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2008 Utilities and Power Industry Technical Update



Dear Clients and Friends:

Wow ... what a year 2008 has been for the U.S. and global economies, as well as for the utility and energy industries. We have seen unprecedented change in the fundamentals of the economy, from the credit market freeze to the demise of several financial institutions which lead to a historic federal government intervention designed to prevent a more severe economic crisis. The effects of the downturn in the economy are being experienced worldwide, and the utilities and power industry is no exception. The credit crisis has spilled over to virtually all markets, causing significant volatility for financial instruments and commodities. For instance, natural gas opened the year at \$7.85 per MMBtu, spiked to \$13.58 in early summer, and dropped all the way back to \$6.74 in late November - electricity prices showed similar volatility. The combined effects of the credit disruption and declining commodity prices resulted in a 37 percent year-to-date decline in the Dow Jones Utilities Index, which lost more than half of the gains from the past three years.

The initial impact of these market events included a significant decline in credit availability, putting a damper on near-term capital expansion plans. Evidence of the impact has been observed with the development of renewable energy projects coming to a near standstill, due to a lack of liquidity in the marketplace and many of the traditional market participants electing to hold on to cash to safeguard their own liquidity. These situations have been exacerbated by significant swings in collateral requirements driven by severe commodity price volatility. These combined factors have resulted in many organizations, especially financial institutions, scaling back their commodity trading activities impacting liquidity for some locations and tenors. These financial institutions became integral participants in the energy commodity markets after the fall of Enron, and many now question who will next step in to fill the new void.

But despite this market turmoil, on an overall basis during the last half of 2008 the utility sector has demonstrated sufficient liquidity and continued access to the capital markets to fund required business operations. As providers of a necessity, power, natural gas, and water producers and distributors know that there will always be customer demand. Therefore, although growth may slow or stall for a period and utilities will experience increased pressure on rates and regulatory recovery, over the longer term, the sector will continue to produce shareholder returns.

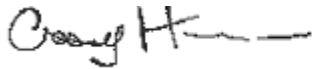
In preparing for year-end reporting and the upcoming year, in addition to tackling the more obvious economic impacts to the business, management teams have numerous ongoing issues to address. Many of these matters are not new, but require continued attention:

- The continued dichotomy caused by rising production costs and regulator resistance to authorizing rate increases, especially given the current troubled economic environment surrounding retail customers (and voters). Utilities have to strike a balance in order to adequately serve customers yet preserve and grow shareholder return.
- The expectation of carbon legislation and the associated significant impacts that a cap-and-trade program may have on power prices.
- The need to expand and update existing infrastructure to meet growing demand in both generating plants and critical transmission and distribution systems.

- Increasing compliance requirements, whether environmental (e.g., renewable portfolio standards and other energy regulations) or operational (e.g., Federal Energy Regulatory Commission policies and regulations).
- Continued transformation in the energy markets (e.g., the upcoming market changes in the California ISO and ERCOT) and required modifications to make sure that internal systems are ready to address the changes.
- Continued evolution and complexity in financial reporting, including fair value accounting, which has gained significant prominence in the last year; ongoing contract accounting issues; the new business combinations standard; and the movement to International Financial Reporting Standards.

All of these issues have wide-ranging effects, but will most certainly have an impact on financial reporting. We have prepared this technical update to assist senior accounting and financial reporting personnel at utilities, merchant energy companies, and energy trading organizations as they address these critical issues. The whitepaper contains an overview of year-end issues, followed by a collection of abstracts on a multitude of current topics. We hope that our views and guidance will be useful and informative as you begin the process of preparing for your year-end financial reporting. We look forward to continuing to work with you to address these issues. And finally, my thanks to the PwC partners and managers for their excellent efforts producing this document.

Best regards,

A handwritten signature in black ink, appearing to read "Casey Herman", with a horizontal line extending to the right.

Casey Herman
U.S. Utilities Assurance Leader
December 3, 2008

Table of Contents

Section 1:	Overview	2
Section 2:	Current Market Events	10
2.1	Fair Value Measurements	11
2.2	Derivatives	11
2.2.1	Hedge Transactions	11
2.2.2	Normal Purchases and Normal Sales Exception	13
2.2.3	Other Derivative Considerations	13
2.3	Investments	14
2.3.1	Pension and Other Postretirement Investments.....	15
2.4	Impairments and Discontinued Operations.....	15
2.4.1	Long-Lived Assets	15
2.4.2	Goodwill Impairments.....	16
2.4.3	Discontinued Operations.....	16
2.5	Presentation and Disclosure Issues	17
2.5.1	Liquidity.....	18
2.5.2	Market Risks	19
2.6	References	19
Section 3:	Fair Value Measurements	22
3.1	Overview	22
3.1.1	Fair Value Reporting Trends in 2008.....	23
3.2	Overall Application.....	25
3.3	Nonperformance Risk.....	26
3.3.1	Determine Unit of Credit Risk Measurement.....	27
3.3.1.1	Impact of Third-Party Credit Enhancements.....	27
3.3.2	Apply a Market Participant Perspective to Available Credit Information	27
3.3.3	Calculate the Credit Reserve	28
3.3.4	Allocate Credit Reserve to Individual Fair Value Measurements	29
3.3.4.1	Allocation Methods.....	29
3.3.5	Impact of Nonperformance Risk on Hedging.....	29
3.4	Fair Value Hierarchy.....	30
3.4.1	How is an Active Market Defined?.....	31
3.4.2	Classification of Valuations Based on Broker Quotes.....	32
3.4.3	Other Broker Quote Considerations	32
3.5	Scope of FAS 157 Disclosure Requirements	34
3.5.1	Cash Equivalents	36

3.5.2	Margin Deposits and Collateral	37
3.5.3	Investments Held by Pension and Other Postretirement Benefit Plans.....	38
3.5.4	FAS 107 Disclosures.....	39
3.6	Other Disclosure Considerations	40
3.7	Application to Nonfinancial Assets and Liabilities.....	43
Section 4:	Commodity Contract Accounting.....	50
4.1	Contract Accounting Framework	50
4.2	Variable Interest Entities	52
4.2.1	Proposed Disclosure Requirements	53
4.2.2	Proposed Changes to the Accounting for Variable Interest Entities	56
4.3	Noncontrolling Interests.....	59
4.4	Equity Method Investments.....	60
4.5	Derivative Instruments and Hedging Activities	61
4.5.1	Gas Capacity.....	62
4.5.2	Significant Market Changes	65
4.5.3	Normal Purchases and Normal Sales: What Is "Clearly and Closely Related"?	67
4.5.4	New Disclosures Required for Credit Derivatives and Credit Guarantees	71
4.5.5	New Derivative Disclosures	72
4.5.6	Hedge Accounting Project: Simplification on the Way?.....	76
4.6	Other Trading Issues	79
4.6.1	Proposed Fair Value Accounting for Trading Inventory	79
Section 5:	Environmental Regulation.....	84
5.1	Emissions Reductions Programs.....	85
5.1.1	Clean Air Interstate Rule.....	85
5.1.2	Regional Greenhouse Gas Initiative.....	87
5.2	Renewable Portfolio Standards	87
5.2.1	Compliance with Renewable Portfolio Standards	89
5.2.2	Investment in New Technologies	89
5.2.3	Purchases of Renewable Energy Credits	90
5.3	Accounting and Reporting for Emission Allowances and RECs	91
5.3.1	Possible Accounting Models	92
5.3.2	Initial Accounting	94
5.3.3	Ongoing Accounting.....	95
5.3.3.1	Intangible Assets	95
5.3.3.2	Inventory Classification	96
5.3.3.3	Property, Plant, and Equipment Classification.....	97

5.3.4	Other Considerations	98
5.3.4.1	Accruals for Potential Shortfalls	99
5.3.4.2	Vintage-Year Swaps.....	99
5.3.4.3	Revenue Recognition	102
5.3.5	Presentation and Disclosure Considerations	102
5.4	Other Contracts for Environmental Assets	103
5.4.1	Accounting for a Forward Contract for RECs or Emission Allowances	103
5.4.2	RECs Embedded in Power Purchase Agreements	107
5.5	Other Environmental Reporting Issues	109
5.6	Renewable Energy Tax Incentives	110
Section 6:	Industry Regulation	114
6.1	State Regulatory Developments	114
6.1.1	State Ratemaking Trends	115
6.1.2	Specific Ratemaking Trends	116
6.1.2.1	Focus on Regulatory Lag	117
6.1.2.2	Cost Management	119
6.1.2.3	Rate Decoupling	119
6.2	Regulation – Accounting and Reporting Considerations	120
6.2.1	Ratemaking and Regulatory Disclosure	123
6.3	Federal Energy Regulatory Commission Developments	124
6.3.1	Gas Capacity	125
6.3.2	FERC Forms No. 1 and 2	125
6.3.3	FERC Compliance	125
6.3.3.1	FERC Policy Statement on Enforcement	127
6.3.4	Other Compliance Requirements	128
6.4	North American Electric Reliability Corporation Standards	130
6.5	Regulatory-Related Tax Considerations	130
6.5.1	Final Normalization Regulations	131
6.5.2	Normalization Rulings	131
Section 7:	Infrastructure	134
7.1	Accounting for Construction Costs	136
7.1.1	General Considerations	136
7.1.1.1	Regulated Construction Activities	137
7.1.2	Ongoing Accounting and Reporting Implications	138
7.2	Plant Maintenance Accounting Considerations	139
7.2.1	Long-Term Service Agreements – Plant Maintenance	139
7.2.1.1	Accounting for Major Maintenance Subject to an LTSA	139
7.2.1.2	Accounting for Routine Maintenance Subject to an LTSA	140
7.2.2	Maintenance Deposits Under Leasing Arrangements	142

7.3	Infrastructure-Related Tax Considerations	142
7.3.1	Bonus Depreciation	143
7.3.2	Research and AMT Credits.....	143
7.3.3	Extension of the Research Credit.....	144
7.3.4	Tangible Assets – Proposed Tax Changes.....	145
7.3.4.1	Unit of Property Rules	145
7.3.4.2	Routine Maintenance Safe Harbor.....	146
7.3.4.3	Materials and Supplies	146
7.3.4.4	New Repair Allowance	147
Section 8:	International Financial Reporting Standards	150
8.1	Current Status in the United States.....	150
8.1.1	SEC Roadmap for Adoption.....	151
8.1.2	Option for Early Adoption	151
8.2	The Trillion Dollar Question	152
8.2.1	The IFRS Framework.....	153
8.2.2	How We Got to This Point	154
8.2.3	Potential Sources of Diversity in Practice.....	155
8.2.3.1	Different Regulatory Regimes	155
8.2.3.2	Different Interpretations of the Framework.....	156
8.2.4	Application of IFRS Threshold of Control	157
8.2.5	Next Steps for Regulated Utilities	157
8.3	The Impact of IFRS Adoption on Regulatory Recovery	158
8.4	IFRS Implementation.....	159
8.4.1	Benefits of an Early Implementation Process	160
8.4.2	Key Elements of a Phased Approach to Implementation	161
8.4.2.1	Phase 1 – Preliminary Study of the Impact of Adoption.....	161
8.4.2.2	Phase 2 – Project Plan and Initial Conversion.....	164
8.4.2.3	Phase 3 – Embed IFRS into the Organization	165
	Appendix: Technical References and Abbreviations	168

Section 1: Overview

Section 1: Overview

Investors, analysts, lenders and other counterparties rely on external financial reporting to understand a company's performance and viability, its identification of and response to key risks and opportunities, and to obtain other information to make knowledgeable decisions. Due to the nature and complexity of the underlying business, the accounting and financial reporting groups at utilities and power companies are required to understand, analyze, and incorporate a wide range of information to issue financial statements to meet those objectives. Furthermore, external financial reports must comply with generally accepted accounting principles, which encompass an immense volume of intricate guidance, rules, and regulations.

Effectively reporting financial results requires a deep understanding of the underlying issues and the related accounting and reporting guidance. We have prepared this technical update to assist senior accounting and financial reporting personnel in the industry as they reflect on and prepare for their 2008 year-end and 2009 financial reporting. The update contains a collection of abstracts on a multitude of current topics that will be most pressing for the industry in the near and medium term.

Figure 1-1

Emerging and Ongoing Accounting Issues

This overview highlights pertinent emerging and ongoing accounting issues and other hot topics impacting utilities and power marketers. Current market events have resulted in certain matters pertaining to fair value, impairments and key disclosures that should be considered at year end. In addition, several other ongoing accounting and reporting issues will affect these companies during the near and medium term. Key issues include:

- Fair value measurements, including current practice issues and the looming adoption of the new fair value standards for nonfinancial assets and liabilities
- Energy trading and risk management, with a focus on liquidity and contract accounting
- Environmental regulation and the complexity of accounting for emission allowances, renewable energy credits, and related deal structures
- State and federal rate regulation and the ongoing impact on rate recovery and compliance considerations
- Infrastructure growth and maintenance with potential issues regarding capitalization policies, accounting for maintenance contracts, and the impact of changing tax regulations

Finally, the potential future adoption of International Financial Reporting Standards (IFRS) and the lack of industry-specific guidance continues to be a topic of specific focus and concern for many rate-regulated utilities.

Key Considerations Arising From Current Market Events

Current market conditions and the related business impacts have resulted in a myriad of potential accounting and reporting issues. The concerns that emerged during the third quarter continue to require additional attention and focus. Impacted areas include fair value measurements, derivatives and hedging, and investments. In addition, certain reporting entities may need to consider impairment of goodwill or operating assets. Furthermore, given the tightening of access to capital, reporting entities should be focused on robust liquidity disclosures. These matters are discussed in more detail in this technical update. Controller organizations should be prepared to spend additional time as part of their closing and reporting process to address the ongoing issues stemming from the market turmoil.

Fair Value Accounting: There Is Still More to Do

Financial Accounting Standards Board (FASB) Statement No. 157, *Fair Value Measurements* (FAS 157), has been one of the most intensely debated accounting standards, even entering the political arena this fall as some theorized that application of fair value accounting contributed to the market crisis. The ongoing lack of liquidity in many financial markets has continued to fuel the discussion over the use and application of fair value accounting. Despite the questions, fair value accounting plays an important role in today's financial reporting, and challenges in fair value reporting continue to exist.

Key issues that may impact utilities and power marketers with commodity contracts and other financial instruments measured at fair value include:

- Adoption of appropriate market-based methodologies for incorporation of nonperformance risk in fair value measurements
- Classification of amounts in the fair value hierarchy
- Appropriate corroboration of information obtained through broker quotes and pricing services
- Focus on robust disclosure, including consideration of the Securities and Exchange Commission (SEC) views expressed in the March and September 2008 "Dear CFO" letters
- Valuation of long-term debt as well as securities held in pension and other postretirement plans for which the new guidance will be applied for the first time at year-end

In addition to working through these and other existing practice issues, as of January 1, 2009 calendar year-end reporting entities will be required to implement fair value measurement accounting for nonfinancial assets and liabilities. Coinciding with that adoption is that of FASB Statement No. 141(revised 2007), *Business Combinations* (FAS 141(R)), which will require reporting entities to record most assets and liabilities acquired at fair value. These new requirements will result in significant changes in the way utilities manage and consider business combinations, the assessment of goodwill and asset impairments.

Because of the pervasiveness of fair value measurements and the volume of issues regarding measuring fair value, controllers should continue to focus on building organizational expertise in this area.

Energy Risk Management and Contract Accounting Play a Pivotal Role

Effective energy risk management, trading, and contract accounting are essential to any utility or power organization. Accounting and reporting for these activities continues to be a challenge for most entities because of the convergence of extremely voluminous and complicated accounting standards and the complexity of the underlying transactions and activities. The recent credit crunch and financial institution mergers and failures have also directly impacted these activities due to lack of credit availability for funding ongoing trading activity and less liquidity in certain commodity markets. These factors have further contributed to the difficulty in accounting and financial reporting in this area.

In addition, contract accounting continues to evolve and require the expansion of knowledge and expertise, with new disclosure requirements for derivatives and a possible new hedge accounting standard. Furthermore, the FASB is planning to issue comprehensive new disclosure requirements for variable interest entities (VIEs) that will be effective for the current year-end reporting cycle. It is also proposing another amendment to the accounting for VIEs.

Controller organizations should also continue to be aware of and understand their company's involvement and interaction with independent systems operators and regional transmission organizations, as these transactions can have a wide range of accounting impacts, from revenue and cost recognition, to derivatives.

The Environmental Agenda is Becoming Front and Center

Recently, the credit crisis has led to a notable decline in near-term funding availability for renewable energy projects; however, the overall trend points to increasing growth in this area to meet regulatory and other legislative requirements. Despite the court ruling to repeal the Clean Air Interstate Rule (CAIR) during July 2008, utilities are generally facing increasing environmental regulation and ambitious renewable portfolio standards goals. For example, California's governor recently approved a 33 percent renewable target by 2020.

The accompanying accounting issues may be thorny because of a lack of clear authoritative guidance for emission allowances and renewable energy credits (RECs). Many renewable deal structures may also involve derivatives or leases, or could trigger VIE accounting issues. Furthermore, the recent issues with CAIR have reminded reporting entities about the need to carefully consider the selection of accounting policies because of potential future accounting implications. As reporting entities address environmental regulations through acquisition and trading of emission allowances and increased involvement in renewable energy projects, the materiality of the related accounting implications will continue to grow. We encourage controller organizations to focus on these issues now and to build capabilities in this area as it evolves.

How is Regulation Impacting Your Financial Results?

Rate regulation is a unique aspect of this industry and requires careful consideration in the reporting process, as the impacts to financial results can be significant. The underpinning of any regulated utility is its regulatory structure and the ability to charge and collect rates sufficient to cover cost of service and to earn the approved rate of return. In addition, both regulated and nonregulated entities in the industry have an obligation to comply with industry-related regulation imposed by organizations such as state regulators and the Federal Energy Regulatory Commission (FERC).

The activities of FERC and state public utility commissions can have an impact on the application of FASB Statement No. 71, *Accounting for the Effects of Certain Types of Regulation* (FAS 71). Therefore, accounting teams should keep abreast of new regulatory rulings, changes in company-specific circumstances, and overall trends in ratemaking to ensure appropriate accounting in accordance with FAS 71. Furthermore, the FERC continues to be active in the industry, with a significant focus on operational compliance by all market participants, including traditional utilities and power marketers. Lack of compliance can result in hefty monetary fines that have a direct impact on cash flow as well as financial reporting. Therefore, controller organizations should also understand these requirements and the company's plan for compliance to ensure appropriate accounting for the impacts.

Infrastructure Maintenance and Construction Are Necessary

Property, plant, and equipment is the most significant class of assets held by utilities and power companies. The infrastructure required to deliver energy is fundamental, yet is in critical need of expansion and updating to address age-related issues and to meet service demand growth. As a result, although short-term expansion plans may have been scaled back because of economic concerns, many utilities and other market participants continue to plan for major construction initiatives.

Numerous accounting issues accompany construction activities and maintenance of infrastructure, from determining the proper expense and capitalization policies during construction, to the accounting for major maintenance activities and long-term servicing arrangements. In addition, current market issues may trigger impairments for certain generating plants, especially independent plants with exposure to fluctuations in fuel costs. Application of the impairment standards may be complicated, and in many cases, it has been a long time since major construction projects were embarked upon; therefore, controllers should revisit the processes in place to ensure proper application of the related accounting standards.

New and Upcoming Accounting Guidance

Application of new accounting pronouncements is also a continuing challenge. Therefore, to help controllers identify new accounting pronouncements that may have an impact on financial reporting, we have prepared the following table of new and emerging accounting pronouncements expected to affect many utilities and power marketers. Reporting entities should evaluate these effective and upcoming pronouncements to determine the potential impacts on their financial reporting. While Figure 1-2 serves as a quick-reference guide,

more in-depth discussion of the new and potential guidance is available in the applicable referenced sections within this whitepaper.

Figure 1-2: Quick Reference to New and Upcoming Accounting Guidance Effective for 2008 Year-End Reporting

Guidance	Description
FSP FAS 133-1 and FIN 45-4 (see Section 4.5.4)	Requires disclosures about the nature, exposure to loss, and fair value of credit derivatives and certain guarantees
FSP FAS 140-e and FIN 46R-e (see Section 4.2.1)	Will require new extensive disclosures about the reporting entity's involvement with variable interest entities, whether or not consolidated (Not issued as of mid-November 2008; however, expected to be issued December 15, 2008 and effective for the current year-end)
FSP FAS 157-3 (see Section 3:	Provides clarifications on measuring fair value when markets are inactive and/or distressed, as well as utilizing broker quotes; became effective immediately upon its issuance in October 2008

Impacting 2009 Financial Reporting

Guidance	Description
FAS 141(R) (see Section 3.7)	Requires most assets and liabilities acquired in a business combination to be recorded at fair value in accordance with FAS 157
FAS 160 (see Section 4.3)	Changes the way that transactions with noncontrolling investors are accounted for in the consolidated financial statements
FAS 161 (see Section 4.5.5)	Requires new disclosures about why derivatives are used, how they are accounted for, and the amount and classification in the financial statements
FSP FAS 132R-a (see Section 3.5.3)	Requires disclosures about the fair value of benefit plan assets similar to those requirements for fair value measurements under FAS 157 (e.g., valuation techniques, fair value hierarchy, Level 3 measurements rollforwards) (Not issued as of mid-November 2008; however, expected to be effective for fiscal years ending after December 15, 2009)
FSP FAS 157-2 (see Section 3.7)	Provided reporting entities with the option to delay the application of FAS 157 to nonfinancial assets and liabilities that are not measured at fair value on a recurring basis

Guidance	Description
EITF 08-3 (see Section 7.2.2)	Provides guidance as to how nonrefundable deposits for maintenance under a lease agreement should be accounted for
EITF 08-5 (see Section 3.3.1.1)	Requires that the value of any third-party credit enhancements that are inseparable from a liability be removed in determining the fair value of that liability
EITF 08-6 (see Section 4.4)	Addresses how an equity method investment should initially be measured, how it should be tested for impairment, and how changes in classification from equity method to cost method should be treated

Proposed or Emerging Guidance

Guidance	Description
Proposed amendment of FAS 133 (see Section 4.5.6)	Numerous changes to the hedge accounting requirements intended to simplify and improve hedge accounting
Proposed FASB standard amending FIN 46R (see Section 4.2.2)	Proposes a qualitative approach to the determination of the primary beneficiary and the requirement to assess changes to variable interest entities and primary beneficiaries at each reporting period
FSP ARB No. 43-a (see Section 4.6.1)	Will require that inventory designated as "trading" inventory be recorded at fair value with the changes recorded through earnings each period, and introduces several new disclosures about inventory
FSP FAS 144-d (see Section 2.4.3)	Changes the definition of and qualifying factors for a discontinued operation and requires some additional new disclosures about assets held for sale

Section 2: Current Market Events

Section 2: Current Market Events

The market turmoil and recent economic events first experienced in the financial service sector have had a domino effect, impacting almost every industry and company. In addition to the business issues, the fallout from the market crisis creates numerous accounting and financial reporting considerations for reporting entities. As management teams experienced during the third quarter reporting cycle, the issues are demanding —highly complex fair value measurements; derivative and hedging issues not seen since Enron; and impairments of investments, goodwill, and other assets. In addition, the unprecedented uncertainty and market chaos create an enhanced need to provide perspective to investors about the potential current and future impact of market issues on the organization.

Controllers and other accounting and reporting personnel undoubtedly have a significant task ahead in addressing these issues in the year-end financial statements. To assist with this challenge, this section highlights key accounting and reporting issues arising from current market events and provides relevant guidance for consideration. Figure 2-1 summarizes the areas of focus.

Figure 2-1

Market Events – Areas of Focus for Utility and Power Companies

Fair value measurements

Recent events have led to steep increases in counterparty credit risk and negative impacts to market liquidity. These factors can have a substantial impact on how fair value is measured.

Derivatives and hedging

Counterparty credit risk is a critical consideration when assessing qualification for hedge accounting and application of the normal purchases and normal sales exception. Actual or probable default by a counterparty may require application of full fair value accounting.

Investments – Other-than-temporary-impairment

Market events may have caused significant declines in the value of all types of investments, including money market funds and nuclear decommissioning trust funds. All investments will need to be evaluated for impairment.

Asset and goodwill impairments

The squeezed economy and market volatility may be putting pressure on the fair value of companies' reporting units and the ability to recover their long-lived assets. Assumptions underlying impairment analyses should be critically reviewed.

Liquidity, market risk, and other disclosures

Disclosures that clearly and accurately explain the company's current liquidity position and liquidity risks are critical in today's environment.

We further discuss the accounting and control considerations associated with these issues below.

2.1 Fair Value Measurements

FAS 157 requires consideration of the impact of nonperformance risk (including credit risk) in the measurement of the fair value of assets and liabilities. Current market events, including the credit downgrades of certain financial institutions and trading companies, are indicative of potential changes in the risk of nonperformance.

There are numerous considerations when developing the credit adjustment to be incorporated into fair value measurements, including the availability and type of market based credit-related information, as well as other factors such as collateral and credit support. Reporting entities should continue to focus on counterparty credit risk as a key factor in the determination of their fair values. Section 3.3 of this technical update includes further discussion of nonperformance risk and other important year-end considerations related to fair value measurements.

2.2 Derivatives

The market changes and financial institution difficulties, also raise a number of issues with respect to the accounting for derivative instruments and hedging relationships. Issues that should be considered are further discussed below.

2.2.1 Hedge Transactions

FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities* (FAS 133), states that there must be an expectation of high effectiveness throughout the hedge period in order to qualify for hedge accounting. In a fair value hedge, both the hedged item and the hedging derivative instrument are recorded at fair value, including the impact of credit risk. To the extent that the impact of credit results in a difference in the change in fair value of the hedged item and hedging derivative instrument, ineffectiveness will result. Management must monitor the difference as part of its periodic assertion of high effectiveness.

In addition to being an integral component of the fair value measurement, nonperformance risk may also impact the expectation that a derivative will provide offsetting cash flows over the hedge period. Therefore, whenever there is significant risk of counterparty default, a question arises as to whether a hedging relationship will be highly effective. Derivatives Implementation Group (DIG) Issue G10, *Cash Flow Hedges: Need to Consider the Possibility of Default by the Counterparty to the Hedging Derivative*, addresses this issue and states that a reporting entity should monitor the counterparty's creditworthiness throughout the hedge period. If the likelihood that the counterparty will not default ceases to be probable, the entity should discontinue hedge accounting.

Consistent with this guidance, a reporting entity should assess the probability of default associated with each of its hedging relationships. Indicators of deteriorating credit quality that could trigger the discontinuation of hedge accounting include the following:

- An increase in spreads on the counterparty's credit default swap rates
- A downgrade of the counterparty's credit rating by a rating agency
- A refusal by market participants to enter into new contracts with the counterparty
- A demand from market participants that the counterparty provide collateral for all new derivative contracts
- A widening of the credit spreads for the counterparty's public debt

In evaluating whether hedge accounting should be discontinued, a reporting entity should consider the specific facts and circumstances related to each counterparty and contract. In some cases, there may be mitigating circumstances (e.g., the counterparty's performance may be secured by collateral or a line of credit) that may indicate that the hedge accounting could continue despite the decline in the counterparty's credit quality. The requirement to continue to evaluate the impact of market events and declines in credit quality applies to all derivative instruments including commodity derivatives, interest rate swaps, and other instruments.

Monitor and Evaluate the Prospect of Counterparty Default

A reporting entity should assess the probability of default associated with each of its counterparty relationships. Indicators of deteriorating credit quality that could trigger the discontinuation of hedge accounting include an increase in spreads on the counterparty's credit default swap rates, a downgrade of the counterparty's credit rating, or other adverse market signals. These factors may also impact the application of the normal purchases and normal sales exception. Recent market events may increase the likelihood of problems. As a result, reporting entities should be monitoring significant counterparties and considering the potential effect of credit changes as part of the year-end reporting process.

Cash Flow Hedges

To the extent management determines that a cash flow hedging relationship no longer qualifies for hedge accounting, the overall change in fair value of the derivative instrument for that period, or subsequent to the triggering event if applicable, should be recognized in earnings. In those circumstances, a question arises as to the appropriate accounting for the amounts previously recorded as part of accumulated other comprehensive income (AOCI).

In accordance with FAS 133, paragraph 33, the net derivative gain or loss related to a discontinued cash flow hedge shall continue to be reported in accumulated other comprehensive income unless it becomes probable that the forecasted transaction will not occur. Therefore, in determining the appropriate accounting, the reporting entity should review the underlying hedge

documentation and consider the likelihood of occurrence of the forecasted transaction. This assessment may result in different conclusions depending on the specifics of the hedging relationship.

For example, in the case of a financially settled derivative instrument used to hedge physical portfolio purchases, the changes associated with the hedging instrument would have no impact on the probability of the forecasted transaction. However, in contrast, in assessing an all-in-one hedge, in which the underlying transaction is delivery of the asset under the hedging instrument itself, a reporting entity should consider whether delivery is still likely to occur (which would result in continued deferral of amounts in AOCI), or is now probable of not occurring (which would trigger immediate recognition in earnings).

Fair Value Hedges

For fair value hedges, nonperformance risk must be included in the measurement of the fair value of the hedging instrument. To the extent that market events cause the impact of credit on the measurement of fair value to be more significant, the hedging instrument may no longer qualify as highly effective in offsetting changes in the fair value of the designated hedged item. In such cases, the hedging transaction would be discontinued.

2.2.2 Normal Purchases and Normal Sales Exception

FAS 133, paragraph 10(b) specifies the requirements that a derivative contract must fulfill in order to qualify for the normal purchases and normal sales scope exception. For contracts designated as a normal purchase or normal sale under the requirements of FAS 133, paragraphs 10(b)(1) and 10(b)(4), a reporting entity must conclude that it is probable at inception and throughout the term of the contract that physical delivery will occur. Deterioration of the credit quality of the counterparty to a contract may call into question whether it is probable that the counterparty will fulfill its performance obligations under the contract (e.g., make physical delivery upon the contract's maturity).

If management determines that it is no longer probable that a contract will result in physical delivery, the contract no longer qualifies for the normal purchases and normal sales exception. Accordingly, such contracts should be recorded at fair value on the balance sheet, with the corresponding debit or credit recorded in earnings. Reporting entities should ensure that nonperformance risk is appropriately incorporated in determining the fair value of these contracts.

To prepare for year-end, reporting entities may want to start the evaluation process now to ensure they understand and can manage potentially negative financial reporting impacts from counterparty credit issues.

2.2.3 Other Derivative Considerations

Credit downgrades, consolidation of financial counterparties, and other issues may also result in a decrease in the level of activity for certain products, trading points, and trading tenors. In many cases, the initial determination that a contract was a derivative was based on the conclusion that the contract met the net settlement criteria outlined in FAS 133, paragraph 9(c), because it

requires delivery of an asset that is readily convertible to cash. However, to meet this criterion, an active spot market must exist today and be expected to exist in the future. Absent an active spot market, once the assets are delivered there is no opportunity for the parties to convert the assets into cash.

DIG Issue A18, *Application of a Market Mechanism and Readily Convertible to Cash Subsequent to the Inception or Acquisition of a Contract* (DIG Issue A18), requires "that the assessment of whether items to be delivered under a contract are readily convertible to cash must be performed at inception and on an ongoing basis throughout a contract's life." Therefore, as part of the year-end procedures and on an ongoing basis at the end of each reporting period, reporting entities should assess whether all applicable contracts continue to meet the readily-convertible-to-cash criterion, focusing on the existence and level of liquidity in the spot market. Because of the ongoing market issues, there is increased possibility of changes in this assessment in the months ahead.

2.3 Investments

Current market events may have negatively impacted the valuation of all security types, ranging from money market funds that have historically been protected from market fluctuations to real estate investments to illiquid hedge funds. For example, in September 2008, some money market funds "broke the buck" and the amount that will ultimately be realized upon liquidation of those funds is still uncertain. Many utilities and power marketers have significant investments in funds such as debt service reserves, decommissioning trust funds, other segregated funds, and corporate investments. As part of the year-end close procedures, reporting entities should continue to assess the appropriate valuation of investments carried at fair value, including consideration of whether any of their investments have an other-than-temporary-impairment (OTTI). OTTI losses arising from such investments must be recognized currently in earnings.

FASB Staff Position (FSP) Nos. FAS 115-1 and FAS 124-1, *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments*, provides guidance on determining whether an impairment of a security is other than temporary. In making this assessment, the reporting entity should consider:

- The investor's ability and intent to hold investments
- The severity and duration of the impairment
- The financial condition and near-term prospects of the issuer

The determination of an OTTI is highly judgmental, as the factors driving the conclusion are subjective.

In general, reporting entities must treat an impaired debt security as having an OTTI if it is probable that the reporting entity will be unable to collect all amounts due under the contractual terms of the security. In addition, unlike investments in debt securities, equity securities do not have contractual maturities; therefore, the investor cannot recover its investment simply by holding it until some future date. As a result, a forecasted recovery of an equity

security is typically even more subjective and less persuasive as evidence that no OTTI has occurred than a forecasted recovery of a debt security.

Furthermore, as a reminder, the SEC has concluded that a reporting entity cannot overcome the presumption of OTTI if the investor does not have the intent and ability to hold the investment until anticipated recovery. As a result, any decline in value of investments held in trust funds, such as nuclear decommissioning trusts, must be recognized immediately because the sponsoring entity does not control the underlying assets. To address this "one-sided" accounting, some reporting entities have adopted the fair value option for investments held in these trust funds.

Reporting entities should ensure they have an accounting policy to assess and determine OTTI in a consistent manner and should not rely solely on predetermined parameters in determining if an OTTI occurred. Reporting entities should prepare contemporaneous documentation supporting the conclusions they reached. In addition, reporting entities should ensure they perform appropriate procedures for the valuation of investments without quoted or readily available market prices.

2.3.1 Pension and Other Postretirement Investments

Valuation issues may also impact investments held by pension and other postretirement plans. Pension and postretirement benefit plans frequently hold less liquid investments, including real estate funds, private equity funds, and other investments without quoted prices. Due to a lack of liquidity and quoted prices, reporting entities may have difficulty estimating the fair value of certain of these investments. Depending on the nature of investments held in their pension and other postretirement plans, reporting entities will want to consider whether current market events necessitate adjustments to their expected returns on plan assets, and consider whether there is any resulting impact on benefit plan liabilities. Reporting entities should start the process of evaluating these investments now to ensure an appropriate valuation approach, which incorporates the requirements of FAS 157, is developed and implemented prior to year-end.

2.4 Impairments and Discontinued Operations

Market events may have triggered impairments of goodwill or long-lived assets or may result in business decisions to dispose of certain plants or other operations. Specific considerations for year-end reporting include the following:

2.4.1 Long-Lived Assets

The dichotomy facing utilities today is that, while long-term growth continues to spur the need for major capital expansion, in some cases companies may also be threatened with potential plant impairments because of the overall economic environment. This question is particularly relevant to those operating in the merchant energy sector, whereby volatility in fuel costs may not be locked into a rate or contract recovery mechanism. Rather, these reporting entities typically depend on successful hedging strategies to assure their margins. The recent softening of natural gas pricing may have alleviated some concerns about potential impairments of natural gas-fired plants; however, the long-term horizon continues to demonstrate an elevated cost of fuel for

generation. In addition, the slump in the economy may strain short-term growth and demand for power as customers tighten spending, putting pressure on projected sales volumes and resulting cash inflows.

FASB Statement No. 144, *Accounting for the Impairment and Disposal of Long-Lived Assets* (FAS 144), requires that reporting entities test whether their long-lived assets are impaired and record an adjustment, if necessary, when conditions arise that would indicate that impairment may be present. During the close of this year and in preparation for year-end reporting, accounting teams should work with other applicable company personnel to carefully consider whether circumstances warrant impairment testing of their long-lived capital assets. Recent changes in conditions may indicate that reporting entities will be unable to recover the carrying amount of certain assets through their future operations. In performing these impairment analyses, utilities and power companies should thoughtfully assess the reasonableness of their assumptions over revenue growth, margins, and costs in the cash flow projections, taking into account current market conditions.

2.4.2 Goodwill Impairments

The recent volatility in the capital markets also may have triggered potential impairments of goodwill. This has become a focus area for the SEC as the market capitalization of some reporting entities declines below book value. In addition, utilities and power marketers may face goodwill issues related to separate reporting units as market conditions adversely impact operations and growth.

Key considerations for year-end reporting include the timing of the goodwill impairment test and the sources of information considered. Many reporting entities have established impairment testing dates prior to year-end. However, if market factors and financial results suggest a potential issue as of December 31st, another impairment test may be triggered. In evaluating whether an impairment test is required, reporting entities should consider market capitalization, financial results, and forecasts to see if there have been changes from original projections. This may require involvement of personnel from operating departments and others with comprehensive knowledge of future business prospects. In performing the test, reporting entities should ensure that they are meticulous in evaluating all available information, contemporaneously documenting all conclusions reached.

2.4.3 Discontinued Operations

As utilities and power marketers assess their current operations, in some cases, they may be electing to discontinue certain business lines or sell certain underperforming assets. FAS 144, paragraph 42, requires that the results of operations of a component of an entity that has been disposed of or is classified as held for sale shall be reported in discontinued operations if both of the following conditions are met:

- The operations and cash flows of the component have been (or will be) eliminated from the ongoing operations of the entity as a result of the disposal transaction

- The entity will not have any significant involvement in the operations of the component after the disposal date

Emerging Issues Task Force (EITF) Issue No. 03-13, *Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations* (EITF 03-13), provides additional guidance in evaluating potentially discontinued operations. EITF 03-13 specifically addresses how an entity should evaluate whether the operations and cash flows have been eliminated and the types of continuing involvement that constitute significant continuing involvement.

During the current year, reporting entities should continue to account for potential discontinued operations in accordance with the relevant criteria of FAS 144 and EITF 03-13. However, management teams should be aware that proposed FSP FAS 144-d, *Amending the Criteria for Reporting a Discontinued Operation* (FSP FAS 144-d), will change the criteria and disclosures for discontinued operations and assets held for sale. FSP FAS 144-d was issued as part of the overall convergence project between FASB and the International Accounting Standards Board (IASB), and provides a common definition of a discontinued operation. In accordance with the proposed standard, a discontinued operation is either:

- A component of an entity that is an operating segment, as defined in FASB Statement No. 131, *Disclosures about Segments of an Enterprise and Related Information*
- A business, as defined in FAS 141(R), that meets the criteria to be held for sale on acquisition

FSP FAS 144-d also requires specific disclosures for components of an entity that have been disposed of or classified as held for sale.

If adopted in its current form, FSP FAS 144-d will be effective for fiscal years beginning after December 15, 2009 (January 1, 2010 for calendar year-end companies), with retrospective application required. Reporting entities with potential or reported discontinued operations should be aware of these proposed changes and the potential impact on future reporting.

2.5 Presentation and Disclosure Issues

Recent market conditions have led to intense scrutiny of financial statement disclosures, as investors and other financial statement users dissect disclosures about liquidity, market risks, and, in certain instances, going-concern considerations. As further described below, SEC rules require certain disclosures regarding public companies' liquidity and management of market risks, including the availability of capital resources and market risks associated with interest rate, currency, equity price, or commodity exposures, as applicable. In addition, if any of these risks raise substantial doubt about an entity's ability to continue as a going concern, additional disclosures are required in the management's discussion and analysis section and in the financial statements.

2.5.1 Liquidity

The consolidation and government intervention in the financial services sector has amplified investor interest in liquidity information for all reporting entities. In the utility and power markets sector, there is pointed interest in disclosures around collateral requirements and the potential impact of credit rating changes, especially for entities heavily involved in trading operations. The SEC frequently requests additional disclosure in this area, including disclosures that are highlighted in Figure 2-2.

Figure 2-2 Suggested Liquidity Disclosures

Due to the extensive use of financial instruments, including derivatives, cash and margining agreements, and debt arrangements by utilities and power marketers, these disclosures may be particularly important for this industry:

- The potential impact to the reporting entity as a result of a downgrade in its credit rating (e.g., contracts that require posting of collateral or allow early counterparty termination)
- Changes in counterparty credit risk, including to insurers and derivative counterparties that are experiencing financial difficulties and/or downgrades in their credit ratings
- How material adjustments to estimates affect capital resources, reflecting current market conditions (not just historical trends)
- An explanation of the gap between perceived market expectations about the reporting entity's performance and the actual performance itself (e.g., why there is no goodwill impairment, no other-than-temporary impairment)
- Subsequent events that may impact the reporting entity's liquidity and capital resources
- Any early warning disclosures about the possibility of an asset or goodwill impairment with a discussion of the conditions that would lead to such an impairment in future periods
- Ease with which or challenges faced in availability of funding sources for current liquidity (e.g., if credit facilities are uncommitted)
- The current or future impact that a lack of previously available funding sources has on the reporting entity (e.g., significant reduction in commercial paper program, limitations imposed on existing lines of credit)

Reporting entities should also consider disclosure of changes in management's intent to hold securities until recovery and the impact on the other-than-temporary impairment analysis, if impaired securities are needed for current liquidity.

Liquidity disclosures should include robust and transparent discussions of current and anticipated uncertainties about commitments or demands that are "reasonably likely" to result in a material change. Furthermore, if a reporting

entity knows of, or anticipates, such uncertainty, it must disclose an appropriate course of action. The disclosures may include reference to internal and external sources of available liquidity, a description of the reporting entity's use of assets, and a discussion of other available remedies. Reporting entities should consider the applicability of these disclosures as they prepare their year-end financial statements.

In some cases, reporting entities may have remarketing agreements, commercial paper arrangements, letters of credit, or other credit support facilities with financial institutions experiencing financial difficulty. Market issues may adversely impact the availability of credit support or letters of credit, which may have an unfavorable effect on both an entity's liquidity and the classification of debt. For example, a reporting entity may have bonds subject to weekly remarketing agreements that are classified as long-term due to the existence of a long-term credit agreement. The reporting entity should consider the status and availability of related credit facilities in determining the appropriate classification of the underlying debt.

In addition, some reporting entities may have debt that was insured by third parties. Credit issues experienced by these institutions could impact the credit rating of the underlying debt, potentially impacting compliance with covenants or interest rates, or creating other issues. Reporting entities should continue to monitor such relationships and consider the accounting implications, as applicable.

2.5.2 Market Risks

Reporting entities should include robust and transparent disclosure of recent material changes in managing market risks (e.g., interest rate risk, commodity price risk). The risk disclosures should include a discussion of significant assumptions so that investors and other users of the financial statements understand management's process for determining the potential impact of and related sensitivity to change. Any limitations on the assumptions that could impact the sensitivity, such as the likelihood of potential scenarios that are considered under a model or the expected volume increases that might need to be made to satisfy commodity price increases, should also be disclosed.

2.6 References

In addition to the relevant authoritative guidance, reporting entities may refer to the following list of current sources of PricewaterhouseCoopers (PwC) guidance on the topics addressed in this section. Additional guidance will be issued as these matters continue to evolve.

