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Kansas Corporation Commission
/S/ Susan K. Duffy

BEFORE THE

STATE CORPORATION COMMISSION OF THE STATE OF KANSAS

IN THE MATTER OF A GENERAL INVESTIGATION

INTO DEPRECIATION ISSUES

DOCKET NO. 08-GIMX-1142-GIV

STATE CORPORATION COMMISSION

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Susan Talbuffy

SWORN AFFIDAVIT

OF

MICHAEL J. MAJOROS, JR.

ON BEHALF OF

CITIZENS' UTILITY RATEPAYER BOARD

DECEMBER 1, 2010

**SWORN AFFIDAVIT OF MICHAEL J. MAJOROS, JR.**

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## SWORN AFFIDAVIT OF MICHAEL J. MAJOROS, JR.

### I. INTRODUCTION

My name is Michael J. Majoros, Jr. I am vice-president of Snavely King Majoros & O'Connor, Inc. ("Snavely King"), an economic consulting firm with offices at 1111 14th Street, N.W., Suite 300, Washington, D.C. 20005. Appendix A is a brief description of my qualifications and experience. It also contains a listing of my appearances before state and federal regulatory bodies. I am submitting these comments on behalf of the Citizens' Utility Ratepayer Board ("CURB").

### II. SUBJECT OF COMMENTS

These comments address public utility depreciation. I have reviewed the Kansas Corporation Commission's ("KCC or Commission") May 26, 2010 Order, Staff's June 30, 2008, motion to open a generic investigation, the accompanying staff report ("Staff Report") and the September 24, 2010 order. The Commission determined that it will examine the appropriate methods to use, or principles to follow, in accounting for depreciation, and directs interested parties to address three designated issues and any other issues they may identify.

### III. QUALIFICATIONS

My firm specializes in public utility depreciation. Our clients have ranged from consumer organizations and utility commissions to large companies that purchase regulated utility services. We have appeared as expert witnesses on depreciation before the regulatory commissions of more than half of the states in the country. I have testified in well over 100 proceedings on the subject of public utility depreciation. I have made several appearances in Kansas stretching back into the 1980s. I have also negotiated on behalf of clients in fifteen of the Federal Communications Commission's ("FCC") triennial depreciation represcription conferences.

## IV. CURB'S OBJECTIVE

CURB and I believe the KCC must design its depreciation policy to provide full capital recovery for each Kansas utility. Consequently, all recommendations discussed herein assume full capital recovery and, if adopted, none of these recommendations will prevent full capital recovery. However, we have also designed these recommendations to prevent artificial acceleration and over-recovery of capital.

## V. SUMMARY OF ISSUES

This Affidavit addresses each of the Commission's designated issues and several other issues that warrant consideration.

A. Treatment of Non-legal Asset Retirement Obligations, such as Net Salvage Costs, in Light of FERC Order 631 (designated issue.)

B. Terminal Net Salvage in Decommissioning Generating Facilities (designated issue.)

C. Criterion for Life Span depreciation (other issue.)

D. Life expectancy of an Asset and Use of Equal Life Group (designated issue.)

E. Proper definition of *service value* (other issue.)

F. Whole Life rather than remaining life depreciation (other issue.)

G. Appropriate accounting for cost of replacements (other issue.)

## VI. UTILITY DEPRECIATION FUNDAMENTALS

Given the complexity of the subject matter, CURB provides the following discussion of depreciation fundamentals to illustrate several important points regarding the issues.

Depreciation is a Noncash Expense That Provides Capital Recovery

Ratemaking depreciation expense is a ratable annual charge (reduction) to a utility's operating income to provide recovery of the cost of its investment (capital) in plant and equipment. Investors provide the initial investment to purchase plant and equipment and ratepayers return the investment through depreciation expense. Public utility depreciation expense provides a return of capital because it provides a positive cash flow stream into the utility from its ratepayers.

Depreciation expense in contrast to a payroll expense, for example, does not involve a specific cash payment. Both depreciation and payroll are included as expenses in the income statement and cost of service, but no cash flows out of the public utility for depreciation expense. In other words, a public utility charges depreciation expense to its ratepayers and then retains the cash it collects. Instead of spending the cash, a utility records depreciation expense on its income statement as an expense and simultaneously records it on the balance sheet in the accumulated depreciation account. The utility retains or spends the cash as it sees fit.

Depreciation Warrants Careful Consideration

Depreciation is a substantial expense for public utilities because they are capital-intensive. As a result, a utility's depreciation expense request warrants a commission's careful consideration because depreciation requires a substantial amount of judgment and arcane analysis. It requires consideration of several different procedures, methods, and techniques. Because it is in a utility's best interest to maximize additional cash flow whenever possible, experienced depreciation analysts should scrutinize the utility's depreciation request closely.

Unique Factors

Several unique factors distinguish public utility depreciation rates from normal depreciation rates. Utilities own millions of individual assets that cost billions of dollars. Given this capital intensity, it is impossible to track and depreciate every single asset. As a result, public utilities utilize group depreciation, reflecting averages of asset service lives and remaining lives within specific groups. Group depreciation assumes full depreciation of retired assets, regardless of whether they are retired before or after the attainment of the estimated life.[1] Consequently, utilities charge the original cost of retired assets to accumulated depreciation as opposed to writing off the undepreciated balance in the retirement year. Utilities also charge the costs of removing or disposing of retired assets to the accumulated depreciation reserve as opposed to recognizing them as operating costs in the year incurred. Each of these factors affect the depreciation rates for a group of assets recorded in a regulated plant account, and each of these factors differ from non-regulated depreciation approaches.

Regulatory Accounting

Public utilities record their plant investment activity in the individual plant accounts set forth in the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USoA"). Additions, retirements, and balances relate to individual accounts - Structures and Improvements (account 321), for example. Assume your personal checkbook starts with a $1,000 beginning balance. An annual addition is the original cost of plant added to the account during the year, similar to a deposit to the checkbook. An annual retirement is the original cost of a prior year's addition removed from service in the current year, similar to writing a check or making a withdrawal. If we assume a $200 addition and a $100 retirement, a $1,100 ending

[1] While parties commonly assume that public utility depreciation relates to tangible asset units such as a pole, in reality public utilities depreciate dollars rather than tangible assets.

balance remains in the checkbook. The ending plant balance becomes next year's beginning plant balance and the process repeats.

**Table 1**
**Plant Account**

| | |
|---|---|
| **Beginning balance** | **$1,000** |
| **Plus addition (deposit)** | **200** |
| **Minus retirement (withdrawal)** | **(100)** |
| **Ending balance** | **$1,100** |

Annual Depreciation Expense

Public utility depreciation expense is straight-line over the service life, which means assigning an equal share of the original cost to annual depreciation expense for each year over the service life. A service life is the period of time during which depreciable plant [and equipment] is in service.[2] Assume an estimated ten-year service for transmission poles. Table 2 illustrates a straight-line whole-life depreciation rate, assuming a ten-year average service life and zero ("0")% net salvage.

**Table 2**
**Straight-line whole-life rate**
**Assuming 10-year life and 0% net salvage**

$$\frac{100\% - (0\%)}{10\ yrs.} = 10.0\%$$

A public utility calculates annual depreciation expense by multiplying its plant balance by the 10% depreciation rate. The cost of service includes the resulting depreciation expense (also called accrual), just as it includes any other expense.

[2] *Public Utility Depreciation Practices*, August, 1996. National Association of Regulatory Utility Commissioners ("NARUC Manual"), p. 321.

**Table 3**
**Annual Depreciation Expense at a 10% Rate**

| | |
|---|---|
| **Plant balance (Table 1)** | **$1,100** |
| **Times depreciation rate (Table 2)** | **x 10%** |
| **Equals depreciation expense** | **$110** |

Net Salvage

Sometimes utilities physically remove retired plant and equipment and resell it for value. For example, if a utility reduces a retired transmission pole to wood chips and sells the chips, the value received for the wood chips would constitute "gross salvage."[3] The expenses incurred in removing the pole from the ground and running it through a chipper would constitute the "cost of removal."[4] Net salvage is the difference between gross salvage and cost of removal.[5]

One of the KCC's designated issues in this proceeding is negative net salvage. The term "negative net salvage" merely indicates that the cost of removal exceeds the asset's gross salvage or, in other words, it cost more to remove the asset from service than the asset was worth when resold or reused. For the remainder of this Affidavit, the terms negative net salvage and cost of removal are synonymous.

Negative Net Salvage Increases A Depreciation Rate

Assume the utility initially estimates that in ten years, the cost to remove and chip a pole will far exceed the value of the wood chips. It estimates that the net cost of removal will be 50 % of the original pole cost. The initial depreciation rate with a negative 50% net salvage rate would be 15.0% as shown in Table 4:

[3] In more technical terms, gross salvage is the amount recorded due to the sale, reimbursement, or reuse of retired property. NARUC Manual, p. 320.
[4] Cost of removal is the cost incurred in connection with the retirement from service and the disposition of depreciable plant. NARUC Manual, p. 317.
[5] Net salvage is the gross salvage for the property retired less its cost of removal. NARUC Manual, p. 322.

**Table 4**
**Straight-Line Whole-Life Rate**
**Assuming 10-Year Life and -50% Net Salvage**

$$\frac{100\% - (-50\%)}{10\ yrs.} = 15.0\%$$

Negative net salvage increases the resulting whole-life depreciation rate from 10.0% to 15.0% because the equation adds 50% to the original cost of transmission poles. Instead of 100% (which represents the original cost of assets), the numerator becomes 150% (100% - (-50%) = 150.0%). The total life time depreciation expense is 150% of its original cost rather than 100% of its original cost.

Accumulated Depreciation Account ("Reserve")

Accumulated depreciation (sometimes called reserve) is a record of the previously-recorded depreciation expense less retirements and net salvage. At any point in time, the accumulated depreciation account represents the net accumulated amount of the original cost of assets and net salvage that a utility has recovered through regulated depreciation rates. It is a measure of the depreciation recovered from ratepayers.

**Table 5**
**Accumulated Depreciation**

| | |
|---|---|
| **Beginning balance** | **$500** |
| **Plus depreciation expense** | **110** |
| **Ending balance** | **$610** |

The Remaining Life Technique

The remaining life technique is similar to the whole-life technique, but it incorporates accumulated depreciation into the numerator of the equation, and the denominator becomes the remaining service life rather than the complete service life. "If transmission poles" had a ten year life and the account is now three years old; it has a seven-year remaining life.

**Table 6**
**Remaining Life Assuming Poles are 3-Years Old**

| | | |
|---|---|---|
| **Life** | **10** | **years** |
| **Less age** | **(3)** | **years** |
| **Equals remaining life** | **7** | **years** |

At the 15% rate from Table 4, the accumulated depreciation account should be 45.0% of its original cost after three years (3 x 15.0% = 45.0%).[6] The remaining life rate would still be 15.0%:

**Table 7**
**Straight-line remaining life rate**
**Assuming 10-year life, 7-year remaining life**
**And -50% net salvage**

$$\frac{100\% - (-50\%) - 45.0\%}{7\ yrs.} = 15.0\%$$

Theoretical Reserves

The 15.0% remaining life depreciation rate and the original 15.0% whole-life depreciation rate are the same because I have assumed that the accumulated depreciation account is in balance. The utility has collected 45%, which is the correct amount assuming a continuation of the initial assumptions. The 45% book reserve and the 45% "theoretical" reserve are the same – they are in balance.

If either the ten-year service life or negative 50% net salvage estimates were to change, the accumulated depreciation account will be out-of-balance because the utility will have collected either too much or not enough depreciation given the revised estimates. The book reserve will be either higher or lower than the theoretical reserve, and in those circumstances the

[6] The result of the calculation I just described is a simplified version of the "theoretical reserve" because it reflects what should be in the book reserve based on current parameter estimates.

remaining life rate will be either higher or lower than the whole-life rate, depending on the direction of the imbalance.

Understated Service Lives Produce Overstated Depreciation Rates

It is axiomatic that the shorter the life, the higher the depreciation rate. For example, an item with a 30-year life requires a 3.3 percent depreciation rate. If a utility uses a ten year life instead of 30 years, the depreciation rate will be 10% rather than 3.33%. The understated ten-year life produces an overstated 10 % depreciation rate.

**Table 8**
**Impact of understated life estimate**

**Correct - 30-year life = 100%/30 = 3.3%**

**Incorrect - 10-year life = 100%/10 = 10.0%**

Excessive Negative Net Salvage Estimates Produce Overstated Depreciation Rates

Overstated negative net salvage ratios also produce overstated depreciation rates. Assume that the original negative 50% estimate should have been negative 5% instead. The next table shows the impact of an excessive cost of removal ratio:

**Table 9**
**Impact of increasing cost of removal ratio from -5% to -50%**

**Correct - 10-year life, -5% NS =100%-(-5%)/10 = 10.5%**

**Incorrect - 10-year life, -5% NS =100%-(-50%)/10 = 15.0%**

The excessive negative 50% cost of removal ratio increased the depreciation rate from 10.5% to 15.0%.

Excessive Depreciation Reserve

A combination of understated lives and overstated cost of removal ratios compounds the excessive depreciation rates. For example, the initial depreciation rate with the correct estimates (30-year life and negative 5% net salvage) should have been 3.5% rather than 15%.

**Table 10**
**Correct Depreciation Rate**

**100%-(-5%)/30 = 3.5%**

At age three, the accumulated depreciation should be 10.5% (3 x 3.5% = 10.5%), but the incorrect ten-year life and negative 50% net salvage resulted in a 45.0% accumulated depreciation balance containing a 34.5% reserve excess (45.0% – 10.5% = 34.5% reserve excess.)

**Table 11**
**Depreciation Reserve Excess**

| | |
|---|---|
| **Book Reserve** | **45.0%** |
| **Theoretical Reserve** | **10.5%** |
| **Reserve Excess** | **34.5%** |

U.S. Supreme Court's Interpretation of Excessive Depreciation

Overstated depreciation rates produce more depreciation expense than necessary to return a company's capital investment over its service life. Excessive depreciation rates result in excessive depreciation reserves. Since depreciation expense flows dollar-for-dollar into cost of service, excessive depreciation expense results in excessive charges to ratepayers.

The U.S. Supreme Court explained excessive depreciation in a landmark 1934 decision, *Lindheimer v. Illinois Bell Telephone Company*:

> If the predictions of service life were entirely accurate and retirements were made when and as these predictions were

> precisely fulfilled, the depreciation reserve would represent the consumption of capital, on a cost basis, according to the method which spreads that loss over the respective service periods. But if the amounts charged to operating expenses and credited to the account for depreciation reserve are excessive, to that extent subscribers for the telephone service are required to provide, in effect, capital contributions, not to make good losses incurred by the utility in the service rendered and thus to keep its investment unimpaired, but to secure additional plant and equipment upon which the utility expects a return.
>
> Confiscation being the issue, the company has the burden of making a convincing showing that the amounts it has charged to operating expenses for depreciation have not been excessive. That burden is not sustained by proof that its general accounting system has been correct. The calculations are mathematical, but the predictions underlying them are essentially matters of opinion. They proceed from studies of the behavior of large groups of items. These studies are beset with a host of perplexing problems. Their determination involves the examination of many variable elements and opportunities for excessive allowances, even under a correct system of accounting, [are] always present. The necessity of checking the results is not questioned. The predictions must meet the controlling test of experience.[7]

Thus, as far back as 1934, the U.S. Supreme Court recognized that excessive depreciation rates extract capital contributions from ratepayers. Where confiscation is the issue, the company has the burden of proving that the amounts it has charged for depreciation have not been excessive.

