Power & Utilities Sector
2008 Accounting, Financial Reporting and Tax Update
November 6, 2008

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This document has been prepared to assist companies in the Power & Utilities sector with their 2008 financial, regulatory and compliance reporting. A central focus is on the specialized industry accounting and reporting applied by rate-regulated enterprises, and recently released and other accounting and disclosure requirements that companies in this sector must address. In addition, particular focus is also given to energy contracts, derivative instruments, hedging activities and the Financial Accounting Standards Board’s continuing emphasis on fair value measurements.

We have also included the latest guidance from the Security and Exchange Commission’s staff on disclosure and accounting matters and a discussion of the transition to International Financial Reporting Standards. This technical information follows a brief review of 2008 industry developments in the Power & Utilities sector.

We hope you find this document to be a useful resource.

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SECTION 1

Industry and Other 2008 Developments
Impact of carbon and other emissions

There has been significant and increasing focus by the governments, regulators, industry and consumers about how to reduce emissions. There are many research studies, proposed legislation and industry groups focused on how to achieve a reduction in these emissions.

Congressional bills have been proposed, such as the Lieberman-Warner Climate Security Act of 2007, which would limit the amount of greenhouse gas emissions and create emission allowances for greenhouse gas. Passage of such action at the federal level is likely in the future as both major presidential candidates have indicated they would propose legislation limiting such emissions. Additionally, many states have entered into coalitions or enacted laws to reduce emissions. Examples of state activities and federal initiatives include:

- Regional Greenhouse Gas Initiative – 10 U.S. states are participating in the RGGI. These states have/are creating plans that are similar to the model rules that were published in 2006 that require 100 percent of allowances for greenhouse gas to be auctioned. The RGGI begins in January 2009.

- Western Climate Initiative – Five U.S. states are participating in the WCI. Most WCI states have already created greenhouse gas laws or goals. Additionally, all WCI states are required to join the Climate Registry, which includes participants from the U.S., Canada and Mexico. The Climate Registry’s goal is to create uniform greenhouse gas accounting and reporting requirements.

- The Office of Fossil Energy is pursuing strategies to reduce carbon emissions by making fossil energy systems more efficient, and capturing and sequestering greenhouse gases.

- Clean Air Interstate Rule promulgated by the Environmental Protection Agency in March 2005, is a cap-and-trade system designed to reduce emissions of SO2 and NOx. The CAIR covers 28 eastern states and the District of Columbia.

However, there is not one simple solution to reduce emissions in the U.S. For instance, nearly 70% of the electricity generated in the U.S. comes from greenhouse gas emitting fossil fuels with coal 50% and natural gas 19%. As such, regulators and companies have to determine whether to continue to use these generation facilities as is, whether to close existing plants and replace with new generation or whether to install technology on the facilities to reduce the amount of emissions. If the decision is made to close these plants, there is still the controversial issue of choosing other sources of fuel (renewable alternatives, nuclear, etc.) to provide electricity to the customer base.

Additionally, there are other challenges to how to reduce emissions in the U.S., such as the U.S. Court of Appeals for the District of Columbia Circuit determination in February 2008 that the Clean Air Mercury Rule issued in March 2005 by the EPA to reduce emissions of mercury was unlawful. Currently, a replacement rule or plan has not been proposed to replace the CAMR. Other challenges include the increasing costs to construct new generation as well as how to comply with various federal and state requirements for complying with renewable energy standards.
New Generation and Pipeline Construction

Electric

According to the Energy Information Administration’s Annual Energy Outlook 2008, electricity consumption is expected to increase at least 30 percent by 2030 and 240 GW of new capacity will be needed at a cost of more than $400 billion. Cost estimates for new generation projects continue to increase and in some cases by 50 percent or more. As of the end of 2006, according to the EIA, there were over 200 new generators planned to be constructed in 2008 – 2011 that would increase generation by 69,000 MW. Such plants are mostly coal and natural gas fired. However, there has been a growing trend against coal fired plants with many coal plant cancellations. While there are approximately 30 applications for new nuclear generation plants, of which approximately 50 percent of these related applications have been accepted by the U.S. Nuclear Regulatory Commission, industry experts assert that no more than six may actually be constructed in the near future. In addition, 2010 – 2030 transmission and distribution investments are estimated by the Brattle Group to be $233 billion and $675 billion, respectively, requiring large capital infusion and higher rates.

While companies have many fuel options for new generation, including natural gas, coal, nuclear, wind and other alternative fuels, each option has limitations and its own unique issues. Additionally, advanced technologies are available to reduce the amount of emissions from new generation but costs become an issue. For example, there are at least six different technologies to help reduce the amount of emissions generated due to coal, including integrated gasification combined cycle, selective catalytic reduction and low-NOx burners.

Additionally, companies have to consider how to implement required or voluntary renewable portfolio standards that have been established through state laws, regulatory orders by state utility commissions, or voluntary participation in various coalitions. These standards require that a certain percentage of energy supply be purchased from qualified renewable sources regardless of cost or price impact. In some cases companies have to determine whether to build new generation that uses renewable energy or purchase this renewable energy from other parties that provide renewable energy.

Natural gas

The EIA estimates that total natural gas consumption will increase approximately 20 percent from 2006 to 2030. Additionally, the price of natural gas has increased from $2 per Mcf in the late 1990s to $8 plus per Mcf in 2008, with price spikes during that period that increased the price of gas to double digit prices.

The increased price and demand for natural gas has resulted in producers drilling for unconventional gas sources, such as the Barnett shale and Bossier Sands in Texas, the Rocky Mountains and Fayetteville shale in Arkansas. The large volume of this “unconventional” source has now made it conventional for gas supply planning purposes. Natural gas pipelines construction has followed suit and companies are building new pipelines to move the gas from these unconventional gas sources. During 2007, the EIA reported that $4.3 billion was spent to install approximately 1,700 miles of pipeline capacity. Pipeline companies have continued to build new projects during 2008. At the end of 2007, approximately 10,000 miles of new large pipeline for approximately 103 Bcf per day of capacity, already are being planned or have been approved by U.S. regulatory authorities for development between 2008 and 2010. These projects, if completed, are estimated to cost $28 billion. The project costs have continued to increase over budgeted costs due to the increased demand for labor and steel.

Alternative energy

There is a significant amount of focus on alternative and renewable energy sources. For example:

- The Energy Independence and Security Act of 2007 was signed into law on December 19, 2007. Among other things, the EISA increased the renewable fuels standard to require total U.S. consumption of renewable fuels to be 36 billion gallons in 2022.

- Twenty five states and the District of Columbia have mandatory renewal portfolio supply programs and four other states have voluntary renewable energy programs.

- In September 2008, Google and General Electric announced that they will be teaming up to promote change in the U.S. power grid and cleaner energy.

Wind is one of the prominent sources of alternative energy. According to the Global Wind Energy Council, installed wind capacity increased to approximately 17 GW in 2007 in the U.S. with new generation costing $9 billion in 2007. Other types of renewable energy sources include solar, hydroelectricity, geothermal heat and biomass.

State mandated RPS have spurred the development of numerous new wind and solar facilities and are leading to lower manufacturing costs and improved technologies. However, renewable energy sources are still not competitive in price and the passage of extension of wind and solar tax credits in 2008 was necessary to insure continuation of large renewable energy projects.
Other Developments

Credit and Valuation Matters

Introduction

There have been significant events during recent months that have impacted the credit markets, financial institutions, and energy and other companies. Although we have highlighted a number of potential issues companies should consider, these items are neither a comprehensive checklist nor a complete analysis. Companies should consider their own facts and circumstances and monitor ongoing developments to determine the impact of market conditions on their financial statements.

Considerations Associated With the Risk of Counterparty Default on a Contractual Arrangement

Noted below are areas of accounting that could be affected when there is a risk that a counterparty to a contractual arrangement could default. Fundamental to any analysis of possible accounting ramifications is an entity’s assessment and inventory of its exposures to counterparties at risk. Such exposures may be direct (e.g., an investment in a security issued by an entity in financial distress) or indirect (e.g., an investment in a mutual fund that is heavily invested in securities issued by an entity in financial distress).

Also, in Section 5, Energy Contracts, Derivative Instruments and Hedging Activities Update, some guidance related to nonperformance risk, and specifically considerations of nonperformance risk to the application of hedge accounting is reemphasized.

Fair Value Measurements/Hierarchy Classification

For transactions with entities or affiliates in financial distress, it is important to understand the legal status of the specific counterparty to the entity’s contracts. For example, is the counterparty bankrupt? Does the bankruptcy of an affiliate of the counterparty trigger the default provisions of the contractual arrangement?

An entity also should assess whether:

- Potential counterparty default would affect the entity’s master netting or collateral agreements and the valuation of its derivatives. That is, would the provisions of those agreements be triggered by the bankruptcy or default of the counterparty or its affiliates? What are the accounting implications of those provisions?

- The pricing inputs used to measure fair value of the contract represent inputs in an active or inactive market.

- Transactions with a defaulted counterparty represent forced or distressed transactions.

- The creditworthiness or legal status of the counterparty trigger transfers between categories in the SFAS 157, Fair Value Measurements, fair value hierarchy (e.g., transfer between level 2 and level 3).

An entity also should consider the recent guidance released by the SEC staff and the FASB, which is discussed in FSP FAS 157-3, Determining the Fair Value of a Financial Asset in a Market That Is Not Active, which was effective when issued on October 10, 2008. Also see Section 6, Fair Value Measurements.

Transfers and Servicing of Financial Assets and Extinguishments of Liabilities

If an entity in financial distress is the counterparty to a repurchase or dollar roll arrangement:

- For open contracts, what are the accounting implications of the settlement terms embedded in the default provisions of the contractual arrangements?

- What is the impact of possible default on recognition and valuation of collateral posted for these arrangements?

- Has it been determined whether the transferor in these transactions has given up effective control?
Considerations Related to the Current Economic Environment

Noted below are some important accounting issues that preparers should also consider in light of the current economic environment.

Goodwill and Intangible Assets

A decline in the price of an entity’s equity securities may indicate an impairment of the entity’s goodwill and indefinite-lived intangible assets. Also see Section 2, SEC Update, regarding SEC staff comment letters.

Other-Than-Temporary-Impairment

The current economic environment continues to require entities to focus on whether impairment of certain investments is other than temporary.

Consolidation Considerations (FIN 46(R), Consolidation of Variable Interest Entities, and Reconsideration Events)

The filing of bankruptcy or default of an enterprise with an interest in a previously determined VIE could cause other interest holders in the VIE to reassess whether they are the primary beneficiary of the VIE under paragraph 15 of FIN 46(R). The primary beneficiary of a VIE consolidates the VIE.

FIN 46(R) requires an enterprise with an interest in a VIE to reconsider whether it is the primary beneficiary of the VIE if, for example, the following events occur:

- A change in “the entity’s governing documents or contractual arrangements…in a manner that reallocates between the existing primary beneficiary and other unrelated parties (a) the obligation to absorb the expected losses of the [VIE] or (b) the right to receive the expected residual returns of the [VIE].”
- The acquisition by the enterprise of additional variable interests in the VIE.

Cash Flow Hedges of Choose-Your-Rate Debt

In applying cash flow hedge accounting to choose-your-rate debt, an entity may have designated the risk of changes in its cash flows attributable to changes in the designated benchmark interest rate as its hedged risk and ignored the rate optionality of the debt when assessing and measuring hedge effectiveness. In such cases, the accounting treatment was based on an assertion that the entity would always select a single benchmark interest rate at each interest reset date. Current market conditions may prompt an entity to select a different rate, which would make application of hedge accounting inappropriate for the reporting period in which the different rate was selected for this hedge and other similar hedges of choose-your-rate debt.

Going Concern/Liquidity

Continued deterioration in the credit markets may present liquidity concerns for entities, such as the following:

- Credit rating/downgrades and market illiquidity may affect an entity’s ability to raise capital when needed.
- The availability of lines/letters of credit may be affected if the lending institution is in financial distress.
- Access to the commercial paper markets may be limited because of lack of demand.
- Declines in the value of investments offered as collateral may require posting of additional collateral.

Income Taxes

Changes in recorded amounts of assets and liabilities without a corresponding change to the tax basis generally result in the recognition of a deferred tax liability or deferred tax asset. Entities should keep in mind that SFAS 109, *Accounting for Income Taxes*, requires deferred tax assets to be reduced by a valuation allowance “if, based on the weight of available evidence, it is more likely than not (a likelihood of more than 50 percent) that some portion or all of the deferred tax assets will not be realized. The valuation allowance should be sufficient to reduce the deferred tax asset to the amount that is more likely than not to be realized.”

An entity should carefully consider whether a valuation allowance is required. Future realization of the tax benefit of a tax asset ultimately depends on the existence of sufficient taxable income of the appropriate character (e.g., ordinary income or capital gain) within the appropriate period available under the tax law.
Disclosures
The credit crisis underscores the importance of providing comprehensive disclosures about the effects of the current credit environment on an entity’s financial position, results of operations, cash flows, and liquidity and the potential exposures associated with this environment. Entities should consider information included in the following Deloitte Alerts:

- Financial Reporting Alert 08-4, *Turmoil in the Credit Markets: The Importance of Comprehensive and Informative Disclosures.*
- Financial Reporting Alert 08-7, *SEC Advises Registrants to Further Explain Fair Value in MD&A.*

Emergency Economic Stabilization Act
The recently signed legislation may raise additional accounting questions in a number of areas, including:

- Income taxes.
- Loan impairments.
- Debt and equity securities.
- Derivatives and hedge accounting.
- Transfers and servicing of financial assets.
- Fair value measurements.

Other matters related to the credit crisis that should be considered include:

- Whether any limitations on the entity’s to issue debt or equity or access credit lines impacts the company’s going concern conclusions.
- Impact on receivables valuation and contractual commitments due to bankruptcies and liquidity issues of counterparties.
- Disclosure of contractual collateral or settlement triggers if the entity’s credit rating is downgraded.
- Impact of funding requirements for pension and post-retirement plans and nuclear decommission trusts as a result of significant decreases in the market values of the respective investment portfolios.
SECTION 2

SEC Update

Introduction

This section summarizes some of the SEC accounting and reporting issues impacting the utility industry. The issues summarized below include:

- SEC Issues Disclosure Rules and Approves One-Year Deferral of Section 404 Requirement for Smaller Companies
- SEC Advises Registrants to Further Explain Fair Value in MD&A
- SEC Holds Roundtable on Fair Value
- SEC Proposes Changes to Oil and Gas Reporting Requirements
- SEC Proposes Rule on Interactive Data
- SEC Advisory Committee Releases Final Report
- SEC Issues Guidance on the Use of Corporate websites
- SEC Proposes to Give Certain U.S. Issuers the Option to Use IFRS in the Annual Report Update and Proposes a Roadmap to a Mandatory Transition Date for All U.S. Issuers
- SEC Accelerates the Deadline for Foreign Private Issuer Annual Filings on Form 20-F
- SEC Staff Explains the Filing Review and Comment Letter Process
- SEC Staff Comment Examples

SEC Issues Disclosure Rules and Approves One-Year Deferral of Section 404 Requirement for Smaller Companies

The SEC adopted new disclosure rules for smaller registrants (i.e., public companies with a public float of less than $75 million). The new rules will eventually require smaller public companies to file the same forms as their larger counterparts (i.e., they will be required to file using standard forms, such as Form 10-K and Form S-1, rather than the current smaller-company forms, such as Form 10-KSB and Form SB-2). Smaller companies are also eligible to use Form S-3 or F-3 for primary securities offerings if they meet certain criteria (listed on the SEC’s website). The disclosure rules are effective as of February 4, 2008. Form S-3 and F-3 eligibility is effective as of January 28, 2008.

On June 26, 2008, the SEC issued a final rule that will allow smaller registrants (non-accelerated filers) a one-year deferral (from December 15, 2008, to December 15, 2009) from complying with SEC rules issued in response to Section 404(b) of the Sarbanes Oxley Act of 2002 that require these registrants’ annual reports to include an auditor’s attestation report on management’s assessment of internal control over financial reporting. The final rule became effective on September 2, 2008. This one-year deferral only applies to the auditor’s attestation report and not to management’s report on internal controls over financial reporting which is already required for virtually all U.S. issuers. Failure to include the management report will result in filings being deficient and impact the ability to use Form S-3 and certain other forms. The revised compliance dates for the Section 404(b) internal control requirements are presented in the table below:
Filer Status | Compliance Dates for the Internal Control Over Financial Reporting Requirements | Auditor attestation
--- | --- | ---
U.S. Issuer | Non-accelerated filer (public float under $75 million) | Annual reports for fiscal years ended on or after December 15, 2007 | Annual reports for fiscal years ending on or after December 15, 2009
U.S. Issuer | Large accelerated filer and accelerated filer (public float above $75 million) | Annual reports for fiscal years ended on or after November 15, 2004 | Annual reports for fiscal years ending on or after November 15, 2004
Foreign Private Issuer | Non-accelerated filer (public float under $75 million) | Annual reports for fiscal years ended on or after December 15, 2007 | Annual reports for fiscal years ending on or after December 15, 2009
Foreign Private Issuer | Accelerated filer (public float above $75 million and below $700 million) | Annual reports for fiscal years ended on or after July 15, 2006 | Annual reports for fiscal years ended on or after July 15, 2007
Foreign Private Issuer | Large accelerated filer (public float above $700 million) | Annual reports for fiscal years ended on or after July 15, 2006 | Annual reports for fiscal years ended on or after July 15, 2006
U.S. or Foreign Private Issuer | Newly public company | Second annual report | Second annual report

SEC Advises Registrants to Further Explain Fair Value in MD&A

A major theme at the 2007 AICPA National Conference on Current SEC and PCAOB Developments was the need for registrants to provide transparent disclosures in their notes to the financial statements and MD&A about the potential for credit losses as well as about their exposures to the current credit environment. In her keynote speech, SEC Commissioner Kathleen Casey indicated that the staff is issuing comments to registrants regarding their disclosures about the subprime developments. Stephanie L. Hunsaker, associate chief accountant in the SEC’s Division of Corporation Finance, observed that registrants should provide investors with information about their:

- Subprime exposure.
- Off-balance-sheet risks.
- Structures that may need to be consolidated in the future.
- Exposure to investments without readily determinable values.

In March 2008, the SEC’s Division sent a letter to certain financial institutions concerning additional MD&A disclosure considerations regarding fair value for their upcoming filings on Form 10-Q. While the letter was sent only to financial institutions, the SEC staff has indicated that the letter “can be applicable to any company.”

The letter reminds registrants that have significant amounts of financial instruments to consider the SEC’s requirements for disclosures in MD&A. Regulation S-K, Item 303, Management’s Discussion and Analysis of Financial Condition and Results of Operations requires registrants to discuss in their periodic filings any known trends, demands, commitments, events, or uncertainties that the registrants reasonably expect to have a material impact, either favorable or unfavorable, on their results of operations, liquidity, or capital resources. The letter also highlights some MD&A disclosure matters relating to SFAS 157. While SFAS 157 disclosures provide financial statement users with detailed information about fair value measurements, the SEC expects that its suggested MD&A disclosures will offer additional insight into registrants’ fair value measurements of financial instruments.


During the third quarter 2008, the SEC sent a letter to certain financial institutions concerning MD&A fair value disclosure considerations for their upcoming filings on Form 10-Q. These considerations are in addition to those identified in the Division’s March 2008 letter. While the September 2008 addendum letter was sent to the same financial institutions as the March 2008 letter, the Division has indicated that, like the March 2008 letter, the addendum applies to other organizations.

The addendum letter is in response to reviews conducted by the SEC as well as roundtables held by the SEC on fair value. The SEC would like companies to disclose, when material, how credit risk affected their fair value measurements, including the gains or losses recognized on their derivative liabilities that are attributable to changes in their own credit risk, since these amounts have been substantial at some financial institutions. In addition, the SEC asks companies to consider disclosing how they factored market illiquidity into their fair value determination,
significant judgments they used in classifying fair value measurements in the SFAS 157 hierarchy, and how they used brokers or pricing services in developing fair value measurements.

While the two letters do not replace or amend existing U.S. GAAP requirements, the SEC believes that the considerations outlined in the letters will provide investors with “clearer and more transparent” disclosures about the registrants’ fair value measurements and the methods and assumptions underlying these measurements.

A full copy of the SEC’s September 2008 sample letter is available at http://www.sec.gov/divisions/corpfin/guidance/fairvalueltr0908.htm

SEC Holds Roundtable on Fair Value

On July 9, 2008, the SEC hosted a roundtable about the benefits and potential challenges associated with fair value accounting and auditing standards. The roundtable consisted of two panels: (1) larger financial institutions and (2) all public companies. Key highlights from the discussions included the following:

- The consensus of both panels was that fair value is the most relevant measure for financial instruments and is widely preferred by investors.
- Panelists stressed the need for high-quality, comprehensive disclosures about fair value measurements.
- Panelists indicated that it is difficult to value assets in the absence of markets.
- Most panelists supported the concept of incorporating an entity’s own risk into fair value liabilities.

SEC Proposes Changes to Oil and Gas Reporting Requirements

On June 26, 2008, the SEC issued a proposed rule that updates the reporting requirements for oil and gas companies, which exist in their current form in Regulation S-K and Regulation S-X under the Securities Act of 1933 and the Securities Exchange Act of 1934, as well as Industry Guide 2, to reflect the significant changes that have occurred in the industry over the past 25 years. According to the proposed rule “the revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves, which should help investors evaluate the relative value of oil and gas companies. The proposed amendments would also codify Industry Guide 2 in Regulation S-K, with several additions to, and deletions of, current Industry Guide items.” For example, the proposed rule:

- Expands the scope of permissible technologies for determining certainty levels of reserves, reserves classifications that a company can disclose in a filing, and the types of resources that can be included in a company’s reserves.
- Allows companies to disclose probable and possible reserves.
- Changes the price used to calculate reserves from a year-end single-day price to an historical average price over the company’s most recently ended fiscal year.
- Adds disclosure requirements relating to the objectivity and qualifications of any third party primarily responsible for preparing or auditing the reserves estimates, if the company represents that it has enlisted a third party to conduct a reserves audit.
- Adds tabular disclosure of the aging of proved undeveloped reserves.
- Provides guidance about the type of information that companies should consider disclosing in MD&A, and would allow companies to include this information with the relevant tables.
- Updates the definition of the term “oil and gas producing activities” as well as updates or creates new definitions for other terms related to such activities, including “proved oil and gas reserves” and “reasonable certainty.”


SEC Proposes Rule on Interactive Data

On May 30, 2008, the SEC issued a proposed rule on interactive data for improving financial reporting. The new rule would require domestic and foreign companies that prepare their financial statements in accordance with U.S. GAAP and IFRS (as issued by the International Accounting Standards Board) to use extensive business reporting language when submitting their financial information for periods ending on or after December 15, 2008, for the largest companies and within the following two years for smaller companies. In certain Exchange Act forms (Forms 10-K, 20-F, and 10-Q) and Securities Act registration statements (containing financial statements) filed for a period ending after the appropriate effective date, a registrant must furnish interactive data as an exhibit to the filing.
This information includes:

- Financial statements (each line item is tagged).
- Notes to the financial statements (each note individually tagged as a single block of text in the first year; detailed tagging of individual amounts and narrative disclosures within each footnote also would be required in subsequent years).
- Financial statement schedules (each schedule individually tagged as a single block of text in the first year; detailed tagging of individual amounts within each schedule also would be required in subsequent years).

A registrant is not required to provide interactive data for MD&A.

The following summarizes the proposed timing for submission of interactive data:

<table>
<thead>
<tr>
<th>Registrant Category</th>
<th>Effective Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Registrants that file under U.S. GAAP and have a public float &gt; $5 billion as of the end of the most recently completed second fiscal quarter</td>
<td>Periods ending on or after December 15, 2008</td>
</tr>
<tr>
<td>All other large accelerated filers using U.S. GAAP</td>
<td>Periods ending on or after December 15, 2009</td>
</tr>
<tr>
<td>Most other registrants, including:</td>
<td>Periods ending on or after December 15, 2010</td>
</tr>
<tr>
<td>• All remaining filers using U.S. GAAP, including smaller reporting companies</td>
<td></td>
</tr>
<tr>
<td>• Foreign private issuers using IFRS in the Annual Report Update as issued by the IASB</td>
<td></td>
</tr>
</tbody>
</table>

To respond to concerns about the expense and burden of initially adopting the proposed rule, the SEC proposed “a 30-day grace period for each filer’s initial interactive data submission, and a 30-day grace period in year two of each filer’s interactive data reporting when its footnotes and schedules initially would be required to be tagged in detail.” Entities taking advantage of the grace period would file the interactive data exhibit as a separate amendment to the filing. If a registrant maintains a website, it must provide on that website the same interactive data that it submits to the SEC on the same day the information is filed or required to be filed with the SEC (whichever is earlier).

What is XBRL?

XBRL is the tool registrants will use to make data furnished in their financial filings interactive. XBRL provides an identifying tag for each individual item of financial data. For example, “net income” has its own unique tag that a computer can read, understand, and treat “intelligently.” Tags can be applied not only to amounts but to nonmonetary financial concepts. For example, under U.S. GAAP, disclosure of qualitative information is frequently required in the notes to the financial statements. XBRL includes tags that an entity can apply to these required disclosures. For such disclosures, the tag is applied to a block of text in the financial statements. The collection of XBRL tags (also referred to as the taxonomy) has been modeled to accommodate most amounts and disclosures that must be reported under U.S. GAAP and includes approximately 13,000 data elements.

The SEC believes that the new XBRL format will enable investors to more quickly and easily (1) download the financial information, (2) compare the information of one company to that of another company, and (3) analyze the information. In addition, the SEC hopes that the XBRL format will help automate the regulatory and business information filing process and eventually reduce the costs of financial reporting.

SEC Advisory Committee Releases Final Report

In July 2007, the SEC formed the Advisory Committee on Improvements to Financial Reporting to independently review the current U.S. financial reporting system and provide the SEC chairman and other commissioners with detailed recommendations for its improvement. CIFiR consists of 16 individuals from diverse backgrounds to represent investors, audit committees, preparers, auditors, and others with key roles in the securities markets and is led by Robert C. Pozen, chairman of MFS Investment Management. The goal of CIFiR is to reduce complexity in the current U.S. financial reporting environment and improve the usefulness of financial information for users and investors.

On August 1, 2008, CIFiR released a final report summarizing its 25 recommendations for reducing complexity in financial reporting and increasing the usefulness of financial information provided to investors. CIFiR’s recommendations cover various processes that affect U.S. public companies (e.g., standard setting, regulatory oversight, and delivery of financial information).
Key themes underlying the recommendations include:

- Increasing the usefulness of information in SEC reports
- Enhancing the accounting standards-setting process
- Improving the substantive design of new accounting standards
- Delineating authoritative interpretive guidance
- Clarifying guidance on financial restatements and accounting judgments.

The following recommendations, if implemented, are likely to result in significant and immediate change to the financial reporting system:

- Increase investor input in standard setting.
- Create a financial reporting forum, which would consist of key constituents of the financial reporting community, including preparers, auditors, and investors.
- Conduct post-adoption effectiveness reviews of new FASB standards.
- Reduce the number of restatements by:
  - Modifying how the materiality of an error is assessed. CIFiR recommends that the FASB or SEC, as appropriate, supplement existing materiality guidance by clarifying how errors are evaluated on both an interim and annual basis. Specifically, errors should be evaluated on the basis of how they affect the “total mix of information available to a reasonable investor.” In addition, CIFiR believes that qualitative factors should be evaluated in the assessment of the materiality of an error, regardless of the quantitative size of the error. Under the current materiality guidance, qualitative factors may lead to a small error being deemed material, but a quantitatively large error not being deemed immaterial. Therefore, CIFiR recommends that the materiality guidance be supplemented to allow for a conclusion that because of qualitative factors a large error may not be material.
  - Changing how errors are corrected. CIFiR believes that the guidance on how to correct financial statements for errors should include the following:
    - “[A]ll errors, excluding clearly insignificant errors,” should be promptly corrected, with no deferral to a future period.
    - “Prior period financial statements should only be restated for errors that are material to those prior periods.” Materiality should be based on the needs of investors making current investment decisions. If errors are deemed not material to those prior periods, they may be corrected in the current period.
    - Companies should be required to provide additional information after a restatement is announced, but before the amended financial statements are filed with the SEC (an interval commonly referred to as the “dark period”).
  - Increase the exercise of professional judgment.
- Phase in the adoption of XBRL.
- Use executive summaries in annual and quarterly reports which would cover the most important information about a company’s business, financial condition, and operations.

SEC Issues Guidance on the Use of Corporate websites

On August 1, 2008, the SEC, responding to CIFiR’s recommendations and entities’ concerns, issued an interpretive release on the use of corporate websites to disclose information about an entity to the public. The interpretive release provides guidance on the following topics:

- What information posted by an entity on its website is considered “public”
- The liability framework for information included on an entity’s website
- The controls and procedures an entity should consider for information it posts on its website
- The format an entity should use for information posted on its website, “with the focus on readability, not printability”
SEC Proposes to Give Certain U.S. Issuers the Option to Use IFRS in the Annual Report Update and Proposes a Roadmap to a Mandatory Transition Date for All U.S. Issuers

On August 27, 2008, the SEC decided to issue a proposed IFRS “roadmap.” The proposed roadmap acknowledges that IFRS in the Annual Report Update have the potential to become the global set of high-quality accounting standards and sets seven milestones that, if achieved, could lead to an SEC decision for mandatory use of IFRS in the Annual Report Update starting for fiscal years ending on or after December 15, 2014.

Milestones 1–4 discuss issues that need to be addressed before mandatory adoption of IFRS in the Annual Report Update:

1. Improvements in accounting standards (i.e., IFRS in the Annual Report Update).
2. Funding and accountability of the International Accounting Standards Committee Foundation.
3. Improvement in the ability to use interactive data (e.g., XBRL) for IFRS reporting.
4. Education and training on IFRS in the Annual Report Update in the U.S.

Milestones 5–7 discuss the transition plan for the mandatory use of IFRS in the Annual Report Update:

5. Limited early use by eligible entities - This milestone would give certain U.S. issuers the option of using IFRS in the Annual Report Update for fiscal years ending on or after December 15, 2009. Details regarding who is eligible and their filing requirements during this “optional period” are described below.

6. Anticipated timing of future rule-making by the SEC - On the basis of the progress of milestones 1–4 and the experience gained from milestone 5, the SEC will determine in 2011 whether to require mandatory adoption of IFRS in the Annual Report Update for all U.S. issuers. If so, the SEC will determine the date and approach for a mandatory transition to IFRS in the Annual Report Update. Potentially, the option to use IFRS in the Annual Report Update when filing could also be expanded to other issuers before 2014.

7. Potential implementation of mandatory use - The proposed roadmap will raise many questions, including whether the 2014 transition date to IFRS in the Annual Report Update should be sequenced. The roadmap envisions a transition approach. That is, large accelerated filers could be required to file IFRS financial statements for fiscal years ending on or after December 15, 2014, then accelerated filers in 2015 and nonaccelerated filers in 2016.

Proposed Timeline in Roadmap
Eligibility

The objective of the eligibility criteria is to identify categories of U.S. issuers whose use of IFRS in the Annual Report Update would promote comparability with their significant global industry competitors. Under the proposed rule, U.S issuers that meet both of the following criteria would be eligible to use IFRS in the Annual Report Update in their financial statements filed with the SEC for fiscal years ending on or after December 15, 2009:

- The U.S. issuer globally is among the 20 largest companies in its industry, as measured by market capitalization.
- IFRS in the Annual Report Update, as issued by the IASB, are used as the basis for financial reporting more often than any other basis of accounting by the 20 largest public companies in that industry, as measured by market capitalization on a global basis.

An issuer that meets these criteria and chooses to use IFRS in the Annual Report Update must prepare its financial statements in accordance with IFRS in the Annual Report Update as issued by the IASB. In addition, the IFRS financial statements must include three years of audited annual comparative periods in the first year of IFRS reporting for SEC filing purposes, as opposed to the two years of annual comparative periods required under IFRS in the Annual Report Update. For example, a calendar-year-end company that is eligible to early adopt IFRS in the Annual Report Update and elects to do so for its 2009 fiscal year would present audited IFRS financial statements for the years ending December 31, 2007, 2008, and 2009, in its 2009 Form 10-K filed in 2010.

Companies that elect to use the option must still provide some financial information relating to U.S. GAAP. The proposed rule will request input on the following two alternatives for presenting this information:

- **Alternative A** — The U.S. issuer would provide a one-time reconciliation from U.S. GAAP to IFRS in the Annual Report Update that covers one year (the year of transition). The reconciliation would appear as a note to the audited financial statements in a manner consistent with the requirements under IFRS 1, *First-time Adoption of International Financial Reporting Standards*.
- **Alternative B** — The U.S. issuer would be required to provide, on an ongoing basis, an unaudited reconciliation from IFRS in the Annual Report Update to U.S. GAAP for the three years of IFRS financial statements included in the Form 10-K.

The SEC has posted to its website the proposed roadmap and proposed rule changes for public comment. The SEC is expected to discuss the comments received and decide, before the end of 2008, whether to issue the proposed roadmap and final rule that allows the optional period. For U.S. issuers that would not be eligible to use IFRS in the Annual Report Update under the proposed rule, the SEC will continue to monitor the progress made and milestones reached over the next few years in preparation for a 2011 decision on mandatory adoption. Companies are encouraged to comment on the SEC proposal regarding eligibility criteria for early implementation, mandatory implementation timing, transition reporting (three years of audited financial information vs. two years required by IFRS and for foreign filers), and other matters.

SEC Accelerates the Deadline for Foreign Private Issuer Annual Filings on Form 20-F

In August 2008, the SEC finalized a rule that would accelerate the deadline for annual filings on Form 20-F from six months to four months after an issuer’s fiscal year-end. This amendment is effective for fiscal years ending on or after December 15, 2011 (i.e., the Form 20-F that would be filed in 2012 for calendar-year-end companies).

SEC Staff Explains the Filing Review and Comment Letter Process

In June 2008, the staff of the Division issued an overview that explains its filing review and comment letter process. At the 2007 AICPA National Conference on SEC and PCAOB Developments, Mr. Wayne Carnall, then the Division’s new chief accountant, indicated that one of his highest priorities would be to help make interactions with the Division as efficient and effective as possible, including encouraging better communication among companies, auditors, and the Division staff. The overview helps accomplish that goal by providing more transparency in the review process and expressing the Division’s willingness to discuss issues with companies.

The overview is divided into two main sections:

- **The Filing Review Process** — This section explains that the Division comprises 11 offices staffed by experts in specialized industries, accounting, and disclosures. The section includes background on the different types (required and selective) and levels of review and covers the comment process, indicating that “[m]uch of the Division’s review [process] involves reviewing the disclosure from a potential investor’s perspective and asking questions that an investor might ask when reading the document.” The section also addresses how to respond to SEC staff comments and close a filing review.
• **The Reconsideration Process** — This section emphasizes that “Division staff members, at all levels, are available to discuss disclosure and financial statement presentation matters with a company and its legal, accounting, and other advisors.” In addressing companies’ potential requests for reconsideration of a staff member’s comment or view on a company’s response, the staff emphasizes that there is no formal protocol to follow. However, the staff explains where companies should start and the steps involved in the normal course of the reconsideration process. The staff also specifies contact information for each office in the Division for both accounting and financial disclosure matters and legal and textual disclosure matters.

The overview is available on the SEC’s website at [http://www.sec.gov/divisions/corpfin/cffilingreview.htm](http://www.sec.gov/divisions/corpfin/cffilingreview.htm).

**SEC Staff Comment Examples**

To prepare for year-end financial reporting, Deloitte Energy & Resources has prepared a summary of recent SEC staff comments. These comments are excerpted from letters received by Energy & Resources sector companies during the past several years and is designed to be an overview based on comments that may be broadly applicable or represent recent trends impacting companies in our industry. To obtain a copy of this summary of SEC staff comments please contact your local Deloitte Energy & Resources professional.

Below we have highlighted a few frequently issued recent SEC staff comment areas relevant to the Energy & Resources sector:

**Subsidiary and Equity Investee Dividend Restrictions and Schedule I Requirement**

The financial flexibility of regulated entities and the nature of their relationships with affiliated persons, including the parent company, could be subject to regulatory restraints. Subsidiaries often have financing agreements which may restrict the transfer of funds to a parent or other affiliated party or other types of transactions with affiliates. In addition, the operations of subsidiaries with significant minority equity interests may be influenced by these minority equity holders.

In situations where the transfer or dividend of assets (cash or other funds) to the parent company/registrant by its subsidiary(ies) or 50 percent or less owned affiliates is restricted, limited or requires third party approval, Rule 4-08(e), 5-04 and 12-04 of Regulation S-X may require (depending on the materiality of the restriction or limitation):

- Footnote disclosure of such restriction,
- Presentation in a financial statement schedule (Schedule I) of condensed parent company financial data or
- Both footnote and Schedule I disclosures.

Schedule I is required to be filed when the restricted net assets of consolidated subsidiaries exceed 25% of consolidated net assets as of the end of the most recently completed fiscal year. Rule 4-08(e) footnote disclosure is required if the total restricted net assets of subsidiaries plus the parent’s equity in the undistributed earnings of 50% or less-owned entities exceeds 25% of consolidated net assets. SAB 6K, *Separate Financial Statements Required by Regulation S-X*, provides further guidance on how to determine the restricted net assets of subsidiaries.

In recent months the SEC has engaged in discussions with various public utilities regarding these SEC requirements. The focus of these recent discussions has been on whether these registrants have adequately considered the provisions of the federal Power Act and federal Energy Regulatory Commission and state regulatory orders restricting the transfer of assets from subsidiaries to the parent company through dividends, loans, advances, or returns of capital without additional regulatory approvals.

As a result of these discussions, several Energy & Resources sector companies have either been required or have agreed, although not required, in future filings (1) to expand their disclosure regarding potential dividend restrictions, and (2) to provide a Schedule I as part of their Annual Form 10-K filing.

**Impairment of Indefinite Lived Intangible Assets and Goodwill**

Continuing declines in the prices of equity securities traded in public markets may indicate an impairment of an entity’s goodwill and indefinite-lived intangible assets under SFAS 142, *Goodwill and Other Intangible Assets*. Paragraph 28 of SFAS 142 states that goodwill of a reporting unit should “be tested for impairment between annual tests if an event occurs or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount.”

Recently the SEC staff has issued comments to entities with significant amounts of goodwill and other intangible assets but for which current market capitalization has significantly declined and in some cases is now below the book value of the Company’s stockholders’ equity, requesting these entities to provide further analysis of why they believe their goodwill and intangible assets are not impaired.
When the quoted market price of an entity’s equity securities has declined, the entity should seek to identify the underlying cause of the decline to determine whether such an event or change in circumstance has occurred. Sometimes, significant declines in the quoted market price of an entity’s securities do not occur suddenly but gradually as a result of a series of events that would not be individually specified as impairment indicators in paragraph 28 of SFAS 142.

The SEC staff has indicated that for multiple reporting units, an entity should be able to reconcile the aggregate fair values of all reporting units to the market capitalization of the entity, including a control premium, if applicable. SFAS 142 does not specifically require this, and completion of such a reconciliation may require additional estimates or assumptions when goodwill is not assigned to portions of an entity’s business (thus, these portions do not have to be periodically measured at fair value). However, entities should be able to perform such a reconciliation as part of an overall assessment of the fair values measured for reporting units.

**Accounting for Impacts of Ratemaking**

SEC staff comments to regulated utilities continue to focus on the following requirements:

- Disclosure of how the company’s current regulated rates are designed to recover its specific costs of providing service (paragraph 5(b) of SFAS 71).
- Disclosure of the nature of all material regulatory assets and liabilities and, in accordance with a best practices approach, affirmatively indicate whether a particular regulatory asset is earning a rate of return and the anticipated recovery period.
- Disclosure of any portion of the regulatory asset balance on which the company does not earn a current return, disclose the nature and amount of each asset and its remaining recovery period (paragraph 20 of SFAS 71).

See Section 4 for example footnote disclosures requested by the SEC staff.

**Separate Disclosure of Regulated and Non-regulated Operations**

SEC staff comments requesting additional separate disclosures of regulated and non-regulated operations and assets have become more frequent. Such comments have included requests for separate disclosures, even though some of this information can be derived from segment disclosures, in such areas as:

- Revenues from public utility operations and other product and service revenues in accordance with S-X Rule 5-03(1)
- Fuel, purchased power and other operating expenses
- Property, accumulated depreciation, and depreciable lives
SECTION 3

International Financial Reporting Standards

As discussed in Section 2 - SEC Update, the SEC has proposed an IFRS Roadmap to mandatory adoption of IFRS detailing certain milestones that must be achieved for a successful transition to IFRS in the U.S. IFRS appears inevitable for public companies in the U.S. and for most companies around the world. P&U sector companies have significant investments in PP&E and often make use of derivative instruments. Further, many U.S. P&U sector companies operate subject to governmental regulatory bodies that set the rates charged to customers. This will present challenges for any U.S. P&U sector company looking to transition to IFRS.

IFRS and U.S. GAAP differ in key ways, including their fundamental premise. At the highest level, U.S. GAAP is more of a rules-based system, whereas IFRS is more principles-based. This distinction may prove more vexing than it initially appears, because most accounting and finance professionals in the U.S. have been schooled in the rules of U.S. GAAP. The overriding lesson from their years of study and work is this: If you have an issue, look it up. Under U.S. GAAP, voluminous guidance attempts to address nearly every conceivable accounting problem that might arise. And if that guidance doesn’t exist, it generally is created. On the other hand, IFRS is a far shorter volume of principles-based standards and consequently requires more judgment than U.S. accountants are accustomed to.

Beyond the issue of rules versus principles, IFRS also can pose particular technical accounting challenges to P&U sector companies. The table below highlights a number of these challenges.

Technical Accounting Issue

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<th>Potential Differences</th>
<th>Potential Implications</th>
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<td>PP&amp;E</td>
<td>IFRS requires a componentization approach; costs eligible for capitalization may also differ; revaluation at fair value is an option</td>
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<tr>
<td>Regulatory Assets &amp; Liabilities</td>
<td>No IFRS equivalent to SFAS 71; regulatory items may only be recorded if they meet the IFRS definition of assets or liabilities</td>
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<tr>
<td>Asset Impairments</td>
<td>Differing impairment assessments (e.g., one-step approach under IFRS) exist; IFRS impairments may be reversed</td>
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<tr>
<td>Income Taxes</td>
<td>No specific guidance related to uncertain tax positions in IFRS; classification of deferred tax assets/liabilities between short and long-term will be different</td>
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<td>Derivative Instruments</td>
<td>U.S. GAAP guidance is more prescriptive than IFRS, particularly in core businesses that have significant contractual activities on a forward basis</td>
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<tr>
<td>Asset Retirement Obligations</td>
<td>Both standards have similar initial treatments, but IFRS amounts adjusted for discount rate changes</td>
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Power & Utilities Sector 2008
Accounting, Financial Reporting and Tax Update

PP&E

Asset componentization: IAS 16, Property, Plant and Equipment, requires the different components of an asset to be identified and depreciated separately if they have differing patterns of benefits and are significant relative to the total cost of the item. This components approach means that different depreciation periods will be used for each component of a fixed asset. For example, a power plant is comprised of separate components with different useful lives (turbine rotor, turbine blades, boiler, electronic equipment and so on), so its total book value will have to be allocated to these separate components. These individual components would then be depreciated over their respective useful lives. Significant parts of an asset that have similar useful lives and pattern of consumption can, however, be grouped together.

Entities that currently recognize plant assets as one overall item depreciated over a single 20- or 30-year useful life may find componentization to be a challenging process, especially if the PP&E ledger under U.S. GAAP is not sufficiently detailed or lacks certain key data necessary to specifically identify components. This is particularly true for old plants, plants owned by joint ventures (where data access may be limited), or in the case of acquired assets where legacy pre-acquisition data may be limited. Consequently, companies may need to involve plant managers and engineers to review the available asset data, including overhaul and replacement schedules, in order to complete the componentization process.

Other potentially significant impacts of asset componentization include: (1) Group depreciation methods that are commonly used by power and utility companies will not be permitted, requiring all gains and losses on retirements to be recognized in earnings. (2) Assets related to planned major maintenance activities need to be identified as separate components if they meet the asset recognition requirements in IAS 16. For example, estimated major maintenance or overhaul costs that would typically be expensed under U.S. GAAP that is scheduled to be performed every five years would need to be identified as a separate component upon acquisition of an asset and depreciated separately rather than depreciating the entire cost of the asset over the longer useful life of the asset. When the major maintenance is performed that component would be retired and the major maintenance cost incurred would be capitalized as a new component.

Revaluation option: IFRS provides companies a choice of accounting for PP&E under either the historical cost model (which is the required model under U.S. GAAP) or a revaluation model. Although the revaluation model is not widely used under IFRS, if elected, it does require companies to remeasure PP&E at fair value and record the change in value directly to equity (to the extent that a net revaluation surplus remains) on a recurring basis. Companies must have a consistent accounting policy for all assets within a particular asset class. When the revalued asset is disposed of, the revaluation surplus in equity remains in equity and is not reclassified to profit or loss. However, under this model, depreciation is recorded from the revalued amount, typically resulting in a higher depreciable basis and higher depreciation expense.