- DataLine 2008-24, *Third Quarter Considerations Given Current Market Conditions*
- DataLine 2008-22, *Accounting Considerations Related to Other-Than-Temporary Impairment of Certain Investments in Debt and Equity Securities*
- DataLine 2008-20, *Impact of FAS 157 on the Measurement and Disclosure of Pension/OPEB Plan Assets*

- DataLine 2007-03, *SEC Staff View Regarding the "Ability to Hold a Security to Recovery" for Purposes of Assessing Other-than-Temporary Impairments of Investments, Including Nuclear Decommissioning Trust Funds*
- DataLine 2006-04, *Evaluating Whether Certain Investments Are Other-than-Temporarily Impaired*
- DataLine 2002-04, *Accounting for a Possible Counterparty Default with Respect to a Hedging Derivative – Guidance which may be Relevant to Contracts with Enron*
- PwC 2007 *Guide to Fair Value Measurements*

These sources of additional guidance are available through PwC's CFOdirect Network (www.cfodirect.com) and PwC's Comperio research tool.

Section 3: Fair Value Measurements

Section 3: Fair Value Measurements

3.1 Overview

It has been less than one year since reporting entities in the United States (U.S.) adopted FAS 157. Despite its short implementation life-to-date, this standard has been one of the most talked-about sources of accounting guidance and has become a focal point in the intense debates over the cause of the economic crisis. The tumultuous events of the past year have undoubtedly pushed fair value accounting into the spotlight. A dispute continues between supporters of fair value, in some cases, with a view towards a full-fair value model, and opponents calling for the abandonment of fair value accounting altogether as summarized in Figure 3-1:

Figure 3-1

The Debate Over Fair Value

Although fair value accounting for many financial instruments is embedded throughout generally accepted accounting principles, debate over the application of fair value and FAS 157 has ensued throughout the last 18 months of financial turmoil. Differing viewpoints are likely to persist for years while practice issues are ironed out and the economy returns to a normalized state. Key points to the debate include:

Supporters

- Fair value accounting reflects economic reality, which facilitates accurate policy and investment decision-making.
- Fair value accounting was not the root cause of the credit crisis. Rather, the problems were driven by:
 - (a) Declining real estate values
 - (b) Relaxed underwriting standards
 - (c) The decisions made by lenders, borrowers, and investors

Critics

- Fair value accounting has created a downward spiral in prices.
 - The impairment of financial assets that we are observing is not factual.
 - Using an exit price is not appropriate because:
 - (a) It distorts the true value, particularly in a distressed market
 - (b) It does not reflect management's intent for use or disposition of the asset
-

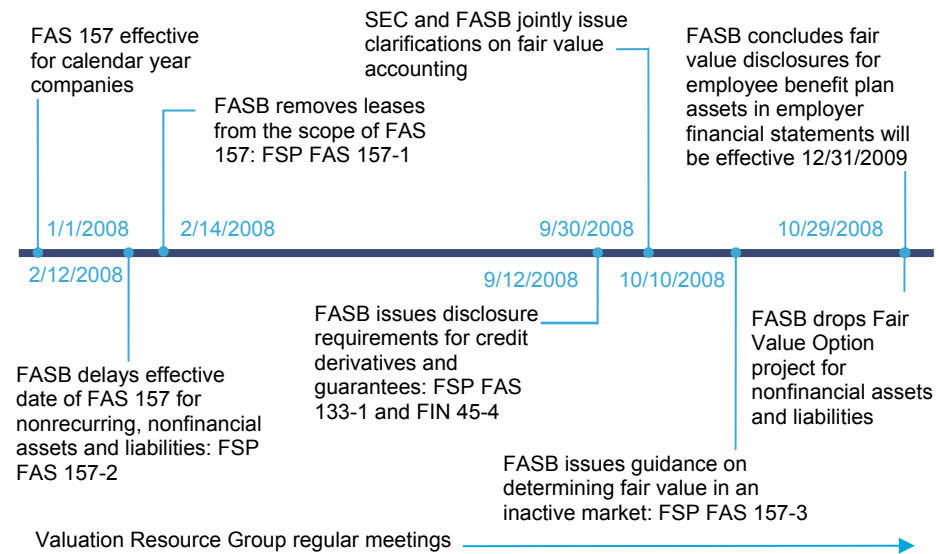
Over the period of this escalating discussion, reporting entities, financial reporting regulators, and standard setters have been working through numerous practice issues associated with FAS 157. The inherent complexities with estimating and disclosing fair value have been exacerbated by the credit crisis and economic difficulties experienced in the financial services industry, which have cascaded through other industries. As a result, new authoritative guidance has been issued, ranging from the delay of the implementation of FAS 157 for nonfinancial assets and liabilities in early 2008, to the issuance of the SEC Office of the Chief Accountant and FASB Staff Clarifications on Fair

Value Accounting (the SEC/FASB Joint Release) and FASB Staff Position No. 157-3, *Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active* (FSP FAS 157-3) in September and October 2008. Most recently, Phase II of the fair value option (for nonfinancial assets and liabilities) was dropped from the FASB agenda.

Figure 3-2 demonstrates the timeline of guidance issued during 2008.

Figure 3-2

Timeline of Fair Value Guidance in 2008



In 2007, the FASB formed the Valuation Resource Group (VRG) to address issues relating to valuation. The VRG, which comprises members representing financial statement preparers, auditors and standard setters, met several times during the past year to discuss FAS 157 implementation issues. While not a standard-setting body, the VRG was established to bring issues that the preparer community is struggling with to the attention of the FASB staff.

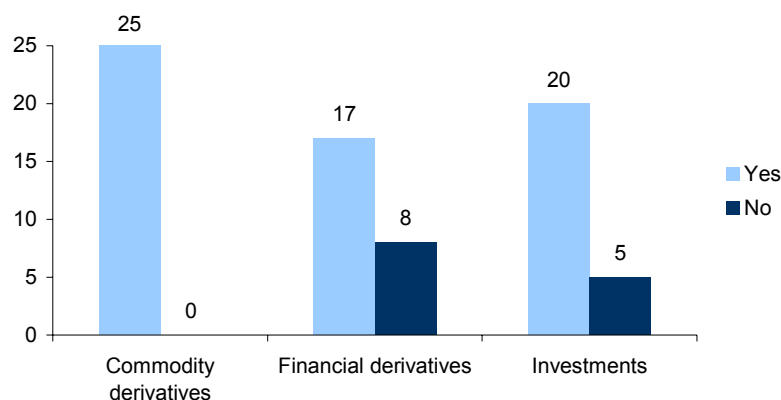
As demonstrated by the continual debate, scrutiny and standard setting, it has been an active year for fair value measurements. In the midst of this discussion, reporting entities have been required to apply FAS 157 to their recurring fair value measurements. This section discusses trends in reporting year-to-date, provides reminders about issues that are critical for 2008 year-end reporting, and highlights important considerations for 2009.

3.1.1 Fair Value Reporting Trends in 2008

Utilities and power marketers have been applying FAS 157 to derivatives and other financial instruments measured at fair value for almost a year. During that period, many reporting entities have toiled to ensure appropriate classification within the fair value hierarchy, to develop an approach to nonperformance risk, and to properly apply the other concepts embedded in

FAS 157. To provide perspective to reporting entities as they prepare for their year-end measurements and disclosures, PwC reviewed the quarterly fair value disclosures made during 2008 by 25 major electric and combination utilities and power marketers. We have summarized certain major trends as follows (note all data based on September 30, 2008 disclosures):

Figure 3-3
Types of Fair Value Measurements



Some of the other fair value measurements disclosed by the reporting entities reviewed included cash and cash equivalents and collateral.

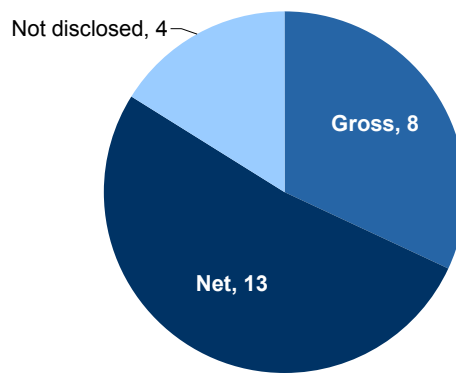
Figure 3-4
Fair Value Measurement Policy Elections

	Yes		Not disclosed	
Pricing convention				
• Mid-point	6	24%	14	56%
• Bid-ask	5	20%		
Application of credit reserves	16	64%	9	36%
Disclosure of credit reserve amount	1	4%	24	96%
EITF 02-3 cumulative effect	7	28%	18	72%
Level 3 transfer convention – beginning of period	3	12%	22	88%
Fair value option	3	12%	22	88%

Two of the companies that adopted the fair value option applied it to nuclear decommissioning trust securities; the other applied it to investments in debt securities. None of the companies included in the benchmarking study reported any impact of reserves on hedging.

We also evaluated trends in the adoption of FASB Staff Position FIN 39-1, *Amendment of FASB Interpretation No. 39* (FSP FIN 39-1), which was effective as of January 1, 2008 for calendar year-end companies. In accordance with FSP FIN 39-1, reporting entities may elect to report certain derivative assets and liabilities subject to a master netting arrangement on a gross or net basis on the balance sheet. If an entity elects net presentation, it is also required to net related collateral amounts, to the extent such amounts are reported at fair value. The adoption of FSP FIN 39-1 provided reporting entities with an opportunity to change their prior election.

Figure 3-5
Application of FSP FIN 39-1



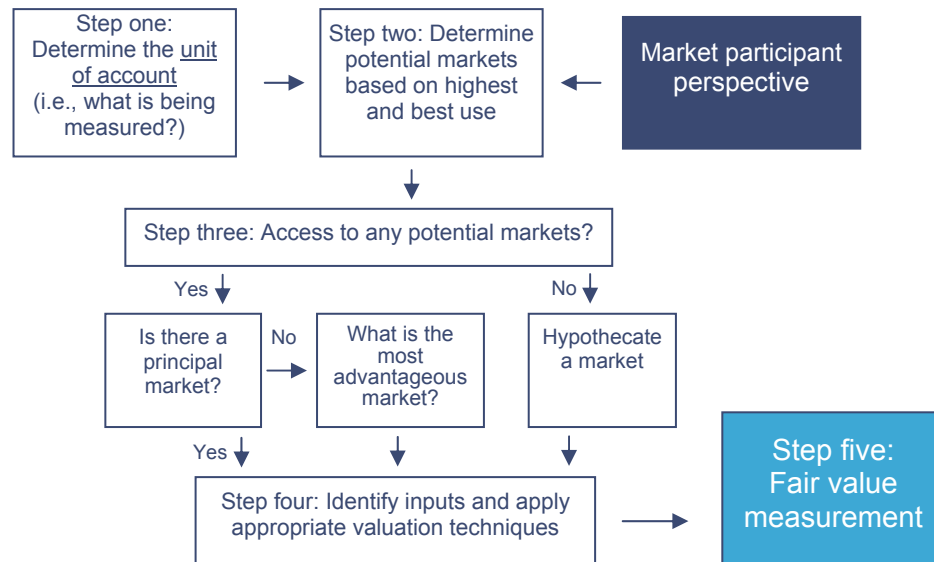
Of the 25 reporting entities surveyed, 14 disclosed cash collateral amounts in the fair value hierarchy table or a separate footnote.

3.2 Overall Application

As reporting entities prepare for their year-end calculations and disclosures of fair value measurements, they should refresh their understanding of the underlying FAS 157 framework. A comprehensive grasp of the key FAS 157 concepts is critical to properly measuring amounts at fair value. FAS 157 does not require any new fair value measurements, but instead creates a consistent framework for the various fair value requirements or elections already existing within generally accepted accounting principles. Figure 3-6 depicts the overall framework for applying FAS 157 to estimate fair value.

The key concept that must be applied is that all fair value measurements should be determined from the perspective of a market participant. In addition, the reporting entity must ensure that it applies the appropriate valuation techniques. FAS 157 outlines three valuation techniques: the cost approach, the income approach, and the market approach. FAS 157 does not prescribe which valuation technique(s) should be used. Instead, it states that reporting entities should measure fair value using the valuation techniques applicable in the circumstances and for which sufficient data are available.

Figure 3-6
Application of FAS 157



Determination of the appropriate fair value measurement requires proper application of the fair value framework.

3.3 Nonperformance Risk

Recent market events and certain counterparty defaults have drawn attention to the importance of one of the most subjective aspects of many valuations — the impact of the risk of nonperformance. Nonperformance risk is the risk that an entity will not perform on its obligation. Credit risk is frequently the largest component of nonperformance risk, especially when measuring the fair value of financial assets and liabilities.

The requirement to incorporate nonperformance risk has been one of the key challenges facing reporting entities when applying FAS 157 to the measurement of certain assets and liabilities at fair value. In considering credit risk, the fair value measurement must be calculated based on the market participant point of view of risk of default. In some cases, that information may not be consistent with the reporting entity's perspective of its own risk or the risk associated with a particular counterparty. However, a reasonable approach to develop credit reserves should consider all available sources of information that market participants would look to when determining how much they would pay to purchase an asset or require to be paid to take on a liability. Such information can be adjusted and weighted to the extent that the reporting entity believes that it is not reflective of market conditions. The rationale for the approach used, and any adjustments made, should be specifically documented as part of the credit assessment.

Key factors in the determination of credit risk include the following key components:

3.3.1 Determine Unit of Credit Risk Measurement

The measurement of credit risk should incorporate all factors that may impact the exposure including collateral requirements, master netting arrangements, parent company guarantees, and structuring considerations. Due to the potential effect of these factors on the calculation of the credit reserve, a reporting entity should ensure that it obtains a full understanding of its rights and obligations associated with a particular contract or counterparty prior to the detailed calculation of the credit adjustment.

3.3.1.1 Impact of Third-Party Credit Enhancements

The EITF recently addressed the accounting for inseparable third-party credit enhancements in EITF Issue No. 08-5, *Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement* (EITF 08-5). The EITF reached a final consensus that the issuer of a liability with a third-party credit enhancement (such as a guarantee) should not include the effect of the credit enhancement in the fair value measurement of the liability. In accordance with this guidance, the credit value adjustment would be calculated as though there was no third-party guarantee, letter of credit, or other form of credit enhancement. Long-term debt and derivative instruments are frequently issued with a third-party guarantee or an underlying credit support arrangement. However, in accordance with this guidance, the issuer of the debt or derivative would ignore the credit enhancement in calculating credit risk and would revert to its own credit.

Note that the guidance in EITF 08-05 does not apply to the holder of the liability. Therefore, the counterparty should consider the benefit of any inseparable third-party credit enhancements in its valuation of a liability.

The guidance in EITF 08-05 should be applied prospectively beginning in the first reporting period after December 15, 2008 (first quarter 2009 for calendar year-end companies). Early adoption is permitted. In accordance with the requirements of Staff Accounting Bulletin (SAB) No. 74, *Disclosure of the Impact That Recently Issued Accounting Standards Will Have on the Financial Statements of the Registrant When Adopted in a Future Period* (SAB 74), public companies should consider disclosing the impact of adoption of this standard in periodic filings made prior to adoption.

3.3.2 Apply a Market Participant Perspective to Available Credit Information

In measuring credit risk, a reporting entity must acquire and evaluate data related to the probability of default and the cost of laying off that risk to another party. When evaluating the impact of credit on a fair value measurement, a reporting entity should consider current market conditions and whether the data it is using appropriately incorporates the most recent market trends. Some data sources may be more responsive to current conditions, while other information may lag.

The following table highlights certain benefits and concerns associated with incorporating the various indicators of potential default into a credit calculation:

Figure 3-7
Comparing Credit Information

Method	Advantages	Disadvantages
Historical default rates	<ul style="list-style-type: none"> • Default information provides one measure of risk and is widely available • Cumulative historical default rates are routinely published by a variety of sources 	<ul style="list-style-type: none"> • Useful only to the extent that historical rates and the market environment are indicative of future conditions • Lags market events • Does not reflect entity-specific information
Bond prices and yields (credit spreads)	<ul style="list-style-type: none"> • Bond prices can be obtained for any publicly traded debt instrument • Provides more accurate depiction of current market view of credit risk than historical default rates 	<ul style="list-style-type: none"> • May be difficult to apply if publicly traded instruments are not available • May not be as responsive to current market events as credit default swap rates
Credit default swaps (CDS)	<ul style="list-style-type: none"> • Current market view of credit risk associated with a specific entity • CDS rates related to a particular industry segment may also be useful in assessing risk 	<ul style="list-style-type: none"> • CDS rates may be volatile and thinly traded • Not available for all companies

In the utility industry, historical practice has been to incorporate credit risk based on the counterparty (for an asset) or reporting entity (for a liability) credit rating and the corresponding historical default rates. However, FAS 157 requires that the measurement of fair value incorporate a market participant perspective. Historical default information is generally not entity specific and may not be reflective of current market conditions. Bond yields and CDS rates provide the most current market view of credit risk associated with a specific entity.

To the extent that entity-specific bond yields or credit spreads are not available, sector information is considered to provide a more reliable indication of the market view of risk of default than use of historical default rates alone. As such, use of historical default information to calculate nonperformance risk is generally not sufficient and other market data should be incorporated.

3.3.3 Calculate the Credit Reserve

Various methodologies are used to calculate and incorporate the credit reserve in the measurement of fair value. There is some flexibility in the method selected; however, management should take a consistent approach to similar measurements. In determining the appropriate methodology to apply for

calculation of the credit reserve, the reporting entity should consider how a market participant would be expected to approach the calculation. Note that market conditions may evolve over time and reporting entities should continue to assess their approach to ensure consistency with updated market participant assumptions.

The key methods that may be used in the calculation of the credit reserve include the discount rate adjustment technique, whereby the risk-free rate is adjusted by credit spreads or CDS rates, or a standalone measurement where CDS rates are separately applied to calculate a credit reserve.

3.3.4 Allocate Credit Reserve to Individual Fair Value Measurements

Once the reporting entity has determined the appropriate credit reserve or adjustment for nonperformance risk, it must ensure that the amount is appropriately classified and disclosed. This process is relatively straightforward in the case of a standalone instrument for which the credit reserve is calculated on an individual basis. However, as a result of collateral or the impact of master netting arrangements, a reporting entity may be required to allocate the calculated reserves among various balances. There may be specific challenges in allocating these reserves among short- and long-term assets and liabilities on the balance sheet, between income and other comprehensive income, and in the fair value hierarchy disclosures.

3.3.4.1 Allocation Methods

The question of how to allocate a portfolio-level credit value adjustment to individual contracts arose during the first quarter of adoption of FAS 157 and was discussed with the SEC staff. Several allocation methods were discussed, including the relative fair value approach, relative credit adjustment approach, marginal contribution approach and "in-exchange" or full-credit approach.¹ Any one of those methods is acceptable when appropriate in the circumstances and consistently applied. Other methods also may be used as long as a reporting entity can support that the method is appropriate for its fact pattern. The method selected should be consistently applied and clearly disclosed.

3.3.5 Impact of Nonperformance Risk on Hedging

FAS 133 requires assessment of effectiveness at inception of a hedge and on at least a quarterly basis. As a result of the requirement to incorporate nonperformance risk in the valuation of derivatives, a question arises as to the impact of these adjustments on the effectiveness assessment when hedge accounting is applied. The impact of considering nonperformance risk may vary depending on the type of hedge (fair value hedge versus cash flow hedge) and the method elected to test hedge effectiveness.

Based on discussions with the SEC in April 2008, we believe that a qualitative approach may be used to determine whether nonperformance risk for a

¹ See further discussion and description of these methods in DataLine 2008-06, *Assessing the Impact of Nonperformance Risk on Derivative Instruments Included in a Master Netting Arrangement*. This DataLine is available through PwC's CFOdirect Network (www.cfodirect.com) and PwC's Comperio research tool.

portfolio of derivatives in a master netting arrangement will impact hedge qualification for the individual derivatives in the portfolio. This qualitative approach may be used for both fair value and cash flow hedges. If the reporting entity is able to support the assertion that nonperformance risk will not impact qualification for hedge accounting, the impact of that nonperformance risk does not need to be allocated for the purpose of assessing hedge effectiveness. However, if the preparer believes that nonperformance risk may impact hedge qualification, the impact of that nonperformance risk should be allocated in a reasonable and consistent manner.

In addition, preparers must continue to measure and record ineffectiveness, considering the impact of changes in fair value due to nonperformance risk, based on the methodologies of assessing and measuring effectiveness and ineffectiveness described above.

3.4 Fair Value Hierarchy

To increase consistency and comparability in fair value measurements, FAS 157 establishes a fair value hierarchy to prioritize the inputs used in valuation techniques.

Figure 3-8
Fair Value Hierarchy

The fair value hierarchy gives the highest priority to quoted prices in active markets and gives the lowest priority to unobservable inputs. Some of the key differentiating factors are:

Level One	Level Two	Level Three
<ul style="list-style-type: none"> • Observable • Quoted prices for identical assets or liabilities in active markets 	<ul style="list-style-type: none"> • Quoted, similar items in active markets • Quoted, identical/similar items, no active market • Must be observable for substantially the full term 	<ul style="list-style-type: none"> • Unobservable inputs (e.g., a company's own data) • Market perspective still required

Level 1 inputs should be used whenever available. Valuations using Level 3 inputs require significantly more disclosure.

In accordance with FAS 157, valuation techniques should maximize the use of observable inputs and minimize the use of unobservable inputs. By distinguishing between inputs that are observable in the marketplace, and therefore more objective, and those that are unobservable, and therefore more subjective, the hierarchy is designed to indicate the relative reliability of the fair

value measurements. Determining the appropriate level in the hierarchy is important, as this information is relied on by financial statement users to help assess the overall quality of a reporting entity's fair value measurements.

Application of the fair value hierarchy is particularly challenging to electricity and natural gas commodity contracts due to the lack of observable forward price data for many locations and products. As a result, fair values are typically developed through a combination of observable forward prices, information obtained from brokers and pricing services, and proprietary models. Key issues associated with the application of the fair value hierarchy to derivative commodity contracts are further discussed below.

3.4.1 How is an Active Market Defined?

The determination of whether inputs are observable is one of the key factors that will impact the classification of an input within the hierarchy. The level of activity in the market will contribute to the determination of whether the input is observable. An observable input that may otherwise be a Level 1 input will be rendered Level 2 if the information relates to a market that is not active. For example, long-dated tenors of natural gas contracts traded on the New York Mercantile Exchange (NYMEX), may have limited trading activity. In that case, although the valuation may be based on quoted prices which may suggest a Level 1 measurement, the lack of liquidity would force classification as Level 2.

Although it may be obvious in some cases that a market is active or inactive, in other situations it may be difficult to determine whether a market qualifies as active. The term "active market" is used throughout accounting literature, including within FAS 157, within the definition of readily convertible to cash in FAS 133, and within the American Institute of Certified Public Accountants (AICPA) Audit and Accounting Guide, *Investment Companies* (Investment Company Guide). In considering the definition of an active market, FAS 157, paragraph 24, provides the following guidance:

....An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. A quoted price in an active market provides the most reliable evidence of fair value and shall be used to measure fair value whenever available, except as discussed in paragraphs 25 and 26.

The working draft of FAS 157, paragraph 21, also provided the following guidance:

Markets in which assets and liabilities are exchanged vary in structure and level of activity. For example, in an active market, transactions for the asset or liability occur with sufficient frequency to provide pricing information on an ongoing basis. Therefore, a quoted price in that market will be both readily available and representative of fair value. In a market that is not active, for example, a market in which there are few transactions for the asset or liability or price quotations vary substantially either over time or among market makers, a quoted price might not be readily available or representative of fair value.

Although this guidance was not included in the final version of FAS 157, it provides useful guidance in assessing whether a market is active. Section 4.4.1 of the PwC *Guide to Fair Value Measurements* also provides useful guidance in assessing whether data is observable and market-based. Based on this guidance, in order to be deemed an active market, a market must have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. In addition, quoted prices from that market will be readily available on an ongoing basis.

Reporting entities should consider this guidance as they evaluate the classification of fair value measurements that consist of market-based information.

3.4.2 Classification of Valuations Based on Broker Quotes

Due to the lack of observable data for many electricity and natural gas derivative instruments, reporting entities in this sector may rely heavily on the use of broker quotes or information from pricing services when measuring the fair value of financial instruments or derivatives. In accordance with the guidance provided by FAS 157, a valuation that is solely based on indicative broker quotes or prices obtained from a pricing service is a Level 3 valuation. For these inputs to move up in the fair value hierarchy (i.e., to a Level 2 measurement), the input must be sufficiently corroborated to observable market data. Absent corroboration through observable information (e.g., a trade for the same or a similar product and quantity at the same location on the same date), these inputs remain in Level 3.

Corroboration can take many forms. The important element of corroboration is that the corroborating support must be derived from market observable information. Ultimately, market observable information derives from and can be traced to trades. Depending on the volume of activity, the nature and level of corroboration to trades can range from tracing to trades on the exact day of the valuation for every price, or a sample of trades at different times. A well-established control should be implemented, monitored, and tested on a regular basis to ensure the form of corroboration continues to produce valid results. For example, a reporting entity could implement procedures to agree quotes from a particular broker to actual market transactions as part of its regular forward pricing validation procedures.

Certain forms of validation are not considered sufficient corroboration. For example, obtaining multiple indicative broker quotes does not constitute corroborating evidence; validating a Level 3 input with another Level 3 input does not render a higher-level input.

3.4.3 Other Broker Quote Considerations

Since the issuance of FAS 157, there has been significant discussion around the use of broker quotes and pricing services when determining the fair value of financial assets and financial liabilities. This topic continues to be a focus of the SEC and the Public Company Accounting Oversight Board (PCAOB).

In general, these service providers are not considered "experts" for reporting purposes and cannot be referenced in a financial filing without consent. In addition, the fact that a broker or pricing service is well known, utilized in the

marketplace, and considered reliable is not considered a substitute for management performing its own due diligence on the pricing input or valuation. Therefore, the SEC has emphasized that management should perform sufficient procedures to take responsibility for their fair value measurements based in part or in whole on broker quotes or inputs obtained from pricing services.

Management should consider the following when using information from a broker or pricing service in developing a fair value estimate:

- Is the quote being provided as an accommodation or is the broker standing ready to trade at the quoted price?
- Is the price obtained based on a quote in an active market, or an observable price in an inactive market, or an observable price for a similar asset or liability?
- Alternatively, is the price unobservable and therefore computed using a model?

If the price was developed based on a model, management should discuss the modeling technique with the broker or pricing service to understand how it was developed. Management should be comfortable with the modeling technique, the assumptions used, and the source of the inputs. It is necessary to gain an understanding sufficient to be able to take responsibility for the fair value measurement, to ensure it has been developed appropriately using the concepts in FAS 157, as well as for the determination of its classification in the fair value hierarchy.

As noted above, management should ensure that quotes used to estimate the fair value follow the concepts of FAS 157. For example, when using broker quotes for liabilities, a reporting entity should consider whether the quote represents a settlement or transfer price (e.g., interest rate swaps which may be quoted at the flat London Interbank Offered Rate (LIBOR) swap rate may be considered a settlement price). Management should also ensure that the principal or most advantageous market has been appropriately considered in the development of the quote.

Public Company Accounting Oversight Board Guidance

In December 2007, the PCAOB issued its Audit Practice Alert No. 2, *Matters Related to Auditing Fair Value Measurements of Financial Instruments and the Use of Specialists* (PCAOB Alert 2). PCAOB Alert 2 provides auditors with additional information on 1) auditing fair value measurements and disclosures and 2) the use of specialists when preparing fair value measurements. It also specifically addresses pricing services:

If a company uses a pricing service for its fair value measurements, the auditor should determine the nature of the information provided by the pricing service. For example, the auditor should understand whether the fair value measurement was determined using quoted prices from an active market, observable inputs (such as prices for similar assets), or fair value measurements based on a model, and adjust his or her audit procedures based on the nature of the information provided by the pricing service. In

addition, if the price is not based on quoted prices from an active market or observable inputs (such as prices for similar assets), the auditor should obtain an understanding of the model and evaluate whether the assumptions are reasonable.

...when a company uses a pricing service, the auditor should evaluate whether the assumptions used by the pricing service reflect the price to sell the asset or paid to transfer the liability in the principal market (or most advantageous market if the company has no principal market) of the company. If the pricing service valuation is based on actual trades or quotes, the auditor should evaluate whether those traded or quoted prices would be available to the company in the company's principal market (or most advantageous market, if the company has no principal market)...

Reporting entities and auditors alike should ensure that they are familiar with PCAOB Alert 2, because it provides useful information about the expectations around fair value measurements and use of specialists (including pricing services) by both management and the auditor.

Focus on Broker Quotes for Year-End Reporting

The presumption that a reporting entity understands and has validated information received from broker quotes and pricing services was a basic premise of the SEC/FASB Joint Release and in FSP FAS 157-3. Given the level of attention to this issue from the SEC, PCAOB, and FASB, it is important for reporting entities to ensure that they have appropriately supported and corroborated any information received from brokers and pricing services used in their fair value measurements.

3.5 Scope of FAS 157 Disclosure Requirements

In addition to the difficulty in determining appropriate classification within the fair value hierarchy, determining which fair value measurements should be included in the tabular disclosures (FAS 157, paragraphs 32 and 33) is another challenge for reporting entities. For some instruments measured at fair value on a recurring basis, such as derivatives and investments, the disclosure requirements are clear. However, there are ongoing questions around inclusion in the fair value hierarchy disclosures of other amounts commonly held by utilities and power marketers, such as cash equivalents and collateral, amounts measured at fair value for disclosure purposes only (such as long-term debt where the fair value option has not been applied), and investments held by pension and other post-retirement benefit plans.

Figure 3-9 summarizes the disclosure requirements for these fair value measurements:

Figure 3-9
Required Fair Value Disclosures

Instrument	Include in Fair Value Disclosures?	
Cash equivalents	It depends	<ul style="list-style-type: none"> • Cash equivalents may be debt or equity securities subject to the requirements of FAS 115 • Reporting entities should determine and document their FAS 115 accounting model (trading, available-for-sale, held-to-maturity) • Securities classified as trading or available-for-sale are recorded at fair value and should be included in the fair value hierarchy disclosures
Collateral and margin deposits	Yes	<ul style="list-style-type: none"> • Amounts are considered a fair value measurement under FSP FIN 39-1 • Amounts should be included in the fair value hierarchy disclosures whether presented gross or net
Investments held by pension and postretirement benefit plans	Not yet for employer financial statements	<ul style="list-style-type: none"> • FAS 157 framework applies to measurement of investments held by pension and other postretirement benefit (OPEB) plans at the employer and plan level • Disclosure provisions apply to the plan financial statements, but not to the employer's financial statements • Proposed FSP 132(R)-a will require disclosures similar to FAS 157 in employer's financial statements; proposed effective date of years ending after December 15, 2009
Amounts subject to FAS 107 disclosures	Partially	<ul style="list-style-type: none"> • FAS 157 framework applies to amounts measured at fair value for disclosure purposes only (FAS 107 disclosures) • Method(s) and significant assumptions used to estimate fair value should be disclosed; tabular disclosures are encouraged but not required

The basis for conclusion for each of these disclosure requirements is further discussed below.

3.5.1 Cash Equivalents

Many reporting entities classify certain short-term debt and equity securities, such as treasury bills, commercial paper and money market funds, as part of cash equivalents. This classification is consistent with the guidance provided by FASB Statement No. 95, *Statement of Cash Flows* (FAS 95). However, these securities may still be subject to the disclosure requirements provided by FASB Statement No. 115, *Accounting for Certain Investments in Debt and Equity Securities* (FAS 115), and FAS 157. Reporting entities that have debt and equity securities classified within cash equivalents should consider these disclosure requirements as part of their quarterly and year-end reporting process.

FAS 115 Disclosure Requirements

In accordance with FAS 95, debt securities and equity securities may be classified as part of cash and cash equivalents on the balance sheet. FAS 95, paragraph 9 states, in part:

Examples of items commonly considered to be cash equivalents are Treasury bills, commercial paper, money market funds, and federal funds sold (for an enterprise with banking operations). ...

Treasury bills and similar instruments are debt securities, while money market funds are a type of equity security. FAS 115, paragraph 117, clarifies the disclosure requirements for debt and equity securities classified as cash equivalents as follows:

The Board decided not to require the presentation of individual amounts for the three categories of investments on the face of the statement of financial position, provided the information is presented in the notes. Thus, enterprises that report certain investments in debt securities as *cash equivalents* in accordance with the provisions of Statement 95 can continue that practice, provided that the notes reconcile the reporting classifications used in the statement of financial position.

Consistent with this guidance, cash equivalents are subject to FAS 115 and should be included in the FAS 115-required disclosures. Many reporting entities may not have historically considered the FAS 115 accounting model for these cash equivalents: whether these securities are classified as trading, available-for-sale, or held-to-maturity (with respect to debt securities only). FAS 115, paragraph 11(a), specifically provides that a sale of held-to-maturity security within three months of its maturity date would not taint the held-to-maturity classification (all debt securities classified as cash equivalents would have maturities of less than 90 days). Therefore, we believe that there may be flexibility in the classification of these securities, depending on the reporting enterprise's management of those amounts. The classification is an accounting policy election that should be documented and consistently applied.

FAS 157 Disclosures

Given the short maturity of these securities, in most cases there will be no material difference between amortized cost and fair value. However, recent

instances where money market funds "broke the buck" highlight the fact that the carrying value of these securities is a fair value measurement. FAS 157, paragraph 32, states, in part:

For assets and liabilities that are measured at fair value on a recurring basis in periods subsequent to initial recognition (for example, trading securities), 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 (Level 3), the effect of the measurements on earnings (or changes in net assets) for the period. ... (emphasis added)

Debt and equity securities classified as trading or available-for-sale are carried at fair value in the financial statements. Therefore, consistent with this guidance, a reporting enterprise should include all such debt and equity securities in its FAS 157 disclosures. Debt securities that are classified as held-to-maturity are carried at amortized cost and would not be subject to the FAS 157 reporting requirements. Note that held-to-maturity debt securities classified as cash equivalents and any non-FAS 115 securities classified as cash and cash equivalents would still be subject to the FASB Statement No. 107, *Disclosures about Fair Value of Financial Instruments* (FAS 107), disclosure requirements, even if such amounts are not subject to FAS 157.

3.5.2 Margin Deposits and Collateral

FSP FIN 39-1 provides reporting entities with an option of reporting certain derivative assets and liabilities subject to master netting arrangements gross or net on the balance sheet. If a reporting entity elects net presentation, it is also required to net related collateral amounts, to the extent such amounts are reported at fair value. Adoption of FSP FIN 39-1 was required as of January 1, 2008 for calendar year-end reporting entities.

Some reporting entities may be reporting derivative assets and liabilities net of collateral and margin deposit balances while others are reporting such amounts gross on the balance sheet. This section reminds reporting entities that collateral amounts are generally subject to the fair value disclosure requirements, whether the collateral is presented gross or net on the balance sheet.

FAS 157 Disclosure Requirements

The FAS 157, paragraph 32, disclosure requirements apply to all assets and liabilities that are measured at fair value on a recurring basis. In determining whether this guidance applies to margin deposits and collateral, reporting entities should consider the guidance provided by FSP FIN 39-1, paragraph 10, which states, in part:

... a reporting entity may offset *fair value amounts* recognized for derivative instruments and fair value amounts⁵ recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) arising from derivative instrument(s) recognized at fair value executed with the same counterparty under a master netting arrangement.

Footnote 5 – Solely as it relates to the right to reclaim cash collateral or the obligation to return cash collateral, *fair value amounts include amounts that approximate fair value*. This footnote should not be analogized to for any other asset or liability. (emphasis added)

Based on this guidance, margin deposits and collateral amounts are considered to be a fair value measurement if they are reported at an amount that approximates fair value. Therefore, consistent with this guidance, cash collateral and margin deposits typically would be considered to be a fair measurement, as the carrying value approximates fair value. However, a long-term collateral deposit may not approximate fair value and thus would not be subject to the requirements of FAS 157.

Reporting entities should evaluate all short-term and other collateral amounts paid or received to determine if the carrying value approximates fair value. All such amounts should be included in the FAS 157 fair value disclosure tables. To the extent that a reporting entity has elected gross presentation and derivative assets, derivative liabilities, and collateral amounts are presented separately on the balance sheet, it would be appropriate to also include these amounts separately in the reporting entity's FAS 157 tabular disclosures. Cash collateral balances recorded at fair value should be disclosed within the appropriate levels of the fair value hierarchy.

Disclosure Presentation Considerations

In determining the appropriate disclosure within the fair value hierarchy, a reporting entity should consider whether the collateral should be separately classified (most likely as Level 2 due to the nature of most collateral balances) or classified as part of the net derivative balance.

When valuing derivatives, credit risk and related credit enhancements (e.g., deposits) are considered to be an important part of the fair value of the liability. Therefore, it would be appropriate for a reporting entity that elects a net presentation in the balance sheet to treat the net balance as a single unit of account for purposes of classifying the total balance within the fair value hierarchy. Reporting entities that have elected a gross presentation on the balance sheet should also disclose collateral amounts separately in the fair value hierarchy disclosures.

3.5.3 Investments Held by Pension and Other Postretirement Benefit Plans

FAS 157 amends existing guidance for pensions and other postretirement plans and generally requires that plan investments should be measured using FAS 157's definition of fair value. However, these plan investments are not separately recognized at fair value in the employer's financial statements; the amount recorded is the funded status of the plans, which is not a fair value measurement. Therefore, the FASB has confirmed that FAS 157 disclosures do not apply to plan assets reflected in the funded status reported in the employer's financial statements.

However, the Board also expressed a view that certain FAS 157 disclosures would be useful for benefit plan assets. Therefore, in March 2008, the FASB exposed for comment FSP No. 132(R)-a, *Employers' Disclosures about Postretirement Benefit Plan Assets* (FSP 132(R)-a). FSP 132(R)-a proposes

enhanced disclosures around plan assets in employer financial statements, similar to those disclosures required for other assets measured at fair value in accordance with FAS 157.

Based on the November 19, 2008 FASB meeting minutes, the proposed additional fair value disclosures related to plan assets are as follows:

- The level within the fair value hierarchy in which fair value measurements of plan assets fall
- Information about the inputs and valuation techniques used to measure the fair value of plan assets
- A reconciliation of beginning and ending balances for fair value measurements of plan assets using significant unobservable inputs (Level 3)

The exposure draft included a proposed effective date of fiscal years ending after December 15, 2008 (this year for calendar year-end companies). However, the recent minutes indicate that the FASB plans an effective date of fiscal years ending after December 15, 2009, with early application permitted. In the first year of adoption, comparative disclosures are not required.

Benefit Plan Asset Fair Value Disclosures in Employer Financial Statements Delayed

The FASB decided to adopt a later effective date for additional fair value disclosures related to plan assets held by pension and postretirement plans included within the employer financial statements. If adopted in their present form, the additional disclosures will be similar in scope to those required by FAS 157 for other recurring fair value measurements. Reporting entities should capitalize on the delay to ensure that they have sufficient information to meet the enhanced disclosure requirements. Note that the regular FAS 157 disclosures are required in the standalone plan financial statements.

3.5.4 FAS 107 Disclosures

FAS 107 requires that reporting entities disclose the fair value of all of their financial instruments whether or not recognized on the statement of financial position. FAS 107 is within the scope of FAS 157; therefore, the concepts within FAS 157 apply when performing fair value measurements for disclosure purposes.

FAS 107, paragraph 10, requires that reporting entities disclose the method(s) and significant assumptions used to estimate the fair value of financial instruments. FAS 157 amended paragraph 10 of FAS 107 to clarify the disclosures required under FAS 107 and to address the additional disclosures, if any, required under FAS 157. The following footnote (3aa) was added:

For financial instruments recognized at fair value in the statement of financial position, the disclosure requirements of FASB Statement No. 157, *Fair Value Measurements*, also apply.

Based on this footnote, reporting entities are still required to provide the qualitative disclosures originally required by FAS 107 for all fair value disclosures. The additional FAS 157 tabular disclosures (paragraphs 32 and 33) are not required unless the financial instrument is recorded at fair value in the statement of financial position. However, in FAS 157, paragraph C102, the FASB encourages these disclosures.

3.6 Other Disclosure Considerations

The SEC continues to focus on the application of FAS 157, particularly as it relates to the incorporation of nonperformance risk for derivatives and investments, and the sufficiency and transparency of disclosures. On September 16, 2008, the Division of Corporation Finance of the SEC posted an illustrative letter sent to certain public companies which appeared to expand the level of expected disclosure regarding fair value in management's discussion and analysis. Consistent with an earlier letter posted by the Division of Corporation Finance in March 2008, we understand that the SEC will expect these comments to be considered by all registrants in preparing their quarterly and annual filings to the extent the matters are material.

The September 2008 letter focused on "clearer and more transparent disclosure regarding fair value measurements" with a focus on instruments measured at fair value that are not actively traded. The letter focuses on enhanced disclosure in the following key areas:

- Judgment – Discussion of judgments made in classifying amounts within the fair value hierarchy.
- Credit risk adjustments – The impact of credit risk adjustments, including additional disclosures of the impact of credit risk on the valuation of assets and liabilities that are required to be carried at fair value (such as derivative assets and liabilities). The expected disclosures include the related gain or loss recognized in earnings as a result of credit risk adjustments as well as the reporting entity's expectation of the ability to collect on the assets.
- Inactive markets – The determination of whether a market is active or inactive and the impact of market illiquidity on the valuation. The reporting entity should also describe financial instruments that have been affected by a lack of market liquidity and how the reporting entity's valuation technique was affected and adjusted to factor in illiquidity.
- Brokers and pricing services – How and the extent to which the reporting entity uses brokers and pricing services for its fair value measurements. Information should include the nature and amount of assets valued using brokers or pricing services; classification in the fair value hierarchy; information on the use of multiple broker quotes; the reasoning and methodology for any adjustments made to prices from brokers or pricing services; the extent to which the brokers are using observable market information as compared to proprietary models and unobservable data; whether the quotes are binding; and procedures performed to validate the fair value measurements.

In addition to the points raised in the September 2008 "Dear CFO" letter, reporting entities should ensure they document their assumptions about nonperformance risk and other judgmental areas that factor into their fair value measurements. Figure 3-10 highlights recent SEC comments on the application and disclosure of fair value measurements in the financial statements.

Figure 3-10

Fair Value-Related SEC Comment Letters

The SEC has been active in issuing comment letters associated with fair value measurements during this past year. To assist reporting entities as they consider the adequacy of their year-end disclosures, we have included a representative sample of comments as follows:

You state that the fair value model you use to determine derivative fair values under SFAS 157 takes into consideration the credit quality of the counterparty. However, we also note on page XX of your December 31, 2007 Form 10-K filing that you do not consider counterparty credit risk to be a significant input. Please address the following:

- Clarify whether you actually factor in the impact of counterparty credit risk into the value of your derivative assets but the impact is just not significant, or whether you do not consider the impact of counterparty credit risk as you have qualitatively determined the impact to be insignificant on the fair value of these instruments.
- Clarify whether this was a change upon the adoption of SFAS 157, or whether you applied a similar methodology prior to the adoption of SFAS 157.
- Tell us, and disclose in future filings, whether you factor in your own credit risk into the value of your derivative liabilities, consistent with the guidance in paragraph 15 of SFAS 157.

You disclose that the use of different market assumptions and/or estimation methodologies may have a significant effect on the estimated fair value amounts of derivative assets and liabilities. Please revise to discuss how your internal models calculate fair value for each significant type of derivative asset and liability, and to provide a more robust disclosure of the various inputs and assumptions used in the respective models. Please discuss how you factored in market credit spreads, default probabilities, default timing, recovery rates, collateral value and any other significant items in your inputs and assumptions. Please also quantify the impact that reasonably likely changes in the key assumptions used would have on the financial statements.

