REG. STATION EQUIP.-GEN.	1,714,716	7%	125,687.14
379.00 MEAS. & REG. STATION EQUIP.-CITY GT	1,009,276	0%	(6.28)
380.00 SERVICES	29,680,885	54%	16,072,643.62
381.00 METERS	5,556,038	7%	397,624.24
382.00 METER INSTALLATIONS	1,395,746	12%	170,171.88
383.00 HOUSE REGULATORS	1,442,672	7%	101,570.53
384.00 HOUSE REGULATOR INSTALLATIONS	413,586	0%	0.73
385.00 IND. MEAS. REG. & STATION EQUIPMEN	92,036	0%	(10.00)
387.00 OTHER EQUIPMENT	18,779	0%	(2.03)
TOTAL DISTRIBUTION	113,994,740		32,565,805
GENERAL PLANT			
392.10 TRANSPORTATION EQUIP-TRUCKS	2,136,820.64	0%	-
392.20 TRANSPORTATION EQUIP-TRAILERS	78,755	-13%	(10,257.04)
394.10 SHOP EQUIPMENT	787,585	-19%	(149,242.27)
395.00 LABORATORY EQUIPMENT	210,471	-8%	(17,182.08)
396.20 POWER OPERATED EQUIPMENT	1,817,977	-18%	(333,709.16)
TOTAL GENERAL PLANT	5,031,609		(510,391)
TOTAL GAS PLANT	158,773,493		41,317,003

Louisville Gas and Electric Company
Estimated Removal Cost in Reserve
at December 2002

	Property Group	Reserve Balance 12-31-02	Salv/Dep Ratio	Estimated Removal Cost
	COMMON PLANT			
	GENERAL PLANT			
390.10	STRUCTS. & IMPROVES. - MISC.	14,643,039	10%	1,394,045.60
390.20	STRUCTS. & IMPROVES. - TRANSP.	582,428	10%	60,377.62
390.30	STRUCTS. & IMPROVES. - STORES	5,877,424	12%	690,342.93
390.40	STRUCTS. & IMPROVES. - OTHER	258,257	15%	39,606.55
390.60	STRUCTS. & IMPROVES. - MICROWAVE	75,498	12%	8,842.73
391.00	OFFICE EQUIPMENT - EXCL. COMPUTER	5,258,703	-4%	(190,421.33)
392.20	TRANSPORTATION EQUIP. - TRAILERS	25,213	-19%	(4,713.03)
393.00	STORES EQUIPMENT	301,474	-7%	(19,924.16)
394.20	GARAGE EQUIPMENT	399,478	12%	47,673.05
395.00	LAB EQUIPMENT	6,221	-13%	(803.81)
396.20	POWER OPERATED EQUIPMENT	266,994	-23%	(61,805.03)
397.00	COMMUNICATION EQUIPMENT	10,120,015	0%	(2.82)
398.00	MISC. EQUIPMENT	147,136	0%	-
	TOTAL DEPREC. GENERAL PLANT	37,961,880		1,963,218.31
	COMPUTER EQUIPMENT	9,559,023	0%	-
	PC EQUIPMENT	7,038,487	0%	-
389.20	LAND RIGHTS	85,682	0%	-
391.1	TRANSP. CARS & TRUCKS	495,338	0%	-
		-	0%	-
	TOTAL GENERAL PLANT	55,140,410		1,963,218
	INTANGIBLE PLANT	18,101,954	0%	-
	TOTAL COMMON PLANT IN SERVICE	73,242,364		1,963,218