Costs Eligible for Capitalization: Under IFRS, costs that are directly attributable to bringing the asset to working condition for its intended use are able to be capitalized. Directly attributable costs include certain directly related employee costs, site preparation costs, delivery costs, installation costs, and professional fees. Directly attributable costs do not include administrative and other general overhead costs, which may have historically been capitalized under U.S. GAAP as part of guidance received from regulators (e.g., FERC or state commissions).
Regulatory Assets and Liabilities

IFRS does not provide specific guidance on regulatory assets and liabilities or on the recognition of revenues and expenses covered by future increases and decreases in regulated tariffs. Instead, under IFRS, costs should be charged to the income statement when incurred, and recoveries from customers should be recognized when receivable.

During its discussions on service concessions, the IFRIC considered the accounting treatment under IFRS of regulated assets and liabilities. No firm conclusion was reached except that entities applying IFRS should recognize only assets that qualify for recognition in accordance with the IASB’s Framework for the Preparation and Presentation of Financial Statements and relevant accounting standards, such as IAS 11, Construction Contracts; IAS 18, Revenue; IAS 16, and IAS 38, Intangible Assets. In other words, an entity should recognize regulatory assets and liabilities to the extent that they meet the criteria to be recognized as assets and liabilities in accordance with existing IFRS. P&U sector companies should consider whether the regulatory assets or liabilities permitted under U.S. GAAP from deferred fuel clause revenues or the securitization of storm costs would meet the IFRS definition of assets or liabilities. In practice, U.S. GAAP regulatory assets or liabilities have not been recognized under IFRS.

The absence of specific guidance similar to the SFAS 71, Accounting for the Effects of Certain Types of Regulation, has impacts that extend beyond the typical regulatory asset and liability accounts. For example, SFAS 71 permits the capitalization of AFUDC, which permits companies to capitalize the cost of financing construction projects including the cost of both debt and equity financings. Under existing IFRS, capitalization of financing costs would be limited to borrowing costs as defined by IAS 23, Borrowing Costs, and would typically not include the equity component of AFUDC, which may be significant for companies with extensive capital programs.

At its September 2008 meeting, the IFRIC indicated that it will continue its data gathering and analysis of this issue. Companies are encouraged to monitor the status of the IFRIC discussion and actively participate in the standard setting process. IFRIC is scheduled to further consider this issue during a future meeting.

Also see the discussion below on Initial Adoption that discusses the exposure draft issued by the IASB which may permit additional exemptions for rate regulated entities upon first time adoption of IFRS.

Asset Impairments

Two major differences exist between U.S. GAAP and IFRS on impairment:

- When assessing for impairment under U.S. GAAP, a “two-step approach” is applied. First, the carrying value of the asset is compared with the undiscounted value of the expected future cash flows to be generated from the asset. Second, where the carrying value is higher, the asset is written down to fair value. Under IFRS, the carrying value is compared with the asset’s “recoverable amount” (defined as the higher of the asset’s value in use, which is based on discounted future cash flows, or fair value less cost to sell), and if the carrying value is higher, the asset is written down to the recoverable amount. The ultimate effect is that impairment may be recorded earlier under IFRS.

- Under U.S. GAAP, reversals of previous impairments are not generally permitted, although one exception is for utility companies with previously disallowed costs that are subsequently allowed by a regulator. Under IFRS, where the indicator that led to the impairment loss no longer exists or has decreased, the previously-recognized impairment charge is reversed up to the new recoverable amount. (Goodwill impairment is an exception. Even under IFRS, goodwill impairment may not be reversed.) Under IFRS, companies will have to track asset impairments even after the initial write-down in order to determine whether the impairment should be reversed. If a change has occurred, the asset impairment may be reversed; however, the asset should not be revalued to an amount greater than the carrying amount would have been if no impairment loss had been recognized (i.e., the otherwise net carrying amount after regular depreciation expense is deducted). This will require tracking the unimpaired cost of the asset to determine the cap on the amount of any future restoration.

Differences may also arise in areas such as determination of the appropriate level of impairment for analysis (e.g., at the plant level or a system level) and the determination of fair value.

Income Taxes

There will be two major effects of a conversion to IFRS on income tax accounting. The differences between IAS 12, Income Taxes, and SFAS 109 will affect how companies account for income taxes on their income statements and balance sheets. In addition, the many differences between other U.S. GAAP and IFRS standards will likely result in additional book-tax differences that will need to be considered for estimated tax payments, tax return preparation and calculation of deferred tax provisions and assets/liabilities.
Differences in accounting for income tax include:

- Recognition, measurement and disclosure of liabilities associated with uncertain tax positions
- The availability of the SFAS 71 exceptions to SFAS 109 for companies that use or have used the flow-through method of accounting for certain book-tax differences and the deferred recognition of the effect of changes in tax rate on deferred tax assets/liabilities
- The classification of deferred tax assets/liabilities (all are non-current under IFRS)

The pre-tax differences between U.S. GAAP and IFRS need to be assessed to determine whether the new IFRS methods of accounting are permissible for tax purposes. If the IFRS methods are permissible and desirable for tax purposes, companies need to assess whether it is necessary to obtain advance consent from the National Office of the IRS for the change in tax method of accounting and determine how the cumulative effect of the change is taken into account for tax purposes. The new IFRS methods of accounting may result in a mandatory change in tax method of accounting (e.g., resulting from the LIFO conformity requirement) or may affect the timing of the recognition of an item for tax purposes (e.g., certain revenue recognition methods). Methods of accounting for which the tax method of accounting has historically followed the book method, but for which a book-tax difference will exist due to conversion to IFRS will result in incremental recordkeeping requirements and a decision as to whether the tax function or another part of the company should maintain the historical calculations needed for tax reporting purposes.

**Derivative Instruments**

Although IFRS and U.S. GAAP guidance on accounting for financial instruments are conceptually similar, differences do arise as a result of the principles-based approach from IFRS versus the rules-based approach from U.S. GAAP.

Broadly speaking, IFRS and U.S. GAAP approach financial instruments in a similar manner, although there are differences between the standards in terms of their detailed application. For instance, even the definition of a derivative differs under the two accounting frameworks, meaning that the contracts within the scope of derivative accounting (e.g., resulting from the LIFO conformity requirement) or may affect the timing of the recognition of an item for tax purposes (e.g., certain revenue recognition methods). Methods of accounting for which the tax method of accounting has historically followed the book method, but for which a book-tax difference will exist due to conversion to IFRS will result in incremental recordkeeping requirements and a decision as to whether the tax function or another part of the company should maintain the historical calculations needed for tax reporting purposes.

Finally, U.S. GAAP has certain exemptions for legacy contracts which were executed before a particular date. Since IFRS adoption is on a fully retrospective basis, P&U sector companies may have long-term arrangements that have to be reconsidered for possible embedded derivative terms.

**Asset Retirement Obligations**

Both IFRS and U.S. GAAP provide for the recognition of costs of dismantling an asset and restoring its site as a liability (e.g., a “provision” under IFRS), with a related amount included in the capitalized cost of the related asset. While both accounting frameworks provide for a present value approach in measuring the liability obligation, the mechanics of each approach differs. For example, IFRS allows a company to incorporate provision estimates based on internally generated costs, whereas U.S. GAAP requires third-party external costs to be used in the provision estimate.

Further, under U.S. GAAP, the company’s credit-adjusted risk-free rate of interest is used to discount the liability, whereas IFRS requires a rate reflecting current market conditions and risks specific to the liability. The selection of the appropriate rate to use in each case requires careful consideration. Under both IFRS and U.S. GAAP, subsequent to the initial recognition of the asset retirement obligation, the provision is reviewed at each balance sheet date and adjusted to reflect the current best estimate which may include adjustments to the discount rate used to measure the provision. However, under IFRS the entire obligation is remeasured using the current discount rate while under U.S. GAAP only the incremental increase in the obligation is remeasured using the current discount rate and the previous portion of the obligation remains measured using the discount rate in use at the time that portion was recorded.

IFRIC 1, *Changes in Existing Decommissioning, Restoration and Similar Liabilities*, specifies the accounting for changes to asset retirement obligations as a result of a change in the timing or amount of cash flows and changes in discount rates (reevaluated annually under IFRS). The accounting for these changes is significantly different depending on whether companies use the cost model or revaluation model for the related asset. If the cost model is followed the change in the liability would generally increase or decrease the related PP&E asset.
Leases

There are several key differences between IFRS and U.S. GAAP in the area of lease accounting, including:

- IFRS lease accounting standards cover a wider range of transactions than under U.S. GAAP. While only PP&E (i.e., land and/or depreciable assets) can be subject to a lease under U.S. GAAP, IFRS covers lease arrangements for all assets, with the exception of certain intangible assets.

- Although many of the lease classification criteria are similar under IFRS and U.S. GAAP, IFRS does not have the bright lines and specific criteria found in U.S. GAAP lease standards. Rather, IFRS focuses on the transfer of risks and rewards for lease classification, with only limited indicators and examples provided. Additionally, the nomenclature of leases under IFRS and U.S. GAAP differs: IFRS has only operating and finance leases (the IFRS term for capital leases) whereas U.S. GAAP has operating, capital, sales-type, direct financing, and leveraged leases.

- In leases of land and building, IFRS requires that the land and building elements of a lease be considered separately for purposes of lease classification, unless the land element is immaterial. However, in addition to the significance of the land element, U.S. GAAP considers the land and building elements a single unit unless certain specific criteria are met. During the European conversion, this proved to be a particularly time-consuming process; many companies sought expert advice from valuation specialists to assist with the allocation.

Inventory

The cost of inventory under both U.S. GAAP and IFRS generally includes direct expenditures of getting inventories ready for sale, including overhead and other costs attributable to the purchase or production of inventory. IAS 2, Inventories, specifically requires use of either the FIFO method or the weighted-average cost method. Further, IFRS requires that the same costing formula be used for all inventories with a similar nature and use to the entity. Most regulated gas distribution utilities have purchase gas adjustment or similar clauses to recover gas costs and several of these gas distribution utilities have for years used the LIFO method of accounting for gas inventories. During periods of rising prices, the LIFO costing method leads to higher recognized costs of sales and, with PGA clauses, more-timely rate recovery. However, LIFO is not a permitted method of inventory accounting under IFRS.

In addition, a LIFO conformity requirement exists for tax purposes: a taxpayer may not use LIFO for tax purposes unless LIFO is also used for financial reporting purposes. Unless the tax law is changed, LIFO taxpayers will need to revert to a non-LIFO tax method of accounting for tax purposes upon adoption of IFRS for financial reporting purposes. The financial reporting effects of adopting IFRS are charged or credited to retained earnings, but the cumulative effect of changing tax methods of accounting is recognized as taxable income over four years (in the case of changes that increase taxable income). LIFO P&U sector companies will need to discuss with their regulatory commissions whether a change from LIFO will also occur for purposes of setting PGA rates and, if so, whether there will be a transition period. If LIFO is also discontinued for purposes of setting PGA rates, the price charged for gas will be reduced for a period of time to reflect the low cost older LIFO layers, but rate base will be increased to reflect the more current costs of gas inventory. In industries without PGA clauses, a change from the LIFO method accelerates the payment of taxes because lower cost of goods sold is recognized for book and tax purposes while sales prices remain constant. With a PGA clause and a change from LIFO for PGA rate-setting purposes also, there is an adverse dollar-for-dollar impact on cash flow because revenues will be lower to reflect the liquidation of LIFO layers, but there will be no impact on current or deferred tax liability.

Initial Adoption

IFRS requires one year of comparative financial information to be reported under IFRS based upon the rules in effect at the reporting date. For example, a company with a December 31, 2008 reporting date would be required under IFRS to also provide comparative financial statements in compliance with IFRS for 2007 using those standards effective as of December 31, 2008. This requirement differs from the SEC announced Roadmap that would require companies to provide two comparative years (in addition to the year of adoption) of statements of income, cash flows, and equity. However, it is worth noting that in 2005, when foreign private issuers from the European Union initially adopted IFRS, the SEC provided an accommodation on the first year that allowed companies to include only one year of comparative information. Thus, the SEC may consider a similar accommodation for domestic registrants upon mandating IFRS for all U.S. issuers. See Section 2, SEC Update, for further discussion related to the SEC Roadmap.

Generally, companies must apply initial adoption rules retrospectively and must recognize all assets and liabilities in accordance with IFRS, and derecognize all assets and liabilities not in compliance with IFRS — with some limited exemptions. Any differences resulting from the change in accounting policies from U.S. GAAP to IFRS upon the initial adoption date of IFRS are recorded directly through retained earnings. Key adoption differences or optional exemptions specific to P&U sector companies include:

- Fair value and other estimates at initial adoption date need to be consistent with estimates made at the same date under U.S. GAAP (after adjustment to reflect any difference in accounting policies), unless there is objective evidence that those estimates were in error.

- PP&E that previously did not require impairment loss recognition if the undiscounted cash flows exceeded carrying value may require write-down at adoption date if recoverable value is less than carrying value. The recoverable value of regulated PP&E will generally equal its carrying value.
At initial adoption, a company may elect to measure PP&E at the date of transition to IFRS at its fair value and use that fair value as its deemed cost at that date (if the historical cost model is subsequently used for property instead of fair value).

Acquisitions and business combinations prior to the date of initial adoption do not require retrospective application of IFRS related to the assets and liabilities acquired.

In September 2008, the IASB issued an exposure draft requesting public comment on additional optional exemptions for first-time adopters of IFRS. Included in the exposure draft are the following proposed exemptions:

- To exempt companies from retrospective application of IFRS for oil and gas assets using the full cost method.
- To permit companies subject to rate regulation to elect to use the carrying amount of items of PP&E held, or previously held, for use in such operations as their deemed cost at the date of transition to IFRS if both retrospective restatement and using fair value as deemed cost are impracticable.
- To exempt companies with existing leasing contracts accounted for in accordance with IFRIC 4, Determining Whether an Arrangement Contains a Lease, from reassessing the classification of those contracts according to IFRS when the same classification has previously been made in accordance with national GAAP.

If adopted as proposed and power and utilities subject to rate regulation elect to use their previously held carrying value of PP&E as their deemed cost at the date of transition, companies will continue to be required to identify components of their deemed cost as of the transition date for prospective application of IFRS, which may require significant effort.

SECTION 4

An Analysis of the Application of SFAS 71, Accounting for the Effects of Certain Types of Regulation, as Amended and Interpreted and Other Specialized Industry Accounting

Introduction

This section summarizes the specialized industry reporting requirements for utilities included in the authoritative accounting literature. Since its issuance in December 1982, SFAS 71 has been the principal accounting document providing this guidance. The FASB, its Energy Issues Task Force and the SEC’s staff have subsequently issued guidance and a number of other pronouncements that have amended, interpreted, supplemented or affected the provisions of SFAS 71. The most significant pronouncements and SEC staff guidance related to SFAS 71 are:

- SFAS 90, Regulated Enterprises – Accounting for Abandonments and Disallowances of Plant Costs – an amendment of FASB Statement No. 71;
- SFAS 92, Regulated Enterprises – Accounting for Phase-In Plans – an amendment of FASB Statement No. 71;
- SFAS 101, Regulated Enterprises – Accounting for the Discontinuation of Application of FASB Statement No. 71;
- SFAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets;
- EITF Issue 93-4, Accounting for Regulatory Assets;
- EITF Issue 97-4, Deregulation of the Pricing of Electricity – Issues Related to the Application of FASB Statements No. 71 and 101; and
- Correspondence from the SEC staff (May 29, 1998) addressing impairment calculations.

SFAS 71

SFAS 71 provides guidance in preparing general-purpose financial statements for most utilities. SFAS 71 specifies criteria for its applicability by focusing on the nature of regulation rather than on specific industries. In general, the type of regulation covered by SFAS 71 permits rates to be set at levels intended to recover the estimated costs of providing regulated services or products, including the cost of capital. The cost of capital consists of interest and a provision for earnings on shareholders’ investments.

SFAS 71 applies to general-purpose external financial statements of an enterprise that has regulated operations if all of the following criteria are met:

- The enterprise’s rates for regulated services or products provided to its customers are established by or are subject to approval by an independent, third-party regulator or by its own governing board empowered by statute or contract to establish rates that bind customers
- The regulated rates are designed to recover the specific enterprise’s costs of providing the regulated services or products
- In view of the demand for the regulated services or products and the level of competition, direct and indirect, it is reasonable to assume that rates set at levels that will recover the enterprise’s costs can be charged to and collected from customers. This criterion requires consideration of anticipated changes in levels of demand or competition during the recovery period for any capitalized costs.

If some of a utility’s operations are regulated and meet all of the above criteria, SFAS 71 should be applied to only that portion.

General Standards

SFAS 71 recognizes that a principal consideration introduced by rate regulation is the cause-and-effect relationship of costs and revenues – an economic dimension that, in some circumstances, should affect accounting for rate-regulated utilities. Thus, a rate-regulated utility should therefore capitalize a cost, as a regulatory asset, or recognize an obligation, as a regulatory liability, if it is probable that through the ratemaking process there will be a corresponding increase or decrease in future revenues.

Regulatory Assets

SFAS 71 paragraph 9 states that the “rate action of a regulator can provide reasonable assurance of the existence of an asset.” All or part of an incurred cost that would otherwise be charged to expense should be capitalized as a regulatory asset if:

- It is probable that future revenues in an amount approximately equal to the capitalized cost will result from inclusion of that cost in allowable costs for ratemaking purposes.
The regulator intends to provide for the recovery of that specific incurred cost rather than to provide for expected levels of similar future costs. An incurred cost is defined in SFAS 71 as “a cost arising from cash paid out or obligation to pay for an acquired asset or service, a loss from any cause that has been sustained and must be paid for.” Equity return (or an allowance for earnings on shareholders’ investment), however, is not an incurred cost that would otherwise be charged to expense.

SFAS 71 requires a rate-regulated utility to capitalize as a regulatory asset an incurred cost that would otherwise be charged to expense if future recovery in rates is probable. Probable is defined in SFAS 5, Accounting for Contingencies, as “likely to occur,” which is a high test to meet. Thus, paragraph 9 has a continuous probability standard to be met at each balance sheet date in order for a regulatory asset to remain recorded. Also, see subsequent discussion of EITF Issue 97-4 for additional considerations in determining the recoverability of regulatory assets.

Additionally, costs that would otherwise be charged to other comprehensive income, and not to expense in determining net income, also qualify to be capitalized as a regulatory asset under SFAS 71 when the other requirements for recording a regulatory asset are met. The basis for this conclusion is primarily that OCI was not well developed when SFAS 71 was written, absent OCI the cost would be charged to expense for determining net income, and such amounts are charged to “comprehensive” income/expense. The SEC’s staff has concurred with this conclusion.

If a regulatory asset is recorded, but no longer meets the above criteria, the cost should then be charged below-the-line to other income and expense if the income statement is in a traditional utility format. See subsequent discussion in this Section on income statement presentation.

Evidence that a regulatory asset is probable of recovery is a matter of professional judgment based on the facts and circumstances of each case. Utility management’s positive representation is required that each regulatory asset is probable of recovery in future rates. The SEC has increasingly scrutinized documentation of the basis for recording regulatory assets. The SEC staff has unofficially suggested that evidence that could support future recovery and corroborates utility management’s representation includes:

- Rate orders from the regulator specifically authorizing recovery of the costs in rates
- Previous rate orders from the regulator allowing recovery for substantially similar costs
- Written approval from the regulator approving future recovery in rates
- Analysis of recoverability from internal or external legal counsel.

The best evidence of a regulatory asset is a rate order. However, the scheduling and length of the regulatory process sometimes does not enable a company to obtain a rate order on a timely basis. As a result, a utility might obtain an “accounting order” or comparable form of communications from its regulator or the regulator’s staff agreeing with the company’s proposed accounting for an incurred cost; even though such orders often include a qualifier that the letter guidance is not authoritative for ratemaking purposes. In a few jurisdictions, accounting orders signed by the regulator may provide the same degree of assurance as a specific rate order. However, this is atypical and the level of assurance provided by an accounting order must be assessed on a jurisdiction by jurisdiction basis, with particular focus on legal authority, who signs the accounting order, and historical regulatory precedents and practices.

Under guidance included in EITF Issue 93-4, an incurred cost that does not meet the asset recognition criteria in paragraph 9 of SFAS 71 at the date the cost is incurred should be recognized as a regulatory asset when it meets those criteria at a later date. Under paragraph 10 of SFAS 71, as amended by SFAS 144, previously disallowed costs that are subsequently allowed by a regulator to be recovered, should be recorded as an asset, consistent with the classification that would have resulted had the cost initially been included in allowable costs. This provision applies to plant costs and regulatory assets created by actions of a regulator.

Paragraph 10 of SFAS 71, as amended by SFAS 144, also concludes that a regulator can reduce or eliminate the value of an asset. If a regulator disallows recovery of part of a regulatory asset, that part of the asset is to be written off. Although special rules apply to disallowances of a recently completed utility plant, any write downs in the value of other assets is limited to the amount appropriate under U.S. GAAP.

Regulatory assets should be amortized over future periods consistent with the related increase in customer revenues.

**Regulatory Liabilities**

SFAS 71, paragraph 11, also recognizes that the rate actions of a regulator can impose a liability on a rate regulated utility, usually to its customers. The following are examples of ways in which regulatory liabilities can be imposed.

- A regulator may require refunds to customers
- A regulator can provide provisions in rates for costs not yet incurred
- A regulator can require that a gain be given to customers by amortizing amounts to reduce future rates.
Paragraph 12 of SFAS 71 expands this idea that “actions of a regulator can eliminate a liability only if the liability was imposed by actions of the regulator.” Thus, a rate-regulated enterprise’s balance sheet should include all liabilities and obligations that an enterprise in general would record under U.S. GAAP, such as for capital leases, pension plans, compensated absences and income taxes. The SEC’s staff, in SAB 10F, Utility Companies-Presentation of Liabilities for Environmental Costs, clarified that such liabilities should not be offset with corresponding regulatory assets.

Regulatory liabilities should be amortized over future periods consistent with the related decrease in customer revenues.

Specific Standards

SFAS 71 also sets forth specific standards for a few isolated accounting and disclosure issues.

- **AFUDC.** Paragraph 15 allows the capitalization of AFUDC, including a computed interest cost and a designated cost of equity funds, if a regulator prescribes this method rather than capitalizing interest on funds used during construction in accordance with the guidelines provided in SFAS 34, Capitalization of Interest Cost. The income statement should include an item of other income for the equity component of AFUDC and/or a reduction of interest for the debt component of AFUDC. AFUDC can only be capitalized under SFAS 71, paragraph 15, if subsequent inclusion in allowable costs for ratemaking purposes is probable. In addition, if AFUDC is not capitalized because its inclusion in the allowable cost for establishing future rates is not probable, the utility cannot alternatively capitalize interest under SFAS 34. Also see subsequent discussion under SFAS 92 in this Section regarding the limitations on capitalizing AFUDC.

- **Intercompany Profit.** SFAS 71, paragraph 16, provides that intercompany profits on sales to regulated affiliates should not be eliminated in general purpose financial statements if the sales price is reasonable and it is probable that future revenues allowed in the ratemaking process will approximately equal the sales price.

- **Income Taxes.** Paragraph 18 of SFAS 71, as amended by SFAS 109, adopts the liability method of accounting for deferred income taxes. Because accumulated deferred income taxes are viewed as a liability under SFAS 109, an income tax liability must be recorded for all temporary differences. However, if a regulator defers an income tax cost for future recovery, and the future recovery through rates is probable, the costs are to be capitalized as a regulatory asset rather than expensed. Assuming that a utility has concluded that future recovery through rates is probable, it would record a corresponding regulatory asset in recognition of future recovery of income tax related to temporary differences not provided in current rates. Measurement of the regulatory asset is based on the probable future revenue that will result from future recovery.

- **Refunds.** Paragraph 19 of SFAS 71 addresses the accounting for significant refunds of revenue recognized in prior periods. For refunds recognized in a period other than the period in which the related revenue was recognized, SFAS 71 adopts the requirements of SFAS 16, Prior Period Adjustments, which precluded recording these refunds as restatements of prior years. Disclosure of the effect on net income and the years in which the related revenue was recognized is required, if material. Adjustment to prior quarters of the current fiscal year is appropriate for such refunds provided all of the following criteria are met:
  - The effect is material (either to operations or income trends)
  - All or part of the adjustment or settlement can be specifically identified with and is directly related to business activities of specific prior interim periods
  - The amount could not be reasonably estimated prior to the current interim period but becomes reasonably estimable in the current period.

Although this treatment of prior interim periods for utility refunds is one of the restatement exceptions contained in paragraph 13 of SFAS 16, it has not been consistently applied in practice, either because of oversight or lack of materiality. The SEC’s staff has questioned utility registrants about situations in which interim periods were not restated.

SFAS 71 does not contain a specific standard on lease accounting. However, accounting for lease transactions is a good example of the application of the conclusion reached in SFAS 71, paragraph 12, in that a regulator can eliminate only a liability it imposed. Appendix B to SFAS 71 addresses accounting for leases directly and concludes that the regulator cannot affect the classification of a lease liability or the inclusion of a capital lease liability on the balance sheet. Therefore, when a lease is capitalized under SFAS 13, Accounting for Leases, it is treated as an operating lease for ratemaking purposes, the balance sheet should still reflect the capitalized asset and the related lease liability. Also see subsequent discussion under SFAS 92 in this section regarding the limitation on phase-in plans.
Examples of Application. Appendix B and Appendix C, the Basis for Conclusions, in SFAS 71 also describes other situations and their treatment based on the general standards. Items discussed include:

- Intangible assets
- Accounting changes
- Early extinguishment of debt
- Accounting for contingencies
- Accounting for leases
- Revenue collected subject to refund
- Refunds to customers
- Compensated absences

After the issuance of SFAS 71, the FASB became concerned about the accounting being followed by utilities for certain transactions. Significant events were occurring for which the FASB concluded that a new “economic” approach to the accounting for the effects of regulation was warranted, such as:

- Disallowances of major portions of recently completed plants
- Significant plant abandonments
- Phase-in plans for the costs of newly completed plant.

These economic events often resulted in utilities not recovering costs currently or not at all. As a result, the FASB amended SFAS 71 with SFAS 90 and SFAS 92.

Due to the increasing level of competition and deregulation faced by all types of rate-regulated utilities, the FASB issued SFAS 101. SFAS 101 addresses the accounting to be followed when SFAS 71 is discontinued. Related guidance for applying SFAS 101 is also provided in EITF Issue 97-24.

**SFAS 90**

SFAS 90 provides guidance for rate-regulated utilities in two specific areas: accounting for abandonments and disallowances of recently completed plants. SFAS 144 does not apply to the costs of recently completed plants that are covered by SFAS 90. If a rate-regulated utility has an unregulated affiliate with costs recorded for recently completed plant, such cost should be evaluated for impairment under SFAS 144. If the affiliate transfers the recently completed plant costs to the rate-regulated utility, and such costs are then subject to the provisions of SFAS 71, an impairment determination should be made under SFAS 90 when the transfer is recorded.

There is no specific guidance in SFAS 90 or SFAS 144 defining recently completed plant, nor is there specific guidance in SFAS 92 defining newly completed plant. It is reasonable to conclude that both terms should have the same definition. In practice, these terms have been effectively defined based on facts and circumstances, so some diversity has resulted without any “bright-lines” being established as guidance. The starting point for determining what is recently/newly completed plant, for both self constructed and acquired plant, is typically the time from the completion in-service date until the plant owner files its initial rate request for inclusion of the plant in allowable costs. If that time period approximates 12 months or less, it would also be reasonable to conclude that the plant is recently/newly completed for purposes of applying SFAS 90 and SFAS 92.

**Disallowances**

SFAS 90 stipulates that, when a direct disallowance of the cost of recently completed plant becomes probable and estimable, the estimated amount of the probable disallowance must be deducted from the reported cost of plant and recognized as a loss. Future depreciation charges should be based on the written down asset basis. Disallowances of plant costs for plants that are not recently completed are recognized in accordance with U.S. GAAP as applied by enterprises in general.

An explicit, but indirect, disallowance occurs when no return or a reduced return is permitted on all or a portion of the new plant. In the case of indirect disallowances, if the regulator does not specify the amount of the disallowance, it must be calculated based on estimated future cash flows. To determine the loss resulting from an indirect disallowance, the future revenue stream/cash flows allowed by the regulator should
be estimated and discounted using a rate consistent with that used to estimate the future cash flows. This amount should be compared to the recorded plant amount and the difference recorded as a charge to current earnings. Under this discounting approach, the remaining asset should be depreciated consistent with the ratemaking and in a manner that would produce a constant return on the undepreciated asset equal to the discount rate.

Abandonments

The SFAS 90 plant abandonment provisions relate to an operating asset or an asset under construction. When it becomes probable that an operating or under construction plant will be abandoned, the associated cost should be removed from plant-in-service or construction work in progress, respectively. If the regulator is likely to provide a full return on the recoverable costs, a separate, new regulatory asset should be established. The new asset value should equal the original carrying value of the abandoned asset less any disallowed costs.

If the regulator is likely to provide a partial return or no return, the new asset value should equal the present value of the future revenues expected to be provided to recover the allowable costs of the abandoned plant and any return on investment. The utility’s incremental borrowing rate should be used to measure the present value of the new asset. Any disallowance of all or a part of the cost of the abandoned plant should be recognized as a loss, when it is both probable and estimable. During the recovery period, the new asset should be amortized to produce zero net income based on the theoretical debt and interest assumed to finance the abandoned plant. Specific guidance is set forth in FASB Technical Bulletin 87-2, Computation of a Loss on an Abandonment.

The SEC’s SAB 10E, Utility Companies-Classification of Disallowed Costs or Costs of Abandoned Plants, states that losses recorded pursuant to SFAS 90 should not be reported as an extraordinary item. EITF Topic D-5, Extraordinary Treatment Related to Abandoned Nuclear Power Plants, interprets paragraph 10 of SFAS 90 to preclude extraordinary item treatment of losses from abandoned plants. When a utility follows the traditional rate-regulated utility reporting format, the effects of an SFAS 90 based cost disallowance should be reported gross, as a component of other income and deductions (below-the-line), and not shown net-of-tax. See subsequent discussion in this Section on income statement presentation.

SFAS 92

SFAS 92 deals with the accounting for phase-in plans and it is applicable to all rate-regulated utilities subject to SFAS 71. It also clarifies the accounting rules on the capitalization of an equity return. A phase-in plan, as defined in SFAS 92, is a method of ratemaking that meets all of the following criteria:

- Adopted in connection with a major, newly completed plant of the utility or one of its suppliers or a major plant scheduled for completion in the future
- Defers the rates intended to recover allowable costs beyond the period in which those allowable costs would be charged to expense under U.S. GAAP applicable to enterprises in general
- Defers the rates intended to recover allowable costs beyond the period in which those rates would have been ordered under ratemaking methods routinely used prior to 1982 by that regulator for similar allowable costs of that utility.

The phase-in definition includes virtually all cost deferrals associated with a major, newly completed plant (see the prior discussion under SFAS 90 in this Section regarding recently/newly completed plant), such as rate levelization proposals, alternative methods of depreciation such as a sinking fund approach and rate treatment of capital leases as operating leases, including sale with leaseback transactions.

Under the accounting provisions of SFAS 92, cost deferral under a phase-in plan is not permitted for plant/fixed assets on which substantial physical construction had not been performed before January 1, 1988. This provision effectively bars any new phase-in plans.

If specified criteria are met, paragraph 9 of SFAS 71 requires capitalization of an incurred cost that would otherwise be charged to expense. SFAS 92 clarifies that AFUDC-equity is not an incurred cost that would otherwise be charged to expense and SFAS 71 only permits it to be capitalized during construction or as part of accounting for phase-in plans and plant abandonments. Accordingly, AFUDC-like equity carrying charges cannot be capitalized in connection with post construction, short-term rate synchronization or any other cost deferrals.

A utility should disclose the terms of any phase-in plans in effect during the year. If a regulator orders a cost deferral plan for a major, newly completed plant that does not meet the criteria in SFAS 92, the financial statements should include disclosure of the net amount deferred for ratemaking purposes at the balance sheet date and the net change in deferrals for ratemaking purposes during the year for the plan. The nature and amounts of any allowance for earnings on shareholders’ investment capitalized for ratemaking purposes but not capitalized for financial reporting should also be disclosed.

From a financial reporting statement viewpoint, costs deferred should be classified and reported as a separate item in the income statement in the section relating to those costs. For instance, if the cost of capital is being deferred, it should be classified “below-the-line.” If depreciation
or other operating costs being deferred, the “credit” should be classified “above-the-line” with the related operating costs. This income statement presentation is consistent with guidance provided by the SEC’s staff.

SFAS 92 eliminated the ability to defer costs for financial reporting purposes in connection with new phase-in plans. However, SFAS 92 should continue to be considered when a utility that applies SFAS 71 acquires or constructs a newly completed plant. Consideration also needs to be given when there is an arrangement, such as with a purchase power agreement, to acquire capacity of a supplier’s newly completed plant (see paragraphs 3a and 30-32 of SFAS 92). The PPA would also need to be analyzed under EITF Issue 01-08, Determining Whether an Arrangement Contains a Lease, to determine if it contains a lease, which would be accounted for under SFAS 13. If so, the regulatory treatment accorded the PPA would also need to be analyzed to determine if any associated costs are being deferred. Examples of such cost deferrals include a capitalized lease receiving operating lease treatment for regulatory purposes and an operating lease with future step increases, which would require straight-line expense recognition, while only receiving pay-as-you-go treatment for regulatory purposes. Potentially, a related cost deferral for regulatory purposes would meet the definition of a phase-in plan. Accordingly, creation of a regulatory asset is not allowed under SFAS 92 for the incurred cost that would otherwise be charged to expense.

As indicated above, SFAS 92 applies to the costs of major, newly completed plant. There are situations in which a regulator subsequently starts to defer rates intended to recover allowable plan costs after return on and recovery of such costs have been previously provided. One example of this situation is when a regulator orders a reduction in the depreciation rate (and rates charged to customers) of a 25 year-old nuclear generation plant with a 40-year license, to factor in a potential future 20-year license extension. Assuming that the new depreciation rate adopted by the regulator cannot be supported under U.S. GAAP (perhaps because the utility does not believe a license extension will occur), a regulatory deferral of plant costs would result, because regulatory depreciation expense would be less than depreciation for financial reporting purposes.

If the rate order was issued in connection with major, newly completed plant, the guidance set forth in paragraph 35 of SFAS 92 presumes that the regulatory deferral of the “old” plant is equivalent to the regulatory deferral of the “new” plant. See previous discussion under SFAS 90 of newly/recently completed plant. Thus SFAS 92 must be applied. And, under SFAS 92, because the regulatory action results in a phase-in plan as defined in SFAS 92, no plant costs can be deferred for financial reporting purposes.

However, if the new rate order was not issued in connection with major, newly completed plant and it is clear that the regulatory deferral relates only to “old” plant, SFAS 92 would not apply. Any deferral for financial reporting purposes must meet the requirements of SFAS 71, paragraph 9, for establishing and maintaining a regulatory asset. That determination should consider, as noted in paragraph 57 of SFAS 92, that the existence of such regulatory cost deferrals calls into question the continuing applicability of SFAS 71.

**SFAS 101**

SFAS 71 and its application has received attention over the last 10 years, due to market-based or other alternative forms of pricing regulation taking place in the gas pipeline and electric industries. Electric companies, including some of the largest in the industry, in several regulatory jurisdictions, have discontinued application of SFAS 71 for the generation portion of their operations as a result of the industry undergoing various fundamental changes. However, these changes were ultimately reconsidered by certain electric companies and their regulators as a result of the energy crisis in California that occurred in 2000 and early 2001. As a result, some companies had to evaluate the reapplication of SFAS 71. SFAS 101 addresses the accounting for a utility to discontinue application of SFAS 71 if it no longer meets the scope criteria set forth in paragraph 5 of SFAS 71.

**Factors Leading to Discontinuing Application of SFAS 71**

SFAS 101 provides several examples of conditions that may cause a utility to no longer meet the criteria for applying SFAS 71. Factors cited in SFAS 101 include: deregulation, a change in the regulator’s approach for setting rates from cost-based ratemaking to another form of regulation, increasing competition that limits the ability to recover costs and regulatory actions that limit rate relief to a level insufficient to recover costs or imposes a rate freeze.

**Discontinuing Application of SFAS 71 and Adoption of SFAS 101**

Once all or parts of a utility’s operations no longer are subject to SFAS 71, it should discontinue application of SFAS 71 and report the impacts associated with discontinuation. Also, if a separable portion of the utility’s operations within a regulatory jurisdiction no longer meets the SFAS 71 scope criteria, application of SFAS 71 for that separable portion must be discontinued.

In EITF Issue 97-4, the EITF reached a consensus that the application of SFAS 71 to the separable portion of the utility’s operation that is subject to a deregulatory transition plan should cease no later than the time when the legislation is passed and the details of the plan are known. Thus, SFAS 71 should be discontinued at the beginning (not the end) of the transition period.

The balance sheet effects of any actions of regulators that had been recognized as assets and liabilities pursuant to SFAS 71 (including regulatory assets and liabilities recorded in or netted against the carrying amounts of plant, equipment and inventory) but would not have been recognized as assets and liabilities by enterprises in general should be eliminated.
EITF Issue 97-4 addresses how regulatory assets and liabilities of the separable operations should be evaluated. Regulatory assets and regulatory liabilities that originated in the separable portion of a utility’s operations should be evaluated on the basis of where (that is, the portion of the operations in which) the regulated cash flows to realize and settle the regulatory assets and liabilities will be derived. Regulated cash flows are rates that are charged customers and intended by regulators to be for the recovery of specified regulatory assets and settlement of specified regulatory liabilities. They can be, in certain situations, derived from a “levy” on rate-regulated goods or services provided by another separable portion of the enterprise that meets the criteria for application of SFAS 71.

Accordingly, if such regulatory assets and regulatory liabilities have been specifically provided for via the collection of regulated cash flows, they are not eliminated until:

- They are recovered by or settled through regulated cash flows, or
- They are individually impaired or the regulator eliminates the obligation, or
- The separable portion of the business from which the regulated cash flows are derived no longer meets the criteria for application of SFAS 71.

EITF Issue 97-4 applies not only to regulatory assets and liabilities already recorded when the separable portion ceases application of SFAS 71, but also to regulatory assets and liabilities that are probable of recovery or settlement regardless of when incurred. For example, a regulatory asset should also be recorded for the buy-out of a PPA that is recognized after SFAS 101 is applied to the electric generation portion of utility operations, if it is specified for recovery in the legislation or a rate order, and a separable portion of the enterprise that meets the criteria for application of SFAS 71 continues to exist.

However, the carrying amounts of plant, equipment and inventory measured and reported pursuant to SFAS 71 should not be adjusted unless those assets are impaired (under SFAS 144), in which case the carrying amounts of those assets should be reduced to reflect that impairment. The net effect of the above adjustments should be recorded in the period of the change and classified as an extraordinary item in the income statement.

Other potential financial effects of applying the accounting provisions of SFAS 101 include recording unbilled revenues if the billed method for recording revenues was applied under SFAS 71, adjusting depreciable lives and future construction costs should reflect interest capitalized under SFAS 34, rather than AFUDC.

**Presentation and Disclosure**

Once SFAS 71 is no longer applied to a separable portion of an enterprise, the financial statements should segregate, via financial statement display or footnote disclosure, the amounts contained in the financial statements that relate to that separable portion.

In the period in which the application of SFAS 71 is discontinued, the utility should disclose the reason for the discontinuation and identify the portions of its operations to which the application of SFAS 71 is being discontinued. A typical example of such footnote disclosures follows.

> With the issuance of a final order by the State Public Services Commission in August 200X addressing the implementation of electric utility restructuring, we discontinued regulatory accounting for financial reporting purposes under SFAS 71 for the generation portion of our operations in the third quarter of 200X. During the third quarter of 200X we wrote off 50% of our net generation-related regulatory assets totaling approximately $XXX million, resulting in an after-tax extraordinary charge of approximately $XXX. The remaining 50% of our net regulatory assets will be retained on the balance sheet because the Commission’s restructuring plan and related order specifically provide for their recovery through a nonbypassable surcharge to distribution customers that will be collected through December 31, 20XX. Our investment in generation-related net utility plant not subject to cost based regulation was $XX.X billion as of December 31, 200X.

**Reapplication of SFAS 71**

As noted in paragraph 43 of SFAS 101, the FASB concluded that the accounting for the reapplication of SFAS 71 is beyond the scope of SFAS 101. There have been several utilities that have reapplied SFAS 71, including registrants that have had the related accounting and financial reporting pre-cleared or reviewed by the SEC’s staff.

When facts and circumstances change so that a utility’s regulated operations meet all of the scope criteria set forth in paragraph 5 of SFAS 71, that Statement should be reapplied to all or a separable portion of its operations. A reasonable approach for reapplication includes adjusting the balance sheet for amounts that meet the definition of a regulatory asset or regulatory liability in paragraphs 9 and 11, respectively, of SFAS 71. AFUDC should commence to be recorded if it is probable of future recovery, consistent with paragraph 15 of SFAS 71. As provided for in SFAS 144, previously disallowed costs covered by SFAS 71 or SFAS 90 that are subsequently allowed by a regulator should be recorded as an asset, consistent with the classification that would have resulted had these costs initially been allowed. Disallowed costs not covered by SFAS 71 or SFAS 90, such as old plants and non-regulatory assets that were previously written down in applying SFAS 101 and SFAS 144, should not be written back up even if
the regulator subsequently provides through new ratemaking the recovery of higher amounts. A new regulatory asset should be recorded instead, if the recognition criteria of SFAS 71 are met. Likewise, any non-legal removal costs previously written off should be reestablished as regulatory liabilities. Given the extraordinary item treatment required for the income statement effects of discontinuing SFAS 71, it would be practical and reasonable for the net effect of the adjustments to reapply SFAS 71 also to be classified as an extraordinary item in the income statement.

For the period in which SFAS 71 is reapplied to all or a separable portion of operations, the utility should disclose the reason for the reaplication. The utility should also identify the portion of its operations to which SFAS 71 is being reapplied. A typical example of such footnote disclosures follows.

In the third quarter of 200X we discontinued regulatory accounting for financial reporting purposes under SFAS 71 for the generating portion of our operations due to the issuance, in August 200X, of an order from the State Public Service Commission addressing the implementation of electric industry restructuring. Our transmission and distribution operations continued to meet the requirements of SFAS 71, as those businesses were expected to remain regulated. During the third quarter of 200X, we also wrote off 50% of our generation related net regulatory assets, totaling approximately $XXX million, resulting in an after-tax extraordinary charge of approximately $XXX million.

In December 200Y, the Governor signed legislation postponing the deregulation and restructuring of our generating business until further consideration in 20XX. Current restructuring proceedings have stopped. In addition, under the new legislation, we are entitled to recover all reasonable and necessary restructuring related expenditures made or incurred before December 200Y, including the regulatory assets that we wrote-off in 200X.

As a result of these legislative developments, we reapplied the provisions of SFAS 71 for our generation operations in December 200Y, as the State Public Service Commission’s previous plans to implement restructuring have been currently abandoned. We will continue to be subject to rate regulation under traditional cost of service regulation consistent with past accounting and ratemaking practices. Accordingly, we have restored $XXX of regulatory assets previously written off and have recorded an after-tax extraordinary gain of approximately $XXX in December 200Y.

### Income Statement Presentation

The traditional form of a utility income statement reflects the classification of revenues and expenses in ratemaking. Utility operating income (subject to regulation) is shown as the result of deducting total utility operating expenses (generally allowable as operating expenses for ratemaking, including income taxes) from total utility operating revenues. Other income and deductions (generally not considered in ratemaking) and interest expense (considered only in determining the allowed rate of return) are then added/deducted to arrive at net income.

Utility operating revenues and expenses are referred to as above-the-line because they are allowable in ratemaking and determine utility operating income. Interest expense (which is recovered through the allowed rate of return) and other income and deductions (generally not considered in ratemaking) and interest expense (considered only in determining the allowed rate of return) are then added/deducted to arrive at net income.

Utility operating revenues and expenses are referred to as above-the-line because they are allowable in ratemaking and determine utility operating income. Interest expense (which is recovered through the allowed rate of return) and other income and deductions (generally not considered in ratemaking) and interest expense (considered only in determining the allowed rate of return) are then added/deducted to arrive at net income.

Many utilities have partially or completely departed from the traditional utility format and moved to a commercial income statement format, primarily because of lack of rate cases, actual or expected deregulation and the establishment of holding companies and non-utility operations, which use the commercial format. Consequently, utilities and affiliate holding companies for consolidated financial reporting and for separate utility company financial reporting currently use the traditional utility income presentation at both levels, the utility level only, or not at all.