You state that the fair value of your fixed maturity securities, preferred stock holdings and other investments is primarily based on matrix pricing models. Please tell us why the valuation of these investments was not identified as a critical accounting estimate. We believe your disclosure should enable the investor to understand how you establish the fair value of your investments when market quotations are not available. Please revise your disclosures to address the following:

- Disclose the nature and the amount of your portfolio for which market quotations are not used to obtain fair value, preferably in a tabular format;
- Describe the methods used to estimate fair value;
- Disclose the significant assumptions and other inputs used in your valuation models and describe how these were derived;
- Disclose whether the valuation models used have changed from prior periods.

Your disclosure here as well as in other portions of the document makes reference to the use of a third party pricing service. While you are not required to make these references, when you do, you must also disclose the name of the third party pricing services. If you include or incorporate by reference this disclosure into a 1933 Securities Act filing, you will also need to include the consent of the third party pricing service.

These key themes were further addressed in the SEC/FASB Joint Release issued on September 30, 2008 as well as FSP FAS 157-3, which was subsequently issued by the FASB on October 10, 2008.

FSP FAS 157-3 provided some clarifying guidance about fair value measurements of assets or liabilities in inactive markets and the use of broker quotes. Key points included the following:

- In the absence of any observable market information, the reporting entity's assumptions about market participant assumptions can be used in determining fair value
- However, when observable data is available, it cannot be ignored, even in the absence of active trading. The reporting entity should consider the activity of the market in which the asset being valued would trade, as well the use of broker quotes and any other pertinent information
- All of the data should be weighted appropriately in order to estimate fair value

FSP FAS 157-3 also reiterated the disclosure requirements in FAS 157, included in paragraph 10 of FSP FAS 157-3:

For recurring fair value measurements using significant unobservable inputs (Level 3), paragraph 32 of Statement 157 requires an entity to reconcile the beginning and ending balances, including separately presenting changes that occurred during the period that are attributable to transfers in and/or out of Level 3. For both recurring and nonrecurring fair value measurements using significant unobservable inputs (Level 3), paragraphs 32 and 33 of Statement 157 require an entity to describe the inputs and the information used to develop those inputs. (footnote omitted)

Therefore, reporting entities should ensure that sufficient information is disclosed to provide the readers with an understanding of the significant assumptions and judgments used to develop their fair value measurements. In addition, reporting entities should thoughtfully consider the requirements of

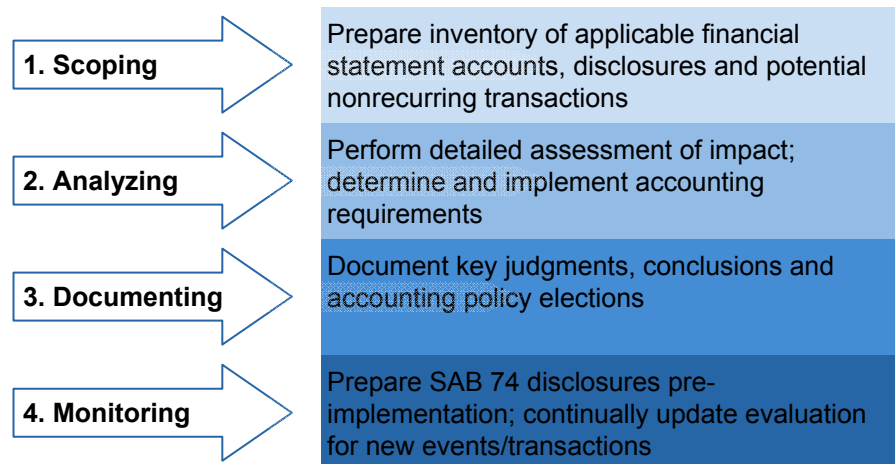
FAS 157 and the supplemental SEC guidance as they prepare their year-end disclosures.

3.7 Application to Nonfinancial Assets and Liabilities

In February 2008, the FASB issued FSP No. FAS 157-2, *Effective Date of FASB Statement No. 157* (FSP FAS 157-2). FSP FAS 157-2 deferred the effective date of FAS 157 for one year for nonfinancial assets and nonfinancial liabilities that are recognized and disclosed at fair value in the financial statements on a nonrecurring basis. The delay was implemented to allow reporting entities additional time to evaluate various implementation issues from the application of FAS 157. However, as the adoption for nonfinancial measures is imminent, reporting entities should now be focused on preparing to implement these provisions. Reporting entities should apply a structured approach to implementation of FAS 157 for nonfinancial assets and liabilities as depicted in Figure 3-11:

Figure 3-11

Phases to Implementing FAS 157 for Nonfinancial Assets and Liabilities



Reporting entities should be in the process of completing the first three stages through the initial implementation date. Although the second phase of FAS 157 applies to "nonrecurring" measurements, as further described below, reporting entities will be able to identify many of these measurements prior to implementation.

Key considerations related to each step of the implementation process are further described below.

Step One – Scoping

Application of FAS 157 to nonrecurring, nonfinancial measurements may be largely unpredictable. For example, a reporting entity may acquire a business or have an unexpected impairment that needs to be considered in accordance with the FAS 157 framework. However, in many cases, reporting entities will

be able to identify key areas where FAS 157 will apply to nonrecurring, nonfinancial measurements before they arise. As part of the scoping process, each reporting entity should prepare a list of fair value measurements that are required only on an annual or periodic basis. Key areas that may impact many utilities and power marketers include goodwill and other intangible impairment testing, as well as impairments of long-lived assets, such as generating stations, asset retirement obligations, and business acquisitions. Figure 3-12 provides examples of nonfinancial assets and liabilities measured at fair value:

Figure 3-12

Potential Nonfinancial Assets and Liabilities Measured at Fair Value

The following table highlights common nonfinancial assets and liabilities measured at fair value that may be applicable to utilities and power marketers:

- Business combinations – FAS 141(R) is also effective January 1, 2009
- Goodwill – Reporting units measured at fair value in Step 1 of the goodwill impairment test under FASB Statement No. 142, *Goodwill and Other Intangible Assets* (FAS 142), and nonfinancial assets and liabilities measured at fair value in Step 2 of that test
- Asset retirement obligations (AROs) – AROs measured at fair value upon initial recognition, or upon certain remeasurements, under FASB Statement No. 143, *Accounting for Asset Retirement Obligations* (FAS 143)
- Impairments – Assets measured for impairments under FAS 144
- Exit and disposal activities – Nonfinancial liabilities for exit or disposal activities initially measured at fair value under FASB Statement No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*

FAS 157 will also apply to impairment testing of intangible assets accounted for in accordance with FAS 142, such as emission allowances or renewable energy credits. See further discussion regarding emission allowances and renewable energy credits in Section 5.

Because FAS 157 requires broad changes to the approach to valuation and related documentation, it will be important for management teams to develop a methodology and ensure appropriate procedures are in place to apply the fair value framework to these nonrecurring measurements prior to the time they arise. For example, consider a company that experiences periodic impairments of long-lived assets. The company should prepare for the valuation of an asset or asset group by application of FAS 157 before the occurrence of the event, to ensure that it will be able to carry out the requirements in the period required for timely reporting.

Step Two – Analyzing

Broadly, we expect that adoption of the second phase of FAS 157 may be more challenging than the initial implementation to financial assets and liabilities. Valuation techniques and related inputs tend to be more available for

financial assets and liabilities, such as derivatives, compared to nonfinancial assets and liabilities. The next wave of fair value accounting will apply to measurements that rely largely on unobservable inputs, which will further challenge the application of the required "market participant" perspective.

Significant time and effort may be required to analyze the impact of application of the fair value framework to nonrecurring, nonfinancial fair value measurements. Specific potential impacts that should be considered include the following:

Business Combinations

The combined adoption of FAS 157 and FAS 141(R) is expected to have the most significant change from prior practice. FASB Statement No. 141, *Business Combinations* (FAS 141), also required that reporting entities record assets acquired and liabilities assumed in a business combination at fair value. However, FAS 141, paragraph 37, provided specific guidance on how to fair value a significant portion of the accounts measured in a combination, thereby eliminating some management judgment.

FAS 141(R) eliminates most of that guidance and requires application of the FAS 157 framework. In accordance with these requirements, a reporting entity will no longer be permitted to determine fair value based on its own intended use, but rather, will be required to value assets and liabilities based on market participant assumptions. Application of the market participant perspective and FAS 157 framework may significantly change current practice with respect to utility combinations. In addition, as a result of other changes in FAS 141(R), this guidance may now apply to many plant acquisitions.

Reporting entities contemplating a plant acquisition or business combination should consider the guidance provided by the PwC *Global Guide to Accounting for Business Combinations and Noncontrolling Interests* and the PwC *Guide to Fair Value Measurements* for further information.²

Goodwill Impairments

In accordance with FAS 142, testing for goodwill impairment must occur at least once per year and encompasses a two-step process. Step 1 is to measure the fair value of the reporting unit. With the implementation of FAS 157 for nonrecurring, nonfinancial measures, the fair value of the reporting unit will be determined based on the framework within FAS 157. This may result in differences from prior valuations due to the use of market participant, rather than entity-specific, assumptions.

For example, a market participant may conclude that a specific asset's highest and best use is "in-use" grouped with other assets. Considerable additional work may be required to determine the appropriate valuation premise. In addition, prior to the issuance of FAS 157, FAS 142 defaulted to use of a present value technique in accordance with the guidance of FASB Statement of Financial Accounting Concepts No. 7, *Using Cash Flow Information and*

² Both Guides are available through PwC's CFOdirect Network (www.cfodirect.com) and PwC's Comperio research tool.

Present Value in Accounting Measurements (CON 7), if market information was not available. FAS 157 deleted references in FAS 142 discussing the use of present value techniques. The use of a present value technique may still be appropriate; however, the reporting entity must also consider whether other techniques are appropriate in the circumstances.

If a reporting unit fails Step 1, it will be required to apply fair value to the assets and liabilities within the reporting unit based on this new measurement framework. Assets that previously had been assigned little or no value due to management's decision to retire or not make use of the assets (e.g., brands and other intangibles) will be assigned values based on their value to an external market participant. This may result in higher values for these assets, thus creating a lower value for goodwill and an increase to potential goodwill impairment.

Long-Lived Asset Impairments

Similar to goodwill, application of the market participant perspective and other aspects of the FAS 157 framework may result in a significant change in the results of impairment tests of long-lived assets. FAS 157 does not change the initial test for recoverability of a long-lived asset, as this test is not based on the fair value of the asset (or asset group); it is based on an entity-specific cash flow analysis. However, if an impairment is deemed to exist, the FAS 157 framework must be applied in measuring the amount of the impairment. This may result in changes due to application of a market participant perspective, the impact of the valuation premise, and in the determination of which valuation models are appropriate in the circumstances.

Control Considerations

In addition to the technical analysis of the impact of phase two of FAS 157, reporting entities should evaluate which controls, policies, and procedures require updating. In many cases, fair value measurements for nonfinancial assets and liabilities will be obtained from information generated outside the accounting department. For example, the information to support the impairment analysis of a generating station may be produced in the planning or risk management department.

Reporting entities will need to ensure that nonfinancial personnel involved in the measurement process understand the key concepts of FAS 157, including unit of account, valuation premise, and the requirement to apply market participant assumptions. In many cases, the approach to valuation may change significantly as a result of adoption of FAS 157. For example, a conclusion that the highest and best use for a generating station is in use with other plants in the region may significantly change the results of an impairment measurement compared to measuring the plant on a standalone basis.

Proper application of these concepts is essential to ensuring fair value is measured in accordance with the new requirements. As such, the accounting organization may need to implement an education process and work collaboratively with operating personnel, especially in the initial year of implementation.

Step Three – Documenting

Designing and documenting a robust approach to the application of FAS 157 for nonrecurring, nonfinancial measurements will be essential for a smooth implementation. Due to their nature, many of these fair value measurements will not occur routinely. The lapse of time between measurements, changes in personnel during the period, and other factors may further complicate the measurement process and create inconsistencies and additional issues on a year-to-year basis.

As a result, reporting entities should ensure that they prepare documentation that discusses the application of the framework to each potential nonrecurring fair value measurement, including discussion of all significant management judgments. In addition to assisting with the periodic process of completing these measurements, formal documentation of key decisions, judgments and conclusions will be important to support the accounting positions taken and may prevent future questions.

Step Four – Monitoring

As part of this year-end reporting process, reporting entities should prepare disclosures in accordance with SAB 74 for year end filings. These disclosures will be especially important in cases where management anticipates a significant change from previous conclusions as a result of application of the FAS 157 framework (e.g., impact from use of a market participant point of view).

Reporting entities should also continue to monitor the business for changes that could impact the scope and application of FAS 157, as well as its related controls and disclosures.

Section 4: Commodity Contract Accounting

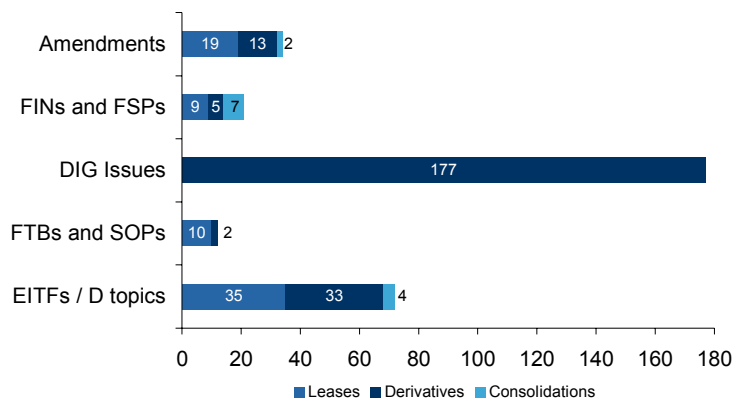
Section 4: Commodity Contract Accounting

The execution of commodity contracts is an integral business function for utilities and power marketers as these entities seek to optimize revenue, manage costs, and procure supply necessary for production or delivery of electricity and natural gas. Due to the nature of the business, companies in this industry enter into a multitude of commodity contracts with different parties and for different business reasons. Whether executed for trading purposes or to secure supply for regulated customers, the accounting for energy risk management and trading transactions, including power sales and power purchase contracts, is multifaceted and may involve multiple potential sources of accounting guidance, depending on the specific terms of the underlying contracts. In addition, when the current economic conditions and ongoing debates about fair value accounting are overlaid with the continual market evolution, it is clear that this is a challenging area for accounting groups.

4.1 Contract Accounting Framework

FAS 133, EITF Issue No. 01-8, *Determining Whether an Arrangement Contains a Lease* (EITF 01-8), and FASB Interpretation No. (FIN) 46 (revised 2003), *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51* (FIN 46(R)), provide a trilogy of accounting for commodity contracts. On a standalone basis, each of these standards — derivatives, leasing and consolidation — is among the most complicated within generally accepted accounting principles in the United States (U.S. GAAP). However, the interaction of these standards adds to the overall complexity of evaluating the appropriate accounting for commodity contracts. As illustrated in Figure 4-1, the volume of authoritative guidance alone is staggering:

Figure 4-1
Contract Accounting Trilogy – Authoritative Guidance



In addition to the authoritative guidance in place, as further discussed in this section, the FASB has proposed two amendments to FIN 46(R) and one additional amendment to FAS 133. *Note – data was accumulated for informational purposes only and may not be fully inclusive.*

Furthermore, the markets and contract structures continue to evolve even as the standard setters amend and interpret the guidance, creating additional difficulty in ensuring the appropriate accounting. As a result, management teams have been required to continually revise and update their accounting assumptions, documentation, disclosures, and conclusions.

To assist reporting entities in meeting this challenge, we have provided a suggested framework to assess and apply the hierarchy of literature and guidance. The framework is supplemented by highlights of key areas where we have observed ongoing issues, plus a discussion of new guidance and proposed authoritative changes.

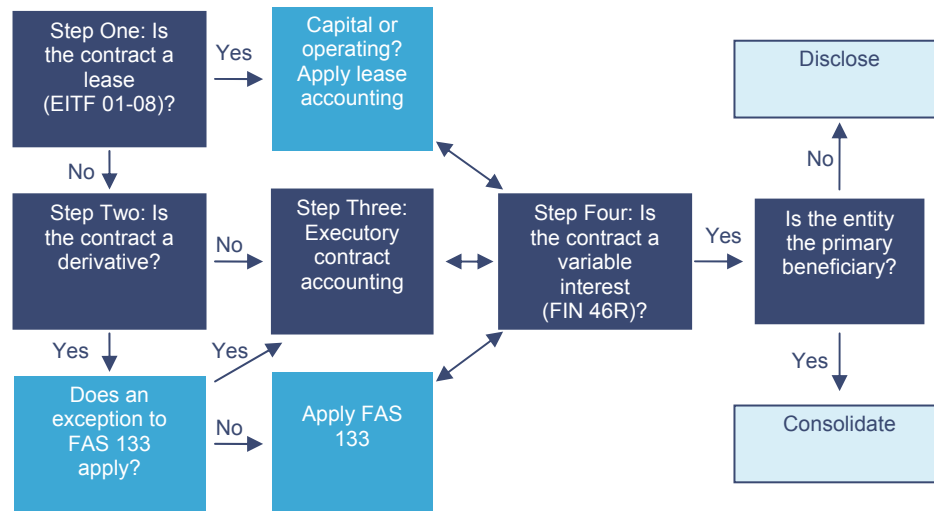
In general, commodity contracts should be assessed as follows:

- Step One – Consider Lease Accounting – The reporting entity should assess whether the arrangement includes a lease, considering the guidance provided by EITF 01-8 and FASB Statement No. 13, *Accounting for Leases*. This assessment should be performed first, as the determination of whether a contract includes a lease may impact the conclusions reached under FAS 133.
- Step Two – Assess Derivative Accounting – Management should assess whether FAS 133 is applicable to the contract, including consideration of whether the contract qualifies for any of the exceptions to the application of FAS 133 (e.g., normal purchases and normal sales). Note that FAS 133 could apply even if it is determined that a contract is a lease, as the contract may include embedded derivatives.
- Step Three – Apply Executory Contract Accounting – If the contract is not a lease and does not include any derivatives, the reporting entity should follow executory contract accounting. Applicable specialized literature for power purchase agreements includes EITF Issue No. 91-6, *Revenue Recognition of Long-Term Power Sales Contracts*, and EITF Issue No. 96-17, *Revenue Recognition under Long-Term Power Sales Contracts that Contain Both Fixed and Variable Pricing Terms*. Accrual accounting will apply if none of the specified guidance applies to a specific agreement.
- Step Four – Consider FIN 46(R) – If one of the parties to the contract is a variable interest entity, FIN 46(R) may apply, regardless of whether the contract is deemed to be a lease, a derivative, or an executory contract. Therefore, after completing the initial evaluation of the accounting model for a particular contract, the reporting entity should consider whether FIN 46(R) applies.

A robust application of the framework and consideration of all potentially applicable guidance is critical, even though the accounting for a particular contract may appear to be straightforward. For example, even a short-term power purchase agreement may contain a lease if the contract is plant-specific and otherwise meets the criteria of EITF 01-8.

Figure 4-2 provides an evaluation roadmap for accounting and reporting personnel in determining the appropriate accounting for all types of commodity contracts and energy-related structures.

Figure 4-2
Commodity Contract Assessment Framework



The general framework for evaluation of commodity contracts provides an overall approach to the analysis.

The application of the framework may be iterative and requires consideration of the subtleties in the authoritative guidance. The following section summarizes key upcoming and potential changes and issue areas for consideration as part of the year-end reporting process.

4.2 Variable Interest Entities

FIN 46(R) was issued in December 2003 and has been effective for almost five years for most reporting entities. However, many reporting entities continue to struggle with application of the standard due to its complexity and the ongoing evolution of the related guidance and interpretations. To address certain issues with the accounting model and to enhance financial statement disclosure, the FASB now has two projects in progress to amend FIN 46(R).

In March 2008, the FASB announced a project to reconsider certain provisions of FIN 46(R) including the factors to determine the primary beneficiary, implicit guarantees, expected losses, and disclosures. The exposure draft issued in September 2008 also included numerous new disclosures intended to help financial statement users better understand reporting entities' involvement and risks associated with variable interest entities. However, due to the timing of the overall project (new guidance is not expected to be effective until 2010) and a perceived pressing need to improve the transparency of FIN 46(R)-related disclosures, the FASB also exposed a proposed FSP that is intended to revise and improve disclosures in the near term. Both of these projects are being addressed contemporaneously with proposed amendments to FASB Statement No. 140, *Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities* (FAS 140).

The New VIE Disclosures Will Be Challenging

The FASB has announced that its proposed FSP on FIN 46(R) disclosures will be effective for public entities' December 31, 2008 financial statements. A number of the disclosures will require reporting entities to obtain new information they currently may not maintain. Reporting entities must also be prepared to make disclosures around significant judgments and assumptions, including those supporting the evaluation of the primary beneficiary. Therefore, reporting entities should start assessing the requirements and preparing for implementation now.

4.2.1 Proposed Disclosure Requirements

On September 15, 2008, the FASB exposed FSP FAS 140-e and FIN 46(R)-e, *Disclosures about Transfers of Financial Assets and Interests in Variable Interest Entities* (FSP FAS 140-e and FIN 46(R)-e). In a news release on November 21, 2008, the FASB publicly announced that it will issue the final FSP on disclosure by December 15, 2008, and that the requirements will be effective for public entities for fiscal years ending after that date (December 31, 2008 for calendar year-end companies). Reporting entities that do not have a calendar year-end will be required to provide the disclosures in their first interim reporting period ending after December 15, 2008 and each reporting period thereafter. The disclosures will be required for all public entities in each interim and annual reporting period. FSP FAS 140-e and FIN 46(R)-e will not apply to nonpublic companies.

The scope of the proposed FSP includes all variable interests held by public entities and nontransferor entities that hold significant interests in qualifying special purpose entities (QSPEs). The proposed disclosures are intended to provide users of the financial statements with greater transparency around a reporting entity's involvement with a variable interest entity. In accordance with FSP FAS 140-e and FIN 46(R)-e, paragraph 8:

The principal objectives of the disclosures required by this FSP ... are to provide users of the financial statements with an understanding of:

- a. The judgments and assumptions made by the enterprise in determining whether the enterprise must consolidate a variable interest entity and/or disclose information about its involvement with a variable interest entity
- b. The nature of restrictions on a consolidated variable interest entity's assets reported by the enterprise in its statement of financial position, including the carrying amounts of such assets
- c. The nature of, and changes in, the risks associated with the enterprise's involvement with a variable interest entity

- d. The current potential financial effects from an enterprise's involvement with a variable interest entity on the enterprise's financial position, financial performance, and cash flows

The proposed disclosure requirements are summarized in Figure 4-3:

Figure 4-3
Proposed FIN 46(R) Disclosure Requirements

Relationship	New Disclosures
All relationships (including sponsors of VIEs irrespective of materiality)	<ul style="list-style-type: none"> • Basis for concluding whether the reporting entity is or is not the primary beneficiary of the VIE (including disclosure of key factors, assumptions, and judgments used in making the determination) • Factors resulting in, and impact on the financial statements of, a change in reporting (e.g., previously consolidated and no longer consolidating the VIE) • Information on financial or other support to the VIE if the reporting entity previously was not contractually required to provide that support • Information (quantitative and qualitative) about the reporting entity's involvement with the VIE, including the nature and size of the VIE and terms of the arrangement that could result in providing financial support to the VIE and possible exposure to loss
Consolidated VIEs	<ul style="list-style-type: none"> • The carrying amount and classification of the VIE's assets and liabilities included in the consolidated financial statements • Information about the amount and restrictions regarding the VIE's assets, if they can be used only to settle liabilities of the VIE • Lack of recourse if creditors of the VIE have no recourse to the general credit of the reporting entity
Significant VIEs Not Consolidated (including sponsors of VIEs irrespective of materiality)	<ul style="list-style-type: none"> • Maximum exposure to loss as a result of involvement with the VIE, including how that amount was determined and the significant sources of that maximum exposure to loss • A tabular, side-by-side comparison of the maximum exposure to loss compared to amounts recorded in the financial statements, supplemented with qualitative and quantitative disclosures to explain those differences • Carrying value and classification of the reporting entity's variable interest in the VIE on its financial statements

FSP FAS 140-e and FIN 46(R)-e allows for the aggregation of information for similar types of entities in the case where providing separate information would

not be more useful to the readers. However, the methodology used to determine that aggregation must be disclosed, and the disclosures must distinguish between VIEs for which the reporting entity is not the primary beneficiary, but for which the VIE is significant to the entity, and VIEs that are consolidated.

Finally, reporting entities that make use of the so called "information-out" clause in paragraph 4(g) of FIN 46(R) will have to continue to describe how many VIEs the exception applies to and why the information is not available. Reporting entities applying this exception will also need to make several disclosures intended to relay information about the VIE, the reporting entity's involvement with the VIE, the maximum exposure to loss, and the level of activity (e.g., expenses or sales) between the reporting entity and the VIE for all periods presented.

In addition to the above requirements for typical VIEs, public reporting entities that are sponsors with a variable interest in, or servicers with a significant variable interest in a qualifying special-purpose entity, will be required to provide certain new disclosures that are similar to those described above.

Key Considerations

Utilities and power marketers may have extensive involvement in variable interest entities, and implementation of these new requirements may be challenging due to the tight timing at year-end. Therefore, management should start the process of reviewing these requirements, updating their understanding of the reporting entity's involvement with VIEs and QSPEs, and determining what additional information will be required. Some of the new disclosures are extensive and ensuring that all required information is available may be difficult, particularly if the reporting entity has interests in multiple VIEs. In addition, if the reporting entity does not maintain the underlying accounting records, it may require enhanced interaction with VIE management to obtain the necessary information. Specific potentially troublesome areas include the following:

Restrictions on Assets of the VIE

Reporting entities that consolidate a VIE will need to disclose restrictions on assets that may be used only to satisfy the VIE's obligations. Examples of assets that may require disclosure include:

- Cash collateral and margin deposits posted for derivative arrangements
- Property, plant, and equipment pledged as collateral under financing arrangements
- Restricted investments held for the purpose of funding future payments such as for pensions and postretirement benefits, debt service, or decommissioning costs

Obtaining this information may take time, depending on the nature of the relationship with the VIE and its management team. In addition, if the reporting entity is involved in multiple VIEs, it may be difficult to aggregate this

information, even in cases where the reporting entity is maintaining the underlying books and records.

Maximum Exposure to Loss

Reporting entities that hold a significant interest in a VIE (or that sponsor a VIE, regardless of its significance to the sponsor) will be required to disclose their maximum exposure to loss from the VIE, including explaining differences between the maximum exposure to loss and amounts recorded in the financial statements. These amounts and disclosures may be highly judgmental.

For example, for an equity investment the carrying value is frequently the maximum exposure to loss. However, there may be other factors and assumptions that would cause the estimated exposure to loss to be different. Such factors could include guarantees and other commitments to the VIE by third parties, guarantees and other commitments on performance or obligations of the VIE by the reporting entity, or a significant difference in the fair value of the assets and liabilities of the VIE as compared to the carrying value of the investment.

Reporting entities will need to ensure they understand all of the potential exposures or mitigating factors that may impact these disclosures. This may require additional discussion or follow-up with the underlying VIE management or their own evaluation.

4.2.2 Proposed Changes to the Accounting for Variable Interest Entities

As previously described, the FASB is also working on a project to consider amending FIN 46(R) for the second time. The key areas being addressed in this project include the following:

- The requirements for reconsidering if an entity is a VIE
- The requirements for reconsidering which enterprise, if any, consolidates the VIE (the primary beneficiary)
- The process for determining which enterprise, if any, is the primary beneficiary in a VIE

The new standard is scheduled to be issued in the first quarter of 2009 and is proposed to be effective at the beginning of each reporting entity's fiscal year beginning after November 15, 2009 (January 1, 2010 for calendar year-end companies). Earlier application will be prohibited.

The overall objective of the proposed changes to FIN 46(R) is to improve financial reporting and transparency related to VIEs. The standard is being issued in response to increasing scrutiny of FIN 46(R), as a result of the substantial ongoing losses incurred in the financial services industry and the related disruption in the credit markets. In addition, there are concerns that there is a lack of transparency by reporting entities of their involvement with structures that contain significant risk, including the nature of the reporting entities involvement and maximum exposure and the current status of that exposure.

Key Accounting Considerations

The original exposure draft included new disclosure requirements, now addressed in proposed FSP FIN 46(R)-e and FAS 140-e. In addition to these proposed new disclosures, the FIN 46(R) exposure draft proposes the following two primary changes:

Ongoing Assessment of Variable Interest Entities and Primary Beneficiaries

As described in FIN 46(R), paragraph 7, reporting entities are currently required to reassess the status of VIEs and potential VIEs when certain predefined conditions occur (i.e., trigger-based reassessment). Furthermore, paragraph 15 of FIN 46(R) requires a reassessment of the primary beneficiary of a VIE if certain defined types of changes arise in the relationship of the variable interest holders with the VIE.

The FIN 46(R) exposure draft requires reporting entities to perform ongoing assessments as to whether there have been any circumstances that would change the status of an existing or potential VIE, or the determination of the primary beneficiary of the VIE. As a result, it removes FIN 46(R) paragraphs 7 and 15. Potential variable interest entities will now be assessed at inception of the relationship, and any time facts and circumstances change that could render the entity a VIE in accordance with the definition in FIN 46(R). The timing of determination of the primary beneficiary of a VIE follows the same concept. The application of changes is not limited to the end of a reporting period (i.e., an entity may become a VIE subject to consolidation or the primary beneficiary could change during a reporting period), resulting in the need for a new consolidation or a deconsolidation at any time.

Arrangements Will Need to Be Continuously Monitored

The change from a "triggering-event"-based assessment to an ongoing assessment for the status of both variable interest entities and primary beneficiaries will require the implementation of new, robust processes and controls. Under current generally accepted accounting principles, changes that could impact the VIE status or primary beneficiary are not considered unless there is a specific triggering event. Under the new proposed standard, such circumstances will need to be continuously monitored and could change the accounting for a VIE from period to period.

Requirement to Perform a Qualitative Analysis First

FIN 46(R) requires that a reporting entity consolidate a VIE if the reporting entity has a variable interest in the VIE that will absorb a majority of the expected losses, receive a majority of the expected residual returns, or both. Current practice relies heavily on both qualitative considerations and quantitative calculations of expected losses and expected residual returns. Under the proposed standard, however, the FASB proposes to require that reporting entities first perform a qualitative assessment as to whether they

have a controlling financial interest in the VIE. Only in the event that they cannot reach a conclusion based on qualitative factors is a reporting entity then required to perform a quantitative analysis.

The FIN 46(R) exposure draft includes some new guidance for purposes of qualitatively assessing whether the reporting entity has a controlling financial interest. The analysis must include an assessment of the reporting entity's variable interest(s) and any other involvement with the VIE (including related-party and defacto agency relationships), as well as the involvement of other variable interest holders. Furthermore, it must take into account the VIE's purpose and design, including risks that the VIE was designed to create and pass through to its variable interest holders. The key qualitative factors that would cause a variable interest holder to have a controlling financial interest include:

- The power to direct matters that most significantly impact the activities of the VIE, including those activities that have an impact on the VIE's economic performance.
- The right to receive benefits from the VIE or the obligation to absorb losses of the VIE, either of which could potentially be significant to the VIE. This analysis is not to be quantitative, but rather should be based on the reporting entity's explicit or implicit financial responsibility to ensure that the VIE operates as designed.

If the above two criteria are met, the reporting entity would be deemed the primary beneficiary. If the reporting entity determines that the powers are shared among multiple parties such that no one meets those criteria above, then it is not the primary beneficiary. In addition, the FIN 46(R) exposure draft indicates that it is expected that only one party can be the primary beneficiary of a VIE (i.e., no more than one party should be consolidating a VIE).

A Note on Passive Interests

A passive interest is an interest in a VIE whose maximum exposure is capped, has no involvement in the design or redesign of the entity, carries no control rights, or is insignificant. Since a passive interest holder has no power over the entity, the new qualitative assessments above effectively render it impossible for a passive interest holder to be the primary beneficiary. Reporting entities will want to carefully consider VIEs with passive interest holders, as previous consolidation conclusions may change upon adoption of the proposed standard.

Considerations for Adoption

Upon adoption of the proposed standard, if a reporting entity is required to newly consolidate a VIE, it will be required to include the assets and liabilities on the balance sheet at their then-fair values (similar to a business combination). Any potential goodwill or a gain or loss on consolidation would

be recorded as a cumulative-effect adjustment to retained earnings. In such circumstance, reporting entities will want to consider the applicable fair value considerations in FAS 157 for nonfinancial assets and liabilities, as well as FAS 141(R).

4.3 Noncontrolling Interests

In December 2007, the FASB released FASB Statement No. 160, *Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51* (FAS 160). FAS 160 amends the consolidation standards and focuses on the accounting and reporting for minority interests (now termed noncontrolling interests). This standard may be applicable in determining the appropriate accounting for and presentation of noncontrolling interests in consolidated entities that are not wholly-owned, including variable interest entities for which a reporting entity concludes it is the primary beneficiary. FAS 160 is effective for both public and private companies for fiscal years beginning on or after December 15, 2008 (January 1, 2009 for calendar year-end companies). The standard is to be adopted retroactively for the presentation and disclosure of all existing noncontrolling interests.

FAS 160 creates a framework for accounting and reporting noncontrolling interests to eliminate some of the existing divergence in practice. This guidance significantly changes the presentation of noncontrolling interests and the accounting for transactions with noncontrolling interest holders. This standard impacts any utility company or power marketer that currently presents minority interests, including situations where a nonequity holder consolidates a VIE. Application of the standard could have potential earnings ramifications in the event of change in control transactions with those noncontrolling interest holders.

In FAS 160 the FASB concluded that a noncontrolling interest represents the residual interest in the net assets of a subsidiary within the consolidated group held by owners other than the parent. As such, the FASB further concluded that the noncontrolling interest should be classified as equity in the consolidated statement of financial position. Following are among the more significant changes from current practice introduced by FAS 160:

- Noncontrolling interests will be reported as part of equity in the consolidated financial statements. This is a change from current practice whereby minority interest is currently presented "mezzanine."
- Both income and losses must be allocated to the noncontrolling interest, even if that allocation results in a deficit balance to the noncontrolling interest. Under current practice, losses are generally attributed to the minority interest only to the extent of its investment. The new guidance will result in less losses being attributed to the controlling party.
- If the controlling party maintains control, changes in ownership interests will be treated as equity transactions. Differences between the fair value of the consideration received or paid and the related carrying amount of the noncontrolling interest will be recognized in the controlling interest's equity balance.
- If the controlling party loses control, changes in ownership interests will be accounted for through earnings. In such cases, any gain or loss on the

interest sold will be recognized in earnings. In addition, any ownership interest that the original controlling party retains will be remeasured at fair value on the date control is lost, with any gain or loss recognized in earnings.

Utilities and other entities in the power industry should prepare for these changes given the potential impact on earnings for dispositions of interests that result in a loss of control. In addition, the shifting of noncontrolling interests into the equity section of the balance sheet will require additional disclosure and dialogue with analysts, shareholders, and regulators in order to ensure understanding of the reporting entity's revised equity balance. Additional guidance can be found in PricewaterhouseCoopers DataLine 2008-02: FAS 160, *Non-controlling Interests in Consolidated Financial Statements* and the PwC *Global Guide to Accounting for Business Combinations and Noncontrolling Interests*.³

Application of FAS 160 May Impact Transactions with VIEs

FAS 160 significantly changes the presentation of noncontrolling interests and the accounting for transactions with noncontrolling interest holders. This standard impacts any utility company or power marketer that currently presents minority interests, including situations where a nonequity holder consolidates a VIE. Application of the standard will change equity and could have potential earnings consequences as a result of remeasurement requirements. Management teams should start the education process now to ensure all stakeholders understand the ramifications of these changes.

4.4 Equity Method Investments

Many utility and power entities have various investments in projects accounted for under the equity method of accounting in accordance with Accounting Principles Board (APB) Opinion No. 18, *The Equity Method Accounting for Investments in Common Stock* (APB 18). These interests may include equity interests in unconsolidated VIEs. In November 2008, the EITF reached a final consensus and the FASB ratified EITF 08-6, *Equity Method Investment Accounting Considerations* (EITF 08-6). This new guidance addresses certain questions that arose as a result of the issuance of FAS 141(R) and FAS 160.

The key areas of focus in EITF 08-6 include:

- How an equity method investment should initially be measured
- How it should be tested for impairment

³ These references are available through PwC's CFOdirect Network (www.cfodirect.com) and PwC's Comperio research tool.

- How changes in classification from equity method to cost method should be accounted for

The consensus will be effective for financial statements issued for fiscal years beginning after December 15, 2008 (January 1, 2009 for calendar year-end companies). Early application is not permitted and the guidance will apply on a prospective basis to new investments acquired after the effective date.

The key change in EITF 08-6 pertains to the accounting for the issuance of new shares by an equity method investee. Under the consensus, the issuance of new shares by an equity method investee should be accounted for as though the equity method investor had sold a proportionate share of its investment, with the related gain or loss recognized in earnings. This is a change from current generally accepted accounting principles, which allows an accounting policy election following the guidance under SAB Topic 5-H, *Accounting for sales of stock to a subsidiary* (SAB Topic 5-H), to recognize the impact of such transactions in either earnings or equity. SAB Topic 5-H will be rescinded upon the effective date of FAS 160.

EITF 08-06 also concluded on the following issues:

- *Carrying amount* – The carrying amount of an equity method investment should be based on the current cost accumulation approach under APB 18. The concept in FAS 141(R) of expensing transaction costs does not apply to the acquisition of equity method investments.
- *Impairment testing* – Other-than-temporary-impairment analysis should be performed only at an overall investment level. Separate testing of underlying basis differences of individual assets (e.g., goodwill) is not required.
- *Change from equity method to cost method* – If significant influence in an equity method investment is lost and the investment becomes a cost-based investment, the basis in the cost-based investment is that of the previous equity-method investee and no gain or loss should be recognized.

The finalization of EITF 08-6 clarifies a number of questions that had been raised subsequent to the issuance of FAS 141(R) and FAS 160. To the extent a utility or power generation company has equity method investments, management should be aware of the changes arising from this new guidance.

4.5 Derivative Instruments and Hedging Activities

A significant part of any energy trading and risk management function includes the accounting for derivative contracts. Despite the fact that FAS 133 has been effective for several years, practice issues and the evolution in the complexity of the instruments subject to the standard result in the need for reporting entities to continually update their understanding and knowledge in this area. In addition, the FASB has continued to be reevaluate FAS 133, proposing amendments to further clarify and improve the accounting for derivative transactions.

The availability of derivative contracts and other financial instruments to meet the needs of market participants continues to expand. Furthermore, many utilities and power marketers around the country interact at some level with

one of the country's seven independent system operators (ISOs) or regional transmission organizations (RTOs). The interaction with these independent bodies adds another dimension to the complexities associated with energy risk management activities.

This section addresses accounting issues and considerations associated with market structure changes, describes and provides guidance in areas where reporting entities continue to experience difficulties in application, and discusses new and proposed amendments to existing guidance.

4.5.1 Gas Capacity

In June 2008, the FERC issued Order No. 712, *Promotion of a More Efficient Capacity Release Market* (Order 712). Order 712 revised previous regulations governing interstate natural gas pipelines to permit market-based pricing for short-term capacity releases (one year or less). Prior to the issuance of Order 712, there was a tariff cap on capacity release transactions. As a result of this change to market-based pricing for short-term releases, a question arises as to whether gas pipeline capacity contracts now meet the definition of a derivative.

In evaluating this issue, we primarily focused on whether gas pipeline capacity contracts have the "net settlement" characteristic required by FAS 133, paragraph 6(c). As further described below, we concluded that these contracts do not currently meet the net settlement criterion and should be accounted for as executory contracts.

In addition, there is ongoing debate as to whether these contracts have other characteristics that would lead to the conclusion that FAS 133 is not applicable (e.g., the contracts are for delivery of a service). We may provide further guidance on these other considerations in the future; however, at this time the contracts do not meet the definition of a derivative as the net settlement characteristic is not present. Therefore, there is no need to further consider the merits of applying FAS 133.

Analysis

In evaluating whether gas pipeline capacity contracts meet the definition of a derivative, we focused on whether the contracts meet the "net settlement" criteria of FAS 133, paragraphs 6(c) and 9. FAS 133, paragraph 9 states that a contract with any one of the following characteristics would meet the net settlement criteria:

- a. Its terms require or permit net settlement
- b. It can be readily settled net by a means outside the contract (market mechanism facilitates net settlement)
- c. It provides for delivery of an asset that is readily convertible to cash

We considered whether gas capacity contracts have the net settlement characteristic as follows:

Paragraph 9(a) – Terms require or permit net settlement

In accordance with FAS 133, paragraph 9.a., a contract meets the definition of net settlement if “neither party is required to deliver an asset that is associated with the underlying and that has a principal amount ... that is equal to the notional amount.” In this case, the provider is required to “deliver” capacity and there are no provisions for net settlement in the contract. Therefore, standard gas capacity contracts do not meet the FAS 133, paragraph 9(a) criterion.

Paragraph 9(b) – Market mechanism facilitates net settlement

FAS 133, paragraph 9(b) states:

One of the parties is required to deliver an asset of the type described in paragraph 9(a), but there is a market mechanism that facilitates net settlement, for example, an exchange that offers a ready opportunity to sell the contract or to enter into an offsetting contract.

DIG Issue A21, *Definition of a Derivative: Existence of an Established Market Mechanism That Facilitates Net Settlement under Paragraph 9(b)* (DIG Issue A21), provides further guidance on indicators to consider in assessing whether an established market mechanism exists. We considered these factors in our overall assessment of whether there is a market mechanism for net settlement of a gas capacity contract. Under the current market structure, there is no mechanism for a provider to be relieved of its full rights and obligations under a previously executed contract. As such, this criterion is not met.

Paragraph 9(c) – Readily convertible to cash

FAS 133, footnote 5 states:

FASB Concepts Statement No. 5, *Recognition and Measurement in Financial Statements of Business Enterprises*, states that assets that are readily convertible to cash “have (i) interchangeable (fungible) units and (ii) quoted prices available in an active market that can rapidly absorb the quantity held by the entity without significantly affecting the price” (paragraph 83(a)). For contracts that involve multiple deliveries of the asset, the phrase *in an active market that can rapidly absorb the quantity held by the entity* should be applied separately to the expected quantity in each delivery.

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* (DIG Issue A19), provides further guidance on the assessment of whether a contract is readily convertible to cash. In discussing evaluation of a five-year commodity supply contract, DIG Issue A19 states:

The criterion in paragraph 9(c) is met *because an active spot market for the commodity exists today and is expected to be in existence in the future for each delivery date* (for example, for quantities to be delivered each day or each month for the next five years) under the multiple delivery supply contract. The spot market can rapidly absorb the quantities specified for each monthly delivery without significantly affecting the price. (emphasis added)

FAS 133, paragraph 265 provides further interpretive guidance as follows:

Net settlement is an important characteristic that distinguishes a derivative from a nonderivative because it permits a contract to be settled without either party's accepting the risks and costs customarily associated with owning and delivering the asset associated with the underlying (for example, storage, maintenance, and resale). *However, if the assets to be exchanged or delivered are themselves readily convertible to cash, those risks are minimal or nonexistent. Thus, the parties generally should be indifferent as to whether they exchange cash or the assets associated with the underlying.* The Board recognizes that determining whether assets are readily convertible to cash will require judgment and sometimes will lead to different applications in practice. However, the Board believes that the use of *readily convertible to cash* permits an appropriate amount of flexibility and describes an important characteristic of the derivative instruments addressed by this Statement. (emphasis added)

Based on this guidance, the key reason that the FASB concluded that delivery of an asset that is readily convertible to cash is equivalent to net settlement is because the "the parties generally should be indifferent as to whether they exchange cash or the assets associated with the underlying." However, in order to meet this criterion, there must be a spot market. Absent a spot market, there is no opportunity for the parties to convert the assets to be exchanged or delivered into cash.