Kentucky Utilities Company
Estimated Re[illegible]n Reserve
at December 2002

Property Group	Reserve Balance 12-31-02	Salv/Dep Ratio	Estimated Removal Cost	
Intangible Plant				
302 Franchises and Consents	30,161			
303 Misc Intangible Plant	9,098,856			
Total Intangible Plant	9,129,016		-	
Steam Production Plant				
Brown Unit 1	31,175,389	22%	6,858,585.60	
Brown Unit 2	25,573,077	17%	4,347,423.02	
Brown Unit 3	81,080,583	13%	10,540,475.75	
Ghent Unit 1	100,224,747	10%	10,022,474.72	
Ghent Unit 2	101,658,765	19%	19,315,165.44	
Ghent Unit 3	175,352,501	12%	21,042,300.15	
Ghent Unit 4	141,254,946	10%	14,125,494.63	
Green River Units 1&2	19,587,149	48%	9,401,831.71	
Green River Unit 3	15,954,468	39%	6,222,242.60	
Green River Unit 4	26,883,951	25%	6,720,987.87	
Pineville Unit 3	2,036,242	32%	651,597.42	
Tyrone Unit 3	25,979,979	52%	13,509,589.09	
System Laboratory	618,402	0%	-	
Pollution Control Equipment	47,474,392	10%	4,747,439.19	
Total Steam Production Plant	794,854,593		127,505,607	
Hydraulic Production Plant				
Dix Dam	7,535,236	25%	1,883,809.03	
Lock # 7	788,668	54%	425,880.79	
Total Hydraulic Production Plant	8,323,904		2,309,689.82	
Other Production Plant				
Brown 5	1,052,014	0%	-	
Brown 6	4,200,846	0%	-	
Brown 7	4,501,716	0%	-	
Brown 8	7,443,528	0%	-	
Brown 9	10,106,714	0%	-	
Brown 9 Pipeline	2,230,833	0%	-	
Brown 10	6,645,682	0%	-	
Brown 11	7,025,522	0%	-	
Haefling	4,284,007	0%	-	
Paddys 13	1,498,867	0%	-	
TC 5	613,822	0%	-	
TC 6	613,501	0%	-	
TC Pipeline	95,855	0%	-	
Total Other Production Plant	50,312,905		-	
Transmission Plant				
350.1 Land Rights	13,791,158	0%	-	
352 Structures and Improvements	3,753,177	45%	1,688,929.50	
353.1 Station Equipment	48,523,476	14%	6,793,286.66	
353.2 Syst Control/Microwave Equip	12,319,025	19%	2,340,614.82	
354 Towers & Fixtures	35,979,699	55%	19,788,834.20	
355 Poles & Fixtures	50,576,279	59%	29,840,004.41	
356 Overhead Conductors and Devices	83,709,013	53%	44,365,776.65	
357 Underground Conduit	98,612	11%	10,847.28	
358 Underground Conductors & Devices	645,771	8%	51,661.68	
Total Transmission Plant	249,396,209		104,879,955	
Distribution Plant				
360.1 Land Rights	951,241	0	-	
361 Structures and Improvements	1,196,111	0.14	167,455.57	
362 Station Equipment	24,988,144	0.13	3,248,458.72	
364 Poles Towers & Fixtures	83,400,337	0.44	36,696,148.39	
365 Overhead Conductors and Devices	86,113,585	0.46	39,612,249.22	
366 Underground Conduit	595,503	0.16	95,280.46	
367 Underground Conductors & Devices	10,039,190	0.11	1,104,310.92	
368 Line Transformers	74,145,010	0.13	9,638,851.32	
369 Services	40,675,621	0.43	17,490,516.97	
370 Meters	23,665,574	0.15	3,549,836.08	
371 Installations on Customer Premises	9,433,568	0	-	
373 Street Lighting & Signal Systems	16,473,489	0.14	2,306,288.50	
Total Distribution Plant	371,679,812		113,909,396	
General Plant				
389.1 Land Rights	154,183	0%	-	
390.1 Structures & Improvements	7,705,511	0%	-	
391.1 Office Furniture & Equipment	15,345,624	0%	-	
392.0 Transportation Equipment	20,582,770	0%	-	
393 Stores Equipment	253,419	-12%	(30,410)	
394 Tool, Shop & Garage Equipment	1,130,302	-8%	(90,424)	
395 Laboratory Equipment	1,219,542	-5%	(60,977)	
396 Power Operated Equipment	117,318	-61%	(71,564)	
397 Communication Equipment	2,718,367	0%	-	
398 Misc Equipment	258,333	0%	-	
Total General Plant	49,485,369		(253,375)	
Total Reserve	1,533,181,808		348,351,273	23%
RWIP	3476144.28			
	1,536,657,952			

Est removal cost in Reserve.xls
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