This diversity in practice, along with other factors, such as the conflict between the traditional utility format with its above-the-line and below-the-line concept, and such documents as the SEC’s SAB 5P, *Income Statement Presentation of Restructuring Charges*, and SFAS 144 (which indicate that losses related to restructuring charges and impairments of long-lived assets, respectively, should be included in operating income/ income from continuing operations before income taxes in the income statement), have resulted in various income statement presentation questions and inappropriate/inconsistent application of the selected income statement format.

If the traditional utility income statement is presented, income taxes related to utility operations should be classified as an operating expense for determining utility operating income. All revenues, expenses, gains and losses that are not allowable for establishing the utility’s rates should be classified, gross, below-the-line in other income and expense. Thus the losses noted above should be classified below-the-line, if such losses are excluded from allowable regulatory costs. The following presentation illustrates the traditional, below-the-line, utility income statement format.
<table>
<thead>
<tr>
<th><strong>Utility operating income</strong></th>
<th>$ XXX,XXX</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Other income and expense:</strong></td>
<td></td>
</tr>
<tr>
<td>AFUDC – equity</td>
<td>XXX</td>
</tr>
<tr>
<td>Disallowed abandoned plant costs</td>
<td>(XXX)</td>
</tr>
<tr>
<td>Disallowed cost of recently completed plant</td>
<td>(XXX)</td>
</tr>
<tr>
<td>Disallowed impairment of existing plant</td>
<td>(XXX)</td>
</tr>
<tr>
<td>Gain on sale of property</td>
<td>XXX</td>
</tr>
<tr>
<td>Donations</td>
<td>(XXX)</td>
</tr>
<tr>
<td>Non-safety related advertising</td>
<td>(XXX)</td>
</tr>
<tr>
<td>Income taxes applicable to other income and amortization of Option 1 ITC, net</td>
<td>XXX</td>
</tr>
<tr>
<td><strong>Total other income and expense</strong></td>
<td>(X,XXX)</td>
</tr>
<tr>
<td><strong>Income before interest charges</strong></td>
<td>$ XXX,XXX</td>
</tr>
</tbody>
</table>

In past discussions with the SEC, its staff was concerned about the inclusion of non-regulated operations in utility operating income on a piecemeal basis. If any non-utility operations are reported in utility operating income, or operating expenses do not include utility income taxes, regulatory disallowances and exclusions should be included in operating income. Additionally, the SEC has continued to provide comments to companies to disclose non-regulated operations in separate financial statement lines from regulated operations in the income statement.

Consideration should be given to disclosing in the notes to the financial statements, the adopted accounting policy for income statement classification and presentation. Because the primary objective of the traditional utility income statement is to clearly present the results of regulated operations, a more complete disclosure would also include the authorized and earned rates of return. An example disclosure follows.

**Income Statement Presentation** – The focus of the Company’s income statement presentation is the regulatory treatment of revenues and expenses as opposed to the income from continuing operations focus of enterprises in general. Above-the-line and below-the-line are financial and regulatory expressions frequently used by rate-regulated utilities. The above-the-line revenues and expenses (including income taxes) on which rate-regulated utility operating income is based, are those that ordinarily are included in the determination of utility revenue requirements. Below this line (operating income) are other income and expense amounts excluded in the determination of utility revenue requirements and interest expense, which utility operating income is intended to cover. The Company’s annual authorized equity return for the State jurisdiction is 12%. The Company’s earned equity return for the year 200X was 11.5%.

**Other SFAS 71 Related Disclosures**

If not already disclosed in the footnotes to financial statements, utilities will be asked in SEC staff comment letters to discuss and quantify the effect of applying SFAS 71. Specifically, footnote disclosures should include information about the regulatory status, amounts and classifications of regulatory assets and liabilities recorded in the financial statements. SFAS 71, paragraph 20, requires disclosure of the amounts and remaining recovery periods of regulatory assets being recovered through rates without a return. The SEC’s staff believes the best practice approach regarding regulatory assets is to affirmatively indicate whether a particular regulatory asset is earning a rate of return and the anticipated recovery period. Also, as noted earlier in this Section, the utility’s authorized and earned rates of return should be disclosed.

Factors and conditions that impact the application of SFAS 71 should be disclosed regarding the likelihood of discontinuing or reapplying SFAS 71. See example footnotes in the SFAS 101 section of this Section.

A typical example of such footnote disclosures requested by the SEC staff follows.

**Note 1: Summary of Significant Accounting Policies**

**Regulatory Assets and Liabilities:**

As a rate-regulated enterprise, we apply SFAS 71, *Accounting for the Effects of Certain Types of Regulation*. Regulatory assets represent probably future revenue associated with certain costs that will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process.
Regulatory assets and liabilities are reflected in the Consolidated Balance Sheets as of December 31 relate to the following (in thousands):

<table>
<thead>
<tr>
<th>Description</th>
<th>200X</th>
<th>200Y</th>
</tr>
</thead>
<tbody>
<tr>
<td>Deferred fuel (included in current assets)</td>
<td>$XXX,XXX</td>
<td>$XXX,XXX</td>
</tr>
<tr>
<td>Income taxes recoverable through future rates</td>
<td>$XXX,XXX</td>
<td>$XXX,XXX</td>
</tr>
<tr>
<td>Purchased power contract termination costs</td>
<td>XX,XXX</td>
<td>XXX,XXX</td>
</tr>
<tr>
<td>Abandoned plant costs</td>
<td>XX,XXX</td>
<td>XX,XXX</td>
</tr>
<tr>
<td>Loss on reacquired debt</td>
<td>XX,XXX</td>
<td>XX,XXX</td>
</tr>
<tr>
<td>Enrichment facilities-related costs</td>
<td>XX,XXX</td>
<td>XX,XXX</td>
</tr>
<tr>
<td>Other postretirement benefits</td>
<td>XX,XXX</td>
<td>XX,XXX</td>
</tr>
<tr>
<td>Environmental costs</td>
<td>XX,XXX</td>
<td>XX,XXX</td>
</tr>
<tr>
<td>Total long-term regulatory assets</td>
<td>$XXX,XXX</td>
<td>$XX,XXX</td>
</tr>
<tr>
<td>Nuclear maintenance and refueling</td>
<td>(XXX)</td>
<td>(XX,XXX)</td>
</tr>
<tr>
<td>Excess deferred income taxes</td>
<td>(XXX,XXX)</td>
<td>(XXX,XXX)</td>
</tr>
<tr>
<td>Deferred revenues</td>
<td>—</td>
<td>(XX,XXX)</td>
</tr>
<tr>
<td>Emission allowance gains</td>
<td>(X,XXX)</td>
<td>—</td>
</tr>
<tr>
<td>Storm reserve</td>
<td>(XX,XXX)</td>
<td>(XX,XXX)</td>
</tr>
<tr>
<td>Cost of removal</td>
<td>(X,XXX)</td>
<td>(X,XXX)</td>
</tr>
<tr>
<td>Total long-term regulatory liabilities</td>
<td>(XXX,XXX)</td>
<td>(XXX,XXX)</td>
</tr>
<tr>
<td>Net long-term regulatory assets</td>
<td>$XXX,XXX</td>
<td>$XXX,XXX</td>
</tr>
</tbody>
</table>

At December 31, 200Y, $XXX,XXX of our regulatory assets and all of our regulatory liabilities are being reflected in rates charged to customers over periods ranging from 3 to 15 years. We intend to request recovery of our remaining regulatory assets in a general rate case filing expected in 200Z. For additional information regarding income taxes, environmental costs and other postretirement benefit costs, refer to footnotes 4(e), 4(f) and 9, respectively. With the exception of those related to other postretirement benefits, deferred revenues and emission allowance gains, the remaining regulatory assets and liabilities were added to or deducted from our rate base on which the State Public Commission allows us the opportunity to earn a 10% overall rate of return, which is our most recent authorized amount.

If all or separable portions of our operations become no longer subject to the provisions of SFAS 71, a write off of related regulatory assets and liabilities would be required, unless some form of transition cost recovery (refund) continues through rates established and collected for the remaining regulated operations. In addition, we would be required to determine any impairment to the carrying costs of deregulated plant and inventory assets.

Criteria that give rise to the discontinuance of SFAS 71 include (1) increasing competition that restricts our ability to establish prices to recover specific costs, and (2) a significant change in the manner in which rates are set by regulators from cost-based regulation to another form of regulation. We periodically review these criteria to ensure the continuing application of SFAS 71 is appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, we believe that our regulatory assets are probable of future recovery.

The SEC’s SAB 10C, *Jointly Owned Electric Utility Plants*, requires a utility participating in a jointly owned power station to disclose the extent of its interests in such plant(s). Disclosure should include a table showing separately for each interest the amount of utility plant in service, accumulated depreciation, the amount of plant under construction and the proportionate share. Amounts presented for plant in service maybe further subdivided into subcategories such as production, transmission and distribution. Information concerning two or more generating plants on the same site may be combined if appropriate.
Disclosure should address the participant’s share of direct expenses included in operating expenses on the income statement (fuel, maintenance and other operating). If the share of direct expenses is all charged to purchased power, then disclosure of this amount, as well as the proportionate amounts related to specific operating expenses in the joint plant records, should be indicated.

A typical example of such footnote disclosures follows.

Under joint ownership agreements with other utilities, we have undivided ownership interests in four electric generating stations and related transmission facilities. Each of the respective owners is responsible for the issuance of its own securities to finance its portion of the construction costs. Energy generated and operating expenses are divided on the same basis as ownership with each owner reflecting its respective costs in its Statements of Income. Information relative to our ownership interest in these facilities at December 31, 200Y is as follows:

<table>
<thead>
<tr>
<th>Plant in Service</th>
<th>Accumulated Depreciation</th>
<th>Construction Work In Progress</th>
<th>Ownership %</th>
<th>In-service Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alpha Unit 1</td>
<td>$ XX,XXX</td>
<td>$ X,XXX</td>
<td>$ XXX</td>
<td>XX</td>
</tr>
<tr>
<td>Alpha Unit 2</td>
<td>XX,XXX</td>
<td>X,XXX</td>
<td>XXX</td>
<td>XX</td>
</tr>
<tr>
<td>Bravo Unit 1</td>
<td>XX,XXX</td>
<td>X,XXX</td>
<td>XXX</td>
<td>X</td>
</tr>
<tr>
<td>Bravo Unit 2</td>
<td>XX,XXX</td>
<td>X,XXX</td>
<td>XXX</td>
<td>X</td>
</tr>
<tr>
<td>Transmission Facilities, including Substations</td>
<td>XX,XXX</td>
<td>X,XXX</td>
<td>XXX</td>
<td>X-XX</td>
</tr>
</tbody>
</table>

**Revenue**

**EITF Issue 91-6, Revenue Recognition of Long-Term Power Sales Contracts**

Some generating plants are built by users primarily for their own energy needs while others are built specifically to sell power, usually to rate-regulated utilities, under long-term power sales or PPAs.

The PPA may provide for:

- As stated prices per kWh that increase, decrease, or remain level over the term of the contract
- A formula-based price per kWh
- Billings that are a combination of the above.

One example of such a combination is a PPA that provides for billings pursuant to a stated price schedule but also provides for a payment to be made or received at the end of the contract so that total revenue recognized and payments made over the contract term equal the amount computed pursuant to the formula-based pricing arrangement. Alternatively, the cumulative balance in the tracker account at a defined point in the PPA’s life may be amortized to zero through adjustments to subsequent billings. Another example of such a combination is a PPA that provides for billings pursuant to a stated price schedule but that provides for a payment to be made by the seller, if necessary, at the end of the PPA so that the total revenue recognized and total amounts received by the seller over the PPA’s term are limited to the lesser of the amount computed pursuant to the stated price schedule or the formula-based pricing arrangement.
The issues addressed in EITF 91-6 are:

- Whether revenue on a PPA that contains scheduled price changes should be recognized based on the schedule prices or ratably over the term of the contract
- Whether the accounting prescribed in the first issue changes if the PPA provides that total revenues for the term on the contract are determined by a separate, formula-based pricing arrangement
- Whether the accounting prescribed in the first issue changes if the PPA provides that total revenues for the term of the contract are limited by a separate, formula-based pricing arrangement.

The EITF noted that PPAs that would qualify for lease accounting pursuant to SFAS 13 are outside the scope of EITF Issue 91-6. The EITF reached a consensus that the seller should recognize as revenue the lesser of the amount billable under the contract or an amount determined by the kWhs made available during the period multiplied by the estimated average revenue per kWh over the term of the PPA. The determination of the lesser amount should be made annually based on the cumulative amounts that would have been recognized had each method been consistently applied from the beginning of the contract term.

The EITF reached a consensus on the second and third issues that a seller should recognize revenue in each period determined under the separate, formula-based pricing arrangement if it determines or limits total revenues billed under the PPA. The separate, formula-based pricing arrangement should not be used to recognize revenue if its only purpose is to establish liquidating damages. Under EITF Issue 91-6, the seller should recognize a receivable only if the contract requires a payment to the seller at the end of the PPAs term and such payment is probable of recovery. Also, a receivable results when amounts billed are less than the amount computed pursuant to the formula-based pricing arrangement.

EITF Issue 96-17, Revenue Recognition under Long-Term Power Sales Contracts That Contain Both Fixed and Variable Pricing Terms

EITF Issue 96-17 addresses how revenue should be recognized on a PPA that contains separate, specified terms for a fixed or scheduled price per kWh for one period of time and a variable price per kWh (based on market prices, actual avoided costs, or formula-based pricing arrangements) for a different period of time, where neither a tracker account nor any other form of adjustment determines or limits the total revenues to be billed under the contract over its entire period.

Under EITF Issue 96-17, such a PPA should be bifurcated and accounted for as follows:

- The revenue associated with the fixed or scheduled price period of the PPA should be recognized in accordance with the consensus reached for the first issue of EITF Issue 91-6.
- The revenue associated with the variable price period of the PPA should be recognized as billed, in accordance with the provisions of the PPA for that period.

EITF Issue 96-17 notes that if the contractual terms during the separate fixed and variable portions of the PPA are not representative of the expected market rates at the inception of the PPA, the revenue associated with the entire PPA should be recognized in accordance with the consensus reached for the first issue of EITF Issue 91-6.

Non-Traditional Ratemaking

Many electric utility companies, their regulators and other interested parties have implemented or are considering or negotiating regulatory agreements based on various forms of non-traditional ratemaking, which include features such as price caps, rate moratoriums or sharing formulas. Some of the agreements also provide for accelerated recovery of high-cost power plants and/or regulatory assets.

One issue with regulatory agreements based on the non-traditional ratemaking is whether application of SFAS 71 continues to be appropriate. Typically, the second criterion required for applying SFAS 71 – “the regulated rates are designed to recover the specific enterprise’s cost of providing the regulated services or products” – is most affected by alternative forms of regulation.

In evaluating whether a particular alternative form of regulation meets this criterion, a utility must conclude that a cause-and-effect relationship between its costs and revenues exists and is expected to continue into the future. Essentially, in order to qualify for continuing with the application of SFAS 71, the adopted alternative form of regulation should be a surrogate, not a replacement, for traditional individual cost-of-service based ratemaking. The following should be considered in making such a determination and developing an acceptable plan:

- The basis used for setting the utility’s initial rates under alternative regulation and whether the regulatory intent is for such rates to be based on the utility’s specific costs
The specificity of price adjustment formulas and how closely changes in the utility’s actual costs track the changes in revenues produced by applying price adjustment formulas

The nature and extent of exogenous cost changes allowed to adjust rates

The ability to “escape” the alternative regulation plan by way of cost-justified tariff filings or other procedures.

EITF Issue 92-7, Accounting by Rate Regulated Utilities for the Effects of Certain Alternative Revenue Programs

The EITF reached a consensus in EITF Issue 92-7 on accounting for the effects of certain alternative revenue programs. This consensus applies only to rate-regulated utilities under SFAS 71. The following discussion is an overview of this issue along with the consensus reached by the EITF.

Traditionally, regulated utilities, whose rates are based on cost of service, charge their customers by applying approved base rates to usage. Some regulators have also authorized the use of additional, alternative revenue programs. The major alternative revenue programs currently used are addressed in EITF Issue 92-7 and can generally be segregated into two types of programs:

- Programs that adjust billings for the effects of weather abnormalities or broad external factors, or that compensate the utility for demand-side management initiatives, which consists of various load management and conservation programs designed to address capacity, potential peak demand reductions and cost-saving opportunities for customers and environmental concerns
- Programs that provide for additional billings (incentive awards) if the utility achieves certain established performance measures, such as reducing costs, reaching specified milestones, or demonstratively improving customer service.

Both types of programs enable the utility to adjust rates in the future (usually as a surcharge applied to future billings) in response to past activities or completed events. The EITF did not address the accounting for credit balances (amounts due to customers) that may also result from alternative revenue programs. The credits should be recognized as liabilities because they are considered “refunds” of past revenues that are accounted for as contingent liabilities or regulatory liabilities that meet the conditions for accrual under SFAS 5 or in accordance with SFAS 71, paragraph 11, respectively.

The primary financial reporting issue for these programs is whether the economic substance of a regulator’s actions should be accrued and recorded as assets when it is probable that amounts will be recovered from customers and no other event is required in the future other than billing.

The EITF addressed the following financial reporting questions:

- What should the appropriate accounting be for the additional revenues to be billed in the future under alternative revenue programs?
- Should accounting for the two types of programs be the same?

The EITF reached a consensus that once the events permitting billing of the additional revenues under either type of program have been completed, the regulated utility should recognize the additional revenues if all of the following conditions are met:

- The program is established by an order from the utility’s regulatory commission that allows for automatic adjustment of future rates. The regulator’s verification of the adjustment in the future would not preclude the adjustment from being considered automatic
- The amount of additional revenues for the period is objectively determinable and is probable of recovery
- The additional revenues will be collected within 24 months of the period in which they are recognized.

In situations where revenue is not accruable as an EITF Issue 92-7 asset, paragraph 9 of SFAS 71 should be followed to the extent that probable future revenue is being provided to recover a specific incurred cost and a regulatory asset exists.
Property

Accelerated Capital Recovery

Utilities and their regulators have taken various actions related to depreciation and capital recovery in the interest of accelerating the recovery of certain generation assets that may have the risk of becoming stranded or as an alternative to adjusting rates downward if a utility is over-earning its allowed return. Such actions have included the following:

- The recording of additional depreciation provisions ratably over a number of years (e.g., $30 million per year for five years), or only under certain circumstances (e.g., if revenues exceed a certain amount or if operating earnings exceed authorized earnings levels).

- Transfers of existing depreciation reserves from one functional property classification to another (e.g., from transmission or distribution property to nuclear generation property).

- Transfer of current period depreciation expense from one functional property classification to another (e.g., from transmission or distribution property to nuclear generation property). In this situation, total depreciation expense for the period typically remains the same. However, an additional provision is recorded in one functional classification while the depreciation provision in another functional classification is reduced by a corresponding amount.

Additional Depreciation

Additional depreciation mechanisms are appropriate if the utility meets the requirements to apply SFAS 71 and its regulatory commission has specifically recognized additional depreciation in evaluating the utility's cost of service (allowable cost) used to establish its rates to customers.

Our conclusion in such situations is premised on an entity and the related plant asset(s) being subject to the provisions of SFAS 71, and in recognition that, in a rate regulated environment, depreciation is not only a cost allocation process but is also the source for capital recovery. This is a fair and reasonable approach for the financial reporting of such regulatory actions and accurately reflects the cause-and-effect relationship between a regulated utility's revenues and costs – in this case, the fact that additional capital recovery has taken place for the utility.

The SEC’s staff has stated that, based on SFAS 71, it will accept the recording of additional depreciation provisions where true economic recovery occurs. The SEC’s staff has also indicated that, if the plant asset is not subject to the provisions of SFAS 71, it does not believe these methods of recording additional capital recovery depreciation are in accordance with U.S. GAAP.

Recording additional depreciation may warrant disclosure in the footnotes because it may be unique and significant enough in the current environment and material to the income statement. Potential footnote disclosure includes the basis of such additional provisions and the related amounts involved, both for the current year as well as the cumulative amount reflected in accumulated depreciation.

A typical example of such footnote disclosures follows.

The State Public Service Commission has authorized us to accelerate capital recovery by recording additional depreciation of utility plant to the extent our actual rate of return exceeds our allowed rate of return. Accordingly, we recorded additional capital recovery of $X million in 200Y, (presented in the accompanying financial statements as depreciation expense and as an addition to the reserve for depreciation). The accumulated amount of such accelerated capital recovery in the reserve for depreciation is $X million as of December 31, 200Y.

Depreciation Expense Transfers

Depreciation expense transfers generally provide for the transfer of some amount of current period depreciation expense of one class of property (most frequently related to transmission or distribution assets) to the depreciation expense of another class of property (generally related to generating assets, nuclear generating assets in particular). As long as these transfers do not result in negative depreciation for any class of property, they are generally acceptable under SFAS 71. The regulator is exercising its right to determine appropriate depreciation rates for each class of property in determining allowable costs to be recognized in establishing rates charged to customers. The FERC requires depreciation studies to justify changes in depreciation rates.

Depreciation Reserve Transfers

Depreciation reserve transfers are similar to expense transfers, but generally provide for the transfer of some amount of one class of property's accumulated depreciation to another class of property's accumulated depreciation. The amount of the depreciation reserve transfer may be supported by a depreciation study that determines a theoretical reserve deficiency or surplus (cumulative historic under depreciation or over depreciation of the respective property classes) because estimated lives are shorter or longer than previously used for regulatory purposes. The only substantive difference between a depreciation expense transfer and a depreciation reserve transfer is that the amount of a reserve transfer may exceed one year's depreciation expense for certain classes of assets and thus could effectively result in negative depreciation expense for that class or a revision to depreciation expense recorded in previous periods.
To date, there have been few situations in which a utility has requested, and the regulator has approved, reserve transfers of existing property. The SEC’s staff has expressed concerns about such transfers being in accordance with U.S. GAAP. In practice, such transfers have been considered contrary to U.S. GAAP for the reasons listed below.

- Past provisions for depreciation have generally been computed and applied at the account or functional level. Although accumulated depreciation is displayed only in total on the face of the balance sheet, it is still supported by this account or functional level calculation.

- U.S. GAAP does not allow for “write-ups” of property absent a reorganization or an acquisition accounted for as a purchase.

- Under U.S. GAAP, specifically SFAS 90 or SFAS 144, there must be an impairment basis for any “write downs” of property.

- Under U.S. GAAP, if there is a change in a depreciation-related accounting estimate, the impact is reflected in the current and future periods as a prospective change and not through restatement or retrospectively adjusting amounts previously reported.

During 1996, the FERC issued an order rejecting a proposed rate change, which reflected a depreciation reserve shift, filed by a jurisdictional company for its wholesale requirements tariff and its open access transmission tariff. The FERC found that the utility’s proposed rate changes failed to comply with the regulations and policies promulgated by its Order No. 888 with respect to stranded cost recovery. The order concluded that the utility’s transfer of depreciation reserve balances from transmission and distribution plant to nuclear production plant was improper under U.S. GAAP and the FERC’s USOA and required correcting book entries.

**SFAS 144**

SFAS 144 addresses financial accounting and reporting for the impairment or disposal of long-lived assets. For long-lived assets to be held and used, SFAS 144 requires the recognition of an impairment loss only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows, and measures an impairment loss as the difference between the carrying amount and fair value of the asset.

The general principles of SFAS 144 do not apply to goodwill, intangible assets not being amortized that are to be held and used, deferred tax assets, regulatory assets that meet the criteria in paragraph 9 of SFAS 71, or plant assets whose accounting is prescribed by SFAS 90.

In order to properly apply SFAS 144, any goodwill recorded in an acquisition adjustment account should be identified and reclassified out of PP&E. Because acquisition adjustments must be allocated to specific assets in testing for recoverability, utilities will have to demonstrate that the combined specific asset and related PP&E-associated acquisition adjustment are recoverable. See subsequent discussion in this section about the treatment of acquisition adjustments.

**Groupings and Identifiable Cash Flows for Impairment Recognition and Measurement**

In accordance with SFAS 144, paragraph 10, “for purposes of recognition and measurement of an impairment loss, a long-lived asset or assets should be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities.”

In its May 29, 1998 letter to representatives of various major accounting firms, the SEC staff stated the following, which continues to provide relevant guidance for applying SFAS 144:

> When performing an impairment calculation in accordance with FASB Statement No. 121, we would expect plant assets to be grouped at the lowest level of identifiable cash flows that are largely independent of the cash flows of other plant assets. We presume that generally would be on an individual plant basis, however, we understand that there may be circumstances where aggregation on some other level would be appropriate. We do not believe that an entity may solely rely on the manner in which those assets are intended to be managed in order to make the aggregation decision.

Once the utility industry started its now delayed shift from a focus on cost recovery (i.e., regulated) to being the low cost provider (i.e., deregulated), decisions were increasingly made on an asset/plant specific basis by both management and regulators. This change was evident in regulatory jurisdictions that adopted industry restructuring plans and in the financial statements of affected companies that discontinued SFAS 71 and applied the provisions of SFAS 101. In practice, such companies generally performed impairment tests pursuant to SFAS 144 on a plant-by-plant basis.

However, for rate-regulated utilities that continue to be subject to traditional, cost-based rate-regulation, some grouping of assets is appropriate even though discrete cash flows could be identified at a lower level of aggregation. The guidance and examples in SFAS 144, particularly paragraph B45, indicate that long-lived assets could be grouped when there is a service obligation (and pricing of services) based on the operations of the group of assets as a whole.
An electric utility that is subject to traditional, cost-based rate-regulation and that uses various sources of generation to fulfill its service obligation provides a good example of this grouping concept. An electric utility's generating mix could range from high cost nuclear power plants and peaking units to lower cost fossil-fuel units and inexpensive hydro-electric facilities. Because this collection of plant assets is used together to meet the electric utility's service obligation and produce joint cash flows (generally based on system-wide average costs), such plant assets are interdependent and potentially could be grouped for recognition and measurement of an impairment loss under SFAS 144.

Facts and circumstances should dictate the level at which the SFAS 144 impairment analysis is performed. It should be recognized that among regulatory jurisdictions, such facts and circumstances will differ depending on the status of industry restructuring towards competition and on an entity’s operating characteristics.

**Measurement of an Impairment**

When events or changes in circumstances indicate that the carrying amount of an asset or asset group may not be recoverable, the utility should conduct a review for impairment. Examples of these events and circumstances include:

- A significant decrease in market value
- A significant adverse change in the extent or manner of use or significant physical damage
- A significant adverse change in legal factors or business climate, including an adverse action or assessment of a regulator
- An accumulation of costs significantly in excess of the amount originally expected
- A current period operating or cash flow loss combined with a history of losses or a forecast of continuing losses
- A current expectation, more likely than not, that a sale or other disposition will occur significantly before the previously estimated useful life or lives.

Significant changes in the regulatory environment or losses of major customers that result in stranded costs are also events that would indicate that a utility should review its assets for impairment.

To test for recoverability, a utility should compare future cash flows from the use and ultimate disposal of the asset or asset group (i.e., cash inflows to be generated by the asset or asset group less cash outflows necessary to obtain the inflows) to the carrying amount of the asset or asset group. Impairment exists when the expected future nominal (undiscounted) cash flows excluding interest charges are less than the carrying amount. SFAS 144 suggests, if a test for impairment is necessary, a utility may need to review its depreciation policies even if it finds that the asset is not impaired.

As discussed in the SEC’s staff May 29, 1998 letter, supplemental future cash flows provided through rate-regulated operations that are no longer subject to SFAS 71 should be excluded from the plant’s future cash flows in determining impairment under SFAS 144 if the utility is entitled to collect the supplemental future cash flows regardless of whether it continues to own or operate the deregulated plant asset. An example of supplemental future cash flows would involve a competitive transition charge passed on to regulated customers for the stranded costs of a plant asset no longer rate-regulated or subject to the provisions of SFAS 71. The basis for excluding such regulated cash flows (and a condition that should be met in order to exclude) is that they do not result from use of the assets.

If an asset in the separate portion is determined to be impaired pursuant to SFAS 144, a regulatory asset should be established when specific recovery of the impairment loss has been provided through regulated cash flows such as the CTC. Creation of the new regulatory asset is consistent with the guidance set forth in EITF Issue 97-4.

If the carrying amount of the asset is not recoverable, the asset is impaired and an impairment loss should be calculated. The impairment loss to be recorded is the amount by which the asset’s carrying amount exceeds its fair value. The best estimates of fair value are quoted market prices. If, as is often the case for utility property, market prices are not available, discounted future cash flows using a discount rate commensurate with the risks involved are an appropriate substitute. Once adjusted for the recognition of the impairment, the “new cost” becomes the depreciable base of the asset. Restoration of the impairment write down is generally not permitted, although one exception is for utilities with previously disallowed costs that are subsequently allowed by a regulator.
Required Disclosures

SFAS 144 requires disclosures about impairments including:

- A description of any impaired assets and the facts and circumstances leading to the impairment
- The amount of the impairment loss recognized and how fair value was determined
- The caption in the income statement in which the impairment is recorded, if not shown separately on the face of the statement
- The business segment affected (if applicable).

Application to Regulated Enterprises – Balance Sheet Classification

Unlike SFAS 90, which specifies that the amount of a disallowance shall be deducted from the reported cost of the plant, SFAS 144 does not specify whether an impairment loss should be recorded as a reduction in the asset’s original cost or as an adjustment to accumulated depreciation. Adjustment to the original cost appears to be consistent with the notion that recognizing an impairment establishes a “new cost” for the asset. However, the FERC’s Office of Chief Accountant requires impairment losses to be credited to accumulated depreciation.

EITF Issue 01-08

EITF Issue 01-08 centers on a company’s rights and uses of specific PP&E. PP&E as used in SFAS 13 only applies to land and/or depreciable assets; therefore inventory and intangibles are outside the scope of EITF Issue 01-08. The ability to use PP&E is based on the right to control the use of the underlying PP&E. The right to use consists of operating components of a facility, controlling access to the facility or whether an enterprise will take all but a minor amount of output from the facility and the price is not fixed per unit nor indexed to market prices.

EITF Issue 01-08 applies to all new contracts and all contracts that are modified or acquired. In addition, EITF Issue 01-08 is applicable to multiple element arrangements, with only the lease element accounted for under SFAS 13. It is important to remember that the same criteria in EITF Issue 01-8 apply to both sellers/lessors and purchasers/lessees so that if a contract contains those provisions it would have to be a lease for both parties. Therefore, companies will have to evaluate each aspect of a contract and determine if any component or components is a lease.

Below are common issues related to EITF Issue 01-08:

The implied asset concept

EITF Issue 01-8 indicates that PP&E may be the subject of a lease even if it is not explicitly identified in an arrangement. That is, PP&E may be subject to a lease arrangement if it is implicitly specified. The evaluation of whether an asset is implied in the contract requires judgment. The purchaser must evaluate if the seller has the means to deliver under the contract using other PP&E. That is, the purchaser has to determine if it is economically feasible for the seller to use any PP&E that it controls to provide the goods or services. These assets may be owned, leased or contracted. If the seller controls only one asset capable of delivering under the contract and it is not economically feasible to use other assets that are controlled by the seller, then the PP&E has been implicitly identified.

Physical change to the specific PP&E

Paragraph 13(d) of EITF Issue 01-8 states, “a substantial change to the specified property, plant and equipment requires reassessment of the arrangement … to determine whether the arrangement contains a lease on a prospective basis.”

This guidance requires companies to incorporate a control process for obtaining information to determine if there is a change in PP&E from which they are obtaining output. For example, Company X has a facility whose output is contracted to Company D. This output is generated by one turbine. Company X decides to increase the capacity of the facility by replacing the existing turbine with a new and improved turbine capable of creating 50% more output. As the contract with Company X was based on the existing turbine, Company D is required to reevaluate this contract as there has been a physically distinct change to the PP&E on which the contract is based.

More than a minor amount of output

One of the factors to determine if a party has a right to use PP&E is if it is remote that one or more parties other than the purchaser will take more than a minor amount of the output that will be generated by the PP&E (For illustration purposes, we are ignoring the following pricing requirements as specified in paragraph 12(c): … the price that the purchaser will pay for the output is neither contractually fixed per unit of output nor equal to the market price per unit of output as of the time of delivery of the output.). In order to properly evaluate the notion of more than a minor amount, preparers must pay close attention to the terms of all agreements associated with the PP&E. Generally, amounts more than 10 percent of the expected output of the PP&E are considered to be more than a minor amount. Thus, the purchaser must be able to identify
the output to which it is entitled. For example, if a contract entitles the purchaser to 90% of the output of an asset during the contract period, this is enough information for the purchaser to determine what output they are entitled to receive. In this situation, the amount of output that is available to one or more other parties is 10%. The purchaser must evaluate what is the likelihood that one or more other parties will take this output. Consideration must also be given to whether there are multiple outputs (e.g., electricity, steam, or renewable energy certificates) from the same asset.

Renewals or extensions

EITF Issue 01-08 was not intended to alter any of the rules in regards to renewals or extensions in accordance with paragraph 9 of SFAS 13. For example, if Company X has a 20 year contract with Company D which includes a renewal option for another 20 year term, exercise of the renewal option in the original contract would not trigger a reassessment under paragraph 13(b) of EITF Issue 01-08. Alternatively, if a renewal option was not included in the original contract, and a renewal of the contract was subsequently granted, then the contract should be assessed prospectively from the renewal period to determine if the arrangement contains a lease.

Pension and Postreirement Benefits Other Than Pension

EITF Issue 92-12, Accounting for OPEB Costs by Rate-Regulated Enterprises

In EITF Issue 92-12, a consensus was reached that a regulatory asset related to SFAS 106, Employers’ Accounting for Post Retirement Benefits Other than Pensions, costs should not be recorded in a rate-regulated enterprise’s financial statements if the regulator continues to limit inclusion of OPEB costs in rates to a pay-as-you-go basis. It was noted that the application of SFAS 71 for financial reporting purposes requires that a rate-regulated utility’s rates be designed to recover the specific utility’s costs of providing the regulated service or product and that the utility’s cost of providing a regulated service or product includes SFAS 106 costs.

Further, EITF Issue 92-12 concluded that a regulatory asset for financial reporting purposes should be recorded for the difference between SFAS 106 costs and OPEB costs included in its rates if the utility determines that it is probable that future revenue in an amount at least equal to the deferred cost (regulatory asset) will be recovered in rates and all of the following conditions are met:

• The utility’s regulator has issued a rate order, including a policy statement or a generic order applicable to utilities within the regulator’s jurisdiction, that allows the deferral of SFAS 106 costs and for the subsequent inclusion of those deferred costs in rates
• Annual SFAS 106 costs should be included in rates within approximately five years of SFAS 106 adoption. The deferral period for such costs has ended
• The combined deferral and recovery period approved by the regulator should not exceed approximately 20 years from the date of adoption of SFAS 106. Recovery periods should end in 2012
• If a regulator approves a total deferral and recovery period of more than 20 years, a regulatory asset should not be recognized for any costs not recovered by the end of the approximate 20 year period
• The percentage increase in rates scheduled under the regulatory recovery plan for each future year should be no greater than the percentage increase in rates scheduled under the plan for each immediately preceding year (no ‘backloading’, similar to phase-in plans under SFAS 92).

The EITF also reached a consensus that a utility should disclose in its financial statements:

• A description of the regulatory treatment of OPEB costs
• The status of any pending regulatory action
• The amount of any SFAS 106 costs deferred as a regulatory asset at the balance sheet date
• The period over which the deferred amounts are expected to be recovered in rates.

SFAS 158, Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106, and 132(R)

SFAS 158 requires all calendar year-end companies that sponsor a defined benefit postretirement plan to fully recognize, as an asset or liability, the overfunded or underfunded status of that plan in its balance sheet. The funded status is measured as the difference between the fair value of the plan’s assets and its benefit obligation (i.e., the projected benefit obligation for pension plans and the accumulated postretirement benefit obligation for other postretirement benefit plans).
In addition, SFAS 158 also requires a company to measure its plan assets and benefit obligations as of its year-end balance sheet date. The provision to require measurement at the entity’s year-end balance sheet date is effective for fiscal years ending after December 15, 2008. Paragraph 5 of SFAS 158 provides two exceptions to the measurement date provision. Those two exceptions, and the way in which the measurement date is affected, are as follows:

- When a subsidiary is the plan sponsor and is consolidated using a different fiscal period than its parent, the parent should measure the subsidiary’s postretirement benefit plan assets and benefit obligations as of the same date used to consolidate the subsidiary; and

- When the plan is sponsored by an equity method investee and the financial statements of the equity method investee are not available timely for the investor to apply the equity method currently, the investor should measure the investee’s plan assets and benefit obligations as of the same date of the investee’s financial statements used to apply the equity method.

Paragraphs 18 and 19 of SFAS 158 provide two approaches for a company to transition to a fiscal year-end measurement date.

SFAS 158 does not address the measurement and recognition issues related to the changes in the fair value of plan assets and benefit obligations. To address those issues, the FASB has a multi-year Phase II project on its agenda to comprehensively reconsider pension and postretirement benefit accounting. The project will focus principally on presentation of postretirement benefit assets, benefit liabilities, the cost of providing postretirement benefits, and disclosure. As part of that project, in March 2008, the FASB issued proposed FSP FAS 132(R)-a which, when finalized, would amend the SFAS 132(R), Employer’s Disclosures about Postretirement Benefit Plan Assets, disclosures about postretirement benefit plan assets. This FSP would be effective for fiscal years ending after December 15, 2009. See the FASB website for further information and updates on this project.

**Consolidated Plans**

Many utilities have consolidated pension and OPEB plans that cover employees of the parent company and several consolidated subsidiaries. These consolidated plans are often, but not always, accounted for as multiemployer plans in which pension or OPEB expense and contributions may be allocated to each subsidiary but the plan assets and obligations are not specifically attributed to any specific subsidiary. In those instances, we believe it is appropriate for the consolidated financial statements to reflect a regulatory asset or liability for the estimated portion of the additional amounts recognized under SFAS 158 in the consolidated financial statements without “pushing down” those amounts to the regulated subsidiary because the subsidiary has no separate right to any estimated allocated plan assets and no separate obligation for an estimated allocation of the consolidated plan obligation.

**Regulatory Treatment**

SFAS 158 has many regulatory implications. Amounts otherwise charged/credited to accumulated other comprehensive income could/should be recorded as a regulatory asset or liability if the utility has historically recovered and currently recovers its SFAS 87, Employers’ Accounting for Pensions, pension expense and/or SFAS 106 OPEB expense in rates (the determination should be made on a plan by plan basis) and there is no negative evidence that the existing regulatory treatment will change.

We do not believe that a specific regulatory order is required to record the regulatory asset or liability in the absence of such negative evidence. The reasoning is that if the utility is currently recovering SFAS 87 and SFAS 106 expense in rates, the AOCI amounts ultimately will be amortized to SFAS 87 or SFAS 106 expense in subsequent years and thus recovered/refunded in future rates. However, if it is probable the utility will have a SFAS 88, Employers’ Accounting for Settlements and Curtailments of Defined Benefits Pension Plans and for Termination Benefits, curtailment/settlement and that the related costs typically would not be recoverable in rates, a regulatory asset should not be recorded without a specific regulatory order.

If the utility has not historically recovered SFAS 106 expense in rates, but is currently recovering, no regulatory asset should be recorded until the cumulative rate recovery of SFAS 106 expense equals or exceeds cumulative SFAS 106 expense.

If SFAS 87 expense is on pay-as-you-go or some other non-SFAS 87 method for rate purposes, but the company has previously established support for a regulatory asset or liability, that previous support would likely be sufficient to continue regulatory asset or liability treatment for pension AOCI amounts. If the company does not recover SFAS 87 expense in rates and cannot currently record a regulatory asset/liability for the difference in expense, it would need a specific regulatory order or change in rate treatment to now record regulatory assets/liabilities for the pension AOCI amounts.

As noted in the previous OPEB discussion, under EITF Issue 92-12 a regulatory asset related to SFAS 106 costs should not be recorded if the company’s regulator continues to follow pay-as-you-go ratemaking treatment. EITF Issue 92-12 applies only to the accounting for regulatory assets related to SFAS 106 costs.
The transition impact of a measurement date change required by SFAS 158 is charged or credited directly to retained earnings rather than the income statement or AOCI. At the time SFAS 71 was issued, the transition impact of most accounting changes was recorded as cumulative effect charges/credits to income. Because SFAS 154, Accounting Changes and Error Corrections, changed the transition model for most accounting changes, we believe that a regulatory asset or liability could still be recorded for the SFAS 158 measurement date change, but only if the utility regulator issues a specific order or similar guidance that assures it is probable that the transition amount will be reflected in allowable costs in setting future rates in the period the remeasurement change is otherwise charged or credited to retained earnings.

Business Combinations

SFAS 141, SFAS 141(R) and SFAS 142
Utility/Energy Specific Issues

Many aspects of SFAS 141, Business Combinations, SFAS 141(R), Business Combinations, a replacement of SFAS 141, and SFAS 142 have implementation concerns for utilities. See Section 7 for a discussion of SFAS 141(R). Among the related utility issues are the following:

- How should acquisition adjustments be treated?
- Are plant licenses separately identifiable intangible assets or components of PP&E?
- Are emission allowances separately identifiable intangible assets or components of PP&E?
- Do favorable or unfavorable leases, fuel purchase contracts or sale contracts acquired result in the recognition of an intangible asset?

Treatment of Acquisition Adjustments

The determination must first be made as to whether acquisition adjustment costs are PP&E, goodwill, or other identifiable intangible assets because of the different amortization and impairment models that will be applied to the costs based on that classification.

To be recognized as an intangible asset apart from goodwill it must meet either the contractual-legal or separability criterion as was defined in paragraph 39 of SFAS 141. In the case of an acquisition adjustment itself, there are no contractual or legal rights that cause it to be created, such as would be the case for other identifiable intangible assets. Furthermore, the acquisition adjustment is not a separable asset capable of being sold or transferred, as might be the case for a customer list or technology.

Given this, the determination must be made as to whether the acquisition adjustment is PP&E. Regulatory uniform system of accounts do not require that “acquisition adjustments” be allocated between identifiable assets acquired and goodwill. SEC Regulation S-X (section 210.5-02 Item 13b) accepts the classification of public utility property, including original cost and acquisition adjustments, in accordance with the regulatory USOAs. As a result, many utilities have historically recorded the entire difference between the purchase price and the net book value of assets acquired as a separate component of PP&E. The regulatory classification as PP&E, however, has no bearing on the treatment of this item as PP&E or goodwill. Regulatory accounting permits certain intangible assets and regulatory assets to be included in PP&E. For PP&E subject to traditional cost-of-service regulation and SFAS 71, depreciated original cost is typically equal to its fair value. If an amount paid for utility plant exceeds its original cost depreciated, and that amount is recoverable through future rates, the fair value has been increased and an acquisition adjustment should be recorded as a component of utility plant. If the excess payment is not included in future rates, that amount typically represents goodwill. Under SFAS 142, paragraph D8b., if an acquisition adjustment is not being amortized as an allowable cost in ratemaking, the related amount is goodwill.

Because the FERC’s USOA does not have an account for goodwill, utilities that have applied “push-down” accounting for an acquisition may have recorded goodwill in the acquisition adjustment account for regulatory reporting. An appropriate reclassification is necessary for U.S. GAAP-based financial statements. The FERC’s accounting policy staff issued related guidance in July 2003, which states that “amounts so allocated to utility plant in excess of depreciated original cost at the date of acquisition should be an acquisition adjustment in Account 114 and the excess of the cost of the acquired company over the sum of the amounts assigned to all identifiable assets acquired and liabilities assumed should be recorded as goodwill in Account 186, "Miscellaneous Deferred Debits.” In such situations the acquisition adjustment would be amortized to the income statement consistent with the recovery through rates and the goodwill would not be amortized.

Plant License

Paragraph A10 of Appendix A to SFAS 141 provided an on point example as to whether plant licenses are separately identifiable intangible assets or components of PP&E and states in part:

An acquired entity owns and operates a nuclear power plant. The license to operate that power plant is an intangible asset that meets the contractual-legal criterion for recognition apart from goodwill, even if it cannot be sold or transferred apart from the acquired power plant.
This Statement does not preclude an acquiring entity from recognizing the fair value of the operating license and the fair value of the power plant as a single asset for financial reporting purposes if the useful lives of those assets are similar.

Given the above guidance, it would appear appropriate to recognize plant licenses apart from goodwill in accordance with paragraph 39 of SFAS 141. To the extent an entity wishes to recognize fair value of the plant license and the fair value of the power plant as a single asset for financial reporting purposes, this would be acceptable provided the useful lives of the assets are similar.

Consideration should be given to the possibility of license renewal or extensions that might cause an existing license to have a different useful life from the other components of PP&E. For example, if an operating license with 10 years remaining had a value of $10 and the other components of the plant had a value of $100, the utility might decide that the entire $110 value should be recorded as a single asset and amortized over 10 years since the plant cannot be operated without the operating license. On the other hand the utility may determine that the $10 license value of the plant had a value of $100, the utility might decide that the entire $110 value should be recorded as a single asset and amortized over 10 years since the plant cannot be operated without the operating license. On the other hand the utility may determine that the $10 license value should be amortized over its remaining 10-year term, but that the plant should be amortized over a 30-year period because it is considered probable that the operating license will be renewed for an additional 20-year period upon expiration of the initial license.