Therefore, in assessing whether the gas capacity contracts meet the definition of a derivative, we must consider whether there is an active spot market for capacity. To be deemed an active market, a market must have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. In addition, quoted prices from that market will be readily available on an ongoing basis.

In the case of the gas capacity market, we understand that there may be some bilateral spot activity, with trading among market participants to manage excess capacity and meet obligations. In addition, the pipeline companies maintain electronic bulletin boards that provide some price information; however, these postings include all transactions, including prearranged deals that may be tariff based. There are no regularly quoted prices in the market and there is no transparency into the level of activity, frequency, and volume of transactions.

Overall Evaluation

Based on the analysis performed as outlined above, gas capacity contracts for which no active spot market exists do not meet the definition of a derivative, as the contracts do not have the net settlement characteristic of FAS 133, paragraph 6(c). However, market participants should continue to monitor activity because this conclusion may change as markets continue to evolve and develop.

Other Considerations

To the extent that the derivative evaluation changes in the future as a result of the evolution of the capacity markets, we would expect that the gas capacity

contracts would meet the normal purchases and normal sales exception provided by FAS 133. As discussed in DIG Issue C12, *Scope Exceptions: Interpreting the Normal Purchases and Normal Sales Exception as an Election* (DIG Issue C12), the normal purchases and normal sales designation is an election that can be made at inception of the contract or at a later date. If a company concludes that its contracts do not currently meet the definition of a derivative, such contracts could still be conditionally designated as normal purchases (assuming that all of the criteria in paragraphs 10(b) and 58(b) are met and documented).

In this case, the contracts would be accounted for as normal purchases or normal sales from the time that the markets developed and the contracts become derivatives. Absent such a designation, management would be required to initially fair value the contracts at the time the contracts are determined to be derivatives, with the related gain or loss immediately recognized in earnings. The contracts could still subsequently be designated as normal purchases or normal sales with no recognition in earnings of subsequent changes in value from the time they are designated.

4.5.2 Significant Market Changes

Many utilities and power marketers transact in markets with ISOs or RTOs, such as PJM Interconnection (PJM), the California ISO (CAISO), and the Electric Reliability Council of Texas (ERCOT). The related market rules may have a significant impact on accounting and reporting due to the unique products and other market structural considerations. During the current year, there were no major new developments with accounting implications in PJM; however, significant changes are on the horizon for California and Texas, as both markets anticipate a change to locational marginal pricing (LMP) in 2009. The market redesigns in California and Texas have been forthcoming for a number of years and are expected to have numerous operational and financial reporting impacts on entities operating in those regions. Figure 4-4 highlights upcoming market changes and potential accounting issues:

Figure 4-4
Key ISO/RTO Developments in 2008

ISO/RTO	2008 Developments
PJM	During 2008, PJM established an auction process for long-term financial transmission rights (FTRs). Financial transmission rights are financial instruments that enable holders to hedge against locational electricity price differences caused by transmission constraints in the day-ahead energy market. Historically, FTRs could be obtained only for one-month, three-month, or one-year durations. Long-term FTRs are for periods of up to four years. With longer term FTRs, market participants are now able to economically hedge transmission for long-term power contracts.

ISO/RTO	2008 Developments
Midwest ISO (MISO)	<p>The introduction of the new auction process for long-term FTRs does not change the accounting framework for FTRs, which are accounted for as derivatives in accordance with the requirements of FAS 133.</p> <p>MISO is scheduled to launch its Ancillary Services Market (ASM), a market-based ancillary system, in the first quarter of 2009. The purpose of moving to a market-based ASM is to provide competitive and transparent economic signals for ancillary services. This structure is expected to allow market participants to compete to provide ancillary services at the lowest cost. This market change will require additional analysis of MISO bill charges and may require more judgment in the budgeting and forecasting process.</p>
CAISO	<p>CAISO is currently scheduled to launch its Market Redesign and Technology Upgrade (MRTU) program on February 1, 2009. MRTU has been delayed several times and is a significant market design change that will move CAISO from a zonal-based energy services market (currently, it has four large geographic zonal clearing prices) to an LMP market containing thousands of discrete clearing prices. The LMP structure provides more transparent pricing because it is based on actual transmission congestion.</p> <p>The new structure will also include congestion revenue rights (CRRs) which are similar to FTRs used in the PJM market. CRRs are derivatives and should be accounted for in accordance with the requirements of FAS 133 and FAS 157. Due to the lack of market information, valuation of CRRs is a challenge; however, lack of information does not change the underlying accounting requirements. As such, management teams should continue to monitor and assess the appropriateness of valuations as the markets evolve.</p>
ERCOT	<p>Similar to MRTU in California, Texas is preparing to launch its Texas Nodal Market Implementation by December 2009. The launch of the program has also been delayed several times. The new program is similar in many respects to the MRTU in California and also incorporates congestion revenue rights. The accounting considerations are similar to those outlined under CAISO above.</p>

In addition to ongoing changes in the energy markets, substantial commodity contract accounting changes have been implemented or are forthcoming, as described in the remainder of this section.

4.5.3 Normal Purchases and Normal Sales: What Is "Clearly and Closely Related"?

FAS 133, paragraph 10(b) provides an elective exception to the application of fair value accounting for contracts that meet the definition of normal purchases or normal sales. The exception provides an exclusion to fair value accounting for certain contracts that involve future delivery of assets (other than financial instruments or derivative instruments) and are "expected to be used or sold by the reporting entity over a reasonable period in the normal course of business." Application of the normal purchases and normal sales exception can be complex and we continue to see issues in practice. One of the key areas of continued confusion is the application of the guidance around the clearly and closely related requirements. In applying the normal purchases and normal sales exception, management must consider the guidance provided by FAS 133, paragraph 10.b., which includes the following requirement:

... However, contracts that have a price based on an underlying that is not clearly and closely related to the asset being sold or purchased (such as a price in a contract for the sale of a grain commodity based in part on changes in the S&P index) ... shall not be considered normal purchases and normal sales.

In July 2003, the FASB issued DIG Issue C20, *Scope Exceptions: Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature* (DIG Issue C20). This DIG Issue superseded the previous guidance provided by DIG Issue C11, *Scope Exceptions: Interpretation of 'Clearly and Closely Related' in Contracts That Qualify for the Normal Purchases and Normal Sales Exception*. DIG Issue C20 guidance requires an assessment of pricing clauses that gives consideration to both quantitative and qualitative factors.

DIG Issue C20 also states that the pricing adjustment would not be clearly and closely related to the asset being sold or purchased if:

- The underlying is extraneous (irrelevant) to both the changes in the cost and the changes in the fair value of the asset being sold or purchased (e.g., a power contract with indexation to the S&P 500); or,
- The magnitude and direction of the impact of the price adjustment is significantly disproportionate to the impact of the underlying on the fair value or cost of the asset being purchased or sold (see further discussion below); or,
- The underlying is a foreign currency exchange rate that meets none of the criteria in paragraphs 15(a) – 15(d) of Statement 133 (as amended).

In addition, Issue C20 provides further guidance for evaluating contracts in which the price adjustment focuses on the changes in the fair value of the asset being purchased or sold. In accordance with this guidance, a price adjustment should be expected, at contract inception, to impact the price in a manner comparable to the outcome that would be obtained if, at each delivery date, the parties were to reprice under then-existing conditions. This guidance can be applied to either the fair value or the cost of the asset being sold or purchased.

PwC previously provided guidance on the evaluation of whether various pricing mechanisms are clearly and closely related to the underlying contract in Alert 02/67, "DIG Issue C15, *Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity*, Impact of 'Clearly and Closely Related' Pricing Requirements." However, this interpretive guidance predates the issuance of DIG Issue C20. To help management evaluate various contracts, we have provided the following example fact patterns demonstrating the application of DIG Issue C20.

Sample Contracts

The sample fact patterns below are included solely for the purpose of assessing whether the pricing under the contract meets the clearly and closely related requirements of FAS 133, paragraph 10, and DIG Issue C20.

Example 4-1

Contract for the sale of power from a gas-fired plant with the pricing linked to a natural gas index.

In evaluating this contract, the company must consider the following factors:

- Source (cost) of production – In evaluating pricing mechanisms, DIG Issue C20 permits companies to consider the impact of the underlying on the fair value or cost of the asset being purchased or sold. In this example, the fuel used to generate the electricity under this contract is natural gas; therefore, a pricing mechanism using a natural gas index would not be extraneous to the cost of the asset being sold (see further discussion of other considerations below).

However, if the underlying plant did not use natural gas (such as a coal or wind facility), changes in a natural gas index would not be reflective of the company's cost of production. In practice, companies have found it difficult to demonstrate that changes in natural gas prices are highly correlated to the fair value of the electricity produced. As such, it would be difficult to conclude that a natural gas index is clearly and closely related when the source of production is a non-gas facility.

- Gas index – Management must also specifically consider the gas index used in the contract. For example, the pricing in a contract may be linked to a NYMEX, Henry Hub contract. However, the generator purchases gas for production at Houston Ship Channel. In that case, the generator would need to consider the correlation in gas prices between Henry Hub and Houston Ship Channel. The prices must be highly correlated in order to reach a conclusion that the pricing is clearly and closely related.
- Potential leverage – Furthermore, the reporting entity must determine whether the effect of the natural gas indexation in the pricing formula will be proportionate to the impact of natural gas prices on the cost of production. To the extent there is a disproportionate effect (i.e., the effect of natural gas is leveraged or other cost components are being indexed to natural gas prices), the contract will not qualify for the normal purchases and normal sales exception. However, if the pricing mechanism limits the adjustment to

the proportionate impact that natural gas prices have on the cost of producing electricity, it will be considered clearly and closely related.

One way to index an energy contract to natural gas prices is to base the contract price on a formula using a specified heat rate multiplied by a natural gas index. Such a pricing formula may be considered clearly and closely related provided that the specified heat rate used is a reasonable approximation of the expected heat rate for the power to be delivered under the contract. For example, if the contract heat rate is 7.5 and the company's plants expected to serve the obligation have a heat rate of 7.25, we would generally conclude that the contract pricing may qualify as clearly and closely related. We accept some cushion to recognize operational constraints and profit margin, but would not expect the heat rate to vary from the actual by more than 10 percent.

However, to the extent that the specified heat rate is significantly in excess of the expected plant or system heat rate (e.g., in the case of a heat rate established based on market prices), the pricing formula would be viewed as either having leveraged the effect of natural gas prices or alternatively having indexed other nonfuel cost components to natural gas prices. Consequently, the pricing under the contract would not be considered clearly and closely related.

Example 4-2

The entire energy charge under a capacity contract is escalated annually based on the generating company's actual variable cost for fuel, labor, and other operations and maintenance costs in producing the power.

The cost of electricity comprises fuel, labor, and other operations and maintenance costs. Assuming the contract pricing formula is based on the respective proportion represented by each of these cost components in the production of the electricity under the contract, the pricing mechanism is considered clearly and closely related to the asset being sold and the contract is eligible for application of the normal purchases and normal sales exception (assuming all other criteria are met).

A conclusion that the pricing is clearly and closely related should be supported by an analysis demonstrating the relative cost of production of electricity from the plant or group of plants supplying the contract compared to the contract terms. Although the proportions do not have to match exactly, if the ranges are not closely aligned, it may suggest that the contract includes leverage and would not qualify for the normal purchases and normal sales exception.

Example 4-3

The entire energy charge under a capacity contract is escalated annually based on changes in the consumer price index.

DIG Issue C20 does not prohibit the use of a broad market index as a proxy for changes in the underlying cost. However, in order to conclude that the pricing is clearly and closely related, a company would need to be able to assert that

the direction and magnitude of changes in the index are reflective of changes in the cost or fair value of the asset being sold.

The cost of electricity comprises fuel, labor, and other operations and maintenance costs. While these costs may be included in the items used to determine the consumer price index (CPI) and certain of these costs may actually correlate with the CPI from time to time, the direction and magnitude of changes in the CPI would not be expected to reflect changes in the cost of production of electricity. Therefore, a contract that has the entire energy charge indexed to the CPI would not be considered to have a pricing mechanism that is clearly and closely related to the underlying and would not qualify for the normal purchases and normal sales exception.

A similar conclusion would be reached in evaluating a gas contract with price changes based on CPI: changes in CPI would not be reflective of changes in the related gas index. As such, the pricing would not be considered to be clearly and closely related and the contract would not qualify for the normal purchases and normal sales exception.

Example 4-4

The energy charge under a capacity contract is based on a combination of two components: fuel costs, which are escalated based on the generating company's actual costs of fuel; and operations and maintenance costs, which are indexed to the CPI.

The cost of electricity comprises fuel, labor, and other operations and maintenance costs. As fuel costs are typically the most volatile cost component, the parties may choose to reflect the fuel costs based on actual costs incurred and the operating and maintenance costs based on the CPI. The operations and maintenance charges under a long-term sales agreement may have been originally based on actual cost, with subsequent years adjusted based on CPI. We understand that a CPI index may be used because it simplifies the pricing mechanism and is viewed as a suitable proxy for the actual movement in operations and maintenance costs given their relatively modest expected volatility.

To the extent management concludes that CPI is an appropriate (and not extraneous) factor, it should also be careful in evaluating the relative proportion of the costs tied to fuel versus CPI. Consistent with the analysis included in Example 4-1 above, management should ensure that the relative linkage to the gas index and CPI in the contract is consistent with the actual cost of production (i.e., if gas costs are 90 percent of the cost of production, then only 90 percent of the pricing of the electricity contract could be linked to the gas index).

Example 4-5

Qualifying facility contract using wind generation with periodic price adjustments based on the utility's avoided cost of production.

In evaluating whether the price adjustment is clearly and closely related, companies must (per DIG Issue C20) assess the impact on changes in the cost or fair value of the asset being purchased or sold. In this case, neither the generator's cost of production nor the fair value of the energy delivered would be expected to be correlated to the utility's avoided cost of production. Therefore, it would be very difficult to assert that the pricing mechanism is clearly and closely related.

The assessment of whether a pricing mechanism meets the Issue C20 criteria is a matter of significant judgment that should be considered on a contract-by-contract basis.

4.5.4 New Disclosures Required for Credit Derivatives and Credit Guarantees

In September 2008, the FASB issued FASB Staff Position FAS 133-1 and FIN 45-4, *Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161* (FSP 133-1 and FIN 45-4). FSP 133-1 and FIN 45-4 requires additional disclosures by sellers of credit derivatives, including credit derivatives embedded in a hybrid instrument and guarantees. FSP 133-1 and FIN 45-4 is effective for reporting periods (annual or interim) ending after November 15, 2008 (i.e., December 31, 2008 for calendar year-end companies).

The project stemmed from the recent turmoil in the credit markets and the drastic growth of the credit default swap market. There has been concern among constituents that improved disclosures are needed for credit default swaps and related instruments. FSP 133-1 and FIN 45-4 focuses on disclosures about the nature, exposure to loss, and fair value of credit derivatives and credit-related guarantees within the scope of FASB Interpretation No. 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others*. FSP 133-1 and FIN 45-4 does not change or provide any additional guidance with respect to the presentation and classification of these instruments.

The disclosure requirements apply to the seller (or party that assumes the credit risk) of credit derivatives or hybrid instruments that have embedded credit derivatives. A credit derivative is a derivative instrument whereby the underlying is tied to the credit risk of an entity or group of entities, or that exposes the seller to risk of loss from credit-risk-related events specified in the contract. Examples include credit default swaps or options or credit-index products. FSP 133-1 and FIN 45-4 requires that sellers or issuers of credit derivatives, hybrid instruments that have embedded credit derivatives, and/or guarantees disclose the following:

- The nature of the credit derivative, including its term and purpose for why the reporting entity entered into it

- The maximum potential amount of future payments (undiscounted) the seller could be required to make under the credit derivative
- The fair value of the credit derivative as of the balance sheet date
- The nature of any recourse actions or third-party collateral that could be relied upon to liquidate the credit derivative
- The current status of payment/performance risks of guarantees

Companies in the utility and power industry are typically not in the business of writing credit protection for others. As a result, we do not believe adoption of FSP 133-1 and FIN 45-4 will have a significant impact. Reporting entities should, however, review and understand their various arrangements, particularly any structured contracts, to determine whether any potential embedded provisions would qualify as a guarantee or other form of credit protection for the counterparty. While not necessarily evident, such provisions may be within the scope of this standard. Complying with FSP 133-1 and FIN 45-4 could be challenging given that information to determine the fair value and potential exposure may be difficult to obtain. Reporting entities will want to ensure they have sufficient time to work through those possible issues.

4.5.5 New Derivative Disclosures

In March 2008, the FASB issued FASB Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities – an amendment of FASB Statement No. 133* (FAS 161). FAS 161 was issued to address concerns that the existing disclosure requirements in FAS 133 did not provide adequate information about how derivative and hedging activities affect an entity's financial position, results of operations, and cash flows.

FAS 161 is effective for interim and annual financial statements beginning after November 15, 2008 and requires expanded disclosures for derivatives and hedging activities for interim and annual periods. In the initial year of adoption, comparative disclosures are encouraged but not required. In addition, the FASB encouraged early application of the standard. It is important to note that FAS 161 is effective for all interim financial statements for periods beginning after November 15, 2008, regardless of the reporting entity's year-end. The FASB clarified this effective date in FSP FAS 133-1 and FIN 45-5.

Multiple Sources of Information May Be Required

FAS 161 is applicable for all reporting entities for interim financial statements for periods beginning after November 15, 2008. The new disclosures require significant additional information that may not be currently tracked by some organizations. Implementation may be complex and may require inputs from multiple sources of data; therefore, all reporting entities with significant derivative activities should be in the process of preparing for adoption of FAS 161.

Adoption of FAS 161 will be significant for most entities in the utility and power sector due to the pervasive use of derivative instruments. Key areas that these entities should focus on include:

- The requirement to disclose volumes of activity and how the reporting entity believes that information will be best presented
- The requirement to present derivatives in the balance sheet table on a gross basis, which is likely to create certain inconsistencies with other financial reporting disclosures (e.g., those made under FAS 157 and in accordance with FSP FIN 39-1 where information may be prepared and presented on a net basis)
- The requirement to provide disclosures of the existence of credit-risk-related contingent features, which are certain to come under significant scrutiny by users of the financial statements in the current economic climate. Management will need to address matters such as material adverse change clauses, as well as the sensitivity of collateral requirements to the credit ratings of all parties to the financial instrument.

FAS 161 includes helpful examples of what the FASB is looking for in these disclosures. Reporting entities should take sufficient time to closely review these examples as they prepare to adopt the standard. In addition, the specific new disclosures required by FAS 161 are further discussed below.

Objectives and Strategies for Using Derivatives

Reporting entities will be required to describe how and why they are using derivative instruments. As part of that disclosure, the reporting entity should describe information about the types of derivative instruments held in the context of its primary underlying risk exposures. FAS 133, paragraph 44, as amended, provides examples of five primary underlying risks:

- Interest rate risk
- Credit risk
- Foreign exchange rate risk
- Interest rate and foreign exchange rate risk
- Overall price risk

These risks are similar to the risks that are permitted to be hedged in FAS 133. While the FASB provides these examples, reporting entities should consider and describe their risks in the context of their business. For example, if a utility enters into forward gas purchase contracts in order to manage its cash flow exposures relating to anticipated gas purchases to be used in the production of electricity, it would describe that strategy in the context of commodity price risk. As another example, if the utility also enters into fixed-for-floating interest rate swaps in order to manage its risk of fluctuating cash flows on its variable-rate debt, it would describe that strategy in the context of interest rate risk.

Derivative Activity for the Period

FAS 161 requires that reporting entities include information about the volume of their derivative instruments. The original exposure draft required that reporting entities disclose only the total notional amount of their derivatives to satisfy this objective. However, understanding that the volumes (e.g., notional amounts) of derivatives held by a reporting entity could vary significantly depending on the strategies employed, in the final standard the FASB provided flexibility as to how and at what level of specificity that information can be presented. See Example 4-6 for potential differences in application.

Given the flexibility permitted under FAS 161 in this area, utilities and power companies will need to consider their individual facts and circumstances, such as their historical activity and their strategies, to determine how they will provide information on the volume of their derivative activity. This requirement may also give rise to implementation concerns about the nature and source of the data underlying volumes and notional amounts. Reporting entities should consider the reliability and completeness of the data and ensure sufficient and appropriate controls exist over the data. Finally, in addition to determining how the volume of derivative activity will be disclosed, these entities will also want to consider the extent and nature to which this information should be "rolled forward" from one reporting period to the next and how changing circumstances are incorporated.

Example 4-6

Ways to view total derivative activity

As part of a hedging strategy, a company may decide to enter into three separate forward contracts, each hedging forward sales of 10,000 megawatt hours (MWhs) each year for three years, as compared to another company that chooses to enter into one forward contract hedging 10,000 MWhs over a three-year period. While these two strategies may achieve the same objective, in the first case the total notional amount would be 30,000, as compared to the second case in which the total notional amount would be 10,000.

FAS 161 provides examples of disclosures of the total notional amounts. However, a difference in notional amounts does not necessarily mean that there are different levels and risks of the derivative activity. Apart from the disclosure of total notional amounts, reporting entities may want to provide other forms of information to put the disclosure of notional amounts in context (e.g., by distinguishing between fixed-for-floating versus basis swaps, or by explaining the company's hedging strategy).

Tabular Disclosure

FAS 161 requires two new tables that summarize derivative information by type of strategy (e.g., cash flow and fair value hedges, nonhedging derivatives) and by type of instrument (e.g., commodity contracts, interest rate contracts). The tabular disclosures provide a structured view of the extent of derivatives used and where and by how much they impact the financial statements. While utilities and unregulated power entities currently maintain information on their

derivative transactions, the aggregation of data for these disclosures may be significant. As such, reporting entities will need to consider and develop processes to ensure that information is collected and reported appropriately in the format required by FAS 161. The two tables can be summarized as follows:

Balance Sheet

A table must be presented that includes the above information for each date at which a statement of financial position is presented. This table must describe the location and fair value of derivatives and hedged items, categorized first by strategy, and then by contract type within each strategy.

A key point to note is that the derivative balances in this table must be presented on a gross basis, regardless of the reporting entity's accounting policy under FSP FIN 39-1. While a reporting entity may be presenting its derivatives and related cash collateral under master netting arrangements on a net basis on the balance sheet, it must present the same derivatives in this table on a gross basis, exclusive of the cash collateral. Reporting entities that elect "net" presentation under FSP FIN 39-1 may want to consider providing a reconciliation in this footnote to the presentation on the balance sheet.

Statement of Income

A second table must be presented that includes the above information for each financial reporting period for the statement of income. This table must describe the location and related gains and losses of derivatives and hedged items (for fair value hedges), categorized first by strategy, and then by contract type within each strategy. In addition, cash flow hedge amounts that are classified into AOCI or out of AOCI into earnings must also be presented.

Credit-Risk-Related Contingent Features

The issue of credit risk and its impact on a company and its financial reporting has gained a significant amount of attention in the last year. As further discussed in the Section 3.3, credit risk can have a significant impact on the fair value of derivatives. Many entities in the utility and power industry report the potential impact of credit-related features and contingent collateral requirements in their financial reports via the liquidity disclosures in their public filings. Similar disclosures will now be required in the financial statements themselves.

Collateral and Other Credit Risk Disclosures

FAS 161 requires significant disclosure of the potential impact of credit-related features, such as the requirement to post collateral or the ability of the counterparty to force immediate payment in the event of a downgrade. This information may be embedded in multiple different contracts and agreements and may not be subject to the reporting entity's established control process. As such, reporting entities should start the process of identifying and aggregating this information now to ensure the ability to properly report this information in 2009.

FAS 161 requires that reporting entities include various disclosures about any credit-risk-related contingent features in their derivative contracts. An example of a contingent feature is the requirement to post collateral or the ability of the counterparty to demand immediate payment upon a decrease in the credit rating of the reporting entity's debt, or upon the reporting entity's debt being rated noninvestment grade. Required disclosure of credit-risk-related contingent features includes:

- The existence of such features and when they could be triggered
- The dollar amount of derivatives in net liability positions that include those features as of the end of the reporting period
- Posted or expected collateral or other assets that would be posted to offset contingent amounts due.

The fair value of derivatives tends to fluctuate significantly and can change from net asset to net liability positions from one period to the next. In addition, many derivative agreements can be very complex. Challenges in ensuring that all such features are clearly identified, interpreted, and disclosed in an appropriate manner will need to be addressed. Therefore, reporting entities should have a robust control in place to inventory and monitor their derivative contracts for contingent credit-risk-related features in order to be able to report the impact in any given reporting period.

4.5.6 Hedge Accounting Project: Simplification on the Way?

Since FAS 133 became effective, hedge accounting has proven to be very complex and proper application has plagued many reporting entities. In fact, it is not uncommon for companies to shun hedge accounting altogether to avoid the complexities and risks of misstatement. In an effort to simplify the application of and resolve major practice issues in hedge accounting, in June 2008, the FASB issued an exposure draft to significantly amend FAS 133, titled *Accounting for Hedging Activities – an amendment of FASB Statement No. 133* (the Hedging Exposure Draft).

The Hedging Exposure Draft proposed for the amendment to become effective for fiscal years beginning after June 15, 2009, including interim periods within those fiscal years (i.e., January 1, 2010 for calendar year-end companies). Currently, the amendment is scheduled to be issued in the first quarter of 2009. However, the effects of the recent market issues and related efforts to improve the accounting for financial instruments could potentially delay this project or may result in this project being incorporated into a broader effort.

The credit crisis has prompted standard setters to take a critical look at how financial accounting and reporting needs to be improved. As a result, in the short term, both the FASB and the IASB are concentrating their efforts on projects to drive improvements in financial reporting in order that reporting entities better reflect the substance and risks associated with their businesses. Furthermore, the FASB has been active with recently issued guidance and other projects in progress that stem from current issues in the marketplace over credit-related transactions and off-balance-sheet structures (e.g., FSP FAS 133-1 and FIN 45-4, proposed FSP FAS 140-e and FIN 46R(R)-e, and the proposed project to amend FIN 46(R)). Another example of a possible

upcoming effort is convergence on the classification of and impairment accounting for financial instruments (e.g., impairments of investments).

In addition to the critical focus on financial accounting and reporting, there is a strong push for cooperative efforts among the FASB and IASB to reduce complexity in financial reporting for derivatives and other financial instruments. One overriding criticism from constituents commenting on the Hedging Exposure Draft is that it is not convergent with IFRS. As the FASB and IASB work together to address complexity in financial reporting, all options are on the table, one of which is a change to full fair value accounting. The adoption of a full fair value model would reduce the importance and necessity of hedge accounting; however, because of the negative sentiment toward fair value that is common today, it is unclear whether such a model would be pursued. Regardless of the direction that ensues, it is possible this project could become subsumed within a broad project to reduce complexity, inevitably delaying its issuance.

Nevertheless, due to the extensive amount of hedging transactions entered into in the utility and power industry, we believe that these potential changes, whether issued in their current form or through a different project, will have a significant impact for industry participants. As a result, reporting entities should continue to closely monitor the status of the project in order to adequately prepare for adoption.

Potential Impact of the Proposed Changes

The primary objective of the Hedging Exposure Draft is to simplify and to improve the accounting and financial reporting for hedge accounting. Key changes proposed to achieve that objective include the following:

Reasonably Effective Threshold

In an effort to allow for hedge accounting when the transaction is economically and reasonably entered into for hedging purposes, the FASB has proposed to adjust the threshold for establishing a hedge relationship. In doing so, the basic requirement for effectiveness has been proposed to be changed from "highly effective" to "reasonably effective." There is no definition of "reasonably effective" in the Hedging Exposure Draft, and reporting entities will need to apply judgment to their proposed hedging relationships to determine whether they will qualify for hedge accounting.

This change is expected to require additional judgment for reporting entities. The exclusion of a definition or parameters of this threshold in the Hedging Exposure Draft raises a concern that practice will gravitate to establishing a new "bright line" for what constitutes "reasonably effective." Determining some qualitative factors for determining "reasonably effective" would likely assist in determining matters, such as the level and duration of divergences in commodity price indices that could imply hedge ineffectiveness, when a difference exists in the underlying pricing index of the hedged instrument and the hedged item. It is unclear whether the FASB will provide guidance for this concept.

Elimination of Quarterly Hedge Effectiveness Assessments

To set up a hedging relationship, reporting entities will be required to demonstrate that the hedge is effective and that an economic relationship exists between the derivative and the hedged item or forecasted transaction. However, subsequent to the establishment of the hedge, an analysis of effectiveness will be required only upon an event that would trigger concern that the hedge relationship potentially would no longer qualify for hedge accounting. Furthermore, under the Hedging Exposure Draft, any assessments of hedge effectiveness can be qualitative instead of quantitative.

Note however, that the calculation and recording of ineffectiveness is still required and a quantitative analysis would not be precluded. Utilities and power entities will want to proceed with caution when considering how to perform assessments of hedge effectiveness. We believe that in many cases, it will be difficult to demonstrate using a qualitative approach that the commodity hedging relationships entered into by participants in this industry are effective. Many electricity and gas hedging transactions involve sources of ineffectiveness, such as settlement date differences or basis differences (locations or price indices), that are highly correlated but require calculations to demonstrate that high correlation. Frequently, quantitative analyses, such as regression, are performed in this industry to demonstrate hedge effectiveness due to these potential sources of ineffectiveness that cannot be assessed qualitatively with a high degree of confidence.

Ineffectiveness for "Underhedges"

Another potential area of concern for the industry is the proposed requirement to record ineffectiveness resulting from both over and underhedges. For cash flow hedges, reporting entities will still be required to record ineffectiveness in earnings. The amount to record would be determined by comparing the fair value of the actual derivative with the present value of the cumulative change in expected future cash flows on the hedged transaction. The current requirement in FAS 133 is that any ineffectiveness to be recorded in earnings is limited to overhedged positions. However, under the proposed hedging guidance, any ineffectiveness resulting from both over and underhedges would be recognized in earnings.

This will be a significant change for reporting entities and raises some conceptual challenges because it leads to the recognition of ineffectiveness in earnings for hypothetical derivative instrument gains and losses that may never be realized or incurred, and that does not necessarily align with companies' hedging practices from a business standpoint.

Other Proposed Changes

Other proposed changes may have a significant impact on some reporting entities as follows:

- The elimination of the shortcut and critical-terms match methods. Utilities and power companies will want to consider their current and expected critical-terms match hedges used for commodity hedging, and determine how their effectiveness methodology will be constructed. Provided that

critical-terms match hedges are operating as intended, a qualitative analysis of such hedge relationships should be able to be used under the guidance of the Hedging Exposure Draft.

- The elimination of an entity's ability to hedge a component risk for financial instruments, other than foreign exchange risk and interest rate risk on a company's own debt at issuance. In addition, reporting entities should be aware that these financial hedges would only qualify if designated at the date they are entered into (i.e., "late" hedging will no longer be permitted).
- Prohibits the discretionary designation of hedging relationships. It is unclear at this time what this means for dynamic hedging strategies. Power entities that employ such a strategy should continue to monitor the developments in this area.
- Places a restriction on the ability of an entity to hedge forecasted intercompany transactions for foreign exchange risk. This change is not expected to have a significant impact for the industry, given that many of the utilities and power entities in the United States maintain primarily domestic operations. However, reporting entities in the industry that have operations overseas should consider this potential change.

The Hedging Exposure Draft also includes some proposed disclosure requirements related to a reporting entity's hedging relationships. We recommend that reporting entities continue to monitor the progress of this exposure draft due to the potential significant impact.

4.6 Other Trading Issues

4.6.1 Proposed Fair Value Accounting for Trading Inventory

Utilities and power entities with any trading activity will want to ensure they consider proposed accounting guidance on inventory that is part of a trading operation. The FASB has issued FSP ARB 43-a, *Amendment of the Inventory Provisions of Chapter 4 of ARB No. 43* (FSP ARB 43-a). The proposed FSP requires that inventories included in an entity's trading activities be initially and subsequently measured at fair value with changes in fair value recognized in earnings.

FSP ARB 43-a, which is scheduled to be finalized in 2008, will be effective for financial statements issued for fiscal years beginning after November 15, 2008, and interim periods within those fiscal years. If issued as planned and in its current form, this proposed FSP will be effective January 1, 2009 for calendar year-end entities. However, given the number of projects currently being addressed by the FASB and the current status of this project, it is possible that the proposed FSP will not be issued and effective in the current scheduled timeframe. Early adoption will not be permitted.

Proposed Guidance

The proposed FSP addresses a specific inconsistency in U.S. GAAP related to the accounting for inventory under the AICPA Audit and Accounting Guide, *Brokers and Dealers in Securities* (Broker Dealer Guide) and the Investment Company Guide, and the accounting for inventory under ARB No. 43, Chapter 4, *Inventory Pricing*.

While the overall basis of accounting for inventory under ARB 43 is a lower-of-cost-or-market model, the Broker Dealer Guide and the Investment Company Guide require that a reporting entity account for inventory at fair value. This inconsistency originally led to proposed *EITF Issue No. 06-12, Accounting for Physical Commodity Inventories for Entities within the Scope of the AICPA Audit and Accounting Guide, Brokers and Dealers in Securities*. The EITF examined the issue, but ultimately deferred any conclusion, at which time the FASB staff took up the issue to examine more broadly whether traded physical commodity inventory should be recorded at fair value, resulting in the proposed FSP.

FSP ARB 43-a requires that inventories included in an entity's trading activities be initially and subsequently measured at fair value, with changes in fair value recognized in earnings. Upon adoption of the FSP, reporting entities must determine and record a cumulative-effect adjustment to retained earnings. FSP ARB 43-a will not change current practice for inventories included in production, retail, wholesale, or other nontrading activities, and will permit reclassifications of inventory between trading and nontrading categories, subject to a significant amount of disclosure as further described below.

The proposed FSP does not define trading inventory, but instead points to other U.S. GAAP and a reporting entity's specific circumstances to determine if the inventory is part of a trading operation. As such, whether an entity's inventory constitutes trading inventory is a matter of judgment. Other areas of U.S. GAAP, such as FAS 115 and EITF Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities* (EITF 02-3), provide guidance on indicators of a trading activity.

While electricity cannot be economically stored, utilities, power marketers and energy traders, buy and sell other commodities that may be "trading inventories," including among other things, coal or natural gas. Determining whether commodity inventories will constitute trading inventory will involve determining the manner in which the inventory is utilized. For example, it is likely that a merchant electricity generator that holds some gas inventory for purposes of production would not consider that inventory to be trading inventory. However, a merchant energy company that also has a division that trades gas to capitalize on market opportunities may consider inventory in that operation to be trading inventory.

Exclusions

The FASB rejected an alternative that would have expanded the scope of this proposed FSP to include trading items other than inventories within the scope of Accounting Research Bulletin (ARB) No. 43, *Restatement and Revision of Accounting Research Bulletins*, Chapter 4, Statement 1 (ARB 43). As such, the proposed FSP specifically excludes noninventory executory contracts such as storage. The FASB has also excluded emissions allowances from the proposed FSP because they do not represent tangible inventory. As discussed in Section 5.3, the FASB has undertaken a separate project on emission allowances in a joint effort with the IASB.

Disclosure Requirements

The proposed FSP requires several new disclosures for trading inventory, which may be onerous, particularly as it relates to the movement of inventory between trading and nontrading categories. The purpose of the new disclosures is to assist readers of the financial statements in understanding why trading inventory has been classified as such, and to provide information on the extent of that activity. These disclosures include the following:

- The basis for the reporting entity concluding that its inventory is trading inventory
- A description of the trading activities relating to inventory classified as trading
- Typical holding periods for the trading inventory
- To the extent that a reporting entity transfers inventory in and/or out of the trading classification, it should disclose why those transfers have occurred, as well as specific information on transfers between trading and nontrading inventory.

The proposed FSP includes several examples of the disclosure requirements. However, as one could expect, the disclosures, especially around transfers, are likely to be difficult to prepare. In particular, FSP ARB 43-a requires the estimation of a "would-be" profit margin of inventory transferring from trading to nontrading which will likely require a significant amount of effort to collect the applicable data to estimate. As such, reporting entities should consider whether the new guidance will be applicable and, if so, what information and processes will be needed to be able to track the activity and prepare the disclosures.

New Volatility for the Income Statement

FSP ARB 43-a would represent a significant change from current accounting and may introduce more volatility and subjectivity in the statement of income. Reporting entities in the utilities and power sector should closely monitor the progress of this project and assess the potential impact early on. In particular, proposed FSP ARB 43-a does not define trading inventory, so reporting entities will need to apply significant judgment when determining whether inventory is trading or nontrading. In addition, complexities may arise in the determination of the fair value of these nonfinancial assets. Therefore, developing a position and understanding the implications for financial reporting will be important.

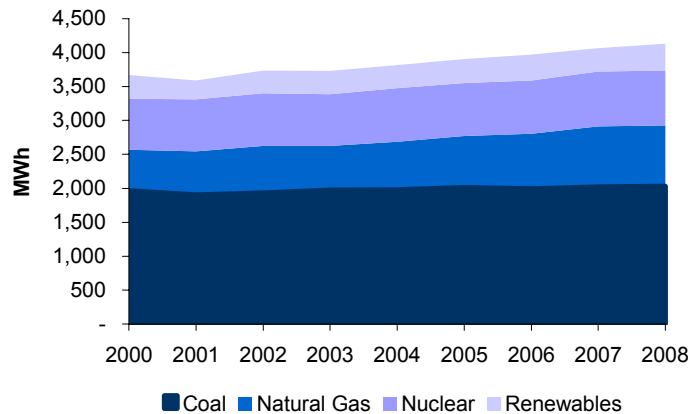
Section 5: Environmental Regulation

Section 5: Environmental Regulation

Prior to the credit crisis in September, climate change and environmental issues were among the most discussed topics of 2008. Addressing these matters continues to be a high-profile issue for the utility sector, due to legislative and regulatory focus on reducing the environmental impact of this industry. Although there is no comprehensive federal mandate, regional and state emission-reduction requirements and renewable portfolio standards are impacting investment and operating decisions.

The industry continues to depend heavily on fossil fuels and it will require significant time, effort, and development of new technologies to reduce some of this dependence. As of August 2008, approximately 71 percent of the country's net generation output was produced using fuels such as coal, petroleum, and natural gas.⁴ As noted in Figure 5-1 below, the types of fuel used for generation has remained relatively flat over the last several years, with some minimal increases in natural gas and renewable energy sources.

Figure 5-1
Source of Generation by Fuel Type



Source: Energy Information Administration (November 2008)

Coal-fired technology remains the dominant source for U.S. electric generation; however, strides are being made in the research, development, and installation of "green power" — generating sources that include wind, solar, and biofuels, among others. Furthermore, industry participants are developing and installing various forms of new technology, with the goal of reducing the environmental impact of fossil fuels. For example, many utilities are installing scrubbers on coal plants, and researchers are examining more advanced technologies, such as carbon capture, for feasibility. Although not renewable, nuclear fuel is also viewed as a "clean" source of power because

⁴ Source: Energy Information Administration

of the lack of air emissions. In fact, renewed interest has spurred plans for 12 nuclear construction projects totaling 26,958 megawatts (MW)⁵ of capacity.

In addition, numerous initiatives and requirements are in place to curtail the impact of emissions on the environment. Generators in the United States have been subject to federal legislation aimed at limiting the emission of sulfur dioxide (SO₂) and nitrogen oxide (NO_x) for the past several years. To meet those standards, power generators must offset fossil-fuel production with emission credits or emission allowances obtained through allocations or by purchase on the open market. More recent initiatives focus on promoting the use of renewable energy through the implementation of regional initiatives and state renewable portfolio standards (RPS). Renewable standards have gained momentum over the past several years, as state governments seek to reduce their individual impacts on the environment. Finally, federal energy tax policy has also supported development and investment in renewable sources of energy through tax incentives.

A myriad of regulatory requirements and the growing focus on green energy create business and operational issues and opportunities for utilities and other sector participants. These evolving rules and the related operational changes also result in a number of potentially complex accounting and reporting issues. In the following section we discuss the recent trends in environmental regulation in the United States and the resulting financial reporting considerations.

5.1 Emissions Reductions Programs

Legislation to govern SO₂ and NO_x emissions has been in place for almost two decades as a result of the Clean Air Act Amendments of 1990 and related legislation. Under the U.S. Environmental Protection Agency (EPA) Acid Rain Program, every major fossil-fuel-burning electric production facility in the United States has an established level of allowable emissions. Affected units are allocated allowances by the EPA at no cost based on their historical fuel consumption and a specific emissions rate. To provide greater flexibility to plant operators, EPA initiated its acid rain emission allowance trading program in 1995. SO₂ and NO_x allowances are fungible and, consequently, can be applied against emissions from any unit participating in the program. The government may impose a fine or penalty if actual plant emissions exceed the allowances held.

5.1.1 Clean Air Interstate Rule

On March 10, 2005, the EPA issued the Clean Air Interstate Rule which was intended to permanently cap SO₂ and NO_x in 28 eastern states and the District of Columbia. The CAIR requirements were supplemental to existing emission reductions required under the Clean Air Act. CAIR required staged reductions in emissions as follows:

- SO₂ – CAIR required 50 percent and 70 percent reductions by 2010 and 2015, respectively, compared to 2003 levels. Reductions were to be achieved by surrendering allowances issued under the Clean Air Act acid

⁵ Source: SNL Interactive

rain cap-and-trade program in a ratio of 2 and 2.86 allowances per ton emitted starting in 2010 and 2015, respectively.

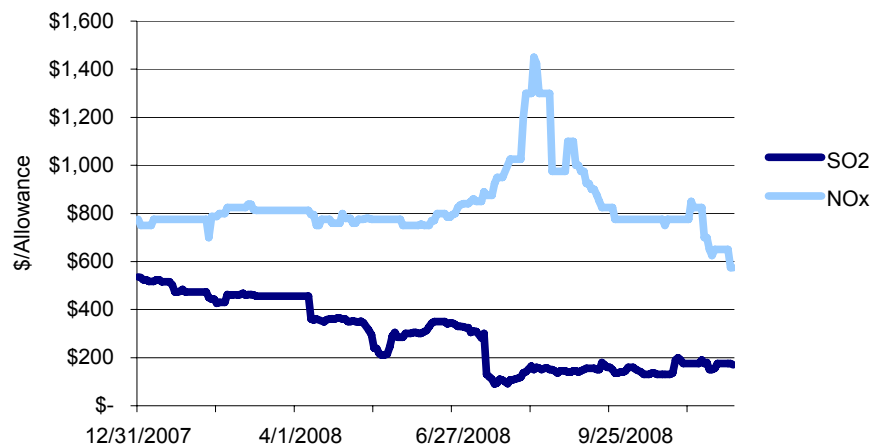
- NOx – CAIR established a regional cap-and-trade program for year-round nitrogen oxide (Annual NOx) reductions beginning in 2009. When fully implemented, CAIR would reduce NOx emissions by more than 60 percent from 2003 levels.