## VII. DISCUSSION OF SPECIFIC ISSUES

### Issue A. Treatment of Non-legal Asset Retirement Obligations, such as Net Salvage Costs, in Light of FERC Order 631 (designated issue.)

Background of FERC Order 631

[7] *Lindheimer v. Illinois Bell Tel. Co.*, 292 U.S. 151, 168-170 (1934) (emphasis added; citation omitted).

In 1994, as a result of a request by the Edison Electric Institute, the Financial Accounting Standards Board ("FASB") issued an Exposure Draft that eventually led to its June 2001 Statement of Financial Accounting Standards No. 143 - Accounting for Asset Retirement Obligations ("SFAS No. 143"). FERC established Docket No.RM02-7-000 as a result of SFAS No. 143. The FERC proceeding included a Technical Conference, Comments, a Notice of Proposed Rulemaking ("NOPR"), Additional Comments and ultimately, Order No. 631, on April 9, 2003. Order No. 631 essentially adopted SFAS No. 143, with one major difference, and then integrated it into the USoA.

Order No. 631 obligates electric utilities to review their long-lived assets to determine if they have any Asset Retirement Obligations ("ARO"). AROs are legal obligations to remove or dismantle plant upon its retirement. For example, decommissioning obligations under federal law relating to nuclear power plants are "legal AROs." Utilities must capitalize the present value of any asset retirement costs ("ARC") relating to these legal AROs as a component of the asset's total original cost.

FERC Order No. 631 defines ARCs for which there is no legal ARO, as "non-legal retirement obligations (*i.e.* 'non-legal AROs')." Non-legal AROs and negative net salvage are the same thing. In other words, non-legal AROs increase depreciation rates for the same reason that negative net salvage increases depreciation rates.

<u>Accounting Aspects of FERC Order 631</u>

Paragraph B.73 of SFAS No. 143 is where GAAP and Order No. 631 diverge. SFAS No. 143 requires utilities that have collected net salvage relating to non-legal AROs to take them out of accumulated depreciation and report them as regulatory liabilities. FERC Order No. 631 allows utilities to collect and retain recoveries of non-legal AROs in their accumulated depreciation accounts. The policy question for the Kansas Commission is whether to follow GAAP and require regulatory liability treatment or continue to allow utilities to include the non-legal ARO recoveries in accumulated depreciation.

FERC explains its new requirements for non-legal AROs, as follows:

> Instead, [of requiring utilities to charge non-legal AROs to expense when incurred] 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.[8]
>
> Jurisdictional entities must identify and quantify in separate subsidiary records the amounts, if any, of previous and current 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.[9]

FERC's Order 631 does not require anything new or more with respect to its requirement for detailed depreciation studies. FERC states:

[8] FERC Docket No. RM02-7-000, Order No. 631, April 9, 2003, para. 38 (emphasis added).
[9] *Id.*, para. 39 (emphasis added).

> 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 of removal, and salvage estimates in rates.[45]. [10]

And footnote 45 states:

> 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.[11]

FERC declines to make policy judgment calls regarding the appropriate treatment of the disposition of prior and future collections contained in these separate allowances. FERC decided to resolve the appropriate treatment of the dispositions of prior and future collections on a case-by-case basis. Specifically, FERC states:

> 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; these 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.[12]

CURB and I are concerned that the value of any cost of removal regulatory liability may be lost to ratepayers. When fully regulated, the telecom industry collected substantial amounts of non-

[10] *Id.*, para 65 (emphasis added).
[11] *Id.*, Footnote 45.

[12] *Id.*, para. 64 (emphasis added).

legal AROs. Once deregulated, instead of recording those excess collections as regulatory liabilities to ratepayers, the telecom industry recorded one-time gains in massive amounts. For example, Southern Bell Company's ("SBC") 2002 Securities and Exchange Commission Form 10-K stated:

> Therefore, in connection with the adoption of SFAS 143 on January 1, 2003, we will reverse existing accrued costs of removal to the extent that it exceeds the estimated salvage value for those plant accounts. The noncash gain resulting from adoption will be recorded as a cumulative effect of accounting change on the income statements as of January 1, 2003. We currently estimate that the noncash gain will be approximately [$4 billion to $6 billion], before deferred income taxes.
>
> Beginning in 2003, for those plant accounts where our estimated cost of removal previously exceeded the estimated salvage value, we will now expense costs of removal only as we incur them (previously those costs had been recorded in depreciation rates.)[13]

SBC, and all of the other Regional Bell Operating Companies ("RBOCs"), recorded noncash gains because they had already collected the cash from their ratepayers in the past. Once deregulated, they took those collections into income rather than retain them in accumulated depreciation. And, at the same time, they reduced their depreciation rates. The RBOCs won (and the ratepayers lost) billions of dollars as a result of negative net salvage ratios bundled in excessive depreciation rates.

International Financial Reporting Standards Place the Regulatory Liability at Risk

The Securities and Exchange Commission ("SEC") is moving towards International Financial Reporting Standards ("IFRS") in place of GAAP. The impending move from GAAP to IFRS puts the regulatory liability at great risk. As demonstrated above, any time a price-

[13] SBC December 31, 2002 Form 10-K, available at: HTTP://WWW.SEC.GOV/ARCHIVES/EDGAR/DATA/732717/000073271703000210/EXHIBIT13.HTM, last checked June 30, 2010.

regulated company moves away from rate base regulation, its regulatory liabilities are at risk. Attachment 1 contains two recent articles from the *Public Utilities Fortnightly*.[14] In a November 2008 article, John Ferguson proposed that when public utilities move to the new IFRS accounting standards, they should transfer the regulatory liabilities to their equity accounts. In a June 2009 article, Scott Hartman from the accounting firm of Ernst & Young makes the same argument. As originally contemplated, the initial adoption of IFRS would have sanctioned this treatment, i.e. transferred the entire regulatory liability into the utilities' equity accounts. Just as with the telephone industry, the utilities' obligation to ratepayers will flow to their bottom lines and never returned to ratepayers, even if the utilities do not incur one penny of future cost of removal.

On July 23, 2009, the International Accounting Standards Board ("IASB") published for public comment an "Exposure Draft on Rate-Regulated Activities." This Exposure Draft would require utilities to report legal and non-legal ARO liabilities "at the expected present value of the cash flows to be recovered or refunded as a result of regulation, both on initial recognition and at the end of each subsequent reporting period"[15] and to take into income all amounts collected above those present values. Since these non-legal AROs are associated with long-lived assets, a reduction to net present value would cause almost all of the excess above the present value to flow into income. Once a utility takes that money into income, there may no longer be any remedy for ratepayers. The utility will consider any regulatory attempt in the future to recover

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14 *See* John Ferguson, "Fixing Depreciation Accounting", Public Utility Fortnightly, October 2008, pp. 16-20, provided as Exhibit No. MSR-23. *See also,* Scott Hartman, "Ready for IFRS?", Public Utility Fortnightly, January 2009, pp. 10-16, provided as Exhibit No. MSR-24.

15 IASB July 2009 Exposure Draft – Rate-regulated Activities, p. 9.

the money, whether through depreciation or otherwise, as a "taking" of property or "confiscation of capital."

On April 16, 2009 the FERC's Chief Accountant, Scott P. Molony, sent a letter to the Secretary of the Securities and Exchange Commission ("SEC") regarding the switch to IFRS. Attachment 2 is a copy of the letter. Mr. Molony stated that:

> Most of the entities under FERC's jurisdiction file financial information with FERC prepared in accordance with U.S. Generally Accepted Accounting Principles (GAAP) with certain departures to recognize the economic effects of regulation. Therefore, the SEC's proposal regarding the adoption of International Financial Reporting Standards (IFRS) will have a significant impact on energy companies regulated by this agency.

Mr. Molony's letter also discusses SFAS No. 71, which is the current GAAP standard addressing regulatory assets and liabilities. Mr. Molony urged the IASB to adopt for IFRS an accounting standard similar to SFAS No. 71. Mr. Molony discusses the types of differences that lead to regulatory assets and liabilities and states, "Such differences have not typically resulted in conflicts between FERC and SEC reporting in the past in part because of the existence of SFAS No. 71 ..."

The problem is that conflicts do exist between FERC and SEC reporting requirements. SFAS No. 143 is GAAP, and it requires that entities under FERC's jurisdiction report non-legal AROs as regulatory liabilities. The SEC has also specifically recognized this requirement and requires such reporting in annual Forms 10K and other reports to the SEC. The magnitude of the accumulated regulatory liability clearly reflects the conflict between FERC and SEC reporting. FERC specifically created the conflict in its Docket No. RM02-7-000. In that proceeding, FERC staff initially intended to require that entities under FERC's jurisdiction follow the GAAP reporting for non-legal AROs. However, as a result of industry input, the Commission did not require utilities subject to its jurisdiction to report the regulatory liabilities.

Instead, FERC left these amounts in accumulated depreciation, thus creating a major accounting conflict. As explained in the fundamentals section above, utilities consider accumulated depreciation to represent capital recovery from ratepayers. In short, utilities consider accumulated depreciation as "their" money. It is their money to the extent it represents a return of their actual investment in plant and equipment. But the unspent portion of prior depreciation collections for future cost of removal is not their money, it is ratepayer money; and it is a lot of money. That is why utilities resist recognition of the regulatory liability.

The Public Utilities Fortnightly issued a survey titled "The 40 Best Energy Companies."[16] In Attachment 3, I used the same 40 energy companies to determine the extent of the SFAS No. 143 cost of removal regulatory liability problem. As of December 31, 2007, the total amount of the regulatory liabilities was $18.4 billion. The Total had increased to $19.2 billion at the end of 2008 and to $19.5 billion in 2009. This is significant because these 40 energy companies view this $19.5 billion as a potential windfall that they can later transfer into their equity accounts if reporting requirements are relaxed. That is why it is so important for regulators to protect the money as regulatory liabilities on behalf of ratepayers. Otherwise, these companies will transfer the money to net income, and ratepayers will lose it forever.

If a utility reclassifies the cost of removal reserve from Account 208 - Accumulated Depreciation to Account 254 - Other Regulatory Liabilities, ratepayers will receive the benefit of their prior contributions in the form of a slower-growing rate base, because the allocated cost of removal will reduce the cost of removal reserve (increase rate base) dollar-for-dollar. The

[16] Public Utilities Fortnightly, September 2009, page 37.

reclassification will not affect rate base because the regulatory liability will continue to be a rate base deduction.

Concomitant with the utilities' reclassification of the cost of removal component of accumulated depreciation to the regulatory liability account, the Commission should evaluate several options to provide transparency and to ensure that utilities use the funds they collect for cost of removal for this intended purpose. The options include: the creation of an independent, external trust fund; surety bond; insurance policy; letter of credit; guarantee; or some other method.[17] Other options the Commission should consider include directly returning the funds to ratepayers or reducing their rate burden by using the funds as a rate base offset for specific incremental projects such as Smart Grid or environmental projects with the use of contributions-in aid-of-construction.

The FASB and the FERC recognize that non-legal cost of removal allowances must be segregated and unbundled from depreciation rates. Regardless of how the level of the allowance, if any, is determined, it most certainly must be separated from, rather than bundled and included in, depreciation expense. This change is necessary to comply with FASB principles and FERC regulations and to protect ratepayer-contributed funds for current and future ratepayers.

<u>Depreciation Rate Aspects of FERC Order 631</u>

Again, the KCC is faced with key policy questions: should it allow utilities to recover Non-legal AROs in depreciation rates, and if so should it require the utilities to measure the Non-legal AROs at their present or inflated values? If the KCC does not allow utilities to recover Non-legal AROs in depreciation rates, how will utilities recover the costs?

[17] Order No. 631-A at P 13, Docket No. RM02-7-000 (2003).

The KCC should not allow utilities to recover non-legal AROs in depreciation rates. If a utility incurs these costs in connection with a retirement of an asset that it does not replace, the utility should record the costs as operating and maintenance expenses in the year incurred. That is how GAAP, the SEC and the IRS treat such costs. If a utility incurs such costs in conjunction with a replacement of an asset, the utility can also capitalize the cost as a component of the new replacement asset in conformance with Instruction 10 to the USoA.

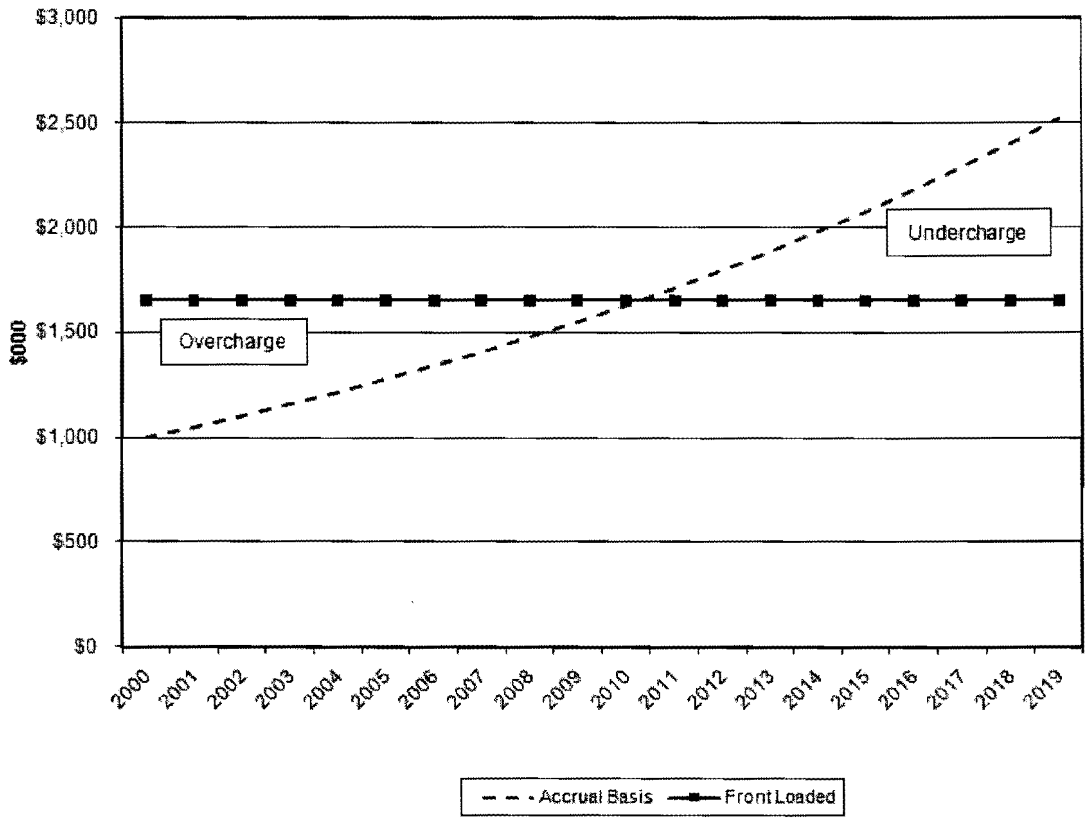
If the KCC decides to allow utilities to recover Non-legal AROs in depreciation rates, it should require utilities to measure the estimated amounts at their net present values at the time of the depreciation study, because utilities are required to keep their accounts on an accrual basis.[18] Accrual accounting matches revenues to the period earned, and it matches expenses to the periods when the expenses are incurred. Many utilities measure non-legal AROs at their future inflated values. This approach front loads future inflation expense to current ratepayers before the utility actually incurs the cost. It results in a huge intergenerational *inequity* which is quantified in the massive regulatory liabilities discussed above. This is an amount charged to past and current ratepayers for cost which has not been incurred. Accrual accounting and intergenerational equity require the matching of costs to the periods incurred.