Emission Allowances

Title IV of the Clean Air Act Amendments of 1990 provides for the issuance of allowances as a means to limit the emissions of certain airborne pollutants by various entities, including public utilities. EAs acquired by a utility that applies SFAS 71 would generally be accounted for in accordance with FERC’s Order No. 552 for regulatory reporting. Section 8 addresses the accounting for EAs for financial reporting purposes.

These EAs meet the contractual-legal criterion and therefore are separately identifiable intangible assets to be recognized apart from goodwill. Though not specifically addressed in SFAS 141/SFAS 141(R), EAs clearly create a legal right and therefore the criterion is met. While the related plant often cannot be operated without the use of EAs, the EAs can be disposed of separately and in fact often are. The plant can also operate by adding emission control equipment, burning cleaner fuels, buying EAs, or paying penalties.

In some instances a utility may be in a position where it has excess EAs. This may be due to a decision to add pollution control equipment, use fuels that are less polluting, make other operating changes that reduce the need for EAs when operating specific plants or not operate the plant. In this regard EAs are similar to inventory that would be separately recorded from the PP&E asset, even though the PP&E cannot be operated without the fuel or other inventory and the intent may be to operate the PP&E with the acquired EAs. In these cases, the EAs should generally be recorded as separately identifiable intangible assets and the amortization period should likely reflect their use similar to inventory.

Because individual vintages of EAs would have different values (e.g., currently usable ones would be worth more than those that would be usable at some future time), those used initially would have higher costs than those used in later years.

In other instances the utility may be in a position where the allowances acquired are deemed to be required to operate the plant for its remaining life. In these cases, existing EAs may qualify as separately identifiable intangible assets to be recognized apart from PP&E or goodwill, but may have a life equal to the plant life so that separate recognition would not be required. If these costs were recorded as plant costs (separately identifiable intangible assets, in cases where the utility has the appropriate amount of EAs or needs to acquire additional allowances) and depreciated on a straight line basis the expense recognition would be back loaded as compared to the inventory treatment (when the utility finds itself in a position with excess allowances).

Favorable or Unfavorable Leases, Fuel Purchase Contracts, and Sales Contracts Acquired

Favorable or unfavorable leases or contracts would result in the recognition of an intangible asset or liability to be recognized apart from goodwill. The impacts of regulation may impact whether a contract is favorable or unfavorable. For example, a contract to sell power at regulated rates (if that is the only way the sale can be made) would not be compared to unregulated prices to determine whether the contract is favorable or unfavorable.

In some instances, these leases or contracts (if they are not derivatives) may contain favorable periods followed by unfavorable periods or vice versa. In those cases, the favorable and unfavorable periods should be amortized on a pro rata basis over the respective periods. For example, assume a three-year contract is acquired that is $3 favorable in year one, $1 favorable in year two, and $1 unfavorable in year three (net $3 favorable). In this case, it would not be acceptable to amortize the net favorable amount on a straight-line basis over the two-year favorable period or over the entire three-year term of the contract. Amortization should reflect amortization of $3 in year one, $1 in year two (even though this changes the recognized value of the contract from its initial positive value to a negative value at the end of year two), and $1 negative amortization in year three.
Investment Impairment

FSP FAS 115-1 and FSP FAS 124-1, *The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments*

Utility Implications

Utility companies that hold underwater available-for-sale investments in decommissioning trusts may have to record impairment write downs on their investments and remove unrealized losses from AOCI. For unregulated decommissioning trusts, these impairment write downs are recognized in income. The NRC requires decommissioning trusts to use third party investment managers who have the discretion to sell investments without the approval of the utility company that holds the investment. As a result, the utility company cannot represent that it has the "intent and ability" to hold the investments until they recover in value since that decision is outside its control. OTTI adjustments for regulated utility companies that have investments in decommissioning trusts that are subject to SFAS 71 should not have an income statement impact, as unrealized gains and losses on investments held by such entities are charged/credited to a regulatory asset/liability rather than AOCI. Thus, recording impairments of unrealized losses would impact the footnote disclosure of unrealized gains and losses on available-for-sale investments, but would not impact the amounts reported in the income statement or balance sheet.
SECTION 5

Energy Contracts, Derivative Instruments and Hedging Activities Update

Introduction

In 2008, we have seen unprecedented volatility in the financial markets and a resulting shakeup on Wall Street of historic proportions. News of failing financial institutions and government intervention dominates the business news on a daily basis. The credit crisis has rippled through all industries and certainly the energy transacting industry is no exception with financial institutions being major players in that industry.

Commodity prices have been volatile as well. In 2008, a barrel of crude oil reached its all time domestic high. A gallon of gasoline also reached its all time domestic high. Liquidity continues to come at a premium.

As companies navigate their way through this time of uncertainty and waning confidence in our financial infrastructure, the need for accurate and timely financial reporting has never been more important. We continue to see slippage in key reconciliations companies are performing and have recommended that a reemphasis on basic “blocking and tackling” in the monthly close process may be warranted. In addition, it is imperative that companies’ financial disclosures go through a rigorous quality control process in order to avoid the intolerance of the investing public for misinformation. Accounting for derivatives has been the subject of recently proposed rulemaking changes, although to what degree changes will occur is currently uncertain. As such, we have prepared this year’s update with an emphasis on accounting guidance currently in place, with the intent of reemphasizing some of the common missteps we see in the industry.

Background

We have provided a discussion of derivative accounting topics herein (some of which may have been addressed in prior publications) that we deemed worthy of emphasis in 2008. We hope that the following section is helpful to preparers as they address this complex area.

The following topics are addressed within this Section:

- Derivative Criteria
- Hedge Accounting
- Commodity Derivative Disclosure Requirements
- Income Statement Presentation
- Other Items

Derivative Criteria

Companies continue to struggle with whether contracts commonly executed in the energy industry meet the definition of a derivative. A derivative instrument is a financial instrument or other contract with all three of the following characteristics:

- It has (1) one or more underlyings and (2) one or more notional amounts or payment provisions or both. Those terms determine the amount of the settlement or settlements, and, in some cases, whether or not a settlement is required.

- It requires no initial net investment or an initial net investment that is smaller than would be required for other types of contracts that would be expected to have a similar response to changes in market factors.

- Its terms require or permit net settlement, it can readily be settled net by a means outside the contract, or it provides for delivery of an asset that puts the recipient in a position not substantially different from net settlement.

The following table expands on the meaning of each characteristic listed above and includes a discussion of common contract characteristics in the energy industry which may satisfy each criterion.
Derivative Characteristic: An underlying is a specified interest rate, security price, commodity price, foreign exchange rate, index of prices or rates, or other variable (including the occurrence or non-occurrence of a specified event such as a scheduled payment under a contract). An underlying may be a price or rate of an asset or liability but is not the asset or liability itself. A notional amount is a number of currency units, shares, bushels, pounds, or other units specified in the contract. The settlement of a derivative instrument with a notional amount is determined by interaction of that notional amount with the underlying. The interaction may be simple multiplication, or it may involve a formula with leverage factors or other constants. A payment provision specifies a fixed or determinable settlement to be made if the underlying behaves in a specified manner.

Application to Contracts in the Energy Industry:

Many contracts in the energy industry will meet this criterion because they reference a specific quantity (the notional) of a specific commodity (the underlying). Common examples include block forward contracts for electricity (e.g., 50 MW, 5x16) and NYMEX futures on natural gas at Henry Hub. The settlement features of such contracts can be physical or financial in nature and can provide for settlement based on a fixed quantity or can provide optionality to one or both of the counterparties.

Many contracts in the energy industry are designed to meet the full requirements of the purchasing counterparty. These contracts typically prevent the buyer from buying quantities beyond their internal needs with the intention of reselling (i.e., the volumetric optionality in the contracts may not be exercised economically). Such contracts may or may not have a notional as defined in SFAS 133, Accounting for Derivative Instruments and Hedging Activities. If a determinable notional amount can be identified (for example, due to the existence of a minimum take amount or settlement or default provisions), a full requirements contract would meet this criterion. Companies should consider the guidance in DIG Issue A6, Definition of a Derivative: Notional Amount of Commodity Contracts, when assessing whether a requirements contract for the physical delivery of a commodity has a notional amount. It should be noted that certain entities, such as load serving entities, will often satisfy the needs of their direct customers under requirements contract with a plant owner. In many such cases, the load serving entity buys for resale but is precluded from exercising the optionality in the requirements contract economically (i.e., the load serving entity can only buy to meet the demand of its native load). We believe it is appropriate to apply the guidance in DIG Issue A6 to such contracts, despite the resale of the commodity, as long as economic exercise is prohibited. For contracts with volumetric optionality that are not requirements based (i.e., economic exercise is allowed), we generally believe that a stated maximum in the contract represents a reliably determinable notional amount.

In addition, certain asset optimization or asset management contracts may contain profit sharing arrangements that need to be evaluated to determine whether such contracts contain an underlying and payment provision that may satisfy the SFAS 133 derivative criteria.

Initial net investment. Many derivative instruments require no initial net investment. Some require an initial net investment as compensation for time value (for example, a premium on an option) or for terms that are more or less favorable than market conditions (for example, a premium on a forward purchase contract with a price less than the current forward price). Others require a mutual exchange of currencies or other assets at inception, in which case the notional amount is the difference in the fair values of the assets exchanged. A derivative instrument does not require an initial net investment in the contract that is equal to the notional amount (or the notional amount plus a premium or minus a discount) or that is determined by applying the notional amount to the underlying. If the initial net investment in the contract (after adjustment for the time value of money) is less, by more than a nominal amount, than the initial net investment that would be commensurate with the amount that would be exchanged either to acquire the asset related to the underlying or to incur the obligation related to the underlying, the initial net investment characteristic is met. The amount of that asset acquired or liability incurred should be comparable to the effective notional amount of the contract.

Energy contracts that provide for future delivery or settlement will typically meet this criterion, as they do not require either party to pay cash at contract inception. A forward commodity contract, for example, is typically priced at the expected market price at the date of delivery and therefore puts neither party at an economic advantage at inception. As the value of the contract is effectively zero at inception, neither party is required to pay cash. Option contracts typically do feature a cash exchange at inception as the option holder pays the option writer a premium for the time value of the option. However, the option premium is typically less, by more than a nominal amount, than an amount determined by applying the notional amount to the underlying and therefore options typically do meet this criterion.

Another characteristic of many energy contracts is a requirement to post margin with a broker or cash collateral with a direct counterparty to the extent that a position is out of the money. Margin and collateral requirements are forms of credit enhancement and are typically designed to protect the counterparty by funding part or all of the value of a contract prior to settlement. Like option premiums, such amounts are typically less than an amount determined by applying the notional amount of the contract to the underlying.

Certain contracts, such as volumetric production payments or prepaid forward contracts, will require additional analysis related to initial net investment. For contracts that require up-front payments consideration should be made as to whether the contract is a hybrid instrument that contains an embedded derivative or contains a financing element. Paragraph 45A of SFAS 133 requires that if an other than insignificant financing element is present at inception of a derivative instrument, then the borrower shall report all inflows and outflows associated with the derivative instrument as financing activities in the Statement of Cash Flows.
It is apparent from the table above that many contracts common to the energy industry will meet the definition of a derivative. Industry participants may then consider whether their contracts (1) qualify for a scope exception to SFAS 133 or (2) qualify as a hedging instrument under SFAS 133. Absent either of these outcomes, a contract must be accounted for at fair value with changes in fair value recorded through earnings.

In addition, we thought it was important to highlight some products whose markets are evolving. For contracts in these markets, where physical delivery of the underlying assets is required, the assessment of the net settlement criteria (more specifically, whether the underlying assets are readily convertible to cash) can be challenging and oftentimes requires significant judgment. A brief discussion of these products and some of the related derivative determination considerations follow.
<table>
<thead>
<tr>
<th>Product</th>
<th>Description:</th>
<th>Derivative Determination Considerations:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquefied Natural Gas</td>
<td>LNG is natural gas that has been processed and then condensed into a liquid by cooling. Where not possible or economical to move natural gas via pipeline, LNG may be processed and transported by sea vessels and road tankers. LNG can also be stored in specially designed tanks.</td>
<td>Consider level of transacting activity for LNG (liquid form). Determination may vary depending on delivery location and spot prices at the inception of the contract.</td>
</tr>
<tr>
<td>Emission Allowances</td>
<td>EAs are generally granted by regulators and may include SO2 and NOx allowances and Certified Emission Reductions. Each allowance permits the entity holding the allowance to emit one ton of the specified pollutant during or after a specified vintage year, depending on type of EA. Entities emitting more than their allocated allowances may choose to reduce emissions, pay a fine, or purchase additional allowances through market “cap and trade” programs. In December 2007, a group of companies announced the creation of a venture entitled the Green Exchange that offers environmental futures, options, and swap contracts, as early as the first quarter of 2008, for markets focused on solutions to climate change, renewable energy, and other environmental challenges. The launch of this venture may create additional liquidity for contracts exchanging EAs and other environmental products.</td>
<td>Distinction should be made between the accounting for the actual allowance and the accounting for forward or option contracts to buy or sell the allowance. See Section 8 where we discuss the different accounting models currently acceptable for EAs. We do not believe EAs are derivatives, but contracts exchanging EAs may meet the derivative criteria. Consideration should be made as to whether an active spot market exists for the EA itself. Determination may vary depending on type of allowance (SO2, NOx, CERs, etc.) and vintage year.</td>
</tr>
<tr>
<td>Installed Capacity/Unforced Capacity</td>
<td>ICAP provides assurance that resources will be available to supply the region or ISO load requirements. ICAP is also a means for compensating those resources for being available. ICAP is not energy or ancillary services. In many regions, load serving entities are required to procure sufficient ICAP/UCAP, thus creating the need for a secondary market. During 2008 the capacity markets for certain regions of the country have undergone substantial modifications. In particular, the PJM capacity market has moved to a financial capacity product that for all intents and purposes settles as a financial instrument swap contract. Many entities have traditionally accounted for PJM capacity products as Normal Purchase Normal Sales arrangements. Following this change in structure, this accounting treatment may no longer be afforded, resulting in the capacity product being accounted for at fair value with changes in fair value recorded through earnings.</td>
<td>Consideration should be made as to whether an active spot market exists. Determination may vary depending on power pool (PJM, NYISO, etc.) Evaluation of existing capacity products to differentiate those that function as financial instruments from those that are traditional physical products is necessary to isolate those capacity arrangements that may not qualify for the Normal Purchase Normal Sales exemption.</td>
</tr>
<tr>
<td>Coal</td>
<td>Approximately 50% of U.S. power generation is from coal-fired facilities. There are many different locations and grades of domestic coal, including Powder River Basin 8400 &amp; 8800 and Central Appalachia 1%. In addition, international coal markets have developed in Europe, South Africa, Australia and Asia. Contracts may include rail or other transportation.</td>
<td>Consideration should be made as to whether an active spot market exists. This consideration should be specific to delivery location. Analysis should consider DIG Issue A10 and whether costs to convert to cash are significant (i.e., greater than 10%), particularly given rise in coal prices. Determination may vary depending on delivery location (i.e., at the mine, river dock or generation facility) or grade.</td>
</tr>
<tr>
<td>Renewable Energy Credits</td>
<td>RECs are allocated through state or regional programs to owners of environmentally friendly power generation (wind, solar, hydro, etc.) Load serving entities may be required to meet their regulatory compliance obligations by acquiring and retiring a certain amount of RECs (although not required to purchase the associated renewable energy), thus creating a need for a secondary market. As noted above, the launch of the Green Exchange and the introduction of more rigorous renewal portfolio standards in some regions, and in some cases, new market participants (i.e., dealers) may create additional liquidity for contracts exchanging RECs and other environmental products.</td>
<td>Distinction should be made between the accounting for the actual credit and the accounting for forward contracts to buy or sell the credit. We do not believe RECs are derivatives, but contracts exchanging RECs may meet the derivative criteria. Consideration should be made as to whether an active spot market exists for the REC itself. Determination may vary depending on state or region. RECs may be combined in some contracts with the purchase or sale of energy, which as stated earlier, we generally believe to be deemed readily convertible to cash.</td>
</tr>
</tbody>
</table>
Hedge Accounting

The application of hedge accounting has remained an area of challenge and concern for industry participants throughout the sector, including producers, wholesale marketing organizations, utilities, and product end users. Hedge accounting has also been an area of focus by the SEC and regulators. We recognize the inherent complexity associated with the application of hedge accounting to commodity activity and accordingly have provided a summarization of certain pitfalls commonly encountered by industry participants for your consideration.

Assuming No Ineffectiveness (“Matched Terms Hedging”)
We continue to note diversity in practice in the designation of hedge relationships as “Matched Term” thus implying that the hedge relationship is perfectly effective. SFAS 133 recognizes that in certain instances when the critical terms of the hedge and hedged item match, alternative approaches to the assessment and measurement of ineffectiveness for reporting purposes may be appropriate. However, this is an area that continues to be a focal point of the SEC, as evidenced by recent comment letters and speeches addressing the topic.

SFAS 133 Paragraph 65 notes that “if the critical terms of the hedging instrument and of the entire hedged asset or liability (as opposed to selected cash flows) or hedged forecasted transaction are the same, the entity could conclude that changes in fair value or cash flows attributable to the risk being hedged are expected to completely offset at inception and on an ongoing basis. An entity may assume that a hedge of a forecasted purchase of a commodity with a forward contract will be highly effective and that there will be no ineffectiveness to be recognized in earnings if:

<table>
<thead>
<tr>
<th>Product</th>
<th>Description:</th>
<th>Derivative Determination Considerations:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ancillary Services</td>
<td>Ancillary Services are designed to ensure the security and reliability of power systems consistent with North American Electric Reliability Council standards. Common Ancillaries include Regulation Service Up and Down, Responsive Reserve Service and Non-Spinning Reserve. Entities may be required to own Ancillaries or pay market clearing prices to participate in some markets.</td>
<td>Consideration should be made as to whether an active spot market exists. Determination may vary depending on region and type of Ancillary Service (Reg Up, Reg Down, etc.). Ancillary Services may be combined in some contracts with the purchase or sale of energy, which as stated earlier, we generally believe to be deemed readily convertible to cash.</td>
</tr>
<tr>
<td>Congestion Products</td>
<td>Congestion products are designed in order to promote open access transmission and facilitate competition in deregulated markets. Commonly referred to as financial transmission rights, these products have different names and behave differently in different ISOs (also known as TCRs in ERCOT, TCCs in NYISO). Each product also can be acquired through different means (via auction, grant, or secondary market) depending on the ISO. In addition, depending on the path of a given contract, there can be significant volatility in the fair value associated with the contract. As a result, there may be considerable challenges with regards to accounting for gains or losses at inception of the contract, as well as ongoing changes in fair value measurements.</td>
<td>Consideration should be made as to whether the net settlement criteria in 9a, 9b or 9c of SFAS133 have been met. Determination may vary dependent on type of congestion product and/or delivery path. It should be noted that many congestion products function like financial instruments with net cash-settlement and satisfy the paragraph 9a criteria..</td>
</tr>
<tr>
<td>Uranium</td>
<td>Uranium is the common fuel used in nuclear power generation, which accounts for about 19% of all power generation in the U.S. A uranium futures market was launched in the second quarter of calendar year 2007.</td>
<td>Consideration should be made as to whether an active spot market exists. This consideration should be specific to delivery location. Analysis should consider DIG Issue A10 and whether costs to convert to cash are significant (i.e., greater than 10%). Determination may vary depending on delivery location. Distinction should be made between the accounting for the fuel and the accounting for forward contracts to buy or sell the fuel.</td>
</tr>
</tbody>
</table>

We understand diversity in practice may exist related to derivative determinations for each of the above products. We have advised our clients to be sure that they have sufficiently evaluated the particular product or market and have documented the support for their conclusions. In addition, it is important that entities have a process to continually evaluate contracts in their portfolio, including an ongoing assessment of whether products are considered readily convertible to cash. There may be instances where products become readily convertible to cash that were previously not deemed to be readily convertible to cash, which may result in accounting for such contracts as a derivative under SFAS 133 and recognition at fair value with a corresponding offset through earnings (unless the contract qualifies and has been designated as a normal purchase/normal sale contract) as described in DIG Issue A18, Definition of a Derivative: Application of Market Mechanism and Readily Convertible to Cash Subsequent to the Inception or Acquisition of a Contract. Finally, entities seeking to mitigate any fair value impacts for contracts involving products above that could meet the net settlement criteria in either paragraph 9b or 9c of SFAS133 subsequent to inception should consider a precautionary designation as a normal purchase/normal sale contract if the criteria in paragraph 10b of SFAS 133 are met.
• The forward contract is for purchase of the same quantity of the same commodity at the same time and location as the hedged forecasted purchase.

• The fair value of the forward contract at inception is zero.

• Either the change in the discount or premium on the forward contract is excluded from the assessment of effectiveness and included directly in earnings pursuant to paragraph 63 or the change in expected cash flows on the forecasted transaction is based on the forward price for the commodity.”

The SEC staff has emphasized that the matched term approach was intended to apply only when all known sources of variability (such as location or timing) are perfectly matched. The application of the “Matched Term” hedge designation does not exempt the company from the evaluation of hedge effectiveness in perpetuity. In fact, at a minimum, entities should update their understanding of the hedge effectiveness drivers and document at least quarterly their expectation that the hedge relationship continues to qualify for “Matched Term” accounting treatment. The ongoing assessment of effectiveness should include verifying and documenting whether the critical terms of the hedged item and the hedging instrument has changed during the period, as well as assessing whether there have been any adverse developments regarding the risk of default by the counterparty to the hedging instrument or forecasted transaction.

During the first quarter of calendar year 2007, the SEC further clarified its expectations relative to the application of matched term hedging. In particular, the SEC noted their concerns with the practice of ignoring interperiod volatility not perfectly offset when the hedging derivative settles based on end of month pricing. Registrants should carefully evaluate the magnitude of any sources of ineffectiveness within all hedge relationships, including matched term relationships. To qualify for matched term hedging in situations where the terms do not exactly match, but the other provisions in paragraph 65 are satisfied, an entity must prove that the relationship is expected to be highly effective and any ineffectiveness within the relationship is de minimis to the overall relationship. This conclusion must be documented and substantiated through quantitative evaluation.

It should be noted that in 2008 the FASB issued an Exposure Draft, Accounting for Hedging Activities - an amendment of FASB Statement No. 133, (“ED”) that would amend certain aspects of SFAS 133, included the removal of the “Shortcut” method and the “Matched Term” methods as acceptable approaches to complying with the hedge accounting requirements of SFAS 133. During the ED’s comment period, many respondents expressed concern regarding certain aspects of this proposed amendment and at this time it is unclear what, if any, amendments will be made to the current requirements as the FASB is currently redeliberating the matter.

In addition, in light of the recent financial turmoil and the resulting increase in the number of companies who have filed for bankruptcy, sought additional capital, seen their credit ratings decline, or who are otherwise in financial distress, we thought it important to reemphasize some guidance related to nonperformance risk, and specifically considerations of nonperformance risk to the application of hedge accounting. As described in paragraph 15 of SFAS 157, nonperformance risk refers to the risk that an entities’ obligation will not be fulfilled and affects the value at which their liability could be transferred and therefore its fair value. Nonperformance risk is specific to each contract and should include considerations of an entities’ credit standing, as well as any credit enhancements.

Nonperformance risk assumptions — Entities should consider the nonperformance risk assumptions used in determining the fair value of the contract or arrangement pursuant to SFAS 157. See further discussion of nonperformance risk assumptions in Section 6.

Cash flow hedge accounting implications — Entities that have derivative contracts that are designated as hedging instruments in cash flow hedging relationships pursuant to SFAS 133 should consider the possibility of counterparty default in accordance with DIG Issue G10, Cash Flow Hedges: Need to Consider Possibility of Default by the Counterparty to the Hedging Derivative, when determining whether the hedging relationship continues to be highly effective. It should be noted that amounts recorded in AOCI should not be released to earnings unless the original forecasted transaction has become probable of not occurring.

In addition, entities that have forecasted transactions that are designated as the hedged item in a cash flow hedge should consider whether, in accordance with paragraph 29(b) of SFAS 133, it remains probable that the forecasted transaction will occur. The nonperformance risk of the counterparty to the forecasted transaction should be considered in this determination.

Fair value hedge accounting implications — Entities that have derivative contracts that were designated as hedging instruments in fair value hedging relationships pursuant to SFAS 133, but no longer qualify because of counterparty default considerations should continue to fair value such derivative contract through earnings but discontinue adjusting the carrying value of the hedged item for subsequent changes in fair value. Previous hedge adjustments made to the carrying amount of the hedged item would be accounted for in the same manner as other component’s of the hedged item’s carrying amount.

Commodity Derivative Disclosure Requirements

Both the SEC and FASB require specific disclosure of derivative activity. To highlight the continued importance of sufficient disclosure around derivative instruments, we have provided the prior year disclosure summary updated with new disclosure requirements introduced during the current year. Note that this discussion excludes consideration of the disclosure requirements of SFAS 157, as these requirements are discussed in detail in Section 6.

The following table provides a summary of key disclosure requirements for derivative activity.
## General Disclosures Concerning Derivative Instruments

<table>
<thead>
<tr>
<th>Relevant Guidance</th>
<th>Guidance Details</th>
</tr>
</thead>
<tbody>
<tr>
<td>SFAS 133 paragraph 44</td>
<td>In accordance with FASB and SEC regulations, entities must disclose general information concerning the nature of the derivative portfolio. This information should include the company’s objectives, strategies, risk management policies, and accounting policies for the different categories of derivative instruments. Example disclosures may include discussion of the application of fair value hedges, cash flow hedges, foreign currency hedges, and other derivatives. For hedges, the company should discuss the criteria required for hedge accounting to be applied. Such disclosures are addressed in more detail below.</td>
</tr>
<tr>
<td>SEC Regulation S-X, Rule 4-08</td>
<td>For assets and liabilities that are measured at fair value on a recurring basis in periods subsequent to initial recognition, the reporting entity shall disclose information that enables users of its financial statements to assess the inputs used to develop those measurements and for recurring fair value measurements using significant unobservable inputs and the effect of the measurements on earnings for the period. The reporting entity shall disclose the following information for each interim and annual period (except as otherwise specified) separately for each major category of assets and liabilities:</td>
</tr>
<tr>
<td>• The fair value measurements at the reporting date</td>
<td></td>
</tr>
<tr>
<td>• The level within the fair value hierarchy in which the fair value measurements in their entirety fall, segregating fair value measurements using quoted prices in active markets for identical assets or liabilities (Level 1), significant other observable inputs (Level 2), and significant unobservable inputs (Level 3)</td>
<td></td>
</tr>
<tr>
<td>• For fair value measurements using significant unobservable inputs (Level 3), a reconciliation of the beginning and ending balances, separately presenting changes during the period attributable to the following:</td>
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<tr>
<td>– Total gains or losses for the period (realized and unrealized), segregating those gains or losses included in earnings (or changes in net assets), and a description of where those gains or losses included in earnings (or changes in net assets) are reported in the statement of income (or activities)</td>
<td></td>
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<tr>
<td>– Purchases, sales, issuances, and settlements (net)</td>
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<tr>
<td>– Transfers in and/or out of Level 3 (for example, transfers due to changes in the observability of significant inputs)</td>
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</tr>
<tr>
<td>• The amount of the total gains or losses for the period included in earnings (or changes in net assets) that are attributable to the change in unrealized gains or losses relating to those assets and liabilities still held at the reporting date and a description of where those unrealized gains or losses are reported in the statement of income (or activities)</td>
<td></td>
</tr>
<tr>
<td>• In annual periods only, the valuation technique(s) used to measure fair value and a discussion of changes in valuation techniques, if any, during the period.</td>
<td></td>
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<tr>
<td>SFAS 157 paragraph 32</td>
<td>For assets and liabilities that are measured at fair value on a nonrecurring basis in periods subsequent to initial recognition (for example, impaired assets), the reporting entity shall disclose information that enables users of its financial statements to assess the inputs used to develop those measurements. The reporting entity shall disclose the following information for each interim and annual period (except as otherwise specified) separately for each major category of assets and liabilities:</td>
</tr>
<tr>
<td>• The fair value measurements recorded during the period and the reasons for the measurements</td>
<td></td>
</tr>
<tr>
<td>• The level within the fair value hierarchy in which the fair value measurements in their entirety fall, segregating fair value measurements using quoted prices in active markets for identical assets or liabilities (Level 1), significant other observable inputs (Level 2), and significant unobservable inputs (Level 3)</td>
<td></td>
</tr>
<tr>
<td>• For fair value measurements using significant unobservable inputs (Level 3), a description of the inputs and the information used to develop the inputs</td>
<td></td>
</tr>
<tr>
<td>• In annual periods only, the valuation technique(s) used to measure fair value and a discussion of changes, if any, in the valuation technique(s) used to measure similar assets and/or liabilities in prior periods.</td>
<td></td>
</tr>
</tbody>
</table>
## Market Risk Disclosures Around Derivative Instruments

<table>
<thead>
<tr>
<th>Relevant Guidance</th>
<th>Guidance Details</th>
</tr>
</thead>
</table>
| SEC Regulation S-K, Item 305 | Entities should provide disclosures of market risk characteristics within Item 7A, *Management Discussion & Analysis* addressing two categories: (1) instruments entered into for trading purposes and (2) instruments entered into for purposes other than trading. The company has the option to choose between one of three quantitative disclosure options for each category:  
  • Tabular presentation of fair value information and contract terms relevant to determining future cash flows, categorized by expected maturity dates,  
  • Sensitivity analysis expressing the potential loss in future earnings, fair values, or cash flows from selected hypothetical changes in market rates and prices, or  
  • Value at risk disclosures expressing the potential loss in future earnings, fair values, or cash flows from market movements over a selected period of time and with a selected likelihood of occurrence. |

## Disclosure of Derivatives Designated as Hedges

<table>
<thead>
<tr>
<th>Relevant Guidance</th>
<th>Guidance Details</th>
</tr>
</thead>
</table>
| SFAS 133 paragraph 45 | For fair value hedges, the company should disclose the net gain or loss recognized during the reporting period resulting from ineffectiveness, the component of a derivative’s gain or loss (if any) excluded from the assessment of hedge effectiveness (and a description of where the gain or loss is reported in the income statement), and the net gain or loss included in earnings when a hedged firm commitment no longer qualifies as a fair value hedge.  
  For cash flow hedges, the company should disclose the net gain or loss recognized during the reporting period resulting from ineffectiveness, the component of a derivative’s gain or loss (if any) excluded from the assessment of hedge effectiveness (and a description of where the gain or loss is reported in the income statement), the net gain or loss included in earnings when the instrument no longer qualifies as a cash flow hedge. A description should be included that describes the transactions or events that will result in the reclassification of amounts in AOCI to earnings. The company should also disclose the estimated net amount of AOCI that will be reclassed into earnings in the next 12 months, as well as the maximum length of time over which the entity is hedging its exposure to variability in cash flows for forecasted transactions.  
  For foreign currency hedges, the company should disclose the net amount of gains or losses included in the cumulative translation adjustment during the reporting period. |

## Disclosures Specific to Derivatives that are Hybrid Financial Instruments Measured at Fair Value

<table>
<thead>
<tr>
<th>Relevant Guidance</th>
<th>Guidance Details</th>
</tr>
</thead>
</table>
| SFAS 133 paragraph 44A-B  
SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities* - including an amendment of FASB Statement No. 115 paragraph 18-22 | For hybrid financial instruments, entities should disclose the rationale for electing the fair value option and provide information that will allow users to understand the effect of changes in their fair value. In addition, entities should disclose the difference between the aggregate fair value and aggregate unpaid balance of the debt/loan instruments. Also for loans, entities should quantify the estimated amount of gains or losses attributable to changes in credit risk (and how the gains/losses were determined), the fair value of the loans that are 90 days or more past due, the aggregate fair value of loans in non-accrual status, and the difference between aggregate fair value and the aggregate unpaid principal balance for loans that are 90 days or more past due, in non-accrual status, or both. For debt, the company should also disclose estimated gains/losses from credit risk and how it was determined.  
  The changes in fair value for each line item on the balance sheet should also be disclosed, as well as the how interest and dividends are measured. In annual periods only, entities should disclose the methods and significant assumptions used to estimate the fair value of items for which the fair value option has been elected. |
## MD&A FRR 61 Derivative Disclosures

<table>
<thead>
<tr>
<th>Relevant Guidance</th>
<th>Guidance Details</th>
</tr>
</thead>
</table>
| SEC FRR 61, Derivative Disclosures | For trading contracts, entities should reflect the change in fair value for all such items period over period specifying between changes in fair value balances due to settlement activity, changes in valuation technique, and other changes in value.  
In addition, entities should disclose fair value balances for trading activity by source of market information organized by term of the contract in question. |

## Additional Disclosures Required by the FASB

<table>
<thead>
<tr>
<th>Relevant Guidance</th>
<th>Guidance Details</th>
</tr>
</thead>
</table>
| SFAS 161, (Effective for Fiscal Years & Interim Periods beginning after November 15, 2008) | SFAS 161, Disclosures about Derivative Instruments and Hedging Activities - an amendment of FASB Statement No. 133, requires disclosure in tabular format of (a) the location and fair values of derivative instruments in the statement of financial position and (b) the location and amount of gains and losses (realized and unrealized) on derivative instruments in the statement of financial performance, in addition to enhanced qualitative disclosures regarding an entities' use of derivatives.  
Qualitative Disclosures: In addition to the existing disclosure requirements in paragraph 44 of SFAS 133 described above, entities should describe:  
• How and why it uses derivative instruments  
• How derivative instruments and related hedged items are accounted for under SFAS 133 and related interpretations  
• How derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows.  
The standard also requires entities to disclose the volume of their derivative activity. However, no specific format is prescribed, and entities are expected to tailor such disclosures to their specific situations.  
Quantitative Disclosures: The standard requires entities to provide these quantitative tabular disclosures for all derivative instruments by accounting treatment designation (Qualifying or designated as hedging instruments or those that are not).  
In each disclosure table summarizing the fair value of derivatives:  
• Derivative instruments should be presented on a gross basis, even when they are subject to master netting arrangements and qualify for net presentation in the statement of financial position in accordance with FIN 39, Offsetting of Amounts Related to Certain Contracts. Cash collateral payables and receivables associated with derivative instruments should be excluded.  
• Fair value amounts should be presented as separate asset and liability values.  
• The disclosure should identify the line item(s) in the statement of financial position in which the fair value amounts for these categories of derivative instruments are included.  
In addition, the standard requires disclosure of the location and amounts of the gains and losses reported in the statement of financial performance (or when applicable, the statement of financial position.)  
Gains and losses are required to be separately presented for:  
• Derivative instruments designated and qualifying as hedging instruments in fair value hedges and related hedged items designated and qualifying in fair value hedges.  
• The effective portion of gains and losses on derivative instruments designated and qualifying in cash flow hedges and net investment hedges that was recognized in OCI during the current period.  
• The effective portion of gains and losses on derivative instruments designated and qualifying in cash flow hedges and net investment hedges recorded in accumulated other comprehensive income during the term of the hedging relationship and reclassified into earnings during the current period.  
• The portion of gains and losses on derivative instruments designated and qualifying in cash flow hedges and net investment hedges representing (1) the amount of the hedges' ineffectiveness and (2) the amount, if any, excluded from the assessment of hedge effectiveness.  
• Derivative instruments not designated or qualifying as hedging instruments under SFAS 161.  
The above information shall be presented separately by type of derivative contract, for example, interest rate contracts, foreign exchange contracts, equity contracts, commodity contracts, credit contracts, other contracts, and so forth. The disclosure shall identify the line item(s) in the statement of financial performance in which the gains and losses for these categories of derivative instruments are included. |
Income Statement Presentation Summary

We continue to note inconsistency in the income statement presentation of derivative instruments. The following table summarizes presentation paths prescribed by the referenced guidance sets.

<table>
<thead>
<tr>
<th>Activity Type</th>
<th>Gross / Net Presentation</th>
<th>Guidance Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Trading</td>
<td>Net Presentation</td>
<td>EITF Issue 02-3, Issues Involved in Accounting for Derivatives Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities</td>
</tr>
<tr>
<td>Non-Trading Derivative – Physically Settled</td>
<td>Facts and Circumstances Gross or Net</td>
<td>EITF Issue 03-11, Reporting Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not “Held for Trading Purposes” as Defined in Issue 02-3 and EITF Issue 99-19, Reporting Revenue Gross as a Principal versus Net as an Agent</td>
</tr>
<tr>
<td>Non-Trading Derivative – Net Settled</td>
<td>Net Presentation</td>
<td>EITF 03-11</td>
</tr>
</tbody>
</table>

It should be noted that the SEC staff has expressed the view that if a derivative does not qualify for hedge accounting, income, expenses, and fair value changes related to that derivative (whether realized or unrealized) should be recorded in one line item in the financial statements, and this line item should not change. For example, a realized gain or loss recognized for a non-hedging derivative should be recorded in the same income statement line item as any unrealized gains or losses previously recognized for that instrument.

Other Items

FSP FIN 39-1, Amendment of FASB Interpretation No. 39

FSP FIN 39-1 addresses certain modifications to FIN 39. Specifically, the FSP provides guidance concerning whether a reporting entity that is party to a master netting arrangement can offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement under FIN 39.

We have provided the following summary of key FSP FIN 39-1 items for your consideration.

- FSP FIN 39-1 requires entities electing to offset derivative asset and liabilities executed under master netting arrangements to offset related fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) with the same counterparty.

- FSP FIN 39-1 implementation guidance allows entities the option to transition from a net presentation of derivative assets and liabilities under FIN 39 to a gross presentation model under FSP FIN 39-1 (or vice versa). For those entities that elect to present balances on a gross basis, there is no requirement to adjust or net reported collateral balances within the reported derivative balances.

- FSP FIN 39-1 was effective for fiscal years ending subsequent to November 15, 2007.

2008 FERC Order Implications

During 2008, the FERC took steps to modify existing transportation capacity regulatory guidance based upon perceived market needs.

In 1992, the FERC issued Order 636 establishing the capacity release market and the overall governance of this new market. FERC Order 636 allowed for the release of unwanted firm natural gas transportation capacity and allowed a replacement shipper to re-release capacity if
permitted by the terms of the initial release. The FERC subsequently issued FERC Order 636-A to interpret, clarify and modify FERC Order 636 on a number of topics, including the bundling of right-to-use options. FERC Order 636-A explicitly allows the bundling of right-to-use options to capture values greater than the maximum rates set forth in the tariff (provided the average value of the individual right to use in the bundle does not exceed the maximum tariff rate). Since that time, the bundling of options has become a common market practice observable by all market participants and the FERC. At the June 19, 2008 meeting the FERC issued new guidance permanently removing the rate cap on capacity release transactions of one year or less. Specifically, the rule permits market-based pricing for short-term capacity releases.

These new events may impact the accounting treatment for transportation capacity contracts. It serves to reiterate the need for entities to evaluate the accounting impact these events may have on their contract population as even slight modifications to contract terms can impact the accounting treatment for commodity contracts.
SECTION 6

Fair Value Measurements

Introduction

Calendar year 2008 saw the implementation of SFAS 157 for most companies and with the volatility in the marketplace at an all-time high, fair value accounting and disclosures have come to the forefront of the accounting landscape. However, we have provided comments relative to the current guidance and some of the implementation challenges we have observed below.

SFAS 157

SFAS 157 was effective for financial statements issued for fiscal years beginning after November 15, 2007 (January 1, 2008 for calendar year entities). SFAS 157 applies both to recurring and nonrecurring items carried at fair value within the financial statements. Through FSP FAS 157-2, Effective Date of FASB Statement No. 157, issued in February 2008, the FASB deferred the application of SFAS 157 for entities that had not early adopted SFAS 157 until fiscal years beginning after November 15, 2007 (January 1, 2009 for calendar year entities) for nonrecurring, nonfinancial items carried at fair value. SFAS 157 provides guidance concerning the measurement of fair value for financial statement accounting and reporting purposes, but does not require any new fair value measurements. The standard represents the FASB’s effort to provide a consistent GAAP definition of fair value and to enhance financial statement transparency regarding fair value measurements.

The following key tenets of SFAS 157 have had an impact on the energy industry:

- A new definition of fair value – SFAS 157 specifies that fair value reflects “the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.” This definition focuses on the exit price as the appropriate fair value measure. Additionally, the definition emphasizes fair value based upon market participant assumptions rather than the entity’s intended use.

- Fair value hierarchy – SFAS 157 establishes a valuation hierarchy designed to classify market data inputs utilized in fair value measurement calculations. The hierarchy classifies market information into three broad levels based upon the transparency of the market data supporting the fair value calculation. The purpose of the hierarchy is to highlight the information sources (whether market-based or internally developed) employed by entities for purposes of fair value measurement through enhanced disclosure. The following provides an overview of the hierarchy levels.

  - Level 1 inputs: Quoted prices in active markets for identical assets or liabilities. An example of a Level 1 input may be the quoted closing price on the exchange for a NYMEX futures contract.

  - Level 2 inputs: Observable inputs other than Level 1 inputs. An example of a Level 2 input may be a binding over the counter commodity quote.

  - Level 3 inputs: Unobservable inputs. An example of a Level 3 input may be an extrapolated over the counter forward commodity price that is not corroborated with observable market data.

- New footnote disclosures: SFAS 157 introduces both quantitative and qualitative disclosures that dependent upon the level of fair value activity managed by an organization may have a substantial impact on the disclosure and reporting process.

- Quantitative disclosures – SFAS 157 introduces two new quantitative disclosures based in large part on the fair value hierarchy discussed above. (1) A disclosure of all items carried at fair value organized by hierarchy level and (2) A disclosure for all recurring fair value items classified as Level 3 that presents the key drivers of fair value change during the reporting period for all Level 3 items and total gains and losses unrealized in earnings related to items held at period end.

- Qualitative disclosures – SFAS 157 introduces additional qualitative disclosures designed to highlight the valuation approaches utilized by the organization.

- New guidance concerning inception gains/losses recognition – SFAS 157 rescinds the derivative inception gain and loss guidance per footnote 3 of EITF Issue 02-3 and amends the overall presumption that the transaction (or entry) price of an asset or liability reflects its initial fair value. As SFAS 157 defines the fair value of an asset or liability based upon its exit price, it notes that the transaction price may not always equal the exit price for an asset or liability. SFAS 157 also recognizes that in certain situations the parties to a contract may appropriately ascribe different fair values to the same transaction at inception. In such circumstances, it may be appropriate for an entity to recognize a gain or loss at inception of a contract under SFAS 157 where as historically, the immediate recognition of earnings may have been precluded.
Entities must recognize that the introduction of new inception gain/loss guidance does not reflect a view that inception gain/loss recognition is the default rule, but rather that in certain circumstances, recognition of such items when supported by specific documentation and disclosure may be appropriate. SFAS 157 provides example situations within paragraph 17 which may indicate that the recognition of inception value associated with the specific agreement is appropriate.

- New guidance concerning liability/obligation fair value – SFAS 157 requires that entities not only recognize the impact of counterparty credit worthiness in the fair value measurement of assets but also requires that entities contemplate their own credit standing in the fair value measurement of liabilities or obligations. Traditionally, entities reflected counterparty credit worthiness in the fair value measurement of assets, thus reducing the asset recognized by the entity commensurate with counterparty nonperformance risk. Under SFAS 157, entities must now consider their own credit standing in the fair value of liabilities or obligations. It should be noted that collateral or other credit enhancements may mitigate the effect of credit changes. See discussion of nonperformance risk considerations as it pertains to hedge accounting in Section 5.

Current SFAS 157 Implementation Issues and Considerations

Disclosure Implementation Items: The SFAS 157 disclosure requirements discussed above introduce multiple implementation issues for most entities. The following provides insight into the key issues faced in implementation and provides high level thoughts relative to each issue.

- **Policy Requirements**: SFAS 157 requires entities to draw policy conclusions impacting the overall disclosure and reporting process. In particular, the definition of fair value hierarchy levels must be thoroughly researched prior to implementation to ensure the most appropriate presentation of fair value balances for disclosure purposes. During this process, entities should consider the key valuation inputs for all items carried at fair value. Such key drivers might include:
  - The nature of the item reported at fair value (existing asset or contractual arrangement / obligation)
  - The market supporting the fair value item (exchange or otherwise)
  - For contractual items, the liquidity of the underlying product supporting the contract
  - For contractual items, the duration/term of the contract in question and the ability to observe reliable market information throughout that term.

- **Data management** - To meet the disclosure requirements of SFAS 157, organizations must not only stratify activity within the hierarchy for initial disclosure, but also track the classifications throughout the life of the fair value asset or liability. At face value, the initial classification of fair value balances based upon the nature of valuation inputs supporting the fair value determination appears relatively simplistic and easily managed for disclosure purposes. However, SFAS 157 requires that entities track these classification levels for ongoing reporting and separately disclose the movement of fair value items into and out of level 3. This ongoing monitoring and tracking has posed issues for some companies as they attempt to implement SFAS 157 as this requirement not only requires the addition of accounting policies and procedures but also the enhancement of data management and system capabilities to archive such disclosure information.