On July 11, 2008, the United States Court of Appeals for the District of Columbia Circuit invalidated CAIR, stating that a regional cap-and-trade program cannot be used to facilitate attainment of the ozone and fine-particulates standards. The decision did not overturn the existing cap-and-trade program for SO₂ reductions and also did not impact the existing seasonal NOx cap-and-trade program. The decision was subject to a 45-day waiting period, during which a challenge could be put forward or a settlement agreement negotiated.

In September 2008, the EPA petitioned the Court for rehearing of the CAIR decision and further, in October 2008, the Court filed an order for a briefing of the issues and has yet to issue its mandate officially vacating CAIR. As a result, the Court's July 2008 order is not effective and, until then, compliance with CAIR, including the annual NOx requirements, is required. At this time, allowances held for planned use to comply with CAIR may still be used for that purpose or, if CAIR is ultimately vacated, they may have an alternative use as part of compliance with the Clean Air Act program.

There are still a market and quoted prices are available for the allowances, although the initial Court decision and subsequent events have produced notable price volatility as noted in Figure 5-2:

Figure 5-2
Comparative SO₂ and NOx Pricing for 2008 Vintage Year



Source: SNL Interactive, December 31, 2007 – November 20, 2008

As noted in Figure 5-2, the spot price of SO₂ allowances has fluctuated from \$536.50 on December 31, 2007 to a low of \$90 in mid-July of 2008. In mid-November 2008, the prices rebounded partially and are hovering around \$175 as companies weigh potential outcomes of the litigation.

As a result of the activities of the Court, reporting entities have been assessing the impact on their financial statements and considering whether the value of their SO₂ or annual NO_x allowances on the balance sheet should be written down or written off. Because of the uncertainty regarding the ultimate outcome, controller organizations will want to continue to work with their legal departments to closely monitor the situation in order to make their assessments for year-end reporting.

5.1.2 Regional Greenhouse Gas Initiative

In addition to the focus on reduction of SO₂ and NO_x, there is current interest in overall greenhouse gas reductions, including carbon dioxide (CO₂) emissions. Currently, the United States does not have a federally mandated greenhouse gas program. However, the Northeast and Mid-Atlantic regions implemented a carbon reduction program, known as the Regional Greenhouse Gas Initiative (RGGI), during 2008. The RGGI is a cooperative effort by 10 states in the region to limit greenhouse gas emissions through mandatory caps on CO₂ emissions from power plants and a 10 percent reduction in these emissions by 2018. Regulated power plants will be able to use a CO₂ allowance issued by any of the 10 participating states to demonstrate compliance with the state program governing their facilities.

While these programs and allowances are meant to discourage emissions by imposing limits, states are also adopting other programs meant to encourage investment in forms of renewable energy technology.

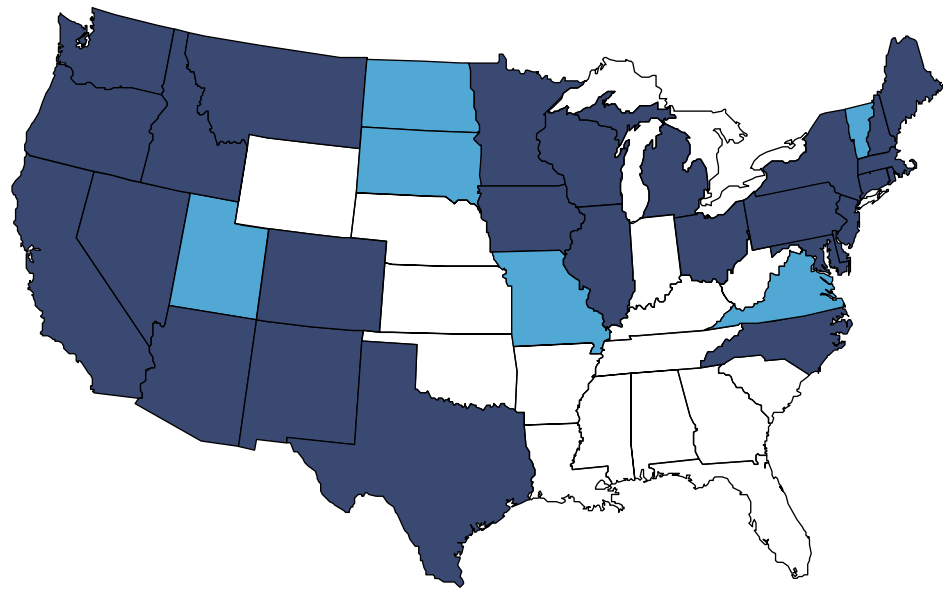
5.2 Renewable Portfolio Standards

Renewable portfolio standards obligate retail sellers of electricity to source a certain percentage or amount of their supply from renewable energy sources. These requirements are typically set on a state-by-state basis by the applicable regulatory commission or other party, or may be established by another governmental organization for certain public power entities. The standards contain different parameters and rules depending on the state. RPS goals include environmental improvement, increased diversity and security of energy supply, reduced volatility in power prices given the absence of significant fuel costs, and local economic development.

To date, 27 states and the District of Columbia have passed mandatory RPS, while 6 states have established renewable energy goals. Although Congress has considered implementing a federal renewable energy standard, no nationwide regulations are in place and, as a result, standard setting continues at a state and local level. Most of the state legislative activity to establish renewable portfolio standards has occurred in the last five years, with 25 states adopting a standard or target since 2004. The current status for each state is noted in Figure 5-3.

Figure 5-3

Current Status of Renewable Standards



- Renewable portfolio standards adopted
- Renewable goals established
- No statewide renewable targets

The District of Columbia and Hawaii have also adopted renewable portfolio standards. Alaska does not currently have a renewable target.

Source: Environmental Protection Agency (September 2008)

There are copious differences among the individual state goals established, especially in the areas of allowable generation sources, resource goals (normally expressed as a percentage), and target dates for compliance:

- Allowable generation – Hydro, wind, solar, and biomass are accepted sources in all states, while approximately half include energy efficiency measures as an allowable source. Sources allowed in certain states vary from clean coal and advanced nuclear technology in Ohio, to carbon capture and sequestration in Michigan, and goal gasification in Pennsylvania. Some states also establish percentage goals for specified renewable sources.
- Resource goals – Many states have established initial minimum targets with the renewable requirement increasing over time. The ultimate goals vary from as low as 5 percent in Texas to as high as 33 percent in California. Most states have set goals between 15 and 20 percent.
- Target dates – Most states have mandated 2010 or earlier as an initial implementation date for some minimum level of compliance. In general,

most states are targeting 2020 or 2025 as the date for the ultimate targeted goal.

The states developed their programs individually and, while there are some similarities in certain jurisdictions, no state has exactly the same program. Consequently, companies that operate in multiple states may confront issues in managing their compliance with unique standards in each jurisdiction.

5.2.1 Compliance with Renewable Portfolio Standards

In general, companies satisfy the requirements of a state RPS by obtaining renewable energy credits; certificates evidencing that one megawatt hour of power has been generated by a renewable-fueled source and sold to an end user. RECs differ from traditional emission allowance programs in that emission allowances provide a disincentive to emit pollutants, while RECs promote greenhouse gas neutral energy by incentivizing electricity generated from renewable sources.

RECs are central to ensuring renewable portfolio standards are operational by providing a method of demonstrating compliance. The terminology for RECs can differ depending on the state, but all operate in a similar manner. Terms analogous to RECs include alternative energy credits, renewable energy certificates, green tags, tradable renewable certificates, and renewable energy attributes. The theory behind RECs is that the additional revenue from sale of the green attributes creates an incentive for power generators to invest in more renewable energy projects. Companies can obtain RECs in three ways:

- Own qualifying renewable energy facilities
- Purchase RECs when purchasing electricity from a counterparty that owns a qualifying renewable energy facility (i.e., through a power purchase agreement)
- Purchase RECs separately, either directly from a renewable energy generator or in the market

Further description of how companies are obtaining RECs follows.

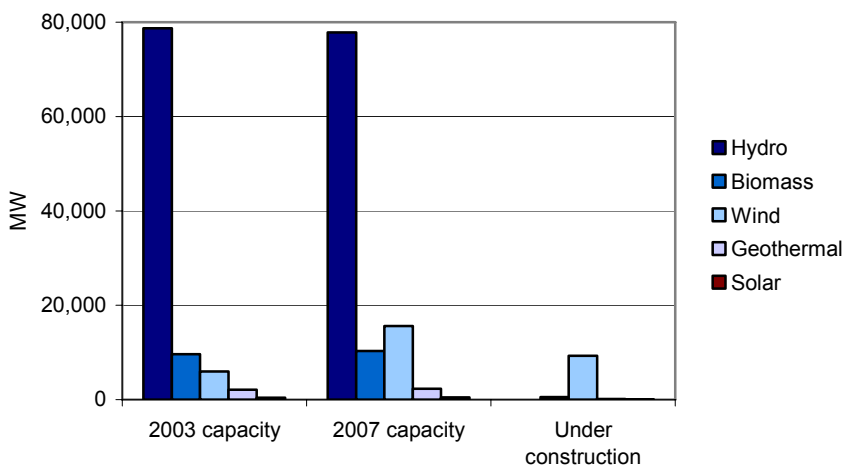
5.2.2 Investment in New Technologies

The combination of state mandates and renewable energy credits has driven a significant increase in renewable energy investment during the past several years. Venture capital funding of renewable technology in the United States has grown from \$30 million in 2001 to \$2.5 billion in 2007, and there is significant additional investment by utilities and merchant power generators. New investment is driven by the demand created by renewable portfolio standards combined with the incentive tax credits that contribute to the viability of certain of these technologies.

Figure 5-4 illustrates the growth in renewable capacity by generation type during the past several years and summarizes current projects under construction. As noted in the chart, hydroelectric generation continues to be the dominant source of renewable supply, primarily due to existing hydro resources, which may not qualify as new renewable sources in many states.

Wind generation is increasing at the fastest pace, both in terms of installations and in planned additions to generation capacity. Despite the recent investment in new construction and ongoing research and development, renewable sources do not typically have the size and scale of gas, coal, or nuclear plants. In 2007, renewable energy accounted for only approximately 10 percent of total capacity and 9 percent of total generation in the United States.

Figure 5-4
Renewable Generation by Source



In addition to renewable generation under construction, planned projects include approximately 66,000 MWs of wind, 23,000 MWs of hydro, 6,000 MWs of solar, 5,000 MWs of biomass, and less than 1,000 MWs of geothermal generation.

Over the longer term, the continuing trend of rising electricity demand will further compound the challenge of meeting renewable portfolio standards. Significant investment in renewable projects and related infrastructure, including needed transmission lines, will be required during the next decade to meet this demand. In addition, recent market events and the credit crisis have stalled interest in some projects and further complicate major capital investment. Companies are finding they must balance the renewable energy tax incentives contained within the Emergency Economic Stabilization Act of 2008 (EESA, see Section 0) against the current strain on liquidity and increases in borrowing costs. Lack of liquidity and access to capital may impact the ability or willingness of market participants to move forward with planned renewable projects.

5.2.3 Purchases of Renewable Energy Credits

Companies that do not have the capacity, willingness, or ability to invest in renewable energy infrastructure may be able to satisfy their RPS requirements through the purchase of RECs. As described above, RECs can be purchased bundled with the power from a renewable energy facility, or RECs may be purchased separately from the market at prevailing market prices. The ability

to separate a REC from the energy allows for the creation of a tradable unit that can be purchased and sold without the locational constraints of a power market. However, some state standards may not recognize RECs generated in other states.

The growing need for RECs and constraints on investments has led to a growth in the open market for RECs. Reporting entities should continue to monitor the REC markets, as that activity becomes an important factor when considering the accounting for forward contracts for the purchase or sale of RECs (see Section 5.4).

5.3 Accounting and Reporting for Emission Allowances and RECs

The accounting for emission allowances and RECs is challenging. The distinctive nature of these environmental assets creates difficulties in evaluating them within existing accounting models. Standard setters worldwide have struggled to offer a solution that satisfies the needs of management, users, and preparers of financial statements and other stakeholders. Although both U.S. and international standard setters have made several attempts to formulate an authoritative model for emission allowances, to date no official guidance has been issued.

The FASB and IASB are currently conducting a joint project to develop comprehensive guidance on the accounting for emission allowances and other environmental attributes. The scope of this project is expected to include all emissions-related issues, including cap-and-trade and baseline and credit programs (whether government mandated or voluntary), as well as project-based certificates and RECs.

The IASB and the FASB had their first joint meeting on this topic in October 2008; however, the meeting involved preliminary discussions and did not result in any progress forward. The discussions focused on the fundamentals, including the question of whether baseline credits and cap-and-trade credits even meet the definition of an asset. The current plan anticipates that an Exposure Draft will be issued in late 2009, with the issuance of a final document in 2010. However, given the difficulties encountered with issuing guidance in this area in the past and the baseline questions discussed at the initial meeting, it may be some time before a standard is issued.

The Road to GAAP for Emission Allowances is Long

Previous attempts to formalize guidance on the accounting for emission allowances have been unsuccessful, demonstrating the complexities involved. Standard-setting bodies, including the Financial Accounting Standards Board, the Emerging Issues Task Force, and the International Financial Reporting Interpretations Committee, have tackled the issues on different levels, but all attempts encountered roadblocks. The path of the current joint project is unknown.

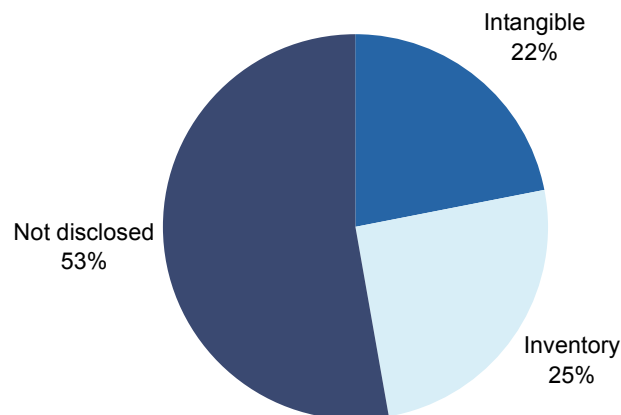
While there is no existing specific U.S. GAAP for emission allowances, in March 1993, the FERC issued Order No. 552, *Revision to Uniform Systems of Accounts to Account for Allowances under the Clean Air Act Amendments of 1990 and Regulatory-Created Assets and Liabilities and to Form Nos. 1, 1-F, 2 and 2-A* (Order 552), to provide guidance for regulatory reporting. Essentially, Order 552 requires that regulated utilities apply a historical cost model for purposes of FERC reporting. Under the FERC model, expense is recognized on a weighted average cost basis, by vintage year, and the monthly amount of SO₂ and NO_x emitted. Given the lack of authoritative U.S. GAAP guidance, many utilities also follow this approach for external reporting. Any changes under U.S. GAAP may result in U.S. GAAP-to-FERC accounting differences that would need to be highlighted in FERC reporting.

5.3.1 Possible Accounting Models

Emission allowances and RECs are comparable in some ways: both types of environmental assets provide intangible environmental benefits and the overriding programs have similar formats for granting and trading. Furthermore, the standard setters have recognized that these environmental assets have similarities, as evidenced by the scope of the latest emissions project described above. Although there are some additional considerations in accounting for both emission allowances and RECs, because of their similarities, we believe that the same basic accounting and financial reporting model can be applied to both.

There are various acceptable approaches to accounting for emission allowances and RECs (collectively for the purpose of this document, environmental assets). Reflecting the various potential accounting models, current practice is diversified as noted in Figure 5-5:

Figure 5-5
Classification of Emission Allowances



Source: Survey of SEC Form 10-K filings as of December 31, 2007 for 55 diversified electric, gas, and water utility and unregulated entities.

We believe that emission allowances are most appropriately classified as intangible assets; this conclusion has been confirmed with the FASB. We also believe that RECs meet the definition of intangible assets in accordance with FAS 142. However, until formal guidance is issued, reporting entities may elect an alternative accounting model, provided that the model is applied on a consistent basis and is reasonable based upon the intended use of the environmental assets. For example, many utilities purchase RECs to meet RPS requirements, while others are in the business of buying and selling RECs for profit. Furthermore, utilities and others may use the RECs for compliance but will also buy and sell as their needs fluctuate. Certain situations such as these may warrant classification of RECs as inventory.

Figure 5-6 highlights key considerations as reporting entities evaluate the available accounting and reporting models:

Figure 5-6
Models for Accounting for Emission Allowances and RECs

Derivative	Emission allowances and RECs themselves are not considered derivatives because they do not contain an underlying. However, contracts to buy or sell these environmental assets (e.g., forwards, futures, swaps, or options) may be considered derivative instruments. The key consideration is whether the contract requires or permits net settlement. See Section 5.4.
Intangible asset	FAS 142 defines intangible assets as "Assets (not including financial assets) that represent future expected benefits but lack physical substance." Emission allowances represent the authorization to pollute, based on the number of allowances that are granted or obtained; these allowances lack physical substance. Similarly, a REC is an environmental attribute of renewable energy, but not the energy itself. Under the intangible asset model, environmental assets are recorded at fair value at acquisition and should be amortized using a systematic and rational method. An impairment assessment must be performed on at least an annual basis or when conditions suggest impairment may be present. Impairment testing follows the guidance in FAS 144.
Inventory	ARB 43 defines inventory as "the aggregate of those items of tangible personal property which (1) are held for sale in the ordinary course of business, (2) are in process of production for such sale, or (3) are to be currently consumed in the production of goods or services to be available for sale." Some entities, such as trading organizations, may be engaged in buying and selling emission allowances and/or RECs in the ordinary course of business.

Some reporting entities may be classifying emission allowances as part of property, plant, and equipment as a result of a prior business combination whereby the emission allowances were obtained with the acquired plant. Such presentation is acceptable for existing allowances provided that management's intent is to use the emission allowances in production. Absent new authoritative guidance, we believe the accounting for newly acquired allowances should follow either the inventory or intangible model.

The adoption of an accounting model has current and future reporting implications; therefore, reporting entities should understand those repercussions and thoughtfully consider their policy selection. A reporting entity should select and document its accounting policy based on its facts and circumstances, and should apply it consistently to similar environmental assets.

5.3.2 Initial Accounting

Emission allowances and RECs generally fit into two categories based on the planned future use and management's intention for disposition: 1) for use in generation/compliance or 2) held for sale. The different intended uses and accounting model elected will have a consequence on the ongoing accounting and impairment frameworks. However, under current guidance, each of the models would result in the same amount recorded on the balance sheet at acquisition. Figure 5-7 summarizes the initial accounting for certain common environmental asset transactions:

Figure 5-7
Initial Accounting for Environmental Assets

Method of Acquisition	Accounting
Emission allowances granted by a governmental agency	Allowances granted at zero cost will be assigned \$0 value.
RECs generated through plant operations	Internally generated RECs should have \$0 value assigned. FAS 142 requires companies to expense as incurred the costs of internally developing, maintaining, or restoring intangible assets.
Emission allowances or RECs purchased through a freestanding contract	Record at fair value.

RECs acquired through a power purchase agreement are similarly recorded at their fair value consistent with the different structures above. Because of how the contracts work, however, there are some additional considerations related to the timing and amount of the valuation that may make the determination somewhat challenging.

Any RECs acquired through a power purchase agreement are actually acquired at the time the power is delivered. However, the rights to purchase

those RECs in the future are obtained at the inception of the contract. In addition, the price of those RECs is also established at the inception of the contract. In some cases, the cost is specified in the contract. However, to the extent that the contract does not separately price the green attributes, the reporting entity would estimate cost based on market prices of renewable energy and nonrenewable energy (i.e., the incremental market price would be an indicator of the amount to attribute to the forward curve used to determine fair value). As a result, we believe that the recording of the value of the RECs at the time of delivery with the fair value established at the date of execution of the power purchase agreement is an appropriate approach.

Currently, transaction price is assumed to represent fair value at acquisition; however, this may change in 2009 as a result of the adoption of FAS 157 for nonrecurring, nonfinancial assets and liabilities, such as environmental assets. FAS 157 requires use of a market participant perspective when recording the fair value of an asset, which may be different from the transaction price. See further discussion of the application of FAS 157 to nonfinancial assets and liabilities in Section 3.7.

5.3.3 Ongoing Accounting

The accounting subsequent to acquisition under each of these models is further discussed below. In addition, specific considerations related to forward contracts for the purchase or sale of environmental assets are addressed in Section 5.4.

5.3.3.1 Intangible Assets

FAS 142 defines intangible assets as "Assets (not including financial assets) that lack physical substance." In their joint emission allowance project, the FASB and IASB are now debating whether environmental attributes and emission allowances meet the overall definition of an asset; however, current interpretation has concluded that it is generally preferable to account for environmental assets as intangible assets.

Expense Recognition

Paragraph 11 of FAS 142 includes factors to consider in determining the useful lives of intangible assets, which include evaluation of the expected use of the assets as well as any provisions that may limit the asset's useful life. In some cases, environmental assets may have indefinite lives; however, most emission allowances and some RECs have a vintage year assigned. Therefore, reporting entities must assess an appropriate amortization methodology. FAS 142, paragraph 11, states:

The method of amortization shall reflect the pattern in which the economic benefits of the intangible asset are consumed or otherwise used up. If that pattern cannot be reliably determined, a straight-line amortization method shall be used.

Reporting entities should review the specifics of their contractual arrangements or regulatory requirements and how they plan to use the instruments in order to determine the appropriate useful life. In most cases, it may be appropriate to

apply a 'units of production' methodology and amortize the cost as the environmental assets are used in operations or sold.

Impairment

Potential impairment of amounts classified as intangible assets should be assessed based on the guidance provided by FAS 142. Potential triggering events for impairment may include significant declines in market values or other adverse events. For example, the CAIR court decision was a trigger that may have resulted in an impairment in the period in which the triggering event occurred. Reporting entities will want to continue to monitor the status of the CAIR case and review whether there are any additional triggering events requiring new assessments. In accordance with FAS 142, any impairment measurements would be performed in accordance with the requirements of FAS 144.

5.3.3.2 Inventory Classification

Expense Recognition

In order to determine how environmental assets are expensed if they are recorded as inventory, reporting entities will need to determine the appropriate costing model. A common costing method used is weighted average cost, which is also consistent with FERC guidance for emission allowances. However, specific identification is another potential method. Either of these costing methods would be used to determine the cost of the environmental assets as they are surrendered or sold.

The expense recognition trigger for inventory held for use would be the delivery of power, as delivery establishes the compliance obligation (for RECs) and a cost of production and delivery (for emission allowances). In addition, reporting entities should perform a lower-of-cost-or-market analysis of these environmental assets on a periodic basis.

Lower-of-cost-or-market Considerations

Changes in market value, such as the recent volatility associated with the CAIR decision, may result in the need to assess whether the carrying value of environmental assets held in inventory should be adjusted. ARB 43, Chapter 4, Statement 6, establishes the lower-of-cost-or-market (LOCOM) rule as the guiding principle to be used in assessing whether cost or a lower estimate of realizable value should be used for inventories; however, paragraph 10 emphasizes that "...Statement 6 is intended as a guide rather than a literal rule."

LOCOM adjustments to inventory are a matter of considerable judgment, and environmental assets represent forms of inventory that are different from traditional inventories. In addition, the approach to the adjustment may vary depending on the reporting entity's intent in holding the inventory:

For Use in Generation/Compliance

The net realizable value (NRV) of allowances or RECs held for future use in generation or to comply with RPS is based on anticipated future electricity

prices. When determining whether an inventory adjustment is required, the reporting entity should consider and document whether its anticipated cost of production (including the cost of the environmental asset) is below future anticipated electricity prices.

In addition, depending on the final outcome of CAIR or other changing circumstances, a reporting entity may determine that it has excess assets that will no longer be required for use in generation or compliance. If so, it may need to consider the NRV of these assets on a standalone basis, as further described under *Held for Sale* below.

Held for Sale

As discussed in Section 5.1.1, the spot price (NRV) of emission allowances has declined substantially in the second half of 2008. However, in evaluating whether an impairment should be recorded, we believe it is important to focus on the nature of the allowance. An emission allowance (as well as a REC) is a unit of account that does not fit neatly into the inventory accounting model — or any other model. It has attributes of a commodity and of an intangible, and there is diversity in the method of accounting.

Environmental assets are different from many other types of inventory that require lead time for production and/or sale. When performing a LOCOM assessment for assets held for sale, reporting entities will want to look to the market price as compared to the carrying value of the balance sheet date and consider the recent activity in the marketplace. A decline in market price below cost and a lack of trading volume may signal that the reporting entity would not have the ability to realize the recorded value of the assets as of the balance sheet date, resulting in the need for a write-down.

5.3.3.3 Property, Plant, and Equipment Classification

As a result of prior acquisitions of emission allowances as part of plant acquisitions, certain reporting entities may have recorded emission allowances as part of the overall plant balance. For new acquisitions, we believe that the inventory or intangible asset model should be applied. However, the following section addresses certain accounting issues associated with those previously recorded amounts.

Expense Recognition

Allowances recorded as part of the overall plant balance are typically depreciated over the underlying useful lives as the allowances are used.

Impairment

Allowances recorded as part of plant should be evaluated for impairment in accordance with the requirements of FAS 144, which states that an impairment analysis should be performed based on the lowest level of identifiable cash flows. In the case of allowances held as part of the overall plant balance, we would expect the asset group for impairment to include the plant balance (or potentially a group of plants, depending on operations and other entity-specific factors). Emission allowances would not be tested for impairment on a standalone basis.

In addition, consistent with the guidance in FAS 144, an impairment analysis should be performed in response to a triggering event. Because reporting entities should consider potential impairments in the context of the entire plant balance, generally a decline in market value of the emission allowances alone would not trigger a potential impairment. Among other indicators, potential triggering events may include:

- A significant decline in the price of the asset or asset group, which may occur as a result of significant declines in wholesale power prices or a significant increase in fuel prices as compared to contractual sales prices
- An adverse change in the manner in which the asset or asset group is being used
- A significant adverse change in the business or regulatory environment, such as a regulatory action requiring that a plant be shut down

To the extent an impairment evaluation is required, the reporting entity should perform the analysis based on facts and circumstances existing at the balance sheet date. Subsequent changes in value would be incorporated in the period in which the impairment occurred.

5.3.4 Other Considerations

Even after an accounting model is selected, various other issues may impact the accounting for emission allowances and RECs. Notable issues are summarized in Figure 5-8 and further discussed below.

Figure 5-8

Issues to Consider for Environmental Asset Transactions

In addition to the day one accounting, reporting entities will want to consider the following issues related to environmental assets:

- Ongoing accounting – expense recognition and impairment considerations
- Accruals for potential shortfalls of allowances or credits
- Vintage year swaps
- Revenue recognition for excess sales
- Presentation on the income statement and statement of cash flows
- Accounting for forward, future, swap, or option contracts for emission allowances and/or RECs
- Accounting for RECs embedded in purchase power contracts

All of the activities above have some complex considerations and are addressed in more detail throughout this section.

5.3.4.1 Accruals for Potential Shortfalls

In some cases, generating units may not have adequate emission allowances for their intended generation requirements. When a reporting entity faces a shortage, if it does not purchase additional allowances or redirect its source of supply (e.g., generate from another plant), it may face penalties from the government or another regulatory body as its operations continue. Generally, a liability for inadequate allowances should be accrued only when actual emission levels are in excess of emission allowances held for a particular vintage year. This approach requires careful tracking of both the expected emissions levels and the emission allowances held. Contractual commitments, along with an inventory of emission allowances held, should be carefully reviewed by management and legal counsel to determine whether to record obligations for emissions.

There is diversity in practice as to the recognition of such liabilities and differing practices are accepted. However, a reporting entity should be able to support its recognition policy within U.S. GAAP and be consistent in its application of its accounting policy. A similar model should be applied to RECs, whereby an obligation related to RECs (or an RPS requirement) should be recognized only when an organization is actually in a position where the number of RECs required to meet a state RPS requirement is greater than the RECs it holds or will generate for a particular vintage year.

Applying the guidance described above using a discrete interim approach could result in potential volatility during interim periods. For example, a company may hold sufficient emission allowances to offset its expected emissions for the first three quarters of a given fiscal year, but must begin accruing a liability (cost of purchasing emission allowances in the open market) in the fourth quarter. This approach leads to an expense recognition pattern that backloads expense, even though the company's actual emission levels may have been constant throughout the year.

5.3.4.2 Vintage-Year Swaps

A form of emission allowance transaction that has increased in volume with significant accounting implications is the exchange of emission allowances, also commonly referred to as "vintage-year swaps." In these types of transactions, companies exchange emission allowance credits in certain vintage years in which they have a shortage in exchange for vintage years in which they have excess allowances. In a vintage-year swap, two entities exchange emission allowances with different vintage years. For example, Company A may swap 1,300 allowances with a 2008 vintage year with Company B for 1,000 allowances with a 2009 vintage year. This may occur if Company A anticipates a shortfall in 2009, but expects to have excess allowances in the current period.

In determining the appropriate accounting for such transactions, a reporting entity should assess the applicability of APB Opinion No. 29, *Accounting for Nonmonetary Transactions* (APB 29), as amended by FASB Statement No. 153, *Exchanges of Nonmonetary Assets an Amendment of APB Opinion No. 29* (FAS 153). APB 29, paragraph 3(c), as amended, states:

Exchange (or exchange transaction) is a reciprocal transfer between an enterprise and another entity that results in the enterprise's acquiring assets or services or satisfying liabilities by surrendering other assets or services or incurring other obligations. A reciprocal transfer of a nonmonetary asset shall be deemed an exchange only if the transferor has no substantial continuing involvement in the transferred asset such that the usual risks and rewards of ownership of the asset are transferred.

Vintage-year swaps would typically meet this definition. APB 29, paragraph 18, provides the basic principles for accounting for nonmonetary exchanges as follows:

The Board concludes that in general accounting for nonmonetary transactions should be based on the fair values of the assets (or services) involved which is the same basis as that used in monetary transactions. Thus, the cost of a nonmonetary asset acquired in exchange for another nonmonetary asset is the fair value of the asset surrendered to obtain it, and a gain or loss should be recognized on the exchange. The fair value of the asset received should be used to measure the cost if it is more clearly evident than the fair value of the asset surrendered. Similarly, a nonmonetary asset received in a nonreciprocal transfer should be recorded at the fair value of the asset received.

In accordance with this guidance, qualifying nonmonetary exchange transactions should be accounted for at fair value. However, APB 29, paragraph 20, provides certain exceptions to the basic principle as follows:

A nonmonetary exchange shall be measured based on the recorded amount (after reduction, if appropriate, for an indicated impairment of value) of the nonmonetary asset(s) relinquished, and not on the fair values of the exchanged assets, if any of the following conditions apply:

- a. *Fair Value Not Determinable.* The fair value of neither the asset(s) received nor the asset(s) relinquished is determinable within reasonable limits.
- b. *Exchange Transaction to Facilitate Sales to Customers.* The transaction is an exchange of a product or property held for sale in the ordinary course of business for a product or property to be sold in the same line of business to facilitate sales to customers other than the parties to the exchange.
- c. *Exchange Transaction That Lacks Commercial Substance.* The transaction lacks commercial substance (paragraph 21). (footnote omitted)

There are quoted prices available for emission allowances; therefore, the paragraph 20(a) exception would not apply. However, as a result of application of the other exceptions, the accounting for an exchange of emission allowances may vary depending on the balance sheet classification of the original allowances. See further evaluation below.

Allowances Classified as Inventory

In accordance with APB 29, paragraph 20(b), exchanges of property held for sale in the ordinary course of business should be accounted for based on the recorded amount of the assets relinquished. In accordance with this guidance,

there would be no gain or loss recognized if emission allowances classified as inventory are exchanged for other emission allowances held for the same purpose.

Allowances Classified as Intangible Assets

Exchanges of emission allowances classified as intangible assets should be accounted for at fair value, unless such exchange qualifies for the "lack of commercial substance" exception. APB 29, paragraph 21 states:

A nonmonetary exchange has commercial substance if the entity's future cash flows are expected to significantly change as a result of the exchange. The entity's future cash flows are expected to significantly change if either of the following criteria is met:

- a. The configuration (risk, timing, and amount) of the future cash flows of the asset(s) received differs significantly from the configuration of the future cash flows of the asset(s) transferred. (footnote omitted)
- b. The entity-specific value^{5d} of the asset(s) received differs from the entity-specific value of the asset(s) transferred, and the difference is significant in relation to the fair values of the assets exchanged.

A qualitative assessment will, in some cases, be conclusive in determining that the estimated cash flows of the entity are expected to significantly change as a result of the exchange.

APB 29, footnote 5d states:

An entity-specific value (referred to as an entity-specific measurement in Concepts Statement 7) is different from a fair value measurement. As described in paragraph 24(b) of Concepts Statement 7, an entity-specific value attempts to capture the value of an asset or liability in the context of a particular entity. For example, an entity computing an entity-specific value of an asset would use its expectations about its use of that asset rather than the use assumed by marketplace participants. If it is determined that the transaction has commercial substance, the exchange would be measured at fair value, rather than at the entity-specific value.

Entity-specific value is different than fair value, and means the value of an asset in the context of a particular entity, incorporating how the asset is expected to be used by the entity rather than by unrelated marketplace participants. We believe that most commercial substance assessments will focus on the degree to which asset-specific cash flows or entity-specific asset values are expected to change as a result of an exchange. FAS 153 does not provide guidance on what is considered significant for purposes of the commercial substance test. Judgments regarding significance should not be made using bright-lines exclusively.

In determining the appropriate accounting for exchanges of emission allowances accounted for as intangible assets, a reporting entity should assess whether it expects a significant change in cash flows or its own value as a result of the exchange. As these exchanges involve swaps between years, in many cases, we would expect that there would be a significant

change and fair value accounting would be applicable. Reporting entities should assess their specific facts and circumstances in evaluating the appropriate accounting for vintage-year swaps.

Impact of FAS 157

As further discussed in Section 3.7, FAS 157 will be applicable for nonfinancial assets and liabilities as of January 2009 (for calendar year-end companies). The adoption of FAS 157 may change the determination of the fair value to be recorded for a vintage-year swap.

5.3.4.3 Revenue Recognition

In some cases, a utility or other power entity may sell emission allowances or RECs for a profit, even though they may require these environmental assets to meet future requirements. In that circumstance, a question arises as to whether it is appropriate to defer any gain on sale as an offset to future expense associated with a potential purchase obligation. To the extent there are no contingencies or other continuing involvement associated with the sale, we are not aware of support within U.S. GAAP for deferral of gains received on the sale or exchange of RECs or allowances, unless the company qualifies for regulatory deferral in accordance with FAS 71.

5.3.5 Presentation and Disclosure Considerations

Reporting entities should ensure they have a well-reasoned approach to the presentation and disclosure of RECs and emission allowances on the income statement and the statement of cash flows. Classification on those statements should generally follow the balance sheet classification and the nature of the underlying activities. The classification of activities relating to environmental assets may vary among different types of entities and activities as follows:

- Renewable generator sells RECs under a long-term power purchase agreement – RECs are being sold as part of the reporting entity's core business activities and should be classified as part of revenue.
- Regulated utility uses emission allowances to offset generation – Allowances are an operating expense and are typically classified as part of operations and maintenance. Alternative presentations may include fuel expense or amortization.
- Plant owner sells excess emission allowances – Assuming the plant owner holds the emission allowances to offset generation, those allowances are considered an operating expense. The sale of excess allowances would generally be classified as a contra-expense.
- Trading entity actively buys and sells RECs to generate profit – Revenue and expense related to RECs purchased and sold as part of a trading operation should be presented net in the income statement. The net balance is typically classified as part of revenue.

As indicated in these examples, reporting entities may apply judgment in determining the appropriate income statement classification, as there is no specific guidance in U.S. GAAP that prescribes the appropriate classification.

However, the model selected should be supportable by the underlying business activities and consistently applied.

Reporting entities should ensure that they provide sufficient disclosure of accounting policies, classification, and rationale when environmental assets are significant to the financial position, results of operations, or cash flows. In addition, reporting entities should disclose in the management discussion and analysis any known trends or known demands, commitments, events, or uncertainties that will result in or that are reasonably likely to result in changes to the company's liquidity. For example, an anticipation of the need to purchase allowances or RECs in future periods may warrant disclosure. Similarly, early warning disclosures may be needed if there is an anticipation of potential impairments.

5.4 Other Contracts for Environmental Assets

Reporting entities may enter into forward purchase or sale contracts for RECs or emission allowances, as well as futures, options, and swaps. These contracts may be standalone agreements or embedded as part of a larger contract. For example, many purchase power agreements for renewable output provide for the sale of energy and the related REC. Such contracts may have lease accounting or consolidation implications. In addition, the reporting entity should consider whether derivative accounting applies.

We will assess the applicability of derivative accounting first to standalone forward contracts for RECs or emission allowances, followed by a discussion of the considerations when a REC is embedded in another agreement.

Is a forward contract for an emission allowance or a REC a derivative?

Emission allowances and RECs themselves are not derivatives because there is no underlying. However, forward purchases and sales of these environmental assets may meet the definition of a derivative. These contracts have an underlying and a notional amount and typically do not require an initial net investment. Therefore, the key question is whether the contracts have the net settlement characteristic. The answer will generally depend on the current status of the spot markets.

5.4.1 Accounting for a Forward Contract for RECs or Emission Allowances

The assessment of whether a forward contract for emission allowances or RECs is a derivative is based on the definition of a derivative in FAS 133, paragraph 6. We evaluated forward contracts for emission allowances and RECs within this definition as follows:

Paragraph 6(a) – Notional Amount and Underlying

Forward contracts for environmental assets typically include a quantity of allowances or RECs to be purchased or sold. In addition, these contracts include an underlying (the amount received or paid in the future for the allowances or RECs). Therefore, forward contracts for emission allowances and RECs usually meet the paragraph 6(a) criterion.

Paragraph 6(b) – Initial Net Investment

Forward contracts for environmental assets normally do not require an initial net investment. Option contracts involve premiums that should be assessed; however, standard option premiums for the time value of money are not considered an initial net investment.

Paragraph 6(c) – Net Settlement

For both emission allowances and RECs, the key question in assessing whether derivative accounting is applicable to forward purchase or sale contracts is whether the contract meets the net settlement criterion. We have examined this criterion in accordance with FAS 133, paragraph 9, which describes three types of possible net settlement as follows:

Contractual Net Settlement

Paragraph 9(a) of FAS 133 states:

Neither party is required to deliver an asset that is associated with the underlying and that has a principal amount, stated amount, fair value, number of shares, or other denomination that is equal to the notional amount...

When a forward contract for the sale of emission allowances or RECs is settled, the applicable assets are delivered/surrendered. Explicit net settlement does not exist for these contracts since there is physical delivery. However, the type of contract and the terms should be carefully reviewed to ensure that there are no implicit net settlement terms or liquidating damage provisions that may imply that the contract could be cash settled.

Market Mechanism

Paragraph 9(b) of FAS 133 states:

One of the parties is required to deliver an asset of the type described in paragraph 9(a), but there is a market mechanism that facilitates net settlement, for example, an exchange that offers a ready opportunity to sell the contract or to enter into an offsetting contract.

DIG Issue A21 provides further guidance on indicators to consider in assessing whether an established market mechanism exists. We considered these factors in our overall assessment of whether there is a market mechanism for net settlement of contracts for environmental assets. Under the current market structure, there is no mechanism in the United States for net settlement of these types of environmental assets. However, various states

and regions are considering an assortment of proposals that may lead to the creation of a market mechanism. Therefore, the evolution of the markets and the potential impact on the assessment of net settlement under this criterion should be monitored on an ongoing basis, as further described below.

Readily Convertible to Cash

FAS 133, footnote 5 states:

FASB Concepts Statement No. 5, *Recognition and Measurement in Financial Statements of Business Enterprises*, states that assets that are readily convertible to cash "have (i) interchangeable (fungible) units and (ii) quoted prices available in an active market that can rapidly absorb the quantity held by the entity without significantly affecting the price" (paragraph 83(a)). For contracts that involve multiple deliveries of the asset, the phrase *in an active market that can rapidly absorb the quantity held by the entity* should be applied separately to the expected quantity in each delivery.

As further discussed in Section 4.5.1, the FASB concluded that contracts that require delivery of an asset that is readily convertible to cash is equivalent to net settlement because the "the parties generally should be indifferent as to whether they exchange cash or the assets associated with the underlying." However, in order to meet this criterion, an active spot market must exist today and be expected to exist in the future. Absent an active spot market, there is no opportunity for the parties to convert the assets to be exchanged or delivered into cash.

To be deemed an active market, a market must have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis. In addition, quoted prices from that market will be readily available on an ongoing basis. We separately considered whether there is an active spot market for emission allowances and RECs below.

Emission Allowances

Typically, forward or futures contracts for emission allowances are considered financial instruments that would meet the readily-convertible-to-cash criterion. A spot market with sufficient liquidity and activity exists for both SO₂ and NO_x allowances, supporting the assertion that the asset delivered under the contract is readily convertible to cash. However, recent issues associated with CAIR have resulted in a significant decline in emissions-trading activity (see Section 5.1.1). Therefore, as further described below, reporting entities should continue to monitor the markets and reassess each period whether the contracts continue to qualify as derivative instruments.

Renewable Energy Certificates

The level of bilateral activity for RECs continues to grow, with renewable producers selling RECs bundled as part of PPAs and separately as green attributes. However, our understanding is that currently there is not sufficient activity and liquidity in a spot market to conclude that RECs are readily convertible to cash. Therefore, absent contractual net settlement provisions, we believe that contracts for RECs do not meet the net settlement criterion at

this time, and thus do not meet the definition of a derivative. As a result, these contracts would follow other U.S. GAAP for executory contracts.

Don't Get Caught Unprepared!

In general, the assessment of whether forward contracts for environmental assets meet the definition of a derivative depends on whether there is an active spot market for the underlying asset. As renewable energy initiatives and other regulations continue to evolve, we expect related changes in the level of activity and liquidity in markets for emission allowances and RECs. Therefore, reporting entities should consider conditional normal designations to manage against future unexpected impacts to net income. In addition, management should monitor activities and markets regularly to identify any potential requirement to change prior conclusions about derivative accounting.

Ongoing analysis

DIG Issue A18 and paragraph 57(c)(3) of FAS 133 require that contracts be reviewed on an ongoing basis throughout their life to evaluate the status as to whether they are readily convertible to cash. Therefore, reporting entities should continue to monitor activity in the markets in which emission allowances and RECs trade. Future changes in the markets may change the assessment of whether forward purchases and sales of these environmental assets meet the definition of a derivative. For example, the CAIR decision and its adverse impact on the market for SO₂ and NO_x allowances is an example of a change in circumstances that would require reassessment.

In addition, given the increasing compliance obligations, and resultant growth in trading activity for RECs, we believe that it is likely just a question of when contracts for RECs may meet the criteria for net settlement. Therefore, while forward contracts for RECs generally do not meet the definition of a derivative at this time, they may at some point in the future. At the time a reporting entity concludes that such contracts are derivatives, any open contracts will need to be recorded at the then-existing fair value on the balance sheet, with the gain or loss recorded in earnings. The potential impact could be significant depending on the number of RECs involved and the length of the contracts.