A present value approach avoids this mismatch and is consistent with accrual accounting. A present value approach matches future inflation expense to the future periods incurred. Table 12 compares the pattern of matching future inflation to the years incurred (represented by the dotted line) versus the front-loading approach (represented by the solid line.) The graph demonstrates that the front loading overcharge, caused by the accounting mismatch of future inflation to the periods incurred, comes at the expense of current ratepayers.

[18] USoA General Instruction 11.

**TABLE 12**

**Comparison of Inflation Expense Patterns**




### Issue B. Terminal Net Salvage in Decommissioning Generating Facilities (designated issue.)

There are two basic life study approaches: the life span approach and the actuarial/semi-actuarial approach. The life span approach assumes that all plant within a property group will retire concurrently a specific number of years after the initial placement. Although there may be interim additions and retirements, the approach assumes all remaining plant is subject to a co-terminus "final retirement."

Rightly or wrongly, utilities typically use the life span method for large structure accounts and units – a complete power plant for example. I say rightly or wrongly because, as I will discuss later, the NARUC Depreciation Practices Manual identified strict requirements for the life span method. Many utilities do not meet those requirements.

Nevertheless, the life span method is used, and the Commission designated "Terminal Net Salvage in Decommissioning Studies" as an issue. The terminal net salvage concept presupposes the use of the life span method. A coal plant decommissioning cost estimate is the same as a nuclear plant decommissioning estimate, except that different types of decommissioning activities and costs are involved and there are very stringent rules and laws relating to nuclear decommissioning. Generally, there are no specific rules and laws relating to decommissioning a coal plant.

In fact, a utility has a legal ARO for a nuclear plant and, if anything, a non-legal ARO for a coal plant. Many utilities complicate the issue by attempting to inflate their non-legal decommissioning cost estimates and then use the inflated amount to calculate depreciation rates. This front-loads recovery of those costs to current ratepayers and creates an intergenerational inequity. Table 12 demonstrates this front-loading.

The appropriate treatment for legal AROs is to estimate the future cost, recognizing future inflation, but reduce that amount to its present value to calculate an annual charge. Many utilities want to treat coal plants as if they had legal AROs, but then only use the inflated cost rather than the present cost to calculate depreciation rates. In fact, in KCC Docket 05-WSEE-981-RTS, Westar filed a depreciation study seeking to include inflated terminal net salvage estimates for decommissioning its generating facilities depreciation rates. The issue was reviewed by the Kansas Court of Appeals.[19]

The Court found that in order to include terminal net salvage in depreciation rates

[19] Kansas Industrial Consumers Group, Inc. v. Kansas Corporation Comm'n, 36 Kan App 2d 83.

charged to ratepayers "there must be *some evidence* that the utility has a reasonable and detailed plan to actually dismantle a generating facility upon retirement."[20] The Court also rejected the inclusion of future inflation in such estimates, citing the fact that such a practice would represent "a departure from prior policy without an explanation by the Commission for doing so" and …" and "there was no evidence before the Commission to support the adoption of the inflation adjustment in calculating depreciation costs."[21] The Court said, "Determining an appropriate depreciation expense is a complex issue in any rate case and inherently involves 'speculation' to the degree it requires projection of future events. However, the need to project future events is not license for the Commission to engage in unchecked speculation. The effect of the Commission's order turns on its head the general principle that changes in rates due to future or non-test year events be, at least to some degree, known and measurable."[22] On remand, the commission approved depreciation rates for Westar that had all terminal net salvage removed.[23]

If the KCC approves the life span method for a particular utility and the utility also seeks recovery of terminal decommissioning costs, the KCC should require the utility to establish a legal ARO under the principle of promissory estoppel, and then follow USoA rules for legal AROs. The utility must promise to the Commission, its ratepayers and the world in an open forum that it will dismantle its production plans when they are retired, thus creating a legal obligation to incur those costs. In no case, however, should the KCC allow a utility to use an inflated decommissioning estimate without reducing it to its present value, because that would be

[20] *Id.*, at 109.

[21] *Id.*, at 109-10.

[22] *Id.*, at 110.

[23] Order, July 31, 2007, KCC Docket No. 05-WSEE-981-RTS, at 3-4.

inconsistent with accrual accounting and produce a mismatch of inflation expense to the periods incurred. This would penalize current ratepayers as discussed above.

**Issue C. Criterion for Life Span Depreciation**

The NARUC Manual states: "For life span groups there may be interim additions and retirements; however, all plant will be subject to a final retirement year.[24] Appropriate estimates must be made for such interim retirements; however, interim additions are not considered in the depreciation base or rate until they occur."[25] The Manual goes on to state:

> As indicated in the above discussion, the final retirement date is the most important factor in the determination of a depreciation rate for life span properties. Therefore, an informed estimate of the final retirement date is essential to ensure adequate recognition of depreciation over the life of the property. Several factors are considered in selecting retirement dates, *e.g.*, economic studies, retirement plans, forecasts, technological obsolescence, adequacy of capacity and competitive pressure.
>
> Retirement plans for utility properties are supported by various kinds of studies, including economic analyses. It is critical that vital information be considered; otherwise the study is analogous to a building which is structurally well built from the ground up but lacking in a sound and proper foundation. Retirement decisions should be based on sound engineering and economic principles and practices so that management may be confident that the planned retirement of existing plant and approval of new investment are the most economical actions.[26]

Therefore, the KCC should require any utility proposing to use the life span method to calculate depreciation rates to meet the criteria for its use as described in the 1996 NARUC Depreciation Practices Manual.

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[24] NARUC Manual, page 141.
[25] *Id.*, page 142.

[26] *Id.*, page 146.

**Issue D. Life expectancy of an Asset and Use of Equal Life Group (designated issue.)**

The equal life group procedure ("ELG") is a weighting technique applied to surviving vintage plant balances to calculate an account's average life and average remaining life. Kansas utilities have not used ELG in the past. CURB recommends that the KCC retain the existing average life group ("ALG") procedure, but if the KCC approves ELG, it should only be used on a going-forward basis.

Most if not all of the utilities in Kansas use the average life group procedure ("ALG"), also called the average service life ("ASL") procedure, as opposed to the ELG procedure to calculate depreciation rates. To understand the issue, I will explain a few group life concepts. A "vintage" is the total of the additions to a depreciable account in a single year. For example, everything added to the Poles account in 2009 is the 2009 vintage. Actuarial and semi-actuarial life studies typically start with "vintage" activity.

Actuarial analysis

The retirement rate method is an actuarial technique used to study plant lives, much like the actuarial techniques used in the insurance industry to study human lives. It requires a record of the dates of placement (birth) and retirement (death) for each asset unit studied. It is the most sophisticated of the statistical life analysis methods because it relies on the most refined level of data. Aged retirements and exposures data from a company's records are used to construct an observed life table ("OLT"). Importantly, the OLT represents the life of a single average vintage. The analysis smoothes and extends the OLT by fitting a family of 31 standardized survivor curves ("Iowa Curves"). The approach uses the least squared differences approach to find a best fit life for each curve. Numerous interactive calculations are required for a retirement rate analysis. In the end, the analysis produces a life and Iowa curve best fit for a single average vintage.

Iowa Curves

An Iowa curve is a surrogate or standardized OLT based on a specific pattern of retirements around an average service life. The Iowa curves were devised over 60 years ago at Iowa State University. The curves provide a set of standard patterns of retirement dispersion. Retirement dispersion merely recognizes that accounts are comprised of individual assets or units having different lives. Retirement dispersion is the scattering of retirements by age for the individual assets around the average service life for the entire group assets. If one thinks in terms of a "bell shaped" curve, dispersion represents the scattering of events around the average.

There are left-skewed, symmetrical and right-skewed curves known, respectively, as the "L curves," "S curves" and "R curves."[27] A number identifies the range of dispersion. A low number represents a wide pattern and high number a narrow pattern. The combination of one letter and one number defines a dispersion pattern. The combination of an average service life with an Iowa curve provides a survivor curve depicting how a group of assets will survive, or conversely be retired, over the average service life.

The following table contains a 5S0 and 10S0 life and curve. I have included these two combinations to demonstrate different iterations with the same curve. The percent surviving represents the amount surviving at each age interval shown in the first column. The 5S0 life and curve sums to the five-year average service life, while the 10S0 life and curve sums to a ten-year average service life.

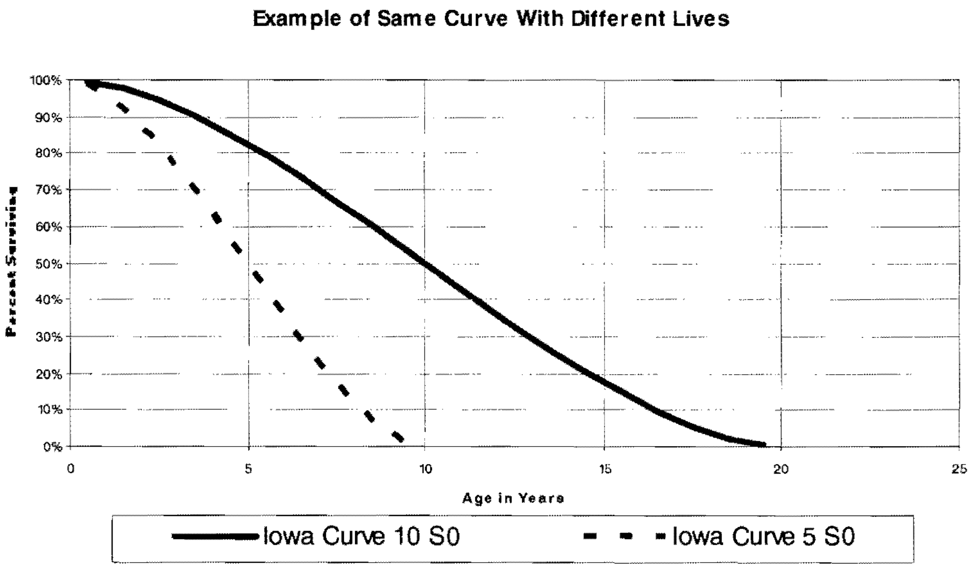
[27] There is also a set of Origin Modal ("O") curves which are essentially negative exponential curves.

## Table 13
## Survivor Curves

| | 5 S0 CURVE | 10 S0 CURVE |
|---|---|---|
| **AGE** | **PERCENT SURVIVING** | **PERCENT SURVIVING** |
| 0.5 | 0.99 | 1.00 |
| 1.5 | 0.92 | 0.98 |
| 2.5 | 0.83 | 0.94 |
| 3.5 | 0.70 | 0.90 |
| 4.5 | 0.57 | 0.85 |
| 5.5 | 0.43 | 0.80 |
| 6.5 | 0.30 | 0.74 |
| 7.5 | 0.17 | 0.67 |
| 8.5 | 0.08 | 0.60 |
| 9.5 | 0.01 | 0.53 |
| 10.5 | | 0.47 |
| 11.5 | | 0.40 |
| 12.5 | | 0.33 |
| 13.5 | | 0.26 |
| 14.5 | | 0.20 |
| 15.5 | | 0.15 |
| 16.5 | | 0.10 |
| 17.5 | | 0.06 |
| 18.5 | | 0.02 |
| 19.5 | | 0.00 |
| **TOTAL** | **5.00** | **10.00** |

These are called "curves" because when plotted on charts with the x-axis representing "age" and the y-axis representing "percent surviving" they appear as shown below:

**Table 14**




Average Life Group Procedure

The ALG procedure develops a single average depreciation rate applied without change over the entire life of an average vintage. For example, assume the average service life for an average vintage of Poles is thirty years. The ALG depreciation rate is 3.33 percent (1/30) designed to recover the entire vintage, i.e., those retired prior to the attainment of the thirty-year average service life, as well as those in service beyond the thirty-year average service life. ALG assumes that that over-recovery of assets retired beyond the average service life of the vintage will offset under-recovery of assets retired before the average service life of the vintage.

Equal Life Group Procedure

The ELG procedure is a more precise application of the same life and retirement pattern assumed in the ALG procedure. The ELG procedure statistically disaggregates the anticipated retirements within the average vintage, and then establishes a separate individual depreciation rate for each of the assets within the average vintage. The practical effect of this disaggregation is higher depreciation rates. In my opinion, ELG is more susceptible to error than ALG. First, ELG requires annual depreciation rate changes, whereas ALG does not. Furthermore, ELG is more susceptible to errors resulting from forecasting inaccuracies because of its greater precision.

Pros and Cons of ELG and ALG

From a theoretical standpoint, ELG has the benefit of producing a more precise cost allocation, assuming perfect foresight. ELG requires annual depreciation rate changes and produces a precise (but wrong) answer as a result of forecasting inaccuracies. On the other hand, ALG has the benefit of a constant depreciation rate, and also in my opinion, a higher probability of producing a correct overall result notwithstanding forecasting inaccuracies. There is no downside risk to the use of ALG, whereas ELG presents significant downside risk because it compounds the effect of an incorrect life and dispersion pattern. Given that the effect of ELG is higher depreciation rates, all of the downside risk is borne by ratepayers.

USoA Does Not Require ELG and it is Not Necessary

The USoA does not mention ELG; and ELG is not required to provide full capital recovery. Both ALG and ELG assume full capital recovery. This Commission must decide, therefore, whether the benefits of ELG are sufficient to adopt its use. From a theoretical standpoint, ELG has some merit, but so does ALG. From a practical standpoint, ELG will produce a significant depreciation expense increase, merely from the adoption and retroactive application of an unnecessary procedure change.