- **Valuation adjustment allocation** - SFAS 157 mandates that the fair value of an item be disclosed based upon the valuation input hierarchy classification at the unit of account level. Traditionally, certain valuation adjustments such as those recognized for credit and liquidity exposure are calculated at the portfolio level through the aggregation of transactions at the counterparty level for credit adjustments and at the delivery location level for purposes of liquidity adjustments. While the calculation of adjustments at the portfolio level reflects the appropriate economics surrounding the portfolio, for disclosure purposes these aggregate valuation adjustments must be allocated to the individual contract level to comply with SFAS 157 disclosure requirements. Dependent upon the nature of the portfolio in question, this allocation process may prove complicated to design and manage on an ongoing basis. Furthermore, the methodology and inputs to portfolio level adjustments may also impact the overall classification of individual contracts within the hierarchy.

- **Balance sheet netting and disclosure** - SFAS 157 requires individual disclosure of fair value assets and liability by market data observability level. For those entities that offset derivative assets and liabilities with the same counterparty within the balance sheet in accordance with FIN 39, the gross disclosure of assets and liabilities will create a reconciling difference between the footnote disclosure and the derivative balances. The difference between balance sheet reported results and SFAS 157 disclosure balances attributable to netting necessitates the addition of a reconciling column to the SFAS 157 disclosures to adjust disclosure balances for netting impact and thus reconcile to the balance sheet.

- **Inception gain implementation items** - In addition to disclosure implementation items, entities continue to address implementation issues relative to inception gain recognition under SFAS 157. Some common issues encountered relative to inception gain recognition include:
  - **Potential transition adjustment** - Upon implementation of SFAS 157, entities must consider whether the continued deferral of inception gains captured in previous periods in accordance with the requirements of EITF Issue 02-3 remains appropriate. In contrast to guidance applicable to newly executed contracts, the FASB staff and SEC staff have indicated that in determining the financial instrument’s fair value, in accordance with the guidance in SFAS 157 on the date of its adoption, an entity is not required to retroactively consider whether any...
paragraph 17 conditions were present at the inception of the financial instrument. Instead, entities should recognize the difference on the date of adoption between the carrying value and the fair value determined in accordance with SFAS 157 (without retrospective application of paragraph 17) as a cumulative-effect adjustment to retaining earnings in period of adoption.

- **Recognition support** - Paragraph 17 of SFAS 157 provides examples of those situations where inception gain/loss recognition may be appropriate. However, this guidance merely reflects examples and is not viewed to be an all inclusive listing. As such, entities should maintain documentation supporting inception value recognition, referencing the supporting factors in support of inception value recognition.

- **Market calibration** - SFAS 157 recognizes that in certain circumstances the recognition of inception value may not be appropriate. In such circumstances, the standard considers the potential for calibration of market data included within valuation models as well as calibration of valuation models themselves. Market data calibration brings to light situations where market information is adjusted to bring inception value to zero. This modification of market information may result in the need to consistently modify similar market information in other transaction models thus impacting current earnings from other transactions post calibration.

- **Valuation adjustment policy items** - In addition to the valuation adjustment requirements specific to credit, SFAS 157 explicitly recognizes for practical expediency purposes it may be appropriate to recognize the fair value of an asset or liability based upon mid market pricing instead of the applicable valuation input bid or asks. It should be noted that while the FASB did introduce the potential to utilize a mid market pricing convention entities must make this decision at implementation of SFAS 157 as it is generally inappropriate for an entity to change to using a practical expedient after an entity adopts SFAS 157. SFAS 157 goes on to note that for an entity to change its approach, persuasive evidence must exist to support that “the change results in a measurement that is equally or more representative of fair value.” Reporting entities should establish and consistently apply an approach for fair value measurements within a bid-ask spread for similar items as a means to meet this requirement.

- **Level 3 reconciliation** - We have seen diversity in the approach entities are taking in their reconciliation disclosure of recurring Level 3 fair value measurements from beginning to end of period. Such diversity pertains to the identification of dates within the period to reflect transfers into or out of the Level 3 classification, and the amount of total gains and losses attributable to unrealized gains and losses for assets and liabilities still held at the end of the period. In such cases, we encourage entities to be transparent of the approach taken in their disclosures and to consult with their auditors if unsure whether their presentation approach is an acceptable alternative.

In addition, a question has been raised whether this reconciliation should be presented just for the year-to-date (e.g., six months ended June 30) or for the quarter and the year-to-date periods. We believe that companies should include both quarterly and year-to-date roll-forward information in their Form 10-Q interim SFAS 157 disclosure.

**Other New Guidance**

**FSP FAS 157-3**

In response to the recent well-publicized effects of the continuing turbulence in the financial markets, the FASB staff issued FSP FAS 157-3. The FSP amends SFAS 157 by incorporating an example to illustrate key considerations in determining the fair value of a financial asset in an inactive market. The FSP is effective immediately and should be applied to prior periods for which financial statements have not yet been issued.

**“Dear CFO Letter”**

Recently, the Division of the SEC sent a letter to certain financial institutions concerning additional MD&A disclosure considerations regarding fair value for their upcoming filings on Form 10-Q. While the letter was sent only to financial institutions, we understand that the SEC staff has indicated that the letter “can be applicable to any company.”

The letter reminds registrants that have significant amounts of financial instruments to consider the SEC’s requirements for disclosures in MD&A. Regulation S-K, Item 303, requires registrants, among other things, to discuss in their periodic filings any known trends or any known demands, commitments, events, or uncertainties that the registrants reasonably expect to have a material impact, either favorable or unfavorable, on their results of operations, liquidity, or capital resources. A sample letter is available on the SEC’s website.

SFAS 157 received a substantial amount of attention during 2008. However, this was not the only new fair value standard with potential impact to the energy commodity industry. Energy companies should also consider the impact of SFAS 159.
SFAS 159

SFAS 159 was effective for financial statements issued for fiscal years beginning after November 15, 2007 (January 1, 2008 for calendar year entities). SFAS 159 provides entities the option to elect fair value accounting treatment for financial items meeting certain requirements. The fair value option is available on an instrument by instrument basis and must be elected at the inception of the instrument. As noted above, the standard is currently only applicable to financial assets, financial liabilities, certain nonfinancial hybrid contracts and firm commitments. However, the FASB is deliberating on a second phase of the fair value option standard that may expand the scope to certain non-financial items. Given the current restriction of SFAS 159’s applicability to financial instruments, election of the option within the energy industry is expected to be limited. That said, SFAS 159 is often applied in the accounting for certain commodity contracts such as prepaid natural gas contracts. A basic prepaid gas contract structure may look as follows:

Company A enters into a prepaid commodity forward contract with Dealer B. Under the contract, Company A delivers $1 million to Dealer B at inception of the contract and receives a fixed quantity of commodity X (assume commodity X is readily convertible to cash) every month for the next 60 months. The contract is a hybrid non-financial instrument. Company A will separately account for the bifurcated derivative at fair value in accordance with SFAS 133. Company A identifies the host contract as a receivable in which it lent $1 million at inception and will receive monthly from Dealer B a fixed dollar amount (equal to the fixed dollar amount identified in the commodity forward).

As the identified host contract in the example above is a financial instrument, Company A may elect to apply the fair value option under SFAS 159 to the host contract upon initial recognition (or other eligible election date) and thus account for the host contract in its entirety on a fair value basis with changes in value reported through earnings.

Should the entity not elect the fair value option, the accounting requirements of SFAS 133 should be followed for all such contracts.

In the event you have questions concerning the accounting treatment for such arrangements, we recommend further consultation with your auditor.

Valuation of derivative contracts involving unobservable or illiquid inputs

In the past, certain situations have been noted whereby entities that had derivative contracts containing unobservable valuation inputs were assuming zero value for the unobservable portions of their contracts at inception and on an ongoing basis. While SFAS 157 introduced new guidance for inception gains and losses as discussed above, full allowance reserves that ignore changes in fair value for periods or elements of contracts subsequent to inception are not permitted under GAAP. Accounting policies requiring the full or predetermined partial reservation of changes in value for unobservable inputs may not be appropriate if not supported by a quantitative analysis that supports the valuation to be the entities’ best estimate of fair value. Our experiences suggests this may be a focus of various regulators, and thus we recommend that entities with long-dated positions or other contracts valued with unobservable market inputs evaluate any reserve policies and address the overall value of the arrangement, applying any adjustments to the entire contract based upon the nature of the inputs. In addition, appropriate disclosure about the use of significant estimates involving unobservable inputs may be warranted.
SECTION 7

FASB and EITF Update

Introduction

In this section we will discuss recent rulemaking by the FASB and EITF. We have also updated our 2007 discussions.

SFAS 141(R)

The issuance of SFAS 141 and SFAS 142 in 2001 marked just the first phase of the FASB’s multiphase project to reconsider the accounting for business combinations. That effort not only eliminated the pooling of interest method of accounting and the amortization of goodwill, but also carried forward without reconsideration much of the already established guidance on purchase accounting (now referred to as the “acquisition method” of accounting).

The FASB recently completed the second phase of this project and on December 4, 2007, issued SFAS 141(R) and SFAS 160, *Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51*.

These statements substantially elevate the role played by fair value and dramatically change the way that companies account for business combinations and noncontrolling interests (referred to as minority interests in current U.S. GAAP). Compared with their predecessors, SFAS 141(R) and SFAS 160 will require:

- More assets acquired and liabilities assumed to be measured at fair value as of the acquisition date.
- Liabilities related to contingent consideration to be remeasured at fair value in each subsequent reporting period.
- An acquirer to expense acquisition-related costs (e.g., deal fees for attorneys, accountants, investment bankers).
- Noncontrolling interests in subsidiaries initially to be measured at fair value and classified as a separate component of shareholders’ equity.

SFAS 141(R) applies to all transactions or other events in which an entity (the acquirer) obtains control of one or more businesses (the acquiree), including those sometimes referred to as “true mergers” or “mergers of equals” and combinations achieved without the transfer of consideration. SFAS 141(R) applies to all business entities, including mutual entities that previously may have applied the pooling of interests method of accounting for business combinations. SFAS 141(R) also amends FIN 46(R) to require that an acquisition of an entity that (1) is a VIE and (2) meets the definition of a business in SFAS 141(R) to be accounted for under SFAS 141(R). However, SFAS 141(R) excludes formations of joint ventures, business combinations between entities under common control, and business combinations involving not-for-profits organizations.

SFAS 141(R) is to be applied prospectively for fiscal years beginning on or after December 15, 2008 (with one important exception noted below for income taxes). SFAS 141(R) prohibits early adoption. Also see Deloitte’s *December 12, 2007 Heads Up* for more information.

SFAS 141(R) retains the fundamental requirements of SFAS 141 that the acquisition method of accounting is used for all business combinations and for an acquirer to be identified for each business combination. It defines the acquirer as the entity that obtains control of one or more businesses in the business combination, and establishes the acquisition date as the date that the acquirer achieves control.

There are three fundamental principles for applying the acquisition method under SFAS 141(R):

- Recognition principle - In a business combination, the acquirer recognizes all of the assets acquired and all of the liabilities assumed. Thus, the acquirer recognizes 100% of the assets acquired and liabilities assumed in a business combination, as well as any noncontrolling interest remaining as of the acquisition date.

- Fair value measurement principle - In a business combination, the acquirer measures each recognized asset acquired and liability assumed, as well as any noncontrolling interest, at their acquisition date fair values. Although SFAS 141(R) requires fair value measurement, certain assets and liabilities such as deferred taxes, employee benefits, and share-based compensation continue to be measured based on other applicable accounting literature. In addition, SFAS 141(R) introduces two new items that are exceptions to the fair value measurement principle:
  - Indemnification assets – The acquiree may indemnify the acquirer for the outcome of a contingency or uncertainty related to an asset or liability. In situations where the related asset or liability for which the indemnification relates to is not recorded at fair value (e.g., FIN 48, *Accounting for Uncertainty in Income Taxes*, liabilities), SFAS 141(R) requires the indemnification asset or liability to be recorded on the same basis as the indemnified item (less any contractual limitations or an allowance for collectibility).
Reacquired rights (e.g., license or franchise) – The intangible asset recognized is measured on the basis of the remaining contractual term of the related contract regardless of whether market participants would consider potential contractual renewals.

Disclosure principle - Users of the acquirer’s financial statements should be able to evaluate the nature and financial effects of business combinations recognized by the acquirer.

SFAS 141(R) retains the guidance in SFAS 141 for identifying and recognizing intangible assets separately from goodwill. The main features of SFAS 141(R) and the more significant changes it makes to how the acquisition method of accounting is applied as compared with SFAS 141, are described below.

Significant Changes to current accounting for business combinations:

<table>
<thead>
<tr>
<th>Current Accounting</th>
<th>New Accounting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Definition of a business</td>
<td>Definition and related application guidance is provided in EITF Issue 98-3. Must have inputs, processes, and outputs.</td>
</tr>
</tbody>
</table>

Under the current rules, an entity would follow the guidance in EITF Issue 98-3, *Determining Whether a Nonmonetary Transaction Involves Receipt of Productive Assets or of a Business*, which provides certain criteria for determining whether a business has been acquired and would be in the scope of SFAS 141. SFAS 141(R) nullifies EITF Issue 98-3 and incorporates the definition of a business included therein, with some important modifications. For example, to qualify as a business under SFAS 141(R), an entity no longer has to be “self-sustaining,” and a group of assets no longer needs to have outputs. That is, development-stage entities could now be businesses under SFAS 141(R). As a result, some transactions that are considered asset acquisitions under current U.S. GAAP will be business combinations under SFAS 141(R).

<table>
<thead>
<tr>
<th>Current Accounting</th>
<th>New Accounting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Measurement date of equity securities issued upon and announced.</td>
<td>Measure the fair value of equity securities issued a few days before and after the terms of the combination are agreed.</td>
</tr>
</tbody>
</table>

Under the current rules, an acquirer would follow the guidance in EITF Issue 99-12, *Determination of the Measurement Date for the Market Price of Acquirer Securities Issued in a Purchase Business Combination*, which states that you measure the value of the acquirer’s securities issued to effect a business combination over the period a few days before and after the terms of the transaction are agreed to and announced. Often times there can be a significant period of time that transpires between the announcement date and the closing date of the transaction. The new guidance in SFAS 141(R) may significantly change the amount recorded for the acquired business if share prices fluctuate from the date that the terms of the transaction are agreed to and announced to the acquisition date.

<table>
<thead>
<tr>
<th>Current Accounting</th>
<th>New Accounting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bargain purchase</td>
<td>Allocate excess as a pro-rata reduction of certain non-current assets; recognize remainder as an extraordinary gain.</td>
</tr>
</tbody>
</table>

Another change from the current rules relates to a bargain purchase, sometimes referred to as negative goodwill. To the extent that the fair value of what an acquirer receives is greater than the purchase price, a so-called excess exists. Under the current rules, an acquirer would reduce certain non-current assets on a pro-rata basis until the excess is eliminated. If an excess remained after reducing these non-current assets to zero, the remainder is recorded as an extraordinary gain. Under SFAS 141(R), an acquirer will not reduce assets for the excess but instead will record the entire amount as a gain. Entities must disclose the amount of the gain and the line in the income statement where the gain is recorded. Be aware, instances of recognizing a gain from a bargain purchase are not expected to be common.
### Current Accounting vs New Accounting

<table>
<thead>
<tr>
<th>Transaction costs of the acquirer</th>
<th>Current Accounting</th>
<th>New Accounting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Include in the cost of the acquired business; generally add to goodwill.</td>
<td>Expense as incurred and exclude from the fair value of the business acquired.</td>
<td></td>
</tr>
</tbody>
</table>

Under the current rules, acquisition-related costs paid to third parties to assist in the transaction, such as investment banker fees, legal fees and accounting fees, are capitalized as part of the transaction, and are generally recorded as a part of goodwill. There is no impact on the income statement unless a goodwill impairment charge is later recorded. In a manner consistent with SFAS 157, the FASB does not believe that transaction costs are a component of the fair value of the business acquired. Therefore, under SFAS 141(R) these costs should be expensed as incurred. Costs incurred for the issuance of debt or equity securities to effect the combination are not within the scope of SFAS 141(R), and will continue to be accounted for in accordance with other applicable U.S. GAAP.

If an acquirer is currently incurring acquisition-related costs for a business combination for which the acquisition date is expected to be after its adoption of SFAS 141(R) the acquirer has two alternatives for recording these costs.

- Costs can be expensed as incurred. Proponents of this alternative believe that since the costs relate to a transaction with an expected acquisition date after the effective date of SFAS 141(R), the transition guidance in paragraph 74 of SFAS 141(R) would result in the expensing of the costs as incurred.

- Costs can be deferred until adoption. Proponents of this alternative believe that because early application of SFAS 141(R) is prohibited, any acquisition-related costs incurred before the effective date of SFAS 141(R) should be deferred until the entity adopts SFAS 141(R). Views differ, however, on the subsequent treatment of those deferred acquisition-related costs. Some hold that such deferred costs should be expensed in the first annual reporting period after adoption of SFAS 141(R), while others subscribe to retrospective application and maintain that the guidance in SFAS 154 on reporting a change in accounting principle should be followed.

In these situations, the acquirer should disclose its transition accounting policy for acquisition-related costs.

<table>
<thead>
<tr>
<th>Restructuring costs</th>
<th>Current Accounting</th>
<th>New Accounting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Restructuring costs are recognized as a liability in the purchase price allocation provided that certain conditions in EITF Issue 95-3 are met.</td>
<td>Only restructuring costs of the acquiree that meet the recognition criteria in SFAS 146 as of the acquisition date are included in the fair value allocation.</td>
<td></td>
</tr>
</tbody>
</table>

Under the current guidance of EITF Issue 95-3, *Recognition of Liabilities in Connection with a Purchase Business Combinations*, an acquirer is allowed to record a liability in purchase accounting for amounts related to restructuring costs it expects to incur for such things as closing duplicate facilities and involuntary employee termination payments. Some believed that these amounts were prone to manipulation and many referred to them as cookie jar reserves. This resulted in a disconnect between how restructuring costs were recorded within a business combination and outside of one.

SFAS 141(R) will align the accounting by only allowing the recording of a liability for restructuring costs for the acquiree if they meet the criteria in SFAS 146, *Accounting for Costs Associated with Exit or Disposal Activities*, as of the acquisition date. All other costs will be expensed as incurred in the post-combination financial statements. Accordingly, a majority of restructuring reserves that were recorded under SFAS 141 will no longer be recorded under SFAS 141(R).

<table>
<thead>
<tr>
<th>Valuation allowances for assets recorded at fair value</th>
<th>Current Accounting</th>
<th>New Accounting</th>
</tr>
</thead>
<tbody>
<tr>
<td>Typically, assets are recognized at present value less a valuation allowance.</td>
<td>Assets are recognized at fair value in accordance with SFAS 157, with no separate valuation allowance.</td>
<td></td>
</tr>
</tbody>
</table>

Under SFAS 141, acquired loans and receivables are recorded at present amounts to be received, determined at appropriate current interest rates less allowances for uncollectibility and collection costs, if necessary. Under SFAS 141(R), separate valuation allowances will not be recognized on assets that are recorded at fair value as of the acquisition date. SFAS 141(R) requires that receivables, including loans, be recorded at fair value. Fair value measurements incorporate assumptions regarding collections risk, obviating the need for a separate valuation allowance. Thus, the impact of an uncollectible receivable becoming collectible after the acquisition date is not recorded until receipt of payment.
An acquirer may decide not to use an acquired asset for competitive or other reasons. For example, an acquirer may decide not to use an acquired brand name because it believes that its own brand is better positioned in the marketplace. Under current practice, these assets are typically assigned either no value or a value related only to the period of expected use. Under SFAS 141(R), if an acquirer decides not to use an acquired intangible asset, it is still required to recognize the asset and measure it at fair value in accordance with SFAS 157. This valuation would need to reflect the asset’s highest and best use, from a market participant’s point of view, both as of the acquisition date and in subsequent impairment tests.

Under the current rules, an entity ascribes value to acquired IPR&D in the purchase price allocation and then immediately expenses this amount. This accounting effectively reduces the amount that would otherwise be assigned to goodwill. In a manner consistent with the FASB’s approach to recognize almost all assets and liabilities at fair value in the acquisition accounting, FASB decided that it did not make sense to value an asset and immediately write it off.

Under SFAS 142, as amended by SFAS 141(R), an entity will value acquired IPR&D and record it as an indefinite lived intangible asset until the point in time that it reaches technological feasibility. This means entities would follow the annual fair-value based impairment test under SFAS 142. At the point technological feasibility is reached, the IPR&D should be treated as a finite-lived intangible asset and amortized over the related product’s useful life. If technological feasibility is not ultimately reached, the IPR&D should be written off.

Current U.S. GAAP requires that contingent consideration amounts that are determinable as of the acquisition date be included in the cost of the acquired entity and recorded at that time. However, contingent consideration is generally not considered determinable and is subsequently recorded when the contingency is resolved and the consideration becomes issuable. Regardless of classification as a liability or equity, current U.S. GAAP states that contingent consideration based on earnings is recorded as an additional cost of the business while contingent consideration based on security prices does not change the cost of the acquired business.

Under SFAS 141(R), companies will have to record contingent consideration at its acquisition date fair value. SFAS 141(R) distinguishes the day two accounting depending on whether the contingent consideration is classified as a liability or equity as of the acquisition date based on existing U.S. GAAP (e.g., SFAS 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity). If the contingent consideration is initially classified as a liability, it will be remeasured to fair value each reporting period, through the income statement, until it is paid out or otherwise settled. If the contingent consideration is classified as equity, there is no subsequent remeasurement.
Preacquisition contingencies | Recorded at fair value if determinable during allocation period | Fair value as of the acquisition date – if contractual. Fair value as of the acquisition date if the contingency more likely than not meets the definition of asset/liability – if non-contractual.

Subsequent accounting for preacquisition contingencies | Do not remeasure to fair value | Liability: > of acquisition date fair value or SFAS 5 Asset: < of acquisition date fair value or best estimate of settlement amount

Under the current guidance in SFAS 141, a preacquisition contingency is recorded in the purchase price allocation if either the fair value is determinable during the allocation period or if the event is probable and the amount can be reasonably estimated. In practice, this often resulted in no amount being recorded in the purchase price allocation and the amount being subsequently recorded upon resolution of the contingency in the post-combination income statement.

In the original ED of SFAS 141(R), entities would have been required to measure the fair value of all preacquisition contingencies at fair value as of the acquisition date. Many of the comment letters noted that these amounts are difficult to value and therefore they should not be recorded at fair value. The FASB tried to address this concern to some extent by delineating between contractual and noncontractual contingencies and by establishing a recognition threshold for noncontractual contingencies. All contractual contingencies are recorded at fair value, whereas noncontractual contingencies are only recorded at fair value if it is more-likely-than-not that the contingency gives rise to an asset or liability that meets the definition in Concepts Statement 6, *Elements of Financial Statements*. In other words, an acquirer only recognizes a noncontractual contingency if there is a greater than 50% chance that it has assumed a present obligation.

SFAS 141(R) provides guidance on subsequent accounting for contingent assets and liabilities recognized as of the acquisition date. A contingent asset is remeasured in each subsequent period to the lower of its acquisition-date fair value or the best estimate of its future settlement amount. A contingent liability is remeasured to the higher of its acquisition-date fair value or the amount that would be recognized if applying SFAS 5.

| Measurement Period Adjustments – General | Generally, recognize changes to provisional amounts prospectively as a change in estimate | Revise comparative information for prior periods

| Measurement Period Adjustments – Income Taxes | Per EITF 93-7, *Uncertainties Related to Income Taxes in a Purchase Business Combination*, adjustments recorded to goodwill (not subject to one-year window) | EITF Issue 93-7 nullified. Adjustments that occur after the measurement period are recorded as a component of income tax expense. Adjustments during the allocation period would generally be recorded as an adjustment to goodwill.

SFAS 141(R) retains the one-year period to finalize the business combination accounting that was permitted in SFAS 141. During the measurement period (previously referred to as the allocation period under SFAS 141), the acquirer gathers information necessary to finalize the business combination accounting (e.g., completes the valuation of certain assets and liabilities). Any adjustments must relate to facts and circumstances that existed as of the acquisition date.

Unlike SFAS 141, where prevailing practice generally accounted for any adjustments to provisional amounts recorded during the allocation period prospectively, SFAS 141(R) requires an acquirer to record all adjustments retrospectively and revise comparative information for prior periods presented. This requirement will place an added burden on the preparer because an acquirer will have to keep track of the income statement impact (e.g., depreciation, amortization) of any adjustments to provisional amounts recorded as of the acquisition date for all periods presented.

Under current U.S. GAAP, any changes in valuation allowances for acquired deferred tax assets and uncertain tax position balances of the acquiree are generally recorded through goodwill, regardless of whether such changes occur during the allocation period or thereafter. SFAS 141(R), however, requires any adjustments to valuation allowances for acquired deferred tax assets and uncertain tax position balances of the acquiree that occur subsequent to the measurement period to be recorded as a component of income tax expense. Additionally, SFAS 141(R) requires the same accounting treatment for business combinations that were consummated prior to the effective date of SFAS 141(R). In other words, this requirement is the one transition provision that could affect future accounting for transactions occurring before SFAS 141(R)’s effective date.
Under current practice, only the acquirer’s portion of the assets acquired and liabilities assumed are recorded at fair value. Under SFAS 141(R), an acquirer will record 100% of the fair value of assets acquired and liabilities assumed on the date control is obtained, even if its ownership interest in the acquiree is less than 100 percent. One result of SFAS 141(R) is that companies are likely to record higher amounts of gross depreciation expense, since the depreciable assets will now have a higher basis.

Under SFAS 141(R), acquirers will now record the noncontrolling interest at fair value, including its share of goodwill. Previously, the assets and liabilities attributable to the noncontrolling interest, as well as the noncontrolling interest balance itself, were recorded at historical cost and no goodwill was allocated. In addition, as a result of SFAS 160, the acquirer will now record noncontrolling interests as a separate component of shareholders’ equity, rather than as a liability or mezzanine (or temporary) equity.

Step acquisitions occur when control of a business is obtained after the acquirer already owns a noncontrolling interest in the acquiree’s equity. For example, assume Company A holds 30% of the equity of another entity, Company B, and accounts for its interest under the equity method. Under the current rules, if Company A subsequently purchases an additional 40% interest in Company B, thereby obtaining control, its previously held interest would continue to be recorded at historical cost.

Under SFAS 141(R) and SFAS 160, gaining and losing control is a significant economic event that results in the remeasurement of all preexisting or remaining interests to fair value. Therefore, upon the acquisition of a controlling interest in another entity, 100% of that entity, including the noncontrolling interest, will be recorded at fair value. In the example above, Company A’s previously held noncontrolling interest (30%) in Company B is remeasured to fair value when control is obtained (i.e., the acquisition date), which will result in a gain or loss being recognized by Company A.

Under existing U.S. GAAP, a parent entity applies the purchase method of accounting when it acquires additional noncontrolling interests, and may recognize gains or losses for a reduction in its ownership interest (e.g., SAB 51, Accounting for Sales of Stock by Subsidiary). Under the new rules, once an acquirer obtains control of an entity, it accounts for changes in its ownership interest of that entity (subsidiary) as equity transactions so long as it retains control. The acquirer cannot apply additional purchase method accounting or recognize any gains or losses. This is consistent with the concept that noncontrolling interests will now be recorded as a separate component of shareholders’ equity, rather than as a liability or mezzanine (or temporary) equity.

**SFAS 160**

SFAS 160 amends ARB 51, Consolidated Financial Statements, and applies to all entities that prepare consolidated financial statements, except not-for-profit organizations. However, SFAS 160 will affect only those entities that have an outstanding noncontrolling interest in one or more subsidiaries (sometimes called a minority interest) or that deconsolidate a subsidiary.

Under SFAS 160, a noncontrolling interest is the portion of equity in a subsidiary not attributable, directly or indirectly, to a parent. Other guidance must be used to determine if the financial instruments held by the noncontrolling shareholders meet the definition of equity (e.g., SFAS 150, EITF Topic D-98, Classification and Measurement of Redeemable Securities). If so, the noncontrolling interest would be classified as a separate component of shareholders’ equity in the consolidated statement of financial position. Limited guidance exists in current practice for reporting noncontrolling interests. As a result, considerable diversity exists. “Minority interests” are currently reported in the consolidated statement of financial position as liabilities or in the mezzanine (or temporary equity) section between liabilities and equity.

SFAS 160 requires consolidated net income to be reported at amounts that include the amounts attributable to both the parent and the noncontrolling interest. It also requires disclosure, on the face of the consolidated statement of income, of the amounts of consolidated net income attributable to the parent and to the noncontrolling interest. Under SFAS 160, the noncontrolling interest will continue to be attributed
its share of losses even if that attribution results in a deficit noncontrolling interest balance.

SFAS 160 also amends SFAS 128, *Earnings per Share*, so that EPS data will continue to be calculated the same way as calculated prior to SFAS 160. Thus, the calculation of EPS amounts in consolidated financial statements will continue to be based on amounts attributable to the parent.

SFAS 160 establishes a single method of accounting for changes in a parent’s ownership interest in a subsidiary that do not result in deconsolidation, or loss of control. For example, SFAS 160 clarifies that all of the following transactions are equity transactions if the parent retains its controlling financial interest in the subsidiary:

- A parent purchases additional ownership interests in its subsidiary
- A parent sells some of its ownership interests in its subsidiary
- A subsidiary reacquires some of its ownership interests or the subsidiary issues additional ownership interests.

SFAS 160 requires that a parent recognize a gain or loss in net income when a subsidiary is deconsolidated. Deconsolidation of a subsidiary occurs as of the date the parent ceases to have a controlling financial interest in the subsidiary. If the former parent retains a noncontrolling equity investment in the former subsidiary, that investment is measured at fair value on the date control is lost and is factored into the overall gain or loss on the deconsolidation of the subsidiary. Under the current rules, the former parent measures the retained noncontrolling equity investment based on the former subsidiary’s carrying value (i.e., no gain or loss).

SFAS 160 requires expanded disclosures in the consolidated financial statements that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners of a subsidiary. Such disclosures include a reconciliation of the beginning and ending balances of the equity attributable to the parent and the noncontrolling owners and a schedule showing the effects of changes in a parent’s ownership interest in a subsidiary on the equity attributable to the parent.

SFAS 160 does not change ARB 51’s provisions related to consolidation purpose or consolidation policy or the requirement that a parent consolidate all entities in which it has a controlling financial interest. SFAS 160 does amend certain of ARB 51’s consolidation procedures to make them consistent with the requirements of SFAS 141(R), as well as to define certain terms and to clarify some terminology.

SFAS 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Earlier adoption is prohibited.

SFAS 160 is to be applied prospectively as of the beginning of the fiscal year in which it is initially applied, except for the presentation and disclosure requirements. The presentation and disclosure requirements are to be applied retrospectively for all periods presented.

**SFAS 162, The Hierarchy of Generally Accepted Accounting Principles**

SFAS 162 affects nongovernmental entities that present financial statements in conformity with U.S. GAAP by reorganizing the U.S. GAAP hierarchy. Under the standard, the hierarchy is as follows:

(a) FASB Statements of Financial Accounting Standards and Interpretations, SFAS 133 Implementation Issues, FASB Staff Positions, and AICPA Accounting Research Bulletins and Accounting Principles Board Opinions that are not superseded by actions of the FASB

(b) FASB Technical Bulletins and, if cleared by the FASB, AICPA Industry Audit and Accounting Guides and Statements of Position

(c) AICPA Accounting Standards Executive Committee Practice Bulletins that have been cleared by the FASB, consensus positions of the FASB’s EITF, and the Topics discussed in Appendix D of *EITF Abstracts*

(d) Implementation Guides published by the FASB staff, AICPA Accounting Interpretations, AICPA Industry Audit and Accounting Guides and Statements of Position not cleared by the FASB, and practices that are widely recognized and prevalent either generally or in the industry.

Entities should follow the hierarchy in applying accounting principles for a transaction or event in the order listed above. If the treatment for a specific transaction or event is not prescribed, the entity should consider the treatment for a similar transaction or event within the categories above, except for those instances where similar treatment is prohibited.

SFAS 162 will be effective 60 days following the SEC’s approval of the PCAOB amendments to AU Section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles*. 
FSP FAS 142-3, Determination of the Useful Life of Intangible Assets

This guidance affects entities with recognized intangible assets. On April 25, 2008, the FASB issued FSP FAS 142-3, which amends SFAS 142’s disclosures for certain recognized intangible assets and the list of factors an entity should consider in developing renewal or extension assumptions used in determining the useful life of newly acquired intangible assets. Newly acquired intangible assets include (1) intangible assets acquired individually or with a group of other assets and (2) intangible assets acquired in both business combinations and asset acquisitions.

Under paragraph 11 of SFAS 142, an entity must analyze all pertinent factors when determining the useful life of an acquired intangible asset. One such factor is whether an intangible asset’s legal or contractual life can be renewed or extended. SFAS 142 currently requires entities to consider whether the renewal or extension can be accomplished without substantial cost or material modifications of the existing terms and conditions associated with the intangible asset. However, because there is no clear guidance on determining what constitutes substantial cost or material modifications, the SFAS 142 assessment often results in a useful life that is shorter than the period of cash flows used to measure the fair value of the intangible asset in a business combination. The result is often an acceleration of amortization expense that does not reflect the “period over which the asset is expected to contribute directly or indirectly to the future cash flows” of the entity.

FSP FAS 142-3 removes the requirement of paragraph 11 of SFAS 142 for an entity to consider whether an intangible asset can be renewed without substantial cost or material modifications to the existing terms and conditions. The FSP replaces the previous useful-life assessment criteria with a requirement that an entity consider its own experience in renewing similar arrangements. If the entity has no relevant experience, it would consider market participant assumptions regarding renewal, including (1) the highest and best use of the asset by market participants and (2) adjustments for other entity-specific factors included in paragraph 11 of SFAS 142.

The FASB believes that removing the substantial cost and material modification assessments will lead to greater consistency between the useful life of recognized intangible assets under SFAS 142 and the period of expected cash flows used to measure the fair value of such intangible assets in a business combination or under other U.S. GAAP. Therefore, amortization expense for finite-lived intangible assets will generally be recognized over the period in which the asset contributes directly or indirectly to the future cash flows of the entity. The FSP may also result in more intangible assets being assigned an indefinite useful life.

The FSP requires entities to disclose information for recognized intangible assets that enables financial statement users to understand the extent to which expected future cash flows associated with intangible assets are affected by the entity’s intent or ability to renew or extend the arrangement associated with the intangible asset. The FSP also adds the following disclosures to those already required by SFAS 142:

- The entity’s accounting policy on the treatment of costs incurred to renew or extend the term of a recognized intangible asset
- In the period of acquisition or renewal, the weighted-average period prior to the next renewal or extension (both explicit and implicit), by major intangible asset class
- For an entity that capitalizes renewal or extension costs, the total amount of costs incurred in the period to renew or extend the term of a recognized intangible asset for each period for which a statement of financial position is presented, by major intangible asset class.

In addition, in determining whether additional disclosures about the intangible asset’s estimated useful life are required, entities should refer to paragraph 13(b) of SOP 94-6, Disclosure of Certain Risks and Uncertainties. Generally, these additional disclosures would be required if a change in the useful life or expected renewal or extension of an intangible asset would be material to the financial statements.

This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. While the guidance on determining the useful life of a recognized intangible asset must be applied prospectively only to intangible assets acquired after the FSP’s effective date, the disclosure requirements of the FSP must be applied prospectively to all intangible assets recognized as of, and after, the FSP’s effective date. Early adoption is prohibited.

For more information, see Deloitte’s April 29, 2008, Heads Up.

FSP APB 14-1, Accounting for Convertible Debt Instruments That May Be Settled in Cash upon Conversion (Including Partial Cash Settlement)

In May 2008, the FASB issued FSP APB 14-1, which applies to convertible debt securities that, upon conversion, may be settled by the issuer fully or partially in cash. The FSP does not change the accounting for more traditional types of convertible debt securities that do not have a cash settlement feature.
Initial Recognition – Split Accounting

Currently, most forms of convertible debt securities are treated solely as debt. Under the FSP, issuers of convertible debt securities within its scope separate these securities into two accounting components:

- A debt component, representing the issuer’s contractual obligation to pay principal and interest.
- An equity component, representing the holder’s option to convert the debt security into equity of the issuer or, if the issuer so elects, an equivalent amount of cash.

The FSP establishes that the proceeds are allocated between the liability and equity components under the so-called “liability first” approach as follows:

- First, the issuer allocates the proceeds to the liability component on the basis of its estimate of the fair value of an identical debt instrument that it would issue (except that the instrument does not have the conversion option).
- Then, the remaining proceeds are allocated to the equity component.

By allocating the proceeds of the convertible instruments as two separate components (liability and equity), a temporary difference under SFAS 109 may result. The initial adjustment to recognize the deferred taxes as a result of this temporary difference should be recorded as an adjustment to additional paid-in capital. Also note that as a portion of the proceeds related to the convertible instrument are allocated to equity, instruments subject to the FSP are not eligible for the fair value option in accordance with the scope exception in paragraph 8(f) of SFAS 159.

Embedded Features

In addition to the equity conversion option, convertible debt securities often contain put options, call options, and other features. Under the FSP, the issuer’s estimate of the liability component’s fair value includes these additional features. For example, if the security can be called from the investor by the issuer or put back to the issuer by the investor, the value of the call or put features would be reflected in the issuer’s estimate of the fair value of the liability component.

Other Considerations

Other considerations of the FSP include the following:

- **Balance sheet classification** – The FSP does not affect how an issuer determines whether the debt should be classified as current or noncurrent in the balance sheet. Even though the equity conversion option is separately recognized in equity, the issuer would still consider the option when determining whether the entity could be required to disburse cash or other assets within one year or the operating cycle, whichever is longer.
- **Conversion option** – If the accounting literature on derivatives requires that the equity conversion option itself be bifurcated and accounted for as a derivative separately from the debt security, then the convertible debt security would be outside the scope of the FSP.
- **Other features** – For instruments that are within the scope of the FSP and have put options, call options, or other potential embedded derivatives, the FSP does not change the GAAP requirement to evaluate these embedded features under SFAS 133 to determine whether any of those features require separate accounting as derivatives. Entities must first identify any embedded features and apply the guidance in SFAS 133 to determine whether they require separate accounting as a derivative. If the conversion option requires separate accounting, the FSP does not apply to the convertible debt security. Entities must then apply the FSP’s liability-first allocation approach on the basis of fair value of the liability component, including any embedded features (except for the conversion option). Finally, for those embedded features requiring separate derivative accounting, entities must separate the embedded derivative from the liability component in accordance with the guidance in SFAS 133.

Subsequent Accounting

The interest method as described in paragraph 15 of APB 21, *Interest on Receivables and Payables* shall be used to accrete the excess of the principal amount of the liability component over its carrying amount. Any debt discounts and debt issuance costs shall be amortized over the expected life of a similar liability that does not have an equity component. This expected life shall not be remeasured unless the terms of the instrument are modified. In addition, the equity component is not remeasured as long as it continues to meet the conditions for equity classification in EITF Issue 00-19, *Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company’s Own Stock.*
**Other Considerations**

Other considerations of the FSP include the following:

- **Equity conversion option** – Subsequent changes in the fair value of the equity conversion options are ignored as long as the option continues to meet the conditions for equity classification.

- **Expected life** – When determining the expected life of the instrument, issuers should ignore the exercise of the conversion option. Thus, the expected life of a convertible debt security without other embedded features is the contractual term of the instrument – even if the instrument may be converted into shares or cash before reaching maturity. At issuance, if an entity determines that it is probable that the embedded feature (e.g., a holder put option) will not be exercised, that feature is also ignored. Moreover, if an entity uses a present value technique to measure the fair value of the liability component at initial recognition, the expected life (i.e., the period used for amortizing the debt discount) should be consistent with the period used to discount the cash flows. Entities are not permitted to reassess the expected life after the initial determination, unless they modify the debt.

**Conversion or Extinguishment of the Convertible Debt**

The FSP indicates that upon derecognition (e.g., conversion, settlement, or extinguishment), the issuer must allocate the fair value of the entity’s shares and cash or other assets transferred to the holder (as well as any truncation costs incurred) between the extinguishment of the liability components (giving rise to gain or loss) and settlement of the equity conversion option. The allocation is made on the basis of the current fair value of the liability component.

**Modifications and Exchanges**

This FSP does not discuss how a modification or exchange of an instrument subject to the FSP should be accounted for. Therefore, guidance in the following EITF Issues should be used to determine whether these changes result in modification or extinguishment accounting:

- **EITF Issue 06-6, Debtor’s Accounting for a Modification (or Exchange) of Convertible Debt Instruments**
- **EITF Issue 96-19, Debtor’s Accounting for Modification or Exchange of Debt Instruments**

Many issuers may seek to change the terms of existing cash-settled convertible debt instruments to avoid the higher interest expense associated with split accounting (as discussed earlier). An issuer’s modification to a cash-settled convertible instrument within the scope of the FSP that removes its ability to cash-settle upon conversion might be so significant that extinguishment accounting applies. If extinguishment accounting does apply, the new instrument is not subject to the FSP prospectively. However, if the modification to which extinguishment accounting applies occurred before the FSP’s effective date, the FSP would be applied retrospectively to the instrument up to the date of the modification. If extinguishment accounting does not apply, the components of the instrument continue to be accounted for separately.

**Disclosures**

The FSP requires entities to disclose the following information. (An asterisk (*) indicates that disclosure is required only for the most recent balance sheet date.)

- “The principal amount of the liability component, its unamortized discount, and its net carrying amount.”
- “The carrying amount of the equity component”
- “The remaining period over which any discount on the liability component will be amortized.” *
- “The conversion price and the number of shares on which the aggregate consideration to be delivered upon conversion is determined.” *
- “The amount by which the instrument’s if-converted value exceeds its principal amount, regardless of whether the instrument is currently convertible.” *
- “Information about derivative transactions entered into in connection with the issuance of instruments within the scope of [the] FSP, including the terms of those derivative transactions, how those derivative transactions relate to the instruments within the scope of [the] FSP, the number of shares underlying the derivative transactions, and the reasons for entering into those derivative transactions.” *
- “The effective interest rate on the liability component for the period.”
- “The amount of interest cost recognized for the period relating to both the contractual interest coupon and amortization of the discount on the liability component.”
Effective Date and Transition

This FSP is effective for financial statements issued for fiscal years (and interim periods) beginning after December 15, 2008. Early adoption is not permitted. The FSP is to be applied retrospectively to all past periods presented – even if the instrument has matured, converted, or otherwise been extinguished as of the FSP’s effective date. The cumulative effect of the change in accounting principle on periods before those presented should be recognized as of the beginning of the first period presented, with an offsetting adjustment to the opening balance of retained earnings for that period, which should be presented separately. However, no adjustment is required to the opening balance for instruments not outstanding during any of the periods presented.

FIN 46(R)

FIN 46(R) provides guidance for identifying the party with a controlling financial interest resulting from arrangements or financial interests rather than from voting interests. FIN 46(R) defines the term VIE and is based on the premise that if a reporting enterprise absorbs a majority of the VIE’s expected losses and/or receives a majority of its expected residual returns (measures of risk and reward), that enterprise (the primary beneficiary) is deemed to have a controlling financial interest in the VIE. An enterprise that bears the majority of the economic risk is considered to have a controlling financial interest of a VIE, even if it has no decision making (voting) authority or equity interest.

An interest that absorbs variability in an entity is a variable interest, while an interest that creates variability in the entity is not a variable interest. An enterprise that holds a variable interest in a VIE must determine whether that interest causes that enterprise, as noted above, to be the primary beneficiary of the entity. Determining whether an interest in an entity is a variable interest can prove tricky. Typically, assets would be considered creators of variability (or non-variable interests) because, generally, they are the sources of an entity’s cash flows or change in fair value. Liabilities and equity, on the other hand, would typically be considered absorbers of variability (or variable interests) because they typically represent claims to an entity’s current period residual cash and any cash flows or fair value that remain at the end of an entity’s life. However, many contractual arrangements exist where the conclusion is unclear (e.g., derivative instruments and power purchase agreements) thereby requiring additional analysis.

The assets, liabilities, and results of the activities of the VIE should be included in the consolidated financial statements of the primary beneficiary. Entities and transactions common to the energy industry that may be impacted by FIN 46(R) include synthetic leases, sale-leasebacks, joint ventures, trust preferred securities, investments in affordable housing partnerships, synthetic fuel tax credit partnerships, and long term power purchase contracts.

FSP FIN 46(R)-6, Determining the Variability to Be Considered in Applying FIN 46(R)

To assist in determining whether an interest in an entity is a variable interest, in April 2006, the FASB issued FSP FIN 46(R)-6. The FSP introduces the “by-design” approach to determine which variability to consider in evaluating whether an interest is a variable interest.