Application of the Normal Purchases and Normal Sales Exception

Reporting entities that hold contracts for emission allowances or RECs may also want to consider whether the contracts are eligible for the normal purchases and normal sales exception provided by FAS 133, paragraph 10(b)(1). This exception provides an exclusion to fair value accounting for certain contracts that involve future delivery of assets (other than financial instruments or derivative instruments) and are "expected to be used or sold by the reporting entity over a reasonable period in the normal course of business." In order to qualify for the normal purchases and normal sales

exception, management must evaluate the reasonableness of quantities and terms in relation to the company's underlying business requirements. This determination requires judgment and a two-step conclusion that the company intends to take physical delivery of the quantity and that it will be used in normal business activities. Any type of financially settled contract (e.g., swaps) or freestanding option contract (in accordance with paragraph 10(b)(2) of FAS 133) would not qualify for the normal purchases and normal sales exception.

In accordance with FAS 133, paragraph 58(b), "The exception in paragraph 10(b) applies only to a contract that involves future delivery of assets (other than financial instruments or derivative instruments)." Contracts for RECs and emission allowances typically require physical delivery of the underlying asset because cash cannot be delivered instead (i.e., it cannot be "net settled"). Therefore, in assessing application of the normal purchases and normal sales exception, management teams should evaluate the expected business purpose, location, and volume in relation to their business needs. For example, if a utility in California obtains a REC generated in California to meet its RPS requirements there, that forward contract may qualify for the normal purchases and normal sales exception. However, if the utility is actively buying and selling RECs in other states for a profit, those contracts would not qualify for the normal purchases and normal sales exception.

In accordance with DIG C12, the normal purchases and normal sales election must be documented and may be made at any time over the life of the contract. If a reporting entity concludes that its contracts do not currently meet the definition of a derivative, such contracts could still be conditionally designated as normal purchases (assuming that all of the criteria in paragraphs 10(b) and 58(b) are met and documented). (Note that we have interpreted DIG Issue A18, paragraph 2, question 2, which permits conditional hedging designation, to permit the conditional designation as normal.)

The contracts would be accounted for as normal purchases or normal sales from the time that the markets developed and the contracts become derivatives. Absent such a designation, management would be required to initially fair value the contracts at the time the contracts are determined to be derivatives, with the related gain or loss recognized in earnings. The contracts could still subsequently be designated as normal purchases or normal sales with no recognition of subsequent changes in value.

5.4.2 RECs Embedded in Power Purchase Agreements

Frequently, RECs are acquired in conjunction with power purchase agreements (a common example is RECs obtained in an agreement to purchase power from a wind farm). In evaluating the appropriate accounting for such contracts, the reporting entity should consider whether the contract is for the sale of two separate products (energy and environmental attributes) or for the sale of one product, energy. This conclusion could impact the overall FAS 133 evaluation of the contract and could also impact the valuation, if applicable.

Key factors in making this assessment include the specific characteristics of this contract and the overall market for energy and environmental attributes in the location of the sale. Contract characteristics that suggest the contract is for the sale of two distinctive products:

- The contract explicitly separates the energy and related environmental attributes – Indicators that the products are separate include identification of the RECs and energy as separate products, the ability to separately purchase or sell the environmental attributes, and contract pricing that includes a separate component for the RECs. Although the price may be higher than energy from another source, it may suggest that the environmental attributes are not a separate product if a contract from a renewable power source does not specifically mention and separate the environmental attributes.
- Existence of separate markets for energy and RECs – In some locations in the United States, energy may be sold as "green" or "brown" and there may be separate purchases and sales of RECs on a standalone basis. The existence of these types of markets would suggest that the RECs are a separable product that should be considered separately from the energy component. In contrast, if there is no distinction in the marketplace, it may not be appropriate to separate the REC from the energy.

The subsequent reporting will vary, depending on whether the reporting entity concludes that the RECs or green attributes are a separable product.

RECs are a Separate Product

If the reporting entity concludes that the contract includes the sale of energy and RECs, it should initially evaluate whether the contract in its entirety meets the definition of a derivative. At this time, absent explicit net settlement provisions, we would typically not expect the entire contract to meet the definition of a derivative. We are not aware of any spot markets or market mechanisms for green power (i.e., power with a REC attached).

The reporting entity should then consider whether the hybrid contract includes an embedded derivative that should be separated and accounted for as a derivative. In most cases, the energy would meet the definition of a derivative and should be accounted for in accordance with the requirements of FAS 133. The energy may be eligible for designation as a normal purchase or normal sale if all of the requirements in FAS 133 are met.

The evaluation of the environmental attributes would follow the approach outlined in Section 5.4.1. Consistent with that discussion, at this time, we would not expect a forward contract for RECs to meet the definition of a derivative. However, the reporting entity will need to monitor market developments to determine if this conclusion changes. Furthermore, the reporting entity may want to consider conditional normal designation to avoid future income fluctuations.

RECs That Are Not Separable

Some contracts for the purchase of power from renewable sources may not have a separate REC designated. This may be the case in contracts for purchases from qualifying facilities that were negotiated several years ago prior to the advent of environmental attributes. In addition, RECs may not be separately identified in contracts in some parts of the country, depending on the level of development of related markets.

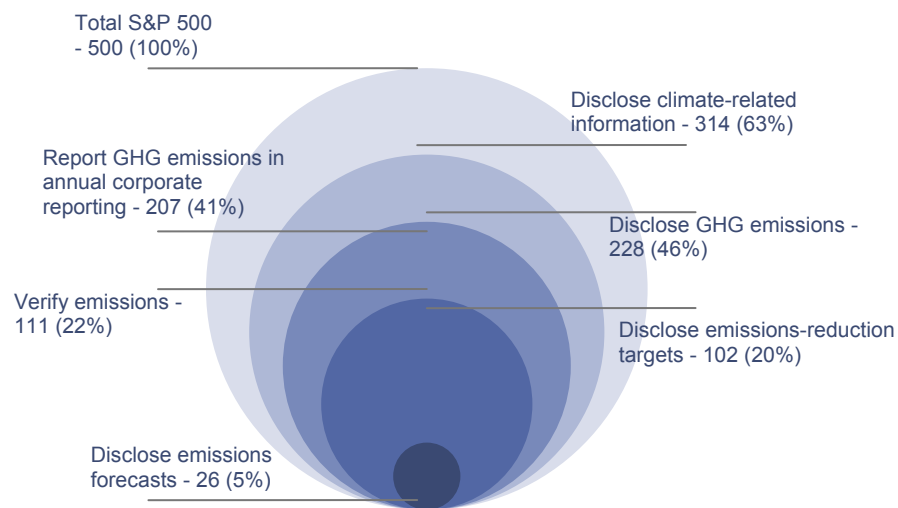
In such cases, it typically would not be appropriate to separately account for the REC and the energy. The reporting entity should instead evaluate the agreement as the purchase or sale of energy. In measuring the fair value of the energy, the reporting entity should consider whether the contract potentially has a higher fair value due to the renewable attribute (since the pricing of the contract will take into account the green attribute). If a higher sale price could be obtained because the energy is from a renewable source, the reporting entity should consider whether a different forward curve (i.e., for green power) should be used to determine the fair value of the energy. However, to the extent that the purchase price under the contract is in excess of amounts that would be paid for "brown" power at the same delivery location, and the reporting entity could not sell the contract based on "green" power market prices, a gain or loss on the contract may need to be recorded.

5.5 Other Environmental Reporting Issues

From our perspective, another issue that reporting entities will need to focus on is nonfinancial reporting on climate change and the environment. This topic is gaining attention from shareholder groups, and as many as 43 climate-related shareholder resolutions were filed with U.S. companies in 2007. The trend is expected to increase, prompting many companies to voluntarily disclose carbon footprints and expectations of future curtailments.

As a result of the interest in this type of information, the majority of the S&P 500 companies are now reporting some type of climate-related information, as illustrated in Figure 5-9.

Figure 5-9
Climate-Related Disclosures



Source: Carbon Disclosure Project Report 2008: S&P 500, written for the Carbon Disclosure Project by PricewaterhouseCoopers, September 2008

Many open questions remain about climate change and other environmental reporting, including the framework used to evaluate a company's carbon footprint and how an entity should establish goals and measure progress. In addition, companies are working with auditors to determine the level of assurance that can be provided on corporate reporting in this area. We expect significant developments during the next several years as companies tackle and resolve these and other related issues. We will continue to be actively involved in this discussion and debate to provide our perspective.

5.6 Renewable Energy Tax Incentives

In addition to emissions-reductions legislation and state-mandated programs, renewable energy tax incentives have played a large role in spurring investment in renewable energy. However, uncertainty continues regarding the ongoing applicability of the various tax incentives. The initial incentives were issued in temporary form and have been extended, modified, or cancelled in various pieces of federal legislation. The unpredictability of whether and how tax incentives would be available has led to an inconsistent pattern of investment with numerous starts and stops.

Historically, federal energy tax policy has promoted energy conservation, the development of alternative fuels, and the commercialization of technologies for producing these fuels (e.g., solar, wind, and biomass). The recent Emergency Economic Stabilization Act of 2008, which was signed into law on October 3, 2008, includes several energy-related tax provisions, including enhanced tax incentives for renewable energy investment and production. The EESA extends alternative energy tax provisions that are expiring and allows for a broader application of tax incentives to other newer forms of renewable or "cleaner" generation investment. Significant changes with potential impact on renewable energy are further discussed below.

Production Tax Credit

The EESA extends the renewable energy production tax credit under Section 45 of the Internal Revenue Code (IRC). This credit allows electricity generators to claim a tax credit of up to 2.1¢/kWh for the production of qualifying types of domestic electricity. The EESA extends the credits one year for wind and certain coal production facilities if placed in service prior to January 1, 2010, and two years for other renewable facilities if placed in service before January 1, 2011. Other renewable facilities include closed-loop biomass, open-loop biomass, geothermal, and qualified hydropower.

Energy Tax Credit

The IRC Section 48 energy tax credit applies to a percentage of eligible energy property placed in service during the tax year, and was originally scheduled to expire at the end of 2008. However, the EESA also extended and modified it as follows:

- 30 percent investment tax credit for solar energy property and qualified fuel cell property placed into service before January 1, 2017
- 10 percent investment tax credit for microturbine property placed in service on or before December 31, 2016

The EESA also amends the Section 48 definition of energy property to remove the restriction that qualifying property could not include public utility property. Among the many changes to the energy tax credits is a new 10 percent investment tax credit for combined heat and power systems and a \$20 per metric ton tax credit for carbon sequestration.

Other Changes

In addition to the changes in Section 45 and Section 48, the EESA also impacted the following areas of existing tax legislation impacting utilities:

- Sales of electric transmission property – The EESA extends the eight-year gain deferral provision for dispositions by vertically integrated electric utilities. This provision had expired in 2007 and the EESA extends the provision by two years.
- Accelerated depreciation for smart meters and smart grid systems – The EESA shortens the recovery period for the cost of smart electric meters and smart electric grid equipment to 10 years and provides that the 150 percent declining-balance method shall be used for such assets. Previously, the Internal Revenue Service (IRS) had historically considered meters to be depreciable over 20 years using the 150 percent declining-balance method.
- Clean coal technologies – Various provisions were included within the EESA to encourage research and development in CO₂ capture and sequestration.

These incentives will provide an opportunity for organizations to benefit by investing in certain types of renewable energy projects. We expect that the investment tax credits would be accounted for under the same method elected for previous investment tax credits, typically resulting in the deferral of the benefit over the life of the property to which it relates. The production credits and capture and sequestration tax credits generally would be accounted for as a reduction of income tax expense in the year earned.

Tax Benefits for Renewable Investment

Although the primary motivation for the Emergency Economic Stabilization Act of 2008 was to respond to unparalleled events in credit markets and the impact on financial institutions in the United States, it has provided utilities, independent power producers, and other industry participants with a slate of tax incentives that will be beneficial as they contemplate investment in renewable energy assets. These benefits will propel organizations to maintain the investment momentum necessary to meet environmental and renewable targets.

Section 6: Industry Regulation

Section 6: Industry Regulation

Historically, the utility industry developed as a small number of monopolies and regulation substituted for competition. Shareholders invested in utilities based on a regulatory promise that prudently incurred capital costs would be returned to investors together with a fair rate of return. The landscape of the utility industry has changed during the past decade because of many factors including deregulation and its effects, increased foreign investment, and new market participants. For regulated utilities, however, the impact of federal and state regulation continues to be one of the predominant influences on success and investor return.

Federal and state regulators directly impact the revenue and net income of rate-regulated utilities through the establishment of approved tariffs, approval of significant investment, and the prospect of prudency reviews. The interchange of these regulator actions with FAS 71 can have a profound impact on the financial statements. Regulators also influence the operations of both regulated utilities and unregulated power companies through the issuance of compliance requirements and their focus on operating standards, enforced through penalties.

To ensure appropriate accounting and reporting for rate actions and compliance requirements, controllers and their teams need to obtain a full understanding of ongoing regulatory developments impacting their organizations. The following section analyzes key regulatory trends, highlights critical compliance concerns, and discusses accounting ramifications to assist reporting entities as they evaluate their regulatory accounting and reporting.

State Regulation

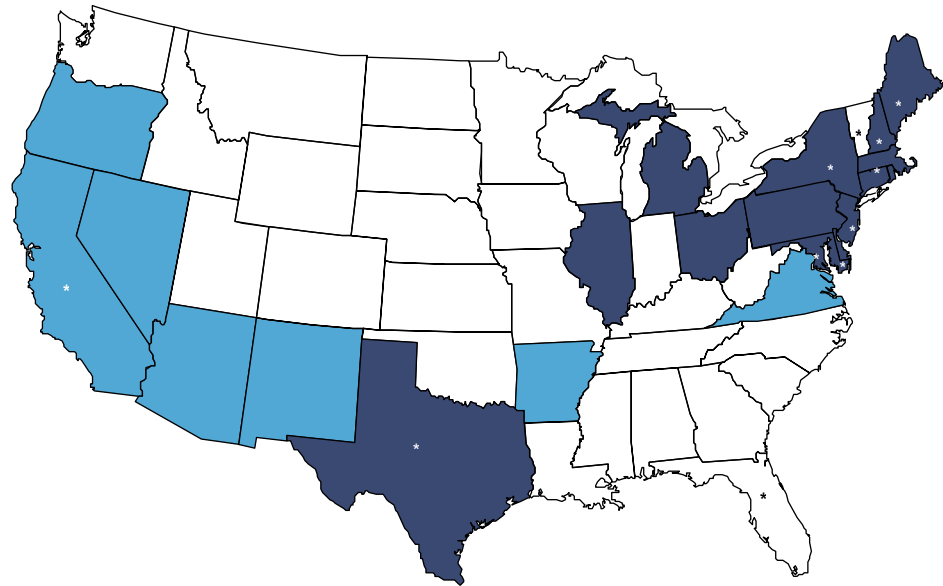
In 1997, all but 2 states were deregulating or considering some form of deregulation to allow retail electric choice. Now, 10 years later, only 15 states have active direct access programs or other forms of deregulation. However, the impact of deregulation and its aftermath continues to influence regulatory policy in some states, even as utilities tackle new issues related to rising costs, fuel price volatility, and recovery of major capital expansion programs.

6.1 State Regulatory Developments

Ten years ago, the deregulation of the retail electric power industry was a burning issue for regulators, utilities, and other stakeholders. The concept of retail choice gained significant momentum and many states adopted various forms of deregulation. In 1997, all but two states were deregulating or considering some form of deregulation legislation. However, as a result of the California energy crisis in 2000 and 2001, the shift to deregulation slowed significantly. The resulting negative impact on the California utilities and their consumers, and the ongoing litigation that embroiled many power market participants, slowed the progress of deregulation and impacted regulation

across the country. Figure 6-1 provides the current status of electric deregulation as of September 2008:

Figure 6-1
Status of Electric Deregulation – 2008



- Competition active
- Competition suspended
- No active competition

States marked with an asterisk (*) have rates more than 10 percent above the national average.

Source: Energy Information Administration (September 2008)

In some cases, the genesis of current state regulatory policy and rate design impacting electric and natural gas utilities stems from the repercussions of the deregulation experience in that state or region of the country. However, regulators and utilities are now also wrestling with new issues related to rising costs, fuel price volatility, and recovery of major capital expansion programs. The interaction of these factors has influenced many of the ratemaking trends in 2008, as further described below.

6.1.1 State Ratemaking Trends

Utilities continue to experience rising costs for power, materials, labor, and other costs to provide service. Also, transition periods and rate freezes adopted during the proposed transition to competition period have ended or are ending in many states. As a result, many utilities are filing rate cases for the first time in years, and are requesting significant rate increases to cover rising costs and capital investment. Utilities are also starting to file rate cases

more frequently (annually in some cases) to address issues associated with regulatory lag, which may be especially significant in periods of increasing costs and increased capital development. To date, 2008 has been an active year for rate actions, with 36 rate cases settled in 27 states, and another 77 cases filed, pending final ruling. Figure 6-2 provides information on key metrics from the rate cases that settled in 2008.

Figure 6-2
Rate Case Statistics

(\$ amounts in millions)	Electric		Gas	
	Requested	Received	Requested	Received
Return on rate base	8.70%	8.25%	9.03%	8.62%
Return on equity	11.13%	10.28%	11.10%	10.42%
Average rate base	\$ 2,186	\$ 2,105	\$ 686	\$ 561
Average rate increase	\$ 144	\$ 65	\$ 40	\$ 19
Equity / capitalization	49.06%	48.58%	51.93%	51.41%
Average lag in months		11		10

Source: SNL Interactive

Consistent with expectations and past experience, regulators are continuing to allow lower return on equity, rates of return, rate base, and rate increases than requested. The reductions and allowed recovery are generally similar for electric and gas utilities. However, we note that although gas utilities received larger reductions of rate base (18 percent compared to 4 percent for electric utilities), gas utilities were also allowed higher equity ratios.

To provide some historical perspective, we also compared these rate case results to the 10-year average cases. During this period, we observed an overall negative trend in return on equity, which has declined 0.38 percent and 0.24 percent for electric and natural gas utilities, respectively. However, the equity ratio has increased slightly over this period from 47.7 percent to 48.6 percent for electric, and from 48.3 percent to 51.4 percent for gas. In addition, average rate base has grown \$373 million (21.5 percent) for electric and \$33 million (6.3 percent) for gas during the past decade.

6.1.2 Specific Ratemaking Trends

In response to utility requests for significant increases in rates, state commissions have sought ways to manage the "rate shock" through a variety of means including extending rate freeze periods, creating deferred recovery mechanisms or phase-in plans and other regulatory mechanisms. In addition, some utilities have seen significant political resistance to rate increases at the state level and have been forced to provide rate concessions.

Utilities are monitoring the rate structures and recovery mechanisms adopted in the recently approved cases to identify key trends and opportunities for improved cost recovery and revenue stability. Evaluation of completed cases provides management with insight into potential mechanisms and alternatives to manage return in their own jurisdictions. Figure 6-3 highlights key trends in ratemaking over the past year.

Figure 6-3

Ratemaking Trends

Key factors influencing ratemaking trends during the past year include efforts to reduce regulatory lag, manage the impact of rising costs, and incentivize utilities to support conservation efforts. Regulator and utility efforts to manage these issues have included:

- Implementation of the use of forecast test years, interim rate increases, inclusion of construction work in progress in rate base, and post-test year capital addition adjustment mechanisms to address regulatory lag
- Creative approaches to enhance rate stability while ensuring cost recovery, including deferred recovery mechanisms and phase-in plans
- Efforts to reduce approved operating expenses, such as the exclusion of stock-based incentives and other executive compensation and extension of plant depreciable lives
- Adoption of decoupling mechanisms that eliminate or reduce the impact of weather on revenue

In addition, utilities continue to pursue cost recovery through trackers, riders, or surcharges to enhance the timeliness of recovery and mitigate the risk of volatile costs such as fuel, storm costs, and pension and other post employment expenses.

Each of the trends is further discussed below, followed by a discussion of key accounting considerations associated with the application of FAS 71 and the impact of some of these mechanisms on regulatory assets and liabilities.

6.1.2.1 Focus on Regulatory Lag

Regulatory lag continues to be an important issue for utility management teams, especially because of the momentous level of planned capital expenditures and the ongoing volatility of fuel and power prices. Utilities are addressing these issues through various rate mechanisms, including:

Increasing Rate Base

Many utilities have announced significant capital programs to replace aging infrastructure, to expand transmission to support renewable projects, and to build new sources of generation. In some cases, utilities are also purchasing completed or partially completed plant assets to obtain reliable sources of supply to meet increasing demand. Although credit market issues may be

delaying some planned construction, over the longer term we expect that these expenditures will continue to grow.

To help mitigate significant regulatory lag during a period of growth and expansion, many utilities are seeking the inclusion of more costs in rate base, such as requesting recovery of construction work in progress. For example, one Midwestern regulatory commission allowed a utility current rate recovery, including a return on investment and recovery of incremental cost, of capital expenditures for emissions reduction equipment before it was put into service. Some regulators also provide annual adjustment mechanisms or capital tracking accounts to prevent significant lag.

Contingent Rate Increases

In many jurisdictions, the rate case process may span more than a year. To address this lengthy period and to provide more timely revenue growth to match increasing costs, some states are allowing rate increases subject to refund while the commission completes the rate proceeding. The interim amount allowed varies, but may be 75 percent or more of the requested rate increase. However, collections under these rates are typically subject to retroactive adjustment based on the final rate order; therefore, utilities that receive such rates should continually assess whether revenue recognition is appropriate prior to the final order (see further discussion in Section 6.2).

Riders, Trackers, and Surcharge Mechanisms

We also continue to observe an increase in the number and variety of riders, trackers, and surcharge mechanisms that provide the utility with current or assured collection of actual costs associated with specific activities. This protects the utility from price volatility while typically resulting in more timely recovery. Fuel adjustment mechanisms are common given the fluctuations in fuel prices. Other riders being requested include:

- Regional transmission operator and independent system operator costs
- Pension and other postemployment costs
- Storm costs
- Inflation

Many utilities are also requesting depreciation, infrastructure replacement, or modernization surcharges, which may cover costs such as smart meters, new transmission lines or other major construction projects.

Forecast Test Years

Many utilities adopt forecast test years where permitted to reduce the impact of regulatory lag, especially in the face of rising costs and large construction projects. However, to be successful using forecast test years, utilities need to have robust, formal planning and budgeting processes in place that produce reliable forecasts which could be evaluated by a state commission review. Furthermore, states often require an accountant's opinion on forecast financial information, which could require a company's auditors to perform an engagement to opine on prospective financial information.

6.1.2.2 Cost Management

As operating costs continue to increase, regulators in some jurisdictions are adopting mechanisms to stabilize customer rates. There is also significant regulatory focus on reducing operating costs through disallowances or changes to depreciation.

Stabilization Methodologies

Rate structures that included stabilization methodologies such as deferred recovery mechanisms or phase-in plans appeared to have had success over the past year. For example, one electric utility in Pennsylvania filed a plan with its state commission including a mechanism whereby customers were provided an option to prepay for rate increases by paying into a 6 percent interest-bearing savings plan prior to the end of the company's transition period (scheduled for the end of 2010). A customer's savings plan payments, plus interest, would then be applied to the customer's bills in 2011. The plan would alternatively allow customers to defer a portion of any initial rate increase by spreading out the amount of the first year's increase during the following two or three years, providing additional time to manage new rates.

Adjustments to Net Operating Income

Regulators are also scrutinizing certain types of operating expenses and proposing rate adjustments that impact net operating income, especially in the area of pensions and other employee benefits. For example, some utilities were denied requested recovery of other postemployment benefit costs on an accrual basis, defaulting to a cash basis recovery model. In addition, stock-based incentives, especially executive compensation, continue to be excluded from rates in some cases, as they can be viewed as expenses for the shareholders, not ratepayers, to bear.

Useful Life Extensions

Recognizing that utilities are generally using their property, plant, and equipment past their original useful lives, many commissions are reducing depreciation rates and extending those lives and recovery periods. Similarly, some regulators are implementing deferral periods or extending recovery of regulatory assets.

6.1.2.3 Rate Decoupling

Another tactic that many utilities and commissions are considering to provide some rate stability is the implementation of rate structures that decouple collection of utility fixed costs from consumption. Under traditional rate regulation, rates are typically created based on test year costs including operations and maintenance expenses, capital recovery, rate of return and other cost components and adjustments. A separate variable rate component may be established for fuel expenses. The approved base revenue is divided by projected customer consumption to develop a rate per kilowatt hour (kWh) or MMBtu. Under this approach, the utility's revenue will fluctuate with the variability of consumption which may be driven by weather, conservation programs or other factors. The utility may overearn in high consumption years while underearning in periods of lower consumption.

Under a decoupling mechanism, the amount collected for transmission or distribution service is separated or "decoupled" from consumption. For a particular rate component, the commission will establish an approved revenue amount which may include adjustments for customer growth and or other similar factors. The utility will balance to the approved amount, thereby ensuring collection of its base rate revenues and allowing focus on cost management. These programs incentivize the utility to support conservation, efficiency, and other demand-reduction programs, while protecting customers and the utility from the impact of weather. Decoupling programs have been in place in some states, such as California, for at least a few years and we have observed that more jurisdictions are considering and adopting these mechanisms.

6.2 Regulation – Accounting and Reporting Considerations

Proper application of FAS 71 is essential to the appropriate presentation of regulated utility operations in accordance with generally accepted accounting principles in the United States. This construct may change in the future with the adoption of IFRS (see Section 8); however, under the current paradigm, FAS 71 is the foundation of accounting for rate-regulated activities. The application of FAS 71 continues to require analysis and careful consideration as management teams consider the impact of new rate cases and unique recovery mechanisms. Figure 6-4 highlights certain accounting issues in addressing new rate orders.

Figure 6-4 FAS 71 – Issues in Application

Common accounting issues related to application of FAS 71 include:

- Overall application of FAS 71 when approved rates do not cover current cost of service
- When and whether revenue subject to refund should be recognized
- Recovery of generation and other plant assets and the application of FASB Statement No. 90, *Regulated Enterprises – Accounting for Abandonments and Disallowances of Plants Costs* (FAS 90)
- Potential impairments of existing plant assets in accordance with FAS 144
- Recognition of regulatory assets when recovery is subject to deferral or a phase-in period, considering the guidance in FASB Statement No. 92, *Regulated Enterprises – Accounting for Phase-In Plans* (FAS 92) by analogy
- Other regulatory deferrals when unique recovery mechanisms are implemented or there is some other uncertainty about recovery

As part of their ongoing process, management teams should be evaluating new rate orders, accounting or advice letters, and other regulator actions for potential accounting implications.

To assist management teams in addressing these issues, we have included some application highlights and reminders below.

Application of FAS 71

Any nontraditional form of rate regulation places additional stress on the FAS 71 assessment and its applicability. Consequently, management should maintain specific documentation of why each segment of the business meets the criteria under paragraph 5 of FAS 71 (including specific discussion of alternative forms of rate regulation, where applicable). This documentation should be updated each time there is a change in the rate structure or significant regulatory developments. In addition, management should ensure that there is contemporaneous documentation of the basis for deferral of new regulatory assets, particularly during rate freeze periods.

Revenue Subject to Refund

In some jurisdictions, a utility may be permitted to start charging customers for proposed rate increases prior to receiving the commission approval. Amounts charged are subject to refund upon issuance of the final rate order. Revenues that are subject to refund may be substantial in amount. Such revenues may require considerable management judgment to determine the timing of revenue recognition, including the future impact if all or a substantial portion of such revenues had to be refunded.

In accordance with FAS 71, paragraph 11(a), potential refunds should be evaluated based on a probability model applied in a manner consistent with the definitions in FASB Statement No. 5, *Accounting for Contingencies*. It is appropriate to record as income the portion of such revenues that might reasonably be expected to be permitted by the regulator. However, reporting entities should carefully consider regulatory actions taken on past cases in the jurisdiction, the opinion of counsel, and other factors before recognizing revenues. In some cases, it may be appropriate to defer recognition of all such amounts until final rate approval is received. Any amounts deferred and ultimately permitted in rates would be recognized in revenue in the period in which the rate order is received.

Recovery of Plant

As public utilities invest in new generation sources and consider building power plants, management teams should closely monitor plant expenditures and evaluate overall costs to assess recoverability. As rates go up across the country, state commissions are under increasing pressure to manage future rate increases, raising the possibility that construction costs will be heavily scrutinized and eventually disallowed when in excess of original estimates or found to be imprudent. Some regulators require construction or management audits to assess whether expenditures incurred in construction projects have been prudent and should be included in rate base. As a result of these audits or based on other factors, regulators may partially or totally disallow some capitalized construction costs from rate base and/or cost-of-service recovery. In these cases, reporting entities should consider FAS 90, which applies to situations where costs of abandoned or recently completed plants are disallowed by regulators.

Paragraph 7 of FAS 90 states that when it becomes probable that part of the cost of a recently completed plant will be disallowed for ratemaking purposes and a reasonable estimate of the amount of the disallowance can be made, that amount should be recognized as a loss. The distinction between what qualifies under FAS 90 as a disallowance of plant costs is important because under FAS 90, a direct disallowance is recorded dollar for dollar, as opposed to the requirement under FAS 144, whereby an impairment loss is measured by comparing the carrying value to the fair value.

Application of FAS 90

We have interpreted “recently completed plant” as plant that has yet to be included in an initial rate case request for inclusion as allowable costs, after the date the plant went into service. We do not believe the length of time between completion of the plant and finalization of a rate case should be considered a key factor in the interpretation of what should be included within recently completed plant, particularly in the current regulatory environment. The key factor is the result of the first rate case after the plant is placed in service, regardless of the length of time after construction.

Indirect Disallowances

FAS 90, paragraph 7, also states that if part of the cost is explicitly but indirectly disallowed, that amount should also be recognized as a loss. An indirect disallowance occurs when, in certain circumstances, no return or a reduced return is permitted on all or a portion of the new plant for an extended period of time. To determine the loss resulting from an indirect disallowance, the present value of the future revenue stream allowed by the regulator should be determined by discounting the expected future cash flows using the last allowed rate of return. This amount should be compared to the recorded plant amount and the difference recorded as a loss. 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.

Recognition of Return

To compensate utilities for delays in including significant capital projects in rate base or deferrals of recovery of certain costs, regulators may permit deferral of costs, including a return on rate base or another form of shareholder return. In accordance with FAS 71, as reiterated in FAS 92, utilities are not permitted to capitalize an allowance for earnings on shareholders' investment in their general-purpose financial statements when it is capitalized for ratemaking purposes other than during construction. Such amounts are not "incurred costs that would otherwise be charged to expense" as required by FAS 71, paragraph 9.

Therefore, to the extent that an asset does not qualify for capitalization of an allowance for funds used during construction (AFUDC), utilities should not defer amounts that represent shareholder returns. However, debt-only carrying costs related to regulatory deferrals may appropriately be recognized.

Accounting for Phase-In Plans

The fact that a commission is unwilling to approve rates based on the current cost of service places stress on the basic premise of FAS 71. The following factors should be carefully considered in assessing whether capitalization of a regulatory asset is appropriate:

- State regulatory history – What is the history of recovery of regulatory assets in the state? Have amounts been disallowed in the past? When the commission is not able to approve current rates at a sufficient level to enable the utility to recover its current costs, what evidence supports that the commission will eventually approve these costs in addition to the costs that will be incurred to provide ongoing service in the future?
- Projected costs – Are the utility's costs expected to continue to increase? As noted above, if costs are expected to continue to increase, is it likely that the commission will be able to approve sufficient rate increases to recover these past costs as well as current costs?
- Length of recovery period – Over what period of time will the costs be recovered? Due to inherent uncertainty in the regulatory process, management teams should carefully evaluate recovery periods that extend over a longer time frame, considering the nature of the related cost (i.e., periodic costs related to operations and maintenance or fuel would suggest a shorter recovery period than longer-term balances, such as those related to plant). In addition, a longer recovery period creates greater uncertainty about whether past regulatory actions will be upheld due to potential changes in the political or regulatory climate.

FAS 71 does not provide specific guidance with respect to the recovery of regulatory assets, except that recovery must be probable. However, as the probable threshold is considered a high hurdle to overcome (75 to 80 percent certainty of recovery), reporting entities should carefully evaluate whether this threshold is met when evaluating the recovery of costs under these plans.

6.2.1 Ratemaking and Regulatory Disclosure

Given the significance of the regulated environment and application of FAS 71, the SEC carefully reviews the disclosures about the status of ratemaking for the reporting entity and the risks involved. The following disclosures about ratemaking activities are typically important:

- Date of the utility's last rate case and the resulting return on equity
- For recent rate orders received, an explanation of the impact the new rate orders had on the period being reported, as well as the impact new rates are expected to have on the business in the future (included in management's discussion and analysis)
- The existence of and any impact of any stabilization mechanisms or disallowances
- Authorized and actual returns on equity, as well as the remaining recovery period for regulatory assets not earning a return

In addition, reporting entities should disclose contingencies or potential impacts to the business for pending rate cases or preliminary or Administrative Law Judge rulings.

In addition, the SEC continues to focus on the appropriateness of various regulatory deferrals. Reporting entities should specifically document their basis for deferral of amounts as regulatory assets or liabilities, including specific consideration of the income statement classification, as part of their assessment of new rate orders. Figure 6-5 highlights recent SEC comments on recognition of specific regulatory assets and other regulatory accounting issues.

Figure 6-5

Recent Regulatory-Related SEC Comment Letters

Registrants continue to receive questions from the SEC on the application of FAS 71, including the following comments during the past year:

Please provide to us a detailed regulatory assessment with respect to the implementation of SFAS No. 158. Explain to us how you have historically recovered pension and OPEB costs for each of your rate-regulated subsidiaries. In this regard, please also explain to us how you concluded the probability of recovery threshold has been met pursuant to SFAS No. 71 with respect to any asset recorded due to adoption of Statement No. 158.

If any portion of your regulatory asset balance includes amounts on which you do not earn a current return, disclose the nature and amount of each such asset and its remaining recovery period. We believe the best practices approach regarding regulatory assets is to affirmatively indicate whether a particular regulatory asset is earning a rate of return and the anticipated recovery period. Refer to the requirements of paragraph 20 of SFAS 71.

We note your discussion regarding the June 2006 Settlement agreement among O&R, the staff of the PSC and other parties. Please explain your basis in GAAP for establishing the regulatory asset of \$5.5 million and accruing revenue in advance of billing. Specifically address how the future rate increase was provided to permit recovery of a previously incurred cost as opposed to provide for expected levels of similar future costs. Given this was a general base rate filing, it is unclear what incurred cost is being capitalized. See paragraph 9.b of SFAS no. 71.

Other comments included questions on phase-in plans, whether deferred amounts met the definition of an incurred cost, and the appropriateness of recognition of certain amounts as adjustments to revenue versus expense.

6.3 Federal Energy Regulatory Commission Developments

The Federal Energy Regulatory Commission impacts rate-regulated utilities through its ratemaking authority and in its position as an enforcement agency. Since the passage of the Energy Policy Act of 2005 (EPAct 2005), the FERC has become increasingly focused on compliance. The FERC is using its

authority to enact significant monetary penalties to create a culture of compliance among utilities and others that are subject to its jurisdiction. This section addresses the accounting implications of certain recent FERC actions as well as the key compliance considerations for FERC-regulated entities.

6.3.1 Gas Capacity

In June 2008, the FERC issued Order No. 712, *Promotion of a More Efficient Capacity Release Market*. Order 712 revised previous regulations governing interstate natural gas pipelines to permit market-based pricing for short-term capacity releases (one year or less). Prior to the issuance of Order 712, there was a tariff cap on capacity release transactions. This change to market-based pricing for short-term releases has potential derivative accounting implications. For a detailed discussion, refer to Section 4.5.1.

6.3.2 FERC Forms No. 1 and 2

In March 2008, the FERC issued Order No. 710, *Revisions to Forms, Statements, and Reporting Requirements for Natural Gas Pipelines* (Order 710), for natural gas pipelines and in September 2008, it issued Order No. 715, *Revisions to Forms, Statements and Reporting Requirements for Electric Utilities and Licensees* (Order 715), for electric utilities. These rulings include new requirements related to the mandatory FERC filings for electric and gas utilities and natural gas pipelines. The new rules were effective January 1, 2008 for filings on FERC Form 2 and are effective January 1, 2009 (and interim periods beginning January 1, 2009) for filings on FERC Form 1.

Order 710

The purpose of the changes to FERC Form 2 and related forms is to improve usefulness by updating them to reflect current market and cost information relevant to interstate natural gas pipelines and their customers. The changes will require certain new schedules, including additional information about revenues and sales, discounts, affiliated transactions, regulatory assets and liabilities and various expenses such as income taxes and employee-related costs.

Order 715

Order 715 is a companion to Order 710 and is similarly intended to provide more relevant information to the FERC, state public utility commissions and the public. The ruling requires that additional detail about revenues, rates and affiliate transactions be provided in the FERC Form 1. In addition, certain technical enhancements were made to the form to expedite reporting and minimum thresholds for reporting certain information were adopted.

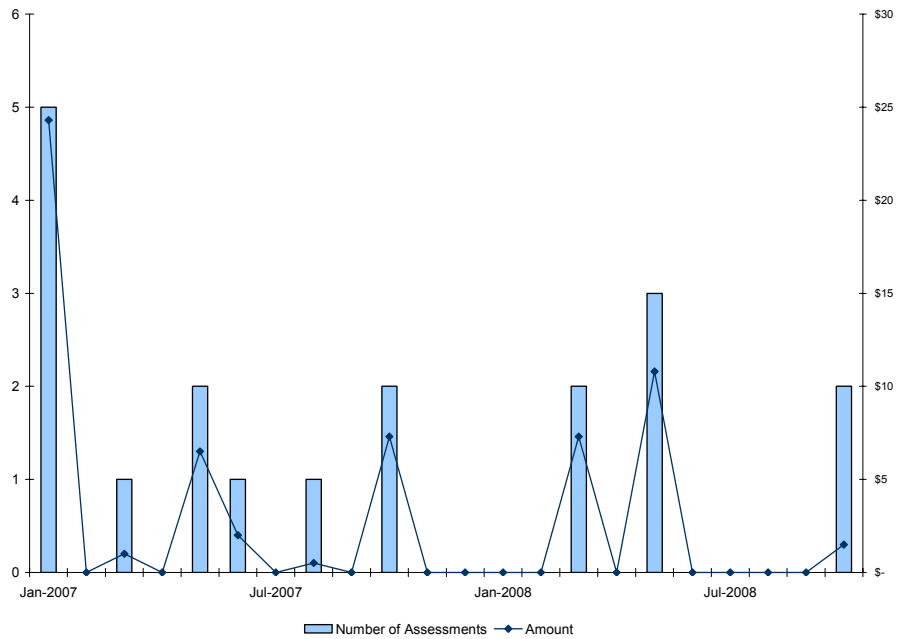
6.3.3 FERC Compliance

The Energy Policy Act of 2005 gave the FERC the ability to enforce energy and utility industry compliance with various regulations and standards through the imposition of new monetary penalties for noncompliance of up to \$1 million per day for each violation. In May 2008 the FERC issued a press release articulating its enforcement plan and focus. The FERC stated its intent to use monetary enforcement mechanisms to create a “culture of mandatory compliance” within the natural gas and electric utility industries. FERC's new concentration in this area has placed additional pressures on management to

ensure compliance with a number of FERC mandates, including orders, rules, regulations, tariffs, and electric reliability standards.

The civil penalty provisions of EAct 2005 can be levied for any violation subject to FERC's jurisdiction. As illustrated in Figure 6-6, utilities and unregulated power entities have paid approximately \$61 million for penalties, compliance programs and disgorgement, including \$52 million in civil penalties, since the FERC gained civil penalty authority.

Figure 6-6
FERC Enforcement Amounts
 (\$ amounts in millions)



Source: Federal Energy Regulatory Commission

In November 2008, the FERC issued its 2008 Report on Compliance, which provides information about enforcement actions during the year, including discussion of the types of violations that were settled and matters closed without penalty. This report highlights an increase in self-reported violations, which doubled in the current year from 31 in 2007 to 68 in 2008.⁶ The FERC believes that the increase in self-reporting can be attributed to improvements in compliance and auditing programs as well as penalty mitigation credits available for self-reporting. Given the magnitude of potential penalties for compliance failures, self compliance and monitoring programs can be a cost-effective method of building a culture of compliance and mitigating potential penalties in the event of compliance failures. Companies lacking a comprehensive compliance program that includes and prioritizes FERC and other regulatory requirements may want to consider establishing one in the near term.

⁶ Federal Energy Regulatory Commission, 2008 Report on Enforcement (Docket No. AD07-13-001)

In the following section, we describe certain aspects of FERC's Policy Statement on Enforcement followed by a discussion of other FERC compliance areas. While the overall environment subject to FERC enforcement is broad, we have focused on key areas that we believe require particular attention by utilities and power companies.

6.3.3.1 FERC Policy Statement on Enforcement

FERC's Policy Statement on Enforcement⁷ (the Policy) sets forth the factors FERC takes into account in determining violation remedies. Pursuant to the Policy, the severity of penalties for a compliance failure may be limited if a company demonstrates adherence to certain positive factors, including an established compliance program, self-reporting of violations, and cooperation with FERC. Figure 6-7 highlights key factors considered by the FERC in evaluating a compliance program:

Figure 6-7 **Effective Compliance Program**

FERC considers the following factors when determining the level of credits to be awarded for a company's compliance program:

- Supervision – The compliance program should be supervised by an officer or other high-ranking official who reports to or with direct access to the chief executive officer and/or the board of directors. The program must be operated and managed with an appropriate degree of independence.
- Documentation and distribution – Compliance policies and procedures should be clearly documented and widely disseminated within the company.
- Resources and training – Sufficient resources must be dedicated to administering, monitoring, and enforcing compliance requirements and sufficiently detailed training must be provided to key employees at an appropriate frequency.
- Compliance audits – A process should be implemented to conduct periodic audits or reviews to ensure compliance with FERC regulations.

In addition, the company should periodically review and modify the compliance program in response to compliance failures or industry changes.

Another aspect of the program is that the FERC may reduce or even eliminate potential penalties when a company self-reports a violation. In evaluating self-reported violations, the FERC has indicated that self-reports are typically closed without an investigation or sanctions "If the violation was inadvertent or isolated, did not cause harm, was corrected, and preventative measures have been taken."⁸ The FERC also views cooperation favorably when considering penalties. The FERC considers the company's willingness to share internal

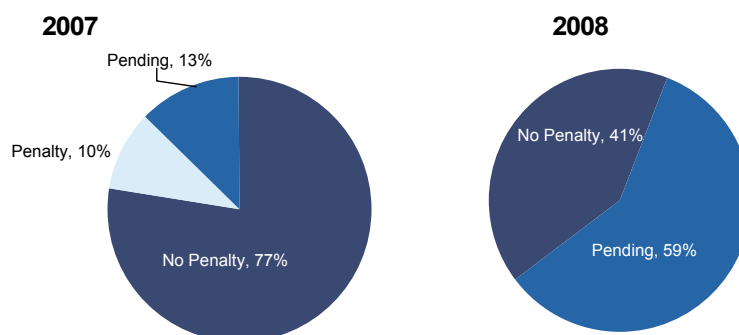
⁷ Issued October 20, 2005 (Docket No. PL06-1-000), revised on May 15, 2008 (Docket No. PL08-3-000), and supplemented on October 16, 2008 (Docket No. PL09-1-000)

⁸ See footnote 6.

information, use of an independent outside entity to assist with the investigation, involvement of senior management, encouragement of cooperation by employees, and fair and accurate determination of the effects of the misconduct. During 2008, examples of self-reports that did not result in any penalty included capacity-release violations related to posting of a capacity release and two shipper-must-have-title violations.