ELG Should Only be Initiated on a Prospective Basis.

The phrase "life expectancy" in the initial designated issue appears to contemplate a continuation of the remaining life technique. Under those circumstances, retroactive application of ELG would cause an abrupt and unnecessary increase to depreciation expense. The fact that Kansas utilities have never used ELG in the past would cause the abrupt increase. Had Kansas utilities always used ELG, their recorded book reserves would now be substantially higher as a result of higher depreciation rates in the past. That is because ELG produces a pattern of depreciation rates very similar in appearance to accelerated depreciation (sum-of-the-years-digits or double-declining balance, for example). Kansas utilities' reserve levels are lower than they would have been had they always used ELG. The depreciation reserve level is a critical element in the calculation of remaining life rate; the lower the reserve, the higher the depreciation rate.

Retroactive application of ELG to all prior vintages produces a composite remaining life for those vintages which is inconsistent with past ALG depreciation rates and therefore inconsistent with the utilities' current book depreciation reserve levels. The practical consequence is that retroactive application of ELG creates a significant but fictitious depreciation reserve deficiency. Once a fictitious reserve deficiency is created, the remaining life technique accelerates amortization of the reserve deficiency.

Correct Application of ELG

The most well-known application of the ELG procedure was in the telecommunications industry. Many companies regulated by the FCC made similar proposals for retroactive application of ELG. All were summarily rejected because the FCC recognized the reserve level mismatches that I described above. The FCC recognized that a switch to the use of ELG creates a sharp increase to depreciation expense, which the reserve mismatches aggravate. Consequently, the FCC's initial approach to ELG implementation was to allow it only on a going-forward vintage basis and furthermore required a phase-in by groups of accounts over several years. At one point, the FCC was allowing implementation of ELG by applying it to one-half of the gross additions for the year immediately following the study date. For example, if a study was dated December 31, 1990, ELG would be allowed on one-half of the estimated 1991 additions. Due to its specious precision, the FCC abandoned that practice and any carrier subsequently applying for ELG would not see its effects until its study actually contained ELG vintages. For example, if ELG was approved as a result of a 1990 study, the first ELG vintage would be 1991. The company would receive the benefit either in its next regularly scheduled depreciation study or in a technical update.

If the KCC approves ELG, I recommend that it not be applied retroactively. If ELG is approved, I recommend that the FCC's approach be adopted, i.e., the first ELG vintage would be 2010 or 2011 for the purposes of the next depreciation study. Otherwise, the Commission must abandon the remaining-life technique. That is because the ELG remaining life for prior vintages will be inconsistent with the Commission-approved ALG procedure previously applied to those vintages. The remaining life technique will increase depreciation expense unnecessarily. I also recommend that the Commission require utilities to file depreciation studies every three (3) years to ensure proper management of the ELG rates.

**Issue E. Proper definition of *service value* (other issue.)**

The FERC USoA defines depreciation as follows:

> *Depreciation,* as applied to depreciable electric plant, means the <u>*loss in service value*</u> not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.

It goes on to define "service value" as:

> *Service value* means the difference between original cost and net salvage value of electric plant.

Utilities interpret these definitions as requiring them to use the future inflated value of Non-legal AROs to calculate depreciation rates. The practice in turn leads to excessive depreciation rates and reserve. The KCC must define service value to reflect the net present value of cost of removal, and not the future inflated value.

KCC definition of service value should be:

> "Service value" means the difference between original cost and future gross salvage value minus the present value of cost of removal of electric plant.

**Issue F. Whole Life rather than remaining life depreciation (other issue.)**

As demonstrated in the fundamentals section above, a whole-life depreciation rate is the reciprocal of the average service life for a plant account. A remaining life rate is the net plant (gross plant minus accumulated depreciation) divided by the <u>remaining</u> life, rather than the whole life of the account. The remaining life technique is a mechanism to account for imbalances in the accumulated depreciation account resulting from changes to service life and net salvage estimates. In theory, a whole-life rate and remaining-life rate are the same if there is no reserve imbalance. On the other hand, if a reserve imbalance exists, the remaining-life rate will be either higher or lower than the whole-life rate depending on the direction of the imbalance.

Whole-life depreciation is superior to remaining-life depreciation for new additions to plant. While a remaining-life rate may be adequate for existing plant, it is inappropriate for new additions because it will create even more imbalances on a going-forward basis. A whole-life rate is appropriate for both existing plant and new additions to plant. If the new rates are remaining-life rates, the only thing we know for sure is that they are the wrong rates for new plant additions.

For example, a utility initially estimates that a $1,000 asset will have a twenty-year life, and therefore depreciates the asset using a 5% depreciation rate (1/20 years = 5.0%). After ten years, the accumulated depreciation would be $500 or 50 percent of the original $1,000 cost (10 * 5% = 50%). Now, assume that at the end of ten years, the utility estimates that the life is going to be fifteen years rather than twenty years. The existing depreciation reserve is immediately deficient. The new whole-life rate is 6.7% (1/15 years = 6.7%), but the remaining life rate is 10% ((100%-50%)/5 years=10%) The 6.7% whole-life rate based on the fifteen-year life assumption is correct for both the original $1,000 asset and any additional assets in the future. Hence, it is appropriate for all assets in the account. On the other hand, the 10% rate is only appropriate for the initial $1,000 asset; it is inappropriate for the new assets. Application of the 10% rate to new assets would create reserve excesses for those assets.

In my opinion, the whole-life rate is appropriate for all assets in the account. The Commission can deal separately with any significant reserve excess or deficiency relating to existing assets. If there is a significant reserve imbalance, the Commission can adopt a separate amortization of the imbalance. This will provide the appropriate depreciation rate for both the existing plant and the new additions going forward, and still correctly amortize the imbalance.

**Issue G. Appropriate accounting for cost of replacements (other issue.)**

The cost of removal that public utilities record on their books is largely an allocation of replacement costs, which they convert to inflated future removal costs that produce huge regulatory liabilities as explained earlier. The USoA does not require this outcome; in fact, I am not certain that the USoA as written even sanctions this outcome. According to Federal Energy Regulatory Commission ("FERC") rules, utilities should capitalize and depreciate all of the cost of a replacement, including the cost of removal. The FERC Uniform System of Accounts ("USoA") defines cost of removal as follows:

> *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.

The FERC USoA also defines replacements as follows:

> *Replacing or replacement*, when not otherwise indicated in the context, means the construction or installation of gas plant, together with the removal of the property retired.

FERC's definition means that cost of removal incurred in connection with a replacement is a component of the replacement cost.

The KCC must make the utilities whole for reasonable and prudent removal costs. However, given that the utilities control what that cost is, I recommend that the KCC not allow utilities to allocate a portion of a replacement project to cost of removal. This will significantly reduce the controversy surrounding future cost of removal.

## VIII. SUMMARY OF FUNDAMENTALS AND RECOMMENDATIONS

This Affidavit addresses public utility depreciation. It recognizes that depreciation must provide full capital recovery, but that it also must not lead to artificial acceleration and over-recovery of capital. It demonstrates that public utility depreciation is a noncash expense that provides capital recovery, but warrants careful consideration. In the fundamentals section, the Affidavit explains regulatory accounting, depreciation expense, net salvage and the fact that negative net salvage increases a depreciation rate. The Affidavit discusses the accumulated depreciation account or reserve, and the difference between whole-life and remaining-life depreciation rates. The Affidavit also discusses theoretical reserves and reserve excesses caused by understated lives and overstated negative net salvage estimates. Moreover, it discusses the U.S. Supreme Court case that declared that excessive deprecation reserves result from the extraction of capital contributions from ratepayers.

The Affidavit addresses the KCC's designated issues, as well as several other issues and makes several recommendations, as follows:

- The KCC should require utilities within its jurisdiction to reclassify the at risk regulatory liabilities they have recorded in their GAAP financial statements out of their accumulated depreciation accounts and into account 254 – other regulatory liabilities.

- The KCC should require that non-legal cost of removal allowances be segregated and unbundled from deprecation rates.

- The KCC should forbid utilities from collecting such amounts in depreciation rates.

- Utilities should expense or capitalize non-legal cost of removal allowances depending on whether they relate to a replacement or a final retirement without replacement.

- If the KCC decides to allow utilities to collect non-legal cost of removal allowances, the estimates should be at present value, not future value.

- The KCC should require utilities using the life span method to meet the stringent requirements specified in the 1996 NARUC deprecation Manual.

- The KCC should recognize that ELG has not been used in the past and is not necessary.

- The KCC should not allow retroactive ELG.

- The KCC should utilize whole-life depreciation rates rather than remaining life depreciation rates.

- The KCC should not allow utilities to allocate any portion of a replacement project to cost of removal.

VERIFICATION

WASHINGTON, )

) ss:

DISCTRICT OF COLUMBIA )

I, Michael J. Majoros, Jr., of lawful age, being first duly sworn upon his oath states:

That he is an attorney for the Citizen's Utility Ratepayer Board, that he has read the above and foregoing document, and, upon information and belief, states that the matters therein appearing are true and correct.

Date: November 30th, 2010

SUBSCRIBED AND SWORN to before me this 30th day of November, 2010.

Notary Public

DONNA ANN JEFFRIES
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires July 14, 2015

My Commision Expires:________________.

# APPENDIX A

**Resume**

## Experience

### Snavely King Majoros O'Connor & Bedell, Inc.

***Vice President and Treasurer (1988 to Present)***
***Senior Consultant (1981-1987)***

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory federal and state regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. His testimony has encompassed a wide array of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice and appeared before the U.S. EPA and the Maryland State Legislature on matters regarding the accounting and plant life effects of electric plant modifications and the financial capacity of public utilities to finance environmental controls. He has estimated economic damages suffered by black farmers in discrimination suits.

### Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros conducted and assisted in various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros provided onsite management accounting and controllership assistance to a municipal electric and water utility. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company), and he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

### Handling Equipment Sales Company, Inc.

***Controller/Treasurer (1976-1978)***

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

### Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

### University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

### Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

## Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

## Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

## Publications, Papers, and Panels

*"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.*

*"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.*

*"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986*

*"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.*

*"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.*

*"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.*

*"Impaired Assets Under SFAS No. 121," National Association of State Utility Consumer Advocates, 1996 Mid-Year Meeting, 1996.*

*"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.*

*"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001*

*"Rolling Over Ratepayers," Public Utilities Fortnightly, Volume 143, Number 11, November, 2005.*

*"Asset Management – What is it?," American Water Works Association, Pre-Conference Workshop, March 25, 2008.*

# APPENDIX B

## List of Prior Testimonies

# Michael J. Majoros, Jr.

| Date | Jurisdiction / Agency | Docket | Utility |
|---|---|---|---|
| | | **Federal Courts** | |
| 2005 | US District Court, Northern District of AL, Northwestern Division 55/56/57/ | CV 01-B-403-NW | Tennessee Valley Authority |
| | | **State Legislatures** | |
| 2006 | Maryland General Assembly 61/ | SB154 | Maryland Healthy Air Act |
| 2006 | Maryland House of Delegates 62/ | HB189 | Maryland Healthy Air Act |
| | | **Federal Regulatory Agencies** | |
| 1979 | FERC-US 19/ | RP79-12 | El Paso Natural Gas Co. |
| 1980 | FERC-US 19/ | RM80-42 | Generic Tax Normalization |
| 1996 | CRTC-Canada 30/ | 97-9 | All Canadian Telecoms |
| 1997 | CRTC-Canada 31/ | 97-11 | All Canadian Telecoms |
| 1999 | FCC 32/ | 98-137 (Ex Parte) | All LECs |
| 1999 | FCC 32/ | 98-91 (Ex Parte) | All LECs |
| 1999 | FCC 32/ | 98-177 (Ex Parte) | All LECs |
| 1999 | FCC 32/ | 98-45 (Ex Parte) | All LECs |
| 2000 | EPA 35/ | CAA-00-6 | Tennessee Valley Authority |
| 2003 | FERC 48/ | RM02-7 | All Utilities |
| 2003 | FCC 52/ | 03-173 | All LECs |
| 2003 | FERC 53/ | ER03-409-000, ER03-666-000 | Pacific Gas and Electric Co. |
| | | **State Regulatory Agencies** | |
| 1982 | Massachusetts 17/ | DPU 557/558 | Western Mass Elec. Co. |
| 1982 | Illinois 16/ | ICC81-8115 | Illinois Bell Telephone Co. |
| 1983 | Maryland 8/ | 7574-Direct | Baltimore Gas & Electric Co. |
| 1983 | Maryland 8/ | 7574-Surrebuttal | Baltimore Gas & Electric Co. |
| 1983 | Connecticut 15/ | 810911 | Woodlake Water Co. |
| 1983 | New Jersey 1/ | 815-458 | New Jersey Bell Tel. Co. |
| 1983 | New Jersey 14/ | 8011-827 | Atlantic City Sewerage Co. |
| 1984 | Dist. Of Columbia 7/ | 785 | Potomac Electric Power Co. |
| 1984 | Maryland 8/ | 7689 | Washington Gas Light Co. |
| 1984 | Dist. Of Columbia 7/ | 798 | C&P Tel. Co. |
| 1984 | Pennsylvania 13/ | R-832316 | Bell Telephone Co. of PA |
| 1984 | New Mexico 12/ | 1032 | Mt. States Tel. & Telegraph |
| 1984 | Idaho 18/ | U-1000-70 | Mt. States Tel. & Telegraph |