Prior to the issuance of the FSP, there was confusion, in some scenarios, as to what variability to consider when applying the provisions of FIN 46(R). The purpose of the FSP is to clarify what variability should be considered by evaluating the design of the entity. One could say that the FSP is only intended to address contractual arrangements for which it is not clear whether a contractual arrangement is a variable interest or not. For example, subordinated debt and equity that is at risk will always be variable interests; there is no basis for using the provisions of the FSP to arrive at a different conclusion. Thus, for the most part, FSP FIN 46(R)-6 will apply to derivative and derivative-like contracts such as forward and option contracts, which could either create or absorb variability. Relative to this, the FSP includes a section specifically addressing a company’s evaluation of derivative contracts.

Applying the FSP

In determining which variability to consider for purposes of applying FIN 46(R), FSP FIN 46(R)-6 requires the following two-step analysis:

**Step 1:** Analyze the nature of the risks in the entity.

**Step 2:** Determine the purpose(s) for which the entity was created and the variability (created by the risks identified in Step 1) the entity is designed to create and pass along to its interest holders.

In applying Step 1, examples of risks that may cause variability include, but are not limited to, credit risk, interest rate risk, foreign currency exchange risk, commodity price risk (on the purchase and sale sides of an entity), equity price risk, and operations risk.

In applying Step 2, the enterprise should determine the purpose for which the entity was created and the variability the entity was designed to create and pass along to its interest holders. In making this determination, the following factors should be considered:

- The activities of the entity
The terms of the contracts the entity has entered into

The nature of the entity’s interests issued

How the entity was marketed to potential investors

Which parties participated significantly in the design or redesign of the entity.

Additionally, in performing this analysis, an enterprise should review the terms of the contracts that the entity has entered into. This review may include a detailed analysis of original formation documents and any amendments, governing documents and any amendments, marketing materials, and other contractual arrangements entered into by the entity and provided to potential investors or other parties associated with the entity.

The FSP provides the following strong indicators of the variability that the entity was designed to create and pass along to its interest holders:

- When the term of the interests transfer all or a portion of the risk or return (or both) of certain assets or operations to the interest holder, the variability that is transferred strongly indicates a variability that the entity is designed to create and pass along to its interest holders (paragraph 10). Interests that absorb this risk or return are likely variable interests.

- Variability that is absorbed by an interest that is substantively subordinated strongly indicates a particular variability that the entity was designed to create and pass along to its interest holders (paragraph 11). Interests that absorb this variability are likely variable interests.

- Variability associated with periodic interest receipts/payments on fixed rate investments that may or will be sold prior to maturity strongly indicates variability that the entity was designed to create and pass along to its interest holders (paragraph 12). Interests that absorb this variability are likely variable interests.

The FSP also provides guidance for determining whether certain derivative instruments are creators of variability or variable interests, which should be of particular importance to the energy industry.

Certain Derivative Instruments

To meet the definition of a derivative, paragraphs 6-9 of SFAS 133 require an energy contract to have an underlying, a notional or payout provision, and a provision for net settlement or physical settlement with an asset that is readily convertible to cash.

Under paragraph 13 of the FSP, contracts that meet the definition of a derivative and have both of the following characteristics could qualify as creators of variability (i.e., not variable interests):

- The derivative contract’s underlying is an observable market rate, price, index of prices or rates, or other market observable variable (including the occurrence or nonoccurrence of a specified market observable event)

- The derivative counterparty is senior in priority relative to other interest holders in the entity. As a result, it is likely that most “plain vanilla” interest rate or currency swaps that possess these characteristics will not be variable interests.

However, the FSP provides two exceptions to derivative contracts that possess the two characteristics above. If either of the two exceptions is met, the design of the entity will need to be further analyzed under the FSP’s two-step analysis to determine whether that instrument is a creator of variability or a variable interest (i.e., the potential exception found in paragraph 13 of the FSP may not be applied). The two exceptions are as follows:

- Changes in the fair value or cash flows of the derivative instrument are expected to offset all, or essentially all, of the risk or return (or both) related to the majority of assets (excluding the derivative instrument) or operations of the entity

- A reporting enterprise, who is a party to the derivative contract, has additional interest(s) in the entity.

Under the first exception above, total return swaps, put options, call options, and some power purchase agreements related to a majority of the entity’s assets or operations would likely be considered variable interests even if they possess the two characteristics in paragraph 13 of the FSP. Reporting enterprises should also evaluate whether energy contracts qualify for lease accounting under the provisions of EITF Issue 01-8.

Many contracts in the energy industry do not meet the definition of a derivative under SFAS 133, and would not meet the requirement of paragraph 13. Such contracts include those with no explicit or implicit notional amounts (e.g., requirements contracts and certain PPAs) or net settlement provisions (e.g., certain PPAs). As a result, many energy contracts will need to be further evaluated under the FSP’s two-step analysis to determine if the energy contract is a creator of variable or a variable interest.
Going Forward

Companies should continue to monitor changes in the interests in assessed entities, or changes in the entities themselves, that may trigger reconsideration of whether the assessed entity is a VIE and/or whether the reporting enterprise is the primary beneficiary. Changes which would result in a company reconsidering whether an entity is a VIE are stipulated in paragraph 7 of FIN 46(R) and include:

- Changes in the entity’s governing documents or contractual arrangements that change characteristics or adequacy of the entity’s equity investment at risk
- Equity investment in the entity is in some part returned to equity investors, and other interests become exposed to losses of the entity
- The entity undertakes additional activities or acquires additional assets, beyond those anticipated at inception or the latest reconsideration event, that increase the entity’s expected losses
- The entity receives additional equity investment that is at risk, or the entity curtails or modifies its activities in such a way to decrease its expected losses.

Note that the FASB ED discussed below will require, if implemented, continuous reconsideration of whether the assessed entity is a VIE and/or whether the reporting enterprise is the primary beneficiary.

FASB ED, Amendments to FASB Interpretation No. 46(R)

In March 2008, the FASB added a project to its agenda to amend and enhance certain guidance in FIN 46(R). The project was undertaken to accomplish the following:

- Address the potential effects on certain provisions of FIN 46(R) of the proposed elimination of the qualifying special-purpose entity concept as proposed in the SFAS 140 ED, Accounting for Transfers and Servicing of Financial Assets. As a result of the elimination of the QSPE concept, many entities may become subject to the consolidation guidance in FIN 46(R).
- Address financial statement users’ concerns about the application of certain key provisions of FIN 46(R), including those in which the accounting and disclosures do not always provide timely and useful information about an enterprise’s involvement or involvements in a VIE that assists users in assessing the potential financial effects on the enterprise.

The project resulted in the ED which was released for public comment on September 15, 2008.

The FIN 46(R) ED proposes the following changes:

Determination of the Primary Beneficiary of a VIE

The proposed amendments in the FIN 46(R) ED primarily focus on how the primary beneficiary of a VIE is determined. Note that the proposed amendments do not change the definition of a VIE. Under the current FIN 46(R) model, an entity often needs to perform a quantitative analysis when determining which interest holder in a VIE absorbs a majority of the entity’s expected losses or residual returns and is its primary beneficiary. In response to concerns regarding the difficulty in applying this model and the lack of transparency that a risks-and-rewards model often creates, the FIN 46(R) ED proposes to modify the approach in paragraph 14 for determining the primary beneficiary of a VIE.

Under the proposal, the evaluation of whether an enterprise is the primary beneficiary of a VIE is a two-step analysis:

Step 1: An enterprise must determine qualitatively whether it has:

- The “power to direct matters that most significantly impact the activities” of the VIE in a manner that impacts the VIE’s economic performance and
- The right to receive benefits from the VIE that could potentially be significant to the VIE or the obligation to absorb losses of the entity that could potentially be significant to the VIE.

If both conditions are met, the enterprise is considered the primary beneficiary and must consolidate the VIE. In performing this analysis, the enterprise is required to consider whether it has any “implicit financial responsibility to ensure that the variable interest entity operates as designed.”

The determination of whether an enterprise has the right to receive benefits or the obligation to absorb losses does not take into account probability. Accordingly, the mere possibility that an enterprise could receive benefits or absorb losses that could be potentially significant to the
The principal objectives of the enhanced disclosures are to provide users of financial statements of public entities with an understanding of:

- Enhance disclosures regarding an entity’s involvement with VIEs and methodologies for applying FIN 46(R).

Many entities becoming VIEs and thus make them subject to the consolidation guidance in FIN 46(R) solely because they experienced significant operating losses. In addition, the removal of the exception that an entity cannot become a VIE solely because of operating losses may result in the income statement should not include amounts attributable to the VIE after the date that the enterprise determines it is no longer the VIE's primary beneficiary. In such a case, that the circumstances changed resulting in the enterprise no longer meeting the conditions for consolidation. This is particularly important in an enterprise determines that it is no longer the primary beneficiary of a VIE, it would need to deconsolidate that particular VIE on the date changes during a reporting period, the enterprise will need to determine when in the reporting period the change occurred. For example, if an enterprise determines that it is no longer the primary beneficiary of a VIE, it would need to deconsolidate that particular VIE on the date that the circumstances changed resulting in the enterprise no longer meeting the conditions for consolidation. This is particularly important in determining what amounts should and should not be included in the income statement related to the operations of the VIE. In such a case, the income statement should not include amounts attributable to the VIE after the date that the enterprise determines it is no longer the VIE’s primary beneficiary. In addition, the removal of the exception that an entity cannot become a VIE solely because of operating losses may result in many entities becoming VIEs and thus make them subject to the consolidation guidance in FIN 46(R) solely because they experienced significant operating losses.

Enhance disclosures regarding an entity’s involvement with VIEs and methodologies for applying FIN 46(R)

The principal objectives of the enhanced disclosures are to provide users of financial statements of public entities with an understanding of:

- The judgments and assumptions made by the enterprise in determining whether the enterprise must consolidate a VIE and/or disclose information about its involvement in a VIE.

- The nature of restrictions on a consolidated VIE’s assets reported in an enterprise’s statement of financial position, including the carrying amounts of such assets.

- The nature of, and changes in, the risks associated with the enterprise’s involvement with the VIE.

- The current and potential financial effects from an enterprise’s involvement with a VIE on the enterprise’s financial position, financial performance, and cash flows.
In summary, the FIN 46(R) ED requires implementation of processes for performing and documenting results of continuous reconsideration assessments and increases reliance on professional judgment when determining whether an enterprise has “power” to direct the activities of the entity. Because of the proposed modifications to the existing consolidation model in FIN 46(R) and the requirement for enterprises to continually reassess consolidation conclusions, enterprises involved with VIEs (even VIEs that are not structured finance vehicles) will need to reevaluate their previous consolidation conclusions.

If adopted, the amendments to FIN 46(R) will be effective for fiscal years (and interim periods within those fiscal years) beginning after November 15, 2009. The comment period for the proposed statement ends November 14, 2008.

Proposed FSP FAS 140e and FIN 46(R)-e, Disclosures about Transfers of Financial Issues and Interests in Variable Interest Entities

Because the FIN 46(R) ED is not expected to become effective until fiscal years beginning after November 15, 2009, the FASB issued a proposed FSP FAS 140-e and FIN 46(R)-e that, if adopted, will make many of the disclosure requirements included in FIN 46R ED effective for public entities for reporting periods (interim and annual) beginning with the first reporting period that ends after the final FSP is issued. The FASB has stated that it expects to issue a final FSP in the fourth quarter of 2008. The disclosures may therefore be effective for reporting periods ending in that quarter (e.g., for calendar year-end filers, the proposed disclosures would be included in the December 31, 2008, annual filings). The comment period for the proposed FSP ended October 15, 2008. The FSP would be superseded when the proposed amendments to SFAS 140 and FIN 46(R) become effective.

FSP EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities

FSP EITF Issue 03-6-1, issued in June 2008, addresses whether instruments granted in share-based payment transactions are participating securities prior to vesting and, therefore, need to be included in the earnings allocation in computing EPS under the two-class method described in paragraphs 60 and 61 of SFAS 128 (see discussion below). The FASB did not address forfeitable dividends in the FSP. Therefore, entities shall continue to apply their existing accounting policy for unvested share-based payment awards that contain rights to forfeitable dividends.

An unvested share-based payment award meets the definition of a participating security if it contains a right to nonforfeitable dividends to participate in undistributed earnings with common shareholders. That is, awards that accrue cash dividends (whether paid or unpaid) any time the common shareholders receive dividends (and those dividends do not need to be returned to the entity if the employee forfeits the award) are considered participating securities. As these awards are considered participating securities, the two-class method of computing basic and diluted EPS must be applied.

The FASB noted share-based payment awards where the dividends reduce the exercise price of the award rather than being paid out in cash would not require the use of the two-class method. In this situation, the FASB noted the holder of the award does not participate in undistributed earnings with common shareholders unless the award is exercised. As the realization of the value transferred is contingent on the holder exercising the award, the FASB concluded that feature does not represent a participation in undistributed earnings with common shareholders that would require use of the two-class method.

The FASB also concluded that because the FSP applies to all outstanding unvested share-based payment awards that contain rights to nonforfeitable dividends, changes in an entity’s forfeiture estimates from one reporting period to the next do not affect the computation of EPS, other than for the increase or decrease in compensation cost as a result of the application of SFAS 123(R), Share-Based Payment.

This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. All prior-period EPS data presented shall be adjusted retrospectively (including interim financial statements, summaries of earnings, and selected financial data) to conform with the provisions of this FSP. Early adoption is not permitted.

Applying Two-Class Method

In accordance with paragraphs 60 and 61 of SFAS 128, the two-class method of computing EPS is used to allocate earnings based upon the following:

- “Income from continuing operations (or net income) shall be reduced by the amount of dividends declared in the current period for each class of stock and by the contractual amount of dividends (or interest on participating income bonds) that must be paid for the current period (for example, unpaid cumulative dividends).”

- “The remaining earnings shall be allocated to common stock and participating securities to the extent that each security may share in earnings as if all of the earnings for the period had been distributed. The total earnings allocated to each security shall be determined by adding together the amount allocated for dividends and the amount allocated for a participation feature.”
• "The total earnings allocated to each security shall be divided by the number of outstanding shares of the security to which the earnings are allocated to determine the EPS for the security."

• "Basic and diluted EPS data shall be presented for each class of common stock."

**EITF Issue 07-4, Application of the Two-Class Method Under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships**

This EITF affects publicly traded master limited partnerships with incentive distribution rights whose incentive distributions are accounted for as equity distributions.

The consensus (1) does not address whether incentive distributions are equity distributions or compensation expense and (2) applies regardless of whether the IDR is a freestanding limited partner interest or embedded in the general partner interest.

The MLP ownership structure is common in industries such as petroleum and natural gas extraction and transportation.

In a typical publicly traded MLP, cash is distributed to common units held by limited partners, a GP interest, and IDRs, in accordance with the terms specified in the partnership agreement.

Generally, the partnership agreement obligates the GP to distribute all of the partnership’s available cash after the end of each quarter to the LPs and GP, and when certain thresholds are met, to the IDR holder. “Available cash” is typically defined in the partnership agreement as all cash on hand at the end of each quarter less cash retained by the partnership as capital to (1) operate the business (e.g., future capital expenditures); (2) comply with applicable law, debt, and other agreements; and (3) provide funds for distribution to the LP common unit, GP, and IDR holders for any one or more future quarters. A complicating factor in computing earnings per unit is that available cash, as determined under the partnership agreement, often differs from earnings (loss). Consequently, distributions may be greater than (or less than) earnings (loss) for any given period.

At issue is how, when applying the two-class method under Statement 128, current-period earnings of an MLP should be allocated to the GP, to the LPs, and when applicable, to the IDR holder.

An additional application issue is whether the MLP becomes obligated to make distributions (and such distributions should be included in earnings per unit) as of the end of the period or once available cash has been determined by the GP. This issue arises because the partnership agreement usually allows the GP 30 to 60 days after the end of the reporting period to determine the amount of available cash.

The EITF reached the following consensus:

**Earnings in Excess of Cash Distributions** — Current-period earnings should be reduced by the amount of distributions to the GP, LPs, and IDR holder determined in accordance with the contractual terms of the partnership agreement. The remaining undistributed earnings should be allocated to the GP, LPs, and IDR holder by using the distribution waterfall for available cash (i.e., a schedule that prescribes distributions to the various interest holders at each threshold) specified in the partnership agreement. If an analysis of the contractual terms of the partnership agreement reveals that available cash represents a “specified threshold” for the reporting period presented, as described in Example F in paragraph 16 of EITF Issue 03-6, Participating Securities and the Two-Class Method under FASB Statement No. 128, no undistributed earnings should be allocated to the IDR holder. Conversely, if the partnership agreement does not address this issue or does not explicitly limit distributions to the IDR holder to the holder’s share of available cash determined in the reporting period presented, then a specified threshold would not exist and the MLP would effectively allocate all current-period earnings (including undistributed earnings) to the GP, LPs, and IDR holder by using the distribution waterfall for available cash specified in the partnership agreement. Thus, current-period earnings are effectively treated as though they are available cash distributions.

**Cash Distributions in Excess of Earnings** — Any excess of distributions over current-period earnings (loss) should be allocated to the GP and LPs on the basis of their respective sharing of losses specified in the partnership agreement (i.e., the provisions for allocation of losses to the partners’ capital accounts for the reporting period presented). If the IDR holder is not contractually obligated to share in current-period losses, the excess of distributions over current-period earnings (loss) amount is not allocated to the IDR holder. However, if the IDR holders have a contractual obligation to share in the losses of the MLP on a basis that is objectively determinable (as described in paragraphs 17 and 18 of EITF Issue 03-6), the excess of distributions over earnings (loss) should be allocated to the GP, LPs, and IDR holders on the basis of their respective sharing of losses specified in the partnership agreement for the reporting period presented.

The EITF concluded that for the MLP to report current-period earnings per unit, the GP must use current-period information to determine the amount of available cash (i.e., the MLP becomes obligated to make distributions of available cash at the end of the current reporting period, which may be before available cash is determined).

This consensus is effective for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years, applied retrospectively for all financial statements presented. Early application is not permitted.
EITF Issue 07-5, Determining Whether an Instrument (or an Embedded Feature) Is Indexed to an Entity’s Own Stock

This EITF affects entities with (1) options or warrants on their own shares (not within the scope of SFAS 150), including market-based employee stock option valuation instruments; (2) forward contracts on their own shares, including forward contracts entered into as part of an accelerated share repurchase program; and (3) convertible debt instruments and convertible preferred stock. Also affected are entities that issue equity-linked financial instruments (or financial instruments that contain embedded equity-linked features) with a strike price that is denominated in a foreign currency.

The instruments described above may contain contract terms that call into question whether the instrument or embedded feature is indexed to the entity’s own stock. A derivative instrument or embedded derivative feature that is deemed indexed to an entity’s own stock may be exempt from the requirements of SFAS 133 for derivatives. In addition, a freestanding instrument that is indexed to a company’s own stock remains eligible for equity classification under EITF issue 00-19.

At issue are the following:

• How an entity should evaluate whether an instrument (or embedded feature) is indexed to its own stock.
• How the currency in which the strike price of an equity-linked financial instrument (or embedded equity-linked feature) is denominated affects the determination of whether the instrument is indexed to an entity’s own stock.
• How an issuer should account for market-based employee stock option valuation instruments.

How an entity should evaluate whether an instrument (or embedded feature) is indexed to its own stock — The EITF reached a consensus that an entity should use the following two-step approach to evaluate whether an equity-linked financial instrument (or embedded feature) is indexed to its own stock:

Step 1: Evaluate the instrument’s contingent exercise provisions, if any, on the basis of the existing consensus on contingent exercise provisions in EITF Issue 01-6, The Meaning of “Indexed to a Company’s Own Stock”. That is, instruments whose exercisability is affected by one or more variables other than the entity’s stock price are considered indexed to an entity’s own stock provided that the exercise contingency is not based on (1) an observable market, other than the market for the entity’s stock, or (2) an observable index, other than one that is solely referenced to the entity’s own operations. If the evaluation in step 1 would not preclude an instrument from being considered indexed to the entity’s own stock, the analysis would proceed to step 2.

Step 2: Evaluate the instrument’s settlement provisions. If the settlement amount will equal the difference between the fair value of a fixed number of the entity’s equity shares and (1) a fixed monetary amount or (2) a fixed amount of another financial asset (such as a fixed stated principal of convertible debt) issued by the entity (also known as “fixed-for-fixed” settlement), then the instrument’s settlement provisions would be considered indexed to the entity’s own stock. Even when the strike price or the number of shares used to calculate the settlement amount is fixed, as long as the only variables that could affect the settlement amount would be inputs to the determination of the fair value of a fixed-for-fixed forward or option on equity shares. When performing this step, an entity should consider all possible settlement alternatives. That is, an entity must presume the occurrence of a contingent event or another condition that would adjust the settlement terms of an instrument or embedded feature when evaluating whether that instrument or embedded feature is indexed to the entity’s own stock.

The fair value inputs of a fixed-for-fixed forward or option on equity shares may include inputs such as the entity’s stock price; time, dividends, or other dilutive activities such as a stock split; stock borrow cost; interest rates; stock price volatility; the entity’s credit spread; and the ability to maintain a standard hedge position in the underlying shares. However, the instrument’s settlement provisions would not be considered indexed to the entity’s own stock when the settlement amount is affected by inputs (variables) that are leveraged or that are extraneous to the pricing of a fixed-for-fixed option or forward contract on equity shares.

How the currency in which the strike price of an equity-linked financial instrument (or embedded equity-linked feature) is denominated affects the determination of whether the instrument is indexed to an entity’s own stock — The EITF reached a consensus that an equity-linked financial instrument (or embedded equity-linked feature, such as conversion options embedded in a convertible debt instrument that is denominated in a currency other than the issuer’s functional currency) would not be considered indexed to the entity’s own stock if the strike price is denominated in a currency other than the issuer’s functional currency.

The EITF decided that the determination of whether an equity-linked financial instrument is indexed to an entity’s own stock is not affected by the currency used in the market(s) in which the underlying shares trade. This consensus is consistent with the FASB’s proposed DIG Issue C21, “Whether Options (Including Embedded Conversion Options) are Indexed to Both the Entity’s Own Stock and Currency Exchange Rates”. For example, the entity’s sale revenue, earnings before interest, taxes, depreciation, and amortization; net income; or total equity.
How an issuer should account for market-based employee stock option valuation instruments — The EITF also reached a consensus that market-based employee stock option valuation instruments are not considered indexed to an entity’s own stock, as defined in step 2 (see above). The settlement amount of these instruments is affected by employee behavior, which is not an input in the determination of the fair value of a fixed-for-fixed forward or option on equity shares. Consequently, such instruments would generally be accounted for as derivatives under SFAS 133.

The consensus is effective for fiscal years beginning after December 15, 2008, including interim periods within those fiscal years. The consensus must be applied to outstanding instruments as of the beginning of the fiscal year in which the issue is adopted as a cumulative-effect adjustment to the opening balance of retained earnings for that fiscal year. Early application is not permitted.

EITF Issue 07-6, Accounting for the Sale of Real Estate Subject to the Requirements of FASB Statement No. 66, Accounting for Sales of Real Estate, When the Agreement Includes a Buy-Sell Clause

This EITF affects entities (investors) that transfer real estate to a venture that they jointly own with another investor when the joint-ownership agreement contains a “buy-sell clause.”

When two investors enter into an arrangement to create a jointly owned venture and one investor (the “selling investor”) transfers real estate to that entity, the agreement commonly includes a buy-sell clause. A buy-sell clause permits either investor (the “offeror”) in the jointly owned entity to irrevocably request a buyout of the other investor’s (the “offeree’s”) entire interest by providing a notice (the “purchase notice”) to the offeree.

In the purchase notice, the offeror typically names a price for the offeree’s interest at its discretion. After receiving the purchase notice, the offeree must either (1) sell its entire interest in the venture to the offeror or (2) buy the offeror’s interest at the named price. This example is known as an “unspecified-price” buy-sell clause. Other, less common, types of buy-sell clauses exist.

At issue is whether a buy-sell clause represents a prohibited form of continuing involvement (e.g., an option to reacquire the real estate) under SFAS 66, Accounting for Sales of Real Estate, that precludes partial sale-and-profit recognition upon transfer of the real estate to the venture by the selling investor.

The EITF reached a consensus that a buy-sell clause, in and of itself, does not constitute a prohibited form of continuing involvement that would preclude partial sale-and-profit recognition under SFAS 66. However, the terms of the buy-sell clause, along with other facts and circumstances, may indicate that the seller has not transferred the usual risks and rewards of ownership and therefore has substantial continuing involvement. The determination of whether the seller has substantial continuing involvement is a matter of judgment and requires consideration of all relevant facts and circumstances of the transaction at the time the real estate is sold.

The consensus is applied prospectively to new arrangements entered into and assessments (In this context, assessments can be defined as any evaluation performed pursuant to SFAS 66 after the effective date of EITF Issue 07-6 for arrangements accounted for under the deposit, profit-sharing, leasing, or financing methods for reasons other than the existence of a buy-sell clause.) performed in fiscal years beginning after December 15, 2007, and interim periods within those fiscal years. Early application is not permitted.

EITF Issue 08-3, Accounting by Lessees for Maintenance Deposits under Lease Arrangements

EITF Issue 08-3, issued in June 2008, clarified whether lessees should account for nonrefundable maintenance deposits as a deposit or as contingent rental expense and whether the EITF should provide revenue recognition accounting guidance for the lessor, either as part of EITF Issue 08-3 or in a separate Issue.

Certain lease agreements require the lessee to make maintenance deposits to the lessor. This is commonly a result of concerns with the lessee’s credit worthiness and their ability to maintain the leased asset during the lease term. Typically, the lessee is entitled to a reimbursement of the maintenance cost to be paid by the lessor from the maintenance deposit upon completion of the required maintenance. However, some lease agreements provide that if, at the end of the lease term, excess amounts are on deposit with the lessor (i.e., the total cost of cumulative maintenance events over the term of the lease is less than the cumulative deposits), the lessor is entitled to retain the excess amounts (nonrefundable maintenance deposit).

When the deposits are nonrefundable, some accounted for the payments as a deposit (i.e., the lessee records a deposit asset upon payment to the lessor). The deposit was then expensed or capitalized (depending on the lessee’s maintenance accounting policy) when the underlying maintenance is performed or it is determined that a portion of the deposit will not be returned. Others accounted for the deposit payments as contingent rent expense or maintenance expense at the time the payment is made.
The EITF reached a consensus that all nonrefundable maintenance deposits that are contractually and substantively related to maintenance of the leased asset are accounted for as deposit assets. The lessee’s deposit asset is expensed or capitalized as part of a fixed asset (depending on the lessee’s maintenance accounting policy) when the underlying maintenance is performed. When the lessee determines that it is less than probable that an amount on deposit will be returned to the lessee (and thus no longer meets the definition of an asset), the lessee must recognize an additional expense for that amount.

The EITF decided not to include any revenue recognition guidance for lessors in EITF Issue 08-3 or provide additional guidance in the future.

The issue is effective for financial statements issued for fiscal years beginning after December 15, 2008, including interim period within those fiscal years, and must be applied by recognizing the cumulative effect of the change in accounting principle in the opening balance of retained earnings as of the beginning of the fiscal year in which this consensus is initially applied. Earlier application is not permitted.

**EITF Issue 08-4, Transition Guidance for Conforming Changes to Issue No. 98-5, “Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios”**

EITF Issue 08-4, issued in June 2008, provides transitional guidance for all conforming changes made to EITF Issue 98-5 that are a result of EITF Issue 00-27, Application of Issue No. 98-5 to Certain Convertible Instruments, and SFAS 150.

This affects entities that have issued convertible debt with beneficial conversion features and that continue to follow certain guidance in EITF Issue 98-5 that was nullified by EITF Issue 00-27 or SFAS 150. Beneficial conversion features are “in-the-money” conversion options as of the commitment date for the issuance of convertible debt.

Much of the guidance in EITF Issue 98-5 was nullified by certain consensuses in EITF Issue 00-27. Transition guidance was added to EITF Issue 98-5 to acknowledge the issuance of EITF Issue 00-27 through a status update. However, the general status update in EITF Issue 98-5 did not specifically identify the portions of EITF Issue 98-5 that were nullified by EITF Issue 00-27 or update the illustrative examples. The issuance of SFAS 150 in May 2003 also affected EITF Issue 98-5, and while a status update was added to EITF Issue 00-27 clarifying that instruments within the scope of SFAS 150 are no longer within the scope of EITF Issue 00-27, a status update for SFAS 150 was not included in EITF Issue 98-5.

The EITF reached a consensus and provided for transitional guidance for all conforming changes made to EITF Issue 98-5 that are a result of EITF Issue 00-27 and SFAS 150 in the Exhibit 08-4A of this issue. The conforming changes affected the guidance related to the amortization period for discount assigned to the beneficial conversion feature and nullified Cases 1(c), 1(d) and 5 in Exhibit 98-5A. For convertible instruments that have a stated redemption date, the discount is required to be amortized from the date of issuance to the stated redemption date, regardless of when the earliest conversion date occurs. For instruments that do not have a stated redemption date, such as perpetual preferred stock, the discount shall be amortized from the date of issuance to the earliest conversion date. In circumstances in which the instrument is converted prior to amortization of the full amount of the discount, the remaining unamortized discount should be immediately recognized as interest expense or as a dividend, as appropriate based upon the form of the convertible instrument.

The issue is effective for financial statements issued for fiscal years ending after December 15, 2008, with early application permitted. The effect, if any, of applying the conforming changes, shall be presented retrospectively for all periods presented, with the cumulative-effect adjustment to retained earnings as of the beginning of the first period presented.

**EITF Issue 08-5, Issuer’s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement**

EITF Issue 08-5 affects entities that incur liabilities (e.g., by issuing debt securities) that have inseparable third-party credit enhancements (e.g., a third-party guarantee) when such a liability is measured at fair value or a fair value measurement is disclosed (e.g., SFAS 107, Disclosures about Fair Value of Financial Instruments, disclosures). This Issue’s scope includes all liabilities (not just debt securities) with attached third-party credit enhancements when the liability is measured at fair value or disclosed by using a fair value measurement. This Issue will not affect entities that account for liabilities measured at amortized (accreted) cost pursuant to APB 21.

Certain entities issue liabilities with credit enhancements obtained from a third-party. Consider an example in which an entity issues a debt security that has been guaranteed by a third-party (the “guarantor”). Generally, the issuer pays the guarantor for the guarantee that is attached to the issued debt. Under this arrangement, the issuer’s payment obligations to the investor are guaranteed. That is, if an issuer defaults on its obligation, the guarantor will make the remaining interest and principal payments to the debt holder. In turn, the guarantor will seek reimbursement from the issuer for the amounts paid to the debt holder. The guarantee generally is incorporated into the terms of the debt security and will transfer with the debt security (e.g., if the investor sells the debt to another party, the guarantee would remain attached to the debt). By issuing debt with a third-party guarantee, the issuer can lower its overall cost of borrowing.
Currently, authoritative accounting literature does not address whether the issuer should determine the fair value of the liability with or without the third-party guarantee. This determination can result in a significant difference in how changes in an issuer’s credit standing affect the fair value of the liability. Paragraph 15 of SFAS 157 requires that the fair value of a liability incorporate the obligor’s nonperformance risk, including its own credit risk. If the fair value measurement of the liability includes the effect of the third-party guarantee, changes in the issuer’s credit standing would not necessarily be reflected in the fair value measurement of its debt because the fair value of the liability incorporates the credit standing of the guarantor. If the fair value measurement of the liability does not include the effect of the third-party guarantee, changes in the issuer’s credit standing would affect the fair value measurement of its liability. At issue is whether an issuer of a liability with a third-party credit enhancement that is inseparable from that liability should measure the fair value of the liability with or without the credit enhancement.

The EITF reached a consensus that an issuer of a liability with a third-party credit enhancement that is inseparable from the liability must treat the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement; therefore, changes in the issuer’s credit standing without the support of the credit enhancement affect the fair value measurement of the issuer’s liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities that are within the scope of this Issue (i.e., that are measured at fair value).

The Issue is effective for the first reporting period after December 15, 2008, applied prospectively, with the effect of the initial application included in the change in fair value of the liability in the period of adoption. In the period of adoption, an entity must disclose the valuation method(s) used to measure the fair value of liabilities in the scope of this Issue and any change in the fair value method used that occurs as a result of the initial application of this Issue. Early application is permitted.

EITF Administrative Matters — Revisions to EITF Topic D-98

At the March 2008 EITF meeting, the SEC observer announced revisions to Topic D-98. The revisions primarily address the SEC staff’s views regarding the interaction between Topic D-98 and SFAS 160. The revisions also reflect other clarifications to Topic D-98 that are unrelated to SFAS 160. The revised Topic D-98 indicates that the classification, measurement, and EPS guidance applies to noncontrolling interests (e.g., when the noncontrolling interest is redeemable at a fixed price by the holder or upon the occurrence of an event that is not solely within the control of the issuer). This includes noncontrolling interests redeemable at fair value.

The revisions to Topic D-98 that are specific to accounting for noncontrolling interests should be applied no later than the effective date of SFAS 160. SFAS 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008.

At the September 2008 EITF meeting, the SEC observer announced additional revisions to Topic D-98. The additional revisions primarily address the SEC staff’s views regarding the application of Topic D-98 to the classification and measurement of convertible debt instruments within the scope of FSP APB 14-1. Instruments within the scope of that FSP include “convertible debt instruments that, by their stated terms, may be settled in cash (or other assets) upon conversion, including partial cash settlement, unless the embedded conversion option is required to be separately accounted for as a derivative” under SFAS 133. The FSP requires entities to separate those convertible debt instruments into a liability-classified component and an equity-classified component. Depending on the terms of the convertible debt instrument and the individual facts and circumstances associated with the convertible debt instrument, when the entire instrument is converted or redeemed, some of the cash outflow may be allocated to the extinguishment of the equity component. The revisions to Topic D-98 require mezzanine classification (i.e., outside of permanent equity) for instruments that are currently redeemable or convertible when the amount of cash required to be exchanged in a hypothetical settlement (as of the balance sheet date) of the liability-classified component exceeds the current carrying amount of that liability-classified component. Specifically, entities would classify a portion of the equity-classified component in mezzanine that is equal to the excess, if any, of the hypothetical cash settlement of the liability-classified component over the current carrying amount of that component (calculated as of the balance sheet date).

Example - An entity issues a convertible debt instrument at par, $100. Upon conversion, the entity is required to pay principal ($100) in cash and the conversion spread in either cash or shares at the issuer’s option. At issuance, the entity allocates $70 in proceeds received to liability and $30 in proceeds to equity (pursuant to FSP APB 14-1). The revisions to Topic D-98 require that if the instrument is immediately convertible, the entity must classify the excess of the hypothetical required cash settlement amount ($100 principal payment in this example) over the current carrying amount of the liability component ($70 in this example) to mezzanine equity.

The SEC staff’s revisions will be effective concurrently with the effective date, and pursuant to the transition provisions, of the FSP.
SECTION 8

Environmental and Asset Retirement Obligations Update

Introduction

Recent years have seen the enactment of new legislation and the continued movement for “green energy” that resulted in companies not just incurring costs associated with clean up, but also incurring substantial costs to modify their generating units to comply with new environmental standards. However, 2008 has also seen new focus on the disclosure of environmental obligations in companies’ public filings. In an unprecedented action, the state of New York subpoenaed financial records from five companies under the Martin Act to determine whether they believed that environmental obligations were appropriate disclosed. One of those companies recently agreed to prospectively amend future filings to include additional disclosures.

Environmental Remediation Liabilities

SOP 96-1, *Environment Remediation Liabilities*, requires an accrual for environmental clean-up (or “remediation”) liabilities (outside the scope of SFAS 143, *Accounting for Retirement Obligations*) when the probable and estimable criteria of SFAS 5 and FIN 14, *Reasonable Estimation of the Amount of a Loss*, an interpretation of SFAS 5, are met. That is, a loss must be accrued by a charge to income if it is both probable and can be reasonably estimated. If a reasonable estimate of the loss is a range, the “reasonably estimated” criterion is met. If no value in the range is more likely than any other, the minimum amount should be accrued. SOP 96-1 also includes benchmarks to aid in the determination of when environmental remediation liabilities should be recognized in accordance with SFAS 5. It should also be noted that SOP 96-1 does not provide guidance on accounting for environmental remediation actions that are undertaken at the sole discretion of management and that are not induced by the threat of litigation or assertion of a claim or an assessment. The decision to incur such costs in the future does not give rise to a present liability, as a company has considerable discretion in changing its plans and avoiding the expenditure.

If a company has a probable but not reasonably estimable environmental remediation obligation that may be material, disclosure is required of the nature of the contingency. That is, a description of the remediation obligation, and the fact that a reasonable estimate cannot currently be made. Disclosure of the estimated timeframe to resolve the uncertainty as to the amount of the loss is encouraged, but not required. Additionally, the SEC Staff has provided comments to issuers when they don’t disclose the potential for additional costs to be incurred associated with environmental liabilities. For example, when a company records the low end of a probable and estimable loss, the company should also disclose the additional possible loss that could be incurred.

An environmental liability should be evaluated independently from any potential claim for recovery. Any loss arising from the recognition of an environmental liability should be reduced by a potential claim for recovery only when that claim is probable of recovery. Accounting guidance generally precludes the offsetting of assets and liabilities, except when a right of setoff exists. The general prohibition was strengthened by the issuance of FIN 39. The SEC staff takes the position that presentation of environmental liabilities net of any claims for recovery is not appropriate under FIN 39.

SAB 10F also sets forth the SEC staff’s position that environmental costs meeting the criteria of paragraph 9 of SFAS 71 should be presented on the balance sheet as a regulatory asset and should not be offset against the liability. Also, a utility should not delay recognition of a probable and estimable liability for environmental costs until a regulator determines whether the cost is an allowable cost for ratemaking purposes.

EITF Issue 95-23, *The Treatment of Certain Site Restoration/Environmental Exit Costs When Testing a Long-Lived Asset for Impairment*, addresses whether the cash flows associated with environmental costs that may be incurred (environmental remediation costs that have not yet been recognized as a liability pursuant to SOP 96-1) if a long-lived asset is sold, is abandoned, or ceases operations should be included in the undiscounted expected future cash flows used to test a long-lived asset for recoverability under SFAS 144. The consensus reached in EITF Issue 95-23 is that whether those unrecognized environmental exit costs should be included in the undiscounted expected future cash flows used to test a long-lived asset for recoverability under SFAS 144 depends on management’s intent with respect to the asset. EITF Issue 95-23 includes various examples of management’s intent and the corresponding treatment of the unrecognized environmental exit costs in the SFAS 144 recoverability test.

In addition to the previously mentioned accounting literature, guidance related to environmental matters is also included in the following:

- EITF Issue 89-13, *Accounting for the Cost of Asbestos Removal*
- EITF Issue 90-8, *Capitalization of Costs to Treat Environmental Contamination*.
AROs

Obligations for dismantlement, restoration and abandonment costs should be accounted for in accordance with the provisions of SFAS 143. Additionally, on March 30, 2005, the FASB issued FIN 47, Accounting for Conditional Asset Retirement Obligations, which clarified certain requirements set forth in SFAS 143. The primary difference between SFAS 143 and SOP 96-1 is that SFAS 143 is limited to legal obligations associated with the retirement of a tangible long-lived asset that results from the acquisition, construction, or development and (or) the normal operation of a long-lived asset. If an environmental remediation obligation is the result of “improper” operation of an asset or the result of a catastrophic event, it would be subject to the provisions of SOP 96-1.

The meaning of the term conditional ARO as used in SFAS 143 is clarified by FIN 47 and refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Uncertainty about the timing and (or) method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO and further requires that all asset retirements be identified.

FIN 47 acknowledges that instances exist in which a lack of necessary information prevents a company from making a reasonable estimate of the fair value of an ARO because the timing and/or method of settlement is uncertain. When does the FASB believe “sufficient information” exists to estimate the obligation?

- When the settlement date and the method of settling the obligation have been specified by others (e.g., contract, law, or regulation)
- When the information is available to estimate reasonably:
  - The settlement date (or the range of potential settlement dates)
  - The method of settlement (or potential methods of settlement)
  - The probabilities associated with potential settlement dates and methods of settlement.

First, before concluding that a liability cannot be estimated reasonably, the preparer should consider sources of information that are expected to provide a basis for estimation, including, but not limited to:

- The company’s own past practice
- Industry practice
- Management’s intent
- The asset’s estimated economic life.

Second, if the only uncertainty is whether or not the company will be required to perform the asset retirement activity and there is no information as to which outcome is more probable, then the company should assign a 50 percent probability to each outcome.

Third, companies should have a reasonable basis for assigning probabilities to each outcome (i.e., each potential settlement date and each potential method of settlement). However, in situations when the company does not have a reasonable basis of assigning probabilities, if the period of time for each potential settlement date is so narrow and/or the cash flows of each potential method of settlement is so similar that the inability to assign probabilities would be immaterial, then a company should still be able to estimate the fair value of the ARO. If the company ultimately concludes that it cannot reasonably estimate the fair value of an ARO, then it records no liability at all. However, the company must still disclose a general description of the ARO and the associated assets. In addition, the company shall disclose in the notes to the financial statements the fact that it could not reasonably make a fair value estimate of the ARO and explain the reasons why such an estimate could not be made. In the first period in which sufficient information becomes available to estimate the ARO’s fair value, the company must record the obligation.

Industry Issues for Consideration

Classification of Removal Costs Recovered Through Rates

For regulated utilities that are recovering costs through rates and that are still applying, SFAS 71, the liability associated with asset removal costs that do not have a legal obligation would be considered a regulatory liability. This regulatory liability may remain in accumulated depreciation only if the company is a non-public entity. For a public entity, this regulatory liability would be removed from accumulated depreciation and would be recorded as a separate regulatory liability. The financial statement location and amount of any regulatory asset or liability should be
Utility depreciation studies often try to provide for depreciation of a class of assets over an average life, quite often tied to an estimate of the retired and replaced for any varied number of reasons, these components may have a legal disposal obligation associated with their disposition.

Utility systems are constructed with many components which ultimately enable the provision of the utility service. As individual components are Interim Retirements with paragraph A26 of SFAS 143.

Approach. In that event, the obligation should be recorded similar to as if a new layer has been created using current discount rates, consistent allow the obligation to be reasonably estimated. Example 4 in FIN 47 specifically addresses this consideration and provides additional guidance on FIN 47 provides that a company record an ARO related to a legal obligation at a future date if more facts or information become available that would be deemed to represent changes in estimate of the asset retirement costs.

Any difference between the rollforward of amounts charged to the ARO during the year and the periodic substantiation thereof) would be charged to this liability during an annual period. At the same time, the liability would be accreted at the appropriate rate critical that each substantiation utilizes current assumptions and projections. Actual legal cost of removal or disposal (or an estimated percentage thereof) would be charged to this liability during an annual period. At the same time, the liability would be accreted at the appropriate rate defined by FIN 47. Any difference between the rollforward of amounts charged to the ARO during the year and the periodic substantiation would be deemed to represent changes in estimate of the asset retirement costs.

Asbestos

Asbestos is a recognized hazardous substance that has specific disposal requirements under law when the asbestos is disturbed. Due to the conditional nature of this disposal requirement, many companies did not record a legal ARO associated with the removal and disposal of asbestos upon the adoption of SFAS 143.

FIN 47 suggests that the FASB believes specific attention should be given to asbestos contamination. Additionally, FIN 47 is very clear in its text that there should be a presumption that no tangible long-lived fixed asset other than land will last forever and eventually the asbestos will have to be removed and disposed of. Accordingly, companies should be very diligent in considering their options for asbestos remediation upon retirement of the fixed asset contaminated by the asbestos. In accordance with FIN 47, each scenario (as to time and method) should be considered and given a probability of occurrence-consistent with the fair value liability approach described in Concepts Statement 7, Using Cash Flow Information and Present Value in Accounting Measurements.

The examples set forth in FIN 47 specifically highlight an instance of asbestos contamination in which the company concluded it could not calculate a reasonable range of scenarios in accordance with the standard. Companies should not use this example as a justification to be complacent about calculating scenarios related to asbestos. Rather, one should consider the evolution of FIN 47 (i.e., asbestos), and diligently set forth reasonable and possible alternatives for disposal and comply with the spirit and intent of FIN 47.

Mass Property

Utilities have certain elements of their fixed assets that represent a substantial number of homogeneous units, often referred to as mass property. Certain of these elements may attach to a legal retirement obligation upon retirement or replacement of the asset. Because these assets are often accounted for under a group or composite method of accounting and depreciation, they may not be tracked separately. This consideration creates a challenge in estimating the costs expected to be incurred to settle the obligation, the period in which the obligation will be settled, and ultimately, determining the difference between the actual costs that are incurred to settle the obligation and the amounts that had been accrued.