Figure 6-8 illustrates the results of the 2007 and 2008 self reports. Based on the 2008 Report on Enforcement, of the 68 self-reports received during 2008, FERC closed 25 after initial review and without opening an investigation. In addition, 3 more were closed without penalty after an investigation was completed. The other cases are still in process. Of the 31 self-reports received in 2007, 24 self-reports were closed without penalty, 19 of those with no investigation. To date, 3 of the 2007 self reports have resulted in penalties and 4 are still pending.

Figure 6-8
Self Reporting Results – Electric and Gas



Source: FERC 2008 Report on Enforcement

6.3.4 Other Compliance Requirements

In addition to the FERC Policy Statement on Enforcement, there are numerous other requirements that utilities and others in the power and natural gas industries must abide by and to which they should monitor adherence. While the Policy has gained significant attention due to the more recent headlines relating to monetary fines, failure to comply with these other various standards, rules and regulations could result in similar unfavorable monetary impacts.

Other FERC standards and regulations for which companies should monitor compliance include the following:

Standards of Conduct

In October 2008, the FERC issued Order No. 717, *Standards of Conduct for Transmission Providers*, which reformed existing standards of conduct to eliminate elements that rendered the standards difficult to enforce and apply. Overall, the standards of conduct are designed to prevent transmission

providers from engaging in undue discrimination, operating the transmission system to benefit marketing affiliates, or granting undue preference to marketing affiliates. The key concepts include requirements to ensure transmission and marketing employees operate independently of each other, rules that prohibit sharing transmission information with marketing function employees, and transparency rules that impose posting requirements to assist in detecting undue preference.

FERC-jurisdictional utilities should already have procedures in place to address the requirements under the previous standards of conduct; however, these companies should ensure that appropriate compliance programs have been implemented.

Affiliate Restrictions (formerly the Codes of Conduct)

In the past, FERC required entities seeking market-based sales of power and ancillary services to abide, on a case-by-case basis, with individually stated "codes of conduct" to protect captive customers by preventing the transfer of benefits to stockholders as well as affiliate abuse. In June 2007, FERC issued Order No. 697, *Market-Based Rates for Wholesale Sales of Electric Energy, Services by Public Utilities*, which revised and codified the standards for obtaining and retaining market-based rates for public utilities. Therefore, in lieu of the case-by-case approach for codes of conduct, FERC adopted the uniform "Affiliate Restrictions," which govern the relationship between a franchised public utility with captive customers and its market-regulated power sales affiliate(s).

Specifically, these restrictions:

- Require a public utility's operating personnel to function independently of the market-regulated power sales affiliate
- Impose a posting requirement if nonpublic market information is shared and could be used to the detriment of captive customers
- Prohibit power sales between a public utility and a market-regulated power sales affiliate without first receiving FERC authorization

Failure to follow these requirements could also result in penalties and enforcement action.

Energy Market Anti-Manipulation Rule

As part of the EPAAct 2005, FERC adopted Order No. 670, *Prohibition of Energy Market Manipulation* (Order 670), which provides new authority to penalize those engaging in fraudulent activity in the electricity and natural gas markets. Order 670 may affect "any entity" that buys, sells or trades electricity or natural gas or purchases or sells transmission or transportation services, including power marketers, natural gas traders, jurisdictional and nonjurisdictional electric utilities, and other market participants. The intent of the rule is to provide an incentive for energy market participants to ensure that they are in full compliance with FERC's rules and regulations, and that they implement appropriate measures to ensure ongoing compliance.

Market Behavior Rules

The FERC also issued Order No. 674, which codified the Market Behavior Rules (Rules Nos. 1, 3, 4, and 5) which had previously been incorporated in market-based rate sellers' tariffs. These Market Behavior Rules require market-based rate sellers to operate, schedule and maintain generating facilities within certain guidelines; provide accurate, factual and true information to the FERC and other independent transmission bodies; provide accurate and factual information on pricing information to index publishers; and have a three-year document retention policy.

6.4 North American Electric Reliability Corporation Standards

The August 2003 eastern blackout and passage of EPAct 2005 set the stage for mandatory compliance with electric reliability standards (standards) promulgated by the North American Electric Reliability Corporation (NERC). Electric reliability standards are applicable to industry participants based on their type of entity as defined within the NERC guidelines. The level of requirements continues to grow each year as FERC approves the various standards. If all standards are applicable to an entity, it would have to comply with over 1,300 individual requirements embedded in the various standards.

Violations are measured according to a grading scale and penalties are assessed based on the degree to which a standard is not complied with. Penalties for noncompliance can reach up to \$1 million per day, per violation. As of June 25, 2008 more than 1,450 violations dating back to June 18, 2007 have been disclosed by NERC. While significant penalties have not been assessed to date, larger monetary fines affecting a greater percentage of entities are expected in the future.

Like FERC, NERC supports the self-reporting of possible violations, and considers self-reporting favorably when determining the possible reduction of monetary penalties. Similar to the FERC compliance considerations, the imposition of fines by NERC may have accounting and reporting considerations. Therefore, reporting entities should consider implementing compliance programs that encompass the NERC requirements. In addition, accounting departments should be generally familiar with the requirement to comply with these rules and should implement mechanisms to communicate with the relevant operational groups about possible violations to ensure appropriate financial reporting.

6.5 Regulatory-Related Tax Considerations

The effect of income taxes may also have a significant impact on regulatory reporting. There are various issues around how the income tax expense of a regulated utility is passed on to ratepayers, how the amounts compare to income taxes of a nonregulated entity, and the accounting for such differences. Tax normalization is integral to accounting for income taxes in a regulated environment. Tax normalization refers to calculating the income tax amount as if transactions recognized in each period for ratemaking purposes are also recognized in the same amount and in the same period for income tax purposes. Differences between regulatory and tax amounts due to normalization are generally deferred on the balance sheet and recovered or paid to ratepayers in the future.

The understanding of and application of the normalization rules is important when determining income tax accruals for purposes of financial reporting. During 2008, the U.S. Department of the Treasury (Treasury Department) finalized new rules for tax normalization. This section addresses these changes and views on the potential impact.

6.5.1 Final Normalization Regulations

After multiple proposed iterations, the normalization regulations were finalized by the Treasury Department on March 19, 2008. The basic rules with respect to accumulated deferred investment tax credits (ITCs) and excess deferred tax reserves are consistent with the last version of the proposed regulations (issued in 2006):

- Deferred ITCs – if property ceases to be public utility property because of disposition, deregulation or other reasons, accumulated deferred ITC may continue to flow through to the ratepayer only to the extent of stranded cost recovery.
- Excess deferred tax reserves – if property ceases to be public utility property because of disposition, deregulation or for other reasons, excess deferred taxes may continue to flow through to the ratepayer as if the property had never been disposed of or deregulated.

With respect to excess deferred tax reserves, "as if" calculations would have to be made to adhere to the new regulations.

The Treasury Department believed that deferred ITC and excess deferred taxes should be treated differently. With respect to excess deferred taxes, there was a belief that the ratepayers had already funded the cost of these reserves in the cost of service calculations for the years that the income tax rates were above the current 35 percent rate. Therefore, the Treasury Department was not opposed to flowing this back to ratepayers even after the underlying property creating the deferred taxes was no longer in rate base. However, with respect to deferred ITC, the credits were always viewed as an offset to the cost of the underlying asset. As a result, the view was if the ratepayers are no longer funding the asset in rate base and cost of service, then they should not receive the benefit of the offset through deferred ITC flow back.

The final regulations are clear that these new rules apply even in a sale to another regulated entity (although, the rules are not as clear regarding a regulated buyer's treatment of the excess deferred tax reserves and/or deferred ITC). They also clarify that ordinary retirements are excluded from the scope of the rules described above. Finally, they indicate that these final regulations will not apply retroactively. Therefore, any agreements already reached with state commissions with respect to the excess deferred taxes and deferred ITC in a state that has mandated deregulation will not be required to apply these final regulations.

6.5.2 Normalization Rulings

The year 2008 saw a relative surge in private letter rulings related to normalization. A number of regulated utilities were seeking assurance that

technical violations of the normalization rules would not trigger the harsh penalties of losing accelerated depreciation and/or the recapture of investment tax credits that statutorily accompany a normalization violation. It is believed a number of these rulings were obtained to help assess the appropriate accounting under FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). The following rulings are representative of the fact pattern and reasoning applied by the IRS in addressing these technical violations.

Private Letter Ruling 200811004

In this fact pattern, a taxpayer co-owned a nuclear generating plant with two other utilities. One of the other major owners of the plant agreed to extend the depreciable life of the plant for regulatory purposes from 40 years to 60 years. The taxpayer, in turn, also extended its life of the plant to 60 years from 40 years for regulatory purposes. However, in its regulatory filings, the taxpayer failed to adjust its deferred ITC amortization and excess deferred tax flow back for the change in the life of the nuclear plant. The IRS ruled that the normalization penalties of disallowed or recaptured ITC would not apply.

To the IRS, the state regulatory commission was not mandating or insisting on a method of accounting that violated the normalization provisions. Rather, the taxpayer inadvertently failed to adjust the ITC and excess deferred tax amortization for the change in life of the plant. Because the taxpayer discovered it and fixed it, it was determined by the IRS that there was no violation of the normalization rules.

Private Letter Rulings 200802025 and 200802026

In two related rulings, the taxpayer used depreciation rates for normalization purposes that included a negative net salvage in its computations. This allowed the utility to recover its costs sooner than without a salvage assumption. The assumptions were also used for deferred ITC flow back. The IRS ruled that no disallowed or recaptured ITC would be mandated for the taxpayer. Similar to the case described above, the state regulatory commission did not insist on accounting using the net salvage value. The determination was that ITC disallowance or recapture should exist where a regulatory body insists on improper treatment from a normalization standpoint.

Inadvertent Normalization Violations May Not Result in Penalties

Based on the above cases, it appears that there must be a willful intent on behalf of the taxpayer's regulatory commission to require accounting that is not aligned with the normalization rules, in order for the IRS to rule that there is a normalization violation and to impose a resulting harsh statutory penalty. For inadvertent violations of the normalization rules, or less-than-perfect bookkeeping, it appears less likely that the IRS will impose penalties.

Section 7: Infrastructure

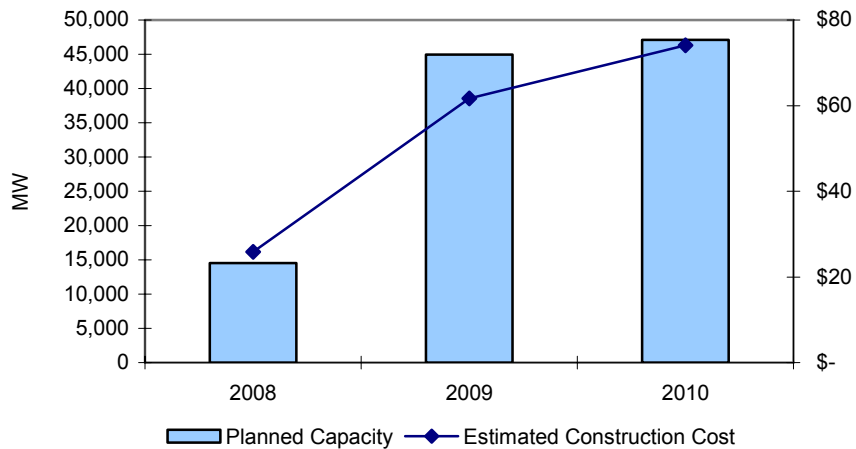
Section 7: Infrastructure

Despite obstacles to obtaining financing as a result of the recent tightening of the credit markets, construction and infrastructure maintenance continues to be an important strategic initiative for utilities and power generators. Economic concerns have had some impact on the pace of new plant and infrastructure construction. However, major construction plans continue to advance, as key factors driving new construction are unchanged by economic conditions:

- Generation – The growth of renewable portfolio standards and other environmental pressures is leading to upgrades of existing assets and development of new green power projects. In addition, continued growth in consumer demand and projected declines in reserve margins in certain regions have prompted demand for generation capacity.
- Transmission – Aging infrastructure and the need for transmission access to support green power and other new projects has stimulated new transmission projects.
- Distribution – Although the lack of growth in new housing has slowed demand for new lines, the aging infrastructure necessitates ongoing maintenance and construction.

As a result of these industry-wide demands, the pace of ongoing construction initiatives continues to increase as depicted in Figures 7-1 and 7-2:

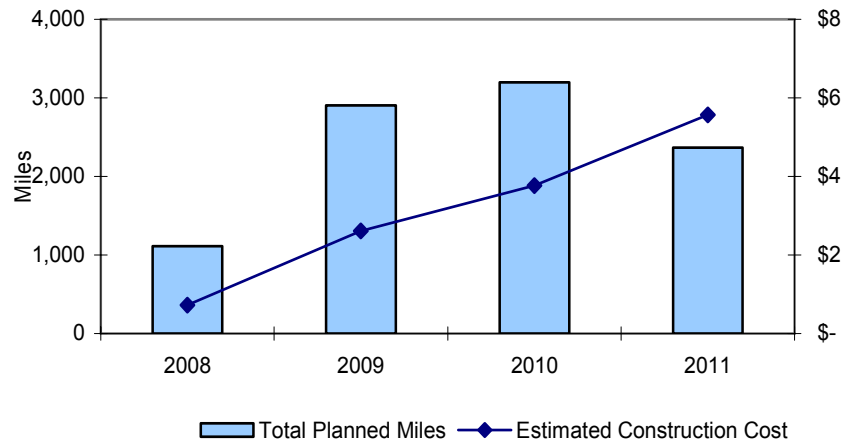
Figure 7-1
Generation Projects
(\$ amounts in billions)



Planned capacity includes announced projects and plants under construction. In periods after 2010, there is a total of 289 gigawatts of planned capacity, with a projected construction cost of \$536 billion.

Source: SNL Interactive

Figure 7-2
Transmission Projects
 (\$ amounts in billions)



Planned miles include announced projects and lines under construction. In periods after 2010, there is a total of almost 18,000 miles of transmission planned, with a projected construction cost of \$35 billion.

Source: SNL Interactive

Planned generation includes a focus on wind projects and other renewable power sources as utilities strive to meet the renewable portfolio mandates. In addition, there is also new interest in nuclear construction as utilities, independent power producers and other industry participants develop generation to meet the demand for new capacity. However, there may be significant hurdles to obtaining financing for new construction in the current environment. In addition, even if financing is available, the resurgence of construction has created a long lead time and increasing prices for major equipment (e.g., wind turbines). These issues may further delay development.

Preparing for large-scale construction projects involves considering and planning for many aspects of the project, implementing ongoing monitoring and reporting, and involving a wide range of key personnel within the organization. Regulated utilities have an additional challenge of ensuring construction expenditures are included in rate base. In some jurisdictions, new construction and acquisitions may be approved prior to incurring the expenditures or regulators may provide for rate adjustments associated with capital growth. However, in many jurisdictions, utilities continue to struggle with regulatory lag and the potential for disallowances.

Accounting and finance personnel play a key role in this process because of the wide range of accounting considerations — from costs incurred during the preconstruction and construction phases of the project, to ongoing issues, such as for maintenance, once the plant has been built. In addition, proposed changes in tax regulations may also impact accounting requirements related to infrastructure investments.

The following section highlights certain key issues to assist reporting entities as they consider policies and procedures regarding accounting for construction and maintenance activities.

7.1 Accounting for Construction Costs

Available authoritative guidance on accounting for plant preconstruction and construction costs includes the Uniform System of Accounts (USoA) issued by the Federal Energy Regulatory Commission and Statement of Position (SOP) 98-5, *Reporting on the Costs of Start-Up Activity* (SOP 98-5).

Due to the diversity of the potential costs that may be incurred and the scope of the related accounting guidance, companies contemplating significant new construction should develop an accounting policy establishing guidelines for the accounting for specified construction costs. In addition, regulated utilities should consider the guidance within their expected regulatory recovery.

7.1.1 General Considerations

In accordance with SOP 98-5, direct costs of acquisition and construction of a plant are outside its scope. SOP 98-5 does, however, address other costs associated with the start-up of a new facility — those costs should be expensed as incurred. Guidance for specific costs is also provided by various other accounting standards, including FASB Statement of Financial Accounting Concepts No. 6, *Elements of Financial Statements*, SOP 98-1, *Accounting for the Costs of Computer Software Developed or Obtained for Internal Use* (SOP 98-1), and FSP FAS 13-1, *Accounting for Rental Costs Incurred during a Construction Period*.

A summary of the accounting for some common types of costs incurred during the preconstruction and construction phase follows.

Preparation to Bid and Scoping Phase

All internal and external costs during the bidding or scoping phase of a project should be expensed as incurred. These costs may include internal salaries, legal, overhead, travel, feasibility studies, and external costs such as due diligence and attorneys' fees.

Preconstruction Costs

The accounting for certain preconstruction costs may depend on whether construction is probable. During the preconstruction phase, but before the project is probable, the company should not capitalize any costs. However, once construction is probable, the company may be able to capitalize internal direct and incremental costs associated with bringing the asset to its intended use, including salaries related to permitting and legal fees.

Other common costs incurred during preconstruction should be accounted for as summarized in Figure 7-3:

Figure 7-3

Accounting for Preconstruction Costs

Type of costs	Accounting
Operating contract negotiation (e.g., fuel supply agreements, operations and maintenance agreements)	Contracts are not specifically required to acquire the asset or bring it to its intended use. Therefore, costs should be expensed as incurred.
Organizational costs (e.g., corporate charter bylaws, other agreements)	Both internal and external organization costs are addressed within SOP 98-5 and should be expensed as incurred.

Construction Phase

During the construction phase, direct and incremental costs of construction should be capitalized in accordance with the company's capitalization policies. However, absent regulatory accounting treatment, companies should continue to expense many indirect costs during construction as described in Figure 7-4:

Figure 7-4

Accounting for Construction Costs

Type of costs	Accounting
Direct charges of company executives, accounting, legal, and other support groups during construction	Indirect costs that do not directly relate to the construction effort (e.g., costs for financial statement preparation) should be expensed as incurred.
Costs related to hiring new employees	Costs are specifically covered by SOP 98-5 and should be expensed as incurred.
Information technology	Accounting should follow guidance provided by SOP 98-1.
Other allocated overhead costs	Indirect and overhead costs associated with the construction office are typically capitalized. Other overhead costs should be expensed as incurred.

7.1.1.1 Regulated Construction Activities

Regulated utilities have unique considerations when accounting for construction of utility plant, as in many cases they may be eligible to recover costs in rate base that would otherwise be expensed. Regulated utilities generally follow the USoA when recording costs associated with planning and constructing a plant, consistent with their expectation of regulatory recovery. Many of those costs would be expensed, absent the regulatory accounting

treatment. Management should ensure that appropriate procedures are implemented to properly identify those costs that qualify for capitalization as a result of expected regulatory recovery. These costs should be specifically assessed to ensure that it is probable such amounts will be included in future rate base.

7.1.2 Ongoing Accounting and Reporting Implications

Key implementation and ongoing accounting and reporting considerations for large-scale construction projects are described in Figure 7-5.

Figure 7-5
Key Accounting Considerations for Construction

Issue	Considerations
Componentization	Reporting entities should consider to what extent an asset componentization methodology will be used. The determination of asset groupings may have an impact in the future when possible impairments are being contemplated and/or recorded.
Potential impairments	Depending on a reporting entity's existing asset portfolio, it should consider whether the new assets result in any impairment triggers pursuant to FAS 144.
Legal or environmental contingencies	In most cases, the process of installing new power-related assets comes with significant community and governmental involvement and, at times, disruption. Reporting entities involved in large-scale construction projects should consider the implications of objections raised by third parties to the proposed activity and whether any contingent liabilities should be recorded.
Joint plant	<p>Construction projects that involve joint owners may involve additional considerations:</p> <ul style="list-style-type: none"> • The appropriate valuation of contributions made to the project when noncash contributions are made in exchange for equity must be determined. • The methodology for allocating shared costs among the joint owners will need to be established. • Project-specific financing may lead to supplemental reporting requirements, such as standalone project financial statements. • The SEC has specific disclosure requirements relating to joint plant accounting, under SAB Topic 10C. <p>Complying with these additional requirements for joint-ownership arrangements may be challenging. We recommend that companies ensure appropriate procedures are implemented at the front-end of any joint project to address these issues.</p>

In addition, reporting entities contemplating significant new projects may want to revisit the requirements of FAS 143. In some cases, an asset retirement obligation is incurred as soon as ground-breaking takes place on a new construction project. In addition, reporting entities should ensure that initial estimates recorded have been appropriately updated.

The accounting considerations for large-scale construction projects and related plant additions extend beyond the specific accounting policies for preconstruction and construction costs discussed above. Decisions about accounting policies and other related financial reporting considerations should be addressed early for the plant's in-service period. In addition, other areas of accounting and reporting could be impacted by new construction projects and should be considered during the construction phase.

Large-scale construction projects also result in a myriad of accounting matters pertaining to financing, power purchase or tolling arrangements, and other arrangements, such as ownership agreements and operating and maintenance contracts. Many projects may take different forms, including joint ventures. All of these factors require reporting entities to consider numerous accounting frameworks, including consolidations, leasing, and derivatives and fair value. Due to recent economic conditions, utilities and independent power producers may also need to consider potential impairment of generation assets in accordance with the requirements of FAS 144. See further discussion in Section 2.4.1.

As utilities and power marketers embark on large-scale construction projects, management should ensure that they have implemented appropriate controls over construction costs and subsequent accounting considerations.

7.2 Plant Maintenance Accounting Considerations

Generation plant owners may also enter into various types of maintenance agreements, whether embedded in a lease agreement or on a standalone basis. The following section addresses the accounting for these agreements.

7.2.1 Long-Term Service Agreements – Plant Maintenance

As part of the construction or acquisition of generating assets, many utilities and power generators enter into long-term service agreements (LTSA) with third-party providers to cover maintenance activities. Generally, payments under an LTSA are made on a recurring basis and maintenance is performed at scheduled dates. The payments under the LTSA are merely a cash flow mechanism and essentially are a prepaid activity. Therefore, questions arise as to expense recognition for routine and major maintenance covered under an LTSA.

7.2.1.1 Accounting for Major Maintenance Subject to an LTSA

The AICPA Industry Audit Guide, *Airlines* (the Airline Guide), as amended by FSP AUG AIR-1, *Accounting for Planned Major Maintenance Activities* (FSP AUG AIR-1), provides the principal source of guidance on the accounting for major maintenance activities. Although based on the Airline Guide, the SEC staff has indicated that the guidance should be applied by analogy to all major maintenance activities. In addition, FSP AUG AIR-1 specifies that the guidance

is applicable for all industries. The Airline Guide, as amended by FSP AUG AIR-1, permits three alternative methods of accounting for major maintenance as follows:

Direct Expensing Method

... recognize the cost of overhauls as expenses as they are incurred.
(Airline Guide, paragraph 3.70)

Built-in Overhaul Method

The built-in overhaul method is based on segregation of the ... costs into those that should be depreciated over the useful life of the [asset] and those that require overhaul at periodic intervals. Thus, the estimated cost of the overhaul component included in the purchase price is set up separately from the cost of [other components] and is amortized to the date of the initial overhaul. The cost of the initial overhaul is then capitalized and amortized to the next overhaul, at which time the process is repeated. (Airline Guide, paragraph 3.71)

Deferral Method

Under the deferral method, the actual cost of each overhaul is capitalized and amortized to the next overhaul. (Airline Guide, paragraph 3.72)

Although utilities and generators generally apply the direct expensing method for major maintenance activities, any of the three methods may be used. The major maintenance expense method is an accounting policy election which should be applied consistently for similar projects.

The fact that there is an LTSA does not impact what major maintenance accounting policies can be applied. The LTSA should be viewed as a funding mechanism and does not drive the timing of expense recognition. Therefore, in accounting for an LTSA, the reporting entity should identify the capital-related portion. Those costs should be established as prepaid assets when paid and expensed in accordance with the reporting entity's policy for major maintenance expense.

7.2.1.2 Accounting for Routine Maintenance Subject to an LTSA

In addition to services for major maintenance, an LTSA may also cover routine maintenance. Under U.S. GAAP, routine plant maintenance should be expensed as incurred. Therefore, the reporting entity needs to determine the amount paid for routine maintenance and should expense these amounts as the underlying work occurs.

Many LTSA agreements include multiple price components, such as a fixed monthly fee, variable monthly turbine fees, milestone payments based on hours, and hot gas path payments. These components typically cover major service events and monthly routine services to monitor and manage the performance of the covered equipment. The LTSA provider may classify the costs into major categories such as capital parts, consumable parts, field services, component repair services and other contractual services. In order to properly account for the costs, the reporting entity should work with the LTSA provider to understand how the payments relate to the underlying cost

categories. This supporting information may be used to classify the costs between routine and major maintenance activities.

Example 7-1

Accounting for an LTSA

Utility A enters into a 15-year LTSA with Service Provider X for planned maintenance services on the gas and steam turbine generating units at one of its generating stations. The LTSA calls for a fixed monthly fee of \$50,000 and other payments to be made as follows:

- Variable monthly turbine fee based on fired hours – estimated as \$100,000 per month
- Payments based on fired hours of \$5,000,000 at various milestones

Utility A determines that the fixed monthly fee is entirely related to routine maintenance, based on discussion with and review of documentation provided by Service Provider X. Utility A also determines that the variable monthly turbine fee includes an expense component (amount related to routine maintenance) of \$25,000 and capital components (including labor and parts) of \$75,000. Finally, Utility A concludes that the fired-hours payments are capital and relate solely to the major maintenance activities. Utility A considers the appropriate accounting for these payments under each of the permitted methods for major maintenance as follows:

Direct expense

Under the direct expense method, the major maintenance activity will be expensed when incurred. Therefore, Utility A would establish a prepaid expense as the variable turbine monthly (capital portion only) and milestone payments are made and would recognize the prepaid expense when the major maintenance is performed. To the extent that a portion of the payments relates to prepaid capital parts, it may be appropriate to classify such amounts as part of materials and supplies inventory until the parts are used.

Deferral method

Under the deferral method, the payments relating to major maintenance should be capitalized as an asset until the maintenance is performed and then that cost is amortized over the period until the next major maintenance event. Utility A would record an asset as the variable turbine monthly (capital portion only) and milestone payments are made, and would begin to amortize the accumulated deferred expense after the first major maintenance occurs.

Built-in overhaul method

This method is similar to the deferral method outlined above except that Utility A would separately depreciate the overhaul component of costs in the initial purchase price to the date of the initial overhaul. The accounting for the LTSA would follow the conclusions for the deferral method.

Under all three scenarios, the monthly fee and the expense portion of the variable turbine fee is expensed as paid.

Reporting entities contemplating significant new construction or plant acquisitions subject to LTSA agreements should ensure that they obtain appropriate visibility into the underlying costs. The costs must be mapped to the appropriate capital or expense activity and recognized in accordance with the reporting entity's maintenance expense policies.

7.2.2 Maintenance Deposits Under Leasing Arrangements

In June 2008, the EITF reached a final consensus and the Financial Accounting Standards Board ratified EITF Issue No. 08-3, *Accounting by Lessees for Maintenance Deposits* (EITF 08-3). EITF 08-3 is effective for fiscal years beginning after December 15, 2008, including interim periods within those fiscal years (January 1, 2009, for calendar year-end companies). Early adoption is not permitted.

EITF 08-3 addresses how a lessee should account for maintenance deposits paid under an arrangement accounted for as a lease in cases where that deposit will be refunded only if the lessee performs certain specified maintenance activities. In some cases, these prepayments for maintenance may be termed in different ways, including "maintenance reserves" or "supplemental rent." EITF 08-3 applies to all types of deposits that are substantively and contractually related to the maintenance of the leased asset.

In accordance with EITF 08-03, maintenance deposits should be accounted for as deposit assets. Maintenance costs should be expensed or capitalized as appropriate when the underlying maintenance is performed. If the lessee determines that an amount on deposit is less than probable of being returned, it shall be recognized as additional expense at that time. Reporting entities should apply EITF 08-3 as a change in accounting principle through a cumulative-effect adjustment to opening retained earnings in the year of adoption.

EITF 08-3 Implementation Considerations

Many utilities and power marketers lease power plants or have entered into power purchase arrangements or tolling arrangements that effectively contain a lease of the related plant pursuant to EITF 01-8. As part of the adoption of EITF 08-3, reporting entities that are the lessee in such arrangements should consider whether they have or are providing payments that would represent deposits within the scope of EITF 08-3.

7.3 Infrastructure-Related Tax Considerations

During 2008, several new and proposed tax regulation changes related to property, plant and equipment occurred that may significantly impact utilities and power marketers. Specifically, President Bush extended the bonus depreciation rules and provided relief for use of research and alternative minimum tax credits as part of economic stimulus packages. In addition, the IRS has proposed regulations that will change certain aspects of the tangible

property rules. This section addresses the potential impact of these significant tax matters regarding property, plant, and equipment and related expenses.

7.3.1 Bonus Depreciation

On February 13, 2008, President Bush signed H.R. 5140, the "Economic Stimulus Act of 2008" (ESA) into law. In addition to provisions aimed at individual taxpayers, the ESA reinstates bonus depreciation for a limited time. General considerations of the 2008 bonus depreciation are as follows:

- Application is mandatory unless a taxpayer elects out.
- Bonus depreciation applies for alternative minimum tax (AMT) purposes.
- There is no income limitation or investment limitation on bonus depreciation allowance.
- Adjusted basis of qualified property acquired in a like-kind exchange or an involuntary conversion is eligible for bonus depreciation.
- Bonus depreciation rules do not apply for purposes of computing earnings and profits.
- There are no short-year adjustments for bonus depreciation.

In addition, the 2008 bonus depreciation is effective from January 1, 2008 through December 31, 2008 (December 31, 2009 for Longer Production Period Property). The 2008 bonus depreciation rules remove property with an estimated production period exceeding two years from the definition of longer period production property.

Tax Planning Opportunity – Bonus Depreciation

The reenactment of bonus depreciation presents many planning opportunities for taxpayers. The limited availability of bonus depreciation, coupled with the favorable and sometimes adverse impact the additional depreciation expense may have on other tax planning considerations, means that taxpayers should refamiliarize themselves with the complex bonus depreciation rules.

7.3.2 Research and AMT Credits

On July 30, 2008, President Bush signed into law H.R. 3221, the "Housing and Economic Recovery Act of 2008." This law included provisions for tax relief for companies in AMT or net operating loss (NOL) positions. Under the new law, companies in AMT or NOL positions may elect to accelerate / monetize a portion of their unused research and AMT tax credits in lieu of the 50 percent bonus depreciation enacted as part of the ESA. This new provision is effective for tax years ending after March 31, 2008.

To accelerate/monetize unused research and AMT, the taxpayer must determine the amount of Eligible Qualified Property. The Eligible Qualified

Property is property that would otherwise qualify for bonus depreciation and that is purchased, placed in service, and originally used by the taxpayer after March 31, 2008 and before January 1, 2009. After determining the Eligible Qualified Property, a taxpayer must calculate the amount of "Excess Depreciation," which is the difference between:

- The sum of the Eligible Qualified Property's bonus depreciation and the modified accelerated cost recovery system (MACRS) depreciation (assuming bonus depreciation is taken), and
- The Eligible Qualified Property's MACRS depreciation (assuming bonus depreciation is not taken)

The Excess Depreciation amount is used in determining the refundable credit amount, or "Bonus Depreciation Amount." The Bonus Depreciation Amount is determined by multiplying the Excess Depreciation by 20 percent. The Bonus Depreciation Amount is limited to \$30 million or 6 percent of the sum of the research credit and AMT credit carryforwards attributable to tax years beginning before January 1, 2006.

Example 7-2

Calculation of Excess Depreciation

Assume that a taxpayer has \$10 million of unused research credits from years beginning before January 1, 2006. The taxpayer has determined that it has Eligible Qualified Property of \$5 million, all of which is 5-year MACRS property. The amount that can be accelerated / monetized would generally be computed as follows:

Bonus depreciation	
Bonus depreciation (\$5,000,000 * 50%)	\$ 2,500,000
MACRS depreciation (\$2,500,000 * 20%)	<u>500,000</u>
Bonus and MACRS depreciation	3,000,000
Less: MACRS depreciation (\$5,000,000 * 20%)	<u>(1,000,000)</u>
Excess depreciation	2,000,000
Bonus depreciation percentage	<u>20%</u>
Bonus depreciation amount	<u>\$ 400,000</u>
Research credit limitation	
Research credits	\$10,000,000
Research credit limit percentage	<u>6%</u>
Research credit limitation	<u>\$ 600,000</u>

In this example, the Bonus Depreciation Amount is less than 6 percent of the research credits from years beginning before January 1, 2006 and therefore the Bonus Depreciation Amount is not limited.

7.3.3 Extension of the Research Credit

On October 3, 2008, President Bush signed into law H.R. 1424, "Emergency Economic Stabilization Act of 2008." This bill includes a provision that

retroactively extends the research tax credit from January 1, 2008 for two years. The legislation also modified the Alternative Simplified Credit by increasing the rate from 12 percent to 14 percent for tax years ending in 2009 and terminates the Alternative Incremental Research Credit for tax years beginning after December 31, 2008. See further discussion of the EESA in Section 5.6.

7.3.4 Tangible Assets – Proposed Tax Changes

In August 2006, the IRS and the Treasury Department issued proposed regulations that would enable taxpayers to determine whether to deduct or capitalize expenditures incurred in selling, acquiring, producing, or improving tangible assets. These regulations were repropounded in March 2008. These proposed regulations present rules with respect to identifying the unit of property for capitalization decisions, provide a routine maintenance safe harbor, provide special rules for materials and supplies, and add the possibility of a new repair allowance.

7.3.4.1 Unit of Property Rules

The proposed regulations generally establish four tests for determining a unit of property for capitalization purposes:

- A building and its structural components are treated as a single unit of property. A leasehold improvement that is IRC Section 1250 property made by a lessee is generally a separate unit of property.
- For property other than a building, in general, a single unit of property includes all components that are functionally interdependent.
- For plant property or functionally interdependent machinery and equipment used in industrial processes or for providing industrial services, all components or group of components performing a discrete or major function represent separate units if property.
- A component that is properly treated as a separate unit of property for any Federal income tax purpose must be treated as a separate unit of property. Thus, a component with a different MACRS class, or different tax recovery method from that of a larger unit of property, may be a separate unit of property.

In the preamble to the proposed regulations, the Treasury Department indicates that the functional interdependence test is designed to follow *Fed Ex v. United States*,⁹ in which a taxpayer was allowed to deduct the scheduled maintenance and repairs done on aircraft engines that supported the fleet of aircraft used by the taxpayer. The Treasury Department indicates that the general functional interdependence test is too broad for equipment in a plant setting, which is why it developed the narrower test for plant property.

Electric generation property is specifically described as an activity falling under the special plant rule. An example in the proposed regulations related to a generation facility indicates that a generation structure, boiler, turbine,

⁹ 412 F.3d 617 (6th Cir. 2005)

generator, and pulverizer would each represent separate units of property.¹⁰ Each turbine blade, however, would not be a separate unit of property.

In accordance with the rules, amounts paid to improve a unit of property must be capitalized if there is a betterment, restoration, or if the property is applied to a new or different use. A betterment results if an amount is paid to ameliorate a material condition or defect that existed prior to acquiring the unit of property, to create a material addition to a unit of property, or to create a material increase in capacity, productivity, efficiency, strength, or quality. A restoration is an amount paid to:

- Replace a component where a loss (other than a casualty loss) was properly deducted
- Replace a component if the basis was taken into account in realizing gain or loss on the component's sale or exchange
- Repair damage for which a taxpayer claimed a casualty loss; return a unit of property to ordinarily efficient operating condition
- Rebuild a unit of property to like-new condition or replace a major component or substantial structural part of the unit of property

The proposed regulations specifically indicate that guidance with respect to network assets, such as electric and gas distribution property, are to be provided later. Taxpayers have been invited by the Treasury Department to participate in the IRS's industry issue resolution program to help define the unit of property for network assets after these regulations are finalized.

7.3.4.2 Routine Maintenance Safe Harbor

The proposed regulations provide a routine maintenance safe harbor under which qualifying activities are deemed not to improve the unit of property. The routine maintenance activities include recurring activities that the taxpayer expects to perform more than once during the property's class life. The activity must keep the property in an ordinarily efficient operating condition. Routine maintenance does not include:

- Replacement of a component deducted as a loss (other than casualty)
- Replacement of a component with basis taken into account realizing gain or loss on sale or exchange of component
- Repaired damage with basis adjustment for IRC Section 165 casualty
- Return property to a former ordinarily efficient operating condition

7.3.4.3 Materials and Supplies

The proposed regulations define materials and supplies as items that are not a unit of property as defined above in the unit of property section, have an expected useful life of less than 12 months, have acquisition or production costs of \$100 or less, or are an item later identified by the IRS as a material or supply. Under the proposed regulations nonincidental materials and supplies

¹⁰ Prop. Reg. §1.263(a)-3(d)(2)(iv) Ex. 3

may be deducted when used or consumed. Incidental materials and supplies may be deducted when purchased (assuming that is a clear reflection on taxable income). Finally, the proposed regulations indicate that rotatable spare parts are consumed when disposed of.

7.3.4.4 New Repair Allowance

Although specific repair allowance rules were provided in the original 2006 proposed regulations, these were removed with the 2008 reproposal. Instead, the Treasury indicated that it plans to propose industry-specific repair allowance guidance. Industries are again encouraged to participate in the Industry Issue Resolution process.

Repairs Opportunities Under Present Law

Many taxpayers do not rigorously analyze fixed asset expenditures for federal income tax purposes, and consequently, have been capitalizing certain expenditures that could appropriately be re-characterized as deductible repairs for federal income tax under IRC Section 162. With respect to the electric utility industry, the following types of expenditures should be analyzed for possible repairs reclassifications:

- Storm damage remediation
- Certain relocations
- Replacement of component parts of a power plant
- Replacement of broken or damaged transmission and distribution poles and/or conduits

The issue of whether taxpayers may amend tax returns in open years to deduct certain repair expenditures previously capitalized or whether taxpayers must request Commissioner consent to do so by filing a Form 3115 has been the source of considerable controversy. In general, the IRS has argued that deducting repair expenditures that were previously capitalized is a change in method of accounting.

Procedures to Change the Method of Accounting for Repair Expenditures

Based on the preamble, the final regulations will provide rules for taxpayers seeking to change a method of accounting to comply with the final regulations. The IRS and Treasury Department stated that they expect the final regulations generally to provide that taxpayers must follow the automatic consent procedures for making a method change. Until the regulations are finalized, the preamble emphasizes that taxpayers may not change a method of accounting in reliance upon the rules contained in the proposed regulations. However, IRS officials have indicated that they will continue to process any nonautomatic Forms 3115 requesting to change the treatment of costs incurred to acquire, repair, or improve tangible personal property under existing law.

Tax Planning Opportunity – Repairs

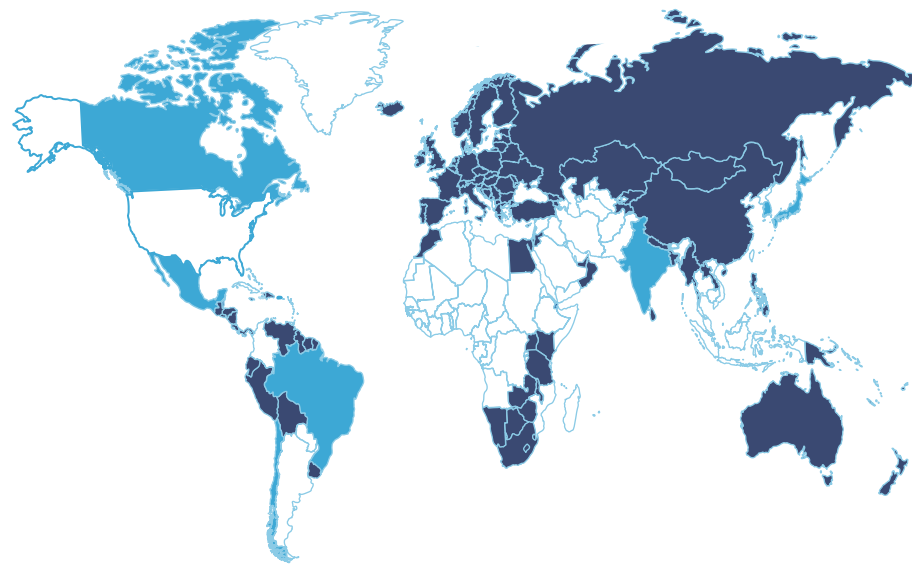
Taxpayers may have a current opportunity to seek an accounting method change with respect to the unit of property for tax capitalization purposes, allowing them to adopt larger units of property for tax than what may be used for financial or regulatory reporting. This will likely result in larger tax repairs being deducted currently with the opportunity to catch up in one year amounts that had been capitalized in prior years under the existing method.

Section 8: International Financial Reporting Standards

Section 8: International Financial Reporting Standards

Globally, nearly 100 countries, including virtually all of Europe, require or permit the use of International Financial Reporting Standards. The United States is the only major global capital market that has not adopted IFRS as its accepted accounting standard for financial reporting. This section addresses the current plan for adoption of IFRS in the United States, considers the "trillion dollar question" for utilities, and provides reporting entities with a template for a thoughtful transition.

Figure 8-1
Global Adoption of IFRS



- Countries that require or permit IFRS
- Countries converging to IFRS with the goal of adoption
- Countries with no current plan to adopt IFRS

All major global capital markets are moving to IFRS.

8.1 Current Status in the United States

As financial and equity markets continue to become more global, many reporting entities are beginning to realize that the U.S. market is not always the most economical market in which to raise funds, and credit is, at times, more accessible outside the United States. In a recent speech, SEC Chairman Christopher Cox commented:

U.S. investors keep buying securities issued by foreign companies that report their financial information using IFRS. Today, two-thirds of U.S. investors own securities of foreign companies. Given the fact that IFRS financial information is reported in home country filings well before it's filed

with the SEC, U.S. investors and market participants have been analyzing and evaluating foreign companies listed in the United States on the basis of only IFRS financial information for more than two years.

These trends are part of the force that is driving the SEC toward the adoption of IFRS. Global accounting standards allow companies in the United States to compete fairly against foreign companies for capital, because their financial information is presented on a consistent basis of accounting. Further, having all major global capital markets reporting under IFRS is expected to reduce costs in the long run by eliminating work required to convert subsidiaries reporting under a different basis of accounting and by eliminating the need to reconcile from one basis of accounting to another. In addition, U.S. companies will have better access to worldwide capital markets that currently seek IFRS-based financial statements.

8.1.1 SEC Roadmap for Adoption

In August 2008, the SEC outlined a potential roadmap for the adoption of IFRS as the primary financial reporting standard in the United States for SEC-registrants. In November 2008, a proposed rule was issued, formalizing the SEC's roadmap. The proposed rule included a timetable for the mandatory adoption of IFRS for U.S. registrants as early as 2014; however, the SEC has indicated that it may phase in the adoption deadline. For example, 2014 could be the deadline for large accelerated filers, 2015 the deadline for accelerated filers and 2016 the deadline for all other reporting entities.