**Michael J. Majoros, Jr.**

| | | | |
|---|---|---|---|
| 1984 | Colorado 11/ | 1655 | Mt. States Tel. & Telegraph |
| 1984 | Dist. Of Columbia 7/ | 813 | Potomac Electric Power Co. |
| 1984 | Pennsylvania 3/ | R842621-R842625 | Western Pa. Water Co. |
| 1985 | Maryland 8/ | 7743 | Potomac Edison Co. |
| 1985 | New Jersey 1/ | 848-856 | New Jersey Bell Tel. Co. |
| 1985 | Maryland 8/ | 7851 | C&P Tel. Co. |
| 1985 | California 10/ | I-85-03-78 | Pacific Bell Telephone Co. |
| 1985 | Pennsylvania 3/ | R-850174 | Phila. Suburban Water Co. |
| 1985 | Pennsylvania 3/ | R850178 | Pennsylvania Gas & Water Co. |
| 1985 | Pennsylvania 3/ | R-850299 | General Tel. Co. of PA |
| 1986 | Maryland 8/ | 7899 | Delmarva Power & Light Co. |
| 1986 | Maryland 8/ | 7754 | Chesapeake Utilities Corp. |
| 1986 | Pennsylvania 3/ | R-850268 | York Water Co. |
| 1986 | Maryland 8/ | 7953 | Southern Md. Electric Corp. |
| 1986 | Idaho 9/ | U-1002-59 | General Tel. Of the Northwest |
| 1986 | Maryland 8/ | 7973 | Baltimore Gas & Electric Co. |
| 1987 | Pennsylvania 3/ | R-860350 | Dauphin Cons. Water Supply |
| 1987 | Pennsylvania 3/ | C-860923 | Bell Telephone Co. of PA |
| 1987 | Iowa 6/ | DPU-86-2 | Northwestern Bell Tel. Co. |
| 1987 | Dist. Of Columbia 7/ | 842 | Washington Gas Light Co. |
| 1988 | Florida 4/ | 880069-TL | Southern Bell Telephone |
| 1988 | Iowa 6/ | RPU-87-3 | Iowa Public Service Company |
| 1988 | Iowa 6/ | RPU-87-6 | Northwestern Bell Tel. Co. |
| 1988 | Dist. Of Columbia 7/ | 869 | Potomac Electric Power Co. |
| 1989 | Iowa 6/ | RPU-88-6 | Northwestern Bell Tel. Co. |
| 1990 | New Jersey 1/ | 1487-88 | Morris City Transfer Station |
| 1990 | New Jersey 5/ | WR 88-80967 | Toms River Water Company |
| 1990 | Florida 4/ | 890256-TL | Southern Bell Company |
| 1990 | New Jersey 1/ | ER89110912J | Jersey Central Power & Light |
| 1990 | New Jersey 1/ | WR90050497J | Elizabethtown Water Co. |
| 1991 | Pennsylvania 3/ | P900465 | United Tel. Co. of Pa. |
| 1991 | West Virginia 2/ | 90-564-T-D | C&P Telephone Co. |
| 1991 | New Jersey 1/ | 90080792J | Hackensack Water Co. |
| 1991 | New Jersey 1/ | WR90080884J | Middlesex Water Co. |
| 1991 | Pennsylvania 3/ | R-911892 | Phil. Suburban Water Co. |
| 1991 | Kansas 20/ | 176, 716-U | Kansas Power & Light Co. |
| 1991 | Indiana 29/ | 39017 | Indiana Bell Telephone |
| 1991 | Nevada 21/ | 91-5054 | Central Tele. Co. – Nevada |
| 1992 | New Jersey 1/ | EE91081428 | Public Service Electric & Gas |
| 1992 | Maryland 8/ | 8462 | C&P Telephone Co. |
| 1992 | West Virginia 2/ | 91-1037-E-D | Appalachian Power Co. |
| 1993 | Maryland 8/ | 8464 | Potomac Electric Power Co. |
| 1993 | South Carolina 22/ | 92-227-C | Southern Bell Telephone |
| 1993 | Maryland 8/ | 8485 | Baltimore Gas & Electric Co. |
| 1993 | Georgia 23/ | 4451-U | Atlanta Gas Light Co. |

## Michael J. Majoros, Jr.

| | | | |
|---|---|---|---|
| 1993 | New Jersey 1/ | GR93040114 | New Jersey Natural Gas. Co. |
| 1994 | Iowa 6/ | RPU-93-9 | U.S. West – Iowa |
| 1994 | Iowa 6/ | RPU-94-3 | Midwest Gas |
| 1995 | Delaware 24/ | 94-149 | Wilm. Suburban Water Corp. |
| 1995 | Connecticut 25/ | 94-10-03 | So. New England Telephone |
| 1995 | Connecticut 25/ | 95-03-01 | So. New England Telephone |
| 1995 | Pennsylvania 3/ | R-00953300 | Citizens Utilities Company |
| 1995 | Georgia 23/ | 5503-0 | Southern Bell |
| 1996 | Maryland 8/ | 8715 | Bell Atlantic |
| 1996 | Arizona 26/ | E-1032-95-417 | Citizens Utilities Company |
| 1996 | New Hampshire 27/ | DE 96-252 | New England Telephone |
| 1997 | Iowa 6/ | DPU-96-1 | U S West – Iowa |
| 1997 | Ohio 28/ | 96-922-TP-UNC | Ameritech – Ohio |
| 1997 | Michigan 28/ | U-11280 | Ameritech – Michigan |
| 1997 | Michigan 28/ | U-112 81 | GTE North |
| 1997 | Wyoming 27/ | 7000-ztr-96-323 | US West – Wyoming |
| 1997 | Iowa 6/ | RPU-96-9 | US West – Iowa |
| 1997 | Illinois 28/ | 96-0486-0569 | Ameritech – Illinois |
| 1997 | Indiana 28/ | 40611 | Ameritech – Indiana |
| 1997 | Indiana 27/ | 40734 | GTE North |
| 1997 | Utah 27/ | 97-049-08 | US West – Utah |
| 1997 | Georgia 28/ | 7061-U | BellSouth – Georgia |
| 1997 | Connecticut 25/ | 96-04-07 | So. New England Telephone |
| 1998 | Florida 28/ | 960833-TP et. al. | BellSouth – Florida |
| 1998 | Illinois 27/ | 97-0355 | GTE North/South |
| 1998 | Michigan 33/ | U-11726 | Detroit Edison |
| 1999 | Maryland 8/ | 8794 | Baltimore Gas & Electric Co. |
| 1999 | Maryland 8/ | 8795 | Delmarva Power & Light Co. |
| 1999 | Maryland 8/ | 8797 | Potomac Edison Company |
| 1999 | West Virginia 2/ | 98-0452-E-GI | Electric Restructuring |
| 1999 | Delaware 24/ | 98-98 | United Water Company |
| 1999 | Pennsylvania 3/ | R-00994638 | Pennsylvania American Water |
| 1999 | West Virginia 2/ | 98-0985-W-D | West Virginia American Water |
| 1999 | Michigan 33/ | U-11495 | Detroit Edison |
| 2000 | Delaware 24/ | 99-466 | Tidewater Utilities |
| 2000 | New Mexico 34/ | 3008 | US WEST Communications, Inc. |
| 2000 | Florida 28/ | 990649-TP | BellSouth -Florida |
| 2000 | New Jersey 1/ | WR30174 | Consumer New Jersey Water |
| 2000 | Pennsylvania 3/ | R-00994868 | Philadelphia Suburban Water |
| 2000 | Pennsylvania 3/ | R-0005212 | Pennsylvania American Sewerage |
| 2000 | Connecticut 25/ | 00-07-17 | Southern New England Telephone |
| 2001 | Kentucky 36/ | 2000-373 | Jackson Energy Cooperative |
| 2001 | Kansas 38/39/40/ | 01-WSRE-436-RTS | Western Resources |
| 2001 | South Carolina 22/ | 2001-93-E | Carolina Power & Light Co. |
| 2001 | North Dakota 37/ | PU-400-00-521 | Northern States Power/Xcel Energy |

# Michael J. Majoros, Jr.

| | | | |
|---|---|---|---|
| 2001 | Indiana 29/41/ | 41746 | Northern Indiana Power Company |
| 2001 | New Jersey 1/ | GR01050328 | Public Service Electric and Gas |
| 2001 | Pennsylvania 3/ | R-00016236 | York Water Company |
| 2001 | Pennsylvania 3/ | R-00016339 | Pennsylvania America Water |
| 2001 | Pennsylvania 3/ | R-00016356 | Wellsboro Electric Coop. |
| 2001 | Florida 4/ | 010949-EL | Gulf Power Company |
| 2001 | Hawaii 42/ | 00-309 | The Gas Company |
| 2002 | Pennsylvania 3/ | R-00016750 | Philadelphia Suburban |
| 2002 | Nevada 43/ | 01-10001 &10002 | Nevada Power Company |
| 2002 | Kentucky 36/ | 2001-244 | Fleming Mason Electric Coop. |
| 2002 | Nevada 43/ | 01-11031 | Sierra Pacific Power Company |
| 2002 | Georgia 27/ | 14361-U | BellSouth-Georgia |
| 2002 | Alaska 44/ | U-01-34,82-87,66 | Alaska Communications Systems |
| 2002 | Wisconsin 45/ | 2055-TR-102 | CenturyTel |
| 2002 | Wisconsin 45/ | 5846-TR-102 | TelUSA |
| 2002 | Vermont 46/ | 6596 | Citizen's Energy Services |
| 2002 | North Dakota 37/ | PU-399-02-183 | Montana Dakota Utilities |
| 2002 | Kansas 40/ | 02-MDWG-922-RTS | Midwest Energy |
| 2002 | Kentucky 36/ | 2002-00145 | Columbia Gas |
| 2002 | Oklahoma 47/ | 200200166 | Reliant Energy ARKLA |
| 2002 | New Jersey 1/ | GR02040245 | Elizabethtown Gas Company |
| 2003 | New Jersey 1/ | ER02050303 | Public Service Electric and Gas Co. |
| 2003 | Hawaii 42/ | 01-0255 | Young Brothers Tug & Barge |
| 2003 | New Jersey 1/ | ER02080506 | Jersey Central Power & Light |
| 2003 | New Jersey 1/ | ER02100724 | Rockland Electric Co. |
| 2003 | Pennsylvania 3/ | R-00027975 | The York Water Co. |
| 2003 | Pennsylvania /3 | R-00038304 | Pennsylvania-American Water Co. |
| 2003 | Kansas 20/ 40/ | 03-KGSG-602-RTS | Kansas Gas Service |
| 2003 | Nova Scotia, CN 49/ | EMO NSPI | Nova Scotia Power, Inc. |
| 2003 | Kentucky 36/ | 2003-00252 | Union Light Heat & Power |
| 2003 | Alaska 44/ | U-96-89 | ACS Communications, Inc. |
| 2003 | Indiana 29/ | 42359 | PSI Energy, Inc. |
| 2003 | Kansas 20/ 40/ | 03-ATMG-1036-RTS | Atmos Energy |
| 2003 | Florida 50/ | 030001-E1 | Tampa Electric Company |
| 2003 | Maryland 51/ | 8960 | Washington Gas Light |
| 2003 | Hawaii 42/ | 02-0391 | Hawaiian Electric Company |
| 2003 | Illinois 28/ | 02-0864 | SBC Illinois |
| 2003 | Indiana 28/ | 42393 | SBC Indiana |
| 2004 | New Jersey 1/ | ER03020110 | Atlantic City Electric Co. |
| 2004 | Arizona 26/ | E-01345A-03-0437 | Arizona Public Service Company |
| 2004 | Michigan 27/ | U-13531 | SBC Michigan |
| 2004 | New Jersey 1/ | GR03080683 | South Jersey Gas Company |
| 2004 | Kentucky 36/ | 2003-00434,00433 | Kentucky Utilities, Louisville Gas & Electric |
| 2004 | Florida 50/ 54/ | 031033-EI | Tampa Electric Company |

# Michael J. Majoros, Jr.

| | | | |
|---|---|---|---|
| 2004 | Kentucky 36/ | 2004-00067 | Delta Natural Gas Company |
| 2004 | Georgia 23/ | 18300, 15392, 15393 | Georgia Power Company |
| 2004 | Vermont 46/ | 6946, 6988 | Central Vermont Public Service Corporation |
| 2004 | Delaware 24/ | 04-288 | Delaware Electric Cooperative |
| 2004 | Missouri 58/ | ER-2004-0570 | Empire District Electric Company |
| 2005 | Florida 50/ | 041272-EI | Progress Energy Florida, Inc. |
| 2005 | Florida 50/ | 041291-EI | Florida Power & Light Company |
| 2005 | California 59/ | A.04-12-014 | Southern California Edison Co. |
| 2005 | Kentucky 36/ | 2005-00042 | Union Light Heat & Power |
| 2005 | Florida 50/ | 050045 & 050188-EI | Florida Power & Light Co. |
| 2005 | Kansas 38/ 40/ | 05-WSEE-981-RTS | Westar Energy, Inc. |
| 2006 | Delaware 24/ | 05-304 | Delmarva Power & Light Company |
| 2006 | California 59/ | A.05-12-002 | Pacific Gas & Electric Co. |
| 2006 | New Jersey 1/ | GR05100845 | Public Service Electric and Gas Co. |
| 2006 | Colorado 60/ | 06S-234EG | Public Service Co. of Colorado |
| 2006 | Kentucky 36/ | 2006-00172 | Union Light, Heat & Power |
| 2006 | Kansas 40/ | 06-KGSG-1209-RTS | Kansas Gas Service |
| 2006 | West Virginia 2/ | 06-0960-E-42T, 06-1426-E-D | Allegheny Power |
| 2006 | West Virginia 2/ | 05-1120-G-30C, 06-0441-G-PC, et al. | Hope Gas, Inc. and Equitable Resources, Inc. |
| 2007 | Delaware 24/ | 06-284 | Delmarva Power & Light Company |
| 2007 | Kentucky 36/ | 2006-00464 | Atmos Energy Corporation |
| 2007 | Colorado 60/ | 06S-656G | Public Service Co. of Colorado |
| 2007 | California 59/ | A.06-12-009, A.06-12-010 | San Diego Gas & Electric Co., and Southern California Gas Co. |
| 2007 | Kentucky 36/ | 2007-00143 | Kentucky-American Water Co. |
| 2007 | Kentucky 36/ | 2007-00089 | Delta Natural Gas Co. |
| 2008 | Kansas 40/ | 08-ATMG-280-RTS | Atmos Energy Corporation |
| 2008 | New Jersey 1/ | GR07110889 | New Jersey Natural Gas Co. |
| 2008 | North Dakota 37/ | PU-07-776 | Northern States Power/Xcel Energy |
| 2008 | Pennsylvania 3/ | A-2008-2034045 et al | UGI Utilities, Inc. / PPL Gas Utilities Corp. |
| 2008 | Washington 63/ | UE-072300, UG-072301 | Puget Sound Energy |
| 2008 | Pennsylvania 3/ | R-2008-2032689 | Pennsylvania-American Water Co. - Coatesville |
| 2008 | New Jersey 1/ | WR08010020 | NJ American Water Co. |
| 2008 | Washington 63/ 64/ | UE-080416, UG-080417 | Avista Corporation |
| 2008 | Texas 65/ | 473-08-3681, 35717 | Oncor Electric Delivery Co. |
| 2008 | Tennessee 66/ | 08-00039 | Tennessee-American Water Co. |
| 2008 | Kansas | 08-WSEE-1041-RTS | Westar Energy, Inc. |
| 2009 | Kentucky 36/ | 2008-00409 | East Kentucky Power Coop. |

# Michael J. Majoros, Jr.

| | | | |
|---|---|---|---|
| 2009 | Indiana 29/ | 43501 | Duke Energy Indiana |
| 2009 | Indiana 29/ | 43526 | Northern Indiana Public Service Co. |
| 2009 | Michigan 33/ | U-15611 | Consumers Energy Company |
| 2009 | Kentucky 36/ | 2009-00141 | Columbia Gas of Kentucky |
| 2009 | New Jersey 1/ | GR00903015 | Elizabethtown Gas Company |
| 2009 | District of Columbia 7/ | FC 1076 | Potomac Electric Power |
| 2009 | New Jersey 1/ | GR09050422 | Public Service Gas & Electric Co. |
| 2009 | Kentucky 36/ | 2009-00202 | Duke Energy Kentucky Co. |
| 2009 | | | |
| 2010 | Kentucky 36/ | 2009-00549 | Louisville Gas and Electric Co. |
| 2010 | Kentucky 36/ | 2009-00548 | Kentucky Utilities Co. |
| 2010 | New Jersey | GR10010035 | Southern New Jersey Gas Co. |