As a method of practical application of the provisions of FIN 47 to a regulated utility, a version of the industry “snapshot” approach would be appropriate. With the presumption that prudently-incurred legal costs of removal and disposal will ultimately be allowed in ratemaking by the regulators, the company would perform a periodic substantiation of its legal obligation related to the mass asset property. This substantiation would be performed no less than annually. The precision to which this amount is calculated depends on the company’s property records, but it is critical that each substantiation utilizes current assumptions and projections. Actual legal cost of removal or disposal (or an estimated percentage thereof) would be charged to this liability during an annual period. At the same time, the liability would be accreted at the appropriate rate defined by FIN 47. Any difference between the rollforward of amounts charged to the ARO during the year and the periodic substantiation would be deemed to represent changes in estimate of the asset retirement costs.

Account for an ARO when it becomes Estimable

FIN 47 provides that a company record an ARO related to a legal obligation at a future date if more facts or information become available that allow the obligation to be reasonably estimated. Example 4 in FIN 47 specifically addresses this consideration and provides additional guidance on approach. In that event, the obligation should be recorded similar to as if a new layer has been created using current discount rates, consistent with paragraph A26 of SFAS 143.

Interim Retirements

Utility systems are constructed with many components which ultimately enable the provision of the utility service. As individual components are retired and replaced for any varied number of reasons, these components may have a legal disposal obligation associated with their disposition. Utility depreciation studies often try to provide for depreciation of a class of assets over an average life, quite often tied to an estimate of the
physical or economic life of the component. Consequently, data derived from a recent depreciation study may provide valuable information as a basis for calculating the estimated settlement amount and the period when the settlement will occur for legal obligations associated with an interim retirement.

**Distinction Between Removal and Disposal**

Utility companies often collect amounts in their rates representing a combined cost of estimated removal and disposal for a given class of assets. However, often times, a legal obligation will attach only to the manner in which the asset is disposed. This could result in disposal costs being a part of an ARO but the costs to remove the asset not being an obligation because there is no legal obligation to remove it. It is important to make this distinction because there are many cases where there is no obligation to remove an asset, only an obligation to dispose of that asset in a certain way when the asset is ultimately removed.

**Lease Application**

The determination of whether an obligation to retire (or to bear the cost of retiring) a leased asset should be accounted for as a minimum lease payment (or contingent rental) or as an ARO is a matter of judgment based on analysis of the relevant facts and circumstances. SFAS 13 defines minimum lease payments from the standpoint of the lessee as “the payments that the lessee is obligated to make or can be required to make in connection with the leased property.” Therefore, as a general rule, if the obligation relates directly to the leased asset, or a component of the leased asset, the lessee should account for the obligation in accordance with SFAS 13.

In addition, the SEC staff believes that retirement obligations accounted for under SFAS 13 should not be treated as contingent rentals, as it does not believe that such obligations meet the definition of contingent rentals described in paragraph 5(n) of SFAS 13. If the ARO relates to assets placed in service by the lessee at the leased premises, or are improvements made to the leased property by the lessee during the lease term (i.e., assets (leasehold improvements) that are owned by the lessee), then the lessee should generally account for the obligation as an ARO within the scope of SFAS 143 and FIN 47.

**Rate Recovery**

As discussed previously, many regulated utilities collect amounts associated with costs of removal and disposal, net of related salvage, as a component of ratemaking currently. The amount of removal and disposal costs previously collected, but not representing the cost of a legal obligation, are currently reflected by companies as a regulatory liability in a presentation in accordance with U.S. GAAP. As a company identifies certain conditional AROs that must be recorded pursuant to FIN 47, it must be cognizant of the fact that some or all of the amounts that need to be reflected as a legal obligation may already be resident on the balance sheet as a regulatory liability. Careful consideration is necessary to assure that there is not a double counting of liabilities in the process.

**Impairment Considerations**

With the current economic environment and other industry issues (e.g., transmission constraints and changing environmental requirements), impairment of long-lived assets could become increasingly frequent. As a result, companies should be cognizant of performing impairment analyses. When performing the impairment analyses, a company shall include capitalized asset retirement costs in the evaluation of the assets. However, the estimated future cash flows related to the asset retirement liability should be excluded from (1) the undiscounted cash flows used to test the asset for recoverability and (2) the discounted cash flows used to measure the asset’s fair value.

**Environmental Disclosures**

In the fall of 2007, New York Attorney General, Andrew Cuomo, subpoenaed financial information about Xcel Energy’s public disclosures in filings with the SEC regarding the expected impact of climate change and the regulation of greenhouse gas emissions on the company’s operations, financial condition and plans to construct a new coal plant in Pueblo, Colorado. In August 2008, Xcel Energy agreed to resolve the attorney general’s investigation voluntarily by agreeing to expand and/or continue to provide a discussion of climate change and possible attendant risks in its Form 10-K filings with the SEC.

**Emission Allowance Accounting Guidance**

In recent years there have been several issues involving the accounting for EAs which have arisen. With the increasing focus on environmental matters, EAs will continue to have a prominent impact on an energy company’s accounting.

Due to the diversity in the accounting for EAs and the impact of SFAS 153, *Exchange of Nonmonetary Assets, an Amendment of APB Opinion No. 29*, the FASB had begun work on a limited scope FSP to address vintage year swaps. However, the FASB terminated that project and focused on a wider based project addressing the accounting for EAs. The FASB has added to its agenda a project to provide comprehensive guidance for participants related to EA accounting.
The project is a joint project to provide comprehensive guidance on the accounting issues that arise related to emissions trading schemes, including asset recognition, measurement and impairment, liability recognition and measurement, timing of profit and loss recognition, accounting for vintage year swaps, presentation and disclosure. This project is intended to cover cap and trade and baseline and credit schemes, as well as project-based certificates and renewable energy certificates.

Diversity in Practice

Diversity in practice exists as to whether EAs are classified as inventory, intangible assets, or something else. Because of the current lack of definitive accounting guidance either inventory or intangible asset classification have been accepted. Questions have arisen as to whether EAs should be recorded at fair value or at cost (generally zero) at the grant date, since there is no specific U.S. GAAP literature that addresses accounting for government grants. SFAS 141 and 142 address recognition of intangible assets, inventory, and other assets that are “acquired.”

If EAs applicable to different vintage years are exchanged (sometimes referred to as “vintage year swaps”) and the EAs are classified as intangible assets, the vintage year swap would be accounted for as an exchange at fair value in accordance with SFAS 153. If the EAs exchanged are recorded as inventory, they would be accounted for in accordance with EITF Issue 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty, and SFAS 153 at carryover basis.

Because EAs are generally initially recognized as zero cost when granted, vintage year swaps recorded at fair value could result in the recognition of significant gains on EAs given up and could establish a significant carrying value for EAs received. Swaps of EAs accounted for as intangible assets post-SFAS 153 will need to be assessed to determine if fair value step up is required. It will be necessary to assess the “commercial substance” criterion but the inventory exception (paragraph 20(b)) would not be applicable. We believe there is a presumption that swaps of EAs of the same vintage year or swaps that involve an agreement to subsequently repurchase the same EAs would not satisfy the commercial substance criterion.

EAs are not financial instruments or derivatives and are not subject to the accounting and disclosure requirements related to fair value measurements. EAs are also not eligible for the fair value option election under SFAS 159. Even though EAs are not derivatives, distinction should be made between the accounting for the actual allowance and the accounting for forward or option contracts to buy or sell the allowance. This is important because contracts exchanging EAs may meet the derivative criteria.

The FASB also has a project that will address whether ARB 43, Restatement and Revision of Accounting Research Bulletins, should be amended to require fair value accounting for inventory included in an entity’s trading activities. The FASB has exposed a draft FSP to address public comments related to this issue. Under this proposed FSP, physical inventory included in a company’s trading activities would be initially and subsequently measured at fair value with changes in fair value recognized in earnings. This project is not expected to be applicable to EAs since they are not “physical” assets.

Additional Issues

There are also additional EA accounting issues that have not yet been addressed and result in diversity in practice.

- Revenue recognition – how to account for profits from sales of EAs and whether or not they should be deferred (for example, if the sales result in anticipated short positions based on forecasted future production)?
- Liability recognition – should a liability for future emission costs be accrued and, if so, at what amount?
- Impairments – if the asset is viewed as something other than an intangible asset, what impairment model should be used?
- Expense recognition – what is the appropriate amortization method?
- Trading activities – should EA trading be recorded on a net or gross basis?
- Cash flow presentation – should the EA activities be presented as operating cash flows or investing cash flows?

Impact of Clean Air Interstate Rule Ruling

On July 11, 2008, the United States Court of Appeals for the D.C. Circuit invalidated the CAIR. CAIR was issued by the EPA in March 2005 to address air quality compliance in 28 states in the Eastern half of U.S. CAIR included provisions that addressed SO2 and NOx emissions, in part through a modified cap-and-trade EAs program.

EAs treated as amortizable intangible assets are to be tested for impairment when there are indications, such as those listed in paragraph 8 of SFAS 144, that the carrying amount of the asset may not be recoverable. The recent declines in market prices and the Court ruling are indicators that should trigger an impairment assessment of EA intangible assets. Amortizable intangible assets are tested for impairment in accordance with
SFAS 144. Paragraphs 10 through 14 of SFAS 144 discuss the grouping of assets to be held and used based on the lowest level of independent cash flows. Paragraphs 16 through 22 of SFAS 144 provide guidance on estimating the cash flows used to test recoverability of long-lived assets. Therefore, if EAs are to be used in the generation of electricity, it may be that the carrying value of EAs, property and other long-lived assets should be grouped and compared to the lowest level of independent cash inflows from the electricity. If the EAs are not to be held and used, they would be written down to their fair value (less cost to sell) if that was less than the carrying cost.

EAs treated as inventory are carried at the lower of cost or market. The LCM consideration should be applied to inventories at each reporting period. EAs carried in a trading portfolio would typically be subject to frequent turnover so that their value should approximate fair value at the end of each reporting period. ARB 43 provides guidance on the application of LCM which is generally a comparison to net realizable value. If the EA inventory is to be used in the production of electricity, the net realizable value would generally be based on the estimated amount realizable from the sale of the electricity reduced by other costs of generation and sale of the electricity. If the EA inventory is to be sold rather than used in the generation of electricity, the carrying value would generally be compared to the amount realizable through existing firm sales commitments or expected sales prices (which may be market prices at the balance sheet date).

Deferral of impairments in a rate regulated business would be appropriate if the criteria in paragraph 9 of SFAS 71 are met. Specific facts in each jurisdiction would need to be considered to determine if recovery of the impairment costs is probable at the balance sheet date. Companies must also determine whether the estimated cash flows from the sale of electricity at regulated rates impacts the impairment or LCM evaluations.
SECTION 9

FERC Update

Introduction

This section summarizes the more significant accounting and financial reporting actions recently taken or proposed by the FERC that affect jurisdictional companies.

Docket No. RM06-11-000, Financial Accounting, Reporting and Records Retention Requirements under the Public Utility Holding Company Act of 2005

On October 19, 2006, the FERC issued Order No. 684 amending its regulations to further implement the Public Utilities Holding Company Act of 2005. Specifically, the FERC added a USOA for Centralized Service Companies, added preservation of records requirements for holding companies and service companies and revised the FERC Form No. 60, Annual Report of Centralized Service Companies. The revisions to the FERC Form No. 60 provided for financial reporting consistent with the new USOA and electronic filing of the FERC Form No. 60. The final rule is intended to provide for greater accounting transparency for centralized service companies subject to PUHCA 2005. This final rule provided for an implementation date of January 1, 2008, resulting in the revised FERC Form No. 60 prescribed in this final rule to be first due on May 1, 2009.

Docket No. RM07-9-000, Revisions to Forms, Statements, and Reporting Requirements for Natural Gas Pipelines

On March 21, 2008, the FERC issued Order No. 710 to revise certain natural gas pipeline reporting forms. The Order eliminates the FERC’s Form No. 11 as well as amends the financial forms, statements, and reports for natural gas companies contained in FERC Form Nos. 2, 2-A, and 3-Q. The revisions are designed to enhance the forms’ usefulness to reflect current market and cost information relevant to interstate natural gas pipelines and their customers. The Order is effective for the calendar year 2008 Forms 2 and 2A and first quarter 2009 for the Form 3-Q. The filing date for the Certified Public Accountant Certified Statement on Forms 2 and 2A has been extended to May 18. Form 11 will be required through February 2009 after which the information in the Form 11 will be included in the Form 3-Q.

Docket No. RM07-15-000, Cross-Subsidization Restrictions on Affiliate Transactions

On February 21, 2008, the FERC issued Order No. 707 to codify restrictions related to affiliate transactions for franchised public utilities (“utility”) that have captive customers or that own or provide transmission service over FERC-jurisdictional transmission facilities. Order No. 707 was amended by Order No. 707-A (Docket No. RM07-15-001, issued July 17, 2008). The two orders are collectively referred to as the Order below.

The following entities and contracts are not subject to this Order:

- Electric cooperatives
- Franchised public utilities without captive customers
- Mandatory purchase obligation sales from qualifying facilities under the Public Utility Regulatory Policies Act of 1978

The Order requires the FERC to approve all wholesale sales between a utility and a market-regulated power sales affiliate. It also requires a utility to:

- Sell non-power goods and services to affiliates at the higher of cost or market price, except that utilities that are single-state holding company systems (as defined by FERC) that do not have a centralized service company should sell non-power goods and services normally provided by centralized service companies to affiliates at cost as long as such services are not also sold to third-parties
- Purchase non-power goods and services from affiliates at a price no greater than market price, except that non-power goods and services purchased from a centralized service company are purchased at cost. Non-power goods and services do not include fuel purchases covered by fuel adjustment clause regulations.
- Develop a code of conduct for all power and non power goods and services transactions between the utility and its affiliates.

The purpose of the Order is to protect captive customers from subsidizing the costs of an affiliate of a utility. Many of the requirements of this Order had previously been imposed on utilities by the FERC under FPA Section 203 and 205. However, this Order expands the nature of the transactions to include both power and non power transactions as well as broadens the definition of entities that are subject to the rules.

Captive customers are defined in the Order as “any wholesale or retail electric energy customers served by a franchised public utility under cost-based regulation.” Retail choice customers are not considered to be customers under cost-based regulation and thus are not captive customers.
An affiliate for non-exempt wholesale generator is defined in the Order as “(A) Any person that directly or indirectly owns, controls, or holds with power to vote, 10 percent or more of the outstanding voting securities of the specified company; (B) Any company 10 percent or more of whose outstanding voting securities are owned, controlled, or held with power to vote, directly or indirectly, by the specified company; (C) Any person or class of persons that the Commission determines, after appropriate notice and opportunity for hearing, to stand in such relation to the specified company that there is liable to be an absence of arm’s-length bargaining in transactions between them as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the person be treated as an affiliate; and (D) Any person that is under common control with the specified company…”

Affiliates for exempt wholesale generators have the same definition as non-exempt wholesale generators, except for the following changes: for (A) and (B), the percentage is decreased from 10 percent to 5 percent; (D) is removed; and officers and directors of the entity are added to the definition.

This Order does not require any new or additional reporting to the FERC. Additionally, the Order is prospective and contracts in effect, as of February 29, 2008, the date of Order No. 707, are not required to be amended to comply with the Order.

**Other Orders Related to Affiliate Transactions**

Other orders governing affiliate transactions include Docket No. RM05-32-000, *Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005* (Order 667), Docket No. RM05-34-000, *Transactions Subject to FPA Section 203* (Order 669), and Docket No. RM04-7-000, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities* (Order 697).

**Docket No. RM08-1-000, Promotion of a More Efficient Capacity Release Market**

On June 19, 2008, the FERC issued Order No. 712 to allow market based pricing for short-term capacity release agreements on natural gas pipelines. Prior to this order, in accordance with Order No. 636, short-term capacity release sales could not exceed the natural gas pipeline’s maximum tariff rate. Prices for long-term capacity releases and the natural gas pipelines’ sale of their own primary capacity are not affected by this Order. The Order is effective as of June 19, 2008.

**Short term capacity release**

The Order allows customers to sell their “excess” capacity on the natural gas pipeline at market-based rates for short-term capacity release agreements that are less than one year in duration. These transactions are still required to follow the existing posting and reporting requirements and the FERC will continue to monitor these transactions through the posting of the capacity release transactions.

The Order also allows customers that release their “excess” storage capacity to require the replacement shipper to take the gas that remains in the released storage capacity and/or return the storage capacity to releasing shipper with a specified amount of gas in storage. This requirement was previously not allowed because it was an extraneous condition to the capacity release.

**Asset management agreements**

This Order allows customers to release short-term capacity to an asset manager under a supply or delivery asset management agreement (see definition below) without having to make the capacity release available to any interested party through the posted electronic bidding process on the pipeline websites. The short-term AMA is exempt from the requirements in Section 284.8 that the release of capacity cannot be tied to other conditions to the transaction as long as certain conditions are met. Additionally, under the Order, short-term AMAs that are not subject to price caps may be renewed without competitive bidding by the asset manager and profit sharing arrangements included in an AMA do not violate any applicable price cap.

An AMA, as defined in the Order, is “any pre-arranged release that contains a condition that the releasing shipper may, on any day during a minimum period of five months out of each twelve-month period of the release, call upon the replacement shipper to (i) deliver to the releasing shipper a volume of gas up to one-hundred percent of the daily contract demand of the released transportation capacity or (ii) purchase a volume of gas up to the daily contract demand of the released transportation capacity. If the capacity release is for a period of less than one year, the asset manager’s delivery or purchase obligation described in the previous sentence must apply for the lesser of five months or the term of the release. If the capacity release is a release of storage capacity, the asset manager’s delivery or purchase obligation need only be one-hundred percent of the daily contract demand under the release for storage withdrawals or injections, as applicable."

A supply AMA is an agreement where an entity releases pipeline capacity in the production area to an asset manager. A supply AMA can be excluded from the tying and bidding exemptions described above as long as it requires the replacement shipper to purchase gas from the releasing shipper up to the maximum daily contract demand of the released capacity. A delivery or end user AMA is an agreement where an entity releases pipeline capacity in an area other than the production area to an asset manager.
The Order also allows shippers to purchase gas directly from a supplier and sell that gas to the counterparty in the short-term capacity release AMA. The AMA counterparty will then sell the gas back to the shipper at a designated delivery point. Such transactions are exempt from the buy/sell prohibition in Order 636.

**State retail choice programs**

The Order allows local distribution companies to release capacity to state approved retail access vendors using the same exemptions from the prohibition against tying and the bidding requirements as capacity releases made within an AMA. The capacity released to the retail vendors must be used to provide gas to the retail customers in the state approved retail program.

**Docket No. RM08-5-000, Revisions to Forms, Statements, and Reporting Requirements for Electric Utilities and Licensees**

On January 18, 2008, the FERC issued a Notice of Proposed Rulemaking to revise the financial forms, statements, and reports for electric utilities and licensees, contained in FERC Form Nos. 1, 1-F, and 3-Q. The changes would make additional information regarding implementing formula rates and affiliate transactions available to the FERC and other interested parties. If approved, the revisions are expected to be made to the forms for the 2009 calendar year.

**Docket No. PL07-2-000, Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity**

On April 17, 2008, the FERC issued a Policy Statement related to the determination of the proxy groups used to determine gas and oil pipelines’ return on equity. The policy was issued due to decreasing number of companies that meet the standards to be in the proxy group due in part to the increase in the number of MLPs. The FERC concluded that MLPs should be included in the ROE proxy group for both oil and gas pipelines, but that adjustments to the long-term growth rate are necessary for MLPs in the proxy group. The FERC also concluded that there should not be a cap on distributions or changes in the basis for the short-term growth forecast or short- and long-term growth factors.

**Docket No. PL08-2-000, Interpretative Order Modifying No-Action Letter Process and Reviewing Other Mechanisms for Obtaining Guidance**

On May 15, 2008, the FERC issued a Policy Statement related to how companies communicate with and ask questions of the FERC. In addition to clarification of ways companies can and should communicate with the FERC, the FERC created a compliance help desk on its website so that companies can submit questions regarding compliance with FERC statutes, rules, regulations and tariffs. The compliance help desk can be found at http://www.ferc.gov/contact-us/compliance-help-desk.asp.
SECTION 10

Tax Update

Introduction

This section summarizes FASB, FERC and IRS pronouncements involving accounting for income taxes as well as federal and state income tax developments affecting the financial and regulatory reporting of income taxes. The discussion of IFRS in Section 3 describes the impact of a conversion from U.S. GAAP to IFRS on accounting for income taxes and the explanation of SFAS 141(R) in Section 7 summarizes the forthcoming changes to the rules regarding purchase price adjustments for income tax matters.

FIN 48

In July 2005, the FASB published an exposure draft with proposed guidance intended to reduce the significant diversity in practice associated with recognition and measurement of income taxes by establishing consistent criteria for evaluating uncertain tax positions. In June 2006, the FASB issued FIN 48, which prescribes a recognition threshold and measurement standard for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. On May 2, 2007, FASB issued FSP FIN 48-1, Definition of Settlement in FASB Interpretation No. 48, to clarify when a tax position is considered effectively settled. On May 25, 2007, the FERC issued Docket No. AI07-2-000, Accounting and Financial Reporting for Uncertainty in Income Taxes, regarding implementing FIN 48 for regulatory accounting and reporting purposes. Some states follow the FERC USOA and some states have their own USOA. We expect that those states that are not legally bound to follow the FERC guidance most likely will follow the FERC guidance.

Scope

FIN 48 applies to all tax positions within the scope of SFAS 109. A tax position is a filing position that an enterprise has taken or expects to take on its tax return. Paragraph 4 of FIN 48 provides the following examples of tax position that are within the scope of FIN 48:

- A decision to not file a tax return
- An allocation or shift of income between jurisdictions
- The characterization of income, or a decision to exclude reporting taxable income, in a tax return
- A decision to classify a transaction, entity, or other position in a tax return as tax exempt.

Applying FIN 48 to determine how to recognize tax benefits in the financial statements is a two-step process in which recognition (Step 1) and measurement (Step 2) should be evaluated separately.

Unit of Account

In its evaluation of the appropriate amount to recognize and measure, a company must first determine the appropriate unit of account for the tax position. The appropriate unit of account for determining what constitutes an individual tax position, and whether the recognition threshold is met for a tax position, is a matter of judgment based on the individual facts and circumstances of that position evaluated in light of all available evidence. The determination of the unit of account to be used in applying the provisions of FIN 48 shall consider the manner in which the enterprise prepares and supports its income tax return and the approach the enterprise anticipates the taxing authority will take during an examination. The determination of the appropriate unit of account may be changed to reflect changing circumstances.

Step 1: Whether to Recognize the Tax Benefit

FIN 48 establishes a “more-likely-than-not” recognition threshold that must be met before a tax benefit can be recognized in the financial statements. For each tax position, an enterprise must make a hypothetical assessment: if a dispute with the taxing authority were taken to the court of last resort, is it more likely than not that the tax position would be sustained as filed? If it is, the recognition threshold is met.

Assessing whether a tax position meets the recognition threshold should be based on the technical merits of each position. When making this assessment, an enterprise should presume that the relevant taxing authority will examine the tax position and has full knowledge of all relevant information. Each tax position should be evaluated separately. Accordingly, an enterprise cannot consider the possibility of offsetting or aggregating different tax positions. However, an enterprise may consider certain widely understood administrative practices and precedents of the taxing authority with respect to tax positions that technically are violations of tax law. Two examples of such administrative practices
Thus, aside from FIN 48 versus SFAS 5 measurement differences, the combination of the FIN 48 liability with the remaining, if any, deferred tax asset/liability accounts. Under FIN 48, unrecognized tax benefits related to temporary items are not classified as deferred tax asset/liabilities.

assets/ liabilities computed in accordance with FIN 48 rather than on differences between the financial reporting and tax return bases. Prior to FIN 48, retained earnings were adjusted for income tax credits or interest on tax credits as zero-cost capital in setting rates because they represent interest-free loans from the government to the utility taxpayer. Under FIN 48, FIN 48 amended the definition of temporary difference as provided in SFAS 109. Deferred tax liabilities are normally treated as reductions to rate base or as zero-cost capital in setting rates because they represent interest-free loans from the government to the utility taxpayer. Under FIN 48, deferred tax liabilities are calculated based on the difference between the financial reporting basis of assets/liabilities and the tax basis of such assets/ liabilities computed in accordance with FIN 48 rather than on differences between the financial reporting and tax return bases. Prior to FIN 48, reserves for uncertain tax positions associated with temporary items resulted in an accrual of interest, but did not impact the associated deferred tax asset/liability accounts. Under FIN 48, unrecognized tax benefits related to temporary items are not classified as deferred tax asset/liabilities. Thus, aside from FIN 48 versus SFAS 5 measurement differences, the combination of the FIN 48 liability with the remaining, if any, deferred tax...
liability or with the resulting, if any, deferred tax asset for a given uncertain temporary item will equal the pre-FIN 48 deferred tax asset/liability.

**FERC Guidance on Temporary Differences**

In Docket No. AI07-2-000, FERC described the FIN 48 change in classification with respect to deferred tax liabilities related to uncertain temporary items as frustrating the important measurement objective of pre-FIN 48 deferred tax liabilities as used in determining rate base. FERC continues to use the pre-FIN 48 definition of temporary difference and indicates that recognition of a separate liability for any uncertainty related to temporary differences is unnecessary. The FERC position results in GAAP/FERC balance sheet and income statement classification differences.

**General FIN 48 Guidance on Classification of the Liability for Unrecognized Tax Benefits**

Whether to classify the FIN 48 income tax liability as a current or noncurrent liability depends on when the enterprise anticipates paying cash to settle it. If the enterprise anticipates payment of cash to the taxing authority within one year (or within its operating cycle, if longer) the liability should be classified as a current liability; otherwise, it should be classified as a noncurrent liability. In determining the classification of its FIN 48 income tax liability, an enterprise should consider all relevant factors, including the expected timing of an examination, related appeals, and settlement. Unrecognized tax benefits may not be recorded as deferred tax liabilities or valuation allowances; however, valuation allowances may be affected to the extent FIN 48 alters the amount of a deferred tax asset.

**FERC Guidance on Classification of the Liability for Unrecognized Tax Benefits**

In Docket No. AI93-5, *Accounting for Income Taxes* (April 23, 1993), FERC indicated that it would not follow the SFAS 109 requirement to separately classify the current and noncurrent portions of deferred tax liabilities and assets. Instead, the entire deferred tax liability and asset balances should be recorded in Accounts 190, 281, 282, or 283, as appropriate. FERC’s position regarding the FIN 48 requirement to classify liabilities for unrecognized tax benefits is consistent with its position regarding deferred tax liabilities and assets and results in a GAAP/FERC balance sheet classification difference. In Docket No. AI07-2-000, FERC indicated that companies should not remove from accumulated deferred income taxes and reclassify as a current liability the amount of deferred income taxes payable within 12 months of the balance sheet date.

**General FIN 48 Guidance on Interest and Penalties**

An enterprise should accrue interest and penalties on unrecognized tax benefits in a manner consistent with the tax law. Interest should be computed and accrued based on the statutory interest rate beginning in the first period it accrues under the tax law. As for penalties, if the tax position taken in the tax return does not meet the minimum statutory threshold to avoid penalties, penalties should be accrued in the first period the enterprise claims or expects to claim the position in the tax return. FIN 48 provides choices of where both interest and penalties are classified in the income statement – interest may be classified as income taxes or interest expense, and penalties may be classified as income taxes or another expense, based on an accounting policy election. Enterprises must disclose in the footnotes where interest and penalties are classified.

The SEC staff indicated to the AICPA SEC Regulations Committee that it believes that registrants are not required to submit a preferability letter for changes in financial statement classification of interest and penalties upon adoption of FIN 48 (i.e., in the first quarter of 2007 for calendar year public companies). The SEC staff indicated that a preferability letter is required for classification changes made subsequent to the adoption of FIN 48.

**FERC Guidance on Interest and Penalties**

In Docket No. AI07-2-000, FERC indicated that interest and penalties related to tax deficiencies should be charged to Account 431, Interest Expense and Account 426.3, Penalties, respectively. Further, classification of interest and penalties on tax deficiencies as income taxes is not permitted. Oil pipeline companies should charge interest expense and penalties related to tax deficiencies to Account 660, Miscellaneous Income Charges, and similarly exclude such amounts from classification as income taxes for regulatory accounting and reporting purposes.

An entity electing to treat tax-related interest and penalties as income taxes will either have GAAP/FERC balance sheet and income statement classification differences or need to follow SFAS 154 and obtain a preferability letter in order to change its GAAP policy.

**Disclosures**

FIN 48’s disclosures are required at the end of each annual reporting period presented. Paragraph A33 of FIN 48 provides an illustrative disclosure about uncertainty in income taxes for an entity that has adopted the FIN at the beginning of its year ended December 31, 2007.
In general, an enterprise’s footnotes must disclose a tabular rollforward of the beginning to ending balances of its total unrecognized tax benefits. FIN 48 requires this rollforward to be made on an aggregate basis; disclosing the rollforward on a by-jurisdiction or by-position basis is not required. The unrecognized tax benefits disclosed in the rollforward include amounts recorded as a reduction to deferred tax assets or a component of equity and do not include interest (regardless of an enterprise’s policy as to the classification of interest in its financial statements). The amount of unrecognized tax benefits (as disclosed in the rollforward) that, if recognized, would affect the effective tax rate must also be disclosed. The total amounts of interest income, interest expense and penalties recognized in the statement of operations and in statement of financial position must be disclosed (without consideration of tax effects).

**Effective Date and Transition**

Public enterprises must adopt FIN 48 at the beginning of their first fiscal year that begins after December 15, 2006. The cumulative effect of applying FIN 48 for the first time is recorded in opening retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that fiscal year, presented separately. The cumulative effect adjustment does not include items that would not be recognized in earnings, such as the effect of adopting FIN 48 on tax positions related to business combinations. In the year of adoption, enterprises should disclose the amount of the cumulative effect adjustment recorded in retained earnings.

On February 1, 2008, the FASB issued FSP FIN 48-2, *Effective Date of FASB Interpretation No. 48 for Certain Nonpublic Enterprises*, deferring the effective date of FIN 48 for certain nonpublic enterprises to annual periods beginning after December 15, 2007. Therefore, calendar-year-end nonpublic enterprises eligible for the deferral are required to adopt FIN 48 as of January 1, 2008 and to reflect that adoption in annual financial statements for the year ending December 31, 2008.

On October 1, 2008 the FASB has released guidance to provide disclosure relief for private companies. Disclosures pursuant to FIN 48 paragraphs 21(a) and 21(b) will not be required for private entities. The FASB will issue a proposed FSP with a 30-day comment period regarding the disclosure relief.

Additionally, the FASB decided to defer the effective date of FIN 48 for pass-through entities to periods beginning after December 15, 2008, allowing for additional guidance to be issued regarding the application of the Interpretation. The FASB will issue a proposed FSP with a 30-day comment period regarding the deferral.

Entities that have already issued either interim or full-year financial statements in which they adopted FIN 48 must continue to apply the requirements of FIN 48.

**Normalization – Deregulation and Asset Sales**

On March 19, 2008, the IRS issued final regulations (T.D. 9387) concerning the application of the normalization requirements with respect to excess deferred federal income tax and accumulated deferred investment tax credit to assets that cease to be public utility property, whether by deregulation, disposition or otherwise. The IRS issued a correction to a portion of the ADITC regulations on April 7, 2008. The final regulations effectuate the change in policy first articulated by the IRS in proposed regulations issued in March 2003 and modified in re-proposed regulations (withdrawing the 2003 proposed regulations) in December 2005. The former policy of the IRS, prohibiting any sharing of EDFIT or ADITC with ratepayers after deregulation or an asset sale (by the seller or the buyer), was consistently applied in private letter rulings issued in the 1980s and 1990s and after the 2005 re-proposed regulations.

The final regulations do not affect the normalization rules applicable to “regular” ADFIT liabilities. In the case of a taxable sale of public utility property, pre-disposition ADFIT is no longer available to the seller or the buyer to reduce rate base or to be treated as a source of zero-cost capital. The loan from the government in the form of deferred taxes is repaid via current tax expense and, thus, the ADFIT no longer exists and should not be considered in ratemaking.

The taxable asset sale transactions covered by the final regulations include “straight asset sales,” stock sales with Section 338(h)(10) elections and sales of interests in disregarded entities. The final regulations do not apply to “normal retirements.” “Pure stock transactions” (whether taxable or tax-deferred to the shareholders) and corporate mergers are not within the scope of either the body of private letter rulings issued in the 1980s and after the 2005 re-proposed regulations.

The final regulations retain the basic rule of the 2003 proposed regulations and the 2005 re-proposed regulations with respect to EDFIT, permitting EDFIT to reduce ratemaking tax expense after the disposition or deregulation of public utility property by the amount by which the EDFIT reserve would have been reduced had the property remained public utility property and the taxpayer continued use of its normalization method of accounting (i.e., the average rate assumption model or the reverse South Georgia method). The final regulations recognize that in the case of sales of property to another regulated public utility, it may be more convenient for the parties if the protected pre-disposition EDFIT is
treated as that of the buyer (e.g., the seller may no longer have a billing relationship with the affected ratepayers). In these situations, the buyer rather than the seller reduces its ratemaking tax expense in order to continue sharing this tax benefit with ratepayers.

The final regulations are generally consistent with the 2005 proposed regulations with respect to ADITC. Utilities may continue to share ADITC benefits with ratepayers to the extent that ratepayers contribute to the cost of the disposed or deregulated public utility property via stranded cost recovery, a surrogate for regulatory depreciation expense. The final regulations are less favorable to utilities than the body of private letter rulings, but not as beneficial to ratepayers as the 2003 proposed regulations. The extent and timing of stranded cost recovery affects the portion of the ADITC ultimately shared with ratepayers; specifically, the rate at which the ADITC is shared via reduction to rate base by Option 1 taxpayers and the reduction to regulatory tax expense by Option 2 taxpayers. Under the final regulations, the rate of sharing of ADITC is based on the dollar amount of rate recovery, not on the regulatory life of the subject property.

The final regulations generally apply to public utility property that ceases to be public utility property by reason of deregulation, disposition or otherwise after December 21, 2005, the date that the re-proposed regulations were published. The final regulations also retain the transition rule of the 2005 re-proposed regulations providing that flowthrough of EDFIT and ADITC consistent with the 2003 proposed regulations will be permitted during the period March 5, 2003, through the earlier of the last date on which the utility’s rates are determined under the rate order in effect on December 21, 2005, or December 21, 2007. The new rules in the final regulations pertaining to assets that become public utility property of a rate-regulated transferee apply prospectively to transactions after March 19, 2008.

Among the issues not addressed by the final regulations are:

- Transfers to rate-regulated partnerships (or limited liability companies)
- Sales at a gain – treatment of ADITC by transferors

**Normalization - Deferred ITC**

During 2008, the IRS issued several private letter rulings related to the amortization of ADITC under Option 2. Under Option 2, ADITC may not reduce rate base, but the related amortization may reduce the tax provision no more rapidly than ratably over the regulatory lives of the assets. Ratably is defined as the period of time used to compute the taxpayer’s regulated depreciation expense. Regulations provide that this depreciation expense must be determined based upon the period of time the assets are used by the taxpayer, without reduction for salvage value or other items.

PLR 200802025 and PLR 200802026 were issued with respect to the rate at which deferred investment tax credits may be amortized under Option 2. Historically, the taxpayers determined depreciation expense for regulatory purposes by applying a composite annual percentage rate. For example, the composite rate for a utility plant asset which is depreciated straight-line over a 40-year period would be 2.5 percent ($100 asset ÷ 40 = $2.50 per year). The taxpayers determined the composite annual percentage rate based on the average useful life of the assets, adjusted for negative net salvage, or the excess of the estimated cost to retire or remove the asset over the estimated salvage value. The taxpayers used the composite depreciation rate to calculate ITC amortization for ratemaking purposes. This resulted in more rapid amortization than is permitted under the normalization requirements.

PLR 200811004 was issued with respect to the rate at which deferred investment tax credits may be amortized under Option 2. The IRS addressed a situation in which the taxpayer extended the depreciable life of a nuclear power plant, but did not make the corresponding adjustment to the rate at which ADITC was amortized. Several years later, the company realized the error occurred and recorded adjustments to correct the excessive ADITC amortization.

In each of these PLRs, the IRS exercised its discretion to not apply the ITC recapture or disallowance sanctions to these companies because the errors were inadvertent and the commissions neither ordered the treatment nor were aware of the mistake. The IRS indicated that its analysis would not apply to rate orders finalized after the dates of the rulings.

**Normalization – Section 199 Deduction**

The Section 199 production deduction is a permanent tax benefit that results in a deduction of a specified percentage or a taxpayer’s qualified production activities income. The provision is a phased-in deduction of up to nine percent of the income attributable to qualified production activities, which includes income from the lease, rental, sale, exchange or other disposition of electricity, natural gas or potable water produced in the U.S. The production deduction is not applicable to income attributable to the transmission and distribution of electricity, natural gas and water. The deduction is available in tax years beginning after December 31, 2004. In 2008, a calendar year taxpayer may deduct six percent of the lesser of: (1) QPAI or (2) taxable income, limited, however, to fifty percent of the W-2 wages paid by the taxpayer. In this context, taxable income is calculated after deduction of a net operating loss carryforward or carryback. QPAI in excess of the deduction limitations may not be carried forward or back. Tax depreciation related to generation or other manufacturing activities is taken into account in calculating QPAI. Neither the Internal Revenue Code nor the regulations under Section 199 addresses whether the production deduction is subject to the normalization
requirements for depreciation and deferred taxes.

PLR 200833014 was issued to a utility that had no federal income tax liability and, thus, no Section 199 benefit, for its test year due to an NOL carryover. The regulatory commission’s rules did not permit the commission to take into account an NOL deduction in determining the income tax component of a revenue requirement. The regulatory commission made a pro forma adjustment in calculating regulatory income tax expense for the test period, including elimination of the NOL deduction and imputation of a Section 199 deduction. Imputation of a Section 199 deduction had the effect of reducing regulatory tax expense and the revenue requirement.

The IRS held that the Section 199 deduction is outside the scope of the normalization requirements and that the specific pro forma tax adjustments did not violate the normalization requirements. The normalization requirements were not amended or expanded upon enactment of Section 199 in 2004 and, thus, the ruling is not surprising. The ruling provided a strained analysis, not essential to its conclusion, describing Section 199 benefits as not the type of tax benefit intended to be within the scope of the normalization requirements. The ruling added that the IRS was not concluding that use of a pro forma federal income tax liability in computing a revenue requirement is never violative of the normalization rules. The ruling did not address how the commission treated or should have treated the deferred tax asset related to the NOL carryover in calculating rate base.

State Income Taxes


TMT

On May 18, 2006, the State of Texas enacted House Bill 3 which replaced the State’s franchise tax with a “margin tax,” referred to in this discussion as the TMT. House Bill 3 was amended for technical corrections on June 15, 2007, with the enactment of House Bill 3829. The TMT is imposed on corporations, partnerships, limited liability companies, business trusts and other legal entities. The tax is computed on a unitary group basis using a “greater than 50%” ownership test and is assessed at 1 percent of Texas taxable margin (except qualifying entities primarily engaged in retail or wholesale trade are assessed at 0.5 percent). However, taxable entities providing retail or wholesale utilities are not eligible for the 0.5 percent tax rate. The taxable margin is computed as the lesser of: (1) 70 percent of total revenue or (2) total revenue less, at the election of the taxpayer, the greater of: (a) cost of goods sold or (b) compensation.

The starting point for calculating a corporation’s revenue is total income from lines 1c and 4 through 10 of IRS Form 1120, less bad debts, foreign royalties/dividends, income from pass-through entities, and certain Form 1120 Schedule C deductions. Cost of goods sold includes direct costs of acquiring or producing real or tangible property and certain other related costs. The TMT contains detailed lists of expenses that are specifically included and expenses that are specifically excluded from cost of goods sold. Compensation expense generally includes wages, cash compensation, employee benefits, and certain stock awards. However, the wage and cash compensation components are limited to a total of $300,000 for any person.

Although House Bill 3 stated that the TMT “is not an income tax,” the tax is determined by applying a tax rate to a base that considers both revenues and expenses. Further, the expense that is taken into account (either compensation or cost of goods sold) will typically be the single largest expense in determining net profit. Therefore, it has characteristics of an income tax. SFAS 109 should be applied even when an entity estimates that its tax will be based only on revenue (i.e., when it expects 70 percent of revenue to be less than 100 percent of total revenue less cost of goods sold or compensation).

Assets and liabilities may have differing Texas tax basis depending on the base used to compute the TMT (i.e., revenue only, revenue less cost of goods sold, or revenue less compensation). Based on paragraph 1b of SFAS 109, an enterprise shall recognize a DTL or DTA for all temporary differences. Based on paragraph 18 of SFAS 109, a deferred tax asset or liability should be measured using the enacted tax rate(s) expected to apply to taxable income in the periods in which the deferred tax asset or liability is expected to be realized or settled. Therefore, if an entity expects to be subject to more than one measure of taxable margin in the future, it may be required to schedule the reversal of applicable temporary differences in order to measure the related Texas deferred tax asset or liability.

The TMT also provides for a temporary credit that can be claimed against tax due. An entity may take a credit based on unexpired business losses established under the previous franchise tax regime. The total credit is computed by multiplying the unexpired business losses by 4.5%. The credit can be utilized at a rate of 2.25% for each of the first 10 years and 7.75% for each of the subsequent 10 years. There are limited carryover rules and the credit expires September 1, 2027. The temporary credit should be recognized as a deferred tax asset (subject to realizability under SFAS 109).

The TMT replaces the Texas franchise tax and is effective for returns originally due on or after January 1, 2008. For calendar year companies, the new TMT model would be applied to 2007 activity. As required by paragraph 27 of SFAS 109, all effects of a tax law change should be accounted for in the period of the law’s enactment (i.e., the reporting period that includes May 18, 2006).
MBT

For taxpayers that are not statutorily defined as an “insurance company” or as a “financial institution”, the MBT is based on a combination of the following two components:

- A business income tax, imposed originally at a rate of 4.95 percent; and
- A modified gross receipts tax, imposed originally at a rate of 0.80 percent.

Subsequent amendments added a book-tax difference deduction and a surcharge to the MBT. The new deduction from the business income tax base is available beginning in the 2015 tax year and extends through the 2029 tax year. It is computed with reference to the pre-apportioned book-tax basis differences on which the business income tax and modified gross receipts tax deferred tax liabilities are determined.

For a taxpayer not statutorily defined as an “insurance company” or “financial institution,” an annual surcharge is levied equal to 21.99 percent of the taxpayer’s MBT liability after allocation or apportionment, but before calculation of credits. In effect, the surcharge increases the business income tax rate from 4.95 percent to 6.0385 percent and the modified gross receipts tax rate from 0.8 percent to 0.976 percent. The surcharge shall not be imposed or levied after January 1, 2017, if specified criteria regarding the economic growth of Michigan are achieved.

The MBT includes various credits applicable to taxpayers with operations in Michigan. Three of the most significant credits include a wage credit for compensation, an investment tax credit, and a research and development credit. The surcharge cannot be offset by any of these three credits. Further, a taxpayer’s aggregate wage and investment tax credits are limited to 50 percent of its liability in the 2008 tax year and 52 percent in subsequent tax years while the research and development credit is limited to 65% of its liability in the 2008 and subsequent tax years.

The MBT replaces the Michigan Single Business Tax and is effective January 1, 2008. As required by paragraph 27 of SFAS 109, all effects of a tax law change should be accounted for in the period of the law’s enactment (i.e., the reporting period that includes July 12, 2007). The deferred tax effects of the MBT must be computed separately for the business income tax and modified gross receipts tax as each element of the MBT will treat differently the recovery of certain assets and the settlement of certain liabilities at their financial reporting carrying values. The book-tax difference deduction was enacted to offset the deferred tax liabilities recognized upon the enactment of the MBT. This deduction from the business income tax base results in a deferred tax asset that must be analyzed for realizability in view of the likely timing differences between when the deduction is available and when the net deferred taxes otherwise reverse (i.e., need for a valuation allowance) as well to account for potential changes in MBT apportionment and potential changes in the business income tax rate (or surcharge rate) between now and when the deduction is available beginning in the 2015 tax year.

Accounting for Income Tax Benefits of Dividends on Share-based Payment Awards

Entities may pay dividends (or dividend equivalents) to employees holding employee-held equity-classified nonvested shares, nonvested share units, or outstanding share options (i.e., “affected securities”). Such dividends are treated as dividends for financial reporting purposes, but generally are deducted as compensation for tax purposes, resulting in a “permanent” tax benefit. At issue is how a realized tax benefit associated with dividends (or dividend equivalents) that are paid to employees holding affected securities and charged to retained earnings under SFAS 123(R) should be recognized.

In 2006, the EITF reached a tentative conclusion in EITF Issue 06-11, Accounting for the Tax Benefit of Dividends on Restricted Stock and Option Awards, that an entity should recognize, as an increase to additional paid-in capital, a realized tax benefit related to in-scope dividends (or dividend equivalents). Amounts recognized should be included in the pool of excess tax benefits available to absorb potential future tax deficiencies on share-based payment awards (i.e., the “additional paid-in capital pool”). However, to the extent a tax benefit is not realized at the time the dividends (or dividend equivalents) are paid (e.g., situations in which an entity has a net operating loss carryforward), the income tax benefit should not be recognized until the deduction reduces taxes payable (i.e., until the tax benefit is realized). Unrealized amounts are not included in the APIC pool.