In addition, the SEC indicated that it will evaluate certain milestones before it mandates use of IFRS by all U.S. registrants. These milestones include:

- Progress on the Memorandum of Understanding (MoU) between the IASB and FASB
- Establishment of a stable funding mechanism for the IASB to enhance independence and accountability
- Enhancement of the interface between IFRS and eXtensible Business Reporting Language, which allows investors to compare financial statements of public companies
- Improvements in IFRS education and training in the United States for investors, accountants, auditors, and others involved in preparing and using IFRS financial statements

Another significant date outlined in the SEC's proposed roadmap for U.S. registrants is 2011. The SEC has established 2011 as the year in which it will reconvene to decide whether the milestones have been achieved and whether a mandatory adoption date should be established for all issuers.

8.1.2 Option for Early Adoption

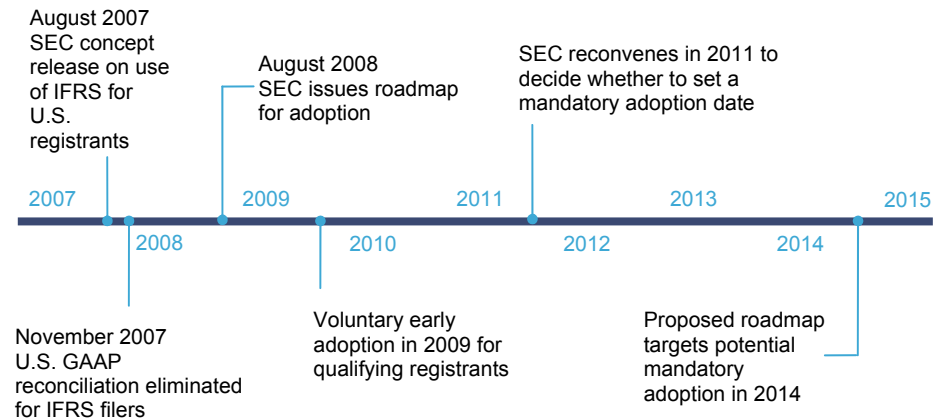
The SEC also proposed a rule that provides certain companies the option to adopt IFRS for financial reporting as early as 2009. The key to eligibility will be the size and industry of the issuer. The issuer would need to meet the following two criteria in order to qualify for early adoption of IFRS:

- The issuer would need to be among the 20 largest companies globally in their industry group (measured by market capitalization)
- IFRS must be used by the majority of the 20 largest companies globally in that industry group (measured by market capitalization)

Reporting entities that meet the criteria and choose to early adopt IFRS must obtain a letter of "no objection" from the SEC's Division of Corporation Finance.

According to its release, the SEC estimates that at least 110 U.S. companies in 34 different industries will qualify for early adoption. However, the number of companies could be as many as 300 companies. The SEC has indicated that it will not release a list of companies that meet the criteria. Instead, it urges companies to complete their own analysis and conclusions. We believe that the largest U.S. companies within the utility sector will be eligible for early adoption.

Figure 8-2
Path to IFRS Adoption



The initial path to mandatory IFRS adoption is based on the SEC roadmap issued in August 2008.

8.2 The Trillion Dollar Question

As IFRS expands as the generally accepted accounting principles around the globe, companies and industries in various countries are evaluating their existing accounting policies and determining what changes may be required to fit within the IFRS framework. For many monopoly utility companies, this evaluation has highlighted a serious issue and concern about the lack of specific guidance within the IFRS rules and framework for accounting for the impacts of rate regulation.

In the United States, regulated companies follow the accounting rules outlined in FAS 71, which establishes criteria that must be met to recognize regulatory

assets and liabilities. By contrast, the IASB has historically avoided issuing industry-specific accounting guidance and does not have a standard equivalent to FAS 71. For regulated utilities in the United States, the lack of specific regulatory accounting under IFRS affects not only financial reporting, but also regulatory reporting and compliance, economic analysis, treasury strategy, and other critical aspects of managing the business. Financial statements prepared in accordance with generally accepted accounting standards in the United States, including FAS 71, are without question the primary source of information used by external parties in analyzing investing, lending, credit rating and ratemaking issues for U.S. regulated utilities.

The U.S. investor-owned utility industry estimates that the combined balances of regulatory assets and liabilities in the United States are \$675 and \$475 billion, respectively.¹¹ Due to the significance of these amounts, we understand that many users of financial statements in North America, including regulatory bodies and staff as well as equity and debt analysts, have indicated that they would likely request disclosure of the effect of future recoveries and refunds if this accounting is not supported under IFRS. This disclosure may be in the footnotes to financial statements of companies applying IFRS or through other means.

8.2.1 The IFRS Framework

IFRS has developed around the concepts detailed in the *Framework for the Preparation and Presentation of Financial Statements* (the Framework), the underlying basis for the IFRS accounting model. IFRS relies more on the Framework in establishing specific standards and guidance rather than on specific, often industry-focused, rules that are prevalent in U.S. GAAP. As a result, IFRS tends to be more principles based, in comparison to U.S. GAAP, which relies more heavily on specific rules and industry practices as a basis for the accounting model. The standard setters for IFRS often frown on industry-specific standards because these standards may be inconsistent with the principles of the Framework and because of the IASB's general philosophy that the Framework should accommodate all accounting issues and judgments.

In contrast, the FASB recognized that cost-based regulation for monopoly service providers creates a unique economic environment in which consumers cannot influence the price they pay for a product, and service providers cannot impact profits through price adjustments. By issuing FAS 71 in 1982, the FASB created a standard that reflected the unique economic effect of the "cost-of-service" regulatory environment in which rate-regulated companies operate. In FAS 71, paragraph 59, the FASB noted that "regulation creates different circumstances that require different accounting," and that allowable costs are the principal influence of price and revenue in a cost-regulated environment.

The standard is largely based on the U.S. ratemaking process, but is also used as authoritative literature in Canada, India, and other countries with similar regulatory regimes, where local generally accepted accounting principles provide no specific accounting guidance for regulated entities.

¹¹ Edison Electric Institute.

The \$1.1 Trillion Question

The question that will need to be answered upon adoption of IFRS in the United States is quite simple. Although there is no specific accounting guidance for rate-regulated companies within IFRS, does the Framework support similar accounting for costs and revenues as exists under FAS 71? For the utility industry, this is the \$1.1 trillion question.

8.2.2 How We Got to This Point

Earlier this year, the International Financial Reporting Interpretations Committee (IFRIC) considered the potential need for further guidance in this area.¹² During its meeting in May 2008, the IFRIC noted that there was diversity among regulated entities reporting under IFRS, whereby some entities were recognizing certain regulatory assets and liabilities and others were not. The IFRIC noted that the differences in interpretation had the potential of becoming more diverse as more jurisdictions adopt IFRS. The issue has been around for a number of years, but has not been fully resolved by standard setters or the industry.

The IFRIC has previously considered the question of regulatory accounting. In 2005, the IFRIC considered adding a project to its agenda because it was asked to clarify whether a regulatory asset meets the requirements for recognition as an asset on the balance sheet. Specifically, the IFRIC was asked to consider whether the concepts of FAS 71 could be applied as an accounting policy decision in the absence of specific guidance in IFRS. However, at that time, the IFRIC concluded that the recognition criteria for regulatory assets and liabilities in FAS 71 were not fully consistent with recognition criteria in IFRS. Instead, the IFRIC concluded that expenses incurred in performing price-regulated activities should be recognized in accordance with applicable IFRS guidance.

The IFRIC decided not to add a project on regulatory assets to its agenda. When explaining its decision not to address FAS 71, the IFRIC stated that entities applying IFRS should recognize only assets that qualified for recognition in accordance with the Framework and relevant accounting standards.

Differences emerged on how companies interpreted the IFRIC's comments. Many companies interpreted the original agenda decision as meaning that it was generally inappropriate to recognize regulated assets. Others looked to the Framework and concluded that some of their pre-existing regulatory assets met the definition of assets and continued to recognize recoverable costs as assets on the balance sheet. The IFRIC acknowledged this diversity in practice in its recent deliberations. However, the IFRIC again decided not to add this

¹² IFRIC is an IASB-sponsored committee established to address emerging issues and provide guidance for existing IFRS principles, similar to the Emerging Issues Task Force in the United States.

item to its agenda. While several factors may be leading to the differences in practice, two key factors are discussed below.

8.2.3 Potential Sources of Diversity in Practice

Sources of diversity may include different regulatory regimes and different interpretations of the Framework:

8.2.3.1 Different Regulatory Regimes

Significant differences exist between regulatory regimes for monopoly service providers around the world, and these different ratemaking approaches may appropriately give rise to different accounting conclusions. In its initial consideration of the recognition of regulatory assets and liabilities, it is possible that the IFRIC did not specifically consider the format of rate making and the associated legal structures supporting the regulatory environments used by the majority of the enterprises that follow FAS 71 and comparable standards. For example, incentive-based regulation is common in Europe. Under incentive based regulation, revenues are based on recovery of a deemed level of efficient operating costs plus a notional cost of capital. Under this type of regulation, the company keeps any profit from reducing operating costs below the assumed level of efficiency or through having a cost of capital lower than that assumed by the regulator. There is no explicit recovery of an enterprise's specific costs of providing the regulated service, the lynchpin concept within FAS 71.

In contrast, the "cost-of-service" rate regulation model that is common in the United States generally allows utility companies to set rates at levels that provide recovery of all prudent operating expenditures plus a return on rate base. Conceptually, the return on rate base is a return on the net assets used in delivering the regulated service, which is based on the weighted cost of equity and debt capital. The operating expenditures used in the calculation of rates may be based on the company's historic or projected expenditures, depending on jurisdiction. Balancing accounts are often provided for expenses that are volatile and cannot be reliably estimated (e.g., fuel) to ensure there is no over- or under-recovery. For those expenses that can be reliably estimated, adjustments are generally permitted only when there is a significant variance, such as in the case of a major storm. The underlying basis for rate setting and for the application of FAS 71 is the cause-and-effect relationship between costs and rates. This relationship is updated to reflect changes to estimated costs and rate base as often as is necessary to ensure fairness among the parties. Although similar on the surface, the cost-recovery relationship is more direct under a rate-regulation model than under the incentive model.

Additionally, regulation of public utilities in the United States is vested in state public utility commissions. A considerable body of case law supports the legal enforceability of historical actions taken by these regulators. State regulatory laws generally prohibit the concept of "retrospective ratemaking," thereby a current commission decision cannot retroactively reverse the actions of a previous commission order. The effect of this prohibition is that once a commission provides for the recovery of a previously incurred cost in future rates, state laws support the legality of that recovery and generally prohibit future commissions from reversing the previous conclusion.

8.2.3.2 Different Interpretations of the Framework

The Framework defines assets as resources an entity controls as a result of past events and from which future economic benefits are expected to flow to the entity (described in the Framework – F.49(a),53-59). The three elements of the definition of an asset under the Framework are:

Figure 8-3

Definition of an Asset Under the Framework

Element	Description
A past event	A past event has taken place, usually a transaction. A cost incurred through a cash outflow or accounting charge would meet this criteria.
Probability of future economic benefit	The probability of future economic benefit beyond the current accounting period exists. If the future economic benefit is uncertain and its outcome depends on a future event not wholly within the company's control, the benefit is considered to be a contingent asset, and the company must be virtually certain of recovery before the asset can be recognized.
Control	Control is usually in the form of legal rights, but substance and economic reality are an important part of the consideration.

The first two criteria are somewhat straightforward. The question of control is more complex and is a key issue for recognizing regulatory assets. The question that arises is whether the company itself actually controls the regulatory assets that have been recognized.

FAS 71, paragraph 9(a), requires that it is "probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes." Although this definition is similar to the requirement under the Framework, the Framework requires a higher level of assurance of recovery (virtually certain) than is required by FAS 71 (probable) when the future economic benefit is not controlled by the entity.

In applying FAS 71, a utility company considers its history of recovery of regulatory assets when considering future capitalization of a regulatory asset. The primary uncertainties of realization include:

- Future actions of the regulator
- The continued use of the service (e.g., electricity, gas, or water) by customers

As discussed above, considerable history of state law supports enforceability of commission actions ordering the prospective recovery of incurred costs. In

addition, in the large majority of cases, there is a strong history of full collection of regulatory assets. For a portion of the assets capitalized, this virtually certain threshold will be supportable for some time horizon or recovery period. However, the change in definition from probable under FAS 71 to virtually certain under IFRS could impact the recognition of a population of regulatory assets that cannot be supported at this higher level of certainty.

8.2.4 Application of IFRS Threshold of Control

The key question is whether the company controls the recovery of regulatory assets. There are several views regarding this question. One view is that the regulator has the power to create, adjust, or eliminate regulatory accounts that have been recognized pursuant to a previous rate case. A regulator's authority, however, is usually subject to administrative and judicial review, which provides the company an appeals process when management believes a decision is unfair. Further, state laws protect regulated entities from the reversal of rate orders that established cost recoveries. In this environment, the regulator retains an element of control over recognized assets, even when those assets are recognized pursuant to authority granted in a rate case. That authority, however, is generally limited to the "prudence" test, and some assets will meet the virtually certain criteria based on facts and circumstances.

In certain circumstances, a company may recognize regulatory assets based on the regulator's past practices for granting recovery of these costs, either when dealing with the company or with other companies in the jurisdiction. The actual recovery of the cost will be confirmed by the regulator in a future rate case. More judgment is required in these situations to determine if regulatory assets are supportable under U.S. GAAP. A reporting entity will need to determine the evidence supporting recovery of assets or liabilities recognized based on management's judgment as to the probability of a future rate action meeting the higher threshold of certainty required by IFRS.

Recovery of most regulatory assets also depends on future delivery of electricity (or other regulated service) to customers by the utility company or an alternative provider. For example, in many cases in the United States, when state deregulation allowed retail customers to switch their utility service to an alternative provider, that alternative provider has been required to collect "transition charges" from the customers, which represent, in part, the continued collection of regulatory assets. Although recovery depends on the future performance of the business and consumption of electricity by customers, these variables are highly predictable in most settings, at least for a period of time.

This discussion has highlighted the issues and illustrates the judgments that companies should make about recognition of regulatory assets within the Framework. We expect that diversity in practice will emerge if there is no clarification of how the principles of the Framework interact with these unique assets.

8.2.5 Next Steps for Regulated Utilities

The IFRIC met in early November 2008 and decided not to add this project to its agenda. During the meeting, members of the Committee expressed widely diverging views on whether regulatory assets and liabilities meet the definitions

of assets and liabilities outlined in the Framework. However, members agreed that companies should evaluate their individual facts and circumstances against the Framework in determining whether regulatory assets and liabilities should be recognized. Although the IFRIC chose not to add this project to its agenda, the IASB may decide to evaluate the accounting for regulatory assets and liabilities in the future.

Industry groups in North America are starting to get involved in an effort to manage the issues associated with the adoption of IFRS and the potential write-off of significant regulatory accounts. The American Gas Association submitted a letter to the IFRIC expressing its concerns and providing some background and information about regulatory schemes in the United States and common types of regulatory assets. The Edison Electric Institute also submitted a letter to the IFRIC addressing how regulatory assets and liabilities fit into the IFRS Framework. Several Canadian organizations and companies are also focused on this issue, as Canadian companies are required to adopt IFRS in 2011.

At this time, it is unclear whether the IASB will consider developing a standard for regulatory accounting or even amend and clarify language within the Framework to assist regulated companies in determining the appropriate accounting treatment. It is likely that regulated companies in the United States will have to analyze regulatory accounts against the current IFRS accounting guidance. It is clear that further evaluation is required.

The mandatory adoption of IFRS in the United States may seem like a distant event; however, the impact of this issue on the financial statements of regulated entities cannot be understated. Utilities should begin to evaluate their regulatory assets within the Framework to identify challenges in meeting this definition. This issue could be the single largest change to financial reporting for regulated companies since the issuance of FAS 71.

8.3 The Impact of IFRS Adoption on Regulatory Recovery

At this time, it is unclear how the FERC or state regulators will react to a change in financial reporting to IFRS. Because the FERC follows its own Uniform System of Accounts, it is not required to adjust reporting requirements to IFRS when adopted in the United States. In addition, it is likely that the regulators will want to continue to track regulatory assets and liabilities. As such, a conversion to IFRS by U.S. utilities may have a number of implications on regulatory recovery. Key considerations after adoption include the following issues:

Certain Costs Included in Rate Base Will Change

Certain costs that are currently included in rate base may be valued differently or may be recognized in a different period under IFRS. For example, the expense recognized for certain pension and other postretirement costs will differ under IFRS compared to U.S. GAAP, and certain costs may never be recognized in the income statement. Reporting entities should identify these differences and discuss them with their regulators to avoid potential loss of or unexpected delays in recovery of these costs.

Regulators may Require Dual Reporting

Currently, most regulated utilities recognize differences in reporting for regulatory purposes compared to the U.S. GAAP financial statements. The adoption of IFRS is expected to significantly increase the number of differences between regulatory reporting and external financial reporting. For example, if regulators continue to allow the equity component of AFUDC to be recognized as a cost of an asset, this represents a difference that must be tracked for constructed assets. Reporting entities may require significant system enhancements to track these differences.

Regulators may Continue to Require Regulatory Assets and Liabilities

Even if regulatory assets and liabilities cannot be recognized for financial reporting, regulators may continue to require this information in some form because it is integral to monitoring the performance of the utility and the future needs for rate adjustments. Again, this introduces a challenge for regulated companies, as they will need to maintain two sets of records to meet all reporting obligations. One set of books will continue to recognize regulatory assets and liabilities and the amortization/recovery of these accounts, and the other set of books will reflect these costs in accordance with IFRS guidance.

Recoverability of Adoption Costs

The cost of adopting IFRS may be significant to some utilities, especially if conversion requires significant system and or process enhancements. Utility companies should discuss these costs with their regulators and should consider whether, how, and when they should be included as part of future rate cases.

8.4 IFRS Implementation

The convergence to a new basis of accounting is not unlike adoption of a new significant and pervasive accounting standard, a significant system implementation, or preparation for implementation of Sarbanes-Oxley Section 404. The adoption of IFRS provides a unique opportunity to establish new accounting policies and procedures; however, it will also present significant challenges that will require time and resources. The SEC's proposed timeline for adoption of IFRS purposefully allows for sufficient time for a measured and successful implementation in the United States. Senior management at European companies who have made the conversion to IFRS have said that if given the chance to do it over, they would start earlier due to the level of effort and time required.

By beginning to plan for conversion now, reporting entities give themselves adequate time for a successful implementation, allowing them to react to the "unknown." The adoption of IFRS is not an accounting exercise, but will require involvement from the right level of resources across the organization because adoption may have a pervasive impact for all stakeholders involved in preparing and using financial data. In addition to the expected changes to systems, processes, and charts of accounts, other areas impacted may include:

- Rates and regulatory processes – Internal regulatory groups will need to understand the changes and should be prepared to explain the differences and educate regulators. Reporting entities may need to prepare to maintain separate rate-based and financial reporting accounting records that may have more differences than under U.S. GAAP.
- Financial statement analysis – Management, analysts, and regulators need to understand how information is being reported and how results compare to historical U.S. GAAP results. The reporting entity may need to adjust the amounts and how earnings guidance is communicated.
- Internal forecasting and budgets – The budgeting and forecasting process may need to change to reflect the new financial reporting structure.
- Compensation plans – Compensation plans with metrics based on U.S. GAAP results may need to be adjusted to reflect differences under IFRS.
- Other contractual arrangements – Management may also need to evaluate debt agreements and covenants, long-term arrangements with suppliers, and other contracts to determine if amendments are required.

With the understanding of the breadth of impact that adopting IFRS will have on the organization, the thought of an IFRS conversion can be daunting, but having a solid project plan in place can ensure success. The following discussion highlights some key considerations in developing and implementing a transition plan based on our experience working with companies that have already adopted IFRS.

8.4.1 Benefits of an Early Implementation Process

Many companies are wary of starting to assess and implement an IFRS conversion before it is mandated. However, from our experience, the best way to manage quality, benefits, and costs of an IFRS conversion is a proactive approach that effectively uses the remaining time before adoption. A measured approach to adoption allows management to implement a strategic instead of tactical approach as discussed in Figure 8-4.

Figure 8-4
Benefits of Strategic Adoption of IFRS

Tactical	Strategic
<ul style="list-style-type: none"> • External reporting prepared by an operationally independent project team, staffed by contractors and consultants • Conversion activities performed outside the normal reporting systems using nonstandard data • Limited knowledge transfer to recurring staff 	<ul style="list-style-type: none"> • Reporting easily replicated each period by knowledgeable employees in a reliable, efficient, and robust manner • Does not depend on resources, processes, and systems that are limited short- to medium-term reliability • Key resources can focus on analyzing results, as compared to preparing information

Other advantages of starting the implementation process early include:

- Successful outcome – The adoption of IFRS provides a unique opportunity to start with "a blank sheet" in establishing accounting policies and procedures. Companies that implement with a measured approach can analyze alternatives to ensure that the new financial reporting information reflects the optimal policy elections available.
- Training and education – A thoughtful timeline allows companies to maximize the use of their internal resources. In addition to saving the cost of external consultants, this approach ensures that employees are appropriately educated and prepared when IFRS is adopted. In addition, the company has time to become knowledgeable about the standard-setting process and IFRS as it continues to evolve during the implementation period.
- Communication – Because an IFRS conversion touches all aspects of the business and requires a significant change in how financial results are reported, internal and external communication must be thoughtful, thorough, and targeted to the right people. A careful implementation plan will provide management with the opportunity to develop a more controlled process for communication with regulators, tax authorities, and other stakeholders about the impact and acceptance of IFRS, thereby allowing for a better chance of successful collaboration.

A longer timeline to adoption also provides management with the ability to capitalize on opportunities to improve other processes (e.g., a faster close process, streamlining of reporting such as for multi-GAAP reporting).

8.4.2 Key Elements of a Phased Approach to Implementation

We recommend a phased approach to IFRS conversion to allow companies to scope, study, investigate, and ensure a carefully considered and well-controlled conversion. Although there are many different acceptable ways to approach an IFRS conversion, our vision of an effective implementation is depicted in Figure 8-5 and further described below.

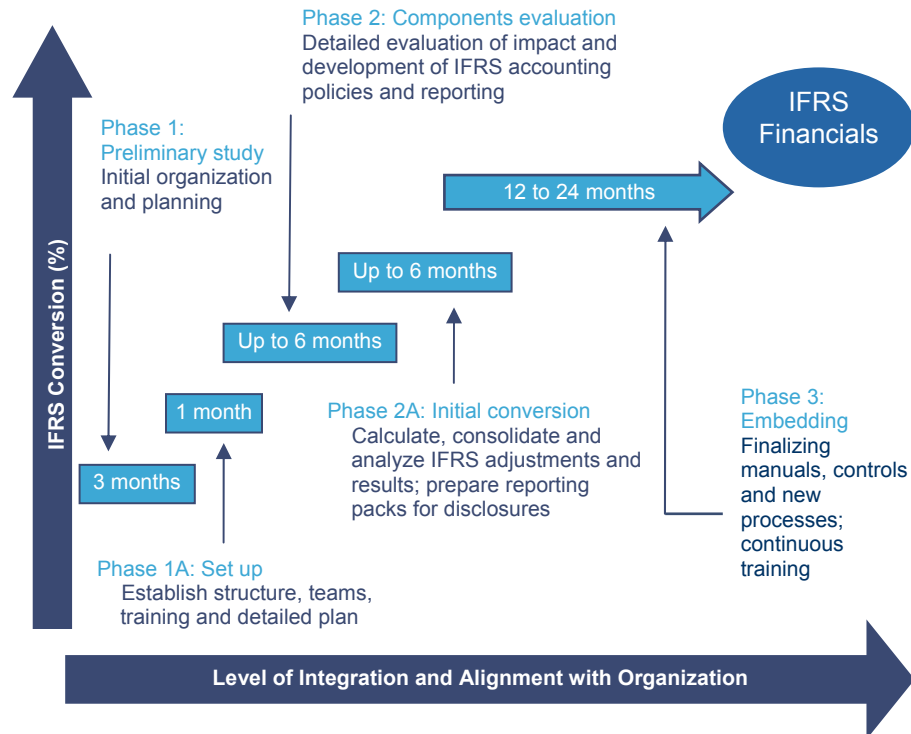
8.4.2.1 Phase 1 – Preliminary Study of the Impact of Adoption

Prior to commencing the project, companies should establish a project oversight committee comprising key members of management who can establish a clear vision and milestones for the project and then monitor progress against that vision. This committee should include senior members of management to set the appropriate tone and governance structure for the project and to ensure that decision-making power exists within the committee. Project management and oversight should bring a sense of focus and uniformity to the project, while acting as a driver to push the project forward.

In addition, the IFRS project steering committee should include cross-functional representation to ensure that final decision making encompasses viewpoints from across the business. The project management team should be responsible for status reporting, project planning and monitoring, and overall coordination of all project activities and workstreams. Overlaying a well-positioned governance framework also ensures that all relevant stakeholders

coordinate effectively and that the appropriate issues are identified at the right time.

Figure 8-5
Stages of IFRS Conversion



Resources

In the beginning stages of the move from U.S. GAAP to IFRS, it is important to involve every functional group that touches financial-related data within the company. Involving more people and departments is preferable to starting the process within the accounting department alone. It will be easier to reduce the number of groups involved during the conversion process than it will be to integrate a new functional group after the process is underway.

The IFRS conversion process also provides an opportunity to train resources and to effectively "learn by doing." Companies that hire external advisors to assist with an IFRS conversion need to work collaboratively with their advisors, rather than outsource the job. The objective of a successful conversion project is a sustainable IFRS reporting framework, housed internally and controlled by internal staff with the appropriate expertise.

Key Phase 1 Objectives

One of the first steps in implementation is identification of overall implementation issues, including obtaining a high level understanding of potential accounting differences between U.S. GAAP and IFRS. As

emphasized in Figure 8-6, numerous areas impact utilities and power marketers where IFRS diverges from current U.S. GAAP. In addition, first time adopters of IFRS need to assess the transition of the opening balance sheet in accordance with the requirements of IFRS 1, *First-Time Adoption of International Financial Reporting Standards*. This guidance is designed to assist first time adopters with the potentially onerous retrospective application of IFRS.

Figure 8-6

Key Differences Between U.S. GAAP and IFRS

Regulatory assets and liabilities

Under IFRS there is no industry standard for rate regulated enterprises. Regulatory assets and liabilities must meet the criteria for recognition under general IFRS standards (see discussion in Section 8.2).

Impact – This results in potentially significant volatility in earnings for most utilities and the need for robust disclosure. In addition, utilities need to educate their regulators and may need to consider the impact of these accounting changes on regulatory recovery.

Property, plant and equipment

There are several differences in utility plant accounting, including the requirement to componentize assets (which may be at a different level than what is required in the FERC USoA); differences in what may be capitalized; impairment assessments and the ability to reverse them, and the requirement to update asset retirement obligation balances each reporting period.

Impact – These differences may require significant system and process changes and may result in the need to separately track and analyze information for financial reporting as compared to regulatory reporting.

Derivatives and hedging

The definition of a derivative is significantly different and the "own use" exception (similar to the "normal purchases and normal sales" exception in U.S. GAAP) is required to be applied if the criteria are met.

Impact – Training and changes in processes are required to appropriately implement changes in the way commodity contracts are assessed. In addition, any contracts outstanding at the time of adoption must be reanalyzed under the new guidance.

Consolidation

Under IFRS, consolidation is focused on the substance of control. IFRS provides indicators to assist companies in assessing control and consolidation is required when an entity has the ability to govern the financial and operating policies of another entity to obtain benefits. If control not is present, a qualitative analysis of risks and benefits is performed.

Impact – The differences require a new way of looking at contracts and may result in the de-consolidation or new consolidation of existing variable interest entities.

Lease accounting

The classification of leases is based on the substance of the transfer of risks and rewards; there are no bright line thresholds for capitalization of a lease.

Impact – Reporting entities will need to change the way they assess leasing arrangements and consider the impacts on transaction structuring.

Loss contingencies

There is a significant difference in how loss contingencies are determined, valued and recorded.

Impact – These differences require a different methodology to monitor and analyze contingencies.

Employee benefits

Differences exist in the periodic recognition of pension, other postretirement benefit and stock compensation expense.

Impact – Consideration needs to be given to accounting policy selection and any potential impact on regulatory recovery (e.g., recognition of actuarial gains and losses for pension expense outside of the income statement may result in a disallowance for rate purposes).

Uncertain tax positions

This area is one of significant divergence as the approach in FIN 48 is not permitted under IFRS.

Impact – This may result in significant differences in tax recognition, and a move back to how tax positions were assessed prior to the adoption of FIN 48.

The project team should also assess the potential impact of IFRS on financial reporting, contractual arrangements, income taxes, and supporting business processes, systems and controls, including potential system constraints. This phase of the project does not necessarily have to quantify or resolve issues, but should create the population of issues or workstreams required to adopt IFRS.

Reporting entities interested in further information on these key differences are encouraged to refer to the following PwC publications: *Financial reporting in the utilities industry – International Financial Reporting Standards* (April 2008) and *IFRS and U.S. GAAP similarities and differences* (September 2008).

8.4.2.2 Phase 2 – Project Plan and Initial Conversion

The project team should commence the second phase by creating workstreams based on the results identified during the planning process. This phase includes much of the legwork of a conversion effort, including the set-up and launch of the project, the evaluation of IFRS and U.S. GAAP differences for specific financial statement line items, the evaluation of accounting policy alternatives, the selection of accounting policies, the initial conversion, and the creation of IFRS financial statements during the dual-reporting period.

Project teams should be assigned to each workstream and key deadlines and milestones should be established. During this phase of the conversion, resources are required from all parts of the business, including legal,

compliance, regulatory, tax, and information technology, among others. These project teams can resolve the issues identified during the first phase of the project, recommend new policies to comply with IFRS, and make decisions about adoption elections and how systems may need to be altered or upgraded to support IFRS reporting. By the end of this phase of the conversion, management should be able to manually produce a set of financial statements in accordance with IFRS.

Evaluate System Changes

In addition, during the second phase, management should evaluate whether any system changes are required. Potential changes vary in terms of breadth and significance, as well as the time, cost, level of testing, and global coordination required. In completing this evaluation, the project team should consider whether the underlying general ledger system allows “multi-GAAP” reporting: the need to have both U.S. GAAP and IFRS reporting capability.

The utility industry has an added nuance of another basis of reporting — that of FERC or other regulatory reporting. While the landscape of FERC reporting and regulatory reporting may shift as a result of IFRS, utility industry companies should still consider this potential impact as part of the planning and implementation process. Companies should also assess critical feeder systems to determine if they can support multi-GAAP requirements. As part of this process, companies should assess current or planned information technology initiatives to determine whether project changes should be made to incorporate IFRS considerations.

8.4.2.3 Phase 3 – Embed IFRS into the Organization

The final phase of adoption consists of embedding IFRS into the organization. This phase helps to ensure a smooth transition to the new reporting framework so the company can apply its new IFRS policies on a sustainable basis in a well-controlled environment. This process includes implementing policies and processes that support IFRS. New systems or upgrades required for IFRS go live during this phase of implementation. Adjustments are required to certain internal controls to ensure the completeness and accuracy of IFRS reporting. Although IFRS conversion is a one-time event, its effects are long lasting and may be difficult to change in the future. It is important to design and embed new processes rather than bolt on additional work to existing U.S. GAAP processes.

Ensuring a Thoughtful Transition

There are a number of key accounting, business, and implementation considerations regarding the adoption of IFRS for utilities and power marketing entities. Addressing many of these issues will be a challenge and will require significant thought, resources, and time. A well-planned approach that capitalizes on the opportunity to take the time needed to implement IFRS will help ensure a successful transition.

Appendix: Technical References and Abbreviations

Appendix: Technical References and Abbreviations

The following tables should be used as a reference for abbreviations used throughout this technical update:

Technical References

CON 6	FASB Statement of Financial Accounting Concepts No. 6, <i>Elements of Financial Statements</i>
CON 7	FASB Statement of Financial Accounting Concepts No. 7, <i>Using Cash Flow Information and Present Value in Accounting Measurements</i>
FAS 5	Statement of Financial Accounting Standards No. 5, <i>Accounting for Contingencies</i>
FAS 13	Statement of Financial Accounting Standards No. 13, <i>Accounting for Leases</i>
FAS 71	Statement of Financial Accounting Standards No. 71, <i>Accounting for the Effects of Certain Types of Regulation</i>
FAS 90	Statement of Financial Accounting Standards No. 90, <i>Regulated Enterprises – Accounting for Abandonments and Disallowances of Plants Costs</i>
FAS 92	Statement of Financial Accounting Standards No. 92, <i>Regulated Enterprises – Accounting for Phase-In Plans</i>
FAS 95	Statement of Financial Accounting Standards No. 95, <i>Statement of Cash Flows</i>
FAS 107	Statement of Financial Accounting Standards No. 107, <i>Disclosures about Fair Value of Financial Instruments</i>
FAS 115	Statement of Financial Accounting Standards No. 115, <i>Accounting for Certain Investments in Debt and Equity Securities</i>
FAS 131	Statement of Financial Accounting Standards No. 131, <i>Disclosures about Segments of an Enterprise and Related Information</i>
FAS 132(R)	Statement of Financial Accounting Standards No. 132 (revised 2003), <i>Employers' Disclosures about Pensions and Other Postretirement Benefits – an amendment of FASB Statements No. 87, 88 and 106</i>
FAS 133	Statement of Financial Accounting Standards No. 133, <i>Accounting for Derivative Instruments and Hedging Activities</i>
FAS 140	Statement of Financial Accounting Standards No. 140, <i>Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities – a replacement of FASB Statement No. 125</i>

Technical References

FAS 141	Statement of Financial Accounting Standards No. 141, <i>Business Combinations</i>
FAS 141(R)	Statement of Financial Accounting Standards No. 141 (revised 2007), <i>Business Combinations</i>
FAS 142	Statement of Financial Accounting Standards No. 142, <i>Goodwill and Other Intangible Assets</i>
FAS 143	Statement of Financial Accounting Standards No. 143, <i>Accounting for Asset Retirement Obligations</i>
FAS 144	Statement of Financial Accounting Standards No. 144, <i>Accounting for the Impairment or Disposal of Long-Lived Assets</i>
FAS 146	Statement of Financial Accounting Standards No. 146, <i>Accounting for Costs Associated with Exit or Disposal Activities</i>
FAS 153	Statement of Financial Accounting Standards No. 153, <i>Exchanges of Nonmonetary Assets – an amendment of APB Opinion No. 29</i>
FAS 157	Statement of Financial Accounting Standards No. 157, <i>Fair Value Measurements</i>
FAS 160	FASB Statement No. 160, <i>Noncontrolling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51</i>
FAS 161	FASB Statement No. 161, <i>Disclosures about Derivatives Instruments and Hedging Activities – an Amendment of FASB Statement No. 133</i>
FIN 45	FASB Interpretation No. 45, <i>Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others</i>
FIN 46(R)	FASB Interpretation No. 46 (revised 2003), <i>Consolidation of Variable Interest Entities, an interpretation of ARB No. 51</i>
FIN 48	FASB Interpretation No. 48, <i>Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109</i>
DIG Issue A18	DIG Issue A18, <i>Definition of a Derivative: Application of a Market Mechanism and Readily Convertible to Cash Subsequent to the Inception or Acquisition of a Contract</i>
DIG Issue A19	DIG Issue A19, <i>Definition of a Derivative: Impact of a Multiple Delivery Long-Term Supply Contract on Assessment of Whether an Asset Is Readily Convertible to Cash</i>

Technical References

DIG Issue A21	DIG Issue A21, <i>Definition of a Derivative: Existence of an Established Market Mechanism That Facilitates Net Settlement under Paragraph 9(b)</i>
DIG Issue C11	DIG Issue C11, <i>Scope Exceptions: Interpretation of 'Clearly and Closely Related' in Contracts That Qualify for the Normal Purchases and Normal Sales Exception</i>
DIG Issue C12	DIG Issue C12, <i>Scope Exceptions: Interpreting the Normal Purchases and Normal Sales Exception as an Election</i>
DIG Issue C20	DIG Issue C20, <i>Scope Exceptions: Interpretation of the Meaning of Not Clearly and Closely Related in Paragraph 10(b) regarding Contracts with a Price Adjustment Feature</i>
DIG Issue G10	DIG Issue G10, <i>Cash Flow Hedges: Need to Consider the Possibility of Default by the Counterparty to the Hedging Derivative</i>
FSP FAS 13-1	FASB Staff Position FAS 13-1, <i>Accounting for Rental Costs Incurred during a Construction Period</i>
FSP FAS 115-1 and FAS 124-1	FASB Staff Position FAS 115-1 and FAS 124-1, <i>The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments</i>
FSP FAS 133-1 and FIN 45-4	FASB Staff Position FAS 133-1 and FIN 45-4, <i>Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161</i>
FSP FAS 157-2	FASB Staff Position FAS 157-2, <i>Effective Date of FASB Statement No. 157</i>
FSP FAS 157-3	FASB Staff Position FAS 157-3, <i>Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active</i>
FSP FIN 39-1	FASB Staff Position FIN 39-1, <i>Amendment of FASB Interpretation No. 39</i>
FSP FAS 132(R)-a	Proposed FASB Staff Position 132(R)-a, <i>Employers' Disclosures about Postretirement Benefit Plan Assets</i>
FSP FAS 140-e and FIN 46R-e	Proposed FASB Staff Position FAS 140-e and FIN 46(R)-e, <i>Disclosures about Transfers of Financial Assets and Interests in Variable Interest Entities</i>
FSP FAS 144-d	Proposed FASB Staff Position FAS 144-d, <i>Amending the Criteria for Reporting a Discontinued Operation</i>
FSP ARB 43-a	Proposed FASB Staff Position ARB 43-a, <i>Amendment of the Inventory Provisions of Chapter 4 of ARB No. 43</i>
FSP AUG AIR-1	FASB Staff Position AUG AIR-1, <i>Accounting for Planned Major Maintenance Activities</i>

Technical References

ARB 43	ARB No. 43, <i>Restatement and Revision of Accounting Research Bulletins</i>
APB 18	APB Opinion No. 18, <i>The Equity Method Accounting for Investments in Common Stock</i>
APB 29	APB Opinion No. 29, <i>Accounting for Nonmonetary Transactions</i>
Airline Guide	AICPA Industry Audit Guide, <i>Airlines</i>
Broker Dealer Guide	AICPA Audit and Accounting Guide, <i>Brokers and Dealers in Securities</i>
Investment Company Guide	AICPA Audit and Accounting Guide, <i>Investment Companies</i>
SOP 98-1	AICPA Statement of Position 98-1, <i>Accounting for the Costs of Computer Software Developed or Obtained for Internal Use</i>
SOP 98-5	AICPA Statement of Position 98-5, <i>Reporting on the Costs of Start-Up Activity</i>
EITF 91-6	EITF Issue No. 91-6, <i>Revenue Recognition of Long-Term Power Sales Contracts</i>
EITF 96-17	EITF Issue No. 96-17, <i>Revenue Recognition under Long-Term Power Sales Contracts that Contain Both Fixed and Variable Pricing Terms</i>
EITF 01-8	EITF Issue No. 01-8, <i>Determining Whether an Arrangement Contains a Lease</i>
EITF 02-3	EITF Issue No. 02-3, <i>Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities</i>
EITF 03-13	EITF Issue No. 03-13, <i>Applying the Conditions in Paragraph 42 of FASB Statement No. 144 in Determining Whether to Report Discontinued Operations</i>
EITF 06-12	EITF Issue No. 06-12, <i>Accounting for Physical Commodity Inventories for Entities within the Scope of the AICPA Audit and Accounting Guide, Brokers and Dealers in Securities</i>
EITF 08-3	EITF Issue No. 08-3, <i>Accounting by Lessees for Maintenance Deposits</i>
EITF 08-5	EITF Issue No. 08-5, <i>Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement</i>
EITF 08-6	EITF Issue No. 08-6, <i>Equity Method Accounting Investment Considerations</i>

Technical References

SAB Topic 5-H	SAB Topic 5-H, <i>Accounting for sales of stock to a subsidiary</i>
SAB 74	Staff Accounting Bulletin No. 74, <i>Disclosure of the Impact that Recently Issued Accounting Standards will have on the Financial Statements of the Registrant When Adopted in a Future Period</i>
SEC/FASB Joint Release	SEC Office of the Chief Accountant and FASB Staff Clarifications on Fair Value Accounting (September 2008)
PCAOB Alert 2	PCAOB Audit Practice Alert No. 2, <i>Matters Related to Auditing Fair Value Measurements of Financial Instruments and the Use of Specialists</i>
IFRS 1	<i>First-Time Adoption of International Financial Reporting Standards</i>
Framework	<i>IFRS Framework for the Preparation and Presentation of Financial Statements</i>

Other Abbreviations

AICPA	American Institute of Certified Public Accountants
ARB	Accounting Research Bulletin
APB	Accounting Principles Board
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
DIG	Derivatives Implementation Group
EITF	Emerging Issues Task Force
EESA	Emergency Economic Stabilization Act
EPA	Environmental Protection Agency
EPAAct 2005	Energy Policy Act of 2005
ERCOT	Electric Reliability Council of Texas
ESA	Economic Stimulus Act of 2008
FASB or Board	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FSP	FASB Staff Position
IASB	International Accounting Standards Board
IFRIC	International Financial Reporting Interpretations Committee

Other Abbreviations

IFRS	International Financial Reporting Standards
IRC	Internal Revenue Code
IRS	Internal Revenue Service
LIBOR	London Interbank Offer Rate
MISO	Midwest Independent System Operator
MoU	Memorandum of Understanding (MoU) between the International Accounting Standards Board and Financial Accounting Standards Board
MRTU	Market Redesign and Technology Upgrade
NERC	North American Electric Reliability Council
NYMEX	New York Mercantile Exchange
PCAOB	Public Company Accounting Oversight Board
PJM	PJM Interconnection
PwC	PricewaterhouseCoopers LLP
RGGI	Regional Greenhouse Gas Initiative
SAB	Staff Accounting Bulletin
SEC	Securities and Exchange Commission
SOP	Statement of Position
Treasury Department	U.S. Department of the Treasury
U.S.	United States
USoA	Uniform System of Accounts of the Federal Energy Regulatory Commission
VRG	Valuation Resource Group

Other Terms

AFUDC	Allowance for funds used during construction
AMT	Alternative minimum tax
AOCI	Accumulated other comprehensive income
ARO	Asset retirement obligation
CDS	Credit default swap
CO ₂	Carbon dioxide
CPI	Consumer price index
CRR	Congestion revenue rights

Other Terms

FTR	Financial transmission right
ISO	Independent system operator
ITC	Investment tax credit
kWh	Kilowatt hour
LMP	Locational marginal pricing
LOCOM	Lower of cost or market
LTSA	Long-term service agreement
MACRS	Modified accelerated cost recovery system
MMBtu	Million British thermal units
MW	Megawatt
MWh	Megawatt hour
NRV	Net realizable value
NOx	Nitrogen oxide
NOL	Net operating loss
OPEB	Postretirement benefits other than pensions
OTTI	Other-than-temporary-impairment
QSPE	Qualifying special purpose entity
REC	Renewable energy credit
RPS	Renewable portfolio standard
RTO	Regional transmission organization
SO ₂	Sulfur dioxide
U.S. GAAP	Accounting principles generally accepted in the United States
VIE	Variable interest entity

About PwC Utilities

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