## Michael J. Majoros, Jr.

### PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

| COMPANY | YEARS | CLIENT |
|---|---|---|
| Diamond State Telephone Co. 24/ | 1985 + 1988 | Delaware Public Service Comm |
| Bell Telephone of Pennsylvania 3/ | 1986 + 1989 | PA Consumer Advocate |
| Chesapeake & Potomac Telephone Co. - Md. 8/ | 1986 | Maryland People's Counsel |
| Southwestern Bell Telephone – Kansas 20/ | 1986 | Kansas Corp. Commission |
| Southern Bell – Florida 4/ | 1986 | Florida Consumer Advocate |
| Chesapeake & Potomac Telephone Co.-W.Va. 2/ | 1987 + 1990 | West VA Consumer Advocate |
| New Jersey Bell Telephone Co. 1/ | 1985 + 1988 | New Jersey Rate Counsel |
| Southern Bell - South Carolina 22/ | 1986 + 1989 + 1992 | S. Carolina Consumer Advocate |
| GTE-North – Pennsylvania 3/ | 1989 | PA Consumer Advocate |

## Michael J. Majoros, Jr.

## PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

| STATE | DOCKET NO. | UTILITY |
|---|---|---|
| Maryland 8/ | 7878 | Potomac Edison |
| Nevada 21/ | 88-728 | Southwest Gas |
| New Jersey 1/ | WR90090950J | New Jersey American Water |
| New Jersey 1/ | WR900050497J | Elizabethtown Water |
| New Jersey 1/ | WR91091483 | Garden State Water |
| West Virginia 2/ | 91-1037-E | Appalachian Power Co. |
| Nevada 21/ | 92-7002 | Central Telephone - Nevada |
| Pennsylvania 3/ | R-00932873 | Blue Mountain Water |
| West Virginia2/ | 93-1165-E-D | Potomac Edison |
| West Virginia2/ | 94-0013-E-D | Monongahela Power |
| New Jersey 1/ | WR94030059 | New Jersey American Water |
| New Jersey 1/ | WR95080346 | Elizabethtown Water |
| New Jersey 1/ | WR95050219 | Toms River Water Co. |
| Maryland 8/ | 8796 | Potomac Electric Power Co. |
| South Carolina 22/ | 1999-077-E | Carolina Power & Light Co. |
| South Carolina 22/ | 1999-072-E | Carolina Power & Light Co. |
| Kentucky 36/ | 2001-104 & 141 | Kentucky Utilities, Louisville Gas and Electric |
| Kentucky 36/ | 2002-485 | Jackson Purchase Energy Corporation |
| Kentucky 36/ | 2009-00202 | Duke Energy Kentucky |
| New Jersey 1/ | ER09080664 | Atlantic City Electric Co. |
| New Jersey 1/ | ER09080668 | Rockland Electric Co. |

## Michael J. Majoros, Jr.

Clients

| | |
|---|---|
| 1/ New Jersey Rate Counsel/Advocate | 34/ New Mexico Attorney General |
| 2/ West Virginia Consumer Advocate | 35/ Environmental Protection Agency Enforcement Staff |
| 3/ Pennsylvania OCA | 36/ Kentucky Attorney General |
| 4/ Florida Office of Public Advocate | 37/ North Dakota Public Service Commission |
| 5/ Toms River Fire Commissioner's | 38/ Kansas Industrial Group |
| 6/ Iowa Office of Consumer Advocate | 39/ City of Witchita |
| 7/ D.C. People's Counsel | 40/ Kansas Citizens' Utility Rate Board |
| 8/ Maryland's People's Counsel | 41/ NIPSCO Industrial Group |
| 9/ Idaho Public Service Commission | 42/ Hawaii Division of Consumer Advocacy |
| 10/ Western Burglar and Fire Alarm | 43/ Nevada Bureau of Consumer Protection |
| 11/ U.S. Dept. of Defense | 44/ GCI |
| 12/ N.M. State Corporation Comm. | 45/ Wisc. Citizens' Utility Rate Board |
| 13/ City of Philadelphia | 46/ Vermont Department of Public Service |
| 14/ Resorts International | 47/ Oklahoma Corporation Commission |
| 15/ Woodlake Condominium Association | 48/ National Assn. of State Utility Consumer Advocates |
| 16/ Illinois Attorney General | 49/ Nova Scotia Utility and Review Board |
| 17/ Mass Coalition of Municipalities | 50/ Florida Office of Public Counsel |
| 18/ U.S. Department of Energy | 51/ Maryland Public Service Commission |
| 19/ Arizona Electric Power Corp. | 52/ MCI |
| 20/ Kansas Corporation Commission | 53/ Transmission Agency of Northern California |
| 21/ Public Service Comm. – Nevada | 54/ Florida Industrial Power Users Group |
| 22/ SC Dept. of Consumer Affairs | 55/ Sierra Club |
| 23/ Georgia Public Service Comm. | 56/ Our Children's Earth Foundation |
| 24/ Delaware Public Service Comm. | 57/ National Parks Conservation Association, Inc. |
| 25/ Conn. Ofc. Of Consumer Counsel | 58/ Missouri Office of the Public Counsel |
| 26/ Arizona Corp. Commission | 59/ The Utility Reform Network |
| 27/ AT&T | 60/ Colorado Office of Consumer Counsel |
| 28/ AT&T/MCI | 61/ MD State Senator Paul G. Pinsky |
| 29/ IN Office of Utility Consumer Counselor | 62/ MD Speaker of the House Michael Busch |
| 30/ Unitel (AT&T – Canada) | 63/ Washington Office of Public Counsel |
| 31/ Public Interest Advocacy Centre | 64/ Industrial Customers of Northwestern Utilities |
| 32/ U.S. General Services Administration | 65/ Steering Committee of Cities |
| 33/ Michigan Attorney General | 66/ City of Chattanooga |

## **ATTACHMENT 1**

Article: *Fixing Depreciation Accounting*, by John S. Ferguson

## **ATTACHMENT 2**

Letter: Federal Energy Regulatory Commission to
U.S. Securities and Exchange Commission
Re: IFRS Roadmap

## **ATTACHMENT 3**

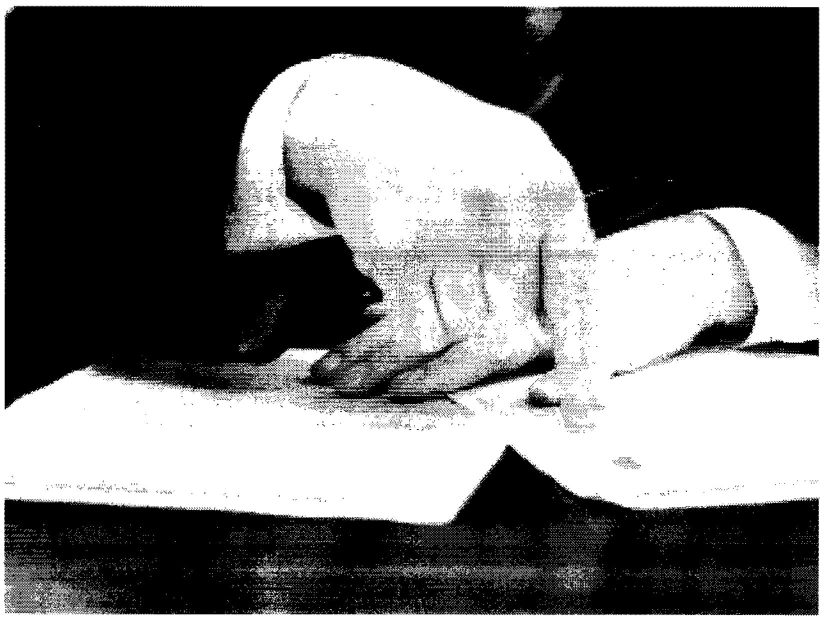
List: *40 Best Energy Companies*

Business & Money

# Fixing Depreciation Accounting

Accumulated provisions for depreciation belong on the right side of the balance sheet.

By John S. Ferguson



Until the late 1940s, the accepted accounting convention was to locate the accumulated provision for depreciation on the right (liability and capital) side of the balance sheet. The convention since has been to locate it on the left (asset) side as a contra-asset. This change was controversial, and has led to some strange accounting for the expenditures incurred to remove or abandon in place property, plant, and equipment (PP&E) at the end of its useful life (referred to here as removal costs or expenditures).

Recent events suggest now is an opportune time to revisit where the accumulated provision belongs. For example, the Financial Accounting Standards Board (FASB) and the International Accounting Standards Board are working to harmonize their respective standards. The Securities and Exchange Commission (SEC) announced its intention to allow financial reporting based on international accounting standards without reconciliation to U.S. generally accepted accounting principles (GAAP). And the SEC's advisory committee on improvements to financial reporting recommended that accounting rules avoid special treatment for specific industries. Finally, financial accounting has moved away from emphasizing the concept of matching to emphasizing fair value.

In this context, accounting practices might be poised for a change, putting accumulated provisions for depreciation back on the right side of the balance sheet.

### Allocation, Not Valuation

The balance sheet location controversy didn't cease with moving the accumulated provision to the left side. For instance, a January 1959 *Accounting Review* article suggested that the location change be revisited.[1] In the article, a random sample of the then-recent annual reports of 90 industrials and railroads and 10 utilities showed one industrial, one railroad and three utilities continuing to report the accumulated provision on the right side, rather than as a contra-asset on the left side. Right-side treatment by utilities is not surprising, because utilities objected to the change 50 years ago.

Depreciation accounting is a cost-allocation concept—not a valuation concept—and an objection to left-side treatment was that it can lead some to incorrectly interpret the resulting net asset amount as being the current value of the assets. An objection to right-side treatment was that the accumulated provision is not a liability, so does not belong on the right side. The accumulated provision obviously isn't a liability, but it is a source of funds, and sources of capital are recorded on the right side. The removal or abandonment obligation clearly is a liability. However, the liability is the estimated expenditure measured at the price level expected at the time of expenditure, not the amount of the estimated expenditure already recorded as an expense and charged by regulated enterprises to their ratepayers.

For enterprises subject to price regulation, the accumulated provision clearly is a source of funds because rate-base regulation treats the accumulated provision as being ratepayer-supplied capital, for which a credit is provided at the allowed cost of capital. Recognizing » depreciation as a source of funds also is evident from the U.S. government allowing income-tax depreciation to be accelerated in order to provide funds (tax savings) for business expansion. This view was reinforced when the initial attempts by price regulators to pass the tax savings on to ratepayers prompted the IRS to deny accelerated tax depreciation to entities not allowed to retain the resulting tax savings.

Being recorded as a contra-asset has led to concern that net asset amounts could become negative, which has led to some strange accounting for expenditures for removing or abandoning PP&E. For long-lived assets, salvage usually is inconsequential, and removal expenditures frequently exceed the historical cost of the related assets. Therefore, accurately recognizing these expenditures for accounting purposes is at least as important, if not more important, than is recognizing the consumption of the related PP&E when providing a product or service. However, accounting practices don't recognize this importance.

Regulatory agencies were well ahead of the accounting profession in recognizing that the concept of retirement accounting made no sense, and so adopted depreciation accounting. Under retirement accounting, investment is recorded as an expense upon retirement, salvage is recorded as income when received, and removal cost is recorded as an expense when incurred. Regulators also were ahead in recognizing there are three components to depreciation—investment, salvage, and removal expenditures—and that accurately charging these costs to ratepayers necessitates recording them ratably over the useful life of the related PP&E.

This recognition means a known investment cost is accrued (recorded as a periodic expense) after being incurred, an estimated future salvage amount is accrued (recorded as a periodic credit) before being received, and an estimated future removal expenditure is accrued (recorded as a periodic expense) before being spent. This treatment assures that ratepayers are charged no more and no less than the costs being incurred to serve them, at the time the service is rendered and the costs are incurred—which is known as the regulatory principle of intergenerational ratepayer equity.

Regulatory depreciation accounting rules are more detailed than are financial accounting rules, and are specified by the Uniform Systems of Accounts (USofAs) prescribed by FERC and other entities. Almost all USofAs dictate that salvage and removal costs be treated as components of depreciation,[2] and this treatment predates World War I. The basic foundation for the regulatory accounting treatment of salvage and removal cost is evident from the FERC USofAs for electric utilities and natural gas companies, which define depreciation as "loss in service value," define service value as "the difference between original cost and net salvage value," and define net salvage value as "the salvage value of property retired less the cost of removal."

**Salvage vs. Net Salvage**

It took a while, but the U.S. accounting profession eventually caught up with the regulators, evident from the definition of depreciation given in a sidebar that was issued during the 1950s. Three aspects of this definition are significant to the treatment of removal costs—the requirement to be systematic and rational, consideration of salvage, and recognition that depreciation accounting is a process of allocation, not of valuation.

The rational aspect of "systematic and rational" means that depreciation is to be recorded in a manner that matches the pattern of usage or revenue-generating capability of the related assets, consistent with the regulatory principle of intergenerational ratepayer equity. Thus, if the asset usage or revenue pattern is decreasing, the depreciation method should be accelerated relative to the life span of the asset. If the pattern is constant, depreciation should be constant relative to the life span, and if the pattern is increasing, depreciation should be deferred relative to the life span.

The PP&E of regulated entities exhibits decreasing or constant patterns over their lifetimes—not increasing patterns. Therefore, U.S. GAAP dictates that the depreciation rates of such entities (and probably of all entities) be constant (ratable) over life defined by either

**DEPRECIATION UNDER GAAP**

Depreciation accounting is a system of accounting that aims to distribute cost or other basic value of tangible capital assets, less salvage value (if any), over the estimated useful life of the unit (which may be a group of assets) in a systematic and rational manner.

It's a process of allocation, not of valuation. Depreciation for the year is the portion of the total charge under such a system that is allocated to the year. Although the allocation properly may take into account occurrences during the year, it's not intended to be a measurement of the effect of all such occurrences.–*JF*

54 percent of the total accretion is recorded after the unit ceases to operate and generate revenues. This is really strange accounting.

time or asset usage.

The U.S. GAAP definition reference to salvage is intended to mean "net salvage," thereby encompassing removal costs. If the definition had been meant to incorporate only salvage into depreciation, it would have stated "gross salvage" rather than merely "salvage." This terminology has proven to be unfortunate, because it has created confusion concerning how removal costs are to be dealt with for accounting purposes. As a result, the true intention of the GAAP definition has been lost, and strange accounting has occurred.