At its June 14, 2007 meeting, the EITF reached a consensus that an entity should recognize a realized tax benefit associated with dividends on affected securities charged to retained earnings as an increase in APIC. The amount recognized in APIC should be included in the APIC pool. When an entity’s estimate of forfeitures increases or actual forfeitures exceed its estimates, the amount of tax benefits previously recognized in APIC should be reclassified into the income statement; however, the amount reclassified is limited to the APIC pool balance on the reclassification date.

On June 27, 2007, FASB ratified the consensus reached by the EITF. The guidance applies prospectively to the income tax benefits of dividends declared on affected securities in fiscal years beginning after December 15, 2007, and interim periods within those fiscal years. Earlier application is permitted as of the beginning of a fiscal year for which interim or annual financial statements have not been issued.
FSP FAS 13-2, Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction

In June 2006, the FASB issued FSP FAS 13-2, Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction. The FSP provides guidance on a change or projected change in the timing of income tax cash flows relating to a leveraged lease as a result of a settlement or expected settlement with the IRS. Such a change shall result in a recalculation, at inception, of the lease rate of return and the allocation of income to positive investment years, which is consistent with guidance in paragraph 46 of SFAS 13. The accounts constituting the net investment balance should be adjusted to conform to the recalculated balances, and the change in the net investment shall be recognized as a gain or loss. The FSP applies only to changes or projected changes in the timing of income taxes that are directly related to the leveraged lease transaction and shall be applied to fiscal years beginning after December 15, 2006.

Only tax positions that meet the FIN 48 more-likely-than-not recognition threshold at the date of adoption of this FSP shall be reflected in the financial statements. In addition, all recognized tax positions in a leveraged lease must be measured in accordance with FIN 48 at the date of adoption of this FSP. If, at the date of adoption, the application of FIN 48 causes a change in the recognition or measurement of the tax position, that change shall be considered a change of an important assumption as of the date of adoption of the FSP. The cumulative effect of applying the provisions of this FSP shall be reported as an adjustment to the beginning balance of retained earnings as of the beginning of the period in which this FSP is adopted.

If the actual or expected timing of income tax cash flows is revised, the rate of return and income allocation should be recalculated from lease inception using the revised assumptions. The recalculation would include actual cash flows that occurred up to and including the point of the actual settlement or expected settlement and the estimated cash flows thereafter. Additionally, the recalculation would not include any interest and penalties assessed or expected to be assessed by the taxing authority.

The FSP requires a lessor to reevaluate the classification of a leveraged lease when a recalculation is required to reflect changes in timing of income tax cash flows. The change in assumptions may result in a situation in which the lease would not have originally qualified as a leveraged lease if the revised assumptions had been used at inception. If this occurs, the lessor should reclassify the lease prospectively as a direct financing lease as of the date the change in assumption occurs. The lessor would separately report (1) its investment in the direct financing lease, (2) the nonrecourse debt, and (3) the deferred taxes related to the direct financing lease on its balance sheet, as if the lease had been classified as direct financing since inception. The difference between these balances and the balance of the net investment in the leveraged lease prior to recalculation would be reported as a gain or loss in the period of change. The gain or loss would be included in income from continuing operations before income taxes in the same line item in which leveraged lease income is recognized.

If the recalculation does not change the classification of the lease, the net investment balance would be adjusted. Any gain or loss would be recorded in the period of change in income from continuing operations before income taxes in the same line item in which leveraged lease income is recognized. The tax effect of the recognized gain or loss shall be included in the income tax line item.

The FSP does not amend EITF Issue 86-43, Effect of a Change in Tax Law or Rates on Leveraged Leases, which indicates that when an enterprise applies paragraph 13 of SFAS 13 and recalculates all components of a leverage lease because the after-tax cash flows of the leveraged lease have changed, the cumulative effect on pretax income and income tax expense, if material, should be reported as separate line items in the income statement. Because FSP FAS 13-2 clarified that the timing of the cash flows related to income taxes generated by a leveraged lease is an important assumption (just as a change in tax rates had always been), this guidance should be applied by analogy.

The IRS continues to challenge the ability to accelerate the timing of tax deductions in lease-in/lease-out and sale-in/lease-out leveraged lease transactions. During 2008, the courts issued several taxpayer-adverse opinions relating to these transactions. These decisions may constitute new information regarding the technical merits of an uncertain tax position that would change previous assumptions used and conclusions reached under FIN 48 and FSP FAS 13-2. For example, adverse court opinions may provide additional information affecting a company’s assessment of (1) whether it will be successful in its litigation in measuring the associated tax benefits and interest and penalties under Interpretation 48 and (2) the timing of cash flows relating to income taxes generated by the leveraged lease under FSP FAS 13-2.

Further, on August 6, 2008, the IRS announced a settlement initiative for LILO and SILO tax shelters. Although settling with the Service may not change a transaction’s total taxable income over the lease term, it would likely result in a change in the timing of when tax benefits are realized.
SECTION 11

Information Technology

Advanced Metering Infrastructure and Home Area Networks

The utility industry is currently in an era offering options for true transformation of the relationship that the utility has with its customers. For many years, the customer relationship was limited to two primary touch points:

- Billing on a monthly basis
- Fielding and addressing customer complaints or issues as they arise

For the most part, as long as the lights came on when a switch was flipped, the customer was satisfied and paid their bills on a timely basis. The introduction of AMI and the extension of AMI into HAN has the potential to take the customer relationship to a whole new level: to allow better management of energy; to enable new tariff structures better matching customer demographics; to enhance the efficiency and effectiveness of customer service; and, to provide the foundation through which the utility and the customer can work together to contribute to a more “green” society.

It’s important for utilities to focus on these initiatives in the coming years, as the expectations of customers for their utility are evolving from the classic supplier-consumer model to one based on a two-way cooperative partnership. The successful utility will be one that embraces this change and uses the opportunity to transform the customer relationship.

Advanced Metering Infrastructure

Investments in AMI have seen a very large growth over the past five years and momentum continues to grow in the industry. The early years of AMR demonstrated that it’s possible to eliminate the need to visit every customer premise once a month to collect the billing read, and AMR systems became commonplace in the industry, justified mainly by the avoided labor cost of manual meter reading. Since these systems were primarily one-way in nature, the functionality available was limited and some utilities with lower labor costs for manual reading struggled to make a business case for AMR implementation.

As technology advances continued, vendors focused less on AMR technology, and more on two-way AMI technology. Utility commissions began studying the potential of AMI systems, and many saw the potential value to the customer if the vision of AMI could truly be realized. Automation was no longer simply about the monthly meter reading process to support billing on a standard rate. The AMI systems of today allow for considerable functionality that is transforming the customer relationship. Examples of this enhanced functionality include:

- **Time Of Use Rates**: AMI systems allow for the collection and processing of many consumption intervals throughout the day (most commonly hourly, but 15 minute intervals are also possible). The utility can now establish tariff structures that incent customers to shift usage out of peak periods and into off-peak periods. This not only allows the customer to save money, but also assists the utility in managing demand during those peak periods. Customers are offered a variety of rate plans and can pick one that best matches their needs and lifestyle. Tools are made available on the utility websites to aid customers in selecting the plan that’s right for them.

- **Critical Peak Pricing**: Significant focus is put on avoiding those few days a year when system loads become critical for the utility. By offering Demand Response programs centered around CPP, utilities have the ability to proactively shift load on a CPP day through communication with the customer. Customers will elect to participate in the CPP program, which provides them incentives (discounts) on their monthly bill. When a CPP day is declared, the price per kWh that day will dramatically increase for those customers participating in the program. The increase in cost will be so significant that customers will do everything possible to keep consumption on those days to as low as possible – thereby lowering the strain on the grid.

- **Enhanced Customer Service**: Without AMI in place, the only way to triage and diagnose an outage at a customer premise is normally rolling a truck. Frequently, the problem ends up not being something related to service at the house – but is instead an issue within the premise itself (such as a tripped circuit breaker or a tripped main breaker). AMI allows a Customer Service Representative to remotely perform diagnostic triage in an attempt to identify whether the outage is in fact the responsibility of the utility or the customer. They can remotely interrogate the meter and perform status checks to determine if service is operational through the meter. If so, they can assist the customer in diagnosing potential causes without the expense of a truck roll.

- **Remote Connect & Disconnect**: The cost associated with visits to connect and disconnect service at a premise are significant. For certain situations such as college campuses which have a very high number of move-ins / move-outs during a short period of time, it’s prohibitive to visit every premise each time. This leads to lost revenue when service is active and being used when no customer has activated it. AMI allows authorized users at the utility (following strict safety guidelines) to utilize the technology to remotely disconnect or connect service as appropriate without the cost of a physical visit to the premise.
These above areas all provide cost savings to the utility, as well as increased levels of customer functionality and service. With many commissions being receptive to AMI solutions, it’s important for utilities to start evaluating an AMI program, if they haven’t already.

However, these benefits may prove elusive if the utility does not thoughtfully approach the design and planning of the technical architecture to support AMI. The technical communication for AMI solutions can be supported on a variety of technical transport layers, with vendors offering solutions based on Wireless RF Mesh, Power Line Carrier, Broadband over Power Line, and most recently WiMax. It’s important for utilities to select a technology (or mix or technologies) that best matches its functionality needs, geographic territory, and customer demographics. Without the right level of due diligence up front, there is potential that the system won’t live up to its expectations – causing potential increased cost to both the utility and the customer if a migration to a different technology is required.

Home Area Networks

Over the past few years, AMI has been expanded to often include HAN functionality. Utilities, utility commissions, and vendors have been looking for ways to increase customer capabilities, and the introduction of HAN functionality is an exciting, transformational direction for the industry. HAN capabilities go hand-in-hand with AMI capabilities. The AMI meter becomes a gateway into the home, providing a communications vehicle for numerous potential in-home devices including:

- Programmable communicating thermostats
- Remote appliance controllers
- In home displays

Communication between these devices is commonly provided through use of industry standard approaches based on the ZigBee® (wireless) and/or HomePlug® (wired) standards. In recent months, a number of large utilities have started working with the ZigBee and HomePlug alliance groups to collaboratively develop a single application standard that will allow for a more seamless integration across both transport mechanisms. The most exciting aspect of this is that the vendors and alliance groups are more and more often working together with utilities to develop standards and solutions that meet the increased needs of the industry. For utilities that are able to get involved in AMI and HAN programs today, there is a huge advantage in that vendors are investing heavily to jointly develop solutions with a great deal of input from the industry.

The HAN functionality is key when looking to achieve as many benefits as possible from the AMI framework. For example, implementing CPP programs can only occur if there are convenient and acceptable ways to notify a customer of the peak event about to occur, and allow them to effectively make decisions on what action to take. The CPP signal can be sent across the AMI network, utilizing the meter as the ZigBee gateway into the home to reach the Programmable Communicating Thermostat.

Rules can be setup within the PCT on actions to be taken in the event pricing signals are received – such as increasing the temperature in the home significantly to avoid air conditioning usage. In addition, Remote Appliance Controllers can be attached to large-load devices such as pool pumps or water heaters to cycle them off during an event.

Remote access into the HAN may also be enabled, allowing customers to manually take actions if desired while away from their homes. In the current age, this is something that customers will expect and something that utilities need to account for. The success of the enhanced customer programs will only be realized if the relationship with the customer becomes one of trust and partnership. The technologies are now becoming available to make this happen, and we cannot miss the unique opportunity that now presents itself.

Summary

Although there has been a buzz in the industry over the past five years related to AMI and HAN, it’s only recently that the products and solutions have reached a maturity level where all utilities should moving forward with the appropriate analysis around how best to leverage these advances to transform the relationship with their customers. AMI and HAN initiatives are transformations not only for the customer relationship, but for the utility as a whole. For utilities that choose to embark on this path, it will lay the groundwork for future expansion into SmartGrid initiatives, and serve as the foundation for the utility of the future.
Enterprise Asset Management

Increasing competition has forced energy companies to develop capabilities to maximize the value that can be derived from their assets. In the evolving utilities market, asset and work management strategies continue to gain in importance as they are some of the most effective tools available to help utilities reduce costs and increase return on investment. EAM encompasses the strategies, technologies and processes to optimize lifecycle value contribution from utility asset portfolios.

Business executives and asset managers are looking for ways to improve the overall performance of their assets – in effect, how do I "do more with less"? Here are few of the challenges facing them:

- Are we optimizing the performance of our entire asset portfolio, or just optimizing discrete asset lifecycle components, thus sub-optimizing the overall portfolio?
- How do we ensure investment dollars are being allocated wisely?
- How can technology be leveraged to enable asset managers to make better business decisions?

EAM is best illustrated in asset intensive industries with a disparate asset base such as utilities. Utilizing EAM philosophies, companies are able to begin to utilize an asset portfolio management philosophy to truly drive shareholder value.

APM

APM attempts to capture and analyze the relationships among the drivers of shareholder value at the asset portfolio level. It provides management with a well-informed, multi-dimensional picture to help make efficient asset investment decisions that optimize the total enterprise shareholder value.

Utilities often fail to realize that optimizing individual asset performance does not always create optimal enterprise value—even though local asset level performance might be aligned with the overall corporate strategy. More often than not, financial performance data is collected and analyzed at an asset level, while the ultimate corporate goal is to optimize business performance at a portfolio level. The disconnect between local asset optimization and shareholder value comes from operating in a multiple-asset, multi-dimensional, complex business environment, while trying to make investment decisions using "two-dimensional" data. A utility ultimately consolidates the financial results of its portfolio of assets into a single set of financial statements.

Under the APM approach, the elements of shareholder value are analyzed to create a visual map linking the creation of shareholder value to strategy, projects and day-to-day operations. APM uses a framework that identifies and captures the relationships among value drivers at the portfolio level. APM, thus, provides a comprehensive multi-dimensional view of corporate performance, from the perspective of a single value-creating entity, thereby supporting portfolio-investment decisions with a unified powerful direction.

At the core of APM is the shareholder value map, which analyzes shareholder value in terms of its components and drivers. In an asset portfolio, each individual asset’s contribution to shareholder value is determined by its effect on four basic components: revenue growth, operating margin, asset efficiency, and expectations. The brief working definitions of these key components are:

- **Revenue Growth**: Improvement in the company's top line, including payments received from customers in exchange for products and services. This is a key measure of operational effectiveness.

- **Operating Margin**: The portion of revenue left over after taxes with the cost of providing goods and services subtracted. This is a key measure of operational efficiency.

- **Asset Efficiency**: The value of assets used to run a business relative to its current revenues. This is a key measure of investment efficiency.

- **Expectations**: The confidence shareholders, analysts and other stakeholders have in the company's ability to perform well in the future.

Managers at an asset level take actions to maximize shareholder value by improving the asset's impact on internal value mechanisms. But a utility company can take actions to improve one of the shareholder value drivers—asset efficiency—and can target a broad set of areas across the company for improvement. There are many levers that a company can use to improve overall shareholder value through targeted projects. This is achieved by allocating investment resources among potential shareholder value improvement projects. At a power generation plant, for example, management may choose to upgrade old equipment and reduce unplanned outages in order to increase production, as well as reduce maintenance costs. In another instance, the best return on investment might come from improved receivables management through better invoicing, bill-to-pay processes and systems. Most of these shareholder value improvement levers can be enabled by technology solutions.
Technology

Technology plays a critical role in enabling asset managers make better business decisions. The next generation of asset management applications will be able to source data from different systems and transform the data to produce and present information relevant to the asset manager or to the line worker to support timely and effective decisions. Some of the major decision making challenges facing utilities from an IT perspective are:

- To improve visibility of information across functions and throughout the asset lifecycle
- The need for real-time information
- The ability to make information available to support decisions
- The need to improve integration of disparate systems

In order to effectively deal with the issues identified above, utilities require a shift in their application strategy and architecture. The application strategy should enable efficient business processes; should transform volumes of data into information that is easily accessible across the fleet for better decision making; and, should be scalable to support business growth. A few guiding principles for an effective application strategy and architecture are:

- IT initiatives should have an executive business sponsor
- Architecture should promote common fleet processes but allow for graded approaches throughout the fleet.
- IT projects should be done in conjunction with process/business transformation
- Redundant data should be eliminated and data managed towards a single “version of truth”
- The business units and IT should partner to deliver information systems and maintain a low total cost of ownership
- Implemented information systems should be organizationally neutral
- Implement commercial off the shelf software products without customization
- Focus on information delivery to support decision making – the right information delivered to the right resources in the proper timeframes

In addition, the application architecture must support the overall business objectives. For example, the business objective to quickly and efficiently assimilate and integrate new acquisitions would require application architecture to be scalable and flexible. Another example is that the architecture must be able to transform large volumes of data into analytical and decision making information in order to support the objective of reducing forced outages. However, the biggest challenge is to tie asset plant information together across the entire portfolio of assets, and technology plays a pivotal role in this process. Key steps in the process are:

- **Get control of asset data and build around a standard equipment hierarchy:** The first action is to establish a solid, stable platform for Fleet Asset portfolio management. Common processes performed in a consistent manner across the fleet are required. In addition, the standard equipment hierarchy provides a consistent taxonomy for identifying assets and equipment across the Fleet.
- **Automate the process:** Processes such as collecting timely asset condition information and work order initiation, execution and close-out need to be automated.
- **Use data analysis tools:** Analytical tools enabled by technology are needed to support both near real time decisions and longer commercial decisions, such as run to failure.
- **Build condition monitoring and predictive maintenance capability:** The ultimate goal of predictive maintenance is to perform maintenance “just in time”, before the equipment fails in service. Time based maintenance is labor intensive, ineffective in identifying problems that develop between scheduled inspections and, in general, is not cost effective. Condition Based Monitoring is a key enabler, integrating real time performance and control room information to enable faster reactions to critical condition data (for example, boiler overheat, breaker trip, etc). This capability improves both safety and financial performance.
- **Provide useful asset information to Asset Managers:** Effective presentation makes the wealth of information usable and available.
Summary

To summarize, EAM is the strategic process to achieve maximized value of the company’s assets. EAM is not just a technology solution, but a business transformation effort that utilities can undertake to move up the Asset portfolio maturity matrix. This requires a shift in focus from plants and equipment at locations to asset portfolios; and, requires an integrated model for all aspects of operations enabled by technology.

Business Intelligence and Enterprise Performance Management

For years, power & utility organizations have struggled with measuring and reporting on their performance. The approaches tried, and the “buzzwords” used, to try to tackle these issues are endless: balanced scorecard, focused financials, simplification, integrated performance management, financial performance management, key performance indicators, key risk indicators, key compliance indicators, corporate performance management, business performance management, operations performance management, enterprise performance management, etc. Search the internet for balanced scorecard and you get thousands of hits. Performance management gets millions. So many terms and so much written on different aspects of a relatively simple concept – planning the work and measuring whether or not you did it. However, the tide may be turning.

Rapid Developments in 2008

Over the past 12 months there has been an increased focus on business intelligence tools and in particular on using meaningful information to get a better return on the asset base. Recent purchases of the providers of these tools, including Business Objects, Outlooksoft and Hyperion, by the big business software vendors (usually called enterprise resource planning or ERP software) have bought the development and marketing capabilities of those formidable companies into play and have created a buzz in the both the software and energy industries. With new versions of the software due in late 2008/early 2009, the promise of real time on line performance management once again has CEO’s asking ‘why can’t I have this’. More often than not they are asking the CFO this question and as such it has become a prime concern in the finance function.

True enterprise performance management is a process that drives beneficial behavior throughout the business. As such it requires not only a dashboard, or things to measure and try to influence, but a cascading set of measures and performance indicators that flow to all levels of the business and drive the desired behavior. As such it is not a simple technology implementation, and there are significant items to consider before promising to deliver an EPM solution.

Barriers to EPM

Whenever business intelligence is raised as an objective there is a temptation to jump straight to the delivery mechanism. This is encouraged by the software vendors’ account teams. After all, if you have the tool to present the data, what could go wrong? Unfortunately, the delivery mechanism is the last concern in providing true business intelligence. There are a number of significant barriers to providing timely performance management metrics:

- **What to measure?** While long lists of KPIs exist for the industry, there is no simple out of the box set that says, ‘Watch these ten things and you will have world class financial performance and return on assets’. Given that human beings can only really focus on trying to change 3 or 4 things at a time, it is absolutely critical to think about the strategic direction of the company and the function, and then choose the KPIs that will drive the right behavior. Furthermore, those KPIs will be different for different levels within the finance function, but they must be interlinked. Measuring the controller on the duration of the close process each month may be appropriate, but would not be appropriate for the accounts payable function. A more suitable measure may be the number of invoices outstanding at month end and the timeliness of accruals processing.

- **Diverse technology platforms:** While the typical major energy company would like to have fully integrated solutions for all of its businesses needs, the reality is that there are gaps in every product suite that result in a diversity of systems being required to meet all of those needs. This is particularly true for utilities, where geographical, property, tax, network, trading, meter and plant operations data are usually outside of any ERP solution. This results in any business intelligence tool needing to gather data from a variety of sources before presenting it to the target audience. This is far easier said than done.

- **Data capture:** Before bringing data together for analysis, you have to make sure that you have captured it on a timely basis. This means ensuring that it has been entered into feeder systems in time to be measured and then passed to the business intelligence tool shortly thereafter. This may require a change in business practices (for example receiving all goods in warehouse and inventory systems the day they are delivered) or the technology architecture (passing data daily or real time instead of weekly).

- **System versions:** Many companies run older versions of ERP and other software that cannot easily integrate with the new EPM tools. These may need to be upgraded in order to feed your business intelligence platform and the impact of upgrading one application may trickle down to others, requiring them in turn to be upgraded. This can quickly become a significant project in its own right and needs to be assessed and planned for before any EPM solution is put in place.
• **Vendor timeline:** It is important to understand what EPM capabilities you need to implement, on what underlying infrastructure and when that will be available as general release software. At the time of this writing, the latest versions of the most widely implemented EPM software solutions were not yet released, though due soon.

• **Competing initiatives:** EPM implementations require a strong understanding of your technical environment, integration between systems and data structures. This means that your most knowledgeable technical resources will need to be engaged and play a key role in any project. Since such resources are limited and often committed to other critical initiatives, any project must be scheduled well in advance and the resources secured before starting.

• **Compensation:** This could be the largest barrier of all. If you want to use EPM to change behavior, you have to make sure that the KPIs being measured are directly linked to staff and executive performance reviews and, ultimately, compensation. This requires careful planning, communication and change management as well as an understanding of where performance measures cannot be changed, for example due to a Union agreement.

**Next Steps**

With all these barriers, should companies even bother to chase the vision of EPM? The trend is that progressive businesses are saying yes, because EPM can be deployed function by function and drive real business benefits. We have found that there is a simple approach to accelerating the availability of timely, accurate business information:

• **Decide where to start:** Pick a function (for example Finance) and a small user community to implement for first. Use this group to iron out any kinks in the process and technology before rolling out to a wider audience.

• **Define what you want to measure:** Review your business strategy, industry KPIs and determine which are most applicable to your business and to each user community. Once the highest level KPIs are determined, the relevant measures for lower levels in the organization should be developed, designed to drive the appropriate behavior at all levels in the business.

• **Identify the source and make sure you capture the data on time:** Determine where the source data is captured and ensure the right controls and business processes are in place to capture the data on a timely basis. This may mean changing business practices, policies or even technologies (for example using bar code scanning to improve transaction capture times in service centers).

• **Define a common language:** Make sure that the terminology being used as part of your KPIs or scorecard is defined, understood and communicated. Most importantly, make sure the KPIs themselves have a single meaning across the business and that everyone understands a trend that is desirable (for example, cash: up is good: or, inventory: down is good).

• **Transform the data into information:** Once collected, data has to be consolidated, manipulated and calculated to provide the final KPIs. Different approaches can be taken to performing this function, from consolidating data in a single application or data warehouse, to calculating and formatting the results in the EPM tool itself. There is no single correct answer to this challenge, and the approach taken may be driven by other concerns, for example consolidating operational and financial data in a single warehouse may simplify the preparation of rate cases as well as enable EPM.

• **Deliver the information:** An appropriate method for delivering the results should be determined. This is not as simple as it sounds, for while the EPM software offerings are a suitable tool for some audiences, they are not a catch-all solution. It is important to consider the level of technology use for a particular audience and whether they are ‘pull’ users of information who will go and find the KPIs and/or dashboard, or ‘push’ users who need the information sent to them and displayed. This can result in a variety of delivery mechanisms from portals to e-mail to a hard print out on a company notice board. Indeed, some companies use a manually created spreadsheet as an interim mechanism while an EPM tool is being implemented.

• **Measure the results:** Lastly, all of these steps are valueless unless you follow through and hold people accountable for achieving the desired results. The EPM scorecard should be examined regularly and users questioned on their importance. Just as importantly, the scorecard should be reviewed to make sure it is still relevant to the direction of the business, and KPIs tweaked or replaced as necessary.

**Summary**

Over the next 12-18 months, the technology to manage Business Intelligence and Performance Management will become more integrated with the ERP solutions. As companies start to consider these solutions, there are number of steps that need to be undertaken to drive business value. These can be started well in advance of the technology implementation and should be part of the overall business strategy. The tools will soon be widely available to implement EPM business practices and we are likely to see early adopters delivering benefits as soon as 2009.
## Appendix I

### Abbreviations

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>ADFIT</td>
<td>Accumulated Deferred federal Income Taxes</td>
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<td>ADITC</td>
<td>Accumulated Deferred Investment Tax Credits</td>
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<tr>
<td>AFUDC</td>
<td>Allowance for Funds used During Construction</td>
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<tr>
<td>AICPA</td>
<td>American Institute of Certified Public Accountants</td>
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<tr>
<td>AOCI</td>
<td>Accumulated Other Comprehensive Income</td>
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<td>AMA</td>
<td>Asset Management Agreement</td>
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<td>AMI</td>
<td>Advanced Metering Infrastructure</td>
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<td>AMR</td>
<td>Advanced Meter Reading</td>
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<td>AICPA</td>
<td>American Institute of Certified Public Accountants</td>
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<td>APB</td>
<td>Accounting Principles Board</td>
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<td>APIC</td>
<td>Additional Paid-In-Capital</td>
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<td>APM</td>
<td>Asset Portfolio Management</td>
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<td>ARB</td>
<td>Accounting Research Bulletin</td>
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<td>ARO</td>
<td>Asset Retirement Obligation</td>
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<td>AU</td>
<td>Auditing Standard</td>
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<td>Bcf</td>
<td>Billion Cubic Feet</td>
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<td>CAIR</td>
<td>Clean Air Interstate Rule</td>
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<td>CAMR</td>
<td>Clean Air Mercury Rule</td>
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<td>CEO</td>
<td>Chief Executive Officer</td>
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<td>CER</td>
<td>Certified Emission Reductions</td>
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<td>CFO</td>
<td>Chief Financial Officer</td>
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<td>CIFIR</td>
<td>Advisory Committee on Improvements to Financial Reporting</td>
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<tr>
<td>Code</td>
<td>Internal Revenue Code</td>
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<tr>
<td>Concepts</td>
<td>Statement of Financial Accounting Concepts</td>
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<tr>
<td>Court</td>
<td>United States Court of Appeals for the D.C. Circuit</td>
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<td>CPP</td>
<td>Critical Peak Pricing</td>
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<td>CTC</td>
<td>Competitive Transition Charge</td>
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<td>DCF</td>
<td>Derivatives Implementation Group</td>
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<td>Division</td>
<td>SEC’s Division of Corporation Finance</td>
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<td>EA</td>
<td>Emission Allowance</td>
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<td>EAM</td>
<td>Enterprise Asset Management</td>
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<td>Exposure Draft</td>
<td>IFRIC</td>
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<td>ED</td>
<td>Exposure Draft</td>
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<td>EDFIT</td>
<td>Excess Deferred federal Income Taxes</td>
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<td>EEI</td>
<td>Edison Electric Institute</td>
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<td>EIA</td>
<td>Energy Information Administration</td>
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<td>EITF</td>
<td>Emerging Issues Task Force</td>
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<td>EPA</td>
<td>Environmental Protection Agency</td>
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<td>EPM</td>
<td>Enterprise Performance Management</td>
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<td>EPS</td>
<td>Earnings Per Share</td>
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<td>ERP</td>
<td>Enterprise Resources Planning</td>
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<td>EA</td>
<td>Energy Information Administration</td>
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<td>FASB</td>
<td>Financial Accounting Standards Board</td>
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<td>Federal Power Act</td>
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<td>FRR</td>
<td>Financial Reporting Policies</td>
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<td>FSP</td>
<td>FASB Staff Position</td>
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<td>FERC</td>
<td>Federal Energy Regulatory Commission</td>
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<td>FIFO</td>
<td>First-in-First-out</td>
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<td>FIN</td>
<td>FASB Interpretation</td>
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<td>GW</td>
<td>Gigawatts</td>
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<td>GP</td>
<td>General Partner</td>
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<td>HAN</td>
<td>Home Area Networks</td>
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<td>IAS</td>
<td>International Accounting Standards</td>
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<td>IASB</td>
<td>International Accounting Standards Board</td>
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<td>ICAP</td>
<td>Installed Capacity</td>
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<td>ICFR</td>
<td>Internal Control over Financial Reporting</td>
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<td>IDR</td>
<td>Incentive Distribution Rights</td>
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<td>IFRIC</td>
<td>International Financial Reporting Interpretations Committee</td>
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<td>IFRS</td>
<td>International Financial Reporting Standards</td>
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<td>IPR&amp;D</td>
<td>In-process Research and Development</td>
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<td>IRS</td>
<td>Internal Revenue Service</td>
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<td>ISO</td>
<td>Independent System Operator</td>
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<td>IT</td>
<td>Information Technology</td>
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<td>KPI</td>
<td>Key Performance Indicator</td>
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<td>kWh</td>
<td>Kilowatt Hour</td>
</tr>
<tr>
<td>Abbreviation</td>
<td>Description</td>
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<tr>
<td>--------------</td>
<td>--------------------------------------------------</td>
</tr>
<tr>
<td>LCM</td>
<td>Lower of Cost or Market</td>
</tr>
<tr>
<td>LNG</td>
<td>Liquefied Natural Gas</td>
</tr>
<tr>
<td>LIFO</td>
<td>Last-in-First-Out</td>
</tr>
<tr>
<td>LILO</td>
<td>Lease-in/Lease-out</td>
</tr>
<tr>
<td>LP</td>
<td>Limited Partner</td>
</tr>
<tr>
<td>MBT</td>
<td>Michigan Business Tax</td>
</tr>
<tr>
<td>Mcf</td>
<td>Thousand Cubic Feet</td>
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<tr>
<td>MD&amp;A</td>
<td>Management’s Discussion and Analysis of Financial Condition and Results of Operations</td>
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<tr>
<td>MLP</td>
<td>Master Limited Partnership</td>
</tr>
<tr>
<td>MW</td>
<td>Megawatts</td>
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<tr>
<td>NOL</td>
<td>Net Operating Loss</td>
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<tr>
<td>NOx</td>
<td>Nitrogen Oxide</td>
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<tr>
<td>NRC</td>
<td>Nuclear Regulatory Commission</td>
</tr>
<tr>
<td>NYISO</td>
<td>New York Independent System Operator</td>
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<tr>
<td>NYMEX</td>
<td>New York Mercantile Exchange</td>
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<tr>
<td>OCI</td>
<td>Other Comprehensive Income</td>
</tr>
<tr>
<td>OPEB</td>
<td>Postretirement Benefits Other Than Pensions</td>
</tr>
<tr>
<td>OTTI</td>
<td>Other-Than-Temporary Impairment</td>
</tr>
<tr>
<td>P&amp;U</td>
<td>Power and Utility</td>
</tr>
<tr>
<td>PCAOB</td>
<td>Public Company Accounting Oversight Board</td>
</tr>
<tr>
<td>PCT</td>
<td>Programmable Communicating Thermostat</td>
</tr>
<tr>
<td>PGA</td>
<td>Purchased Gas Adjustment</td>
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<tr>
<td>PJM</td>
<td>PJM Interconnection</td>
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<td>PLR</td>
<td>Private Letter Ruling</td>
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<td>PPA</td>
<td>Power Purchase Agreement</td>
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<tr>
<td>PP&amp;E</td>
<td>Property, Plant and Equipment</td>
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Appendix II

Technical Resources

Readers seeking additional information about the topics discussed in this publication and other activities of key standard-setters and regulators may find information on the following websites:

The FASB website at www.fasb.org
The SEC website at www.sec.gov
The PCAOB website at www.pcaobus.org
The AICPA website at www.aicpa.org
The IASB website at www.iasb.org
The FERC website at www.ferc.gov
The EEI website at www.eei.org
The EPA website at www.epa.gov

The following represents a listing of the Technical resources used in drafting this document:

FASB

SFAS 5, Accounting for Contingencies
SFAS 13, Accounting for Leases
SFAS 16, Prior Period Adjustments
SFAS 34, Capitalization of Interest Cost
SFAS 66, Accounting for Sales of Real Estate
SFAS 71, Accounting for the Effects of Certain Types of Regulation
SFAS 87, Employers’ Accounting for Pensions
SFAS 88, Employers’ Accounting for Settlements and Curtailments of Defined Benefits Pension Plans and for Termination Benefits
SFAS 90, Regulated Enterprises—Accounting for Abandonments and Disallowances of Plants Costs – an amendment of FASB Statement No. 71
SFAS 92, Regulated Enterprises—Accounting for Phase-In Plans – an amendment of FASB Statement No. 71
SFAS 101, Regulated Enterprises—Accounting for the Discontinuation of Application of FASB Statement No. 71
SFAS 106, Employers’ Accounting for Post Retirement Benefits Other Than Pensions
SFAS 107, Disclosure about Fair Value of Financial Instruments
SFAS 109, Accounting for Income Taxes
SFAS 123(R), Share-Based Payment
SFAS 128, Earnings per Share
SFAS 133, *Accounting for Derivative Instruments and Hedging Activities*


SFAS 141, *Business Combinations*

SFAS 141(R), *Business Combinations*

SFAS 142, *Goodwill and Other Intangible Assets*

SFAS 143, *Accounting for Asset Retirement Obligations*

SFAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*

SFAS 146, *Accounting for Costs Associated with Exit or Disposal Activities*

SFAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*

SFAS 153, *Exchanges of Nonmonetary Assets* – an amendment of APB Opinion No. 29

SFAS 154, *Accounting Changes and Error Corrections* – replacement of APB Opinion No. 20 and FASB Statement No. 3

SFAS 157, *Fair Value Measurements*

SFAS 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* – an amendment of FASB Statements No. 87, 88, 106, and 132(R)


SFAS 160, *Noncontrolling Interests in Consolidated Financial Statements* – an amendment of ARB No. 51

SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities* - an amendment of FASB Statement No. 133

SFAS 162, *The Hierarchy of Generally Accepted Accounting Principles*

ARB 43, *Restatement and Revision of Accounting Research Bulletins*

ARB 51, *Consolidated Financial Statements*

APB 21, *Interest on Receivables and Payables*

FIN 14, *Reasonable Estimation of the Amount of a Loss*

FIN 39, *Offsetting of Amounts Related to Certain Contracts*

FIN 46(R), *Consolidation of Variable Interest Entities*

FIN 47, *Accounting for Conditional Asset Retirement Obligations*

FIN 48, *Accounting for Uncertainty in Income Taxes*

FASB Technical Bulletin 87-2, *Computation of a Loss on an Abandonment*

FASB ED, *Amendments to FASB Interpretation No. 46(R)*

FASB ED, *Accounting for Hedging Activities* – an amendment of FASB Statement No. 133

Concepts Statement No. 5, *Recognition and Measurement in Financial Statements of Business Enterprises*
Concepts Statement No. 6, *Elements of Financial Statements*

Concepts Statement No. 7, *Using Cash Flow Information and Present Value in Accounting Measurements*

FSP FAS 13-2, *Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction*

FSP FAS 115-1 and FSP FAS 124-1, *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments*

Proposed FSP FAS 132(R)-a, *Employer’s Disclosures about Postretirement Benefit Plan Assets*

Proposed FSP FAS 140-e and FIN 46(R)-e, *Disclosures about Transfers of Financial Assets and Interests in Variable Interest Entities*

FSP FAS 142-3, *Determination of the Useful Life of Intangible Assets*

FSP FAS 157-2, *Effective Date of FASB Statement No. 157*

FSP FAS 157-3, *Determining the Fair Value of a Financial Asset in a Market That Is Not Active*

FSP APB 14-1, *Accounting for Convertible Debt Instruments That May Be Settled in Cash Upon Conversion (Including Partial Cash Settlement)*

FSP FIN 39-1, *Amendment of FASB Interpretation No. 39*

FSP FIN 46(R)-6, *Determining the Variability to Be Considered in Applying FASB Interpretation No. 46(R)*

FSP FIN 48-1, *Definition of Settlement in FASB Interpretation No. 48*

FSP FIN 48-2, *Effective Date of FASB Interpretation No. 48 for Certain Nonpublic Enterprises*

FSP EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*

DIG Issue A6, *Definition of a Derivative: Notional Amount of Commodity Contracts*

DIG Issue A8, *Definition of a Derivative: Asymmetrical Default Provisions*

DIG Issue A10, *Definition of a Derivative: Assets That Are Readily Convertible to Cash*

DIG Issue A12, *Definition of a Derivative: Impact of Daily Transaction Volume on Assessment of Whether an Asset Is Readily Convertible to Cash*

DIG Issue A18, *Definition of a Derivative: Application of Market Mechanism and Readily Convertible to Cash Subsequent to the Inception or Acquisition of a Contract*

DIG Issue A19, *Definition of a Derivative: Impact of a Multiple-Delivery Long-Term Supply Contract on Assessment of Whether an Asset Is Readily Convertible to Cash Proposed*

Proposed DIG Issue C21, *Whether Options (Including Embedded Conversion Options) Are Indexed to both an Entity’s Own Stock and Currency Exchange Rates*

DIG Issue G10, *Cash Flow Hedges: Need to Consider Possibility of Default by the Counterparty to the Hedging Derivative,*
EITF

EITF Issue 86-43, Effect of a Change in Tax Law or Rates on Leveraged Leases

EITF Issue 89-13, Accounting for the Cost of Asbestos Removal

EITF Issue 90-8, Capitalization of Costs to Treat Environmental Contamination

EITF Issue 91-6, Revenue Recognition of Long-Term Power Sales Contracts

EITF Issue 92-7, Accounting by Rate Regulated Utilities for the Effects of Certain Alternative Revenue Programs

EITF Issue 92-12, Accounting for OPEB Costs by Rate-Regulated Enterprises

EITF Issue 93-4, Accounting for Regulatory Assets

EITF Issue 93-7, Uncertainties Related to Income Taxes in a Purchase Business Combination

EITF Issue 95-3, Recognition of Liabilities in Connection with a Purchase Business Combinations


EITF Issue 96-17, Revenue Recognition under Long-Term Power Sales Contracts That Contain Both Fixed and Variable Pricing Terms

EITF Issue 96-19, Debtor’s Accounting for Modification or Exchange of Debt Instruments

EITF Issue 97-4, Deregulation of the Pricing of Electricity-Issues Related to the Application of FASB Statements No. 71 and 101

EITF Issue 98-3, Determining Whether a Nonmonetary Transaction Involves Receipt of Productive Assets or of a Business

EITF Issue 98-5, Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios

EITF Issue 99-12, Determination of the Measurement Date for the Market Price of Acquirer Securities Issued in a Purchase Business Combination

EITF Issue 99-19, Reporting Revenue Gross as a Principal versus Net as an Agent

EITF Issue 00-19, Accounting for Derivative Financial Instruments Indexed to, and Potentially Settled in, a Company’s Own Stock

EITF Issue 00-27, Application of Issue No. 98-5 to Certain Convertible Instruments

EITF Issue 01-6, The Meaning of “Indexed to a Company’s Own Stock”

EITF Issue 01-8, Determining Whether an Arrangement Contains a Lease

EITF Issue 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities

EITF Issue 03-6, Participating Securities and the Two-Class Method Under FASB Statement No. 128

EITF Issue 03-11, Reporting Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not “Held for Trading Purposes” as Defined in Issue 02-3

EITF Issue 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty

EITF Issue 06-6, Debtors Accounting for a Modification (or Exchange) of Convertible Debt Instruments

EITF Issue 06-11, Accounting for the Tax Benefit of Dividends on Restricted Stock and Option Awards

EITF Issue 07-4, Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships
EITF Issue 07-5, Determining Whether an Instrument (or an Embedded Feature) Is Indexed to an Entity’s Own Stock

EITF Issue 07-6, Accounting for the Sale of Real Estate Subject to the Requirements of FASB Statement No. 66, Accounting for Sales of Real Estate

EITF Issue 08-3, Accounting for Lessees for Maintenance Deposits under Lease Arrangements

EITF Issue 08-4, Transition Guidance for Conforming Changes to Issue No. 98-5, Accounting for Convertible Securities with Beneficial Conversion Features or Contingently Adjustable Conversion Ratios

EITF Issue 08-5, Issuer’s Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement

EITF Topic D-5, Extraordinary Treatment Related to Abandoned Nuclear Power Plants

EITF Topic D-98, Classification and Measurement of Redeemable Securities

SEC

SEC Regulation S-X, Rule 3-05, Financial Statements of Businesses Acquired or to Be Acquired

SEC Regulation S-X, Rule 3-09, Separate Financial Statements of Subsidiaries Not Consolidated and 50 Percent or Less Owned Persons

SEC Regulation S-X, Rule 4-08, General Notes to Financial Statements

SEC Regulation S-X, Rule 5-02, Balance Sheets

SEC Regulation S-X, Rule 5-03, Income Statements

SEC Regulation S-X, Rule 5-04, What Schedules Are to Be Filed

SEC Regulation S-X, Article 11, Pro Forma Financial Information

SEC Regulation S-X, Rule 12-04, Condensed Financial Information of Registrant

SEC Regulation S-K, Item 303, Management’s Discussion and Analysis of Financial Condition and Results of Operations

SEC Regulation S-K, Item 305, Quantitative and Qualitative Disclosures About Market Risk

SAB 5P, Income Statement Presentation of Restructuring Changes

SAB 6K, Separate Financial Statements Required by Regulation S-X

SAB 10C, Jointly Owned Electric Utility Plants

SAB 10E, Utility Companies-Classification of Disallowed Costs or Costs of Abandoned Plants

SAB 10F, Utility Companies – Presentation of Liabilities for Environmental Costs

SAB 51, Accounting for Sales of Stock by Subsidiary

FRR 61, Derivative Disclosures
PCAOB

AU Section 411, *The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles*

AICPA

SOP 94-6, *Disclosure of Certain Risks and Uncertainties*

SOP 96-1, *Environmental Remediation Liabilities International Accounting Standards*

**International Accounting Standards**

IAS 2, *Inventories*

IAS 11, *Construction Contracts*

IAS 12, *Income Taxes*

IAS 16, *Property, Plant and Equipment*

IAS 18, *Revenue*

IAS 23, *Borrowing Costs*

IAS 38, *Intangible Assets*

**International Financial Reporting Standards**

IFRS 1, *First-time Adoption of International Financial Reporting Standards*

IFRIC 1, *Changes in Existing Decommissioning, Restoration and Similar Liabilities*

IFRIC 4, *Determining Whether an Arrangement Contains a Lease*
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Upcoming Events

Save these Dates

- **March 26-27, 2009** – Deloitte Utility Tax Training Seminar – Hilton Walt Disney World Resort For more information, please contact kathobrien@deloitte.com

- **April 20-21, 2009** – Deloitte Energy Conference – Washington, D.C. For more information or to obtain a synopsis of the 2008 Deloitte Energy Conference, please contact sblitch@deloitte.com

- **December 1, 2009** – Deloitte Energy Accounting, Financial Reporting and Tax Update – Chicago For more information please contact sblitch@deloitte.com

- **December 2, 2009** – Deloitte Energy Transacting: Accounting, Risk Management and Valuation – Chicago For more information please contact thoang@deloitte.com

- **December 9, 2009** – Deloitte Oil & Gas Conference – Houston For more information or to obtain a synopsis of the 2007 Deloitte Oil & Gas Conference, please contact marreynolds@deloitte.com

Power & Utilities IFRS Webcast Series - Save the Date

- **Friday, November 7, 1:00 p.m. (EST):** Overview of the Impact of IFRS on Power & Utilities

- **Friday, November 14, 1:00 p.m. (EST):** IAS 32 and 39, and Energy Transacting

- **Friday, November 21, 1:00 p.m. (EST):** IAS 12, Income Taxes

- **Friday, December 12, 1:00 p.m. (EST):** IAS 16, Property, Plant and Equipment

- **Friday, December 19, 1:00 (EST):** Regulatory Assets and Regulatory Liabilities

For more information about these webcasts and to register for the webcasts, click this link: http://www.deloitte.com/dtt/event/0%2C1008%2Ccid%25253D226936%2C00.html