Several facts support the "net salvage" definition of "salvage" within GAAP. At the time of the definition, the term "salvage" generally was used to mean "net salvage" (*i.e.*, salvage proceeds less removal expenditures), and utilities typically incorporated removal costs into depreciation for regulatory accounting purposes. Additionally, the "net salvage" definition supports greater consistency in treating different end-of-life transactions (salvage and removal costs) ratably through depreciation. Treating removal costs differently from investment and salvage conflicts with the premise that accounting practices should be reliable and relevant.

The ratable treatment of removal costs through depreciation for regulatory accounting purposes has a long history, but periodically is challenged by proposals to defer recording and recovery. Such challenges also have a long history, but have taken on renewed vigor as a consequence of FASB Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations*, (SFAS 143), issued in 2001.

Challenges to ratable treatment of removal costs for regulatory purposes are unfortunate, because they lead to proposals for deferral mechanisms that, if accepted by regulators, increase the costs to be borne by ratepayers over the life of the related PP&E, thereby increasing energy costs and damaging the competitiveness of the state[3] (*see "Depreciation Shell Game," Fortnightly, April 2008*).

Removal cost deferrals result from regulatory decisions that emphasize near-term political considerations over long-term economic considerations. The financial community and large energy users can be expected to interpret such regulatory unfairness as signaling deterioration of the business climate. The financial community might react to such a signal by downgrading the securities of jurisdictional entities and of the state itself. Additionally, large energy users typically work from multiple locations, so they can shift production between locations in reaction to regulatory decisions—and sometimes they do. Large energy users participating in regulatory proceedings typically emphasize long-term considerations, through addressing cost-allocation (equity) issues, rather than issues concerning the magnitude of cost of service. It's not unusual for such users to react to a business-climate deterioration signal by shifting from emphasizing equity to emphasizing the near-term cost-of-service magnitude in their participation in regulatory proceedings.

**The removal obligation clearly is a liability, but rate-base regulation treats accumulated provisions for depreciation as ratepayer-supplied capital.**

SFAS 143 is an example of the movement away from emphasizing matching to emphasizing fair value. It segregates retirement obligations (removal expenditures) imposed by law, statute, regulation or contract (legal obligations) from depreciation, and specifies that such obligations be recorded as liabilities—not as depreciation. The specified treatment is to record the initial discounted amount of the expected expenditure as part of the depreciable cost of the related asset and as an initial liability, and to record future accretion—due to the discounting unwinding over time—as accretion expense. This treatment is a single-payment (prepaid) annuity, but is recorded in a manner that gives it a structure similar to a multiple-payment annuity—the typical form of sinking-fund depreciation.

SFAS 92, *Regulated Enterprises—Accounting for Phase-in Plans*, defines annuity methods of depreciation as phase-in plans that are precluded from use for either regulatory or financial accounting purposes, unless the practice was regulatory policy prior to 1982. SFAS 143 side steps this limitation by classifying legal obligations as liabilities, so the specified treatment is not required to be "rational." Also, SFAS 92 is interpreted as applying only to investment, which is another consequence of the accumulated provision being on the left side of the balance sheet.

The deferral inherent in SFAS 143 treatment is evident in the obligation for decommissioning a nuclear generating unit, which is the obligation that prompted issuance of SFAS 143. A nuclear unit that receives a renewed operating license from the Nuclear Regulatory Commission is likely to have an operating life span of about 55 years. If decommissioning occurs 10 years after operations cease and the SFAS 143 discount rate is 8 percent, then 99.3 percent of the obligation would be recorded as accretion over 65 years, with the accretion amount recorded during the final year being 137 times the amount recorded during the first year, and 54 percent of the total accretion being recorded after the unit ceases to operate and generate revenues—and, for a single-asset entity, after the enterprise ceases to be viable. This is really strange accounting.

### Intergenerational Equity

The exposure draft of what eventually became SFAS 143 called for liability treatment of both legal and constructive obligations, which is the same as for international standards. However, SFAS 143 was limited to only legal obligations when FASB concluded that constructive obligations could not be defined tightly enough for consistent application, which suggests the international standard is not consistently being applied.

Limiting SFAS 143 to legal obligations did not preclude inconsistent application, and the FASB felt the need for clarification through issuing FASB Interpretation 47, *Accounting for Conditional Asset Retirement Obligations*, (FIN 47) in 2005. FIN 47 improved the consistency of reporting, but did not eliminate the problem—which is due, in part, to the difficulty in applying SFAS 143 by entities practicing the group concept of depreciation accounting. However, the remaining inconsistency pales when compared to the inconsistency resulting from the misinterpretation of the GAAP definition of depreciation accounting.

This misinterpretation means that regulated entities record removal or abandonment obligations ratably over the life of the related PP&E, except for a few that are subject to the jurisdiction of regulatory agencies that have imposed deferral mechanisms. At the same time, non-regulated entities record such obligations using one of two deferral mechanisms—SFAS 143 treatment for legal obligations, and cash treatment for other obligations. Entities practicing the item concept of depreciation accounting record and depreciate each item of PP&E separately, so related legal removal obligations easily are identified, recorded and tracked. Entities practicing the group concept easily can identify, record, and track such obligations for PP&E recorded and depreciated by location, such as for power plants, but it is next to impossible to track such obligations for PP&E not so recorded and depreciated, such as for electric and gas distribution systems.

> Using the group concept of depreciation accounting, it's nearly impossible to track legal obligations for electric and gas distribution systems.

SFAS 71, *Accounting for the Effects of Certain Types of Regulation*, allows qualified entities to utilize accounting practices that cannot be utilized by non-qualifying entities. The effect of qualification is that the income statement reflects regulatory accounting requirements, with any differences from financial accounting requirements being disclosed on the balance sheet as regulatory assets or liabilities. For example, obligations qualifying for liability treatment under SFAS 143 typically are reflected in depreciation for ratemaking purposes, so depreciation treatment would be reflected on the income statement and a regulatory liability disclosed. Disclosing a regulatory liability means that regulated entities must maintain accounting records for both depreciation treatment and liability treatment of legal obligations. SFAS 71 would be rescinded, if the SEC follows the recommendation of its advisory committee to avoid special treatment for specific industries. Rescinding would be a problem for regulators, because the financial statements of regulated entities could no longer match removal costs to the usage of the PP&E providing service to ratepayers, thereby violating the principle of intergenerational ratepayer equity.

It wouldn't be difficult to eliminate the strange removal cost accounting and the potential for violating the principle of intergenerational ratepayer equity. Doing so would allow financial statements to more accurately depict the financial position and results of operations of the reporting enterprises and ensure that ratepayers bear the costs being incurred to serve them. All that's necessary is to recognize that the accumulated provision for depreciation is a source of funds that belongs on the right side of the balance sheet, and to change the reference to "salvage" in the GAAP definition of depreciation accounting to "net salvage."

These two actions would allow FASB to rescind SFAS 143, and would promote consistency, comparability, reliability, and relevance by requiring all enterprises to use the same removal cost treatment for accounting purposes.

*John Ferguson, CDP, formerly was a principal with Deloitte & Touche, and now chairs the current issues committee of the Society of Depreciation Professionals. This article reflects the views of the author and not Deloitte or the Society. Email him at johnferg@swbell.net.*

### ENDNOTES

1. Simon, Sidney, "The Right Side of Accumulated Depreciation" *Accounting Review*, Rutgers University, January 1959.
2. The only exception to incorporating removal or abandonment costs in depreciation that the author is aware of is the railroad USofA of the Surface Transportation Board, and that exception is limited to PP&E other than the track structure accounts.
3. Detrimental impacts easily are demonstrated, but are beyond the scope of this article.

Business & Money

# Ready for IFRS?

International reporting standards are coming for U.S. public companies.

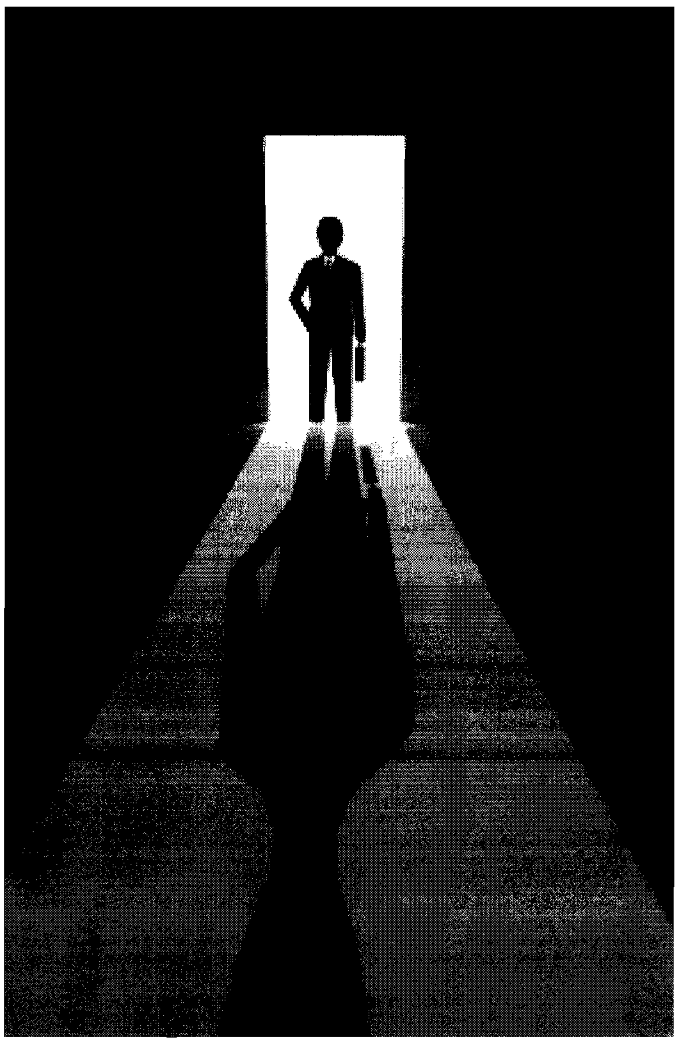
By Scott Hartman

Adoption of IFRS (International Financial Reporting Standards) in the United States undoubtedly would mark a significant change for many U.S. companies. It would require a shift to a more principles-based approach, place far greater reliance on management (and auditor) judgment, and spur major changes in company processes and systems.

But this change should not be feared. A move to IFRS also presents a tremendous opportunity. Moving to an entirely new accounting structure ultimately might enable companies to streamline reporting processes and reduce compliance costs.

IFRS has fewer bright lines and less interpretive and application guidance than does U.S. GAAP (Generally Accepted Accounting Principles). Companies will need to consider carefully the economic substance of their transactions and then apply the principles embodied in IFRS to that substance. Arguably, doing so might enable a closer alignment with underlying business objectives.

Many financial professionals in the power and utility industries today are aware of IFRS, which presently is used or under consideration in every major financial market around the world. There is a growing recognition, both in the United States and internationally, that a single set of high-quality global accounting standards offers real benefits. IFRS seems increasingly likely to provide that single set of standards.



**Going Global**

The Securities and Exchange Commission (SEC) is aware of the growing global acceptance of IFRS and has taken comments from listed companies, audit firms, investment groups, rating agencies, the legal community and government agencies in an effort to create a comprehensive plan for a smooth transition to using IFRS in the United States. These discussions take into consideration issues like whether to allow U.S. filers the option of either adopting IFRS or setting an effective date for implementation by all U.S. registrants.

The SEC hosted a roundtable meeting in August 2008 that focused on the performance of IFRS during the market turmoil that already was churning earlier this year. While panelists shared a general consensus that IFRS performed quite well, they acknowledged that challenges exist in the application of both IFRS and U.S. GAAP in areas such as fair-value accounting. In addition, the roundtable focused on accounting for off-balance sheet arrangements and commodity pricing, both topics of particular interest for the power and utility industries. Panelists also expressed the view that IFRS could benefit from additional application guidance to reduce certain inconsis- »

## Five Steps to Implementing IFRS

■ **Step 1**: Develop goals: The company's management team and board of directors decide how best to present the company's financials on an ongoing basis. Then, preliminary mapping begins and high-level risk assessments are conducted, outlining the potential impact that IFRS can have on the company's balance sheet, financial reporting and accounting policies, tax liabilities, and contracts and joint venture agreements.

■ **Step 2**: Design and planning: The transition team validates the conversion recommendations made in Step 1 and evaluates the various options to determine the impact that different financial accounting and reporting policies will have across the enterprise.

■ **Step 3**: Solution development: New IFRS policies are modeled, and the transition team develops the process and system change requirements that the new guidelines require.

■ **Step 4**: Implementation: At its heart, implementation is a straightforward change-management effort that includes communication and training, followed by carrying out the agreed-upon approaches. At this step, the transition team can begin to test the new guidelines as implemented and remediate as needed.

■ **Step 5**: Post-implementation review: This occurs when all key parties—financial accounting and reporting, treasury, tax and others—meet to debrief and identify opportunities for improvement.

These five steps might take as long as two or three years from initial diagnostic discussions to post-implementation changes. This period allows for a thoughtful, well-planned transition that increases the long-term benefit of IFRS. Companies that wait—until either the SEC determines a definitive timeline or their competitors accelerate efforts toward transition—might find themselves playing catch-up.–*SH*

tencies as presently applied.

In late August, the SEC approved for public comment its long-awaited "Roadmap" to the eventual use of IFRS by U.S. companies. The proposed Roadmap anticipates mandatory reporting under IFRS beginning in 2014, 2015 or 2016, depending on the size of the issuer, and provides for early adoption in 2009 by a small number of very large companies that meet certain criteria. The SEC later might decide to allow other companies to adopt IFRS early, before the mandatory date of conversion. The roadmap also identifies several milestones that the SEC will consider in making its decision in 2011 about whether to proceed with mandatory adoption of IFRS.

While there are differences between U.S. GAAP and IFRS, the general principles, conceptual framework and accounting results between them are often the same, or similar, for most commonly-encountered transactions.

In general, IFRS standards are broader than their U.S. counterparts, with limited interpretive guidance. While U.S. standards contain underlying principles as well, the strong regulatory and legal environment in U.S. markets has resulted in a more prescriptive approach—with far more "bright lines," comprehensive implementation guidance and industry interpretations.

The International Accounting Standards Board (IASB) generally has avoided issuing interpretations of its own standards, preferring instead to leave implementation of the principles embodied in its standards to preparers and auditors, and its official interpretive body, the International Financial Reporting Interpretations Committee (IFRIC).

The more principles-based approach of IFRS will present some unique challenges for regulated utilities.

### IFRS Challenges

The more principles-based approach offered by IFRS will present some unique challenges for the regulated utility industry. With IFRS likely to arrive in the near—rather than distant—future, affected utilities should consider the implications of IFRS and start planning now.

■ **Accounting by regulated entities:** Under U.S. GAAP, FASB Statement No. 71, Accounting for the Effects of Certain Types of Regulation, regulated entities are allowed to account for certain incurred costs that will be able to be recovered through future rates as regulatory assets. Conversely, amounts previously collected but owed back to ratepayers are accounted for as regulatory liabilities. There is no comparable provision under IFRS, which means that, from the regulatory-asset perspective, certain costs (including stranded costs from deregulation, fuel recoveries, storm damage, environmental remediation, and losses on refinancing to a name a few) will need to be written-off (despite the regulatory provision to recover such costs from ratepayers in the future). This would result in the recording of future revenues with no corresponding cost recognition.

■ **Property, plant and equipment:** Accounting for items such as property, » plant and equipment may be more granular under IFRS than under U.S. GAAP. IFRS requires companies to account for fixed assets at the component level, which is defined as the unit of measurement to separately identify an asset, or part thereof, with a separately identifiable estimated useful life. Although most utilities account for assets using a retirement-unit level, reviewing current fixed-asset accounting records will help utilities determine which components should be depreciated over what estimated useful lives.

Lack of a parallel standard to Statement No. 71 in IFRS will mean that the treatment of gains and losses arising from disposal of assets belonging to regulated entities also will require review, as will the treatment of impairments and decommissioning obligations for current operating assets—particularly as the trend toward new nuclear generation and expansion into alternative energy sources continues. Policies that bear reviewing include those relating to allowable capitalized costs and accounting for subsequent replacement of components to make sure amounts are not overcapitalized on a company's balance sheet.

■ **Financial instruments**: This area poses probably the biggest conversion challenge. Commodity contracts and hedging activity play a significant part in the operations of utilities. Although the two relevant accounting standards, FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities (as amended for U.S. GAAP purposes), and IAS 39, Financial Instruments: Recognition and Measurement, generally are comparable, some fundamental differences merit utilities' consideration. Review of contractual language and details will be key: Reevaluating contracts will allow utilities to determine the proper accounting treatment in accordance with IFRS.

IFRS uses the "own-use" definition to exempt contracts that were entered into and continue to be held for the purpose of receipt or delivery of a non-financial item in accordance with the entity's expected purchase, sale or usage requirements. Certain hedging relationships—or the concept of normal purchases and normal sales—might be treated differently under U.S. GAAP than they are under IFRS and its related own-use determination. Under IFRS, it's also possible to hedge components (portions) of risk that give rise to changes in fair value. The overall valuation of financial instruments (specifically, considering the definition of fair value as set forth in the literature) and the accounting for day-one gains also may result in differing accounting results under the two standards.

Certain hedging relationships might be treated differently under IFRS and its "own-use" determination.

■ **Accounting for joint ventures**: Currently, IFRS states that investments in associated companies are accounted for using the equity method, and investments in jointly controlled entities are accounted for under the equity method or proportionate consolidation. However, the treatment of joint ventures, including jointly-controlled assets, operations and entities, and the use of *pro rata* consolidation currently allowed under IFRS, are under review. This is another challenging area that likely will affect certain operating structures in place in the U.S. power and utilities industries. While varying structures allow companies to account for such joint ownership in the United States, some companies also have used the *pro rata* consolidation concept in U.S. GAAP-based financial statements to account for ownership interests in plants and related assets.

■ **Emissions**: Due to a worldwide focus on climate change, emissions generated by power and utility companies have received a lot of attention, and this also has raised accounting awareness. In addition, the recent District of Columbia Circuit Court of Appeals ruling in July 2008 striking down the U.S. Environmental Protection Agency's Clean Air Interstate Rule raised valuation and potential impairment issues related to nitrogen oxide and sulphur dioxide trading programs. This ruling has affected companies that began installing certain emissions-reduction control equipment at their plants. While both the Financial Accounting Standards Board (FASB) and IASB have accounting for emission allowances as current projects, neither U.S. GAAP nor IFRS currently sheds much light on any specific method of accounting for these allowances, resulting in at least two different methods of accounting. The two methods primarily focus on whether the emission allowances should be recorded as inventory or intangibles with the valuation question focused on whether to carry the allowances at historical cost or fair value. A related question arises as to whether an obligation should be recorded, and as of what date, related to a company's emissions.

IFRIC previously issued Interpretation 3 related to accounting in this area, but that interpretation was withdrawn, leaving unanswered questions about accounting for emissions. However, IASB recently added an Emission Trading Schemes project onto its agenda. The board tentatively decided that the scope of the project will address accounting for all tradable emission rights and obligations, and for activities to receive tradable rights in the » future. Accounting commentary and literature increasingly address IFRS issues, so conversion likely will lend additional guidance in this area.

**Agency Treatment**

Investor-owned U.S. power and utility companies are regulated by the SEC as well as other entities, such as the Federal Energy Regulatory Commission (FERC) and local agencies of the states in which they operate. The accounting rules of FERC and other regulatory agencies heavily have influenced the accounting policies guiding U.S. utilities. To date, IFRS makes no allowance for other regulators, and this is not likely to be covered by the continuing SEC roundtable and other planning discussions.

At this point, FERC isn't expected to change its Uniform System of Accounts simply because of a proposed U.S. conversion to IFRS. Even if a change eventually would be forthcoming, it wouldn't happen until after U.S. issuers convert to IFRS.

For most industries, IFRS ultimately might enable companies to streamline reporting processes and reduce the cost of compliance. However, for U.S. power and utility companies, if the concepts of Statement No. 71 are not adopted or embraced by IFRS rule makers, accounting practices mandated by FERC and other regulatory bodies might result in the requirement to maintain a separate set of financial records, similar to the process for current statutory reporting in certain international jurisdictions. The need to generate the required accounting information could have significant implications for a company's information-technology system. As a result, these companies would need to continue evaluating accounting for industry-specific issues and how it affects their IFRS planning.

> Momentum is building for U.S. adoption of IFRS, and conversion no longer appears to be a matter of "if," but more a matter of "when" and "how."

In any case, momentum is building for U.S. adoption of IFRS, and conversion no longer appears to be a matter of "if," but more a matter of "when" and "how." For companies that report in multiple jurisdictions, the adoption of a single global set of accounting standards can be a benefit in terms of process standardization and related efficiency gains. Multiple approaches to financial reporting continue to be inefficient and troublesome, and many affected companies strongly support the SEC's continued efforts in the U.S. transition to IFRS.

The question that power and utility executives and directors need to tackle—sooner, rather than later—is how they can maximize the opportunities presented by IFRS and effectively and efficiently deal with any challenges as a result of the conversion. The straightforward answer is to start planning now, dedicate the appropriate management focus and create a project team across all aspects of the company—including the financial accounting and reporting, tax and IT departments—to assess the effort and work toward transition activities. Also, it's never too early to begin educating analysts and investors on how a conversion to IFRS might impact the company's financial results.

Now is the time to begin planning for conversion from GAAP to IFRS. The resources needed and the impact on the organization will be far-reaching. But with proper strategic planning, benefits can be substantial.

*Scott Hartman is executive director with Ernst & Young Assurance and Advisory Business Services.*

FEDERAL ENERGY REGULATORY COMMISSION
Office of Enforcement
Washington, D.C. 20426

April 16, 2009

Ms. Elizabeth M. Murphy
Secretary
U.S. Securities and Exchange Commission
100 F Street, N.E.
Washington, DC 20549

Reference: File Number S7-27-08- IFRS Roadmap

This letter is in response to the SEC's request for comments on the Securities and Exchange Commission's (SEC) *Roadmap for the Potential Use of Financial Statements Prepared in Accordance With International Financial Reporting Standards (IFRS) by U.S. Issuers*. The Federal Energy Regulatory Commission (FERC) is an independent agency charged with regulating, among other responsibilities, transmission of electric energy, natural gas, and oil in interstate commerce, wholesale sales of electric energy and natural gas, and the reliability of the electric transmission system. Such responsibilities include rate regulation, accounting and financial reporting.

Most of the entities under FERC's jurisdiction file financial information with FERC prepared in accordance with U.S. Generally Accepted Accounting Principles (GAAP) with certain departures to recognize the economic effects of regulation. Therefore, the SEC's proposal regarding the adoption of International Financial Reporting Standards (IFRS) will have a significant impact on energy companies regulated by this agency. The following comments represent the views of the FERC staff on the SEC's proposed rule.

Under current international accounting standards, cost-based rate regulated entities would not be able to reflect the economic effects of regulation on their publicly issued financial statements as currently permitted under U.S. GAAP pursuant to Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation, and its predecessor, the Addendum to Accounting Principles Board (APB) Opinion No. 2. As discussed below, should the SEC adopt IFRS, I urge the SEC to encourage the International Accounting Standards Board (IASB) to adopt an accounting standard similar to SFAS No. 71 that would permit cost-based rate regulated entities to reflect the rate actions of regulators in their financial statements.

**Need for Specialized Accounting for Cost-Based Rate Regulated Entities**

Under cost of service ratemaking, a regulator establishes the rates that a rate-regulated entity may charge its customers. The resulting rate is based on costs incurred plus a reasonable return. A rate regulator may require that costs incurred in one period be deferred and recovered from customers over a future period in order to smooth the resultant rate over time. Similarly, a rate regulator may require revenues or gains realized in the current period to be returned or refunded to customers over a future period. Cost of service ratemaking relies on accurate cost and revenue data that reflects a company's true economic position in order to establish just and reasonable rates. Adoption of sound and uniform accounting standards are particularly important for cost-based, rate regulated entities, because of the degree of reliance which must be placed on financial statement information for purposes of accurate cost-based pricing. Without reliable financial statements that depict the economic substance of the rate regulator's actions on the regulated entity, federal and state regulators, customers, and stakeholders would not be able to accurately determine the costs that relate to a particular time period, service, or line of business; determine whether a given utility has previously been given the opportunity to recover certain costs through rates; or compare how the cost of one utility relates to that of another.

Intertwined with the accounting and reporting responsibilities and authorities of the SEC and the Financial Accounting Standards Board (FASB) are those of the FERC. The FERC's Uniform Systems of Accounts (USofA) and related financial reporting regulations were adopted in 1936 and have been refined and modified over the last 70 years to support FERC's role in ensuring the justness and reasonableness of cost-based rates. The USofA and related financial reporting requirements prescribed by the Commission are based on U.S. GAAP with certain differences to accommodate the manner in which costs are recovered in cost-based rates. As mentioned, differences can occur when the regulator allows or requires costs (or revenues) to be recognized over a number of future periods rather than being recognized in the year in which they occur. Some examples of differences are plant phase-ins, normalization of significant non-recurring operating and maintenance expenses, rate refunds, and gains or losses on the sale of assets.

Such differences have not typically resulted in conflicts between FERC and SEC reporting in the past in part because of the existence of SFAS No. 71, and its predecessor, the Addendum to APB Opinion No. 2. These accounting statements recognize that differences may arise in the application of U.S. GAAP between regulated and non-regulated businesses because of the economic effect of cost of service rate-making on regulated businesses, a phenomenon not present in non-regulated businesses.

Rate-regulated entities currently report hundreds of billions of dollars in cost and revenue/gain deferrals to recognize the economic effects of regulator actions. Without an equivalent SFAS No. 71 standard, these entities may be required to derecognize reported deferrals, which could have a dramatic impact on earnings, equity and capital structure, dividends, debt covenants, and rate making. Further, cost-based rate regulated entities' results of operations as reported in financial statements to FERC could differ greatly from the results of operations reported in the same companies' publicly issued financial statements, leading to inconsistency and potential investor confusion.

In December 2008, the IASB resolved to add a project on rate regulated activities to its agenda with a tentative exposure draft publication date of May 2009. If the IASB does not ultimately adopt such a standard, the true economic position of rate-regulated entities may not be recognized. Should the SEC adopt IFRS, I urge the SEC to encourage the IASB to adopt an accounting standard similar to SFAS No. 71 to appropriately recognize the economic effects of a regulator's actions in setting cost-based rates.

Sincerely,

Scott P. Molony
Chief Accountant

Snavely King Majoros O'Connor & Bedell
40 Best Energy Companies
2007-2009 Regulatory Liability



| Companies (1) | State | COR ($M) 2009 | 2008 | 2007 |
|---|---|---|---|---|
| DPL | OH | 99.1 | 96 | 92 |
| Energen | AL | 137 | 130 | 122 |
| PPL | PA | 0 | 0 | 0 |
| National Fuel Gas (**) | NJ | 105 | 103 | 91 |
| Exelon | IL | 1,212 | 1,145 | 1,145 |
| First Energy ( Note 1) | OH | 0 | 215 | 183 |
| Entergy | LA | 44 | 63 | -6 |
| NJ Resources (**) | NJ | 56 | 63 | 61 |
| Southern Company | GA | 1091 | 1,321 | 1,308 |
| Questar | UT | 0 | 0 | 0 |
| CLECO | LA | 0 | 0 | 0 |
| Equitable Resources | PA | 0 | 0 | 0 |
| Edison International | CA | 2,515 | 2,368 | 2,230 |
| MDU Resources | MN | 251.1 | 94.7 | 90 |
| TECO Energy | FL | 554 | 551 | 543 |
| Dominion Resources | VA | 766 | 688 | 623 |
| Public Service Enterprise Group | NJ | 289 | 307 | 325 |
| Allegheny Energy | PA | 374 | 407 | 396 |
| Sempra Energy | CA | 2,557 | 2,430 | 2,522 |
| AGL Resources | GA | 183 | 178 | 169 |
| Mirant | GA | 0 | 0 | 0 |
| Nicor | IL | 797 | 752 | 721 |
| OGE Energy | OK | 168 | 151 | 140 |
| UGI (**) | PA | 0 | 0 | 0 |
| Nstar | MA | 220 | 217 | 214 |
| So Jersey Industries | NJ | 50 | 49 | 49 |
| Delta National Gas (*) | KY | 304 | 615 | 304 |
| Centerpoint Energy | TX | 818 | 779 | 734 |
| DTE Energy | MI | 506 | 534 | 581 |
| PG&E | CA | 2933 | 2,735 | 2,568 |
| El Paso Electric | TX | 0 | 0 | 0 |
| NRG | PA | 0 | 0 | 0 |
| SCANA | SC | 733 | 688 | 643 |
| WGL Holdings (**) | VA | 319 | 306 | 285 |
| MGE Energy | WI | 12 | 12 | 13 |
| Vectren | IN | 294 | 292 | 288 |
| AES | VA | 402 | 291 | 351 |
| Northwest Natural Gas | OR | 239 | 224 | 205 |
| Alliant | WI | 403 | 409 | 411 |
| Ameren | MO | 1,084 | 1,018 | 980 |
| | | 19,515 | 19,233 | 18,382 |

Companies (1) Fiscal Year December 31, 2009
*: Fiscal year June 30,2009
**: Fiscal year September 30, 2009
Note 1: First Energy is now a subsidiary of Basic Energy
Source: 10k filings with the SEC

**CERTIFICATE OF SERVICE**

08-GIMX-1142-GIV

I, the undersigned, hereby certify that a true and correct copy of the above and foregoing document was placed in the United States mail, postage prepaid, electronic service, or hand-delivered this 1st day of December, 2010, to the following:

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## CERTIFICATE OF SERVICE

08-GIMX-1142-GIV


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